# Energy Bill – Impact Assessments (IA)

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| **Title:** Energy Bill IA – $CO_2$ Transport and Storage Networks<br>**IA No:** BEIS036(F)-22-ESNM<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy and Industrial Strategy (BEIS) | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary Legislation<br>**Contact for enquiries:** ccustandsconsultations@beis.gov.uk |
| **Summary: Intervention and Options** | **RPC Opinion: Green** |

| Cost of Preferred (or more likely) Option (in 2020 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** Qualifying provision |
| N/Q[1] | N/Q[2] | £1m | |

**What is the problem under consideration? Why is government action or intervention necessary?**

Carbon Capture, Utilisation and Storage (CCUS) is integral to the efficient and cost-effective decarbonisation of our economy, and the successful deployment of CCUS technologies require the operation of carbon dioxide ($CO_2$) transport and storage (T&S) networks. Developing transport and storage infrastructure for $CO_2$ will require large upfront capital expenditure, and it is expected that without government intervention, a transport and storage network for $CO_2$ would not be provided by the private sector due to uncertainty around the scale and timing of demand for the use of such a T&S network and therefore the future revenues of a network operator. In addition to the uncertainty around future revenues, there are certain remote high impact low probability risks associated with the transport and storage of carbon dioxide, in relation to asset stranding and CO2 leakage from a store, that the private sector would not be able to bear at an efficient price. These particular risks are likely to be outside the control of T&SCo and without government intervention affect the capacity for investment in CO2 transport and storage networks. The second element that drives a need for government intervention is that the provision of a T&S network is likely to take the form of natural regional monopolies that will need regulation to ensure that the fees charged by the T&SCos are reflective of a reasonable return on their operational costs and investment.

**What are the policy objectives of the action or intervention and the intended effects?**

The UK is committed to the legally binding target of Net Zero greenhouse gas emissions by 2050. In 2021, the Government enshrined in law a new target to reduce greenhouse gas emissions by 78% by 2035, compared with 1990 levels, as part of the Sixth Carbon Budget. An essential part of the Government's approach to meeting the Sixth Carbon Budget is the successful large scale deployment of CCUS[3], central to the deployment of which is putting in place infrastructure to transport and permanently store the $CO_2$. The aim of this legislation is to remove barriers to entry for T&S network providers, as well as to introduce a regulatory framework for these networks, given their monopolistic characteristics, to ensure fees charged by T&S network operators reflect efficient costs while ensuring a reasonable return on investments.

[1] Benefits of the primary legislation aren't expected to be realised until the successful deployment of T&S networks following subsequent secondary legislation and business model negotiations, so benefits can't be quantified at this juncture.

[2] Benefits of the primary legislation aren't expected to be realised until the successful deployment of T&S networks following subsequent secondary legislation and business model negotiations, so benefits can't be quantified at this juncture.

[3] The 2021 Net Zero Strategy outlined that the UK was expected to need to reach capacity for a total of ~20-30 MtCO2 per year by the early 2030s and at least ~50 MtCO2 by the mid-2030s.

| **What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)** |
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| A full-chain, fixed price business model was favoured in the past for CCUS programmes in the UK. This model has been assessed in detail by organisations including the National Audit Office who concluded that it was not capable of absorbing the different risk appetites of different organisations involved in the full chain, resulting in cost increases￼ In light of these assessments, Government undertook a review of delivery and investment frameworks for CCUS and consulted in 2019￼ on alternative business models for supporting the deployment of CCUS. This included the consideration of a number of potential models for $CO_2$ Transport and Storage (T&S) networks. A Government Response was published in 2020 which analysed the evidence presented as part of the review and the conclusion that given $CO_2$ T&S networks are likely to be operated as regional monopolies, which encompass a range of different network users and emitters operating under different commercial models, Government was minded to progress the development of a new regulated network model under which future T&S networks can be developed and operated which will prevent the abuse of these monopolistic characteristics and certainty provided to both investors and the network users in terms of revenue flows, risk allocation and service provision.<br><br>This model has been developed further and updates published in December 2020, May 2021 and January 2022 to outline its key components. Under the proposed T&S Regulatory and Investment ("TRI") Model for $CO_2$ transport and storage, a transport and storage company (T&SCo) receives a licence from an economic regulator which grants it the right to charge a regulated price to users in exchange for delivering and operating the T&S network. In order to prevent monopolistic disadvantages, the charges for users of the T&S network would be set by an independent economic regulator who considers allowable expenses over a set period of time, to ensure costs are necessary and reasonable. This should facilitate the delivery of new T&S networks at a cost of capital which is as efficient as possible and thereby reduce the total cost to the users of the network. To establish a regulated asset model for $CO_2$ transport and storage requires new legislation to provide a statutory mandate for an economic regulator and to establish the economic licensing framework. |

**Will the policy be reviewed?** It **will not** be reviewed. **If applicable, set review date: N/A**

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro**<br>**Yes** | **Small**<br>Yes | **Medium**<br>Yes | **Large**<br>Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions?<br>(Million tonnes $CO_2$ equivalent) | | **Traded:**<br>**N/A** | **Non-traded:**<br>**N/A** | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ____________ Date: 24/06/2022

# Summary: Analysis & Evidence — Policy Option 5

**Description: T&S TRI legislation with new decommissioning and SAR legislation**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 2022-2030 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low: N/Q** | **High: N/Q** | **Best Estimate: N/Q**[4] |

| **COSTS (£m)** | **Total Transition** (Constant Price) Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|
| **Low** | £14.3m | | **£13.6m** |
| **High** | £15.0m | | **£14.2m** |
| **Best Estimate** | £14.7m | | **£13.8m** |

**Description and scale of key monetised costs by 'main affected groups'**

The costs incurred as a result of the primary legislation are legal and familiarisation costs for the economic regulator (Ofgem) (£5.4m PV) and the T&SCo's (£9m PV) who will provide the network, as they will need to understand the primary legislation, comply with Codes and enter into network agreements. The estimated cost of this primary legislation, by itself, is limited, as it provides an enabling framework to regulate the transport and storage of $CO_2$. Further costs may be incurred at a later date if and when economic licences are granted to transport and storage operators, subject to the terms and conditions of those licences, and secondary legislation which also remains subject to agreement. Secondary legislation which is expected to incur costs will be accompanied by an impact assessment.

**Other key non-monetised costs by 'main affected groups'**

This impact assessment examines the non-monetised costs associated with the agreement and implementation of legislation to enable the deployment of T&S networks under the TRI model. These illustrative costs include costs to government, costs to businesses (outside of the T&SCo) and costs to consumers.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|
| **Low** | N/Q | N/Q | **N/Q** |
| **High** | N/Q | N/Q | **N/Q** |
| **Best Estimate** | N/Q | N/Q | **N/Q** |

**Description and scale of key monetised benefits by 'main affected groups'**

The primary legislation is enabling in nature, and therefore the estimated benefit of this primary legislation by itself is zero. However, there are expected to be benefits associated with the construction and operation of T&S infrastructure and the establishment of a CCUS market, some of which this Impact Assessment illustrates, including the monetisation of GVA and jobs created by the deployment of a transport and storage network.

**Other key non-monetised benefits by 'main affected groups'**

Again, the primary legislation is enabling in nature, and therefore there are no direct non-monetised benefits. However, the non-monetised benefits associated with the primary legislation which enables implementation of an economic regulatory regime for CO2 transport and storage are illustrated in Section 6 and include emissions reductions, reduced costs for energy intensive businesses, the protection of jobs and output and protection against anti-competitive behaviour by network operators.

[4] Benefits of the primary legislation aren't expected to be realised until the successful deployment of T&S networks following subsequent secondary legislation and business model negotiations, so benefits can't be quantified at this juncture.

| Key assumptions/sensitivities/risks | |
|---|---|

The key assumption for this Impact Assessment is that without government intervention, there would be no deployment of a transport and storage network as a result of a number of factors including a lack of access to capital support given the uncertain returns, and challenges associated with the allocation of T&S specific risks such as stranded asset and CO2 storage leak risks, and varying build out rates between a capture plant and T&S infrastructure.

This legislation enables the establishment of a new market where the deployment of infrastructure to transport and store $CO_2$ at this scale is the first of a kind. Given this, there are some risks and uncertainty regarding design which we have mitigated through providing flexibility within the legislative provisions.

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# 1. Problem under consideration and Policy Objectives

## 1.1 Problem under consideration

1. The UK is committed to the legally binding target of Net Zero greenhouse gas emissions by 2050. In 2021, the Government enshrined in law a new target to reduce greenhouse gas emissions by 78% by 2035 when compared against 1990 levels, as part of the Sixth Carbon Budget. A key part of meeting the Sixth Carbon Budget will be to reduce emissions across industry and the UK's power generation network. For many key industries, such as chemicals and cement, there are significant challenges associated with reducing the emissions generated as a by-product from their output, so CCUS technologies are the most feasible solution.

2. The Climate Change Committee has stated that the successful deployment of CCUS is a necessity for meeting the UK's net-zero target. In order to put the UK on course to meet the Sixth Carbon Budget and its 2050 Net Zero ambition, the UK's Net Zero Strategy sets out the ambition to capture and store 20-30Mt of $CO_2$ per year by the 2030s.

3. In order to deliver CCUS within the UK, $CO_2$ transportation and storage (T&S) networks will be required to transport $CO_2$ from carbon capture equipped clusters across the UK's industrial regions, through a pipeline to be permanently stored in sub-surface storage sites (such as depleted oil and gas fields, and saline aquifers).

4. It is expected that for a variety of reasons that are explored later on in this Impact Assessment including high upfront capital costs coupled with uncertain returns, a lack of access to finance, revenue instability and the existence of low probability, high-cost risks that investors are unable to bear at an efficient cost, the private sector won't deploy a transport and storage network without government intervention. The lack of a timely deployment of transport and storage networks would inhibit the deployment of carbon capture technologies, and by extension, require the UK to meet its climate targets through alternative means.

5. A full-chain, fixed price business model was favoured in past CCUS programmes in the UK. This model has been assessed in detail by organisations including the National Audit Office who concluded that it was not capable of absorbing the different risk appetites of different organisations involved in the full chain, resulting in cost increases[5]. Government undertook a review of delivery and investment frameworks for CCUS and consulted in 2019 on alternative business models for supporting the deployment of CCUS. This included the consideration of a number of potential models for $CO_2$ Transport and Storage networks. A Government Response was published in 2020 which analysed the evidence presented as part of the review and the conclusion that given $CO_2$ T&S networks are likely to be operated as regional monopolies, which encompass a range of different network users and emitters operating under different commercial models, Government was minded to progress the development of a new regulated network model under which future T&S networks can be developed and operated and certainty provided to both investors and the network users in terms of revenue flows, risk allocation and service provision.

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[5]National Audit Office – Carbon Capture and Storage: the second competition for government support – Jan 2017: https://www.nao.org.uk/report/carbon-capture-and-storage-the-second-competition-for-government-support/

6. The proposed CO2 Transport and Storage Regulatory Investment Model ('TRI Model') is based on an economic regulation funding model. This approach seeks to balance the need to provide long term confidence to investors with predictable and stable returns within a broadly bounded range. The model design is derived from a range of precedents including utility regulation.

7. As such, the proposed legislative measures seek to implement a framework for economic regulation of CO2 transport and storage, address barriers to investment by facilitating the creation (via funding), and provide for regulatory oversight of, transport and storage networks, supporting the deployment of CCUS clusters in line with commitments in the UK government's Net Zero Strategy.

## 1.2 Policy Objectives

8. Under the proposed legislation, a $CO_2$ transport and storage company (T&SCo) would receive an economic licence from the economic regulator (Ofgem) which grants it the right to an allowed revenue which allows for the recovery of its efficient costs incurred and a reasonable return on its capital investment. The economic licence allows the T&SCo to charge T&S network users for the costs of delivering and operating the T&S network. Users of the T&S network may initially include power plants, industrial facilities, and low carbon hydrogen producers, which generate $CO_2$ which is then captured by the emitter and transferred to T&SCo for the transport and permanent storage of that $CO_2$. Other types of users may join these networks in the future (e.g. direct air capture).

9. The legislation seeks to introduce a prohibition on operating or charging for the use of a T&S network without an economic licence, and the legislation would provide Ofgem with the necessary legal powers to issue, enforce and modify economic licences. To prevent monopolistic disadvantages, the independent economic regulator would have oversight of charges and would determine whether costs are economic and efficient. The terms and conditions which T&S Operators must comply with will be set out within the licence itself, and will include conditions which set out for example, how allowed revenues would be calculated and the price control regime. Decisions made by the economic regulator would be appealable to the CMA or subject to judicial review, depending on the nature of the decision being challenged.

10. The proposed regulatory funding model for T&S derives from a range of precedents including utility regulation, and the proposed approach to the legislation is modelled on the existing statutory regimes for other regulated utilities, albeit substantially simplified. Such a model is considered appropriate for T&S given the exclusive nature of certain T&S infrastructure and assets (pipelines; offshore storage and related assets) where it is not economical or efficient to have multiple service providers, and which mean T&S networks have regional monopoly characteristics.

# 2. Rationale for intervention

## 2.1 Rationale for intervening in CCUS Markets

11. To meet the legally binding target of net zero emissions by 2050, large scale deployment of CCUS technologies is key. However, the private market is unlikely to achieve this at the scale or pace needed due to market failures or barriers, which include the following:
    a. **A low carbon price** in the near term, which leads to a lack of incentives for private sector investment in CCUS capture units which will be needed in the medium and long-term.

    b. **Investment coordination failure within CCUS**. Potential providers of T&S networks face significant uncertainty around their expected revenue as there are no guarantees as to the existence and scale of future network users.

    c. **Early mover risk of adopting a new technology and business models**, where initial developers may face higher costs that subsequent ones.

    d. **There are a number of positive spill-over effects from CCUS deployment,** including lower costs across the power system, security of supply for the power sector and supporting businesses through a green transition.

12. **Carbon Pricing insufficient**: To address the negative externality of carbon emissions, firms that produce $CO_2$ need to internalise the full cost of such emissions production. This internalisation of costs will be achieved through the UK ETS which places a cap on carbon emissions from energy intensive industries, and creates a framework for pricing those carbon emissions.

    However, even when carbon is priced at a socially efficient level (i.e., accounting for and then fully pricing in the negative externality), this alone would not lead to large scale CCUS deployment through private developers without government intervention. The other barriers noted in this section will still prevent the initial commercial deployment of CCUS technologies which will have to be resolved separately.

13. **Investment coordination failure within CCUS**: In order to make the deployment of a T&S network commercially viable, there need to be a number of carbon emitters equipped with carbon capture technologies, whilst in order to make the deployment of carbon capture technologies viable, there needs to be a transport and storage solution for the captured carbon dioxide. This creates a coordination failure as both technologies need to be deployed together, or incentives need to be provided to facilitate the deployment of one technology in order to create demand for the other.

14. **First mover disadvantage**: There is a significant disincentive to be a first mover in the CCUS market. Investors require a return on their investment over the short term e.g. 10-15 years and if there is a lack of certainty over that timeframe, they may not invest. As there is currently no CCUS in the UK it is likely the first developers of CCUS plants will face higher costs compared with subsequent developers. This, coupled with the risks outlined above, creates an incentive for developers to wait until they can observe what their competitors are

doing or benefit from wider industry learning (and thus benefit from possible falls in costs or increases in efficiencies).

There are also positive externalities in the form of spill-over effects for the sector and wider economy that aren't factored into private sector decisions around investment and deployment.

a. Wider power system benefits - Analysis suggests that overall system costs are lower when CCUS is deployed in the power sector, compared to scenarios with there is no power CCUS deployment, given the need to achieve our climate targets. In addition, there are also other security of supply benefits. If traditional flexible carbon intensive electricity generators get priced out of the future market due to a higher carbon price, there could be a risk that the current low carbon technologies are not flexible enough to be able to meet short term or unexpected periods of demand (e.g. wind generation is reliant on the wind blowing, irrespective of the level of demand for power). This would have consequences as any disruptions may lead to a loss of outputs for both consumers and businesses.

b. Supporting Green Business Transitions - UK industry faces international competition in global markets and consumers are not currently always willing to pay a premium for low carbon products. For these reasons, without CCUS, and under the assumption that the UK carbon price will increase in the future, there is a risk that some industry players such as producers of steel and cement may be forced to close or relocate their business outside of the UK potentially resulting in the continuation of high carbon emitting processes elsewhere in the world, known as "carbon leakage". This is already recognised as a risk under the EU ETS such that many industrial emitters are allocated free ETS allowances to help them reduce their exposure whilst securing the carbon reductions that the system is designed to secure. By supporting industry through this transition by incentivising CCUS deployment, carbon leakage as well as the financial and societal costs of large-scale regional unemployment can be avoided.

## 2.2 Rationale for intervening in T&S Markets

15. There are a number of factors that we expect will mean that the private sector won't provide a T&S network in the short term, and possibly indefinitely, without government intervention. These factors include:

a. **High upfront capital costs and uncertain returns –** The pipeline transport network, and the required storage technologies, have significant capital costs associated with their deployment and as returns are highly uncertain (and dependent on government policy), this acts as a significant barrier to entry for prospective T&S providers. The risks associated with the nascent technology and significant capital costs create challenges in obtaining adequate private capital support to facilitate network creation.

b. **Revenue uncertainty –** Without government intervention, revenue from the T&S network is unlikely to be sufficient to justify investment, particularly immediately after construction. This is because network users will join over time (utilisation build-up). Further, initial network users may also face uncertainty over CO2 capture volumes which further impact on revenue uncertainty for the network operator. In addition, while the T&S network is in its infancy and has a small number of users, the impacts of new users not arriving or existing users underutilising or leaving the network has a much greater impact on the T&S network provider's revenues. Finally, given the nascent nature of the CO2 capture technologies combined with uncertainty as to whether CO2 prices being sufficient to support private investment in capture technologies there will remain some uncertainty over potential demand for T&S network capacity.

c. **Low probability, high-cost risks –** There are two main areas of low probability, high-cost risks that greatly reduce the likelihood that the private sector provides a T&S network in the short term. These risk areas are leakage of CO2 from the storage complex and stranded asset risk. Given the nascent nature of the technology, it may not be possible for the T&S network provider to secure insurance from third parties against these risks. This would mean that either the investment will not be made or the T&S network operators would need to earn a risk premium as part of their network costs.

16. The structure of the transport and storage network lends itself to being a natural (regional) monopoly which would see a single T&S business operating within each UK region, allowing them to set higher prices due to a lack of competition. These natural monopolies will occur as a result of:

    a. Significant Economies of Scale – There are minimal additional costs associated with increasing the diameter (capacity) of the transport pipeline and with connecting new users, meaning that it is more efficient for there to be a single T&S operator given the significant economies of scale at the point of network establishment.

    b. Significant Barriers to Entry – As identified above, there are a number of barriers to entry for prospective T&S network operators, including challenges with risk indemnification and high upfront capital costs.

17. If the T&S networks were to be allowed to operate as unregulated natural regional monopolies, they would have the option of charging uncapped fees which could exceed the reasonable costs and return on investment associated with deploying and managing the network. These higher fees would be levied on T&S network users, which may have the adverse effect of pricing some businesses out of CCUS deployment in favour of continued carbon emissions or ceasing trading.

18. It is therefore the view of BEIS that there is a need for HMG to intervene in a similar fashion to interventions imposed on other natural monopolies (through the appointment of a regulatory body) such as the utilities (Ofgem for energy, Ofwat for water) to address these market failures.

## 2.3 Rationale for powers sought under the primary legislation

19. The proposed primary legislation contains powers to enable the establishment of an economic regulatory framework for CO2 transport and storage as well as to enable the provision of financial assistance to address other barriers to private investment in $CO_2$ T&S projects.

*Financial Assistance*

*20.* To address market failures and barriers to entry, powers are sought to enable the government to incur such costs or liabilities and provide such financial assistance as the Secretary of State considers necessary and proportionate to incentivise investment in, and facilitate delivery of, the transport and permanent storage of $CO_2$.

*Economic Regulation of transportation and storage of carbon dioxide*

21. There is not currently a body with a statutory mandate to economically regulate $CO_2$ transport and storage or with statutory powers to set and enforce economic regulatory requirements specific to CCUS infrastructure. This primary legislation establishes a mandate for Ofgem to act as an independent economic regulator for $CO_2$ Transport and Storage, including an articulation of Ofgem's duties and objectives as economic regulator for $CO_2$ Transport and Storage, data collection and information sharing requirements, and relevant reporting and accounting requirements which Ofgem would be required to fulfil in this capacity.

22. The primary powers establish an economic licensing framework under which it is prohibited to operate, or charge for use of, a $CO_2$ Transport and Storage network without an economic licence. These licences will be regulated by Ofgem and the legislation provides the necessary legal powers to issue, enforce and modify economic licences within this framework. Powers include determining appropriate penalties for non-compliance with licence conditions, appropriate requirements upon Ofgem to consult as part of the regulatory decision-making process, and to provide for an appeals process against decisions made by Ofgem as the regulator as well as providing Ofgem with powers to monitor and enforce breaches of competition law, which may be exercised concurrently with the CMA.

23. To ensure that the prohibition on operating a $CO_2$ transport and storage activities without an economic license doesn't impact activities which it is not considered necessary or appropriate to economically regulate, powers are sought to enable the Secretary of State to grant exemptions from the requirement to hold an economic licence. Conditions under which exemptions may be granted are proposed to be defined in secondary legislation following appropriate consultation.

24. The prohibition covers the transport of $CO_2$ via onshore and offshore pipelines and the storage of $CO_2$. The capacity for T&S networks to be able to accept $CO_2$ from dispersed sites, and international sources, transported by non-pipeline methods of transport (ship, road, rail) will be vital to our long-term objectives of achieving carbon budgets and net zero targets. While pipeline methods of transportation and storage sites have monopolistic characteristics, we do not currently consider that non-pipeline methods of $CO_2$ transportation will share these same characteristics. This is because there are potentially lower costs of entry, and fewer barriers which prevent or make it non-economical for non-pipeline transport services being provided by multiple entities. The need for economic regulation of non-pipeline transportation may be low if the regulator considers that there is sufficient competitive pressure in the market for the provision of non-pipeline transportation services. However, until there is more certainty over how non-pipeline transportation services will be provided, it is not possible to take a view on whether these services should be subject to economic regulation. Given this, we have sought the powers to

enable new licensable activities to be brought into the scope of the economic licensing regime in future through the secondary legislation process.

25. Given the nascency of the CCUS sector and financial assistance which may be provided by Government to aid the establishment of T&S networks, the legislative proposals would enable the Secretary of State to determine which T&SCo's should be granted economic licences initially and to determine the terms and conditions of those licences. Powers are sought to transfer licence designation powers to Ofgem at such a time as may be considered appropriate in the future, once the sector has sufficiently matured. Provision is also made for the determination of future licence applications to be on a competitive basis if this is considered appropriate and beneficial to achieve value for money and facilitate subsidy control compliance.

26. As in other regulated sectors, it is proposed that the Secretary of State would continue to set strategic policy direction for $CO_2$ transport and storage, while day-to-day regulatory decisions are made independently by the economic regulator in line with its statutory duties and obligations that are set out in the legislative proposals.

27. The proposed legislative measures are intended to establish a clear and predictable framework for independent regulatory decision making, to provide confidence to investors in making long-term investment decisions and ensure that transparent, fair, reasonable and non-discriminatory regulatory decisions are taken by the body with the expertise and capability to arbitrate between the required trade-offs. This should facilitate the delivery of new $CO_2$ transport and storage networks at a cost of capital which is as efficient as possible.

*Designation of a counterparty*

28. The TRI model is a 'user pays' model. Particularly in the early years of operation, there are structural risks to an operator's revenue, including as a result of the first users of the network not joining the network as quickly as envisaged. To ensure the investability of the TRI model for initial T&S networks, mechanisms are under consideration to enable revenue shortfalls to be recovered from users of the network. The legislation seeks a delegated power for Secretary of State to be able to designate and direct a counterparty to enter into revenue support agreements and manage revenue support payments to T&S operators, where the source of any revenue support payments would be linked to the user contracts. A delegated power is sought to enable Secretary of State to designate and provide direction to a counterparty to enter into revenue support agreements, where the counterparty may be the same as the counterparty to the carbon capture contracts to be agreed between HMG and emitters, or another body.

*Asset decommissioning and re-use*

29. As with oil and gas assets, $CO_2$ transport and storage networks will have a finite life beyond which they must be "decommissioned" in accordance with environmental expectations. Decommissioning requirements for both oil and gas and CCUS assets are already enshrined in law. However, given the planned regulated nature of the CCUS sector, which is not the case for oil and gas, new measures are sought to require prospective operators of $CO_2$ transport and storage networks to ensure sufficient financial provision is made for an end-of-life decommissioning programme. These centre around the establishment of 'decommissioning funds' for each storage site. The detailed requirements for these decommissioning funds would be set out in secondary legislation.

30. Legislation already allows, in certain select circumstances, for the Secretary of State to relieve previous owners of an oil and gas asset of their decommissioning obligations when they sell this asset for re-use in CCUS. This is to facilitate the re-use of existing oil and gas assets for $CO_2$ transport and storage purposes, where this is feasible, efficient and appropriate. We are seeking to amend the legislation to align it with the wider CCUS policy landscape, in particular adding further conditionality on the issuance of this relief to mitigate risk to the taxpayer.

*Special Administration Regime*

Powers are sought to establish a Special Administration Regime and Transfer Scheme to apply to $CO_2$ Transport and Storage networks. Special Administration Regime and Transfer schemes are an established part of utilities regulation (water, power, gas, etc) as they allow for the protection of essential services where normal insolvency could otherwise cause disruption or harm. These powers will provide the Secretary of State with an opportunity to intervene in the very unlikely scenario of a T&SCo's insolvency, to keep the asset running and prioritise its continued operation [insofar as possible, or ensure the safe decommissioning of the asset]. The intended measures are designed to protect the interests of users and the public purse, given that insolvency during construction or operation could involve significant costs, and to ensure $CO_2$ emissions continue to be safely transported and stored without interruption.

31. Together this package of proposed measures facilitates the introduction of the Transport and Storage Regulatory Investment (TRI) model[6] as an option for future T&S projects. It does this by allowing the Secretary of State to appoint a T&SCo which will receive an economic license granting it the right to an allowed revenue which is primarily collected through charging its users fees for the delivery and operation of the T&S network. This TRI model ensures that network users are charged a fair, non-monopolistic price despite the T&SCo having a regional monopoly on the provision of T&S services, whilst at the same time ensuring a fair and consistent revenue for the T&SCo that reflects both costs and reasonable returns on capital.

32. The primary legislation facilitates the ability of SoS to set the initial license terms and conditions applied under the TRI and to designate which businesses are provided with such a license in the first instance. These powers, combined with the powers to allow SoS to establish a competitive allocation mechanism for future licences are intended to ensure that the best value for money (VfM) is achieved in network provision of the T&S network by the appointed T&SCo.

33. The primary legislation enables Ofgem to act as the economic regulator for the T&S market, providing Ofgem with the power to issue, modify and enforce existing and future economic licenses. This would allow Ofgem to adjust the requirements for license holders, as well as the fees they're allowed to charge users as is deemed appropriate, with an appeals process built into the legislation for T&S companies to challenge Ofgem's decisions if necessary.

34. The combination of powers sought in the primary legislation seek to resolve the market failures within the T&S market:

    a. The economic licensing powers granted to SoS and Ofgem seek to address the natural monopoly within T&S markets by regulating the prices which can be charged

[6] Further information on the T&S Regulatory Investment Model is included in the sections below.

by T&S businesses to ensure that there isn't a monopolistic disadvantage for users of the network.

b. The financial assistance powers in the primary legislation seek to incentivise capital investment within the sector by tackling the high initial costs of network provision and addressing the revenue shortfalls associated with low levels of initial demand for the T&S network as CCUS projects come online, and to allow for the Secretary of State to provide guarantees and indemnities in relation to specified high-impact, low probability risks associated with T&S network provision, which have proven to be barriers to investment.

## 2.4 Rationale for amending the Climate Change Act (CCA)

35. The rationale for amending the Climate Change Act (CCA) is to allow the UK greenhouse gas net emissions calculations to take account of not only removals of gases due to LULUCF activities in the UK as currently set out in section 29, but also other engineered GGR methods which are rapidly developing.

36. The current definition in section 29 of the Climate Change Act 2008 (the "CCA") limits the scope to removals of greenhouse gases from the atmosphere due to land use, land-use change or forestry activities (LULUCF) in the United Kingdom. This means that the latest technologies being developed and used for greenhouse gas removals (GGRs) in the UK cannot currently count towards UK carbon budgets.

37. The proposed amendment to the CCA would enable the UK to account for negative emissions occurring in its carbon accounting. The clause itself will not impact business activities, nor will it have any direct impacts on other primary or secondary legislation. Activities that will lead to negative emissions can go ahead without this amendment, but the UK Government would not be able to count the emissions towards its carbon budgets. This may be relevant for the deployment of the CO2 TRI networks should it be used for the transportation and storage of emissions captured from the atmosphere using direct air capture (DAC) technologies.

# 3. Options Analysis

## 3.1 List of policy options under consideration

38. The policy options that have been considered for this Impact Assessment are:

    a. **Policy Option 1 – Business as usual**: This option would rely on existing mechanisms to fund and develop a T&S network.

    b. **Policy Option 2 – T&S TRI legislation without new decommissioning or Special Administration Regime (SAR) legislation**: This option would introduce legislation to facilitate a T&S TRI, which would be the first step to introducing a T&S TRI model, but would not introduce new decommissioning or SAR legislation.

    c. **Policy Option 3 – T&S TRI legislation with new decommissioning legislation**: This option would introduce legislation to facilitate a T&S TRI, which would be the first step to introducing a T&S TRI model, but would not introduce new SAR legislation. However, it would introduce decommissioning legislation to ensure that T&S network operators collect appropriate funds from network users to cover future decommissioning costs, and that they are administered sensibly in appropriate security trusts.

    d. **Policy Option 4 – T&S TRI legislation with new SAR legislation**: This option would introduce legislation to facilitate a T&S TRI, which would be the first step to introducing a T&S TRI model, but would not introduce new decommissioning legislation. However, it would introduce new SAR legislation that would allow for the Secretary of State (SoS) or Ofgem to appointment an administrator under a number of circumstances, such as if the network operator were unable to pay its debts.

    e. **Policy Option 5 (Preferred Option) – T&S TRI legislation with new decommissioning and SAR legislation:** This option would introduce legislation to facilitate a T&S TRI, which would be the first step to introducing a TRI model for the provision of a T&S network. It would also introduce new decommissioning legislation which would define the acceptable roles and responsibilities of security trustees and creditors. Finally, it would introduce new SAR legislation that would allow for the SoS or Ofgem to appoint an administrator in certain circumstances, such as if the network operator were unable to pay its debts.

## 3.2 Preferred Option

39. The preferred option is to introduce legislation which would be the first step in enabling the creation of transport and storage networks under a TRI model, with the introduction of both decommissioning and SAR legislation (policy option 5). BEIS believes that this is the best option for achieving the stated policy objective of ensuring transport and storage networks are deployed in a cost-effective and timely manner that will allow for the utilisation of CCUS to help meet the UK's Net Zero emissions target.

40. The TRI model is a type of economic regulation that is similar in nature to the RAB model typically used in the UK for monopoly infrastructure assets such as water, gas and electricity

networks[7]. BEIS believes the TRI model is appropriate for the development of T&S networks as the infrastructure assets which support the decarbonisation of existing industries equally have monopolistic characteristics. Under the TRI model, regional monopolies for the provision of CO2 Transport and Storage will be created and network operators will be appointed who will be regulated by the licensing regime. As part of this regulation, the T&S network operators will receive a license from the Economic Regulator, which grants them the right to charge a regulated price to users in exchange for provision of the infrastructure in question.

41. The T&S network provider will be able to collect revenues through the operational life of the network in line with the allowed revenue determined by the economic regulator. Allowed revenues during the first regulatory period will be determined by the licence granted by the Secretary of State. Thereafter, Ofgem will set allowed revenues for the subsequent regulatory periods. In setting the licence conditions Ofgem will act in accordance with its statutory duties. The setting of allowed revenues across the T&SCos operational life removes the risk of monopolistic pricing that may impede the deployment of Carbon Capture technologies within the UK.

42. Under the preferred option a government support package (GSP) will be introduced which will facilitate the provision of revenue support to the T&SCo's prior to the connection of the first network users, in the event of missed connections or under utilisation of the network. Additionally, the GSP will allow for the indemnification of risks such as CO2 leakage that can't be insured through commercial avenues. These support measures seek to remove the demand risks that act as a barrier to entry for unregulated provision of CO2 Transport and Storage networks.

43. There is a risk that without the introduction of decommissioning legislation, the T&SCos would fail to collect adequate fees from users of the network for the decommissioning of the T&S networks at the end of their lifespan, that they may collect revenues that exceed the expected costs for the decommissioning of the network, or that they may not manage the funds adequately in the period between their collection and use for decommissioning. The preferred option is therefore to introduce decommissioning legislation in order to ensure the collection of appropriate revenues and their management in appropriate security trusts.

44. Without the creation of a Special Administration Regime, the T&SCos would be subject to the existing insolvency regime, meaning that if a T&SCo were deemed unable to pay its debts, an ordinary insolvency administrator would be appointed. The objectives of such an administrator would be to protect creditors, which may result in the partial or full liquidation of the network, which may adversely impact users of the T&S network and disrupt the government's climate ambitions. As such, the legislation introduces a SAR regime to ensure that in the case of insolvency, the objectives set for the administrator are to continue the operation of the T&S network as a going concern.

## 3.3 Illustrative Theory of Change

45. An Illustrative Theory of Change is utilised in the following sections to illustrate how the preferred policy option should lead to further steps, including the development of secondary

[7] A Regulated Asset Base model is a tried and tested method for financing large scale infrastructure projects, under which a company receives a license from an economic regulator to charge a regulated price to users in exchange for providing the infrastructure project under regulation.

legislation, which will ultimately create impacts which will result in the policy objectives being met.

46. The primary legislation under consideration is not expected to have any impact by itself. The primary provisions enable the provision of financial assistance and the establishment of an economic regulation and licensing framework. The CCUS cluster sequencing competition is expected to identify the first T&S Operators to be granted financial support and an economic licence enabled under this framework, and to determine the conditions of those licences. This process, along with the supporting legislation, are together expected to help facilitate the deployment of a T&S network by appointed T&SCo(s)

47. This illustrative Theory of Change has been structured by the costs associated, the benefits created (monetised and non-monetised) and the wider economic impacts expected. Illustrative impacts are explored further in Sections 4, 5 and 6.

# 4.Costs

## 4.1 Summary of monetised costs

Table 1 – Summary of costs from the primary legislation (2020 prices, 2022 present value base year)

| Party | Assumed Number | Cumulative Costs per Party | Total Cumulative Costs | EANDCB |
|---|---|---|---|---|
| Economic Regulator (Ofgem) | 1 | £5.2m (columns 1 and 2 of table 2) | £5.2m | N/A |
| T&SCos | 3 | £2.9m (column 1 of table 3) | £8.7m | £1m (i.e. cost to business) |
| Total Combined Costs | | | £13.9m | £1m |

48. The primary legislation has a total cumulative discounted cost of £13.9m which is made up of £8.7m in costs spread across three T&SCos within the appraisal period, and a further £5.2m in costs to the economic regulator (Ofgem). For more detail on how these costs have been calculated see sections 4.2 and 4.4.

49. These costs represent an annual net cost to business (EANDCB) of £1m per annum based on the projected expenditure of the T&SCos after discounting, with each T&SCo spending £0.3m per annum. This cost is the total cost of familiarisation for the T&SCos of £8.7m prior to the end of negotiations between HMG and the T&SCo, final investment decisions being made and the start of T&S network construction as costs beyond that but which fall within the overall appraisal period (2022 -2030) will be driven by a variety of factors and cannot be attributed solely to the primary legislation.

## 4.2 Costs to the economic regulator

50. Ofgem will be the designated economic regulator and responsible for the implementation of the T&S framework established under the primary legislation, and as such it is expected that Ofgem will bear the majority of the legal and familiarisation costs.

51. Ofgem have provided BEIS with a forecast of their costs for their role as the economic regulator for financial years 22/23 through to 29/30. These costs are made up of their internal core staffing costs and their projected consultancy costs for legal and technical expertise, which have been estimated based on their experience regulating other infrastructure industries. Whilst some of these costs can be attributed to the primary legislation (via familiarisation), a majority of these costs won't be realised until the CCUS cluster sequencing process has successfully concluded and decisions to award economic licences have been made.

Table 2 – Ofgem's projected costs (2020 prices, 2022 present value base year)

| | Costs to the Economic Regulator (£m) - 2020 Prices | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 22-23 | 23-24 | 24-25 | 25-26 | 26-27 | 27-28 | 28-29 | 29-30 | Total |
| Total Costs (Central Estimate) | 2.4 | 2.8 | 3.0 | 3.1 | 3.0 | 2.9 | 2.8 | 2.7 | 22.7 |
| Total Costs (Upper Bound) | 2.4 | 2.8 | 3.0 | 3.2 | 3.1 | 3.0 | 2.9 | 2.8 | 23.3 |
| Total Costs (Lower Bound) | 2.4 | 2.8 | 3.0 | 2.9 | 2.8 | 2.7 | 2.6 | 2.5 | 21.7 |

52. Ofgem have forecast that their costs across the appraisal period (to 2030) as a result of the full package of legislation will be £22.7m. Ofgem's forecast costs rise over the first three years of the appraisal period before plateauing in FY25-26 and beyond as the legislation comes into force and they begin administrating the T&S networks in full.

53. Ofgem have also provided a sensitivity range for their expected costs based on their experience as the economic regulator for existing elements of the energy industry. These sensitivities show an upper estimate of £23.3m across the appraisal period and a lower estimate of £21.7m across the appraisal period.

54. The introduction of the primary legislation creates familiarisation and implementation costs for the economic regulator who must employ a core team of staff, as well as technical and legal experts in order to familiarise themselves with the legislation and their role as the economic regulator prior to the development of any secondary legislation and future network deployment.

55. This assessment views costs created in the first two years of the appraisal period to be driven by the primary legislation, with any costs thereafter being attributed to a combination of secondary legislation, and the regulation of deployed T&S networks as a result of the conclusion of network negotiations between HMG and the T&SCos.

56. The expected costs of the primary legislation for the economic regulator are therefore £5.2m across two-years in all scenarios, as reflected in Table 1.

## 4.3 Costs to government

57. The primary legislation introduces financial assistance powers which enable government to provide financial support, including:

    a. **Capital Investment Support** – Due to CCUS' status as a nascent industry, it is challenging for businesses to obtain private capital investment to support the deployment of CCUS technologies including transport and storage networks.

The direct provision of this capital investment support for any T&SCos that are appointed by SoS to provide a transport and storage network in reliance on this power will create cost for HMG.

b. **Revenue Support** – The primary legislation allows for the provision of revenue support for T&SCo's during the early deployment of the network to close the gap between income from allowed fees and operating costs, if the network is not fully utilised at the outset.

c. **Risk indemnification** – The financial assistance powers included in the primary legislation will also allow for HMG to incur liabilities and indemnify high-cost, low probability risks which would act as a barrier to the T&SCo providing a network, and which may not be insured against by the private sector.

If government provides assistance through these provisions, such liabilities and indemnities may represent a cost to government should any of the low-probability risks come to pass, as HMG would bear any costs associated with addressing them.

58. Whilst the spending powers are enabled by the primary legislation, the exact scope and scale of the costs to government are yet to be agreed as network delivery is still being negotiated between government and prospective T&SCos.

## 4.4 Costs to the T&SCo

59. The primary legislation prevents the operation of a T&S network without an economic license which stipulates the terms under which a T&S network can be operated. The primary legislation therefore introduces costs for prospective T&SCos who have to familiarise themselves with the legislation in order to understand the legal framework, any associated codes and who have to enter into connection agreements. This section discusses these costs.

60. Ofgem have estimated the amount of resource an average T&SCo would need to put in place to meet the requirements of the primary legislation[8]. These estimates are based on their experience working with private businesses in existing sectors where they act as the economic regulator. Ofgem are well placed to provide this data because:

a. **Familiarity with the legislation –** Ofgem, as the intended economic regulator of Transport and Storage networks, under the powers to be provided by the Bill, and as a non-ministerial department under BEIS auspices, have been consulted by BEIS on the development of T&S economic regulatory policy including to support the development of the legislation. The draft legislation is modelled on the existing statutory regimes for other regulated utilities, in particular the regulatory regimes which apply in the gas and electricity sectors. As such, Ofgem have the requisite understanding of the size and scope of the primary legislation and what it might take for those impacted to familiarise themselves with it.

b. **Expertise in adjacent industries –** Ofgem are already the acting economic regulator for several adjacent industries including electricity and gas networks, as part of

[8] These estimates are indicative and intended to represent an average T&SCo, Ofgem – with input from the T&SCo's – will revisit and review these estimates for purposes of deciding allowed revenues in the future on a case-by-case basis.

which they are expected to scrutinise costs incurred by the network providers being regulated to determine if they are reasonable and how they should be reflected in allowed revenue. This means that Ofgem are best placed to provide evidence for the familiarisation costs for the T&S industry given its nascent status.

61. Ofgem have stated that they expect an average T&SCo to need to employ the equivalent of 12 full time (FTE) staff in order to familiarise themselves with the primary legislation and a further 6 FTE staff per annum in order to comply with the regulatory burden. Ofgem have indicated that these employees are expected to have a similar mix of skills and sit across a similar range of pay bands as their own internal staff. As such, the costs incurred by each T&SCo have been derived from the forecast costs to the economic regulator.

62. These costs have had a 15% uplift applied to them based on ONS wage data to account for the higher wages earned by those employed in knowledge intensive services privately when compared with the public sector.[9]

Table 3 – Projected familiarisation costs for a single T&SCo (2020 prices)

| **Familiarisation Costs (£m, 2020 prices, 2022 present value base year)** | **22-23** |
|---|---|
| Central Estimate | 2.9 |
| Upper Bound | 3.0 |
| Lower Bound | 2.8 |

63. In order to familiarise themselves with the legislation and ensure compliance with the economic licensing scheme, each T&SCo is expected to require the equivalent of 12 full time (FTE) staff at a cost of £1.3m in the first year. In addition to this, each T&SCo is expected to spend an additional £1.6m in the first year on external consultancy support including legal and technical consultancy.

64. At the recommendation of Ofgem, a sensitivity range has been included that accounts for possible discrepancies in the staffing needs of each T&SCo, with a staff level of 11 FTE in the lower bound at a cost of £1.2m in the first year and a staffing level of 13 FTE in the upper bound at a cost of £1.4m across the appraisal period. When applied to the final costs for each T&SCo this results in an upper bound of £3m and a lower bound of £2.8m in the first year.

65. It is expected that there will be at least three T&SCos active within the appraisal period as HMG has committed to two CCUS clusters under the Track-1 clusters announcement[10], and at least one more will be introduced under Track-2 clustering. However, this expectation is still subject to future changes as a result of changes in the timing of the Track-2 cluster(s) and possible future expansions to the UK's CCUS commitments and ambitions.

[9] Office for National Statistics - ONS Annual Survey of Hours and Earnings (ASHE) - 2019

[10] UK Gov – Track-1 Clusters Confirmed – Nov 2021: https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest/october-2021-update-track-1-clusters-confirmed

66. The introduction of the primary legislation creates familiarisation costs for the prospective T&SCos who must employ a core team of staff, as well as technical and legal experts in order to familiarise themselves with the legislation and their role as a network operator prior to the development of any secondary legislation and future network deployment.

67. This assessment views costs created in the first year of the appraisal period to be driven by the primary legislation, with any costs thereafter being attributed to a combination of primary and secondary legislation, as well as the conclusion of network negotiations between HMG and the T&SCos.

68. These familiarisation costs represent an annualised net cost to business of £1m over an eight-year period running between 2022 and 2030. These costs are derived from the £2.9m cost per T&SCo in the first year arising from the primary legislation, multiplied by three to reflect the previously outlined assumption that there will be at minimum three active T&SCos within the appraisal period, however should more T&SCos be agreed in the future, the annualised net cost to business will rise.

Table 4 – Projected regulatory costs for a single T&SCo (2020 prices, 2022 present value base year)

| | **Regulatory Costs (£m)** | | | | | | |
|---|---|---|---|---|---|---|---|
| | **24-25** | **25-26** | **26-27** | **27-28** | **28-29** | **29-30** | **Total** |
| Central Estimate | 1.7 | 1.7 | 1.6 | 1.5 | 1.5 | 1.4 | 9.4 |
| Upper Bound | 1.7 | 1.7 | 1.7 | 1.6 | 1.5 | 1.5 | 9.7 |
| Lower Bound | 1.6 | 1.6 | 1.5 | 1.5 | 1.4 | 1.4 | 9.0 |

69. Ofgem have also provided an estimated cost for an average T&SCo's compliance with the regulatory burden introduced in part by the primary legislation between 2024 and 2030, with this cost stemming from the employment of 6 FTE staff per annum and external consultancy costs of £1m per annum.

70. Ofgem have indicated that these employees are expected to have a similar mix of skills and sit across a similar range of pay bands as their own internal staff. As such, the costs incurred by each T&SCo have been derived from the forecast costs to the economic regulator. These costs have had a 15% uplift applied to them based on ONS wage data to account for the higher wages earned by those employed in knowledge intensive services privately when compared with the public sector.[11]

71. Overall, these costs suggest that each T&SCo will face regulatory costs of £1.6m per annum on average, resulting in a cumulative regulatory burden of £9.4m between 2024 and 2030. These costs are at their highest in the first year (24/25) and fall over the appraisal period to £1.4m in the final year (29/30) as staff become more familiar with regulatory requirements and less time is spent ensuring compliance.

72. Upon publication of the legislation, and as the TRI business model more generally is refined, BEIS will be able to work with the T&SCos to refine these cost estimates; any reasonably incurred costs (as determined by the regulator) can form part of the allowed revenue, and will be recoverable through the fees they are allowed to charge users). The powers introduced in this legislation form part of a wider suite of policies that BEIS has been actively discussing with prospective T&SCOs.

[11] Office for National Statistics - ONS Annual Survey of Hours and Earnings (ASHE) - 2019

## 4.5 Costs to business

73. Private businesses that deploy CCUS technologies and require access to and use of the T&S network will be expected to agree to the connection agreements established by the T&SCo in accordance with the economic licensing scheme enforced by the economic regulator.

74. These businesses will face some minimal familiarisation costs prior to and immediately following their decision to enter into an agreement with the T&SCo for use of the T&S network, as well as legal costs associated with the creation and signing of any contracts required to facilitate this relationship.

75. Similar business models exist in other sectors which aren't part of an economic licensing regime such as the one detailed under this package of legislation. The Oil & Gas transportation, processing and storage industry is one such industry which has a private framework that is comparable to the expected framework employed by the T&SCos.

76. Potential users of the T&S network will have sight of any such costs prior to the deployment of any capture technologies and their joining of the T&S network, allowing them to account for them in their business planning and decide whether the benefits of deploying carbon capture technologies outweigh the costs.

## 4.6 Costs to consumers

77. The primary legislation provides enabling powers to facilitate the development and regulation of T&S networks within the UK for use by carbon intensive businesses and industries. This primary legislation in and of itself does not directly create any additional costs to consumers. Some users of CO2 transport and storage services may be funded by existing or new consumer levies but these costs are not assessed here. The TRI model ensures that network users are charged a fair, non-monopolistic price despite the T&SCo having a regional monopoly on the provision of T&S services, whilst at the same time ensuring a fair and consistent revenue for the T&SCo that reflects both costs and reasonable returns on capital.

78. The impact of CCUS deployment and the role played by the T&S network on the pricing of consumer bills will continue to be assessed alongside future delivery of the network following the completion of negotiations between government and the T&SCos, as well as under the monitoring and evaluation plan detailed below (section 7).

## 4.7 Decommissioning

79. The primary legislation includes enabling powers for the regulation of a decommissioning regime, which will be expanded in future secondary legislation. These powers include the requirement that the T&SCo will be responsible for collecting funds towards future decommissioning costs from network users and will be responsible for their investment in the interim years between their collection and the decommissioning of the network.

80. It is however expected that even without decommissioning clauses in the primary legislation, or the subsequent decommissioning secondary legislation, that the T&SCo would actively seek to collect fees to cover future decommissioning expenditure from network

users. As such, the additional costs introduced by the legislation that are associated with decommissioning stem from the regulation of the interim investment of any collected fees, and the legal and familiarisation costs associated with implementing the primary legislation.

81. A separate impact assessment will be produced alongside the decommissioning secondary legislation that will seek to monetise the costs and benefits for both the T&SCo and for any network users that stem from the decommissioning legislation.

# 5. Benefits

82. The benefits associated with the successful deployment of a transport and storage network will manifest following the enactment of the full legislative package, final agreement of the T&S business model, and the consequential construction and operation of the networks.

## 5.1 Emissions Reductions

83. The deployment of T&S networks as a result of the package of legislation (primary and secondary) and conclusion of network negotiations will enable the deployment of carbon capture within energy intensive industries and power generation, resulting in a reduction in future carbon dioxide emissions.

84. At this point in time, it isn't possible to quantify the expected capacity of the T&S networks or what utilisation will look like over any given time period. This is because negotiations between government and industry are on-going to agree optimal networks that will provide value for money. As such it isn't possible to calculate the social costs of the carbon that would be emitted without the provision of a T&S network.

85. Additionally, it is not possible to meaningfully allocate the social value of captured and stored carbon to the transport and storage network specifically. The network is part of a wider CCUS system that in totality will reduce carbon emissions and contribute towards achievement of the UK's climate ambitions.

## 5.2 Benefits for Business

86. The UK introduced the UK Emissions Trading Scheme (UK ETS) in January 2021 which caps the total carbon production of energy intensive and high emissions industries and introduces a trading scheme which results in a cost on carbon emissions. As a part of the UK ETS programme and the UK's pathway to Net Zero, the cap on carbon emissions will be reduced year-on-year, which will in turn raise the carbon price and the cost of producing high carbon and energy intensive products.

87. As the cap on carbon emissions is reduced under the UK ETS, it is expected that the UK's traded carbon price will increase. This will result in businesses in energy intensive industries seeking alternative arrangements to reduce their carbon emissions, such as the deployment of CCUS technologies. This deployment of CCUS technologies within their operations will be reliant on a transport and storage network but will ultimately allow them to remain competitive and reduce costs in the face of rising carbon prices.

88. The benefits offered by the preferred option via the primary and secondary legislation are two-fold for these businesses:
    a. The T&SCo business model and the government support enabled by the primary legislation will help enable the timely delivery of a T&S network which in turn would enable businesses to adopt CCUS technologies within their operations where there is capacity to transport and store the captured carbon.
    b. As reliance on CCUS technologies (including access to transport and storage solutions) rises amongst firms operating within energy intensive industries, a risk emerges that they could be subjected to predatory or monopolistic pricing. The preferred option protects businesses from this through the setting of reasonable

charges by the economic regulator, allowing for increased confidence in future T&S costs.

## 5.3 Wider economic benefits

89. The UK government's Energy Innovation Needs Assessment highlights that the deployment of CCUS clusters connect to North Sea storage (via T&S networks) in the 2020s would help enable the UK to capitalise on a growing CCUS exports market, creating opportunities for jobs and GVA growth to 2050.

90. The Energy Innovation Needs Assessment found that capitalising on these export opportunities within the CCUS sector could create 46,000 jobs by 2030 and generate £3.5bn in GVA per annum.[12]

91. In addition to the jobs and GVA generated by the deployment of CCUS, the delivery of a T&S network would allow for the deployment of CCUS within industries that are vulnerable to international competition and carbon leakage, allowing them to remain competitive as carbon prices rise under the tightening cap of the UK ETS. The continued competitiveness of these industries as a result of the T&S network facilitating CCUS deployment will provide wider economic benefits through the protection of both direct jobs within energy intensive industries and indirect jobs that are created in the surrounding area and industries.

92. Many of these energy intensive industries that would benefit from access to a T&S network for CCUS deployment are industries of strategic importance such as Power, Steel and Chemicals.

[12] UK Gov – Energy Innovation Needs Assessment – CCUS sub-theme - https://www.gov.uk/government/publications/energy-innovation-needs-assessments

# 6. Additional Impacts

## 6.1 Nascent Industry Risks

93. CCUS industries, despite increasing levels of domestic and international deployment, are still an infant industry, and so there are a number of risks associated with supporting the development of CCUS projects such as transport and storage networks.

94. The T&S business model and economic licensing scheme which are enabled by this package of legislation addresses a number of nascent industry risks including:

    a. **Cost Overruns** – There is an increased risk (compared with established industries) that cost projections by the T&SCo will suffer from Optimism Bias and that costs will exceed any projections. This increased risk is the result of there being no established $CO_2$ storage industry within the UK from which to base assumptions and learn lessons.

    b. **T&S Construction Delays** – Should there be a delay in the completion of construction of the T&S network, there may be a risk to the deployment of CCUS technologies within the UK and the UK's Net Zero targets.

    c. **T&S Unplanned Outages –** If there were unplanned outages within the T&S network, it is possible that users of the network may be forced to cease operations or emit $CO_2$ as a by-product of their output.

    d. **T&S Capacity Constraints –** A risk exists that the T&S network may not be able to carry as much $CO_2$ as projected or the storage site may not have as much capacity as initially anticipated, which may reduce the lifetime revenues of the T&SCos and introduce knock-on impacts for the users of the T&S network.

    e. **$CO_2$ Leakage from T&S network –** There is a risk that $CO_2$ leakage from the transport and storage network may lead to temporary impacts on network users similar to an unplanned outage, or more permanent impacts should the network and storage site be deemed unfit for long-term use.

## 6.2 International Trade Impacts

95. The primary legislation is not expected to directly impact international trade and investment.

## 6.3 PSED Impacts

96. A Public Sector Equality Duty (PSED) assessment has been completed for this primary legislation. The PSED gives due regard to meeting the three aims under Section 149 of The Equality Act 2010 including eliminating unlawful discrimination, the advancement of equality of opportunity among those with protected characteristics and fostering good relations between people with protected characteristics.

    The primary legislation is not expected to have any impact by itself on the protected characteristic groups (PCGs). There are no disproportionate impacts currently identified for any of the PSED groups which include: Age, Marriage/Civil Partnership, Religion or Belief, Sex, Gender Reassignment or Sexual Orientation PCGs, Disability, Race and Pregnant/Maternity PCGs.

97. This assessment will be kept under constant review. A separate PSED assessment will need to be conducted, reviewed, and monitored for impacts associated with any secondary legislation which may follow. In particular, while the primary legislation in itself does not directly affect energy bills or costs to consumers, some of the charges that a T&S operator is able to charge end users of CO2 transport and storage services may ultimately be funded by levies on consumers. Where this is the case, PSED considerations will need to be taken into account as part of the design of any new levies or modifications to existing levies and the associated legislation that will be required.

98. The regulator should also have regard to PSED in its decision-making and in line with its statutory duties.

## 6.4 Impact on small and micro businesses

99. As identified in Section 2.2, it is expected that the $CO_2$ transport and storage networks will be operated by larger businesses as a result of the sector lending itself to being a natural monopoly as a result of the resources and expertise required to build, operate and manage the network. As such, it is expected that the package of primary and secondary legislation will predominantly impact large businesses in the form of the regional T&S network operators.

100. There is however a risk that the economic licensing regime will impact small and micro businesses wishing to operate a small-scale T&S network. These businesses may be faced with disproportionate costs in order to obtain an economic license as a result of possible fees (similar to those seen in the electricity license scheme), the cost of familiarisation with the legislation and any legal consultancy required to submit the application. There may be certain persons or classes of activity which it would be appropriate to exempt from the requirement to hold an economic licence for the transport and storage of $CO_2$ and there are powers in the primary legislation to allow the Secretary of State to provide exemptions.

101. This Impact Assessment hasn't sought to quantify the number of small and micro businesses (SaMB) impacted by the primary legislation due to the nascent status of the industry – and therefore the composition of businesses seeking to operate within it – and the lack of clarity as to how the economic regulator will distribute licenses at the current time. Quantification of the number of SaMB's impacted will be sought following the introduction of the economic licensing scheme and will be revisited in Impact Assessments for any subsequent secondary legislation.

102. Whilst quantification of the number of businesses likely to be granted exemptions or to be disproportionately impacted by the TRI primary legislation isn't possible at the current juncture, it is expected that few small and medium businesses will be impacted. Within the electricity licensing scheme operated by Ofgem, a total of 26 exemptions have been granted or consulted on since 2011[13], whilst over 500 businesses were in possession of licenses[14] in April 2022.

[13] UK Gov – Electricity License Exemptions – April 2022
[14] Ofgem – List of all electricity licenses – April 2022

103. Classes of activity that could be exempt might include small scale localised networks, or networks transporting $CO_2$ for usage and which may require short-term storage. We intend to consult further on the need for and appropriate application of any potential exemptions which would then be provided for through secondary legislation. We also recognise it will be important to retain the flexibility to review the approach to exemptions as the T&S networks grow and become established.

# 7. Monitoring and Evaluation

104. A monitoring and evaluation plan will be devised in full detail alongside the implementation of the regulatory framework, following finalisation of the T&S business model, the outcomes of CCUS cluster sequencing process and the enactment of any secondary legislation following the primary legislation discussed in this Impact Assessment.

105. This section seeks to detail illustrative examples of what an appropriate monitoring and evaluation framework could look like.

106. The objectives of a monitoring and evaluation (M&E) plan could be to:

a. Assess the effectiveness of the legislation (primary and secondary) in supporting the deployment of a T&S network
b. Provide evidence to inform decision making for future changes to the licensing arrangement and/or acceptable pricing parameters of T&S capacity
c. Provide evidence to inform decision making around future business models for future CCUS projects

107. To assess what needs monitoring and evaluating, SMART objectives would be devised for the policy. Such objectives may include:

a. Successful deployment of at least three T&S networks, to support the development of the four CCUS clusters that were announced as part of HMG's Net Zero Strategy in October 2021.
b. Fully funded decommissioning of the T&S network at the end of the network's lifespan, without excess funding leftover as a result of network users being overcharged.

108. The final shape of the evaluation will be decided once a negotiated settlement with the first T&SCo's is in place and the first economic licences have been granted. However, we anticipate that any such evaluation will include:

a. process evaluation to potentially assess the effectiveness of the TRI funding model for future re-use
b. interim progress assessments to assess progress towards policy objectives and address any shortfalls or areas of concern
c. Impact evaluation and value for money assessments to determine whether the T&S network as delivered provides value for the taxpayers money that is invested.

109. The types of high-level questions an evaluation might explore include:

a. Has the intervention been delivered as intended?
    i. How effective were the processes for establishing and allocating economic licenses under the T&S model?
b. Has the intervention contributed towards its objectives?
    ii. To what extent was there an appropriate balance of risk assignment between government and the T&SCo?
    iii. How effective was the T&S business model for providing appropriate levels of revenue support and access to capital investment?
c. What are the implications of the monitoring and evaluation findings for future transport and storage projects?

d. Has the implementation of the primary and secondary legislation been delivered in such a way that the costs to taxpayers of deploying a T&S network have been minimised?

110. Potential sources of evidence for monitoring and evaluation could include a combination of:

a. Focus groups with key stakeholders
b. In-depth interviews with stakeholders such as the T&SCo, network users and the economic regulator to explore key themes
c. Surveys of network operators and users
d. A systematic review of any evidence collected across the project's lifespan
e. Using statistical data collected during the project's lifespan

# 8. Conclusion

111. This Impact Assessment lays out the case for why government intervention is required in order to ensure the timely provision of a transport and storage (T&S) networks for carbon dioxide and the regulation of such networks to combat market failures. As well as this, this Impact Assessment seeks to provide a summary of the costs and benefits associated with the preferred form of government intervention which includes the deployment of a TRI model for network provision, the introduction of an economic licensing and regulation framework and the introduction of new SAR and decommissioning regimes.

112. When compared against other options considered (section 3.1), the preferred option analysed in this Impact Assessment is the most likely to result in the timely deployment of T&S networks and CCUS technologies within the UK in order to meet the UK's climate ambitions as laid out in the Net Zero Strategy, including the sequestration of 20-30Mtpa of carbon dioxide by 2030 and net zero by 2050, whilst minimising costs and ensuring that other benefits such as the creation and protection of jobs are realised.

113. Under the preferred option, the primary legislation introduces monetised costs for the economic regulator (Ofgem) and for the T&SCos with a total value of £14.4m (2020 prices, 2022 present value base year), as a result of the need for both parties to familiarise themselves with the primary legislation and network codes, as well as prepare themselves for the next steps which are acting as the economic regulator and network operater respectively. In addition to these monetised costs, costs are expected to materialise for government as a result of their use of the financial assistance powers which enable the indemnification of risks, the provision of revenue support to T&SCos and capital support packages for network creation. Finally, following the creation of networks, costs are expected to materialise for businesses that make use of the T&S networks as they'll be charged fees by the T&SCos operating the networks.

114. Under the preferred option, the primary legislation alone will not result in any benefits being realised, however the primary legislation is expected to allow for the realisation of T&S network deployment following the end of negotiations between HMG and prospective T&SCos, which will in turn unlock significant future benefits. These future benefits include a reduction in emissions as the T&S network allows for the deployment of CCUS technologies and the sequestration of carbon dioxide, the creation of domestic jobs and GVA through domestic network deployment and capitalising on export opportunities, and the protection of jobs and GVA in energy intensive industries that might otherwise be forced to cease trading or move offshore as the UK emissions cap contracts.

# Energy Bill 2022 – Fusion Clause

## Policy background

The UK has regulated fusion energy facilities effectively via the Environment Agency ("EA") and Health and Safety Executive ("HSE")[1] for decades. Fusion energy facilities have not and do not require a nuclear site licence. The proposed Energy Bill clause for fusion will amend the Nuclear Installations Act 1965 ("NIA 1965") to explicitly exclude fusion energy facilities so they will not require nuclear site licences and regulation by the Office for Nuclear Regulation ("ONR"). This will enable a regulatory framework for fusion that is appropriate and proportionate to the overall hazard of a fusion energy facility.

The current nuclear site licencing regime is intended to regulate higher hazard nuclear sites with fissile materials (such as uranium and plutonium). Fusion energy facilities do not require fissile materials and have a significantly lower associated hazard than traditional nuclear (fission) sites, and the fusion reaction has no risk of a runaway reaction.

Without this clause, the only elements of a fusion facility that could trigger the requirement to hold a nuclear site licence are those that store a "bulk quantity" (as per ONR guidelines) of fission-produced tritium (one of the fuels required to start fusion reaction). Tritium will subsequently be produced inside fusion reactors, the storage of which wouldn't trigger NIA 1965 requirement to hold a nuclear site licence, even if the amount is otherwise sufficient to classify it as "bulk quantity".

This clarification clause in the Energy Bill is to reflect the fundamental differences in technology and risk profile between fission and fusion plants and the required safeguards vis-à-vis radioactive materials. The clause will provide clarity for industry, investors and the public with regards to the Government's approach to wider fusion regulatory framework.

## Discussion of impacts

The clause confirms the status quo and removes ambiguity, there is no change to the existing regulatory framework and therefore no business impact is expected to stem from this provision. There are currently no fusion energy facilities in construction or operation which would trigger a nuclear site licence as per current regulations as well as ONR guidelines so no business can currently be directly impacted by this legislation.

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[1] For a list of applicable legislation, see pp.40-41 of "Towards Fusion Energy: The UK Government's proposals for a regulatory framework for fusion energy", available at: https://www.gov.uk/government/consultations/towards-fusion-energy-proposals-for-a-regulatory-framework

Contact for enquiries: fusionregulation@beis.gov.uk

| | |
|---|---|
| **Title:** IA: Legislation to Enable a Hydrogen Heating Village Grid Conversion Trial<br>**IA No:** BEIS026(F)-22-CH<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** None | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** hydrogenheatingcorrespondence@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| Not quantified | Not quantified | Not quantified | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

Low carbon hydrogen could have the potential to be a key option for decarbonising heat in buildings. However, further evidence is required to assess the feasibility, costs, and benefits of hydrogen conversion to enable the Government to take strategic decisions on its potential role in 2026. A grid conversion hydrogen heating trial will be critical to evaluating the practicalities of converting to hydrogen. To enable such a trial, legislation is needed to allow Gas Distribution Network Operators (GDNs) to effectively and safely carry out the activities needed to deliver a grid conversion hydrogen trial and to ensure that all consumers in the trial area continue to receive fair treatment for the duration of the trial.

**What are the policy objectives of the action or intervention and the intended effects?**

The core objective of this package of measures is to enable the delivery of a hydrogen heating village grid conversion trial in a safe, timely, and cost-effective way while maintaining consumer protection. Our preferred option intends to extend existing powers of entry for the GDN(s) in relation to a hydrogen grid conversion trial and introduce secondary powers for the Secretary of State to implement a range of consumer protections, balancing the needs of the GDN(s) and the rights of the consumer. In doing so, it would minimise any negative impacts of the intervention for individual households or local businesses that might ultimately be subject to the powers of entry, whilst also considering operational requirements, such that GDN(s) are able to conduct a trial in a safe, timely and cost-effective manner.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Option 0 (Do Nothing): No legislation is introduced in advance of attempting to run a conversion trial. In the absence of additional legislation, there is a risk that the GDN(s) are unable to safely and legally disconnect any consumers in the trial area who cannot be contacted or do not accept either hydrogen or an alternative offer, leading to delay and putting the overall viability of the trial at risk.

Option 1: Extend existing GDN powers of entry only. Legislation would be introduced to provide GDNs with clear legal grounds to enter private property to carry out activities essential to a safe trial, such as disconnecting customers safely from natural gas. This would reduce the chance of costly delay to the trial. However, it also carries a small risk that powers may be used more than necessary.

Option 2 (Preferred Option): Extend existing GDN powers of entry and build in additional consumer protection safeguards. This delivers the benefits of Option 1 but also ensures that consumers are treated fairly and that powers of entry are used only where absolutely necessary. We consider that this option provides the optimal balance between GDNs' operational needs and consumer protection.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:** N/A

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro**<br>No**Error! Bookmark not defined.** | **Small**<br>No | **Medium**<br>No | **Large**<br>Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:**<br>N/A | **Non-traded:**<br>N/A | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

# Summary: Options Analysis

| Policy Option | Benefits | Costs |
|---|---|---|
| **Option 0 (Do Nothing)** | | • Significantly higher chance of trial delay or abandonment, risking sunk public and private resources and potentially undermining the development of the evidence base for hydrogen heating.<br>• Consumers may spend a longer period off gas if works are delayed or prolonged. |
| **Option 1** | • More certainty for GDN(s): the legislation provides a clear legal basis for the trial to go ahead.<br>• The trial is much more likely to proceed, providing a critical part of the evidence base for hydrogen heating.<br>• We expect that the majority of domestic consumers and local businesses will take part in the trial voluntarily. For these consumers, the necessary time off gas would be minimised. | • Any small number of domestic consumers and local businesses for whom the powers might need to be invoked would experience disruption.<br>• There is the potential that the powers may be used before all other options to engage with consumers have been exercised, causing unnecessary disruption and stress.<br>• Any use of powers in circumstances that aren't broadly recognised as a last resort may be contentious, which may lead to reputational damage for the government and/or GDN(s), and may, in a worst-case scenario, prevent the trial going ahead. |
| **Option 2 (Preferred Option)** | • More certainty for GDN(s): the legislation provides a clear legal basis for the trial to go ahead.<br>• The trial is much more likely to proceed, providing a critical part of the evidence base for hydrogen heating.<br>• We expect that the majority of domestic consumers and local businesses will take part in the trial voluntarily. For these consumers, the necessary time off gas would be minimised.<br>• Taking power to require GDN(s) to follow reasonable process incentivises them to engage consumers appropriately and in good time, providing reassurance that the powers will be used proportionately and only as a last resort – reducing the potential for disruption and stress.<br>• Following from the point above - this also reduces the risk of reputational damage to the government and/or GDN(s) from inappropriate use of powers. | • Any small number of domestic consumers and local businesses for whom the powers might need to be invoked would experience disruption.<br>• GDN(s) may incur costs in additional consumer engagement. We do not expect these to be significant or disproportionate. |

# Evidence Base

## Problem under consideration and rationale for intervention

### Strategic Context

The UK is a global leader in the energy transition and in 2019 became the first major economy to make a legally binding commitment to net zero greenhouse gas emissions by 2050.

Decarbonising buildings is central to that challenge. To meet our Net Zero goal, we urgently need to address the carbon emissions produced in heating our homes, workplaces and public buildings. There are about 30 million buildings in the UK. In total, these buildings are responsible for around 30% of our national emissions. The vast majority of these emissions result from heating: 79% of buildings emissions and about 23% of all UK emissions.

A mix of technologies and consumer options will need to be available to enable us to decarbonise at scale. Low carbon hydrogen could have the potential to be a key option for decarbonising heat in buildings. However, unlike other technologies such as heat pumps and heat networks, 100% hydrogen for heat is not yet an established option. Further work is required to assess the feasibility, costs and benefits.

The Government is working with industry, regulators and others to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heating. This work includes a pioneering programme of community trials. As set out in the Prime Minister's Ten Point Plan for a Green Industrial Revolution, the Government will support industry to deliver a neighbourhood trial by 2023, a village scale trial by 2025 and a potential hydrogen heated town before the end of the decade.

The local trials and planning work, together with the results of a wider R&D and testing programme, will enable strategic decisions in 2026 on the role of hydrogen for heat decarbonisation and whether to proceed with a hydrogen heated town.

### Trial Timeline and Design

In July 2021, BEIS and Ofgem wrote to the UK's four Gas Distribution Network Operators (GDNs), inviting them to come forward with outline proposals to deliver a hydrogen heating village trial. In December 2021, the GDNs submitted their Stage 1 Early Design proposals which BEIS and Ofgem have assessed.

The village trial will need to convert a section of the existing gas network infrastructure in a local area containing around 1,000-2,000 properties, to enable repurposing for hydrogen. This will require disconnecting a section of the local gas grid from the natural gas supply and connecting it instead to a hydrogen supply. The specific location of the trial is dependent on the outcome of the trial selection process. Final decisions on where the trial will take place are expected to be taken in 2023.

Trials of hydrogen heating will be key to evaluating the practicalities of converting to hydrogen. The village trial will look to build on evidence gained from the neighbourhood trial by providing hydrogen heating to a greater number and diversity of consumers and building types. A key difference is that, in the village trial, the existing local natural gas network will be converted from carrying natural gas to hydrogen. The real-world nature of the evidence that the trial will generate (including on the process of conversion and use of existing infrastructure) cannot be obtained by other means, making the trial crucial to enable strategic decisions on the role of hydrogen in heat decarbonisation in 2026.

The Government currently intends to support industry to conduct one village-scale trial of this nature, although additional trials may be considered should further evidence requirements come to light.

As consumers in the chosen location will not be able to remain on natural gas, they will need either to switch to hydrogen supplied through the gas distribution network or to accept provisions from the GDN for an alternative heating solution.

The GDNs have significant experience of working in local communities and directly with consumers to deliver gas projects. As part of their Village Trial proposals, the GDNs are developing consumer strategies to ensure that all occupiers in their respective proposed trial localities will be treated fairly, including those who do not want to or cannot participate in the hydrogen heating trial.

The trial will largely be funded by Ofgem and BEIS, with some private sector investment. It is therefore important that the trial provides good value for money for public funds and billpayers, including by minimising additional costs.

**Rationale for Intervention**

BEIS has analysed whether the existing legal framework adequately provides the powers necessary to carry out a village trial safely. It is not certain that GDNs would be able to rely on existing powers of entry where entry might be necessary for safety or operational reasons to enable the delivery of a hydrogen grid conversion trial. In addition, it is expected that as well as the replacement of the boiler itself, the GDNs may need to undertake alterations and works in the process of safely converting properties. These alterations and works may not be covered by the GDNs’ existing statutory remit.

Because of the interconnected nature of the local gas distribution grid, the trial could be delayed or unable to proceed at all without targeted powers to enable the GDNs to carry out the required works in all properties. In effect, without the powers, each individual consumer in the trial area could, either intentionally or inadvertently, either delay it or prevent it from happening – jeopardising a significant potential societal benefit that could be unlocked by the evidence generated by the trial and risking public funds.

Late-stage delays caused by an inability to carry out required works at the point of conversion would have a material disruptive impact on consumers and businesses in the immediate trial area, who could be left without heating and cooking for a longer period than necessary, while a broader threat to the trial taking place at all would have a much wider social impact if hydrogen were incorrectly discounted as a heat decarbonisation option as a result. Legislation is therefore required to give powers to GDNs so that they can confidently, safely and efficiently set up, run and conclude a grid conversion trial, generating crucial evidence to enable strategic decisions on the role of hydrogen in heat decarbonisation in 2026.

We expect GDNs to reach an agreement with all consumers in the chosen trial location, including those who do not want hydrogen or cannot participate in the trial. However, as it is not clear that GDNs will be able to rely on existing powers of entry to disconnect consumers from natural gas and carry out other necessary works, we are proposing to introduce powers to be used by GDNs as a last resort. These powers are necessary for the safety of consumers as it would be unsafe for people to use hydrogen without the necessary changes being made in their properties.

It is likely that access to properties within the trial area will be required prior to the commencement of the trial, in order to carry out surveys and other preparatory works. While these works would not be as time-critical as those required at the point of conversion or during the trial itself, they are a pre-requisite to conducting a trial and there may be situations where powers of entry are required to undertake them – for example, where a property is vacant and its owner cannot be contacted. We expect these instances to be very rare and the use of powers exceptional, after all other avenues have been exhausted.

In designing the intervention, we have attempted to identify a solution in the form of a bundle of provisions that appropriately balances operational considerations and consumer protection, to ensure that any potential negative impacts of the intervention are minimised. This is explored in more detail in the options assessment below.

To provide balance to the new powers of entry and minimise the likelihood of their use, BEIS is seeking powers to enable the Secretary of State to enhance existing consumer protections. These powers and protections would be in addition to the existing consumer protections for energy consumers that would apply to all consumers in the trial area. These powers would a) enable the Secretary of State to make regulations to require GDNs to follow reasonable process to ensure consumers are appropriately informed about the trial and the need for them to be disconnected from their gas supply, before they are disconnected, and b) allow the SoS to make regulations or issue a code of practice for the purpose of enhancing consumer protection. Such regulations or a code of practice could cover issues such as complaints and redress, ensuring transparency, fair treatment for all, financial fair treatment and quality of service. If regulations concerning these areas were introduced, these would be subject to consultation and have their own impacts assessed separately.

**Proportionality**

The proposed intervention has no direct regulatory impact on businesses. Furthermore, as the trial itself will involve only 1,000-2,000 properties in a tightly defined area – and we expect that the proposed powers of entry would at most be used only on a very small fraction of those properties – the impacts of the proposed powers will be small-scale and localised. The framework for the trial, reinforced by the proposed regulations, is being designed to ensure that the GDN(s) responsible for the trial use the powers only as a last resort, thereby minimising their use and consequent impact. It should also be noted that GDNs already have various powers of entry – the proposed powers are similar to these, but are specific to a hydrogen trial.

In light of these factors, and because the annual business impact of the legislation would be below the threshold value of £5m set by the Regulatory Policy Committee, we have concluded that it would be proportionate to conduct a de minimis, qualitative IA, which does not attempt to monetise impacts. In any case, the types of impacts associated with the legislation, such as potential annoyance or distress, are primarily qualitative in nature and are not readily monetised.

## Description of options considered and expected impacts

### Option 0 (Do Nothing): Attempt to run a trial with no additional legislation in place

In the 'Do Nothing' scenario, we assume that no additional legislation is introduced in advance of an attempt to run a hydrogen heating grid conversion trial. The GDN(s) responsible for delivering the trial would need to spend public and private resources over a planning, engagement and build out period of several years, without any guarantee that the trial will ultimately go live. Since it may not always be possible to isolate and/or safely disconnect an individual property externally if the required internal works cannot be carried out, any one of the 1,000-2,000 consumers in the trial area could, either intentionally or inadvertently, delay the trial or prevent it from happening.

We consider that, in the absence of additional legislation, the prospect of a very small minority of individual property owners/occupiers not accepting hydrogen or the alternative offer, or being unreachable or otherwise absent at the pre-agreed time of conversion, presents a significant risk that either the conversion process in that part of the grid, or the trial as a whole, may be delayed, or aborted altogether.

This would undermine the Government's ability to obtain the evidence necessary to enable a strategic decision on hydrogen rollout in 2026, putting at risk the broader societal benefits of exploring hydrogen as a heat decarbonisation option.

In addition to the uncertainty in planning and the risking of public and private resources, the uncertainty of timing and the potential for an inefficient rollout could have a negative impact on the consumers in the trial area, who may be without gas for longer than necessary and planned.

### Option 1: Extend existing GDN powers of entry only

Under this option, legislation would be introduced to extend the GDNs' existing powers of entry in line with those identified and required to conduct a smooth and safe rollout of hydrogen for a village trial. The Gas Act 1986 and related secondary legislation would be amended so that any legal ambiguity is removed by providing GDNs with clear legal grounds to enter private property for activities related to a hydrogen heating trial – similar to the existing powers that GDNs have when operating the natural gas networks. This would be for the purpose of a hydrogen grid conversion trial only, including necessary activities such as conducting a pre-trial survey, safely disconnecting the gas supply or safely converting the property to use hydrogen heating. It would not be for other purposes, including hydrogen trials which are not conversion trials, such as dual-pipe trials.

Extending the GDNs' powers in this way would reduce the chance that any individual consumer could – either intentionally or inadvertently – prevent the trial from proceeding, by providing a firmer legal footing for the necessary works to take place. In doing so, it would improve the chances of a timely and successful trial, <u>protecting public resources</u> and ensuring the overall value for money of the trial. It would also help <u>protect the potential benefits for society at large</u> associated with the Government's wider programme of work on hydrogen heating.

At a more localised level, the powers in themselves would impact on different groups differently. The main impacts are outlined below:

<u>GDNs (Strong Positive Impact).</u> The extended powers would only apply to the GDN(s) that are ultimately chosen to conduct the village trial. But, for the GDN(s), they would remove the high uncertainty over whether or not the trial could ultimately go ahead in the chosen area,

given the underlying ability of any one consumer to hold up essential works. By enabling necessary works to be carried out, and in an efficient and timely manner, sunk costs during the earlier phases would be protected and rollout costs would be minimised.

Domestic Consumers (Net Impact Dependent on Balance of Effects). The powers would likely have a negative impact on the very small number of households where they might be needed to be invoked. This might include stress and distress, a sense that privacy and/or choice has not been respected and, in very rare cases, temporary damage to property which would need to be remediated. However, this would be partially or fully offset by the likelihood that the powers would also make a rollout more efficient for a much larger group of households (those that have chosen to convert to hydrogen as part of the trial), whose time disconnected from a gas supply would be minimised. As it is not possible to quantify these impacts with any degree of certainty, it is not clear whether the powers will have a net positive, negative or neutral impact on domestic consumers.

Local Businesses (Net Impact Dependent on Balance of Effects). The extended powers would impact on businesses in a similar way to households. It is possible that the powers might be used to access a business premises, although there will likely be only a very small number of businesses in the trial area (the vast majority of the 1,000-2,000 properties will be domestic) and the chosen location is very unlikely to include large numbers of businesses that are reluctant to engage (see Impact on Small and Micro Businesses section below). It is not clear whether time disconnected from a gas supply would be more impactful for businesses or households overall – local stores, for example, may be less impacted, while businesses relying on gas to cook food might be more impacted. Nonetheless, as with domestic consumers, the negative impacts of the likely small number of businesses that might be affected by the extended powers would be partially or fully offset by the positive impact of a more efficient trial rollout. It is therefore also not clear whether the powers will have a net positive, negative or neutral impact on businesses.

With their powers extended, the GDN(s) would be able to ensure the safety of all consumers and properties regardless of their layout and configuration, enabling the trial to go ahead even if some property owners and/or occupiers are not contactable, or hold up the trial. The powers, therefore, minimise the delivery risk for the trials programme as a whole and provide the best chance of obtaining high-quality evidence on the feasibility of a wider grid conversion. This is of clear benefit to all consumers.

However, there are two potentially material and connected risks that may undermine the positive impacts of the powers and increase any negative impacts, making this option sub-optimal:

Over-use of powers. The GDNs already have significant experience of engaging constructively with consumers in relation to gas projects, and as a result rarely use their existing powers of entry. Nonetheless, there remains a small risk that the availability of the extended powers as a fallback would leave the GDN(s) insufficiently incentivised to properly engage with consumers or to act proportionately, responsibly and sensitively. In this case, the powers could be over-used, affecting more consumers and shifting the balance between those that are positively and negatively impacted – potentially shifting the net impact on domestic consumers and local businesses in a negative direction.

Reputational risk. It is possible that the use of powers in some circumstances could be interpreted as being controversial or contentious. This risk increases when powers are used more – the more circumstances or scenarios in which the powers are used, the greater the chance that they might be used in one that is seen as contentious. This risk carries the potential for reputational damage for both the GDN and the government, and in the worst case scenario the potential to prevent the trial from taking place.

While the trial is likely to still be able to go ahead under this Option despite these risks, it is desirable to minimise them (and so minimise any potential negative impacts) by balancing the operational needs of the GDN(s) with the rights of consumers, which we propose in our Preferred Option (Option 2) below.

**Option 2 (Preferred Option): Extend existing GDN powers of entry and build in additional consumer protection safeguards**

Under this option, legislation would be introduced to extend the GDNs' existing powers of entry by amending the Gas Act 1986 and related secondary legislation, as in Option 1, but it would also include provisions that strengthen protections for consumers in the trial area. In so doing, it would maximise the chances of a successful trial by capturing the positive impacts of the extended powers discussed above and reducing the risks that could compromise them.

It will be vital that consumers are fairly treated throughout the trial and are not disadvantaged as a result of living in the trial area. To ensure that consumers are treated fairly and to minimise the need to use the powers of entry we are proposing that the Secretary of State has the power to make regulations by statutory instrument to require the GDN(s) to follow reasonable processes to ensure consumers are appropriately informed about the trial and the need for them to be disconnected from their gas supply, before this happens.

Informed by our public consultation, we have developed a set of consumer protection policy objectives that we would expect the GDN(s) to comply with before, during and after the trial. These consumer protection policy objectives will build on existing protections within the gas regulatory system, such as: the licences that Ofgem grants to regulated entities; industry codes such as the Retail Energy Code and Uniform Network Code; and the Gas (Standards of Performance) Regulations 2005. While the existing legislative and regulatory system and trials funding framework should enable delivery of most of these objectives, we are also proposing that the Secretary of State has the power to make regulations by statutory instrument or through a code of practice. This should mitigate against the risk that the existing set of protections is found to be inadequate in the novel circumstances of a hydrogen heating trial. As the impacts of this power would only be realised via secondary legislation, they are outside of the scope of this impact assessment – but they would undoubtedly be positive for consumers.

The power to make regulations to require the GDN(s) to follow reasonable process before using the extended powers of entry would have an in-scope impact, however, insofar as it would act as a deterrent in relation to the primary powers. The prospect of binding regulations would incentivise the GDN(s) to engage properly and in good time, and to only ever use their revised powers of entry as a last resort, upon satisfying certain criteria, if all other attempts to contact the owners and reach an agreement were exhausted. For domestic consumers and local businesses, the protections ensure that any extended powers of entry are used fairly and only where absolutely necessary. The knock-on effect of this would be to minimise the number of consumers that might ultimately be subject to the powers and so minimise any negative impact.

For the GDN(s) responsible for delivering the trial, any additional consumer engagement may slightly increase their administrative burden and costs, but would materially increase the likelihood that they are seen to be acting fairly, so minimising the impacts of any potential reputational risk. Furthermore, the spending and delivery risks the GDN(s) would bear – involving both private and public resources – would still be far lower than in the 'Do Nothing' scenario where the GDNs' powers are not extended, under which any one of the 1,000-2,000 consumers could potentially prevent the trial from proceeding by either refusing to engage or being absent or uncontactable at the point of conversion.

The proposed legislative package therefore best balances the operational needs of the GDN(s) and the rights of the consumers, as well as the impacts on the two distinct groups.

This can be seen in the table below, which summarises the main impacts of the two components of the proposed legislative package and presents the net impacts of the two Options for the different groups.

| Group | Powers of Entry | SoS Powers for Reasonable Process | Net Impact (Option 1) | Net Impact (Option 2) |
|---|---|---|---|---|
| **GDN(s)** | Strong positive impact.<br><br>- Removes ability of each individual consumer to delay or prevent the trial going ahead, reducing risk, uncertainty and costs.<br>- Enables work and rollout to be carried out in an efficient and timely manner. | Weak negative impact.<br><br>- Some administrative burden and engagement costs.<br>- But ensures that GDNs are seen to be acting fairly and so mitigates against any potential reputational risk. | Strong positive. | Strong positive. |
| **Domestic Consumers** | Net impact dependent on balance of effects.<br><br>- The powers would likely have a negative impact on the very small number of households where they might be needed to be invoked.<br>- However, they would also likely make a rollout more efficient for a much larger group of households (those taking part in the trial area), whose time disconnected from gas supply would be minimised. | Positive impact.<br><br>- Ensures that powers are used fairly and only where absolutely necessary, and that GDN(s) act proportionately, responsibly and sensitively. | Dependent on balance of effects. | High likelihood of positive impact. |
| **Local Businesses** | Net impact dependent on balance of effects.<br><br>- As with households above, but with far fewer consumers affected as the vast majority of properties will be domestic.<br>- Positive impact of reduced uncertainty and more efficient rollout may be more pronounced for businesses. | Positive impact.<br><br>- Ensures that powers are used fairly and only where absolutely necessary, and that GDN(s) act proportionately, responsibly and sensitively. | Dependent on balance of effects. | High likelihood of positive impact. |
| **General / Other** | Strong positive impact. | Strong positive impact. | Strong positive. | Strong positive. |

| | | | | |
|---|---|---|---|---|
| | - Higher chance of timely and successful trial, protecting public resources and ensuring overall value for money of the trial.<br>- Lower chance of safety incidents. | - Reduces reputational risks associated with negative impacts of powers by minimising use and contentiousness. | | |

Both Options 1 and 2 would greatly reduce the risks associated with delivering a hydrogen village grid conversion trial, significantly improving the chances of producing essential evidence on hydrogen to enable strategic decisions on heat decarbonisation to take place in 2026.

Both Options also have strong positive impacts on the GDN(s) carrying out the trial and ensure that any funds for financing the trial are used appropriately and effectively.

The preferred Option (Option 2), however, balances the needs of the GDN(s) and the rights of the consumer, to minimise the use of the powers of entry and any negative impacts of the intervention for domestic consumers and local businesses that might ultimately be subject to them, while maintaining the GDNs' ability to achieve their core goal: delivering a trial in a cost-effective, timely and efficient manner.

**Distributional Impacts**

The legislative and regulatory tools proposed under the Preferred Option (Option 2) will include powers in relation to consumer protection, particularly with regards to the requirement for due process to be followed. This will ensure that all consumers remain protected and are treated fairly before, during and after the trial.

We do not expect that there will be any material distributional effects associated with this legislation and have made appropriate public sector equality duty (PSED) considerations when producing this impact assessment. It was concluded that the proposed changes to legislation would not directly disadvantage participants because of any protected characteristics they may have. While we cannot rule out the possibility that powers of entry may need to be exercised more frequently upon certain groups, the GDN(s) will be required, under the overall trial framework and reinforced by secondary powers, to exercise appropriate duty of care for each consumer within the trial area, which should address any variation in engagement needs between different groups.

At a wider scale, the cost of the village trial itself will be socialised. Therefore, any operational efficiencies achieved through the introduction of our preferred legislative option (Option 2), compared with the Do Nothing alternative, could result in lower trial costs overall and so have a very small positive impact on consumer bills at the individual household level.

## Impact on small and micro businesses

Since the proposed legislation will only apply directly to GDN(s) conducting a hydrogen grid conversion trial, it would not regulate business behaviour at large and therefore would not cause any regulatory costs under the business impact target framework.

Furthermore:

(i) The proposed legislation would only affect the very small number of small and micro businesses that fall directly within the trial area. The village trial will involve only 1,000-2,000 properties, the vast majority of which will be domestic.

(ii) It is not clear that the proposed legislation – even the powers – would have a net negative impact on those small businesses that do lie within the trial area. As outlined above, any negative impacts experienced by the small subset of businesses on whom the powers might need to be used are likely to be partially or fully offset by the positive impact of those powers on a larger subset of businesses who would experience a smoother and more efficient switchover process, with any time disconnected from a gas supply minimised. This is particularly the case in the Preferred Option (Option 2), as the added protections would minimise the instances in which the powers are used and therefore minimise any potential negative impacts.

It is also the case that, throughout the trial planning phase, the GDN(s) will be required to engage constructively with all consumers, including owners of small or micro businesses. The GDNs will need to demonstrate strong public support from consumers within the trial area as a pre-requisite for any trial taking place – again limiting the likely use of powers and any impacts.

It is therefore unlikely that small or micro businesses within a trial area would be significantly impacted as a result of the proposed legislation.

## Summary and preferred option with description of implementation plan

We are proposing to introduce primary legislation in order to:

- extend existing powers of entry as described above.
- include a power for the Secretary of State to make regulations by statutory instrument to require the GDN(s) to follow reasonable processes to ensure consumers are appropriately informed about the trial and the need for them to be disconnected from their gas supply, before this happens.
- include a delegated power for the Secretary of State to make secondary legislation (through regulations or a code of practice), if it becomes necessary, for the purposes of ensuring that consumers are treated fairly and protected from being disadvantaged in relation to a trial.

As the proposed amendments to the GDNs' powers build on what is already covered in the Gas Act 1986, there will not be any transitional arrangements.

The legislative proposals will facilitate the delivery of the grid conversion trial and its objective, which is to gather evidence and inform strategic decisions on the role of hydrogen in heat decarbonisation in 2026.

Specifically, the proposals will achieve this by ensuring that:

- The gas networks are able to carry out the necessary activities to deliver a safe and effective trial, by resolving ambiguity within the current legislative framework and therefore reducing the likelihood of delay.
- Consumers remain protected and treated fairly for the duration of the trial and after through the option of secondary legislation to underpin our wider consumer protection policy that will be achieved through existing legislative and other non-legislative levers.

Together, these proposals form a balanced package of amendments that will provide for safe and effective delivery of the trial, while safeguarding consumers' interests.

It is envisaged that the proposed amendments will come into force by the summer of 2023.

The existing enforcement regime under the Gas Act 1986 will apply for the powers of entry. This means that consumers who consider that a GDN is seeking to enter their property for a purpose not covered by the new powers of entry would still have the same recourse as now. For example, they would be able to appeal the issue of a warrant in the magistrates' court.

Consumer protection will be delivered through a range of tools, such as legislation (including the new proposed powers) and regulatory frameworks, such as licence obligations and industry codes, and conditions placed on funding provided to the GDN(s). Enforcement related to any secondary legislation on consumer protection will be determined in due course. It is currently envisaged that a core aspect of the redress available to consumers would be for them to bring a complaint through an alternative dispute resolution process.

## Monitoring and Evaluation

As the primary purpose of the village trial is to generate evidence on the feasibility of hydrogen conversion, monitoring and evaluation will be a key consideration for all aspects of the trial. Government will monitor any instances where the additional powers of entry need to be used, working with the GDN(s) to ensure that they are being used proportionately while fulfilling their intended purpose.

The regularity of the GDNs' updates to Government on the operation of their trial and the format they will use for data collection is still to be decided – the framework will continue to evolve over the first half of 2022. The GDN(s) will start collecting evidence from spring 2022 and are already in the process of commencing local stakeholder engagement.

Should Government become aware of any unforeseen instances where powers of entry are being used disproportionately, it will take action to ensure that such instances are prevented in future, including through the Secretary of State's new powers to make regulations by Statutory Instrument. This will provide an avenue through which action can be taken to ensure existing consumer rights are protected and built upon.

All feedback Government receives from consumers or the GDN(s) regarding the operation of the powers or consumer protections will be used to inform any future legislative amendments of a similar nature.

| | |
|---|---|
| **Title:** Hydrogen and Industrial Carbon Capture Business Models<br>**IA No:** BEIS049(F)-22-HICCD<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy and Industrial Strategy (BEIS)<br>**Other departments or agencies:** | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** EnergyBill2021@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** Not a regulatory provision |
| n/a | n/a | n/a | |

**What is the problem under consideration? Why is government action or intervention necessary?**

The deployment of low carbon hydrogen (referred to throughout as "hydrogen") production and carbon capture for industrial users will be essential in decarbonising the UK economy. To overcome market barriers and realise the contribution these technologies can make to achieving the Government's statutory carbon emissions reduction targets, the Government has announced a number of measures aiming to accelerate deployment, including the hydrogen and industrial carbon capture ("ICC") business models. This impact assessment considers the primary provisions that will underpin the delivery of these business models.

**What are the policy objectives of the action or intervention and the intended effects?**

The hydrogen and ICC business models aim to provide funding for long-term revenue support which enables the private sector (and Government) to take Final Investment Decisions (FIDs) on a pipeline of decarbonisation projects, playing an important role in putting the UK on a pathway to (i) meet the 2030 deployment ambitions set out in the Net Zero Strategy and British Energy Security Strategy; (ii) ensure the required emission reductions for the Sixth Carbon Budget; and (iii) reach net zero by 2050.
The primary objective of the primary legislation covered by this impact assessment is to allow Government to:

- Incur expenditure and provide financial assistance to support the establishment of hydrogen production and ICC through the business models;
- Designate and direct a counterparty to each business model;
- Enable the establishment of a competitive allocation process in respect of each business model.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

The policy options considered for meeting the business model objectives are:

**Policy option 1:** Do nothing/business as usual. Under this option there is no hydrogen or ICC business model.

**Policy option 2:** Legislate for financial assistance and counterparty powers to enable business model support.

**Policy option 3:** Legislate for financial assistance and counterparty powers to enable business model support, and powers which facilitate competitive allocation.

| **Will the policy be reviewed?** It will not be reviewed | | **If applicable, set review date:** n/a | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro** No | **Small** No | **Medium** No | **Large** No |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** - | **Non-traded:** - | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

## Summary: Analysis & Evidence

Policy Option 3

**Description:**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year | PV Base Year | Time Period Years | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| n/a | n/a | 2022-2050 | **Low:** n/a | **High:** n/a | **Best Estimate:** n/a |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | n/a | | n/a | **n/a** |
| **High** | n/a | | n/a | **n/a** |
| **Best Estimate** | n/a | | n/a | **n/a** |

**Description and scale of key monetised costs by 'main affected groups'**

The estimated cost of this primary legislation, by itself, is zero. Costs are likely to be incurred through revenue support contracts which are entered into with hydrogen producers and industrial carbon capture entities. The scale of these costs will depend on policy decisions that go beyond the design of these primary provisions and is therefore out of scope of this impact assessment.

**Other key non-monetised costs by 'main affected groups'**

Secondary legislation may create administrative and familiarisation costs which have not been monetised in this impact assessment. These may include costs incurred by project developers, a counterparty in undertaking its role in managing revenue support contracts, an allocation body in administering a future competitive allocation process and any body dealing with appeals.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | n/a | | n/a | **n/a** |
| **High** | n/a | n/a | n/a | **n/a** |
| **Best Estimate** | n/a | | n/a | **n/a** |

**Description and scale of key monetised benefits by 'main affected groups'**

The estimated benefit of this primary legislation, by itself, is zero. Benefits may be realised through revenue support contracts which stimulate the deployment of hydrogen and ICC. These could include reduction in carbon emissions, potential cost savings to end users of displacing fossil fuel use, and wider economic benefits such as in the UK supply chain and jobs. These are not monetised in this impact assessment for reasons outlined above.

**Other key non-monetised benefits by 'main affected groups'**

The estimated benefit of this primary legislation, by itself, is zero. Revenue support contracts may also provide additional non-monetised benefits. These might include long term strategic benefits of cost reductions and the option value to use new technologies to further increase carbon savings beyond 2030.

| **Key assumptions/sensitivities/risks** | **Discount rate** | n/a |
|---|---|---|
| This impact assessment assumes this primary legislation by itself will have no impact on businesses and consumers. | | |

**BUSINESS ASSESSMENT (Option 3)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** n/a | **Benefits:** n/a | **Net:** n/a | n/a |

# 1. Problem under consideration and policy objectives

## 1.1. Problem under consideration

1. The UK is committed to the legally binding target of net zero greenhouse gas emissions by 2050. In 2021, the Government enshrined in law a new target to reduce greenhouse gas emissions by 78% by 2035 when compared against 1990 levels, as part of the Sixth Carbon Budget. This will require emissions reductions across the economy.

2. Low carbon hydrogen (referred to throughout as "hydrogen") will be a key source of low-carbon energy as we decarbonise. It is especially useful in 'hard to electrify' areas like parts of industry and heavy transport including shipping, and aviation, and could provide flexible low carbon energy for the power sector and domestic heating. While in some sectors there is a degree of optionality (e.g., heating), significant hydrogen production is needed to achieve net zero even at the lower end of projected demand ranges[1].

3. For many key industries, such as chemicals, cement and waste management, there are significant challenges associated with reducing the emissions generated as a by-product from their output. Without carbon capture usage and storage (CCUS), emissions from current industrial processes cannot be reduced to levels consistent with net zero.

4. Deployment of hydrogen and ICC over the 2020s and 2030s is essential to meeting carbon budgets and net zero by 2050. While hydrogen production and ICC are technically proven and have been deployed successfully internationally, they have not been deployed at scale in the UK and remain pre-commercial. In particular, both hydrogen production and ICC (including application of CCUS in waste management processes as well as in traditional industry), are currently not cost competitive compared to the higher carbon and more technologically mature alternatives (such as using natural gas as a fuel vs hydrogen). Without viable commercial models that address key market failures and barriers, the private sector will not invest and deploy these technologies at the scale nor speed required.

5. Government has set out its ambition in the Net Zero Strategy[2] to deliver four CCUS clusters, capturing 20-30 megatonnes of carbon dioxide ($MtCO_2$) across the economy, including $6MtCO_2$ of industrial emissions, per year, by 2030. The British Energy Security Strategy[3] doubled the Government's ambition to up to 10GW of low carbon hydrogen production capacity by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen. The Government has also set out an ambition to have up to 2GW of low carbon hydrogen production capacity (1GW of electrolytic; 1GW of CCUS-enabled) in operation or construction by 2025. To achieve these ambitions, the Government has committed to business models for hydrogen and ICC which are intended to overcome the significant market barriers faced across the value chain which inhibit their widespread deployment.

6. The Net Zero Strategy announced the establishment of the Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme which will fund these business models. Up to £140m was committed to establish the IDHRS scheme, including up to £100m to enable the deployment of the first electrolytic hydrogen projects. Further details on the funding envelope for ICC projects (including application of CCUS in waste management processes as well as in traditional industry) and CCUS-enabled hydrogen projects is expected in 2022, with the first contracts being awarded from 2023 through the Cluster Sequencing process[4].

7. The Net Zero Strategy also stated that from 2025 at the latest, all revenue support for hydrogen production will be levy funded, subject to consultation and legislation being in place. A separate impact assessment has been prepared for the hydrogen levy (see Annex 1.5).

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[1] https://www.gov.uk/government/publications/uk-hydrogen-strategy

[2] https://www.gov.uk/government/publications/net-zero-strategy

[3] https://www.gov.uk/government/publications/british-energy-security-strategy

[4] https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-2

8. This impact assessment considers the primary legislation which is required to deliver the hydrogen and ICC business models.

### 1.2. Policy objectives

9. This legislation is designed to support three specific policy objectives:

- **Provide revenue support for low-carbon hydrogen production and ICC projects** from 2023 to bring through investments and enable successful deployment of projects from 2024/5 onwards;

- **Provide funding certainty on a return on capital investment and operational costs for hydrogen and ICC projects** over their business model contract lifetime including by addressing technology-specific risks, helping to de-risk private sector investment and create a pipeline for future projects; and

- **Drive down deployment costs throughout the 2020s and 2030s** by supporting initial projects (subject to value for money (VfM) considerations) seeking to take final investment decisions (FIDs) in the 2020s, and subsequently through competitive funding allocation and business model design.

## 2. Rationale for intervention

### 2.1. Rationale for intervention in the hydrogen market

10. There are a number of market failures and barriers inhibiting the production of hydrogen. The main barriers include:

- The **cost of hydrogen** is higher than most high-carbon counterfactual fuel alternatives. The lack of a fully developed market, imperfect investor information and the presence of a negative externality linked to carbon all contribute to this lack of cost competitiveness.

- Hydrogen technologies are **risky for investors** as they have not been proven at commercial scale in the UK. While some technology is already in use, many applications need to be proven at scale before they can be widely deployed. There is a first mover disadvantage, where project developers for the first at-scale hydrogen projects bear significant learning costs and risks but may not capture the full benefits of the investment, as market competitors capture their know-how.

- The **lack of a market structure** also means that coordination failures might lead to suboptimal market outcomes, for example undersupply, as lack of investment in one section of the market deters investment elsewhere. Uncertainty about future supply might deter end users to switch to hydrogen, in turn lowering the incentives for new producers to enter the market. At the same time, even if producers enter the market, they might still face uncertain demand for hydrogen they produce as a result of market's immaturity. This could lead to the producers having to sell at low prices or build-up stocks and could pose a risk to the economic viability of the project.

11. The Government has been working with industry to develop the hydrogen business model to incentivise the production of hydrogen by overcoming these barriers and giving investors the long-term revenue certainty they require to invest. This business model was consulted on from August to October last year, and a government response was published on 8 April 2022[5].

### 2.2. Rationale for intervention in the ICC market

[5] https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

12. There are a number of market failures inhibiting the deployment of ICC (including application of CCUS in waste management processes as well as in traditional industry). The main barriers include:

- The presence of **negative externalities that arise due to the social costs from carbon emissions that** are not accounted for by industrial plants when operating their business. This is mitigated to some extent but not fully by application of the UK ETS to industrial sectors. The waste management processes in scope of the ICC business model as part of Phase-2 of the CCUS cluster sequencing programme are also not currently part of the UK ETS or any other carbon pricing mechanism. However, Government has consulted on Developing the UK ETS in 2022, which included a call for evidence on expanding the UK ETS to include waste incineration and energy from waste.

- Initial developers of **ICC will face higher costs** compared with subsequent competitors. Firstly, due to technology having higher capital costs for installation and operation until it is demonstrated more widely at scale. Secondly because initial investment requires a higher return to account for the risk associated with technology uncertainty. Industrials will be reluctant to be the first mover in carbon capture as they create knowledge and de-risk the technology for others and face the risk of stranded assets.

- ICC requires **coordination of multiple actors**, each facing investment decisions with long lead times. Emitters require a functioning and accessible $CO_2$ transport and storage (T&S) network before installing capture technology. Similarly, $CO_2$ T&S operators require certainty over emission streams before appraising storage sites and laying pipelines. These interdependencies lead to uncertainty around risk allocation in the event of a failure of a component within the CCUS value chain.

- ICC investors face **imperfect information**. The market mechanism fails to support CCUS on its own due to a competitive disadvantage relative to mature technologies, uncertainties surrounding the precise costs and challenges of operating the technology, and the level of future carbon prices.

13. Taken together, these market failures make it highly unlikely that ICC would be rolled out to the levels necessary to reach net zero emissions by 2050 without government intervention.

## 2.3. Rationale for primary powers

*Financial Assistance*

14. To address market failures, high start-up costs and uncertainty, powers are sought to enable the Government to incur such costs or liabilities and provide such financial assistance as the Secretary of State considers necessary and proportionate to incentivise investment in, and facilitate delivery of, hydrogen production and ICC. The taxpayer will provide funding for initial hydrogen business model contracts and the duration of the ICC business model contracts. The hydrogen business model then will transition to levy funding, subject to consultation and legislation being in place (see hydrogen levy impact assessment in Annex 1.5).

*Powers to designate and direct a counterparty*

15. The contractual nature of the hydrogen and ICC business models require a counterparty to manage the revenue support contracts and act as conduit for the funding. A private law contract with a counterparty that manages it in an operationally independent manner delivers a clear and transparent approach to hydrogen producers and ICC entities, with clear rules around how the contract will be managed, and any disputes handled. This in turn provides industry with more certainty about what its obligations are and that it will be treated fairly. The legislation includes powers for Secretary of State to designate and direct a counterparty to each of the hydrogen and ICC business model revenue support contracts.

*Powers to establish a competitive allocation process*

16. An important feature of the hydrogen and ICC business models is determining how support will be allocated. It is anticipated that support will be awarded through a series of allocation rounds and the format of these allocation rounds is expected to change over time to reflect evolving market conditions and policy objectives. Initial projects are expected to be allocated support through a bilateral process following an evaluation against set criteria.

17. In the medium term, the hydrogen and ICC business models are expected to move to a more competitive allocation approach (e.g. auction). Such a process can achieve similar benefits to the contracts for difference ("CFD") auctions for low carbon electricity generation, which is seen as a key driver for cost reductions in low carbon generation, particularly offshore windfarms, and is underpinned by provisions in the 2013 Energy Act. Underpinning this process in legislation will provide important assurance to investors and encourages the continued to development of the project pipeline. More competition within the allocation process itself encourages projects to identify cost savings which can be passed through to government and consumers. For the hydrogen and ICC business models the transition to a more competitive process and the final design will depend on a variety of different factors, including (but not limited to):

    - Size of the pipeline – large enough pipeline to facilitate competition
    - Sector maturity – (for hydrogen) a more mature market reduces demand risk
    - Interdependencies – ICC and CCUS-enabled hydrogen projects are reliant on $CO_2$ T&S

18. The legislation includes powers for Secretary of State to establish, and set out the details of, a competitive allocation process in respect of each of the hydrogen and ICC revenue support contracts. This includes the power to appoint an allocation body to administer the competitive allocation process.

## 3. Option analysis

### 3.1. List of policy options under consideration

19. **Policy option 1: Do nothing/business as usual. Under this option there is no hydrogen or ICC business model.** Capital co-funding for hydrogen and ICC projects may still be available through the Net Zero Hydrogen Fund (NZHF) and Carbon Capture and Storage Infrastructure Fund (CIF), and industry would rely on market revenue once operational. There is a mix of market failures, set out in more detail in section 2, which means that without revenue support through the business models in addition to these funds and other interventions, it is likely that private investors would delay investment decisions, move investment abroad, or decide not to invest altogether, meaning there would be no large-scale hydrogen or ICC deployment in the UK in the 2020s. This would make the ambition for up to 10GW of low carbon hydrogen production and $6MtCO_2$ captured and stored industrial emissions by 2030 unachievable. This is highly unlikely to deliver the levels of deployment to put the UK on a pathway to meet the Government's legally binding carbon budget and net zero targets. Therefore, this option has not been taken forward.

20. **Policy option 2: Legislate for financial assistance and counterparty powers to enable business model support.** Under this option, the Government would secure the primary provisions needed to provide financial assistance to industry through revenue support contracts. Government would also take powers to designate and direct a counterparty which would be responsible for holding private law contracts with industrial carbon capture entities and hydrogen producers. This contractual arrangement would provide investors and projects with the confidence they need to invest their upfront capital into a project. This option therefore has the potential to deliver on the Government's ambition for up to 10GW of low carbon hydrogen production and $6MtCO_2$ captured and stored industrial emissions by 2030.

21. **Policy option 3: Legislate for financial assistance and counterparty powers to enable business model support, and powers which facilitate competitive allocation.** Under this option, in addition to the benefits of policy option 2 which are critical to achieving our 2030 ambitions, it is possible for the business models to be allocated on a more competitive basis in the future. This is seen as the best way to reduce costs to government and the consumer (when the hydrogen levy is in place). In addition to meeting the Government's decarbonisation ambitions, this policy option brings the additional benefits of driving down technology costs by improving competitive tensions in the allocation process. By legislating for competitive allocation now, the transition from the initial bilateral allocation process could take place as soon as possible.

### 3.2. Preferred option

22. BEIS considers that policy option 3 is the most viable approach to achieving the policy objective set out in section 1.2. BEIS assesses that securing this option will help to achieve the policy objective of deploying hydrogen and ICC at a scale sufficient to meet ambition for 6Mt$CO_2$ captured and stored industrial emissions and up to 10GW of low carbon hydrogen production capacity by 2030, and to put the UK on a pathway to achieving the legally binding carbon budgets and net zero targets.

23. The consultation on the design of a business model for low carbon hydrogen set out this approach as the preferred option and sought stakeholder views. BEIS published a government response to that consultation on 8 April 2022. This confirmed our intention to proceed with a contractual producer-focused business model, applicable to a range of hydrogen production pathways and able to facilitate hydrogen use in a broad range of sectors. The model will provide price support through a variable premium, which pays the difference between a strike price reflecting the cost of producing hydrogen and a reference price reflecting the market value of hydrogen. The model will provide volume support through a sliding scale in which the strike price will be higher if hydrogen offtake falls.

24. The Government consulted on CCUS business models in 2019[6] which set out the emerging findings from work on possible new business models and sought views from stakeholders. BEIS published a government response to that consultation on 17 August 2020. This confirmed the Government's preferred approach to implement an industrial form of the CFD model with a counterparty to manage contracts. It was also stated that government envisages the allocation of business model contracts could transition from bilateral negotiations towards more competitive auctions.

25. The proposed powers will enable the Secretary of State to provide funding for the business models and designate a counterparty to manage the revenue support contracts. Subsequent regulations will be required for elements of the regime, for example to define who is eligible for support. It is anticipated that these powers will be exercised shortly after the Bill receives Royal Assent so that FIDs can be taken with hydrogen producers and ICC entities so the Government's decarbonisation ambitions can be realised.

26. Work is underway on the design of a future competitive allocation process, which will aim to provide VfM to government and consumers by increasing competition and driving down technology costs. The establishment of a future competitive allocation process would be given effect through secondary legislation, following more detailed policy design and consultation.

## 4. Costs

### 4.1. Costs to Government

27. This primary legislation includes financial assistance powers which enable government to provide revenue support to hydrogen producers and ICC entities. Funding will be provided through the

[6] https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models

IDHRS scheme which will fund ICC business model contracts and initial hydrogen business model contracts.

28. The legislation will not specify any direct quantum of funding which will be allocated through the financial assistance powers. The financial assistance powers grant the flexibility for government to provide financial assistance to the activities specified, with money which will be allocated through the normal budget and spending review processes. The funding will be subject to the usual spending controls, such as business cases, to ensure options appraisal and VfM considerations are fully evaluated. Decisions on how to use this power will be taken separately and an assessment of impacts will need to be taken at the point when the power is used.

### 4.2. Costs to business

29. This primary legislation provides enabling powers to facilitate the deployment and operation of the hydrogen and ICC business models and does not, by itself, directly create any additional costs to businesses.

30. Secondary legislation may create administrative and familiarisation costs. These may include costs incurred by project developers, a counterparty in undertaking its role in managing revenue support contracts, an allocation body in administering a future competitive allocation process and any body dealing with appeals. An assessment of these impacts will be conducted for any secondary legislation which may follow.

### 4.3. Costs to consumers

31. This primary legislation provides enabling powers to facilitate the deployment and operation of the hydrogen and ICC business models and does not, by itself, directly create any additional costs to consumers.

## 5. Benefits

The estimated benefit of this primary legislation, by itself, is zero. Benefits will be realised following the enactment of the full legislative package (primary and secondary), finalisation of the hydrogen and ICC business models, implementation of the allocation process and the consequential construction and operation of hydrogen production plants and carbon capture entities once revenue support contracts are entered into. These could include a reduction in carbon emissions, potential cost savings to end users of displacing fossil fuel use, and wider economic benefits such as in the UK supply chain and jobs.

## 6. Other impacts

### 6.1. Potential trade implications of the measure

32. This primary legislation is not expected to directly impact international trade and investment.

### 6.2. Public Sector Equality Duty

33. A Public Sector Equality Duty (PSED) assessment has been completed for this primary legislation. The PSED gives due regard to meeting the three aims under Section 149 of The Equality Act 2010 including eliminating unlawful discrimination, the advancement of equality of opportunity among those with protected characteristics and fostering good relations between people with protected characteristics.

34. The primary legislation is not expected to have any impact by itself on the protected characteristic groups (PCGs). There are no disproportionate impacts currently identified for any of the PSED

groups which include: Age, Marriage/Civil Partnership, Religion or Belief, Sex, Gender Reassignment or Sexual Orientation PCGs, Disability, Race and Pregnant/Maternity PCGs.

35. This assessment will be kept under review. A separate PSED assessment will need to be conducted, reviewed, and monitored for impacts associated with any secondary legislation which may follow.

### 6.3. Impact on small and micro businesses

36. This primary legislation is expected to have no impact by itself. Therefore, its estimated impact on small and micro businesses is zero. Secondary legislation may create administrative and familiarisation costs for small and micro businesses for example, costs incurred by project developers. An assessment of these impacts will be conducted for any secondary legislation which may follow.

### 6.4. Regional impacts

37. The deployment of hydrogen and ICC can play a vital role in levelling up the economy throughout the UK. Business model support is intended to be UK wide and has the potential to particularly benefit industrial regions which are to a large extent located in Scotland, South Wales, and the North of England.

38. There are industrial clusters in England, Scotland and Wales where significant investment into CCUS-enabled hydrogen and ICC will help to secure existing jobs whilst creating new jobs. Electrolytic hydrogen will often be co-located in areas of high renewable potential such as Scotland and coastal areas. The proposed industrial clusters and the known project pipeline is likely to see major projects delivered across the UK in England, Scotland, and Wales, with potential for plans for Northern Ireland in the future.

## 7. Monitoring and Evaluation

39. A monitoring and evaluation (M&E) plan is currently being developed in conjunction with the NZHF and CIF capital co-funding schemes.

40. The scope of the M&E plan will include a process, impact, VfM and ultimately a system evaluation. This is to capture all aspects of policy impacts alongside dependent policy interactions.

41. Through a process evaluation we will aim to understand the effects of the allocation process, and the transition to a future competitive allocation, as well as aspects such as counterparty reporting.

42. Through an impact evaluation we will seek to understand aspects of business model design to allow for improvements between allocation rounds.

| | |
|---|---|
| **Title:** Hydrogen Levy Powers<br>**IA No:** BEIS050(F)-22-HICCD<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy and Industrial Strategy (BEIS) | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** EnergyBill2021@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2020 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** Not a regulatory provision |
| £0m | £0m | £0m | |

**What is the problem under consideration? Why is government action or intervention necessary?**

The deployment of low carbon hydrogen (referred to throughout as 'hydrogen') will be essential in decarbonising the UK economy. However, due to a range of barriers and market failures including high costs of hydrogen relative to fossil fuels, first mover disadvantage and uncertainties about future demand, technology readiness and regulatory environment, this won't be realised without government intervention. To realise the contribution hydrogen can make to achieving the Government's statutory carbon emissions reduction targets, the Government has announced a number of measures aiming to accelerate hydrogen deployment, including a hydrogen business model to bring forward private sector capital investment in hydrogen production. The business model will be delivered within the framework of the new Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme. The 2021 Spending Review provided tax-payer funding for IDHRS up until 2024/25. As set out in the Net Zero Strategy, all revenue support for hydrogen production will then be levy funded from 2025 at the latest. This Impact Assessment evaluates both tax-payer and levy funding options for the hydrogen business model and focuses on new primary powers to enable the creation of a dedicated hydrogen levy as set out in the Net Zero Strategy.

**What are the policy objectives of the action or intervention and the intended effects?**

The IDHRS scheme (irrespective of funding source) aims to provide funding for long-term revenue support which is delivered via a hydrogen business model. This enables the private sector (and Government) to take Final Investment Decisions (FIDs) on a pipeline of decarbonisation projects, playing an important role in putting the UK on a pathway to: a) Meet the hydrogen deployment ambitions set out in the British Energy Security Strategy by 2030; b) Ensure the required emission reductions for Carbon Budget 6; and c) Reach Net Zero by 2050.

Securing a stable funding source for the hydrogen business model is instrumental in meeting those objectives. The preferred funding route will have to be sustainable over the long term, protect public finances, consider affordability and fairness for payers, and be adaptable to changes in the energy market.

The powers under consideration relate to funding hydrogen production projects only (referred to throughout as 'hydrogen projects').

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

The options considered for meeting the objectives with regard to the hydrogen business model are:

**Option 1:** Do nothing. Under this option there is no funding for the hydrogen business model.

**Option 2:** Tax-payer funding as the funding source for the IDHRS scheme to fund the hydrogen business model.

**Option 3:** Expand existing levy frameworks to provide the funding source for the IDHRS scheme to fund the hydrogen business model.

**Option 4:** Obtain new powers to establish a levy funding mechanism to provide the funding source for the IDHRS scheme to fund the hydrogen business models.

| **Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:** n/a | | | | | |
|---|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | | |
| Are any of these organisations in scope? | **Micro**: Yes | **Small** Yes | **Medium** Yes | | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** n/a | | **Non-traded:** n/a | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

# Summary: Analysis & Evidence

Policy Option 4

**Description:** Obtain new powers to provide the option of establishing a dedicated hydrogen levy to fund the hydrogen business model

**FULL ECONOMIC ASSESSMENT**

| Price Base Year | PV Base Year | Time Period Years | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| 2020 | 2020 | 2021 - 2050 | **Low:** £0m | **High:** £0m | **Best Estimate:** £0m |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | n/a | | n/a | **n/a** |
| **High** | n/a | | n/a | **n/a** |
| **Best Estimate** | n/a | | n/a | **n/a** |

**Description and scale of key monetised costs by 'main affected groups'**

The estimated cost of this primary legislation, by itself, is zero. Costs may be incurred when secondary legislation is passed at a later date which introduces a levy and final investment decisions on specific projects are made. Funding is only delivered via the hydrogen business model when a project becomes operational. This Impact Assessment presents a set of illustrative estimates highlighting the potential distributional impacts and the trade-offs associated with future levy design, without providing full costings of secondary legislation decisions.

Any attempt to monetise future costs and benefits of the proposed levy in full would require making assumptions about IDHRS policy design decisions and, by implication, would be subject to significant uncertainty. We are, therefore, unable to monetise the expected size of the IDHRS scheme for hydrogen projects, its net overall impacts, and by implication the full costs and benefits of the preferred funding route. The total IDHRS costs to support hydrogen projects depends on policy decisions that go beyond levy design considerations. Therefore, this IA focuses on impacts flowing directly from competing levy choices, that is predominantly on their cost distribution implications.

**Other key non-monetised costs by 'main affected groups'**

When implemented at secondary legislation stage the levy would create administrative costs which have not been monetised in this Impact Assessment. These are likely to include familiarisation costs, updating systems and engagement to notify customers of the new levy, and the costs of managing levy payments.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | n/a | | n/a | **n/a** |
| **High** | n/a | | n/a | **n/a** |
| | | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

The estimated benefit of this primary legislation, by itself, is zero. Benefits would be unlocked if secondary legislation is agreed at a later date resulting in the deployment of hydrogen. These could include reduction in carbon emissions, potential cost savings to end users of displacing fossil fuel use, air quality improvements, and wider economic benefits such as in the UK supply chain and jobs. These are not monetised in this IA for reasons outlined above.

| **Other key non-monetised benefits by 'main affected groups'** | |
|---|---|
| When secondary legislation is agreed at a later date, there may also be additional non-monetised benefits. These might include long term strategic benefits of cost reductions and the option value to use new technologies to further increase carbon savings beyond 2030. | |
| **Key assumptions/sensitivities/risks** **Discount rate (%)** | |
| This Impact Assessment assumes this primary legislation by itself will have no impact on businesses and consumers. When a new levy is implemented its impact will depend on policy decisions about hydrogen business model design, and these will have a significant impact on the estimates of the total cost of the IDHRS scheme and the revenue required to be raised through the levy, all of which are highly uncertain. To avoid this policy uncertainty, this IA uses a hypothetical example of an £1/MWh increase in electricity and gas prices to illustrate potential distribution of levy costs. The analysis uses BEIS internal assumptions about the future trajectory of the gas and electricity market. | |

**BUSINESS ASSESSMENT (Option 4)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** 0 | **Benefits:** 0 | **Net:** 0 | n/a |

## 1. Problem under consideration and rationale for intervention

1.1. Low carbon hydrogen (referred to throughout as 'hydrogen') is critical for the UK's transition to net zero as a versatile replacement for high carbon fuels used today. Hydrogen has the potential to help decarbonise vital UK industrial sectors and provide a source of low carbon energy across heat, power and transport. The British Energy Security Strategy[1] builds on the Net Zero Strategy[2] and the Hydrogen Strategy[3], both published last year, to set out how the UK can drive progress in the 2020s to deliver the government's ambition of up to 10GW of hydrogen production by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen. The Government has also set out an ambition to have up to 2GW of low carbon hydrogen production capacity (1GW of electrolytic; 1GW of CCUS-enabled) in operation or construction by 2025. This will put the UK on a pathway to meeting the legally binding Sixth Carbon Budget and Net Zero by 2050.

1.2. There are a number of market failures and barriers inhibiting the production of low carbon hydrogen. The main barriers include:

- The cost of hydrogen is higher than most high-carbon counterfactual fuel alternatives. The lack of a fully developed market, imperfect investor information and the presence of a negative externality linked to carbon all contribute to this lack of cost competitiveness.
- Hydrogen technologies are risky for investors as they have not been proven at commercial scale in the UK. While some technology is already in use, many applications need to be proven at scale before they can be widely deployed. There is a first mover disadvantage, where project developers for the first at-scale hydrogen projects bear significant learning costs and risks but may not capture the full benefits of the investment, as market competitors capture their know-how.
- The lack of a market structure also means that coordination failures might lead to suboptimal market outcomes such as undersupply where the lack of investment in one section of the market deters investment elsewhere. Uncertainty about secure future supplies of hydrogen might deter end users from switching to hydrogen, which in turn lowers the incentives for new producers to enter the market. Similarly for producers they might still face uncertain demand for the hydrogen they produce as a result of the market's immaturity. Currently there is limited use of hydrogen in the UK and producers face some uncertainty over whether their supply will be matched by market demand. This could lead to the producers having to sell their hydrogen below cost or build-up stocks and could pose a risk to the economic viability of the project.

1.3. The government has been working with industry to develop a hydrogen business model to incentivise the production of hydrogen by overcoming these barriers and giving investors the long-term revenue certainty they require to invest. This business model was consulted on from August to October last year[4], and a government response was published on 8 April 2022.

1.4. The government's Net Zero Strategy also announced the establishment of the Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme to fund the hydrogen and Industrial Carbon Capture business models[5]. Up to £140m was committed to establish the IDHRS scheme up to 2024/25, including up to £100m to enable the deployment of the first electrolytic hydrogen projects..

1.5. Finally, the Net Zero Strategy also stated that from 2025 at the latest, all revenue support for hydrogen production will be levy funded, subject to consultation and legislation being in place[6]. To enable this, primary legislation will be progressed at the earliest opportunity.

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[1] https://www.gov.uk/government/publications/british-energy-security-strategy

[2] https://www.gov.uk/government/publications/net-zero-strategy

[3] https://www.gov.uk/government/publications/uk-hydrogen-strategy

[4] https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

[5] This impact assessment considers options for funding the hydrogen business model only.

[6] As confirmed in the May 2021 Cluster Sequencing launch document, an Industrial Carbon Capture Contract will be funded from the exchequer.

1.6. This Impact Assessment considers options for securing a sustainable long-term funding stream for the hydrogen business model through the IDHRS scheme, building on the views expressed through the hydrogen business model consultation last year, and the strategic approach to net zero funding set out in HM Treasury's Net Zero Review[7].

## 2. Policy objective

2.1. The IDHRS scheme has been established to provide the framework for funding the hydrogen business model. The primary objective of the IDHRS scheme is to **provide a sustainable, long-term funding stream for the hydrogen business model, sufficient to deliver on the government's ambition for up to 10GW of low carbon hydrogen production by 2030.**

2.2. The duration of hydrogen business model contracts is still under consideration although we have indicated through the Government Response to the hydrogen business model consultation that our starting point is for contract duration to be set between 10 to 15 years. This builds on precedents for similar support schemes where contract durations are 10-20 years and provides contractual certainty of support needed by investors and projects.

2.3. Revenue support provided through the hydrogen business model will, for some projects, be complemented by up-front capital co-funding through the Net Zero Hydrogen Fund. This 'one-off' capital co-funding can be beneficial to encourage and accelerate hydrogen deployment and uptake. Capital support is, however, unlikely on its own to incentivise supply and use of hydrogen without support to overcome the relatively higher ongoing costs of producing and using hydrogen compared to counterfactual fuels, with some exceptions[8]. Cost-effective scaling up of hydrogen deployment requires concerted action across the entire hydrogen value chain. Providing long-term revenue support to hydrogen producers as part of a range of actions across the hydrogen value chain is important to ensure that the full benefits of hydrogen deployment are realised and also minimises the risk of stranded assets.

2.4. This impact assessment considers options for providing long-term funding for the hydrogen business model through the IDHRS framework. In assessing these options, the following principles have been considered and applied:

2.4.1. **Considers affordability and fairness for energy users and taxpayers**. There are several potential end-uses for hydrogen, meaning the impacts of any chosen funding mechanism must be considered across a range of different sectors and consumers. Whether funding via energy users or taxpayers, consideration needs to be given to compatibility with the wider policy landscape, fairness across the economy, and impacts on those least able to bear the costs.

2.4.2. **Protects public finances and is consistent with fiscal sustainability**. Funding the transition to a net zero economy has material fiscal consequences. These arise alongside wider pressures on public finances and will need to be managed to maintain fiscal sustainability.

2.4.3. **Provides flexibility and future proofs the approach to future changes in the energy system**. The exact technology and energy mix in 2050 cannot be known now, and the path to net zero will respond to the innovation and adoption of new technologies over time. However, in all pathways and scenarios, the transition to net zero will transform our energy system by 2050. The approach established now needs to be robust to future changes to the energy system and the future scale of demand across potential end-use sectors for hydrogen.

## 3. Description of options considered

3.1 This Impact Assessment considers the following options for funding revenue support for hydrogen deployment in the hydrogen business model through the IDHRS framework:

[7] https://www.gov.uk/government/publications/net-zero-review-final-report

[8] For example, there might be cases in which end users are prepared and able to pay a price premium to switch to low carbon hydrogen, or cases where low carbon hydrogen may be cost-competitive with high-cost fuels (e.g. diesel) and where switching costs are minimal.

3.1.1. **Policy option 1: Do nothing.** Under this option there is no funding for the hydrogen business model. Capital co-funding for hydrogen projects may still be available through the Net Zero Hydrogen Fund, and hydrogen producers would rely on market revenue once operational. There is a mix of market failures, set out in more detail in paragraph 1.2, which means that without revenue support through the business model to complement other interventions, it is likely that private investors would delay investment decisions, move investment abroad[9], or decide not to invest altogether, meaning there would be no at-scale hydrogen deployment in the UK in the 2020s. Consequently, this option does not support the objective to provide a sustainable, long-term funding stream for the hydrogen business model, sufficient to deliver on the government's ambition for up to 10GW of low carbon hydrogen production by 2030 and is highly unlikely to deliver the hydrogen deployment to put the UK on a pathway to meet the government's legally binding Carbon Budgets and Net Zero target. Therefore, this option has not been taken forward.

3.1.2. **Policy option 2: Taxpayer funding.** Under this option, the funding source for the IDHRS scheme would be the taxpayers. As set out in the Net Zero Strategy, the IDHRS scheme will be tax-payer funded until 2024/25, beyond which funding will switch to a levy. For the purpose of this impact assessment BEIS has considered the option of ongoing tax-payer funding beyond 2025. Ongoing tax-payer funding for hydrogen business model payments would provide investors and projects with the confidence they need to invest their upfront capital into a project. This option therefore has the potential to deliver on the government's ambition for up to 10GW of low carbon hydrogen production by 2030. This option would not involve passing costs on to energy users and could therefore minimise affordability impacts as a result of increased energy prices on energy consumers and industry beyond 2024/25. However, depending on the source of taxpayer funding, there may be corresponding affordability impacts for households and businesses. Provision of a sustainable, long term funding stream would be contingent on the future state of public finances and on agreeing successive funding envelopes through fiscal events, and is therefore not consistent with a principle of fiscal sustainability. This option provides flexibility and would be future proofed to future changes in the energy system as the availability of funding would not be contingent on future energy mixes or end uses of hydrogen across different sectors or consumer bases. As set out in the Net Zero Strategy, this is not the Government's preferred option beyond 2024/25.

3.1.3. **Policy option 3: Expand existing levy frameworks.** BEIS has considered expanding existing levy frameworks to provide the funding source for the IDHRS scheme to fund the hydrogen business model. BEIS does not consider that existing levy frameworks can be made to fit with government's policy objectives for providing funding for the low carbon hydrogen business model through the IDHRS scheme. This option does not support the objective to provide a sustainable, long-term funding stream for the hydrogen business model, sufficient to deliver on the government's ambition for up to 10GW of low carbon hydrogen production by 2030. Therefore, this option has not been taken forward.

3.1.4. **Policy option 4: Obtain new powers to establish a levy funding mechanism.** Under this option new enabling powers would facilitate the creation of a levy funding mechanism through secondary legislation. BEIS intends to consult on the details of the new levy mechanism that will be set out in secondary legislation. A new levy mechanism is likely to operate in a similar way to existing levy schemes. For example, revenue support for clean electricity has been funded by passing on costs indirectly, through supplier obligations and suppliers passing costs onto energy bills. This approach has been used in the electricity sector to support the deployment of renewables through Contracts for Difference, Renewables Obligation and Feed in Tariffs, and in the gas sector through the Green Gas Support Scheme via the Green Gas Levy. These funding mechanisms are well understood by investors and projects, and establishing a similar new levy funding mechanism through secondary legislation will provide investors and projects with the confidence they need to invest. There are also other options for how a future levy may be designed, which include placing an obligation to pay the levy at a different point in the supply chain, for example on

[9] Other countries are putting mechanisms in place to support early deployment of hydrogen. For example, the Dutch SDE++ energy subsidy scheme, worth €30 billion (until 2025), covers low carbon hydrogen production projects. While Germany, which has committed to invest €9 billion in its hydrogen plans, will be launching a Carbon Contracts for Difference pilot programme to support the use of hydrogen in the steel and chemical industries.

gas shippers. This option is therefore likely to deliver on the government's ambition for up to 10GW of low carbon hydrogen production by 2030. Through the design of the levy funding mechanism, consideration will be given to affordability and fairness, for both consumers and industry. Passing the costs of funding the hydrogen business model through to energy users through a levy funding mechanism protects public finances and is therefore consistent with a principle of fiscal sustainability. While initial taxpayer funding has been committed to 2024/25 to enable the deployment of the first electrolytic hydrogen projects, the Net Zero Strategy set out a clear approach for levy funding from 2025 at the latest. This option enables that approach and is the Government's strong preference.

## 4. Preferred option

4.1. As set out in the Net Zero Strategy, the IDRHS scheme will be taxpayer funded (option 2) until 2024/25, and then will be levy funded from 2025 at the latest. The preferred option is therefore to introduce primary legislation which will enable BEIS to establish a dedicated levy funding mechanism to provide a revenue stream for the hydrogen business models in the future (policy option 4). BEIS believes that this will help to achieve the policy objective of deploying hydrogen at scale sufficient to meet ambition for up to 10GW of low carbon hydrogen production capacity by 2030, in a fiscally sustainable way. This will contribute to putting the UK on a pathway to achieving the legally-binding Carbon Budgets and Net Zero targets.

4.2. The proposed powers will enable SoS to make regulations specifying the levy design and to appoint a levy administrator.

4.3. The establishment of a levy will be given effect through secondary legislation following consultation. The Hydrogen Business Model Consultation[10] sought stakeholder views on how the hydrogen business model should be funded. BEIS published a government response to that consultation on 8 April 2022. BEIS intends to consult on detailed levy design ahead of secondary legislation being brought forward.

[10] https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

## 5. Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

5.1. Sections 2 and 3 assessed the relative merits of introducing primary legislation to obtain new powers to establish a levy funding mechanism (our preferred option) against our policy objectives and principles.

5.2. The following analysis considers the potential impacts of the preferred option on households and businesses that would materialise when the secondary legislation stage is implemented.

5.3. At this stage, the Government is only seeking to establish the powers to introduce a levy when required. The primary legislation will have no impact until relevant secondary legislation is introduced. Thus, the estimated impact of this primary legislation, by itself, is zero.

5.4. This IA sets out some of the potential secondary stage impacts to inform future decisions about the levy and to illustrate the key trade-offs to be considered when designing it.

5.5. When introduced, the impacts of the levy will be driven by four broad groups of factors:

- Deployment path: decisions about the exact scale and timing of hydrogen deployment to be supported by Government.
- Ongoing hydrogen business model and funding regime design (e.g. the commercial design of the business model incorporating the reference price, risk allocation and contract length).
- Wider conditions: future trajectory of key hydrogen market characteristics (e.g. energy and ETS prices; technology cost decreases, etc.).
- Levy design decisions (e.g. composition of the levy base)

5.6. While policy choices around deployment and hydrogen business model design will have a significant impact on the estimates of the total cost of the IDHRS scheme, and in turn the revenue required to be raised by the levy, there are currently significant uncertainties around these factors which limit the scope of the analysis that can be presented in this IA.

5.7. The exact trajectory of hydrogen deployment, which will shape the revenue raising profile of a new levy is still to be decided. Additionally, the full detail of eligibility and assessment criteria for future hydrogen business model allocation rounds have not been announced and there is uncertainty around the pipeline of projects that could apply for production support.

5.8. Final business model design is also subject to uncertainty, given the drafting of the hydrogen business model contract is still ongoing.

5.9. There also is uncertainty around wider market conditions such as energy and ETS prices. This uncertainty will affect the levy through the interaction with the deployment profile, business model characteristics and the total cost of the scheme. As such, it cannot be analysed in isolation.

5.10. Therefore, as the relevant details of the IDHRS scheme are still in development, BEIS is unable to monetise the expected size of the scheme (that the levy would fund) and the costs and benefits of the levy.

5.11. Instead, this IA focuses on impacts flowing directly from levy design choices. It presents an illustrative analysis of the trade-offs involved in different levy characteristics and presents a qualitative assessment of the potential cost of the future levy. By itself, levy design will only impact cost distribution and not the total cost and spend profile and, therefore, this IA focuses on the former.

5.12. A more detailed assessment of levy options will be presented at secondary legislation stage, subject to more information about the key policy design choices being available at that point.

## 6. Illustrative monetised impacts of the preferred option

6.1. This section considers what choices BEIS will have at secondary legislation stage in how the levy is designed, and what the potential impacts of these may be.

6.2. As mentioned above, given the uncertainties around the total cost of the IDHRS scheme, this analysis focuses on how levy design might impact consumers and businesses and the distribution of these. It does not attempt to estimate the precise level of these impacts.

6.3. The key levy design decisions which will determine how consumers and business will be affected include:

- the size and the composition of the levy base (gas vs electricity; domestic vs non-domestic consumers),
- how much revenue to raise from different payer groups.

Levy choices: composition of the levy base

6.4. The first factor to consider when designing a levy is who should be included in the levy base. The composition of the levy base will determine its size and how much revenue can be raised. This will be the key driver of individual price and bills impacts.

6.5. While final decisions are yet to be determined, it is likely that all three major energy user groups (households, commercial users and industry) will contribute to the cost of hydrogen support.

6.6. Similarly, no decisions have yet been made regarding the energy sources in scope of the levy. Levy funding could come from electricity or gas consumers, or a combination of the two.

6.7. The trajectory of gas and electricity consumption in the UK will determine consumer and business impacts. In addition, the levy might have a second order effect on energy consumption as consumers react by switching fuels but it is not possible to estimate this effect at this stage.

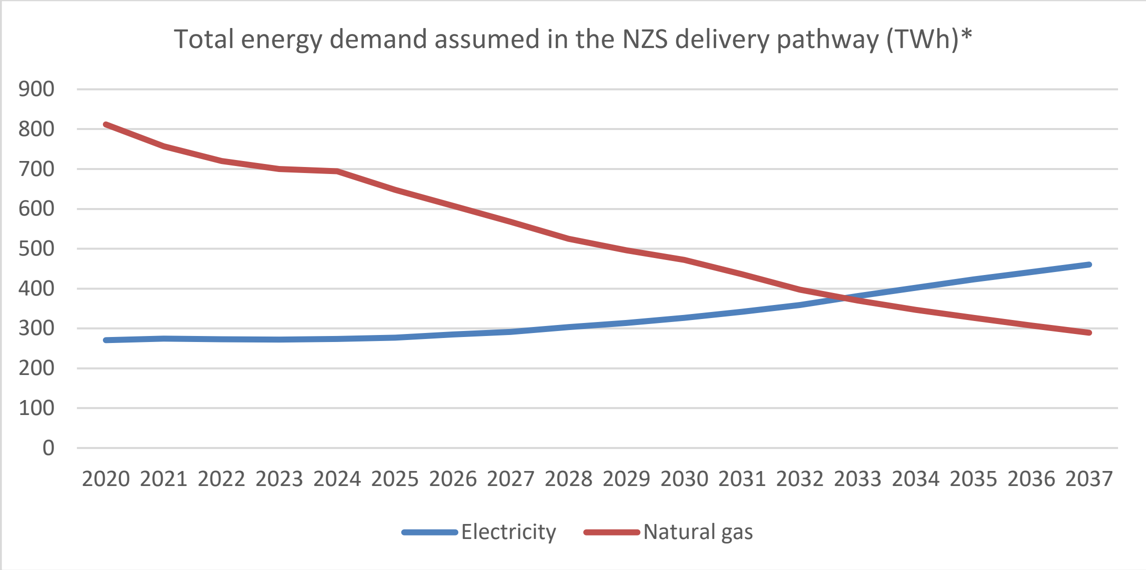
6.8. In terms of volumes sold, the UK gas market is currently much larger than the electricity market. In 2020, total demand for natural gas was approximately 810TWh, of which 490TWh comprised consumption by households, commercial and industrial users (i.e. excluding gas for energy industries and generators). By contrast, electricity demand was only 270TWh.

6.9. Energy demand modelling up to 2037 consistent with the pathways published in the Net Zero Strategy shows gas consumption decreasing, and electricity consumption increasing over time (e.g. as households switch from gas boilers to heat pumps and industrial processes switch from natural gas to hydrogen). In these pathway scenarios total gas demand (including gas for the energy sector) in 2030 is estimated to fall to 470TWh and the demand for electricity to increase to 330TWh.[11]

**Figure 1. Modelled future total electricity and gas demand in the UK[12]**

[11] This energy consumption pathway is based on a set of assumption about future policy and market conditions and should not be interpreted as forecast Source: Net Zero Strategy: Build Back Greener, https://www.gov.uk/government/publications/net-zero-strategy

[12] Ibid.




*Includes gas demand from the electricity sector.

6.10. These potential long-term trends will have to be considered when designing a new levy as they will determine its total long-term revenue raising potential.

6.11. For example, assuming the levy is applied on volumetric basis, and excluding gas for electricity generation, £1 charged per MWh of natural gas sold would raise approx. £490m in 2020, but only £280m in 2030[13]. Conversely, revenue from electricity consumers would be approximately £270m in 2020 and £330m in 2030. By implication, a levy targeting natural gas consumers is likely to see a decreasing revenue stream (other things equal), and a levy on electricity consumers would see a gradual increase in revenue raised (other things equal).

6.12. Limiting the scope of the levy to specific payer groups, as opposed to including all consumers, will predictably have an impact on the cost for individual consumers – holding total cost constant, a smaller levy base will lead to higher costs for individual consumers. For example, if only gas industrial users were in scope of the levy, the revenue raised by charging £1 per MWh gas sold would be approximately a fifth of the sum raised from the full gas consumer base (£95m).[14]

6.13. However, revenue raising potential of different configurations of the levy base, and ultimately the consumer and business impacts, will also depend on how the cost of the levy is distributed across payer groups.

Levy choices: cost distribution

6.14. Deciding how to distribute the cost of the levy is the second key choice determining consumer and business impacts. As different payer groups will have different energy consumption patterns and pay different prices, the same nominal per unit increase in energy prices might have varying consequences on different payers.

6.15. To illustrate consumer impact trade-offs involved in levy design choices, Table 1 presents estimates of price increases required to raise £490m per year – i.e. the sum equivalent to charging every household, commercial and industrial gas consumer an extra £1/MWh of gas consumed in 2020 as described above. The table also shows the resulting relative increases in energy prices and bills.

[13] Assuming non-energy sector gas demand in 2030 is the same proportion of total gas demand as in 2020.

[14] Based on the current industrial gas consumption share. Source: BEIS Digest of Energy Statistics (DUKES) natural gas, December 2021

**Table 1. Consumer group size comparison. Per unit price increase required to raise the same about of money across chosen consumer groups (constant prices)** [15]

| Consumer group | | Equivalent price increase/MWh (2020) | Equivalent price increase/MWh (2030) | Equivalent price increase (percentage change) (2020) | Equivalent price increase (percentage change) (2030) |
|---|---|---|---|---|---|
| Gas consumption | Total (non-energy) | £1 (Baseline) | £1.7 | Household: 2%<br>Small Business: 4% | N/A<br>(2030 price data not available) |
| | Domestic | £1.7 | £2.9 | Household: 4% | |
| | Non-domestic | £2.5 | £4.3 | Small Business: 10% | |
| Electricity consumption | Total | £1.8 | £1.5 | Household: 1%<br>Small Business: 1% | |
| | Domestic | £5.4 | £4.4 | Household: 3% | |
| | Non-domestic (small business) | £2.7 | £2.2 | Small Business: 2% | |

6.16. Table 1 shows how much one would need to charge each group separately to raise the same revenue (equivalent to charging £1/MWh on all non-energy gas consumers in 2020). The variation in equivalent price increases presented in the table is driven by differences in their respective total energy consumption (in MWh terms). For example, all electricity consumers would need to pay £1.8/MWh in order to raise the same revenue as by charging all gas consumers £1/MWh reflecting lower electricity consumption (in MWh terms).

6.17. While differences might appear significant in absolute terms, as when comparing equivalent increases between domestic gas and electricity, they may not be as stark relative to baseline energy prices. In the case of domestic gas and electricity, a much larger absolute increase for electricity results in still lower percentage price change relative to the baseline price.

Energy price and bill impacts

6.18. As mentioned above, the baseline level of energy prices will determine the relative impact of the levy. Currently, the per unit price of electricity is much higher than that for gas: domestic consumers paid ~£196/MWh for electricity and ~£41/MWh for gas in 2020. Consequently, comparable per unit increases in prices of gas and electricity would have a larger relative impact on gas consumers (other things equal).

6.19. Consumer impacts will also depend on the amount of energy consumed by individual users as this will determine how energy price increases translate into bill impacts. Average household consumption of gas is much higher than electricity consumption – domestic consumers used on average 3.5MWh of electricity and 13.6MWh of gas in 2020.[16] Consequently, comparable gas and electricity price increases will have a much stronger overall bill impact on gas consumers.

6.20. For the purposes of this IA, we have made a simplifying assumption that the average energy consumption will not change radically by 2030. However, there is uncertainty over future consumption patterns and it is possible that average individual electricity and gas consumption might diverge from the current levels, for example as a result of mass adoption of heat pumps for domestic heating. This would in turn affect the relative differences in bill impacts across gas and electricity consumers. Possible future shifts in energy consumption will have to be considered when designing the new levy.

[15] Price increase required to raise revenue equivalent to charging £1/MWh on all non-energy gas consumers in 2020.

[16] Source: BEIS Annual Domestic Energy Bills 2021 (QEP 2.2.5 and 2.3.5)

6.21. To give an indication of how a levy would affect individual consumers the effects of a hypothetical increase in electricity and gas prices by £1/MWh relative to current prices and bills is presented below. These estimates are not meant to reflect the full impact of the future levy but serve as a reference point for future levy design and bill impact considerations.

6.22. £1/MWh charged on all electricity sales in the UK in 2020 would increase the annual average domestic electricity bill from £707 to £711 (0.5%). The equivalent increase for gas would be £557 to £571 (2.4%).

Exemptions or other protections

6.23. BEIS will consider if the new levy risks disproportionately affecting certain consumer groups and will test how potential adverse impacts can be mitigated through exemptions or other measures before the levy is introduced. This will involve looking into the impacts of the new measures on those groups that may be least able to bear the costs, including energy intensive industries and fuel poor households.

Administrative costs

6.24. In addition to the direct cost to consumers and businesses in the form of levy payments, the new measures will impose administrative costs on businesses directly responsible for collecting the levy (e.g. energy suppliers).

6.25. Parties responsible for collecting the levy (e.g. energy suppliers) will incur initial administrative costs through familiarising themselves with the policy, updating systems and engagement to notify customers of the levy. Once the policy is in place, suppliers will also face recurring costs from managing levy payments (including collecting and making payments, interacting with the counterparty to the hydrogen business model revenue support contracts).

6.26. There will also be a cost to government of collecting the levy.

Illustrative impact on small and micro businesses

6.27. The proposed new primary legislation is expected to have no impact by itself. Therefore, the estimated impact on small and micro businesses is zero.

6.28. However, if a levy is implemented through secondary legislation, small and micro business may be affected.

6.29. As mentioned above, while the composition of the levy base is still to be determined, it is likely that all three major energy user groups (households, commercial users, and industry) will contribute to the cost of hydrogen support, and this will include small and micro businesses.

6.30. The factors determining levy impacts presented in the preceding section in relation to households will also play a role with respect to small businesses. While final decisions will be made at secondary legislation stage, it is expected the levy will have the same per unit impacts on small businesses as on individual consumers.

6.31. Small and micro businesses are likely to face different baseline energy prices to individual consumers. Table 2 presents the impact of £1/MWh increase in energy prices relative to baseline prices in 2020 for businesses of different sizes.

6.32. The overall bill impact will be driven by energy consumption of individual businesses. Unlike in the case of households, there is likely to be greater heterogeneity in energy consumption across businesses. By implication, levy impacts, when applied on volumetric basis, will vary significantly across businesses.

6.33. If the new levy is implemented, in addition to the additional cost of the levy payment itself, it would impact small and micro businesses through an increased administrative burden on parties responsible for collecting the levy (e.g. small energy suppliers) – these costs are expected to be passed through to consumers.

**Table 2. Relative impact of £1/MWh increase in gas and electricity prices by business size**

| Business size | Baseline price (2020) (£/MWh) | Baseline + £1/MWh | Percentage change |
|---|---|---|---|
| Electricity: Very Small | 166 | 167 | 0.6% |
| Electricity: Small | 147 | 148 | 0.7% |
| Electricity: Small/Medium | 136 | 137 | 0.7% |
| Gas: Very Small | 46 | 47 | 2% |
| Gas: Small | 25 | 26 | 4% |
| Gas: Medium | 21 | 22 | 5% |

Regional impacts

6.34. The deployment of hydrogen can play a vital role in levelling up the economy throughout the UK. The funding is UK wide but will particularly benefit industrial regions which are primarily located in Scotland, South Wales, and the North of England.

6.35. There are industrial clusters in England, Scotland and Wales where significant investment into CCUS-enabled hydrogen will help to secure existing jobs whilst creating new jobs. Electrolytic hydrogen will often be co-located in areas of high renewable potential such as Scotland and coastal areas. The proposed industrial clusters and the known project pipeline is likely to see major projects delivered across the UK in England, Scotland, and Wales, with potential for plans for Northern Ireland in the future.

## 7. Risks and assumptions

7.1. The main sources of consumer and business impact uncertainty discussed in this section relate to non-policy driven factors. As mentioned in section 5, there is significant uncertainty about the key cost drivers of the IDHRS scheme viz. deployment ambition and hydrogen business model design. BEIS expects to have more clarity on these drivers later in the levy development process.

7.2. Key non-policy risk factors affecting levy impacts include:

- Gas and energy market dynamics and short/long-term variations in predicted gas and electricity consumption. Short term gas consumption is subject to significant uncertainty, due to factors including weather effects, housing development and external shocks, such as those seen from COVID-19. Year-on-year changes between 2009 and 2018 varied between -8.1% and +3.7%. More broadly, modelled energy consumption underpinning the illustrative analysis in this IA is itself based on a set of assumptions about policies, consumption behaviours and wider market trends. Over a longer time period, there may be significant changes to these across the system. As such, the projections used to inform the levy design will need to be updated over time to reflect any changes to the underlying energy market trends.
- Impacts on individual users. By necessity, this analysis relies on average energy consumption estimates and does not fully consider variations in consumption patterns. The impact of any proposed future levy design might in practice vary significantly, especially for businesses in energy intensive industries. During the design work of the levy, BEIS will undertake additional analysis to identify those users and will consider measures to mitigate impacts where they could be disproportionate.
- There is a range of additional risks potentially affecting implementation and operation of the levy, including interactions with other decarbonisation policies, the impact of the energy market conditions on the viability of the levy, unintended consequences especially around consumer incentives, as well as risk to stability of the revenue stream (e.g. shortfall in levy payments). These factors will also be considered at later stages of levy development.

## 8. Equalities Impact Assessment

8.1. A Public Sector Equality Duty (PSED) assessment has been completed for IDHRS.

8.2. This primary legislation is not expected to have any impact, by itself, on protected characteristic groups (PCGs). However, if secondary legislation is passed, there may be some impacts on PCGs. Those impacts are discussed below.

8.3. While the expected impacts on PCGs are likely to be small, three characteristics might potentially be affected: race/ethnicity[17], disability (long-term illness)[18], and age (measured as the age of the oldest household member).

8.4. The remaining characteristics are either less relevant at a household level and/or there is limited energy consumption data available at this level of granularity; these characteristics are sex, gender reassignment, sexual orientation, marriage and civil partnership, religion or belief, and pregnancy and maternity.

8.5. The analysis below uses a hypothetical example of a volumetric gas levy charged on all gas consumers across the economy and leading to an increase in gas prices of £1/MWh. The presented estimates below are used for illustrative purposes only and do not reflect the Government's position on the final design of the levy and the amount of revenue to be raised. This analysis focuses on relative differences in bill impacts across groups with different characteristics and, as such, won't be affected by changes in the absolute bill impact values.

8.6. For age, 16–24-year-olds and over 75s would be most impacted by the levy relative to income – this is driven primarily by lower median annual income of those two groups.

8.7. For disability/long-term illness, there is a small difference in the direct impact of the levy for groups with and without a long-term illness as their annual gas consumption is similar. However, as people in the former category tend to have much lower incomes, the levy would impact them disproportionately more.

8.8. For race/ethnicity, there is a small difference in relative bill impacts, once again, driven by differences in incomes.

8.9. Data on electricity consumption of the three PCGs analysed below is not currently available but it is likely the relative differences in electricity use between relevant groups will follow a similar pattern to that presented for natural gas.

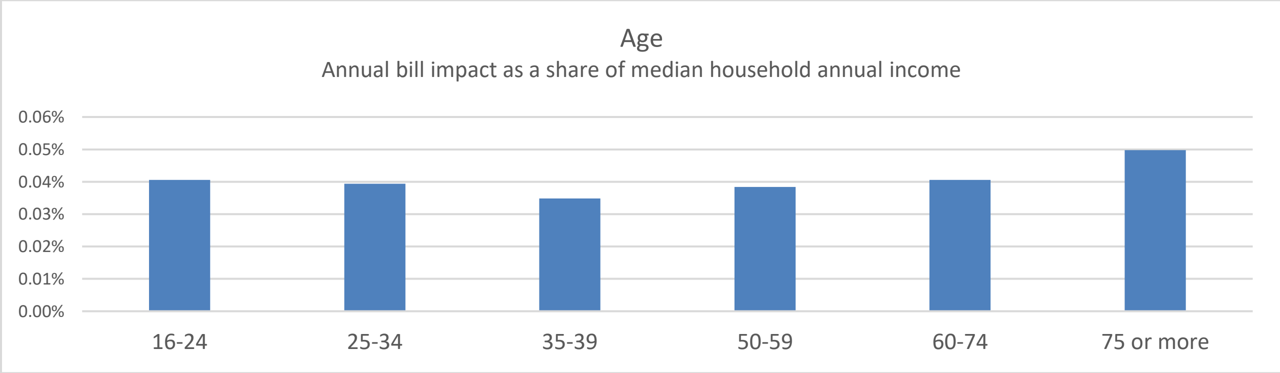
8.10. In summary, at this early stage of policy design, BEIS can identify that a levy where the costs are passed through to consumers has the potential to have a negative impact on certain groups with protected characteristics. We are likely to see small variations in direct bill impacts across domestic households with and without protected characteristics, but expect income differences to exacerbate these differences. Although analysis of protected characteristics can provide an indication of likely levy distribution, and impact on various groups, ultimately the levy bill impact will depend on individual household consumption which is heterogenous and may be influenced by a variety of factors.

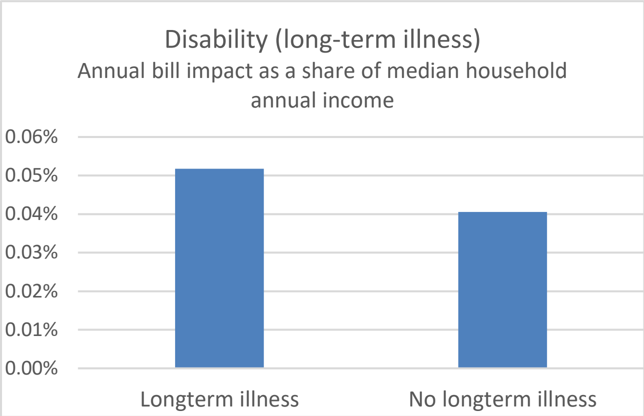
8.11. This assessment will be kept under review. An updated PSED assessment will be conducted in the run-up to secondary legislation.

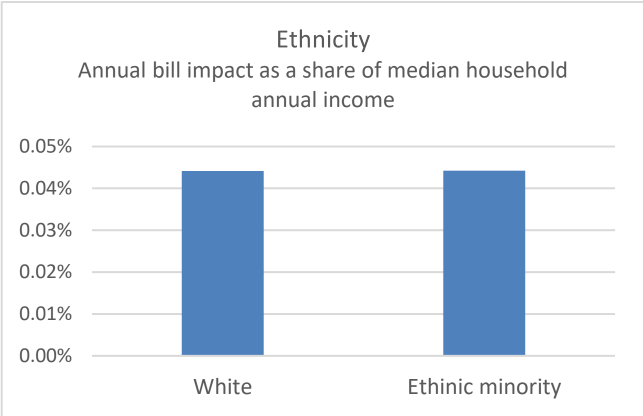
**Figure 2. Impact of £1/MWh increase in gas prices across three Protected Characteristic Groups: Age, Disability/Long-term illness, Ethnicity/Race**

[17] Source data is available for 2 ethnic groups only: White – White ethnic groups (including White British and White ethnic minorities); Other (all other ethnic minorities). This is because the number of people surveyed was too small to make any reliable conclusions about any of the 18 ethnic groups or 5 aggregated groups. Source: BEIS Fuel Poverty Statistics 2021

[18] A household that contains someone with a long-term illness/disability that states their condition reduces their ability to carry out day-to-day activities. Examples of long-term illnesses/disabilities include, but are not limited to, conditions which affect vision, hearing, mobility and/or mental health.




Fuel poverty

8.12. A household is considered to be fuel poor in England[19] if: a) they are living in a property with a fuel poverty energy efficiency rating of band D or below[20]; and b) when they spend the required amount to heat their home[21], they are left with a residual income below the official poverty line.[22] [23]

8.13. There are 3 important elements in determining whether a household is fuel poor: household income, household energy requirements, fuel prices.

8.14. There were 3,176,000 households in fuel poverty in England in 2019, which corresponds to 13.42% of all households.[24]

8.15. For illustration, a hypothetical increase in natural gas price of £1/MWh would increase the number of fuel poor households in England by under 6000.

## 9. Potential Trade Implications of the Measure

9.1. The impacts from these measures are not considered to impact international trade and investment.

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[19] Under Low Income Low Energy Efficiency (LILEE) methodology

[20] Energy efficiency rating is measured using the Fuel Poverty Energy Efficiency Rating (FPEER) Methodology, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/332236/fpeer_methodology.pdf

[21] Fuel costs required to have a warm, well-lit home, with hot water and the running of appliances. An equivalisation factor is applied to reflect that households require different levels of energy depending on who lives in the property. Further information on how fuel costs are calculated can be found in Section 5 of the Methodology Handbook: https://www.gov.uk/government/publications/fuel-poverty-statistics-methodology-handbook

[22] Residual income is defined as equivalised income after housing costs, tax and National Insurance. Equivalisation reflects that households have different spending requirements depending on who lives in the property. We note that sources of income counted has changed to remove some disability benefits. Further information on how income is modelled can be found in Section 3 of the Methodology Handbook (https://www.gov.uk/government/publications/fuel-poverty-statistics-methodology-handbook)

[23] The poverty line (income poverty) is defined as an equivalised disposable income of less than 60% of the national median in a given year: (see Section 2 in: https://www.ons.gov.uk/peoplepopulationandcommunity/personalandhouseholdfinances/incomeandwealth/articles/persistentpovertyintheukandeu/2015)

[24] Fuel Poverty 2019 data published in April 2021 Annual Fuel Poverty Report

## 10. Monitoring and Evaluation

10.1. The monitoring and evaluation (M&E) plan will be developed in more detail at secondary legislation stage when a levy funding mechanism would be introduced. However, this section sets out our initial consideration of what an appropriate monitoring and evaluation framework could look like for this later stage.

10.2. The evaluation could focus on three broad themes:

- Impact evaluation, which would assess the impacts of the levy design, including how it affects consumers, businesses, hydrogen producers and wider stakeholders.
- Outcome evaluation, which would focus on whether the levy meets the objective of providing sustainable long-term funding for the hydrogen business model scheme, building on the Theory of Change that BEIS will develop in more detail at secondary legislation stage. This might involve testing the interactions between the chosen levy base, the energy market and revenue raised.
- Process evaluation, which could also examine the administrative operation of the scheme, assess the efficiency of levy collection, scheme compliance and enforcement.

10.3. For each of these BEIS would need to define SMART objectives and outline specific research questions the evaluation would need to address. We expect the policy principles identified earlier in this IA (for instance, the importance of maintaining affordability and fairness for energy users) would form the basis of these objectives.

10.4. The methods used to undertake the evaluation would be informed by the Theory of Change to be developed at later stages of levy development, taking into consideration key uncertainties involved in the operation of the levy. BEIS would consult key stakeholders on the proposed evaluation methods. Given the likely nature of the policy, it is expected a combination of methods and a range of data sources would be applied, for instance:

- data collection during the funding application process
- data shared by projects in receipt of production support
- market data analysis
- stakeholder engagement
- surveys

10.5. The M&E methodology will aim to be as robust and thorough as possible given the high-profile character of the policy, but will also be proportionate to ensure methods are used appropriately and to address potential data limitation issues.

10.6. BEIS is currently developing a detailed monitoring & evaluation plan and cost controls framework for the IDHRS scheme, which will focus more on the impacts and outcomes of how the funding is used and process by which it is allocated (rather than how the funding is raised). We will consider how the levy M&E plan sits alongside it or whether it is considered as part of this wider IDHRS M&E plan. This is to ensure efficient use of resources devoted to the process by identifying synergies between both programmes of work. For example, we would aim for data relevant to both workstreams to be collected once and shared between them.

| | |
|---|---|
| **Title:** Market-based mechanism for low-carbon heat<br>**IA No:** BEIS046(F)-22-CHD<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** None | Impact Assessment (IA)<br>**Date: 06/07/2022**<br>**Stage:** Final (primary legislation)<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** heatmarketmechanism@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| Cost of Preferred (or more likely) Option | | | |
|---|---|---|---|
| **Total Net Present Social Value**<br>- | **Business Net Present Value**<br>- | **Net cost to business per year**<br>- | **Business Impact Target Status**<br>Qualifying Provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

*As the 2021 Heat and Buildings Strategy sets out, the government has an ambition to grow the market for heat pumps to approximately 600,000 installations per year by 2028. This level of heat pump deployment is strategically important for any of the potential routes to net zero and is essential for ensuring route based primarily on the electrification of heat remains viable. Heat pumps are largely unable to compete on cost with established fossil fuel and less efficient heating options, such as natural gas, oil and direct electric heating. This is partly due to the emerging nature of low-carbon heating, which means that it does not benefit from economies of scale or from mature supply chains to the same degree as conventional technologies. Additionally, the full societal costs of fossil fuel combustion are not reflected in their market prices, including for example impacts on health and climate change. In the absence of an effective policy framework, including regulatory policies such as the policy assessed here for which powers are being legislated for in the Energy Bill, the heat pump market would not be expected to grow at the targeted rate. This would result in lower greenhouse gas emissions reductions from buildings than targeted in near-term carbon budgets and would also mean that the target of net zero emissions by 2050 could not be reached in a cost-effective manner. Without policies to develop the market and supply chain for heat pumps to a sufficient capacity, cost-effectively implementing further policy action necessary for reaching net zero emissions, such as for phasing out of the installation of natural gas heating appliances from 2035, may be at risk.*

**What are the policy objectives of the action or intervention and the intended effects?**

*Through the Energy Bill, the Secretary of State is requesting the powers to introduce a market-based mechanism for low-carbon heat, a 'Low-Carbon Heat Scheme', in order to underpin an industry-led transformation of the heating appliance market, through the introduction of a market obligation. As detailed in an October 2021 consultation, this mechanism, when established through secondary legislation will create a market incentive to grow the numbers of low-carbon heating appliances installed each year, providing industry with a clear, long-term policy framework for investment and innovation. The policy aims are to:*

- *Support development of the UK heat pump market in line with the targeted growth trajectory in the Heat and Buildings Strategy (~600,000 installations p.a. by 2028);*
- *Contribute to decarbonising heating in the UK and to meeting carbon budgets.*

*This proposed policy is part of a policy framework, described in the Heat and Buildings Strategy, aimed at decarbonising heating as part of the government's net zero greenhouse gas emissions commitment. Such a structural shift comes inevitably with high uncertainty, which is reflected in the estimates presented in this Impact Assessment.*

*As presented in the summary tables, the direct impacts of the acquisition of the powers are likely to be very limited. However, in this Impact Assessment we also aim to appraise, to the extent possible, the illustrative impact of the proposed scheme when established through secondary legislation, under the best current assumption of how the policy proposals will be pursued. Further impact assessment will accompany future consultation and the preparation of secondary legislation establishing the scheme.*

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

*The policy options considered in this impact assessment are:*

- *Option 0 (counterfactual): do nothing.*
- *Option 1 (preferred option): introduce an obligation on the manufacturers of gas and oil boilers sold on the UK market to achieve the sale of a certain number of heat pump, proportional to their boiler sales over a given period.*

*As the market mechanism consultation document set out, there are a range of models that a mechanism such as this could take under the powers being requested for the Secretary of State, and we expect to consult on more detailed design proposals to inform secondary legislation in due course. This policy is also expected to form part of a wider policy framework supporting heat decarbonisation; the combination of policies in this overall framework will have a bearing, for instance, on how policy costs are distributed across different groups.*

*In this Impact Assessment we have estimated only the quantifiable social costs and benefits associated with the heat pump deployment ambition targeted. Further stages of consultation and Impact Assessments are expected in due course as detailed design of this policy and associated secondary legislation and of the wider policy framework continues over the next 18 months.*

*The principal alternative to option 1 would be to pursue only subsidy-based measures and/or regulatory measures focused on consumers or building-owners without an accompanying market obligation. Such alternatives are less likely to reach the policy goals and would be likely to lead to higher overall social costs; they have been therefore disregarded from analysis.*

**Will the policy be reviewed?** It will be reviewed**. If applicable, set review date:** N/A

| | | | | |
|---|---|---|---|---|
| Does implementation go beyond minimum EU requirements? | | N/A | | |
| Is this measure likely to impact on international trade and investment? | | N/A | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** - | **Non-traded:** - | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

## Summary: Analysis & Evidence - Policy Option 1

**Description:** To introduce, through secondary legislation under the powers now being requested, an obligation on the manufacturers of gas and oil boilers sold on the UK market to achieve the sale of a certain number of heat pumps, and potentially other low-carbon heating appliances, proportional to their boiler sales in each period.

**FULL ECONOMIC ASSESSMENT**

| Price Base Year | PV Base Year | Time Period Years | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | Low: - | High: - | Best Estimate: - |

| COSTS (£m) | Total Transition (Constant Price) Years | | Average Annual (excl. Transition) (Constant | Total Cost (Present Value) |
|---|---|---|---|---|
| Low | - | | - | - |
| High | - | | - | - |
| Best Estimate | - | | - | - |

**Description and scale of key monetised costs by 'main affected groups'**

The only costs associated to the primary legislation are familiarisation costs, which are assumed to be negligible.

When established through secondary legislation, we expect the largest societal costs of the proposal to be the additional capital costs associated with installing clean heating technologies, followed by long run variable costs.

**Other key non-monetised costs by 'main affected groups'**

There is likely to be some cost of compliance with the obligation for the obligated parties, for instance administrative overheads in relation to reporting. Estimating/monetising possible compliance costs will depend upon more detailed policy design and scheme administration considerations in due course as well as the further development of the wider policy framework for low-carbon heat. In this Impact Assessment we have included an indicative estimate of the administrative costs in the Business Impact section; a full assessment will be able to be conducted at the point of secondary legislation.

| BENEFITS (£m) | Total Transition (Constant Price) Years | | Average Annual (excl. Transition) (Constant Price) | Total Benefit (Present Value) |
|---|---|---|---|---|
| Low | - | | - | - |
| High | - | | - | - |
| Best Estimate | - | | - | - |

**Description and scale of key monetised benefits by 'main affected groups'**

No benefits associated to the primary legislation. When established through secondary legislation, we expect the largest monetised benefits to be the carbon emissions savings in the non-traded sector, followed by air quality improvements.

| **Other key non-monetised benefits by 'main affected groups'** |
| --- |
| Innovation benefits, reduced technology costs due to learning from wider deployment leading to future decarbonisation being more cost effective. Development of competitiveness in UK's clean goods and services related to heat. Alignment with net zero strategy. Reduction of risks in other future policies. Growth in the market for low-carbon heating appliances and the businesses that produce, sell and install them, produce or operate ancillary goods (e.g., heat batteries) and services (e.g., smart energy management and flexibility services), etc. Policy framework stability, with market-wide application, enabling strategic confidence to invest in supply chains, training, etc. |

| **Key assumptions/sensitivities/risks** | |
| --- | --- |
| Deployment level, costs and performance of heating systems (actual in-situ performance of heating system), future fuel costs and carbon savings. This IA presents the uncertainty through sensitivity analysis in the Modelling Approach and Results section of this report. | |

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
| --- | --- | --- | --- |
| **Costs:** - | **Benefits:** - | **Net:** - | - |

# Executive Summary

This impact assessment accompanies powers sought through the 2022 Energy Bill for the Secretary of State for Business, Energy and Industrial Strategy to establish a market-based mechanism for low-carbon heat, a 'Low-Carbon Heat Scheme'. While the direct impacts of the acquisition of the powers are likely to be limited, this assessment also aims to provide an illustrative appraisal, to the extent possible, of the likely impact of the proposed scheme when the powers are applied through secondary legislation, under the best current assumption of how the policy proposals will be pursued. It also illustrates the analysis that has supported key policy proposals. Further impact assessment will accompany future consultation and the preparation of secondary legislation.

Under the lead proposal in the October 2021 consultation, the government proposed to introduce an obligation on the manufacturers of fossil fuel boilers (including gas, oil and LPG boilers) sold on the UK market to achieve the sale of a certain number of heat pumps, and potentially other low-carbon heating appliances, proportional to their boiler sales in each period. This mechanism will create a market incentive to grow the numbers of heat pumps installed each year, providing industry with a clear, long-term policy framework for investment and innovation. As set out in the Heat and Building Strategy document, we are aiming to develop the UK heat pump market to reach around 600,000 heat pump installations by 2028. This scale of heat pump deployment is strategically important for any pathway to net zero, including a hydrogen-led scenario, and is essential for ensuring an electrification-led pathway remains viable. An electrification-led route will require substantial further growth in annual installations by the early-2030s.

To assess the impact of the scheme, we have developed deployment ambitions consistent with the strategy set out in the Heat and Building Strategy documents. We have estimated the potential level of additionality of the proposed policy (the market-based mechanism) and the associated profiles for policy costs and carbon savings. These estimates have been produced by drawing on a range of sources, including market intelligence. A range of policies will contribute to achieving the overall ambition for heat pump market growth including, notably, planned regulations on phasing out fossil fuel heating off the gas grid and regulations on low-carbon heating in new-build properties, as well as various spending policies such as the new Boiler Upgrade Scheme. In practice, the market-based mechanism is expected to complement many of these policies, for instance through improving the overall consumer appeal of heat pumps and thus supporting earlier decarbonisation action in response to heating regulations than in a counterfactual scenario. However, the focus of this impact assessment is only on the *additional* deployment beyond that anticipated from other policies.

The focus on the purely additional deployment allows us to minimise the risk of analytical overlaps with other policies: the costs and benefits shown in this IA are attributable to the market-based mechanism and there is no double counting of the impact of other policies. However, we expect the market-based mechanism to be an enabler of the other policies, which tend to have a more positive Social Net Present Value (SNPV), meaning that the SNPV presented in this IA is likely to be lower than the SNPV associated with the installation of the full 600,000 heat pumps per year by 2028.

There is a high level of uncertainty as the estimated impact of the proposal will depend on how primary powers are used as well as on the impact of a suite of other policies. The costs and benefits presented in the IA should therefore be considered only as an illustration, based on current assumptions; the Risks and Uncertainties section of this report explores in more detail the possible range of the policy impact.

We anticipate that the scheme could deliver 1.2 and 5.5 $MtCO_2e$ of non-traded carbon abatement over Carbon Budgets 4 and 5, respectively. However, Carbon Budget 5 non-traded savings could be as low as 4 $MtCO_2$ or as high as 16 $MtCO_2$, as shown in the Risks and Uncertainties section.

There are also significant uncertainties in the Social Net Present Value (SNPV) of the scheme. Our central estimate of the SNPV is -£500m, but the uncertainty analysis we have performed shows a range between -£5.3bn and +£2.5bn.

# Contents

# Introduction & Background

## Background

1. The UK was the first major economy in the world to set a legally binding target to achieve net zero greenhouse gas emissions by 2050. To achieve this, we need to transition to low-carbon ways of heating our homes, businesses and public buildings across the board.
2. Currently, heat in buildings is responsible for 23% of the UK's greenhouse gas emissions[1]. Meeting our legally binding target of a 78% reduction in carbon emissions by 2035, and to reach net zero emissions by 2050, means decarbonising virtually all heat in buildings and most industrial processes. This is a critical decade for action on the decarbonisation of heat and upgrading the energy efficiency of homes and other buildings.
3. Published in October 2021, the government's Heat and Buildings Strategy sets out the policy action we are taking now to accelerate this transformation and our plans to go further.
4. There are several strategic pathways to full decarbonisation of heat by 2050 with a range of low-carbon technologies and systems that may have an important role to play, including a potentially leading role for hydrogen. However, the electrification of heating is the only currently proven option for the decarbonisation of buildings at scale and electric heat pumps must form a major part of how we heat our buildings in all future scenarios.
5. As the Heat and Buildings Strategy sets out, this means we need to grow the market for heat pumps to approximately 600,000 installations per year by 2028. This level of heat pump deployment is strategically important for any of the potential routes to net zero, and it is essential for ensuring an electrification-led route remains viable. This would require further growth to much higher numbers of annual heat pump installations by the early-2030s. This scale of market growth over the 2020s is also expected to directly support around 40,000 jobs by 2030.

## Rationale for intervention

6. The current market for heat pumps is relatively small: only around 35,000 heat pumps were sold in the UK in 2020, in comparison to 1.7 million fossil fuel boilers. Heat pumps are largely unable to compete on cost with established fossil fuel-based and less energy-efficient heating options, such as natural gas, oil and direct electric heating. This is partly due to the emerging nature of low-carbon heating, which means that it does not benefit from economies of scale or from mature supply chains to the same degree as conventional technologies.
7. A key element of the rationale for this intervention is the market failure with respect to the uncaptured negative externalities of conventional heating technologies, which renders their market price too low compared to the price of heat pumps. The full societal costs of heating based on fossil fuel combustion should consider the impacts on health (related to the air quality impacts) and the emission of greenhouse gases, leading to climate change. The need to deliver advancements in the decarbonisation of heating requires more urgent government action to correct the effects of this market failure within the UK heating system.
8. Likewise, the relative positive effect of heat pump deployment on air quality and emissions, and thus their lower societal cost, is not captured in their price. This is likely to result in under-investment in this technology, due to a lower expected payoff than what would be provided by a market price reflecting the full range of social and private costs and benefits.
9. Some further reasons for intervention related to the above include:

[1] BEIS (2021), 'Final UK greenhouse gas emissions national statistics: 1990 to 2019' (https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-to-2019) and BEIS (2021) 'Energy Consumption in the UK' (https://www.gov.uk/government/statistics/energy-consumption-in-the-uk).

a. Intervention in this market is needed to reduce the cost of decarbonising heat use in buildings, as well as meeting legally binding carbon targets. Given the price effects of market failures set out above, support for the heat pump market, through a clear market growth trajectory underpinned by a market-wide obligation, is likely to improve investor certainty and generate growth and development of the supply chain.
b. Additional R&D and economies of scale are also expected to follow a successful intervention in the heat pump supply chain. This will result in spill-over benefits to society, which are not currently reflected in the price of low-carbon heating.
c. Consumer research has shown that consumers are unfamiliar with heat pumps as an alternative to fossil fuel heating systems[2]. This introduces information asymmetry by reducing the ability of consumers to choose the heating appliance based on merit, and thus constraining the technology's ability to compete in the market. An intervention in the market would raise consumer awareness, addressing this market failure.

### Policy objective

10. Through the Energy Bill, the Secretary of State is seeking powers to introduce a market-based mechanism for low-carbon heat in order to underpin an industry-led transformation of the heating appliance market, through the introduction of a market obligation. As detailed in an October 2021 consultation, this mechanism, when implemented through secondary legislation plans to establish a platform for an industry-led transformation of the heating appliance market. The introduction of a market obligation will create a firm market incentive to grow the numbers of low-carbon heating appliances installed each year, providing industry with a clear, long-term policy framework for investment and innovation. This is expected to see the industry take a range of steps, directly and in partnership with other actors, to improve the consumer appeal and awareness of heat pumps in order to grow uptake.
11. This scale of heat pump deployment is needed to make an electrification-led pathway to net zero a viable option at least-cost, which will require substantial further growth in annual installations by the early-2030s and is a strategic level of deployment even in a hydrogen-led transition. A Heat Pump Manufacturing Supply Chain project, published in December 2020, concluded that manufacturers could adapt flexibly to the level of demand required and increase supply into the UK market relatively quickly.[3]
12. The main aims are:
    a. To develop the UK heat pump market in line with the targeted growth trajectory in the Heat and Buildings Strategy (towards ~600,000 installations p.a. by 2028), with a focus on the retrofit market, working alongside other policies; and so
    b. To contribute to decarbonising heating in the UK and to meeting carbon budgets.

# Outline of policy options

13. The policy options considered in this impact assessment are:
    a. **Option 0 (counterfactual)**: do nothing.

[2] The BEIS Public Attitudes Tracker indicates that 43% of the public are unfamiliar with air source heat pumps, having never heard of them https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/959601/BEIS_PAT_W36_-_Key_Findings.pdf Figure 15

3 BEIS (2020), 'Heat pump manufacturing supply chain research project', p. 14 https://www.gov.uk/government/publications/heat-pump-manufacturing-supply-chain-research-project.

b. **Option 1 (preferred option):** introduce an obligation on fossil fuel boiler manufacturers to achieve the sale of a certain number of heat pumps, and potentially other low-carbon heating appliances, proportional to their boiler sales over a given period.

14. While the direct impacts of the acquisition of the powers are likely to be limited, this assessment aims to appraise, to the extent possible, the impact of the proposed scheme when the powers are applied through secondary legislation. There are a range of models that a mechanism such as this could take, and we expect to consult on more detailed design proposals to inform secondary legislation in due course.
15. In this Impact Assessment we have estimated only the quantifiable social costs and benefits associated with the level of heat pump deployment consistent with the levels set in the Heat and Buildings Strategy, without analysing the impact of specific design options. We have not quantified how costs and benefits of the policy will be spread across society, in part because this is highly dependent on the wider policy framework of which the market mechanism is one part which is still in development, and on wider market developments. We have, however, included a qualitative assessment of the potential impact on different businesses and consumers, as well as an indicative quantitative assessment of the possible scale of direct costs to business. Further stages of consultation and Impact Assessments will be published in due course as detailed policy design continues and as secondary legislation is brought forward under the primary powers being sought.
16. The proposed market-based mechanism is intended to work alongside targeted spending (e.g., the Boiler Upgrade Scheme) and regulatory measures (e.g., regulations on heating installations off the gas grid[4]) as part of an overall policy framework to support the development of the market in low-carbon heating. Future policies within this broader framework are currently at different stages of development. The principal overall policy alternative would therefore be to pursue either the same or further subsidy-based measures (e.g., 'heat pump grants') and/or the same or further consumer or building-owner regulatory measures (e.g., 'fossil fuel appliance installation bans') alone on the demand side without an accompanying market obligation. Doing so would both reduce confidence of achieving the targeted deployment outcome and reduce the incentives for an industry-led transformation of the market to achieve downward pressure, through competitive market efficiencies, on the overall social cost. Such alternatives are less likely to reach the policy goals and would be likely to lead to higher overall social costs; they have been therefore rejected.
17. Policy alternatives with different overall heat pump deployment targets have not been evaluated since they would not be consistent with government's Heat and Buildings Strategy.

**Option 0 (counterfactual): do nothing**

18. In this impact assessment, the quantified costs and benefits of an obligation on fossil fuel boiler manufacturers (option 1) are estimated against a counterfactual where no policy is introduced.

**Option 1 (preferred option): introduce an obligation to support deployment of low-carbon heating technologies**

19. The government is proposing to introduce, through secondary legislation under the primary powers being sought, a new market-based mechanism from 2024, which will create a market incentive to grow the numbers of low-carbon heating appliances installed each year.

[4] https://www.gov.uk/government/consultations/phasing-out-fossil-fuel-heating-in-homes-off-the-gas-grid

This mechanism will work alongside a range of subsidy-based and regulatory policy approaches, targeted where most appropriate, to establish an overall policy framework capable of supporting a transformation of the market.

20. Under the lead option in the October 2021 consultation expected to be pursued, this mechanism would create an obligation on the manufacturers of fossil fuel heating appliances (i.e., gas and oil boilers) to achieve the sale of a certain level of heat pumps, or potentially alternative low-carbon appliances, proportional to their fossil fuel boiler sales over a given period.
21. In response, we would expect obligated parties to take a range of steps, both directly and in partnership with other market actors, to find and build consumer demand for heat pumps. In this way, we expect the policy to help create the conditions for rapid innovation across the market, for example, in consumer journeys and marketing, in products and product bundles, in service-based or consumer finance offerings, in the efficiency of or approach to surveys and installations, etc.
22. As the Heat and Buildings Strategy sets out, there remain important choices as to how the costs of the transition to low-carbon heating and buildings are met across society, but the government is committed to ensuring affordability through addressing market distortions, providing near-term financial support, and working with and creating the conditions for industry to rapidly drive down costs. We share the ambitions of leading businesses for 25-50% reductions in the installed costs of heat pumps by 2025 and approaching parity with boilers by the end of the decade.
23. At the heart of the government's approach to reviewing and developing the overall policy framework will be ensuring that the costs of decarbonising the energy system are fair and affordable for all energy users.
24. As a result, while the overall potential social costs of this policy can be assessed at this stage, assessing how such costs may in practice be met by different groups of consumers, businesses, and taxpayers will depend upon the development of the wider policy framework and on wider market developments. Where full quantitative analysis of the impact on different groups has not been possible, we have included a qualitative assessment of the potential impact; we have also included an indicative quantitative assessment of the potential range of direct costs to business, which will be refined in a full EANDCB assessment accompanying secondary legislation when key policy details will be known.

## Scope of the scheme

25. An October 2021 consultation sets out the rationale for the proposed scope of the scheme. The government's intention is that the proposed obligation should apply throughout the UK and would apply to manufacturers of fossil fuel heating appliances (i.e., gas and oil boilers).
26. The heating appliances in scope are electric hydronic heat pumps that provide both space and water heating and can be retrofitted to the majority of domestic properties in the UK. Therefore, 'air-to-water', 'ground-to-water' or 'water-to-water' heat pumps up to a capacity of 45kW would be within scope, with 'air-to-air' heat pumps out of scope. Low-temperature air-to-water heat pumps can deliver high levels of energy efficiency, emissions and energy demand reductions and thermal comfort and generally have lower running costs than many other low-carbon heating systems, including high-temperature heat pumps. It is therefore the development of the market in low-temperature heat pumps that the market mechanism is primarily aiming to incentivise. While certain other low-carbon heating technologies could in principle be included in scope of the market mechanism, in the central scenario of this impact assessment we have made the modelling assumption that all the installations under the obligation to be air-to-water heat pumps.
27. Whether and to what extent hybrid heat pumps (systems combining an electric heat pump with a combustion boiler) will be included in the scope of this policy is still being considered.

Due to this uncertainty, this impact assessment has excluded hybrid heat pumps but has performed a sensitivity analysis to show the impact of the deployment of some hybrid heat pumps.

28. Heat pump installations in non-domestic properties are expected to be allowed under the policy, provided that the other installation and appliance criteria (such as on maximum appliance capacity) are met. Many non-domestic properties with energy use and floor area similar to domestic properties use the same or similar heating systems and therefore the installer base and supply chains often overlap.
29. Heat pump installations in new-build properties will not be in the scope of this policy to qualify towards meeting the obligation, since the forthcoming Future Homes Standard will be seeking to ensure that new-build homes are constructed zero-carbon-ready from the mid-2020s.

## Obligation design

30. The October 2021 consultation explores options for differentiation in the incentives under the obligation for different types of heating system or installation. For this impact assessment we have assumed that:
    a) obligated parties will meet the deployment targets as the penalties associated with the obligation will be designed to deter non-compliance.
    b) the obligation will apply to all manufacturers of appliances sold in the UK, including imported goods.
    c) in principle, the obligation allows for a secondary market to emerge in qualifying heat pump installations, allowing appliances not sold directly by the obligated party to qualify towards meeting their obligation. A secondary market will not affect the total number of heat pumps installed so has not been explicitly modelled for this impact assessment.

# Analytical approach

31. This section outlines the evidence base on which impacts of the policy proposals have been modelled and the overall analytical approach undertaken to assess the illustrative costs and benefits of the proposed market mechanism. The impact assessment presents the evidence of the impacts of the proposals for households, the business sector and wider society on the best assumption at the time of analysis of how policy proposals are expected to be enacted though secondary legislation under the primary powers being sought; the direct impact of the acquisition of the primary powers itself is negligible. It follows the principle of the Green Book guidance in identifying the key direct costs and benefits for these groups. The changes are compared with a counterfactual scenario and then monetised using standard Green Book appraisal values. Net present values are derived by comparing the aggregate costs and benefits which are discounted by the social discount rate.
32. Assumptions are varied to produce sensitivity analysis to show the sensitivity of Social Net Present Value (SNPV) and carbon savings with respect to changes in the assumptions used.
33. A cost-benefit approach is limited in assessing non-marginal change, such as the creation of markets and accelerated innovation, which are among the objectives of the proposal. As such, the impact assessment is supplemented by a qualitative discussion on non-monetised costs and benefits which sets out the relevant evidence to wider strategic considerations. Therefore, the calculated SNPVs are not intended to be viewed in isolation but should be assessed in combination with the strategic considerations.

## Evidence base

34. The appraisal values used in the analysis include:
    a. Carbon values - HMT Green Book supplementary guidance on valuation of energy use and greenhouse gas (GHG) emissions is used to value greenhouse gas savings.

b. Electricity and fossil fuel air quality damage costs – Values from Department for Environment, Food and Rural Affairs (Defra) are used to measure air quality damage costs.
c. Electricity and fossil fuel carbon emissions factors - HMT Green Book supplementary guidance is used to measure carbon emissions from electricity and fossil fuels.
d. Long-run variable costs of energy supply - HMT Green Book supplementary guidance is used to value the long-run variable costs of energy supply (LRVCs).

35. All prices in this analysis have been converted into 2020 prices using the GDP deflator.
36. The Green Book social time preference rate ('discount rate') of 3.5% has been applied for social present values.

## Monetised costs and benefits

37. Analysis has been conducted to estimate the costs and benefits associated with low-carbon heating technologies, relative to the counterfactual. The quantified costs and benefits contributing to the SNPV are:
    a. **Additional upfront capital costs** - these are the total additional upfront costs of the purchase and installation of low-carbon heating technologies (excluding VAT), compared to the purchase and installation costs of the counterfactual heating system. This includes additional ancillary costs such as new radiators for heat pumps.
    b. **Generation costs and benefits** - the estimated value of the change in energy demand due to low carbon heating technologies displacing counterfactual heating systems.
    c. **Carbon savings** – the estimated value of the carbon abated in both the traded and non-traded sectors due to heat from low-carbon sources replacing heat from fossil fuels.
    d. **Air quality impacts** – the estimated value of the public health impacts of changes to emissions of nitrogen oxides and particulate matter.
    e. **Maintenance** - the difference between the annual costs to maintain the different heating system. Different technologies sometimes require different levels of maintenance costs.

## Non-monetised costs and benefits

38. There are several non-monetised costs and benefits that are not captured in the cost-benefit analysis, including:
    **a. Supply chain development** – by incentivising additional deployment of low-carbon heat technologies relative to the counterfactual, the scheme will support the development of low-carbon heat supply chains. This will provide a base for the mass roll-out of low-carbon heating in the 2020s and subsequent decades, which will be needed to achieve the government's target of net zero carbon emissions by 2050. It will also help create green jobs and create opportunities for UK manufacturers. If monetised, this would have a positive impact on the SNPV.
    **b. Innovation and cost reductions** – BEIS expects that supporting low-carbon heat deployment will reduce costs and possibly increase performance over time, as supply chains develop and barriers that customers currently face are reduced through technologies being deployed successfully. The cost reduction and performance improvement benefits from low-carbon heating technologies installed after the period in scope of the market mechanism are not quantified in this impact assessment. If monetised, they would have a positive impact on the SNPV.
    **c. Health benefits** – switching away from fossil fuels can lead to improved indoor air quality for occupants, improving their health. If monetised, this would have a positive impact on the SNPV.
    **d. Consumer familiarity and perception towards renewable heat** - the BEIS Public Attitudes Tracker indicates that 43% of the public are unfamiliar with air source heat

pumps, having never heard of them[5]. However, customers who have installed renewable heating technologies have expressed high levels of satisfaction[6]. Heat pumps would require consumers and businesses to operate their heating systems in an unfamiliar way compared to conventional heating systems. The installation of hundreds of thousands low-carbon heating appliances will improve the familiarity of the public with technologies essential to reach the net zero target. If monetised, this would have a positive impact on the SNPV.

e. **Grid reinforcement** - electrification of heat increases the demand for electricity, potentially increasing the amount of electricity grid reinforcement needed (as well as costs and disruption associated with it). However, the Electricity Network Strategy[7] shows that heat pump deployment by 2028 will have a very limited impact on electricity peak demand, and therefore power sector and network costs. Therefore, any monetised grid reinforcement cost driven by this policy is likely to be very small.

# Modelling approach and results

39. We have estimated the aggregate costs and benefits of clean heat installations over the period between 2024 and 2028, appraised until 2047, when all the appliances installed are assumed to have reached the end of their lifetime.

## Deployment assumptions

40. The Heat and Building Strategy sets out the ambition of growing the heat pump market from the current 35,000 per year to 600,000 per year by 2028[8]. The Heat Pump Manufacturing Supply Chain Research Project[9] shows that manufacturers do not consider meeting such deployment levels to present significant difficulties in terms of manufacturing capacity.
41. The Future Homes Standard will come into force from 2025. All new-build homes built to this standard will be 'zero-carbon-ready' with low carbon heat and high levels of energy efficiency. We expect most new-build properties to install heat pumps; as an indicative estimate, this could add up to around 200,000 installations per year from 2027. This is consistent with DLUHC estimates of around 250,000 annual net new-build completions from 2023 to 2029.[10]
42. By setting an obligation for the retrofit market, the market-based mechanism will help to ensure that heat pump installations meet the overall ambition. This would imply setting a target of around 400,000 heat pump installations by 2028. The indicative targets between 2024 and 2027 support a smooth growth of heat pump installations from the estimated

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5 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/959601/BEIS_PAT_W36_-_Key_Findings.pdf Figure 15

6 https://www.gov.uk/government/publications/rhi-evaluation-interim-report-applicant-reaction-to-reform-announcements

7 BEIS (2022), forthcoming

8 BSRIA (2020), 'Heat pumps market analysis' https://www.bsria.com/uk/product/rg76mr/world_market_for_heat_pumps_2020r2019_8a707622/

9 Heat pump manufacturing supply chain research project, https://www.gov.uk/government/publications/heat-pump-manufacturing-supply-chain-research-project

10 Future Homes Standard consultation impact assessment, Appendix A https://www.gov.uk/government/publications/the-future-homes-standard-consultation-impact-assessment
These estimates of new build completions are produced by an independent consortium. They are indicative and should be used for appraisal purposes only and do not represent an official forecast of changes in housing supply.

deployment in 2023 and the 2028 target, giving enough time to build the supply chain and train installers.

43. In this Impact Assessment we have assumed that the obligated parties would meet the deployment targets as the penalties or payment tariffs associated with the obligation are expected to be designed to deter non-compliance. By changing the obligation targets we would in principle be able to reach the same level of deployment (and therefore costs and benefits) in scenarios with compliance rates lower than 100%. Therefore, at this stage we are not considering optimism bias per se but are planning to take it into account in future Impact Assessments.
44. By 2024, there will be either in place or shortly coming into force a suite of policies supporting or regulating deployment of low-carbon heating appliances, mostly acting on the demand-side. This includes the regulations to phase out high-carbon fossil fuel heating in existing homes, businesses and public buildings off the gas grid as set out by the published consultations. The low-carbon heating retrofit installations performed in the years between 2024 and 2028 will count towards the obligation target set for the year.
45. We expect the market-based mechanism to support or enable part of this deployment, for instance through contributing to market conditions in which more consumers take decarbonisation action in response to heating regulations earlier than in a counterfactual scenario, but it is very difficult to produce a quantified estimate of its additionality. For simplicity in this assessment, in the counterfactual scenario we have assumed that other policies would maintain the same level of low-carbon heating appliance deployment as in the absence of the market mechanism. Therefore, in the policy scenario of this impact assessment we have estimated only the impact of the additional deployment not primarily driven by (and therefore attributed to) other policies. This has been calculated as the difference between the target and the deployment already taking place because of other policies (the counterfactual). Costs and benefits of the deployment of low-carbon heating appliances in households off the gas grid, for example, have been separately estimated in the Impact Assessment for the regulations to phase out fossil fuel heating off the gas grid, to which this deployment would be primarily attributed.
46. This approach allows us to avoid any double counting of the impact of other policies. However, as above we expect the market-based mechanism to be in practice a partial enabler of the other policies, which tend to have a more positive SNPV, meaning that the SNPV presented in this IA is likely to be lower than the SNPV associated to the installation of the full 600,000 heat pumps by 2028. A good example is the consultation to phase out the installation of fossil fuel heating in homes off the gas grid[11], where the preferred option has a SNPV of +£9.8bn. This and other policies are likely to benefit from the market-based mechanism, in terms of cost efficiencies throughout the supply chain, shared marketing and search costs, and improvements to the overall consumer appeal of heat pumps which shore up demand and therefore potentially lead to earlier consumer action to decarbonise.
47. The 'market mechanism additional deployment' depends on the deployment levels of other policies. Estimating this level of deployment is challenging and subject to a high degree of uncertainty at this stage, especially since the installation of low-carbon heating appliances is only one of the possible outcomes for certain policies in consideration.
48. In this impact assessment, we have considered two illustrative deployment scenarios corresponding to different levels of such 'additional' deployment from the market-based mechanism.

[11] https://www.gov.uk/government/consultations/phasing-out-fossil-fuel-heating-in-homes-off-the-gas-grid

*Table 1: central market mechanism additional deployment scenario*

| | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|
| **Deployment from other policies** | 150k | 150k | 190k | 190k | 190k |
| **Market mechanism additional deployment** | 30k | 50k | 80k | 120k | 210k |
| **Overall market mechanism obligation target** | 180k | 200k | 270k | 310k | 400k |

*Table 2: high market mechanism additional deployment scenario*

| | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|
| **Deployment from other policies** | 50k | 50k | 70k | 70k | 70k |
| **Market mechanism additional deployment** | 130k | 150k | 200k | 240k | 330k |
| **Overall market mechanism obligation target** | 180k | 200k | 270k | 310k | 400k |

49. The two different levels of deployment from other policies are based on modelling estimates in different scenarios; the wide range has been chosen to illustrate the high degree of uncertainty in the deployment driven by other policies. We assume deployment from other policies to target mostly off-gas-grid areas, driven by policies like the domestic and non-domestic Off-Gas-Grid Regulations. In the first scenario we assume significant deployment driven by other policies both in buildings currently heated by direct electric appliances and in buildings currently using fossil fuel boilers; in the second scenario we assume a reduced number of heat pump installations, mostly replacing fossil fuel boilers in buildings off the gas grid.

## Household characteristics assumptions

50. The design of the obligation leaves the obligated parties (and their consumer base) a high degree of freedom to choose in which buildings to install low-carbon heat appliances. There is, therefore, a high degree of uncertainty around the precise mix of building-types where heating systems primarily attributable to the market mechanism will be installed; however, it is reasonable to expect that the majority of this *additional* deployment will take place in households connected to the gas grid, since:
    a) Approximately 85%[12] of UK households are connected to the gas grid and use natural gas for heating and around 63% of non-domestic floor area is heated by gas[13]. Therefore, it is more likely that obligated parties will largely find a consumer base for voluntary uptake of heat pumps in this largest market segment.
    b) Other policies will largely target buildings off the gas grid and so deployment in this sector is largely attributed to those other policies. For example, the Off-Gas Grid Regulations impact assessment estimates the impact of phasing out fossil fuels from off-grid homes from 2026.

[12] Based on the results of the most recent housing surveys that took place in England, Scotland, Wales, and Northern Ireland.
[13] 'Building Energy Efficiency Survey (BEES)', Figure 2.12, https://www.gov.uk/government/publications/building-energy-efficiency-survey-bees

c) Before 2026, we expect a package of policy measures to be the main driver of heat pumps installations in buildings off the gas grid.

Therefore, as a modelling assumption, in the core scenario of this impact assessment we have assumed that the additional deployment from the market mechanism will take place in the average domestic building connected to the gas grid. The policy impact is very sensitive to this assumption, so we have tested alternative deployment assumptions in the Risks and Uncertainties section.

51. We expect most of the heat pump deployment to take place in domestic buildings, but in practice it is possible that some installations may be in small non-domestic buildings. As only non-domestic buildings with the same characteristics (in terms of heat demand and installation costs) of domestic properties are within the policy scope, the proportion of non-domestic installations does not affect the quantifiable policy costs and benefits.

    a. Current evidence suggests that heat pumps are technically suitable for most buildings. BEIS modelling suggests around 90% have sufficient energy efficiency and internal electrical connection capacity to accommodate a heat pump system. Other factors, such as space constraints, might reduce the proportion of buildings suitable for heat pumps in practice; however, it is unlikely that the obligated parties will target segments of the building stock where extensive new energy efficiency (e.g., insulation) measures are needed or where other factors could make the installation challenging. Therefore, in this impact assessment we have not included the cost of any energy efficiency measures. We do however include the cost of in-home changes which we expect to be required in most buildings, such as hot water storage and larger radiators.

52. We expect some households to deploy energy efficiency measures, which will reduce their heat demand, between now and 2024. However, low-carbon heating installations under the market-based mechanism will be on a voluntary basis so it is difficult to accurately predict the possible level of heat demand reduction in households benefitting from the mechanism. Therefore, as a modelling assumption in this impact assessment we have assumed the average heat demand of buildings to remain at today's levels, both in the counterfactual and in the policy scenario. This assumption carries the risk of overestimating both costs and benefits of the policy; a lower heat demand would lead to reduced heat pump installation costs and reduced carbon savings potential.

53. The model uses assumptions which draw on evidence which is discussed in Annex I – full list of modelling assumptions and risks.

## Impact appraisals

54. This section of the impact assessment quantifies the costs and benefits of the market mechanism, when established through secondary legislation. In the table below we have summarised the key results in a central and high scenario, consistent with the central and high deployments described in **Error! Reference source not found.** and **Error! Reference source not found.**.

55. The capital cost shows the total difference between the heat pump capex and the capex of the counterfactual heating appliance. The market-based and market-wide nature of the policy should help to keep overall costs as low as possible, with obligated parties competing to develop the heat pump market in the most efficient ways possible. Evidence published in 2016 suggests that deployment and R&D could bring down the total capital cost of heat pumps, including both appliance and installations costs, by around 20% in a mass market

scenario[14]. In this impact assessment we assume that this level of cost reduction is achieved by 2030. In practice, several businesses believe that significantly higher cost reductions can be achieved significantly faster and the Government's ambition is for cost reductions of 25-50% by 2025 and towards parity on lifetime costs with gas boilers by 2030.

*Table 3: Results*

| **2020 prices, Present Value base year of 2022** | **Central deployment scenario** | **High deployment scenario** |
|---|---|---|
| **SNPVs** | **- £0.5bn** | **- £1.4bn** |
| *Capital costs* | - £2.7bn | - £5.9bn |
| *Carbon savings* | + £3.6bn | + £7.7bn |
| *Long Run Variable Costs* | - £1.6bn | - £3.4bn |
| *Air quality benefits* | + £0.1bn | + £0.2bn |
| **Lifetime Carbon savings 2024-2047** | **19 MtCO2e** | **41 MtCO2e** |
| Carbon Budget 4 savings 2023-2027 | 1 MtCO2e | 4 MtCO2e |
| Carbon Budget 5 savings 2028-2032 | 6 MtCO2e | 12 MtCO2e |
| **Lifetime non-traded CCE** | **213 £/tCO2e** | **220 £/tCO2e** |

56. In both deployment scenarios, the SNPVs of the monetised costs and benefits described in this IA show that the impacts of the proposed policy would lead to a net cost overall. The main driver for this is the capital costs of heat pumps which outweigh the capital costs of conventional technologies, namely gas boilers which are assumed to be the main technology being replaced by heat pumps under the market mechanism. This is followed by long-run variable costs: households switching to heat pumps experience higher long-run variable costs because although heat pumps use less energy to heat homes, at present, electricity unit prices are much higher than gas prices. This result depends on the modelling assumption that deployment occurs in the average home on the gas grid – a different assumption would lead to a more favourable LRVC impact.

[14] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/498962/150113_Delta-ee_Final_ASHP_report_DECC.pdf

57. The net benefits include the carbon savings and air quality benefits. As heat pumps are more efficient than gas boilers and use less energy, overall switching from a lower-efficiency technology to a more efficient technology results in a net carbon saving and air quality benefit.

## Risks and Uncertainties

58. The quantified impacts are sensitive to changes in the underlying assumptions. Sensitivities around the scenarios are conducted on the key factors, which are discussed here. The full list of sensitivity assumptions is included in Annex I – full list of modelling assumptions and risks.

59. Supplementary guidance to the Green Book on valuing energy use and greenhouse gas emissions[15] suggests that when capital is tied up in a specific project, alternative profitable use of such capital is ruled out and there is a foregone social benefit. The opportunity cost of capital where private funds are used to achieve social aims vary and is subject to final policy design. At this stage this has not been monetised and this will be reviewed ahead of the final Impact Assessment.

**S1: Deployment assumptions – replacement of direct electric appliances**

60. In the central scenario we have assumed that all the additional market mechanism deployment will take place in buildings connected to the gas grid. Here (S1), however, we assume that a proportion of the heat pump installations will be installed in households currently heated by direct electric heating appliances. This has an impact on the total carbon savings and the proportion of savings which are 'non-traded' as well as an impact on costs.

**S2: Deployment assumptions – higher-income households targeted**

61. Installation costs and emissions savings depend on the type of buildings which will install low-carbon heating appliances under the market mechanism. It is very difficult to predict what buildings the obligated parties will target. This sensitivity test (S2) estimates the impact of assuming that households with a higher-than-average income are targeted (or that heat pump demand is higher in this consumer segment). Income level might be associated with a higher ability to pay for low-carbon heating appliances. Households with higher income tend to occupy larger than average homes and therefore have higher installation costs and heat demand.

**S3: Low-carbon appliances installed**

62. The market-based mechanism consultation document included questions on the inclusion and treatment of hybrid heat pumps under the policy proposals. Compared to standalone heat pumps, hybrids imply lower emissions savings as fossil fuels are used to meet part of the heat demand. The level of emissions savings for each fossil fuel hybrid installation is proportionate to the level of heat demand met by the heat pump component.
63. In this scenario (S3), we assume that a proportion of total low-carbon heating installations are hybrid heat pumps and that measures will be in place to ensure that they operate in a way consistent with our emissions reduction targets (i.e., with the heat pump bearing the large majority of the heat load). If such measures were not implemented the carbon savings could be much lower, with potentially significant impact for our emissions targets.

[15] Available at: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

**S4: Future capital cost reduction for heat pumps**

64. Evidence published in 2016 suggests that deployment and R&D could bring down the capital cost of heat pumps by 20% in a mass market scenario[16] with the majority of the reduction associated with non-equipment costs (e.g., labour associated with installation) – in the central scenario we assumed this reduction to take place by 2030. In this sensitivity analysis (S4) we explore a scenario with 50% cost reductions by 2030, which is more consistent with – although still short of – the Government's ambition for cost reductions over this decade. Impact assessments will be updated as the published evidence base on this evolves.

**S5: Efficiency of heating system**

65. The efficiency of a low-carbon heating system has an impact on fuel consumption and running costs. This is expected to vary with weather condition, quality of the building stock, and level of innovation. The low and high end of the assumption range is tested here (S5). This sensitivity test is also intended to reflect uncertainty with future improvement of clean heat system performance.

**S6: Energy prices**

66. Low and high fuel price projections are used to test the sensitivity on energy prices, which are expected to be highly uncertain.

**S7: Carbon prices**

67. Low and high carbon value projections in the Green Book guidance are used for this sensitivity test.

16 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/498962/150113_Delta-ee_Final_ASHP_report_DECC.pdf

*Table 4: Sensitivity results*

| 2020 prices, Present Value base year of 2022 | Central deployment scenario | | High deployment scenario | |
|---|---|---|---|---|
| | **NPV (£bn)** | **CB5 savings (Mt)** | **NPV (£bn)** | **CB5 savings (Mt)** |
| **Central scenario** | - £0.5bn | 6 MtCO2e | - £1.4bn | 12 MtCO2e |
| **S1: Deployment 1** | + £0.0bn | 4 MtCO2e | - £0.1bn | 8 MtCO2e |
| **S2: Deployment 2** | - £0.2bn | 7 MtCO2e | - £0.8bn | 16 MtCO2e |
| **S3: Low-carbon appliances installed** | - £0.6bn | 5 MtCO2e | - £1.5bn | 11 MtCO2e |
| **S4: Future capital cost reduction for heat pumps – higher** | + £0.2bn | 6 MtCO2e | +£0.0bn | 12 MtCO2e |
| **S5: Efficiency of heating system - lower** | - £1.1bn | 6 MtCO2e | - £2.6bn | 12 MtCO2e |
| **S5: Efficiency of heating system higher** | + £0.2bn | 6 MtCO2e | + £0.2bn | 12 MtCO2e |
| **S6: Energy prices - lower** | - £0.7bn | 6 MtCO2e | - £1.8bn | 12 MtCO2e |
| **S6: Energy prices - higher** | - £0.2bn | 6 MtCO2e | - £0.8bn | 12 MtCO2e |
| **S7: Carbon values- higher** | + £1.3bn | 6 MtCO2e | + £2.5bn | 12 MtCO2e |
| **S7: Carbon values- lower** | - £2.3bn | 6 MtCO2e | - £5.3bn | 12 MtCO2e |

# Distributional impact

68. The scale of consumer costs associated with this policy, and the distributional allocation and impact of those costs across different groups, will depend in large part upon the wider policy framework for heat decarbonisation of which it is part, which will be continuing to develop in parallel to the further development of this policy, as well as wider market developments.
69. As the Heat and Buildings Strategy sets out, the government will be reviewing the overall policy framework for net zero, including how costs associated with the transition to low-carbon heating are distributed across different consumer groups. At the heart of this will be efforts to help ensure that low-income and fuel-poor households are not disproportionately affected and that there is support where it is needed to make sure the transition is accessible and affordable across society.
70. Further stages of consultation and Impact Assessments are expected in due course as the development of the overall policy framework for heat decarbonisation, including but not limited to the market-based mechanism policy, continues over the next 18 months. In particular, a detailed Impact Assessment will be published to accompany the secondary legislation on the proposed scheme, where key policy details will be set out.

## Equality impact

71. Under the Public Sector Equality Duty, the government must have due regard to the potential impact of the market-based mechanism on people with protected characteristics as set out in s.149 of the Equality Act 2010 (age, disability, gender reassignment, marriage or civil partnership, pregnancy and maternity, race, religion or belief, sex, sexual orientation). This requires BEIS to pay due regard to the need to:

    - eliminate unlawful discrimination, harassment and victimisation and other conduct prohibited by the Act;
    - advance equality of opportunity between people who share a protected characteristic and those who do not;
    - foster good relations between people who share a protected characteristic and those who do not.

72. The main groups that will be affected by the policy are:

    - Households – who will decide to install the heat pumps deployed by the obligated parties
    - Installers of heat pumps – who will be contracted for installations of low carbon heat technologies
    - Manufacturers – who will need to meet the obligation.

73. We do not expect any impact on equalities from the acquisition of the powers under primary legislation. Our assessment at this stage – informed by stakeholder responses to the October 2021 Consultation – is that the proposed scheme, when the powers are applied through secondary legislation, should have limited or no disproportionately negative impact on people who share a protected characteristic. This is because deployment of heat pumps under the scheme will be on a voluntary basis. The main intended outcomes of the policy - carbon emissions reductions and strategic alignment to net zero objectives - are non-excludable public goods and therefore expected to benefit the majority of the population without distributional impacts for specific groups.

74. The cost of a low carbon heating system may remain a barrier to those on lower incomes, which may limit the direct benefits of the policy for this group. While lower household income is not itself a protected characteristic, it is often correlated with several protected characteristics. On the other hand, without policies such as this to drive market scale and promote long-term cost reduction, costs and prices of low-carbon heating are less likely to reduce over time, meaning that the cost of switching to low-carbon heating will remain prohibitive for more households for longer.

75. We will continue to assess the potential impact on groups with protected characteristics and on wider inequalities during the course of more detailed policy design.

## Impact on Business

76. The direct cost to businesses of the acquisition of the relevant primary powers is expected to be nil or negligible. The impact of the policy on businesses, both in the heating appliance sector and more broadly, once implemented through secondary legislation, will depend in part upon the wider policy framework for heat decarbonisation of which it is part as well as wider market developments, which will be continuing in parallel to the further development of this policy. Therefore, the assessment in this section should be considered only as illustrative and indicative. The full Equivalent Annualised Net Direct Cost to Business (EANDCB) for the scheme, as well as a fuller assessment of indirect costs and benefits to businesses, will be prepared as part of impact assessments supporting the development of

the secondary legislation, where significant aspects of the policy detail for conducting that analysis (including target levels, payment tariffs, and reporting requirements) will be determined.

77. Under the implementation model anticipated in this impact assessment, the obligation under the market-based mechanism would apply to the manufacturers of fossil fuel heating appliances sold in the UK. This is a relatively concentrated market sector, with four companies responsible for around 90% of annual gas boiler sales (ca. 1.7m per year), and five companies responsible for around a further 7.5% of sales.[17] The four largest companies, and a number of the second-tier companies, are all multi-technology corporations producing and selling a range of appliances including heat pumps in several countries. Companies with a smaller market share are likely to be out of scope of the obligation, under the *de minimis* conditions expected to be applied. In the oil boiler sector, four companies share around 92% of annual sales (over 50k per year), and another four companies a further 9%,[18] although it is likely that these would fall beneath a *de minimis* threshold if applied. The largest four also produce heat pumps.
78. There are likely to be negligible impacts for these businesses from the acquisition of the relevant powers through primary legislation. However, there will be limited familiarisation costs associated with the primary legislation and then more substantial familiarisation costs associated with subsequent secondary legislation and scheme guidance. We estimate this at around £85,000[19]. There are also likely to be administrative costs to these businesses associated with compliance with the scheme once in force, for instance from reporting and the provision of evidence of compliance subject to the final design of administrative processes, participation in audit processes, etc. Internal estimates, and comparisons with comparable schemes, produce a conservative indicative estimate of around £10m per year.[20]
79. The costs to these businesses of meeting the obligation – associated with activities to market and promote heat pumps, for instance – are difficult to assess with confidence, as is the extent to which such costs may be offset by higher revenue associated with such sales. However, an indicative range can be assessed at this stage. Factors that will determine the overall direct cost to business include: the level of cost reductions achieved on heat pumps, their marketing and their installation as the market scales; consumers' willingness to pay for heat pumps and ability to access more flexible financing arrangements; the level of targets and of any penalties or payments-in-lieu set in the final policy design; and the contribution of other policies to heat pump demand and deployment. There is also likely to be variation in the net impact on different businesses in this sector, with the possibility that certain businesses face a net cost and others a net benefit, for instance through benefitting from trading surplus credits under the mechanism. An indicative potential range of annualised costs to business over the assessed lifetime of the policy would be £11-360m.[21] This

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[17] BSRIA (2020), 'Domestic Boilers Market Analysis', https://www.bsria.com/uk/product/n7Wq6n/domestic_boilers_world_market_for_heating_boilers_2021r2020_8a707622/

[18] ibid.

[19] Based on illustrative estimates of 10 hours needed for familiarisation with primary legislation and 2 weeks for secondary legislation. We used the hourly wage for management consultants and business analysts (~£24/hr) from the ONS, uplifted with the non-wage cost uplift from RPC / Eurostat 2019 (21.78%)

[20] Internal estimates are at present significantly lower than this. However, here we conservatively use an administrative cost estimate from the Renewable Transport Fuel Obligation post-implementation review. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/307437/impact-assessment-pir.pdf. We will further assess and engage with relevant parties on the possible administrative costs during further scheme development.

[21] This indicative range will be affected by the extent of cost reductions, the availability of consumer finance, and the wider policy contribution to heat pump deployment. The upper end of this range uses an assumed reduction in the installed cost of heat pumps of 20% by 2030, in line with projections published in 2016 (n14).

estimate will continue to be refined in the light of new evidence and as the details of the policy continue to evolve. The theoretical upper bound of cost to businesses in scope of the obligation will be the level of any payment required for a missed target. This payment framework and the associated targets have not yet been decided and therefore a full assessment of the potential costs to business will be able to be conducted at the point of secondary legislation, where such scheme details central to the analysis will be established.

80. The policy should have a significant positive impact for installers and maintenance engineers of the low-carbon heating appliances in scope, many of which are small or micro enterprises, through increased business activity. There are currently estimated to be around 3,000 such installers, but around 30,000 are expected to be needed by 2028[22]. If the policy contributes to a decline in fossil fuel boiler sales in future, then by the same token this could lead to a negative impact over time, through reduced business, for the approx. 130,000 installers and service engineers of such products who do not diversify into the growing low-carbon market.
81. The policy is likely also to have a positive impact for other market actors involved in the promotion, retail, financing or installation of heat pumps, of ancillary equipment such as thermal storage, or of related services, for instance in relation to demand-side response. This may include certain energy suppliers and energy service companies, for instance; on the other hand, if an alternative implementation model were pursued which placed an obligation on energy suppliers, there would likely be a net cost to this sector.
82. Regarding impacts on businesses more broadly, i.e., outside the heating market and wider supply chain, while direct impacts are likely to be limited, it is likely that over time there will be an indirect benefit from reduced costs of low-carbon heating appliances and their installation, reducing the costs of switching to appliances that consume less energy and of compliance with present and future minimum energy efficiency standards and building regulations. Being indirect, such benefits would not feature in an ultimate EANDCB assessment calculation for the policy.

## Competition and Trade Impact

83. While we assess that the acquisition of these powers will have no or negligible impact on market competition, we will continue to assess the potential impacts that this policy, in using the powers, could have on competition and competitiveness throughout the development of both this policy and the wider policy framework of which it will be part. At this stage, we do not assess that the policy would lead to significant negative impacts on competition in terms of range of suppliers in the market, suppliers' ability to compete, suppliers' incentives to compete vigorously, or the choice and information available to consumers. Rather, our assessment at this stage is that the fossil fuel appliance market will remain highly competitive and that the low-carbon heating appliance market is likely to become larger, with more actors and more pressure to compete vigorously on costs and other differentiators, with benefits for consumers. However, we will continue to keep any potential implications for competitiveness across the market under review as policy development and consultation continues and are confident at this stage that policy design choices, such as the ability to trade in credits on the secondary market and potential *de minimis* conditions, will be able to appropriately limit risks on this front.
84. The fact that the policy is also expected to apply equally to the manufacturers of fossil fuel heating appliances imported to the UK market as to those manufactured in the UK makes it

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However, the Government's ambition is for cost reductions of 25-50% by 2025 and towards parity of cost with boilers to install and run a heat pump by 2030. We therefore expect cost reductions to be greater than estimated here. We will continue to refine estimates as new evidence is published and as the policy detail continues develops.

[22] According to estimates by the Heat Pump Association.

important to consider the potential effects of the policy on international trade and on inward investment to the UK. Our assessment at this stage is that the policy is unlikely to have significant negative effects on trade or inward investment and may in fact have positive effects. As with broader market competitiveness above, we will continue to assess this during further policy development and in further consultation with market actors.

85. On the one hand, the policy could in principle lead to fossil fuel appliance manufacturers who were otherwise considering commencing trade of their products into the UK choosing not to do so. In practice, however, the UK gas boiler market is highly mature and significant new fossil fuel entrants in the absence of this policy, while not impossible, would perhaps therefore be unlikely.
86. On the other hand, by providing a market signal of a firm and fast-growing UK heat pump market, the policy is likely to increase the attractiveness of the UK market to international actors in the heat pump market, either to begin or expand import of their products or services and/or to consider investing in establishing a UK presence, potentially up to and including manufacturing. Attributing any increase in inward investment in the UK heat pump market solely to this policy, rather than to a combination of policy and market drivers, would though be very difficult.
87. Exports of fossil fuel heating appliances are not in scope of the policy and so would not be expected to be affected; on the other hand, the policy may contribute to a modest positive impact on exports of heat pumps if it contributes to e.g. investment decisions to locate heat pump manufacturing capacity in the UK (and subsequent export) and/or the development in the UK of exportable know-how, product innovations or successful ancillary services related to the heat pump market.

## Small and Micro Business Assessment (SaMBA)

88. A full Small and Micro Business Assessment will be included in future Impact Assessments when relevant policy details – for instance relating to any *de minimis* threshold exclusions from scope – are determined for secondary legislation. However, we include discussion and our best assessment of potential impacts and associated mitigations at this stage.
89. At this stage, we do not expect that micro businesses will directly incur costs associated with the regulatory measures proposed in the market mechanism consultation and expected to be implemented through secondary legislation under the powers now being sought. That is, we do not expect that there are micro businesses which manufacture sufficient boilers sold on the UK market. If there are businesses with few or zero UK employees whose products are sold in the UK and therefore may be in the scope of the obligation, these would almost certainly not be micro businesses in their headquarter and/or manufacturing locations, although it may be prudent for completeness to treat them as 'micro UK businesses' when we produce a SaMBA at secondary legislation stage.
90. During further consultation and policy development, we will continue to explore the possible impacts on small businesses and means of ensuring through policy design that the impacts of the policy are proportional, including the potential role of *de minimis* conditions to limit the impacts on small enterprises (e.g., small specialist fossil fuel appliance manufacturers, with a very small share of overall annual appliance sales). It is likely that a number of businesses whose products comprise a relatively small share of the UK fossil fuel boiler market may class as small businesses in terms of numbers of UK employees (i.e. fewer than 49), but be larger entities in global terms, with higher staff numbers in the countries where they manufacture their appliances. Businesses with a small market share, e.g. less than 1% of total sales, are likely to be excluded from the scope of the policy by *de minimis* levels expected to be set in the secondary legislation, subject to final policy design decisions, in order both to limit disproportionate impacts on smaller businesses and reduce the overall administrative complexity of the scheme as a whole.

91. It is possible that small, or smaller, businesses in scope of the obligation – for instance those with 1-2% market share (around five in total at present) – may face some disproportionality of costs compared to larger businesses in scope. For instance, the opportunity costs of upfront familiarisation with requirements and ongoing administration/reporting may be higher for a firm without dedicated compliance or regulatory affairs staff. Beyond administrative costs, potential disproportionality in costs associated with meeting the obligation (e.g. for heat pump marketing) is likely to be offset by the fact that all businesses in scope but not producing and selling heat pumps, and with no plans to do so, will have the option of purchasing credits from other heat pump manufacturers under the planned policy design, reducing transition and other fixed costs for such firms.
92. Outside of parties in scope of the obligation, a substantial number of existing, diversifying or new micro and small businesses engaged in the installation of low-carbon heating are likely to benefit from the policy's increase in business in this area. Data from the Heat Pump Association indicates that the large majority of existing installers are small or micro businesses[23]. Since a key objective of the market-based mechanism is to build the supply chain, we expect the proposal to maintain existing small or micro low carbon heat businesses and create opportunities for growth and new businesses in this segment to emerge. There are currently approximately 3,000 such installers in the UK, but there is expected to be demand for around 30,000 by 2028, according to the Heat Pump Association. Correspondingly, if the policy contributes to a decline in fossil fuel boiler sales in future, this could lead to a negative effect over time, through reduced business, for the approximately 130,000 installers and service engineers of such products who do not diversify into the growing low-carbon market, many of whom work for small or micro enterprises.

## Monitoring and Evaluation

93. We plan to implement a robust monitoring and evaluation plan, to investigate and demonstrate the impact and outcomes of the proposed policy. A thorough evaluation plan will be developed in advance of the implementation of the regulations and will be integral into the delivery of the policy. It is expected that the evaluation will seek to answer questions such as:
    - To what extent has the regulation achieved its aims?
    - How has the design of the regulation influenced the impacts that were achieved?
    - To what extent has the regulation been complied with by the sector?
    - What is the quality of installations?

    More information on our monitoring and evaluation strategy will be provided in the final impact assessment. This will include proposed timelines for evaluation.

[23] https://www.heatpumps.org.uk/wp-content/uploads/2019/11/Installer-Skills-Survey-Summary.pdf

# Annex I – full list of modelling assumptions and risks

## General assumptions

*Table 5: Appliances characteristics in central scenario*

| | Capex (average price today exc. VAT)[24] | Capex reduction by 2030 | Maintenance costs (annual) | Average annual efficiency[25] | Lifetime (years) |
|---|---|---|---|---|---|
| **Heat Pump** | See Table 6 below | 20% | £100 | 244%[26] | 20 |
| **Hybrid Heat Pump** | £9,900 | 20% | £100 | 244% for the HP and 84% for the gas boiler | 20 |
| **Gas boilers** | £2,600 | - | £100 | 84%[27] | 15 |
| **Storage heaters** | £5,700 | - | £0 | 100% | 15 |

*Table 6: Heat demand and HP Capex costs of households installing HPs*

| | Households on the gas grid (OnGG) - Average | Households heated by direct electric appliances (for S1 sensitivity analysis only) |
|---|---|---|
| **Average heat demand (kWh)[28]** | 10,300 | 7,200 |
| **Space heating demand increase after HP installation** | 10%[29] | 10%[29] |
| **Capex costs of installing a HP (average price today exc. VAT)[30]** | £10,800 | £11,800[31] |

## Sensitivity analysis assumptions

**S1: Deployment assumptions – replacement of direct electric appliances**

In this sensitivity, we assume 30% of the "market mechanism additional deployment" takes place in buildings currently heated by direct electric appliances; the remaining 70% are installed in buildings connected to the gas grid. 30% is the proportion of heat pump installations supported by the

[24] BEIS' analysis of the National Housing Model results.
[25] We assumed no improvement over time on the efficiency performance of fossil and low-carbon technologies. This is also applied as a conservative assumption in both the policy scenario and in the counterfactual.
[26] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/606818/DECC_RHPP_161214_Final_Report_v1-13.pdf
[27] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/180950/In-situ_monitoring_of_condensing_boilers_final_report.pdf
[28] BEIS' analysis of the National Housing Model results. Includes space and hot water heating
[29] https://discovery.ucl.ac.uk/id/eprint/1566603/

[30] BEIS' analysis of the National Housing Model results. Heat Pumps capex costs are for air source heat pumps. This includes the cost of the unit, fixtures, buffer tank and hot water cylinder, controls, labour and upgrade to radiators.
[31] Including the cost of installing a wet distribution system. Households currently heated by direct electric appliances tend to be smaller than average which partly offsets the increase in price due to the installation of a wet distribution system

Renewable Heat Incentive scheme that have replaced direct electric heating systems.[32] The heat demand and cost assumptions from Table 5 and Table 6 are used.

**S2: Deployment assumptions – able-to-pay households targeted**

"Market mechanism additional deployment" takes place in households connected to the gas grid whose annual income is higher than £50,000, representing 13% of all households connected to the gas grid. Homes in this segment are larger than average households and therefore both heat demand and heat pumps installation cost are higher.

*Table 7: Heat demand and heat pumps cost in able-to-pay households*

| | **Average for households OnGG** | **Average for households OnGG with an income > £50k** |
|---|---|---|
| **Average heat demand (kWh)** | 10,300 | 13,900 |
| **Cost of installing HPs (average price today exc. VAT)** | £10,800 | £12,100 |

**S3: Low-carbon appliances installed**

Half of the market mechanism additional installations are hybrid heat pumps, in which a heat pump works together with a gas boiler. The heat pump component is assumed to meet 80% of the heat demand with the gas boiler meeting the remaining 20%. Cost and performance assumptions on hybrids heat pumps are provided in Table 5. Heat demand assumptions are the same as those for OnGG households shown in Table 6.

**S4: Future capital cost reduction for heat pumps**

In this sensitivity analysis we explore a scenario with 50% cost reductions by 2030. This assumption is dependent on innovation in the equipment as well as economies of scale benefits in heat pump installations. We have assumed a linear cost reduction from 2023 to 2030 as shown in Table 8 below.

*Table 8: Heat pumps cost reduction*

| | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|
| HP capex - central cost reduction (20% by 2030) | £10,800 | £10,400 | £10,100 | £9,800 | £9,500 | £9,200 | £8,900 | £8,600 |
| HP capex - high-cost reduction (50% by 2030) | £10,800 | £10,000 | £9,200 | £8,400 | £7,700 | £6,900 | £6,100 | £5,400 |

32 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/928221/RHI_monthly_official_stats_tables_Sep_20_final.xlsx

**S5: Efficiency of heating system**

We tested a low and a high scenario, with average heat pumps efficiencies of 2.15 and 3.00 respectively. The low efficiency of 2.15 represents the 25th percentile of data from the RHPP trial[33], while 3.00 is closer to the design efficiency of current heat pumps on the market (the average design efficiency of the heat pumps supported by the RHI is 3.2).

**S6: Energy prices**

Low and high fuel price projections come from the HMT Green Book supplementary guidance.[34]

**S7: Carbon prices**

Low and high carbon values series comes from the HMT Green Book supplementary guidance.[35]

33 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/606818/DECC_RHPP_161214_Final_Report_v1-13.pdf

34 https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

35 https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

| | |
|---|---|
| **Title:** Impact Assessment on the Introduction of a Special Merger Regime for GB Energy Networks | **Impact Assessment (IA)** |
| **IA No:** BEIS047(F)-21-ESNM | **Date: 06/07/2022** |
| **RPC Reference No:** RPC-BEIS-5173(1) | **Stage:** Development/Options |
| **Lead department or agency:** BEIS | **Source of intervention:** Domestic |
| **Other departments or agencies:** N/A | **Type of measure:** Primary legislation |
| | **Contact for enquiries:** ESSupport@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** (EANCB) | **Business Impact Target Status** Qualifying provision |
| -£160m | -£65m | £7.5m | |

**What is the problem under consideration? Why is government action or intervention necessary?**

Ofgem, as the independent energy regulator, use price controls to set the costs that electricity and gas network companies can pass onto their customers. Ofgem do this by benchmarking the performance of regional monopoly energy network companies and sets a price control using the data as a proxy for competitively set prices.

Mergers involving energy network companies reduce the amount of independent data about the real costs of running networks, making it harder for Ofgem to set the benchmark accurately. Evidence from an independent (unpublished) report for Ofgem indicates that merging of companies may lead to higher costs and reduced levels of service. Currently, the Competition and Markets Authority (CMA) has the power to assess mergers based on whether they will lead to a substantial lessening of competition (SLC). As energy network companies do not compete for market share, existing SLC powers are ineffective, meaning that government intervention is required to allow proper regulation of the impacts of mergers in this sector.

**What are the policy objectives of the action or intervention and the intended effects?**

The main objective of this policy is to provide the CMA with further powers when considering the impact on consumers of energy network companies merging. These powers will come into affect when the Energy Bill receives royal assent. The policy intends to:

- Give the CMA the power to block mergers between energy network companies if the merger would impact Ofgem's ability to regulate comparatively[1].
- Protect Ofgem's ability to serve consumers' interests by giving the CMA these additional powers.
- Support delivering affordable energy for households and businesses.

[1] Comparative regulation is used here to refer to the process that Ofgem rely on when setting the price controls for the network companies. The formal process for how they regulate comparatively is set out fully in each Sector Specific Methodology Decision, but in brief, the network companies submit business plans to Ofgem. Ofgem compare the different plans, looking at specified performance markers and they use this information to set a benchmark. This benchmark is then used to determine what energy network companies are able to spend over the price control period.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

'Do Nothing': The CMA considers mergers of energy networks solely based on whether they will cause a substantial lessening of competition. Intervention on this basis is unlikely as the companies are regional monopolies and do not compete for market share.

'Do Nothing – Alternative': Under the current regime, the CMA must bring to the attention of the Secretary of State for Business, Energy and Industrial Strategy (BEIS) any merger that it believes raises a public interest consideration. The Secretary of State will be empowered to direct the CMA to do or not to do anything under Part 3 Enterprise Act 2002, if the Secretary of State considers that this direction is necessary and proportionate for the purpose of preventing, remedying or mitigating a risk to national security. In the context of energy network mergers, this means that the Secretary of State could direct the CMA to carry out or refrain from carrying out an investigation for substantial lessening of competition. This option therefore still does not serve the Government's policy objective of ensuring that Ofgem's ability to regulate effectively through comparative benchmarking, is protected, and is arguably the same as 'do nothing' above.

**'Policy Option' (preferred option):** Introduce a special merger regime for energy network businesses, largely modelled on the pre-existing regime in the water sector. For energy network mergers, the CMA will be asked to consider the impact of the merger on Ofgem's ability to carry out its functions (i.e. set the price control through comparative regulation). This test will not necessarily lead to a blocking of all relevant mergers but would enable the CMA to take a number of steps in response to the merger, including doing nothing, requiring remedies that offset any potential consumer detriment, or prohibiting it.

'Policy Option – Alternative': Ofgem could modify the licences granted to energy network enterprises to prohibit mergers de facto, as a means of ensuring that Ofgem's ability to regulate effectively through comparative benchmarking is protected. Government are of the view this is a less desirable option than the preferred policy option identified above because the licensing regime is not designed to deal with the particular problem identified and does not provide the flexibility needed.

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:** 5 years post implementation

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | Yes | | |
| Are any of these organisations in scope? | **Micro** No | **Small** No | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** 0.1 | **Non-traded:** 0.4 | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

# Summary: Analysis & Evidence

Policy Option

**Description:** Introduce a special merger regime into the GB energy sector

**FULL ECONOMIC ASSESSMENT**

| Price Base | PV Base | Time Period | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| **Year** 2020 | **Year** 2022 | **Years** 10 | **Low: -£190m** | **High: -£1m** | **Best Estimate: -£180m** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | £0.5m | | £23m | **£190m** |
| **High** | £0.5m | | £0m | **£1m** |
| **Best Estimate** | £0.5m | | £21m | **£180m** |

**Description and scale of key monetised costs by 'main affected groups'**

All costs in the 'central'[2] scenario:

- Avoided transfer[3] from consumers to network companies of up to £600m (not included in NPV).
- Administration costs of around £10m.
- Foregone efficiency gains to network companies of around £65m.
- Increased carbon costs of around £105m.

The 'Low', 'Best Estimate' and 'High' costs are not in ascending order above, instead they are in order when calculating the NPV values.

**Other key non-monetised costs by 'main affected groups'**

The IA has monetised all identified direct costs.

As the CMA is funded by Government, any increase in its costs represents a cost to society through higher taxes or lower public expenditure (indirect cost to businesses, the level of which cannot be accurately forecast because of uncertainties around future fiscal policy).

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | £0m | | £0m | **<£0.5m** |
| **High** | £0m | | £0m | **£0m** |
| **Best Estimate** | £0m | | £0m | **<£0.1m** |

**Description and scale of key monetised benefits by 'main affected groups'**

All benefits in the 'central' scenario:

- Avoided transfer from consumers to network companies of up to £600m (not included in NPV).
- Avoided deadweight loss of less than £0.1m.
- Total net benefit to energy consumers of up to £420m.[4]

The 'Low', 'Best Estimate' and 'High' benefits are not in ascending order above, instead they are in order when calculating the NPV values.

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[2] The 'central' scenario is the central mergers scenario as explained in Table 1 in *Background*.

[3] In line with HMT Green Book guidance, economic transfers between groups are excluded from the overall estimate of Net Present Social Value. Transfers benefit the recipient and are a cost to the 'donor' and therefore society as a whole is neither worse or better off (there is no net effect). Economic transfers, however, may have distributional impacts. We have not deemed it proportionate to estimate these impacts for the purposes of this Impact Assessment. For more details, please see: HM Treasury and Government Finance Function (2020), The Green Book, Chapter 6, https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

[4] Calculated by combining the best estimate for NPV and the central estimate for avoided transfer from consumers to energy networks.

**Other key non-monetised benefits by 'main affected groups'**

The 'Policy Option' has other, non-monetised, benefits such as:

- Helping to reduce fuel poverty
- Rebound effects.
- Ability to compare performance and quality of service.
- Greater diversity of approaches due to prevented consolidation.
- Better price discovery.

| Key assumptions/sensitivities/risks | Discount rate (%) | 3.5% |
|---|---|---|

See the Assumptions and Risks section for further detail.

- The number of future mergers is derived using the current number of firms in operation.
- Estimates of merger costs to consumers in electricity distribution come from a 2010 Cambridge Economic Policy Associates (CEPA) report, commissioned by Ofgem. Gas distribution estimates have been derived based on the results for electricity distribution.
- Administration costs are based on information from Ofgem, and precedents set by CMA investigations in the water sector.
- Price elasticities of gas and electricity demand are consistent with BEIS' Energy Demand Model.
- The merger efficiency gain percentage is based on evidence from mergers in the water sector.
- The IA assumes 100% pass-through of network costs and savings to consumers.
- The IA assumes that all network companies' profits remain in GB and therefore costs to consumers (and benefits to network companies) are transfers, with no change in net social welfare. However, as only two of the six electricity distribution companies have their parent companies and main shareholder headquarters in GB, some transfers would leave GB as a net cost to GB society. Due to lack of evidence, this is not reflected in the estimated Net Present Values.
- Throughout the IA, cost values derived from internal analysis have been rounded and may not sum consistently.
- The IA has monetised the impacts of the options available to the CMA following a phase 2 investigation, such as the blocking of a merger or the requiring of remedies to mitigate any negative impacts of the merger. Other options, such as undertakings in lieu of reference to a phase 2 investigation, have not been monetised; their impacts are likely to be within the range quantified.
- The IA is in 2020 prices and all present values are discounted to 2022. The IA uses a 10-year default time horizon, as the 'Policy Option' does not have an end-date. There are significant uncertainties around future regulatory arrangements as well as efficiency incentive schemes of future price control periods beyond RIIO-T2 and RIIO-ED2.

**BUSINESS ASSESSMENT (Policy Option)**

| **Direct impact on business (Equivalent Annual):** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs: £8.5m** | **Benefits: £0m** | **Net: £8.5m** | 37.5 |

# Evidence Base, problem under consideration and rationale for intervention

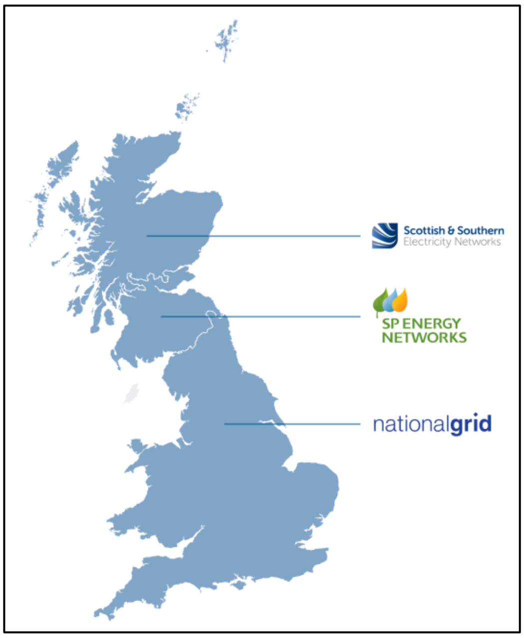
1. Energy networks transport gas and electricity from the place they are generated, produced or imported, to customers. Electricity is transmitted at high voltage through Great Britain by electricity transmission operators (TOs). It is conveyed from the transmission network to the consumer by distribution network operators (DNOs). Gas is transported at high pressure through the national transmission system and delivered at lower pressure to consumers by regional distribution companies.

2. The current structure of the energy network industry involves multiple licensee ownership by a small number of independent groups:

- *Electricity distribution*: Six independent groups own 14 distribution network operators, of which: one group owns four licensees, another owns three licensees, three groups own two licensees, and one group has a single licensee.

- *Gas distribution*: There are eight regional gas distribution networks (GDNs), owned by four independent groups. Cadent owns four of the networks but only has one licence. Although Cadent only owns one licence, its four networks each have a separate price control in the same way as the other four licensees. Of the remaining three groups, one holds two licences, and two hold one licence each.

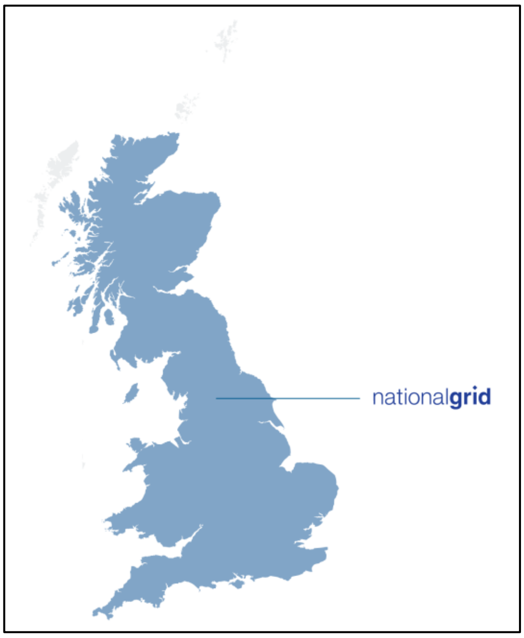
- *Gas and electricity transmission*: Three independent groups own four licences of which one group owns two licensees and two groups own one licensee each.[1]

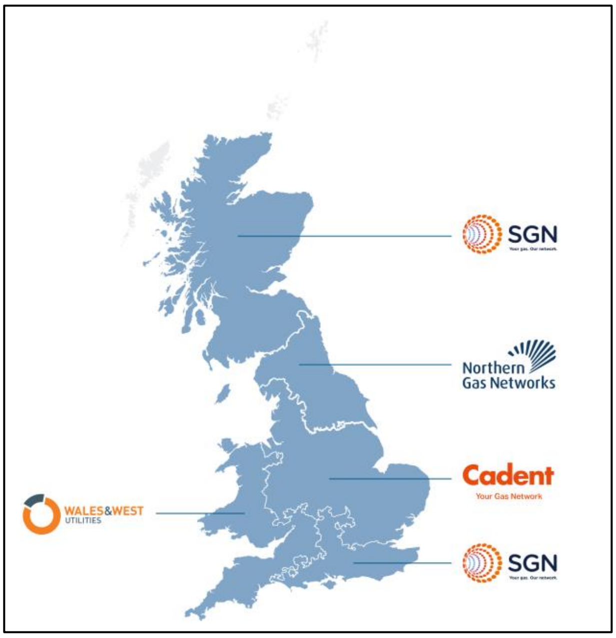


Electricity transmission networks

Electricity distribution networks

[1] Energy Networks Association, Who's my energy supplier or network operator?, https://www.energynetworks.org/operating-the-networks/whos-my-network-operator




Gas transmission network

Gas distribution networks

3. Fifteen independent distribution network operators (IDNOs) operate smaller distribution networks within areas covered by DNOs[2], largely serving new housing and commercial developments. Independent gas transporters (IGTs) serve a similar function. Some licensees provide offshore and cross-border transmission services, connecting offshore electricity generation and other electricity systems, respectively, to GB mainland.

4. Since privatisation, several mergers have taken place in electricity and gas distribution, these are listed below:

- 1995: Scottish Power took over Manweb;
- 1998: Merger between Scottish Hydro Electric and Southern Electric;
- 2000: Merger between CSW (owner of SEEBOARD) and AEP (part owner of Yorkshire Electricity);
- 2000: Western Power Distribution (South Western Electricity) purchased Hyder (owner of South Wales Electricity);
- 2001: Mid-American (owner of Northern Electric) acquired Yorkshire Electricity;
- 2002: EDF (owner of London Electricity) purchased Eastern Electricity (from TXU Europe) and SEEBOARD (from AEP);
- 2004: E.ON (owner of East Midlands Electricity) purchased Aquila Networks (Midlands Electricity); and
- 2011: PPL (owner of 2 WPD networks) purchased E.ON's Central Networks business (2 Midlands DNOs).
- 2019: National Grid Gas Distribution sold its four gas distribution networks to a consortium of international investors.
- 2022: SSE complete sale of a 33% stake in SGN to Ontario Teachers', and Brookfield.
- 2022: National Grid Gas Transmission has agreed to sell a 60% equity interest in its UK gas transmission and metering business ('NGG') to a consortium of long-term infrastructure investors.

## Ofgem's regulation of networks

5. Energy network businesses are natural monopolies: they do not directly compete for business within the geographical extent of their marketplace. Ofgem, the industry-funded regulator for energy markets, instead protects current and future consumer interests by regulating the companies through price

[2] Ofgem (2022), List of all electricity licensees including suppliers, https://www.ofgem.gov.uk/publications/list-all-electricity-licensees-including-suppliers

controls, which function as a proxy for competitively set prices[3]. The price controls set the amount of revenue which energy network owners can receive, recovered through the charges they levy on users of their networks. This revenue covers their costs and includes a return in line with performance against an agreed package of outputs and licence requirements.

6. Price controls are set for the 14 DNOs, the four energy transmission networks and the eight GDNs. Ofgem's price control process for setting price controls in gas and electricity transmission and distribution is called RIIO ("Revenue = Incentives + Innovation + Outputs"). RIIO places emphasis on incentives to drive the innovation needed to deliver a sustainable, value for money energy network. Price controls are generally set for five-year periods and reported on annually.

| Price control | Networks regulated | Start date | End date |
|---|---|---|---|
| RIIO-T2[4] | Gas and electricity transmission | April 2021 | March 2026 |
| RIIO-ED1[5] | Electricity distribution | April 2015 | March 2023 |
| RIIO-ED2 | Electricity distribution | April 2023 | March 2028 |
| RIIO-GD2 | Gas distribution | April 2021 | March 2026 |

7. Under RIIO, Ofgem sets targets for environmental performance, customer service, and a range of other measures, by comparing the incumbent operators. To set stretching targets, Ofgem conducts benchmarking: energy network companies submit data to Ofgem on outputs, inputs and input prices, and Ofgem uses these to set reasonable and competitive price levels for the period of the next price control. Whilst the precise approach varies slightly for each specific price control, in all cases, it involves analysis which combine data across companies and over time.[6]

**The impact of a merger on comparative regulation**

8. The process of setting price controls through benchmarking is founded on data provided by the operators themselves. The larger the number of operators that Ofgem can use in its analysis, the stronger its ability to robustly benchmark performance and set revenues and targets that would imitate competitive market pressures.

9. While mergers and takeovers in the energy sector can deliver benefits for producers and consumers such as efficiency gains, mergers or takeovers between different regulated companies also reduce the number of independent observations that Ofgem can use in its benchmarking.

10. Even where merged companies retain individual licences, the analytical value of comparisons is reduced because the performance of the merged companies no longer reflects the impact of different management strategies and capabilities, but rather the same management approach to different regions. The loss of a comparator from a merger thus affects:

    - The analysis used to determine the weights for the cost drivers;
    - The analysis used to determine the efficiency scores; and
    - The benchmarks set from this analysis.

11. An Ofgem-commissioned report, completed in 2010 by CEPA, considered the potential value of a loss of a comparator company following a merger in the energy network industry. The report estimated

[3] BEIS intend to open the onshore network to competition when new assets are being built, as part of our wider work towards net zero. This may happen in tandem with the introduction of the special mergers' legislation. Even with opening the network to competition, the incumbent networks will still be regulated through the price control framework, and so the underlying policy rationale on Ofgem's ability to benchmark remains.

[4] Ofgem, Network price controls 2021-2028 (RIIO-2), https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2/electricity-distribution-price-control-2023-2028-riio-ed2

[5] Ofgem, Network price controls 2013-2023 (RIIO-1), https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2013-2023-riio-1

[6] Information provided by Ofgem.

that the loss of a licensee in the electricity distribution sector, calculated on a five-year NPV basis with a discount rate of 4.7%[7], could lead to higher network charges. These could result in a transfer from consumers, who pay the charges, to electricity network companies of between around £40m and £150m (NPV, 2007/08 prices) over five years, and £190m to £730m in perpetuity. The report found that this is an approximate increase of between around 0.5% and 2.5% in the amounts electricity network companies are allowed to recover. In addition, the report concludes that the number of independent groups in both the electricity and the gas distribution sectors is already at the level where serious concerns could arise about the robustness of comparative benchmarking if there were any further reduction in the number of comparators. Since the report was published in 2010, there have been three further mergers.

12. Although Ofgem uses some information derived from international operators for the purposes of comparing GB operators, this information will always be an inferior substitute because of different accounting practices, technical standards and auditing processes.

13. Due to the time elapsed and the further electricity and gas network company mergers since this report, the data provided by the remaining energy network companies may prove to be of increased value to Ofgem's comparative benchmarking process.

**The Competition and Markets Authority**

14. The Competition and Markets Authority (CMA) is the UK-wide competition authority responsible for ensuring that competition and markets work well for consumers. The CMA has a function to obtain and review information relating to merger situations, and a duty to conduct a preliminary 'Phase 1' investigation and to refer for an in-depth 'Phase 2' investigation in any relevant merger situation where it believes that it is or may be the case that the merger has resulted (or may be expected to result) in a substantial lessening of competition in a UK market.

15. After a Phase 1 investigation, if the CMA finds that it is or may be the case that a merger has or may be expected to give rise to a significant lessening of competition, it must refer the merger to a Phase 2 investigation, unless the merger parties concerned offer acceptable undertakings in lieu of reference. These undertakings should be designed to offset any negative impacts of the merger identified by the CMA. In the absence of such an offer, or if those undertakings are not accepted, the CMA will conduct a Phase 2 investigation during which it will determine whether: (i) there is a relevant merger situation, (ii) that relevant merger situation has resulted, or may be expected to result, in a substantial lessening of competition, and (iii) it should take action to remedy, mitigate or prevent any substantial lessening of competition. At the end of that process, the CMA may allow the merger to proceed, impose structural or behavioural remedies on the companies concerned, or prohibit the merger altogether.

**The problem under consideration**

16. Energy network businesses in gas and electricity transmission and distribution are regional monopolies. Therefore, it is highly unlikely that the CMA would find that a merger between them would lead to a substantial lessening of competition under the current merger regime as laid out in the Enterprise Act 2002.

17. However, a reduction in Ofgem's ability to compare energy network businesses and to benchmark effectively can lead to societal costs. Currently, the CMA does not have the *vires* (i.e. ability, as defined within legislation) to consider this potential detriment outside of its assessment of a lessening of competition.

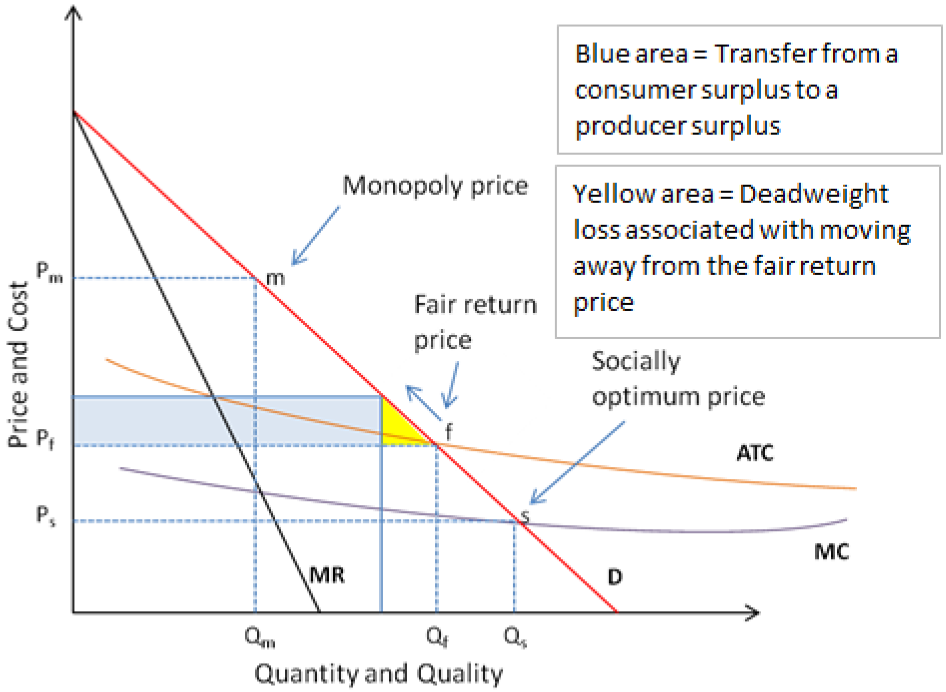
[7] This was the cost of capital allowed by Ofgem for DNOs under Distribution Price Control 5, the price control in operation at the time the commissioned report was written.

18. Government therefore believes that there would be benefit in introducing a special merger regime for energy network businesses that would allow the CMA to also consider the detriment to consumers due to a reduction in Ofgem's ability to compare energy network businesses and benchmark effectively.

## Rationale for Intervention

19. As with all regulated markets, the regulator (Ofgem, in this instance) does not have access to the same level of information as the companies it regulates. It is therefore difficult to ensure that those companies are acting in consumers' best interest. Figure 1 illustrates the monopolist's incentive to maximise profits (where marginal cost (MC) equals marginal revenue (MR)) resulting in under-delivery of quantity and quality and also higher prices than is socially efficient.[8] Therefore, the regulator seeks to ensure that the companies face output optimising prices, where average total cost (ATC) equals demand (D) at the fair return price.[9] To assess a fair return price in energy networks, the regulator (Ofgem) undertakes comparative benchmarking.

**Figure 1: Demand and supply in a natural monopoly**




*Note that in the first order, any change in price is felt by energy retail companies, gas shippers, and distributed electricity generators. They are assumed to pass higher prices through to domestic and non-domestic consumers.*

20. Mergers or takeovers can bring about efficiencies in the interest of consumers and society, including reduced overheads, synergies resulting from a shared cost base and improved bargaining or procurement power. However, the ability to undertake comparative benchmarking and therefore to protect consumers could be negatively affected should a merger or takeover take place, as this could increase the information asymmetry and market power which would decrease incentives to become more efficient.

21. A merger or takeover will decrease the number of independent companies, therefore decreasing the strength of Ofgem's comparative benchmarking as the analysis becomes less valid the fewer data points available.[10] Because this decreases the reliability of estimates of the ATC of network regions,

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[8] Marginal cost/revenue is the cost/revenue associated with an additional (marginal) unit of output.

[9] At the socially optimum price the company would not be able to cover the full costs of its output and would eventually go out of business; therefore the fair return price corresponds to the maximum level of output at which the company earns a fair return (i.e., where price equals average total cost).

[10] It will also impact on other analysis such as assessing the quality of companies' evidence, narrative justification, need case for investment, asset life and loading assumptions.

Ofgem's price control determinations might enable network companies to increase prices for consumers, increasing their profits above the fair return price

22. This potential outcome is represented in Figure 1 by the price move above $P_f$, which results in a transfer from consumers to producers (the blue area) and an aggregate welfare loss to society (the yellow area – deadweight loss (DWL)). In addition to increasing profits, it also reduces the incentive for the network company to be efficient, which could shift the ATC curve upwards and result in a fall in productivity.

23. The potential benefits delivered from mergers or takeovers include cost reductions, improved service quality, greater technological investment and sharing of innovation benefits across merged regions. However, without appropriate comparative benchmarking, it will be difficult for Ofgem to help ensure these benefits are passed onto consumers.

24. If the benefits of a merger or takeover in a given region were sufficient to compensate for the reduction in comparative benchmarking, then consumers and society in that region would benefit from a merger or takeover. However, the decrease in information caused by a merger comes at a cost to consumers across all regions in Ofgem's price control setting or for other regular reviews of allowed revenues.

25. The policy option under consideration in this IA is to extend the power of the CMA to take account of the impact on Ofgem that arises from the loss of comparative data and weigh this against any benefits that the merger may offer. This policy does not intend to stop mergers in the energy network marketplace *per se*, rather enabling the CMA to consider the full benefits and detriments that might arise from them before making a final decision.

26. An independent (unpublished) report for Ofgem, undertaken by Cambridge Economic Policy Associates (CEPA) in 2010 concluded that there could be a significant, negative impact on Ofgem's ability to regulate if its ability to compare energy network companies in the future is increasingly restricted. The CMA is already enabled to consider such impacts (i.e. on the regulator's ability to regulate) in the water sector, and competition authorities since 1992 have concluded on a number of occasions that the loss of comparator information was a relevant factor in assessing the broad benefits and disbenefits of a proposed merger. To extend a similar power to the CMA in the energy network industry, primary legislative change is required.

27. The primary policy objective of the 'Policy Option' is to better protect consumers by requiring the CMA to consider the impact on the effectiveness of the regulator's ability to comparatively benchmark prices and to compare performance standards when considering a merger or takeover between energy network businesses of the same type. Businesses within scope are those that transmit electricity, distribute electricity, or transport gas, as defined in section 6 of the Electricity Act 1989 and section 7 of the Gas Act 1986. The policy objective is to also include a power allowing BEIS to amend the definition of "energy network enterprise" by reference to the type of license it holds under the Gas Act or Electricity Act.

28. The policy excludes from scope any enterprise that only holds licence/s that have been awarded competitively. Providers of network services for other energy sources (such as 'heat networks') also remain out of scope of the regime.

29. The proposed regime for energy network industries is modelled closely on the existing (more general) merger regime: during the 'Phase 1' investigation, the CMA will consider the impact of the merger on Ofgem's ability to regulate comparatively. The CMA will decide, on the basis of the outcome of this consideration, whether to refer the merger to a more detailed 'Phase 2' investigation. If it does, the relevant companies may consider offering undertakings in lieu of reference to Phase 2, designed to mitigate or prevent the negative outcomes of the merger. During a Phase 2 investigation, the CMA would then be able to consider the impact of the merger of Ofgem's ability to regulate comparatively – before deciding whether to ask for remedies from the merging enterprises (which seek to remedy, mitigate or prevent any negative impact of the merger), or indeed to block the merger altogether.[11]

[11] It is also possible under the policy, for the CMA to investigate for both (i) a substantial lessening of competition, and (ii) prejudice to Ofgem's ability to carry out its functions under the price control. Such situations could arise where mergers, or proposed mergers, of energy network enterprises involve both (i) the parts of the business regulated by the price control, which would not otherwise engage the substantial lessening of competition test (i.e. because they are run as regional monopolies by virtue of their licensing conditions), and (ii) the parts of the business which would result in the substantial lessening of competition (i.e. because they are subject to external market forces i.e. providers of connection services to the electricity network).

30. In principle, the proposed measure would allow the CMA to take a more comprehensive view of the impact of the merger on consumers and the market. The regime would only prevent mergers or takeovers were the CMA to believe that any consumer detriment arising from the merger would outweigh any benefit.

31. The CMA is already enabled to consider the impact of a merger on the regulator's ability to compare prices and service standards in the water sector, where a special merger regime has been in place since 1992. There are clear differences between the operational requirements of the water and energy networks, such as the need for the electricity system to be kept in constant balance and different potentials for storage to help balance demand and supply. However, providers of water and sewerage networks, just like electricity and gas networks, are natural monopolies, regulated through price controls by an industry-funded regulator. Further, both Ofwat and Ofgem use benchmarking to set competitive targets for the regulated companies under their price controls. Both regulators agree that the larger the number of comparators, the more effective the benchmarking.

32. Given the similar regulatory approaches, it is appropriate to consider how the special merger regime for water and sewerage enterprises has delivered value for consumers. At the same time, it is important to note that there are 16 independently owned companies[12] (providers of water and sewerage networks) available to Ofwat for the purposes of benchmarking, while in gas and electricity there are 4 and 6 respectively. This suggests that the introduction of a special merger regime in energy networks is both more urgent and carries the possibility of securing substantial value.

33. Several mergers in the water sector have been considered by the UK competition authorities since 1992, with a variety of outcomes. For example, in 2007, the Office for Fair Trading referred to the Competition Commission (CC) the acquisition of Hastings Luxembourg Water Sarl (the holding company for South East Water Limited) by Mid Kent Water Limited. The CC concluded that the merger may be expected to prejudice, to a limited extent, the ability of Ofwat to make comparisons between water companies. It found that:

- It was not likely that there would be an adverse effect as a result of the loss of a potential benchmark for either operating or capital expenditure in the next two price reviews; however the merger would adversely affect the precision of the operating expenditure econometric models used by Ofwat, which could result in future price caps being based to a greater extent on company's own costs; and
- The merger would not be likely to remove a potential comparator for the purpose of standard cost comparisons, however there was a risk that the merger could result in an adverse impact on Ofwat's ability to make qualitative comparisons.

34. The CC concluded that the prejudice may result in higher prices for customers in England and Wales, whilst there were likely to be consumer benefits including costs savings and the ability of the merged entity to plan across existing company boundaries. These benefits substantially outweighed the prejudice identified. It therefore concluded that a price reduction would mitigate the adverse effects, and a one-off price reduction of around £55m for the affected customers was passed to them through bills. In addition, to ensure that consumers continue to receive the benefit of the cost savings from the merger, the company was required to accept a price determination in the 2009 price control review that reflected up to £5m annual operating expenditure savings.[13]

35. The CEPA report stated that in 2002, the CC approved the merger of Vivendi (majority owner of water-only companies Three- Valleys, Tendring Hundred, and Folkestone & Dover, and minority shareholder of water-only company South Staffordshire) & First Aqua (owner of water and sewerage company, Southern) subject to remedies to offset any value of a loss of comparator. It found that:
    - This merger could cause some tainting of Southern and Folkestone & Dover's data, consequently lessening their use for comparisons.
    - The Director General of Water Services estimated a NPV loss for Southern's operating expenditure of £450m (over 25 years), and a £40m loss for Folkestone & Dover.
    - The merger would impair the regulator's ability to make comparisons through the loss of an independent comparator or potential benchmark with Southern and through lower precision of the models for operating expenditure and maintenance capital expenditure.

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[12] Information provided by Ofwat.

[13] Practical Law Competition, Mergers in the water sector, http://uk.practicallaw.com/1-375-8777

36. The remedies the merger was subject to, in order to be approved included:
    - Vivendi divesting its minority share in South Staffordshire. Consequently, the special water regime allowed the CC to exercise effective powers enabling this possible loss to consumers to become a benefit through the creation of a new comparator.

37. Two options have been considered and appraised qualitatively and, where possible, quantitatively in this impact assessment. These are:
    - **Do Nothing:** Continue the status quo. The CMA considers mergers or takeovers in the energy network sector using the substantial lessening of competition test. The CMA will not be able to consider the impact of a merger on Ofgem's ability to compare energy network companies, and mergers may lead to overall consumer detriment.
    - **Policy Option:** Introduce a **special merger regime for energy network businesses**, similar to the special merger regime currently in place for water companies. The CMA is enabled to consider the impact of a merger on Ofgem's ability to compare network companies (as part of a Phase 1 investigation), and will assess that impact alongside any relevant consumer benefit that may arise from a merger (e.g. efficiency gains passed onto consumers) before determining whether to refer the merger to a phase 2 investigation and eventually either allow the merger to go ahead, impose structural or behavioural remedies on the companies concerned, or to prohibit the merger altogether. The regime would be introduced through primary legislation and come into effect as soon as possible. This option should ensure that Ofgem's ability to regulate through comparative benchmarking remains effective.

38. We also considered whether there are alternative do nothing and policy options for addressing the policy issue (i.e. ensuring that Ofgem's ability to regulate through comparative benchmarking remains effective). Neither of the alternatives considered were deemed sufficient methods of addressing this issue but for thoroughness, we include them here. The main alternatives considered are:
    - **Alternative 'Do Nothing' - Reliance on Public Interest declarations:**

      Under the current regime, the CMA must bring to the attention of the Secretary of State for Business, Energy and Industrial Strategy (BEIS) any merger that it believes raises a public interest consideration. The specified public interest considerations on which the Secretary of State may intervene are national security (including public security), media plurality (covering accurate presentation of news, free expression of opinion and plurality of views in newspapers and rage of broadcasting and genuine commitment to broadcasting standards), the stability of the financial system and the need to maintain in the UK the capability to combat, and to mitigate the effects of, public health emergencies. In these cases, the Secretary of State may choose to issue a public interest notice. We consider it unlikely that mergers between energy network enterprises will fall within scope of the public interest declaration route. This option is only intended to be extended sparingly. Therefore, it is not considered a suitable option to ensure that Ofgem's ability to regulate effectively through comparative benchmarking is protected.

      The National Security and Investment Act (NSIA) 2021, which was given Royal Assent on 29 April 2021 and came into force on 4 January 2022, amends the public interest notification section of the Enterprise Act 2002. The NSIA bolsters the government's power to investigate and intervene in mergers, acquisitions and other deals that could threaten UK national security. Where a final order or notification is made under NSIA 2021 and is in force, the Secretary of State will be empowered to direct the CMA to do or not to do anything under Part 3 Enterprise Act 2002 (the part of the Act which empowers the CMA to investigate mergers for substantial lessening of competition), if the Secretary of State considers that this direction is necessary and proportionate for the purpose of preventing, remedying or mitigating a risk to national security. In the context of energy network mergers, this means that the Secretary of State could direct CMA to carry out or refrain from carrying out an investigation for substantial lessening of competition. This option therefore still does not serve the Government's policy objective of ensuring that Ofgem's ability to regulate effectively through comparative benchmarking, is protected, and is arguably the same as "do nothing" above.
    - **Alternative 'Policy Option' - Modification of network company licence conditions:**

      We also have considered whether Ofgem could modify the licences granted to energy network enterprises to prohibit mergers de facto (for example by preventing an energy network company from holding more than one distribution licence) as a means of ensuring that Ofgem's ability to regulate effectively through comparative benchmarking is protected. Government are of the view this is a less desirable option than the preferred policy option identified above because the licensing regime is not designed to deal with the particular problem identified and does not provide the flexibility needed. For example, it may be more appropriate to protect comparative benchmarking by requiring quasi structural changes to a company's structures/constitution instead of preventing a merger outright, such as limitations on the ability to appoint directors or on voting rights). Furthermore, Ofgem are arguably not as well placed to assess and decide on the appropriate remedy to address the impacts of the merger as the CMA who specialise in this. For this combination of reasons, Government do not view this as an effective option to address the policy issue of ensuring that Ofgem's ability to regulate effectively through comparative benchmarking, is protected.

39. Neither of these alternative options adequately achieve Government's objectives for this policy area: the first (reliance on Public Interest declarations) is unlikely to address the type of harmGovernment is concerned with, while the latter (modification of licenses) may not fully address the issue and relies on one regulator when there is a more suitable option (in the CMA). The preferred policy option should address the policy issue in a proportionate manner. As such, these alternatives to the preferred policy option will not be considered further in this IA.

# Monetised and non-monetised costs and benefits of each option

## Background

40. The 'Policy Option' is compared against 'Do Nothing', to estimate the additional costs and benefits. Before considering the two options, this section sets out some background to the monetisation of costs and benefits.

*Number of potential mergers under 'Do Nothing' and the 'Policy Option'*

41. It is impossible to say for certain how many energy network companies in the future would seek to merge and how many of those would be blocked, as this would depend on the level of the costs and benefits that a merger would bring, and the extent to which these were identified by the CMA. There has been significant consolidation of the electricity distribution sector since privatisation in 1989.

42. To set out the likelihood of a merger arising in either electricity or gas networks, guidelines and literature on mergers provide a vast range of reasons (including financial, operational and strategic) for why companies have merged in the past. However, there is no overarching framework on which this kind of analysis can be based and it is therefore difficult to assess the likelihood of a merger in the future. This IA therefore considers scenario-based analysis.

43. In *electricity distribution*, there have been eight mergers or takeovers in GB since 1995 and six companies currently own all the electricity distribution licences. This means that there could be a maximum of five mergers or takeovers taking place in the future in the electricity distribution sector, which would result in just one company being left in that sector (see Table 1). Therefore, the minimum and maximum number of potential mergers or takeovers is zero and five, respectively, with the central estimate being two mergers over a ten-year period. Two mergers are considered a mid-point between zero and the maximum of five, since as the number of companies falls, the opportunities to merge falls.

44. In *gas distribution*, up to two group mergers would be possible, given that four independent groups (of which two are majority owned by the same investment funds as set out above) currently own the licences. Therefore, this IA estimates that the minimum and maximum number of potential mergers or takeovers is zero and two, with the central estimate being one merger over a ten-year period.

45. This IA has not quantified any costs and benefits associated with mergers in *gas and electricity transmission*. This is because Ofgem does not use the same type of comparative benchmarking to set transmission price controls. This is discussed further in the 'loss of comparator costs' sections below.

*Number of blocked mergers under 'Do Nothing' and the 'Policy Option'*

46. Under 'Do Nothing' all energy network mergers go through a phase 1 investigation but no merger is referred to a phase 2 investigation, because no mergers of energy network companies will result in a significant lessening of competition (at least not in relation to overlaps in their network activities).

47. Under the 'Policy Option' all mergers go through a phase 1 investigation, following which they may go through a phase 2 investigation, at the end of which the CMA either accepts or imposes steps to remedy, mitigate or avoid any negative impact on Ofgem (such as a one-off payment to consumers); or to block the merger altogether. It would be unrealistic to assume that all mergers under the Policy Option would be blocked, because that approach might be disproportionate and because other remedies, such as compensation for consumers, might be more appropriate. In these cases, there would be no foregone efficiency gain to society.

48. As a central estimate this IA assumes that approximately half of the mergers in the electricity and gas distribution sector are blocked (see Table 1). This is based on evidence of previous water merger cases, where under a special mergers regime approximately half have not been able to proceed [14]. As there are fewer energy network companies one might expect a higher incidence of prohibitions than in the water mergers regime, though for the basis of this analysis we will proceed with this assumption to align with this pre-existing evidence in the water sector.

[14] Ofwat (2015), Ofwat's approach to mergers and statement of methods, p.80, https://www.ofwat.gov.uk/publication/ofwats-approach-to-mergers-and-statement-of-methods-2/

49. It is important to note that there are other potential scenarios, such as:

- A merger is not deemed to negatively impact Ofgem and therefore is not referred to a phase 2 investigation. This would result in no impacts under the 'Policy Option' compared to 'Do Nothing', except for some regime set-up costs and some additional phase 1 administration costs.
- A phase 1 investigation concludes that a merger is deemed to negatively impact Ofgem, and the relevant companies offer undertakings in lieu of a reference to a phase 2 investigation. In this case, the undertakings would need to be considered and drafted, and then potentially monitored on an ongoing basis to ensure compliance. The administrative burden of dealing with undertakings in lieu of a reference varies enormously between cases, but the CMA has advised that the process will typically be much less costly than a full phase 2 investigation due to the requirement that remedies accepted at phase 1 are clear cut.
- The phase 2 investigation results in no action being taken (if it is not deemed to negatively impact Ofgem). This would result in no impacts under the 'Policy Option' compared to 'Do Nothing', except for regime set-up costs and additional phase 1 and phase 2 administration costs.

These have not been quantified specifically in this IA but could be reflected within the low to high range.

50. Table 1 shows the numbers of mergers blocked in electricity and gas networks for each proposed merger or takeover scenario. Under the 'Policy Option', the first merger is blocked, followed by every other merger being blocked. In the central estimate of two proposed mergers in electricity distribution, one is blocked, whilst in the gas distribution, the sole proposed merger is blocked. This results in one allowed merger in electricity distribution, and zero in gas under the central estimate.[15]

**Table 1: Number of potential mergers under 'Do Nothing' (those that are assumed to be blocked under the 'Policy Option' are in parentheses), and the years in which the mergers may occur**

| | Number of proposed mergers or takeovers | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Electricity distribution | 0 (min estimate) | | | | | | | | | | |
| | 1 | (M) | | | | | | | | | |
| | 2 (central estimate) | (M) | | M | | | | | | | |
| | 3 | (M) | | M | | (M) | | | | | |
| | 4 | (M) | | M | | (M) | | M | | | |
| | 5 (max estimate) | (M) | | M | | (M) | | M | | (M) | |
| Gas distribution | 0 (min estimate) | | | | | | | | | | |
| | 1 (central estimate) | (M) | | | | | | | | | |
| | 2 (max estimate) | (M) | | M | | | | | | | |

*Loss of comparator costs in electricity distribution*

51. Quantification of the potential value of loss of comparators because of a merger between two energy network companies (with quantifications focusing on electricity distribution) has previously been

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[15] Throughout the analysis in this IA we will be referring to 'min', 'central' and 'max' scenarios, which align with the proposed merger scenarios set out in Table 1 under 'Do Nothing' and 'Policy Option'.

undertaken by CEPA, commissioned by Ofgem (see Annex 1 for a summary of the unpublished report). This evidence has been used to estimate some of the benefits for consumers if detrimental mergers or takeovers do not go ahead. CEPA's analysis for Ofgem concluded in May 2010 and was based on analysis of what was the previous price control period (DPCR5 for electricity distribution and GDPCR for gas distribution). Ofgem believes that this analysis remains relevant and provides a good guide to the impacts of future mergers, on the basis that:

- There have been further mergers in electricity distribution since the analysis was completed. This, if anything, is likely to increase the value of the remaining comparators and so does not undermine the case presented in this IA.
- Another price control period has been completed, which is when the analysis could have been updated. In any event, it is difficult to say that any update would change the range of figures materially because the underlying costs in the sectors, and the relative differences between the companies, remain stable.

*Loss of comparator costs in gas distribution*

52. CEPA did not estimate a monetary value for the loss of a licensee for gas distribution because of the relatively limited data set in that sector. Unlike in electricity distribution where Ofgem uses licensee data points as independent observations, in the gas distribution sector some of the benchmarking analysis uses group level rather than licensee data points. This implies that in the event of any mergers or takeovers in the gas distribution network, the negative impact on Ofgem's comparative benchmarking and therefore costs of mergers for consumers are likely to be larger than for electricity distribution because the starting point is only four independent groups[16], of which two are majority owned by the same foreign investment funds[17]. In the absence of better information, this IA therefore assumes that the 'high' transfer from consumers to network companies in the event of a merger in the electricity distribution sector is applicable for the gas distribution sector (see further detail in the 'Do Nothing' section below).

*Loss of comparator costs in gas and electricity transmission*

53. In terms of the one gas and three electricity transmission companies, Ofgem does not use econometric comparative benchmarking to set the price controls. Instead, it undertakes unit cost benchmarking (as well as other less formal comparisons). On cost of capital, Ofgem considered international benchmarks where appropriate. However, there were significant limitations in comparability due to the terms of different regulatory regimes and methodologies. Should Ofgem decide to use comparators more extensively going forward there could be costs attached to the loss of a comparator in electricity and gas transmission. This IA has not quantified this eventuality.

*Pass-through assumptions*

54. This IA assumes that in the first instance any changes to allowed revenues for electricity network companies will be passed through to electricity retail companies ('suppliers') and generators connected to the distribution network ('distributed generators'). It is assumed that any changes in these charges are then passed through in energy bills to domestic and non-domestic consumers. This IA also assumes that in the first instance any changes to allowed revenues for gas network companies will be passed through gas shippers to gas suppliers, who pass them through energy bills to domestic and non-domestic consumers. For further details, see the Assumptions and risks section.

[16] There are currently eight gas distribution networks with four independent groups owning the licences.

[17] Northern Gas is majority owned by CK Holdings (47%) and Power Asset Holdings (41%), Wales and West Utilities is majority owned by CK Holdings (30%), CK Infrastructure (30%) and Power Asset Holdings (30%).

## Do Nothing

55. Costs and benefits under 'Do Nothing' are zero, as no policy is being introduced. Impacts of a merger under 'Do Nothing' are discussed here to form a baseline for evaluating the 'Policy Option'.

**Table 2: Summary of baseline cost and benefits of a merger under 'Do Nothing'**

| | | Cost | Benefit |
|---|---|---|---|
| **1.** | **Network companies*** | • Administration costs incurred as part of a standard phase 1 investigation<br>• Fixed merger fee charged by the CMA. The fee is £0.12m (cost, 2020 prices) where the company to be taken over has a turnover of more than £70m, and £0.16m (cost, 2020 prices) where the turnover is more than £120m, per merger. This is paid into the Consolidated Fund (see 'Benefit' in this table under *Society as a whole*). | • Transfer of money from energy retail companies, gas shippers and distributed electricity generators (and ultimately domestic and non-domestic consumers), to network companies following one of Ofgem's regular reviews of allowed revenues[18], due to loss of comparator data weakening Ofgem's regulatory power and resultant higher prices.<br>• Network companies can achieve economies of scale in management, innovation and overheads when merging with another company. |
| **2.** | **Energy retail companies, gas shippers, and distributed electricity generators*** | • Transfer of money from energy retail companies, gas shippers, and distributed generators (and ultimately domestic and non-domestic consumers) to network companies, due to loss of comparator data weakening Ofgem's regulatory power and resulting higher prices.<br>• Pass-through of network company administration costs<br>• Pass-through of the fixed merger fee that network companies face. | • Pass-through of some efficiency gains realised by network companies through mergers. |
| **3.** | **Domestic / non-domestic consumers** | • Pass-through of the higher costs faced by energy retail companies in the form of higher energy prices.<br>• Pass-through of the admin costs faced by energy retail companies (passed on from network companies)<br>• (Via energy retail companies) pass-through of the fixed merger fee that network companies face. | • Pass-through of some efficiency gains realised by network companies through mergers. |

[18] This can be as part of the Annual Iteration Process, mid-period price control reopeners or at the setting of a new price control.

| | | | |
|---|---|---|---|
| 4. | **Society as a whole (including all of the above)** | • Increased energy prices lead to less energy being demanded (DWL to society) and therefore lower emissions and lower carbon prices.<br>• CMA budget funded by central Government through taxation | • Fixed merger fee collected by the CMA and paid into the Consolidated Fund. |
| 5. | **CMA** | • Administration costs incurred as part of a standard phase 1 investigation | • N/A |
| 6. | **Ofgem** | • N/A | • N/A |

* Ofgem's pass-through administration costs include the transmission network companies and transmission connected generators.

***<u>Monetised Costs under 'Do Nothing'</u>***

1. ***Network companies***

    - **Administration costs:** Under 'Do Nothing', where energy network companies decide to merge, the CMA will undertake a phase 1 investigation ("the substantial lessening of competition test"). A phase 1 investigation (including pre-notification) could take up to 100 working days. This implies costs for network companies, which need to provide information to the CMA, and the CMA, whose costs in general are borne by society as a whole through taxation but also through a fixed fee – where the company that is to be taken over has a turnover of more than £70m, that fee is £0.12m (cost, 2020 prices) and if the turnover is more than £120m, the fee is £0.16m (cost, 2020 prices) per merger – levied on the person who has filed or taken control of the merger notification. While the size of these costs under 'Do Nothing' is irrelevant for the appraisal in this IA, it is important to note their existence under 'Do Nothing', forming the baseline for the 'Policy Option', where only costs associated with additional tasks during a phase 1 investigation should be monetised (see the section on the 'Policy Option').
    - As network mergers or takeovers do not (substantially) lessen competition due to being regional monopolies, under 'Do Nothing' mergers are not referred for a phase 2 investigation and therefore there are no phase 2 investigation costs. This means all phase 2 investigation costs under the 'Policy Option' are additional.

2. ***& 3. 'Energy retail companies, gas shippers, and distributed electricity generators' and 'Domestic / non-domestic consumers'***

    - **Transfer:** Under 'Do Nothing', Ofgem's ability to benchmark is reduced (because of a loss of a comparator) and Ofgem is less able to set the most efficient price control determinations. Consequently, network companies would be able to set higher network charges, implying higher costs to energy retail companies, gas shippers, and distributed generators in the first instance and ultimately domestic and non-domestic consumers. The analysis assumes that energy retail companies fully pass through these costs to domestic and non-domestic consumers in the form of higher energy prices.

    *Electricity distribution*

    - CEPA estimate that the transfer from consumers (and in the first instance from energy retail companies) to network companies ranges between £40m and £150m Net Present Value (NPV) over the five years of the price control period (DPCR5)[19]. To derive the NPVs, CEPA used a 4.7% discount rate, which reflects the cost of capital allowed by Ofgem under the Distribution Price Control 5 (2010/11-2015/16).

[19] CEPA's estimates are based on the previous DPCR5 price control period. However, Ofgem is confident that the potential size of this impact is also applicable for the RIIO price control regime.

- This IA, on the other hand, follows the Green Book[20] and aims to discount all costs and benefits at the social 3.5% discount rate. Therefore, it is important to strip the 4.7% discount rate out of the CEPA figures; this can be done by back-calculating the undiscounted average annual costs that underlie the CEPA NPV figures. To do so, this IA has solved the following formulae to find 'x', the annual undiscounted cost. This assumes that the annual cost is constant.

$$\frac{x}{(1+4.7\%)^0}+\frac{x}{(1+4.7\%)^1}+\frac{x}{(1+4.7\%)^2}+\frac{x}{(1+4.7\%)^3}+\frac{x}{(1+4.7\%)^4}=£40m$$
$$\frac{x}{(1+4.7\%)^0}+\frac{x}{(1+4.7\%)^1}+\frac{x}{(1+4.7\%)^2}+\frac{x}{(1+4.7\%)^3}+\frac{x}{(1+4.7\%)^4}=£150m$$

- The resulting undiscounted annual cost to energy retail companies and distributed generators (and ultimately domestic and non-domestic consumers) 'x' is £9m in the low case and £33m in the high case, when expressed in 2007/08 prices (DPCR5 price base)[21]. Converting this into 2020 prices give annual costs to consumers of between £10m and £45m[22].

- Assuming an annual cost to energy retail companies and distributed generators (and ultimately domestic and non-domestic consumers) of between around £10m and £45m (cost, 2020 prices) per merger or takeover in electricity distribution, and a merger every two years, over the ten-year period from 2022 the maximum annual consumer cost would be up to £130m (cost, 2020 prices) by 2031 (a maximum of five mergers having taken place at a high transfer cost). The net present value of this cost to consumers over a ten-year period is between £0m and £1060m (cost, 2020 prices, discounted to 2022), with a central estimate of around £410m (cost, 2020 prices, discounted to 2022) for two mergers at central transfer costs.

- Electricity retail companies are assumed to fully pass on these costs to domestic and non-domestic consumers (see *Assumptions and Risks* section). Assuming 62%[23] of electricity consumption is from businesses, the transfer from business consumers would be between £0m and £660m (cost, 2020 prices, discounted to 2022), with a central estimate of around £250m (cost, 2020 prices, discounted to 2022).

- It should be noted that the transfer value relates to the loss of one licensee, while a merger between groups could result in more than one licensee being lost (different groups own more than one licence). In addition, Ofgem's view is that, as the number of mergers increases, the negative impact on consumers and society is likely to increase exponentially (as more and more vital data points are lost). Therefore, the central estimates in this IA are likely to be conservative.

*Gas distribution*

- As mentioned above, the CEPA report did not quantify the transfer from consumers to producers in the gas distribution sector due to a lack of quantitative evidence. However, due to there being only four independent groups (of which two are majority owned by the same investment funds) it can be argued that the costs to consumers would be larger than those identified for electricity distribution. To approximate potential costs in the gas distribution sector, this IA assumes that the 'high' transfer from consumers to producers in the electricity distribution sector is applicable for the gas distribution sector as a central estimate.

- Assuming an annual consumer cost of around £45m (cost, 2020 prices) per merger or takeover in gas distribution and two mergers over the ten-year period from 2022, the maximum annual cost to energy retail companies (and ultimately domestic and non-domestic

[20] HM Treasury and Government Finance Function (2020), The Green Book, Chapter 6, https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

[21] The calculations are consistent with the Better Regulation Framework Manual methodology for estimating equivalent annual net cost and a 4.7% discount rate (the cost of capital allowed by Ofgem for DNOs under DPCR5).

[22] HM Treasury (2022), GDP deflator at market prices and money GDP December 2021 (Quarterly National Accounts), https://www.gov.uk/government/statistics/gdp-deflators-at-market-prices-and-money-gdp-december-2021-quarterly-national-accounts

[23] Average over the ten-year period from 2022 to 2031. Based on BEIS (2021), Energy and emissions projections, https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

consumers) would be around £75m (cost, 2020 prices) by 2031 (a maximum of two mergers having taken place). The net present value of this cost to energy retail companies, gas shippers and ultimately domestic and non-domestic consumers over a ten-year period is between £0m and £660m (cost, 2020 prices, discounted to 2022), with a central estimate of around £370m (cost, 2020 prices, discounted to 2022) for one merger.

- Gas distribution companies are assumed to fully pass these costs through gas shippers and on to domestic and non-domestic consumers (see *Assumptions and Risks* section). Assuming 34%[24] of gas consumption is from businesses then the transfer from business consumers would be between around £0m and £220m (cost, 2020 prices, discounted to 2022), with a central estimate of around £125m (cost, 2020 prices, discounted to 2022).

*Total*

- Table 3 presents the range of costs from CEPA's analysis arranged as low, central and high annual estimated costs to energy retail companies, gas shippers, and distributed generators (and ultimately domestic and non-domestic consumers) under 'Do Nothing', assuming different numbers of mergers over the next ten years. The central estimate assumes two mergers in electricity distribution and one in gas distribution over the next ten years and central annual cost estimates. These costs represent a benefit to network companies.
- **Pass-through of the network company incurred admin cost**: The costs incurred by network companies to provide information to the CMA under a phase 1 investigation will be passed on to energy retail companies, gas shippers, distributed electricity generation and ultimately domestic and non-domestic consumers.
- **Pass-through of the fixed merger fee:** Under 'Do Nothing', energy network companies pass on the fixed per merger fee, £0.12m or £0.16m (cost, 2020 prices), which they must pay irrespective of a reference to a phase 2 investigation to energy retail companies, gas shippers, distributed electricity generation and ultimately to domestic / non-domestic consumers.

**Table 3: Transfer from energy retail companies, gas shippers, and distributed electricity generators (and ultimately consumers) to network companies, due to different numbers of mergers over the next ten years (2020 PV over ten years, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| **Transfer from consumers to network companies** | Low cost | £0m | £170m | £280m |
| | **Central cost** | £0m | **£410m** | £670m |
| | High cost | £0m | £650m | £1060m |
| **Number of proposed mergers or takeovers** | **Gas Distribution** | 0 | **1** | 2 |
| **Transfer from consumers to network companies** | Low cost | N/A | N/A | N/A |
| | **Central cost** | £0m | **£370m** | £650m |
| | High cost | N/A | N/A | N/A |
| **Total transfer from consumers to network companies (central cost)** | | £0m | **£780m** | £1320m |

- As mentioned above, these costs to energy retail companies, gas shippers, and distributed generators (and ultimately domestic and non-domestic consumers) are transfers as there is no net change in social welfare assuming that all network companies' profits remain in GB. However, in reality this may be unlikely. Of the six electricity distribution companies only two have their parent companies and main shareholders headquarters in GB[25]. Consequently, it

[24] Average over the ten-year period from 2022 to 2031. Based on BEIS (2021), Energy and emissions projections, https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

[25] Information provided by Ofgem.

is likely that there will be a transfer from consumers to energy network companies that would leave GB and thus be a net cost to GB society. Due to lack of evidence this has not been monetised in this IA.

4. ***Society as a whole***

- All of the above costs are costs to society but can specifically be allocated to producers or consumers. The following costs are costs to society as a whole.
- **Deadweight loss (DWL):** Society as a whole is negatively impacted by higher prices (driven by increased network charges, following the loss of a comparator for the purposes of setting the price control and other regular reviews of allowed revenues) which imply lower energy consumption and represents a net cost to society (also called the DWL).
- It is possible to estimate this DWL using the transfer estimate associated with the loss of a licensee in the electricity distribution sector (discussed above). To derive the DWL to society we need to derive the change in price (network charges) and change in electricity or gas demand following a merger. It is important to note that this change would only follow one of Ofgem's regular reviews of allowed revenues. This can either be as part of the Annual Iteration Process, mid-period price control reopeners or at the setting of a new price control. This IA assumes that the transfer and deadweight loss occurs in same year as the merger.
    - <u>To derive changes in price</u>: The annual transfer from consumers to producers (approximately £10m to £45m (2020 prices) per merger in electricity distribution and around £45m (2020 prices) per merger in gas distribution) is calculated by multiplying the increase in network charges (due to a reduction in Ofgem's benchmarking ability) by electricity or gas demand at that price. Therefore, by dividing the transfer estimates per merger by electricity and gas demand (from BEIS central future electricity projections)[26], respectively, we get an estimate of the change in network charges associated with one merger. To derive the change in network charges due to up to five mergers in electricity distribution and up to two mergers in gas distribution, the same calculation needs to be repeated but for up to five times the transfer value for electricity distribution and for up to twice the transfer value for gas distribution. This gives us changes in price (network charges) associated with different numbers of mergers.
    - <u>To derive changes in demand</u>: The change in electricity or gas demand depends on the price elasticity of electricity or gas demand, which is assumed to be -0.14 for electricity demand and -0.23 for gas demand[27]. Rearranging the price elasticity of demand equation to $dQ = e*Q_1*dP/P_1$ (where $P_1$ refers to the original price and $Q_1$ to the original demand without loss in Ofgem's regulatory power[28]) allows us to derive the change in demand. This is done for one up to five mergers in electricity and one up to two mergers in gas.
    - <u>To derive DWL</u>: By multiplying the change in demand by the change in price (network charges) and dividing the product by two we can estimate the DWL to society associated with different numbers of mergers (Figure 1 shows a typical depiction of DWL)[29].
- This methodology was considered against different levels of price elasticity of electricity and gas demand and the assumed annual cost and number of mergers or takeovers. The results,

[26] BEIS (2021), Energy and emissions projections, https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

[27] Price elasticity of demand is a measure of the responsiveness of demand for a good to changes in the good's price. An elasticity of X means that a 1% increase in its price leads to an X% increase in demand for it. A range of evidence suggests that price elasticity of electricity demand, while small in magnitude, is non-zero. According to estimates in BEIS' Energy Demand Model (EDM), long-run price elasticities for electricity demand and gas demand are -0.14 and -0.23, respectively. These values are uncertain and so we have tested sensitivities around these central estimates, using 0 for our low estimate, and -0.5 for our high estimate. Demand elasticity varies between sectors of the economy and the estimates derived are based on the average impact on demand for the fuel across all sectors. They have been estimated from the responsiveness of final energy consumption to changes in retail price in the EDM. The potential impact on demand for fuels other than the fuel subject to the price change has not been considered.

[28] BEIS (2021), Energy and emissions projections, https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

[29] The costs associated with this extra quantity demanded are removed within this calculation. These include the increase in variable costs of producing electricity; the increase in costs of purchasing carbon allowances; and the increase in air quality damage costs.

which are shown in Table 4, suggest that the DWL is between £0m and £1m (cost, 2020 prices, discounted to 2022) for electricity and between £0m and £1m (cost, 2020 prices, discounted to 2022) for gas. In the central estimate case (of two mergers and central costs in electricity distribution and one merger and high costs in gas distribution), there is expected to be a cost to society of less than £0.1m (cost, 2020 prices, discounted to 2022) in the electricity sector and a cost to society of less than £0.1m (cost, 2020 prices, discounted to 2022) in the gas sector. Total DWL in both electricity and gas distribution in the central estimate is estimated to be around £0.1m (cost, 2020 prices, discounted to 2022).

**Table 4: Net social welfare cost (DWL) under different levels of price elasticity of demand, number of mergers and annual cost variance (PV over ten years, 2020 prices discounted to 2022)**

| Net welfare cost to society (domestic and non-domestic) | | Price elasticity of demand | | |
|---|---|---|---|---|
| | | Low (zero) | Central (-0.14) | High (-0.5) |
| Electricity distribution | **Min estimate (0 mergers)** | | | |
| | | £0m | **£0m** | £0m |
| | **Central estimate (2 mergers)** | | | |
| | Low cost estimate | £0m | <£0.1m | <£0.1m |
| | Central cost estimate | £0m | **<£0.1m** | £0.1m |
| | High cost estimate | £0m | <£0.1m | £0.3m |
| | **Max estimate (5 mergers)** | | | |
| | Low cost estimate | £0m | <£0.1m | <£0.1m |
| | Central cost estimate | £0m | **<£0.1m** | £0.3m |
| | High cost estimate | £0m | £0.2m | <£1m |
| | | **Low (zero)** | **Central (-0.23)** | **High (-0.5)** |
| Gas distribution | **Min estimate (0 mergers)** | | | |
| | High cost estimate | £0m | **£0m** | £0m |
| | **Central estimate (1 merger)** | | | |
| | High cost estimate | £0m | **<£0.1m** | <£0.2m |
| | **Max estimate (2 mergers)** | | | |
| | High cost estimate | £0m | **£0.3m** | <£1m |
| **Total DWL** | | **Min Mergers** | **Central Mergers** | **Max Mergers** |
| **Central (Total)** | | **£0m** | **£0.1m** | **£0.3m** |

- **CMA budget funded by central Government:** The CMA is funded by central Government. It therefore represents a cost to society as a whole through taxation.

*5. CMA*

- **Administration costs:** Under 'Do Nothing', when energy network companies decide to merge, the CMA will undertake a phase 1 investigation (including "the substantial lessening of competition test"), which including pre-notification) could take up to 100 working days. This implies costs for the CMA (which, as it is funded by central Government, implies a cost to society as a whole through taxation). While the size of these costs under 'Do Nothing' is irrelevant for the appraisal in this IA, it is important to note these activities and costs exist under 'Do Nothing' and therefore form the baseline for the 'Policy Option', in which only costs associated with additional tasks during a phase 1 investigation should be monetised (see section on the 'Policy Option').
- As network mergers or takeovers do not (substantially) lessen competition due to them being regional monopolies, under 'Do Nothing' mergers are not referred for a phase 2 investigation and therefore there are no costs. This means all phase 2 investigation costs under the 'Policy Option' are additional.

*6. Ofgem*

- Under 'Do Nothing' there are no costs for Ofgem relating to network mergers. Ofgem will undertake its usual activities but with fewer data points.

***<u>Non-monetised costs under 'Do Nothing'</u>***

- There are further areas where mergers or takeovers could have harmful effects for energy retail companies and ultimately end-consumers. These are:

- Innovation – initiatives such as the Network Innovation Competition (NIC) (which provides funding for network companies to test new innovative, 'smart' ways of operating the networks) rely on competition between companies. Added competition between companies is likely to encourage them to present better ideas to secure the project funding (and associated reputational benefits). This type of tool to spur innovation and facilitate the move to a low-carbon economy is a key pillar of the RIIO price control model for both electricity and gas but it could be undermined by consolidation in the sector.
- Quality of service – the ability to compare companies' performance in this area is helpful to consumers in terms of the targets that Ofgem can set for issues like interruptions and customer satisfaction.
- Cost of capital – at price control reviews when the industry's interests are all aligned, they have an incentive to argue collectively. At past reviews some companies have broken ranks on some issues which reduces the information asymmetry between the operators and the regulator. Consolidation in the sector might reduce this diversity in approaches.
- Policy development – this is strengthened when there are more companies in a sector putting forward ideas and being constructive during the development process. Mergers or takeovers could reduce this diversity in approaches and hinder the introduction of policies or incentives that would benefit consumers or the environment.

***Monetised benefits under 'Do Nothing'***

1. ***Network companies***

   - **Transfer:** Under 'Do Nothing', Ofgem's ability to benchmark is reduced (due to a loss of a comparator) and Ofgem is less able to set the most efficient price control determinations. This means that network companies would be able to set higher network charges, implying higher costs to energy retail companies, gas shippers, and distributed generators (and ultimately end-consumers). The costs shown in Table 3 above therefore represent the benefits to energy network companies. These are transfers from energy retail companies, gas shippers, and distributed generators (and ultimately domestic and non-domestic consumers) to energy network companies.
   - **Efficiency gains:** Under 'Do Nothing', network companies benefit from potential efficiency gains associated with lower corporate overheads, shared services, and greater bargaining power following a merger. The potential efficiency gains of a merger are hard to predict, as these differ by industry, merger and context.
   - To estimate the potential efficiency gains that mergers in the electricity and gas distribution sector could bring about, we have used the reduction in operational expenditure applied in the water sector following a merger between Hastings Luxembourg Water Sarl (the holding company for South East Water (SEW) Limited) and Mid Kent Water Limited. The Competition Commission (CC, a precursor of the CMA) estimated that the efficiencies gained would result in annual operating savings of around £4m (2020 prices) a year[30]. In addition, it was suggested that the merger would result in security of supply benefits, particularly to customers in SEW's Southern region; improved planning of water resources that it would expect to enable some investment projects to be postponed; capital expenditure savings from PR09 onwards (quantifications of these have not been published); and possible additional savings from sale or lease of office space.
   - The CC allowed the merger to go ahead but required that this £4m (2020 prices) benefit was considered as an efficiency saving in the price control period, therefore ensuring that it was passed on to consumers. In addition, it insisted on an up-front reimbursement of £5m

[30] Given in 2007/08 price base at Competition Comission (2007), South East Water Limited and Mid Kent Water Limited, p.80, http://webarchive.nationalarchives.gov.uk/20121212135622/http://www.competition-commission.org.uk/assets/competitioncommission/docs/pdf/non-inquiry/rep_pub/reports/2007/fulltext/525.pdf

(2020 prices) to consumers to cover the loss of a comparator for the regulator (and thus consumer detriment).

- The roughly £4m (2020 prices) efficiency savings represented a 3.8%[31] reduction in the allowed annual operating expenditure for South East Water under PR09. This percentage has been used as the high estimate in our analysis, as these savings are likely to be lower in the electricity and gas distribution sector. We have assumed a low estimate of 0% (no efficiency gains) and a central average estimate of 1.9%. Applying these percentages to the RIIO price control settlements (adjusted for Ofgem's annual iteration process) in the electricity and gas distribution sectors implies the operational efficiency gains as set out in Table 5 below.

**Table 5: Efficiency gains due to different merger scenarios over the next ten years (2020 prices, discounted to 2022)**

| | | Min | Central | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| **Network company benefit** | 0% annual efficiency gains | £0m | £0m | £0m |
| | **1.9% annual efficiency gains** | **£0m** | **£60m** | **£95m** |
| | 3.8% annual efficiency gains | £0m | £115m | £190m |
| **Number of proposed mergers or takeovers** | **Gas Distribution** | 0 | **1** | 2 |
| **Network company benefit** | 0% annual efficiency gains | £0m | £0m | £0m |
| | **1.9% annual efficiency gains** | **£0m** | **£35m** | **£60m** |
| | 3.8% annual efficiency gains | £0m | £65m | £120m |
| **Total network company benefit (central efficiency)** | | **£0m** | **£90m** | **£155m** |

*2. & 3. Energy retail companies and end-consumers*

- **Efficiency gains:** As a result of a merger, network companies may realise efficient gains as discussed above. Some of these efficiency gains could be passed through to consumers, perhaps through particular mechanisms included in the RIIO price control, such as the efficiency incentive mechanism.[32]

*4. Society as a whole*

- **Reduction in emissions:** In addition, under 'Do Nothing', the loss of a comparator due to different numbers of mergers over the next ten years implies increased prices (driven by increased network charges) and therefore a fall in energy consumption. The DWL calculations above provide us with the assumed changes in demand per year under the different merger scenarios (zero to five mergers in electricity distribution and zero to two mergers in gas distribution over the next ten years), which can be used to estimate changes in emissions and carbon costs. This is set out in Table 6 below.
- It is important to note that the reduction in carbon emissions resulting from lower energy consumption due to higher charges is likely to be offset partially. This is because Ofgem also set environmental objectives for the companies it regulates. If Ofgem's comparative

[31] The 3.8% reduction has been calculated by dividing the £3.1m (2007/08 prices) efficiency gain by the allowed annual operational expenditure pre- efficiencies under PR09, to be found at Ofwat (2009), Final determinations on price limits, p.99, https://webarchive.nationalarchives.gov.uk/ukgwa/20150603210142mp_/https://www.ofwat.gov.uk/pricereview/pr09phase3/det_pr09_finalchap4.pdf

[32] The efficiency incentive mechanism ensures that any efficient under- or overspend achieved by a network company against its price control allowance is shared with consumers. The efficiency incentive rate, i.e. the share of any efficient under- overspend that can be retained or borne by the network companies, varies between 53-70% under RIIO-ED1 and 49%-50% under RIIO-GD2. The remainder is passed on to energy retail companies, gas shippers, and distributed generators (and ultimately domestic and non-domestic consumers) through lower or higher allowed revenues and therefore lower or higher network charges.

regulation ability is weakened, they will also be less able to set appropriate targets for carbon reductions. Because this could not be quantified, the reductions in carbon costs represent high or conservative estimates.

**Table 6: Assumed decreases in demand, emissions, and carbon costs (2020 prices, discounted to 2022) over the next 10 years**

| | Number of proposed mergers or takeovers | Total reduction in demand | Total reduction in traded sector emissions | Total reduction in non-traded sector emissions | Total reduction in carbon costs |
|---|---|---|---|---|---|
| **Electricity distribution** | 0 (min estimate) | 0 GWh | 0 MtCO2e | N/A | £0m |
| | **2 (central estimate)** | **400 GWh** | **0.1 MtCO2e** | **N/A** | **£15m** |
| | 5 (max estimate) | 700 GWh | 0.1 MtCO2e | N/A | £25m |
| **Gas distribution** | 0 (min estimate) | 0 GWh | 0 MtCO2e | 0 MtCO2e | £0m |
| | **1 (central estimate)** | **2400 GWh** | **0.1 MtCO2e** | **0.4 MtCO2e** | **£100m** |
| | 2 (max estimate) | 4200 GWh | 0.1 MtCO2e | 0.7 MtCO2e | £175m |
| **Total decreases in demand, emissions, and carbon costs** | | | | | |
| **Central mergers estimate** | | **2800 GWh** | **0.2 MtCO2e** | **0.4 MtCO2e** | **£115m** |

Note: Emissions are calculated by using long-run marginal emission factors and gas emission factors from https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

Note: Carbon costs are calculated by using central traded carbon prices for power generation and energy-intensive industries' use of gas https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/793632/data-tables-1-19.xlsx (Table 3).

- **Fixed merger fee:** The person who filed or took control of the merger notification must pay a fixed merger fee, which the CMA collects on behalf of HM Treasury and therefore benefits all taxpayers by reducing the overall costs funded through taxation.

***5. & 6. CMA and Ofgem***

- There are no monetised benefits for the CMA or Ofgem under 'Do Nothing'.

***<u>Non-monetised benefits under 'Do Nothing'</u>***

- The efficiency gain caused by increased economics of scale following a merger has been discussed above. There can be other non-monetised benefits, such as improved service quality, greater technological investment or sharing of innovation benefits across merged regions.

## Policy Option

56. This section sets out the costs and benefits under the 'Policy Option' relative to the baseline costs and benefits identified under 'Do Nothing'. Table 7 summarises all impacts.

**Table 7: Summary of additional cost and benefits under the 'Policy Option'**

| | | Cost | Benefit |
|---|---|---|---|
| **1.** | **Network companies*** | • Additional familiarisation costs related to understanding the special merger regime **(direct cost to business)**. Note the fixed merger fee is the same as under 'Do Nothing', so there are no additional costs for network companies.<br>• Pass-through of set-up, familiarisation and administration costs incurred by Ofgem for the special merger regime **(direct cost to business)**.<br>• Foregone transfer of money from energy retail companies (and gas shippers and distributed generators) and ultimately domestic and non-domestic consumers to network companies, because of protecting Ofgem's regulatory power **(indirect cost to business)**.<br>• Foregone efficiency gains (if a merger is blocked altogether) **(direct cost to business)**. | • N/A |
| **2.** | **Energy retail companies, gas shippers, and distributed generators*** | • Foregone pass-through of network companies' efficiency gains through the efficiency incentive rate under the RIIO price control **(indirect cost to business)**.<br>• Pass-through of set-up, familiarisation and administration costs incurred by Ofgem and familiarisation costs incurred by network companies for the special merger regime **(indirect cost to business)**. | • Avoided transfer of money from energy retail companies (and gas shippers and distributed generators) and ultimately domestic and non-domestic consumers, due to protecting Ofgem's ability to benchmark effectively **(indirect benefit to business)**. |
| **3.** | **Domestic and non-domestic consumers** | • Foregone pass-through of efficiency gains from energy retail companies (and gas shippers and distributed generators) **(indirect cost to business)**.<br>• Pass-through of set-up, familiarisation and administration costs incurred by Ofgem and familiarisation costs incurred by network companies for the special | • Avoided increase in fuel poverty as more consumers are able to afford the energy they need to increase their living standards and well-being **(indirect benefit to consumers).**<br>• Consumer bills impact: a lower average annual dual fuel household bill **(indirect benefit to consumers)** |

| | | | |
|---|---|---|---|
| | | merger regime **(indirect cost to business)**. | • Avoided pass- through of higher costs faced by energy retail companies(and gas shippers and sistributed generators)**(indirect benefit to business)** |
| **4.** | **Society as a whole (including all of the above)** | • Foregone increases in energy retail prices leading to increased energy consumption and therefore emissions and carbon prices **(indirect cost to business)**.<br>• Pass-through of set-up, familiarisation and administration costs incurred by the CMA for the special merger regime through increased taxation or reduced public expenditure **(indirect cost to business)** | • Avoided increase in energy prices leading to increasing energy consumption (avoided DWL to society) **(indirect benefit to business).** |
| **5.** | **CMA** | • Additional administration costs related to merger investigation **(indirect cost to business)** | • N/A |
| **6.** | **Ofgem** | • Administration costs related to merger investigation **(direct cost to business)** | • Ability to comparatively assess network companies to accurately set price control determinations is strengthened through maintaining a higher number of comparitors **(direct, non-monetised benefit to business)** |

*For Ofgem's pass-through administration costs, this includes the transmission network companies and transmission connected generators.

***Monetised additional costs under the 'Policy Option'***

1. ***Network companies***
   - **Administration costs (direct cost to business):** Under the 'Policy Option' the additional "comparative regulation test" takes place as part of the phase 1 investigation. This adds additional activities and parties (i.e. Ofgem) to the phase 1 investigation, implying additional costs for network companies. Specifically, network companies will now have to make contact with Ofgem (usually during the 10 working day pre-notification period) to discuss their views on the extent of the merger's impact on Ofgem's ability to regulate comparatively. This is assumed to have the same resource implications for network companies as for Ofgem. Ofgem's total additional administration cost for the pre-notification period (1 to 3 months), the phase 1 (up to 40 working days) and phase 2 investigation (24 to 32 weeks) is estimated to be <£0.5m (cost, 2020 prices) based on information from Ofgem. Assuming costs are spread equally, the additional cost for the pre-notification period is estimated to be <£0.1m (cost, 2020 prices) per merger (irrespective of the outcome of any investigation).
   - All of a phase 2 investigations' administration costs are additional to 'Do Nothing'. A phase 2 investigation can take between 24 to 32 weeks, with the possibility of a three-week standstill if parties are considering abandoning the merger. BEIS has found that the typical cost range to companies for a phase 2 investigation is between £1m and £3m (cost, 2020 price). While this range is dependent on a number of factors, e.g. the complexity of the issues at hand, this IA uses a £2m (cost, 2020 price) average cost estimate as an appropriate average.

- Some familiarisation costs associated with new CMA guidelines and other processes are also likely. Based on the water sector, the CMA guidelines are likely to consist of a 46-page document setting out the process, analytical approach to and methodologies for estimating the impact on Ofgem's ability to regulate. Similarly, Ofgem will be required to complete a 'Statement of Methods', which is likely to consist of a 10-page document setting out the criteria against which any merger impacts are measured, as well as the approach to estimating any consumer benefits of a merger. Familiarisation costs are therefore likely to be small. However, to avoid underestimating costs to businesses, this IA assumes that at the maximum, this could present an additional one-off cost for potentially merging network companies of <£0.1m (cost, 2020 prices), equivalent to the usual pre-notification costs faced by network companies.
- Network companies face the same fixed merger fee of <£0.5m (cost, 2020 prices) as under 'Do Nothing'[33]; hence there are no additional costs to network companies for being referred to a phase 2 investigation. The additional set-up and per merger costs incurred by the CMA are funded by central Government and will be passed on to society as a whole through taxation or lower public expenditure (see 'society as a whole' section below).
- Network companies bear (as a direct cost) the set-up and per merger costs incurred by Ofgem, the industry-funded regulator, as Ofgem will pass on these costs as a direct cost to some licensees (the System Operator (SO), electricity distribution network operators, and gas distribution network operators). This IA assumes that these costs are then passed to generators and suppliers and ultimately domestic and non-domestic consumers. Ofgem's passed-on costs are estimated to be <£0.5m (cost, 2020 prices) for set-up costs and <£0.5m (cost, 2020 prices) for phase 1 and phase 2 investigation costs of every merger. See the Ofgem section below for further detail.
- The total additional administrative costs (including set-up and familiarisation costs) for the central estimate of two mergers or takeovers in electricity distribution and one merger or takeover in gas distribution being referred to a phase 2 investigation, over a ten-year time period, is around £10m (cost, 2020 prices, discounted to 2022). These costs exclude the CMA's costs passed on to society as a whole – up to £15m (cost, 2020 prices) – as it is not possible to say how much network companies would bear through higher taxes or lower public spending. We might expect these costs to be lower, as companies may be put off by the proposed policy regime and therefore fewer mergers or takeovers that are likely to have a negative overall impact may come forward.

**Table 8: Total additional administrative costs to society and business under 'Policy Option' (2020 prices, PV over ten years, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| | **Gas Distribution** | 0 | **1** | 2 |
| **Number of blocked proposed mergers or takeovers** | **Electricity Distribution** | 0 | **1** | 3 |
| | **Gas Distribution** | 0 | **1** | 1 |
| **Additional total cost to society** (including costs of industry- and Government-funded bodies) | | £0m | **£10m** | £20m |
| **Additional total cost to network companies** (including costs of industry-funded bodies) | | £0m | **£5m** | £15m |

- **Foregone transfer (indirect cost to business):** Under the 'Policy Option', network companies forego the transfers from energy retail companies, gas shippers and distributed generators (and ultimately domestic and non-domestic consumers) as set out in Table 9.

[33] Notification is voluntary, but historically network companies that have merged have always voluntarily notified.

**Table 9: Avoided transfer from energy retail companies, gas shippers, and distributed electricity generators (and ultimately consumers) to network companies, due to different numbers of mergers over the next ten years (2020 PV over ten years, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| **Number of blocked proposed mergers or takeovers** | | 0 | **1** | 3 |
| **Avoided transfer from consumers to network companies** | Low cost | £0m | £100m | £170m |
| | **Central cost** | £0m | **£230m** | £400m |
| | High cost | £0m | £370m | £640m |
| **Number of proposed mergers or takeovers** | **Gas Distribution** | 0 | **1** | 2 |
| **Number of blocked proposed mergers or takeovers** | | 0 | **1** | 1 |
| **Avoided transfer from consumers to network companies** | Low cost | N/A | N/A | N/A |
| | **Central cost** | £0m | **£370m** | £370m |
| | High cost | N/A | N/A | N/A |
| **Total avoided transfer from consumers to network companies (central cost)** | | £0m | **£600m** | £770m |

- **Foregone efficiency gains (direct cost to business):** Under the 'Policy Option', network companies forego efficiency gains should a merger be referred for a phase 2 investigation and be blocked. As set out in the 'background section' above, this IA assumes that every other merger under the core scenarios is blocked as per Table 1 above; all other mergers are assumed to come forward but with remedies (i.e. appropriate compensation for consumers) in place. Based on this, Table 10 sets out our estimates of the foregone efficiency gains under each scenario.

**Table 10: Foregone efficiency gains based on number of mergers blocked over the next ten years under 'Policy Option' (2020 prices, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| **Number of blocked proposed mergers or takeovers** | | 0 | **1** | 3 |
| **Forgone network company benefit** | 0% annual efficiency gains | £0m | £0m | £0m |
| | **1.9% annual efficiency gains** | **£0m** | **£35m** | **£55m** |
| | 3.8% annual efficiency gains | £0m | £65m | £115m |
| **Number of proposed mergers or takeovers** | **Gas Distribution** | 0 | **1** | 2 |
| **Number of blocked proposed mergers or takeovers** | | 0 | **1** | 1 |
| **Foregone network company benefit** | 0% annual efficiency gains | £0m | £0m | £0m |
| | **1.9% annual efficiency gains** | **£0m** | **£35m** | **£35m** |
| | 3.8% annual efficiency gains | £0m | £65m | £65m |
| **Total foregone network company benefit (central efficiency)** | | **£0m** | **£65m** | **£90m** |

***2. and 3. 'Energy retail companies, gas shippers and distributed generators' and 'Domestic / non-domestic consumers'***

- **Foregone pass-through of efficiency gains (indirect cost to business):** Efficiencies realised by mergers could be shared with energy retail companies, gas shippers and distributed generators (and ultimately domestic and non-domestic consumers) as a result of an incentive mechanism under RIIO. By foregoing the efficiency savings caused by mergers, energy network companies in the first instance will forego higher profits, while secondary effect retail companies, gas shippers, distributed generators, and domestic and non-domestic consumers will forego lower network charges, as no efficiency savings are shared with them.
- **Pass-through of set-up, familiarisation and administration costs of network companies and Ofgem (indirect cost to business)**: As mentioned above under '*1. Network* companies', the administration costs of network companies, and the costs passed onto them by Ofgem, are assumed to fully pass through to energy retail companies, gas shippers and distributed generation (and ultimately domestic and non-domestic consumers). Therefore, the total additional administrative costs for our central-estimate of two mergers or takeovers in electricity distribution and one merger or takeover in gas distribution being referred to a phase 2 investigation, over a ten-year time period, is around £10m (cost, 2020 prices, discounted to 2022).

***4. Society as a whole***

- **Increase in emissions (indirect cost to business):** Under the 'Policy Option', as set out in the 'background section' above, this IA assumes that every other merger under the core scenarios is blocked as per Table 1; all other mergers are assumed to come forward but with remedies (i.e. appropriate compensation for consumers) in place. Based on this, Table 11 sets out our estimates of the increases in demand, emissions and carbon costs over the next ten years for 'Policy Option', compared to the 'Do Nothing' option shown in Table 6. For example, this means that whereas before our central estimate in Table 6 was that two mergers would take place, now we assume that only one of these mergers has happened and we have calculated the increase in demand, emissions and carbon costs for this. Table 11 shows that in our central scenario of one merger in electricity distribution and zero mergers in gas distribution, this increase in carbon costs is around £105m (cost, 2020 prices, discounted to 2022).

**Table 11: Assumed increases in demand, emissions and carbon costs (2020 prices, discounted to 2022) under 'Policy Option' over the next ten years**

| | Number of proposed mergers or takeovers | Number of blocked proposed mergers or takeovers | Increase in demand | Increase in traded sector emissions | Increase in non-traded sector emissions | Increase in carbon costs |
|---|---|---|---|---|---|---|
| **Electricity distribution** | 0 (min estimate) | 0 | 0 GWh | 0 MtCO2e | N/A | £0m |
| | **2 (central estimate)** | **1** | **200 GWh** | **0.1 MtCO2e** | **N/A** | **£5m** |
| | 5 (max estimate) | 3 | 300 GWh | 0 MtCO2e | N/A | £10m |
| **Gas distribution** | 0 (min estimate) | 0 | 0 GWh | 0 MtCO2e | 0 MtCO2e | £0m |
| | **1 (central estimate)** | **1** | **2400 GWh** | **0.1 MtCO2e** | **0.4 MtCO2e** | **£100m** |
| | 2 (max estimate) | 1 | 1900 GWh | 0 MtCO2e | 0.3 MtCO2e | £75m |
| **Total increases in demand, emissions, and carbon costs** | | | | | | |
| **Central mergers estimate** | | | **2600 GWh** | **0.1 MtCO2e** | **0.4 MtCO2e** | **£105m** |

Note: Emissions are calculated by using long-run marginal emission factors and gas emission factors from https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

Note: Carbon costs are calculated by using central traded carbon prices for power generation and energy-intensive industries' use of gas https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/793632/data-tables-1-19.xlsx (Table 3).

- **Pass-through of set-up, familiarisation and administration costs of the CMA (indirect cost to business):** The CMA is funded by central Government and therefore its set-up, familiarisation and administration costs are ultimately borne by society as a whole through higher taxation or public expenditure reductions. The CMA's additional costs over a 10-year period are estimated to be up to £15m (cost, 2020 prices, discounted to 2022). These costs are indirect costs to society as it requires HM Treasury to revise tax rates or public spending plans. It is not possible to say how much of these costs would be borne by businesses, due to uncertainty over future fiscal action.

***5. CMA***

- **Administration costs (indirect cost to business)**: The CMA will face an initial one-off set-up cost (e.g. preparing guidance). This IA assumes that these costs are similar to the set-up costs faced by Ofgem, <£0.5m (cost, 2020 prices), as set out in the Ofgem section below. This includes any familiarisation costs the CMA might face, although these are likely to be low given that a similar regime has already been put in place in the water sector.
- As set out in the 'Do Nothing' section above, the CMA already incurs phase 1 investigation costs for considering mergers or takeovers, when notified, under the current regime. However, the CMA will face additional costs as the CMA's information-gathering now also involves liaison with Ofgem, including requesting its views on the impact of the proposed merger on its ability to compare companies and any relevant consumer benefits that may arise as a result of the merger. In some instances, this additional cost could be offset as network companies no longer have to make an assessment on the existence of an SLC.
- If the CMA decides to refer the proposed merger or takeover for a phase 2 investigation, the CMA will face additional administration costs compared to 'Do Nothing' (where no mergers or takeovers would have been referred). A phase 2 investigation can take between 24 to 32 weeks with the possibility of a three-week standstill if parties are considering abandoning the merger. The CMA's guidance on 'Exceptions to the Duty to Refer'[34] sets out that the typical cost is around £0.5m (cost, 2018 price). This results in a total phase 2 investigation cost of around £0.5m (cost, 2020 prices).
- As the CMA is funded by central Government, these additional costs are passed on to society as a whole through higher taxes or lower public spending. These pass-through costs are assumed to be indirect costs, as they require changes to taxes and public spending first and there is uncertainty about any future fiscal action.
- The total additional administration cost (including set-up and familiarisation costs) for our central-estimate of two mergers or takeovers in electricity distribution and one merger or takeover in gas distribution being referred to a phase 2 investigation, over a ten-year time period is around £2m (cost, 2020 prices, discounted to 2022).

***6. Ofgem***

- **Administration costs (direct cost to business)**: Ofgem will face an initial one-off set-up cost (because, for example, it must publish a Statement of Methods, which explains how they make and use comparisons between energy network companies). Ofgem has advised that its set-up costs are <£0.5m (cost, 2020 prices). This includes any familiarisation costs that Ofgem might face.
- Compared to 'Do Nothing', all activities and costs for Ofgem under a phase 1 investigation (typically up to 40 working days), are additional. These include contacting network companies to discuss the merger's likely impact on Ofgem's ability to regulate comparatively and providing information to the CMA During a typical phase 2 investigation, Ofgem now also has

[34] Competitions and Markets Authority (2018), Mergers: Exceptions to the duty to refer, p.4, https://www.gov.uk/government/publications/mergers-exceptions-to-the-duty-to-refer-and-undertakings-in-lieu

to submit information to the CMA. Ofgem estimates that its total combined costs for a phase 1 and phase 2 investigation are <£0.5m (cost, 2020 prices).

- As Ofgem is an industry-funded regulator, all of these additional costs are passed on as direct costs to network licensees (the System Operator, DNOs, and GDNs) who are then assumed to pass these costs through to generators, suppliers and ultimately domestic and non-domestic consumers[35].
- The total additional administrative costs (including set-up and familiarisation costs) for our central estimate of two mergers or takeovers being referred to a phase 2 investigation in electricity distribution and one merger or takeover in gas distribution, over a ten-year time period is around £1m (cost, 2020 prices, discounted to 2022).

***<u>Monetised benefits under the 'Policy Option'</u>***

- By introducing a special merger regime for energy network companies, it is likely that either the costs to society or the transfers from consumers to network companies under 'Do Nothing' are avoided or at least reduced. Consequently, all the monetised costs (avoided transfer of up to £600m for our central estimate (benefit, 2020 prices, discounted to 2022) over 10 years and avoided DWL of <£0.1m for our central estimate, (benefit, 2020 prices, discounted to 2022)) and non-monetised costs considered under 'Do Nothing' can be considered as benefits under the 'Policy Option'.

**Table 12: Avoided net social welfare cost (DWL) under different levels of price elasticity of demand, number of mergers and annual cost variance (PV over ten years, 2020 prices discounted to 2022), under 'Policy Option'**

| **Avoided DWL to society (domestic and non-domestic)** | | **Price elasticity of demand** | | |
|---|---|---|---|---|
| | | **Low (zero)** | **Central (-0.14)** | **High (-0.5)** |
| **Electricity distribution** | **Min estimate (0 mergers, 0 blocked)** | | | |
| | | £0m | **£0m** | £0m |
| | **Central estimate (1 merger, 1 blocked)** | | | |
| | Low cost estimate | £0m | <£0.1m | <£0.1m |
| | Central cost estimate | £0m | **<£0.1m** | <£0.1m |
| | High cost estimate | £0m | £0m | £0.2m |
| | **Max estimate (2 mergers, 3 blocked)** | | | |
| | Low cost estimate | £0m | <£0.1m | <£0.1m |
| | Central cost estimate | £0m | **<£0.1m** | £0.2m |
| | High cost estimate | £0m | £0.1m | £0.5m |
| | | **Low (zero)** | **Central (-0.23)** | **High (-0.5)** |
| **Gas distribution** | **Min estimate (0 mergers, 0 blocked)** | | | |
| | High cost estimate | £0m | **£0m** | £0m |
| | **Central estimate (0 mergers, 1 blocked)** | | | |
| | High cost estimate | £0m | **<£0.1m** | **£0.2m** |
| | **Max estimate (1 merger, 1 blocked)** | | | |
| | High cost estimate | £0m | **£0.2m** | <£0.5m |
| **Total DWL** | | **Min Mergers** | **Central Mergers** | **Max Mergers** |
| **Central cost and central PED** | | **£0m** | **<£0.1m** | **£0.2m** |

[35] Ofgem costs are passed on to the network businesses that hold licences for gas transportation and electricity transmission with system operator conditions (National Grid Electricity Transmission), and electricity and gas distribution. These costs are treated as 'pass-through costs', which means that licence holders, in turn, recover the costs from generators and suppliers, which ultimately pass costs onto consumers.

- **Consumer Bills Impact:** The 'Policy Option' could prevent additional costs for consumers from higher distribution network charges, by allowing any impacts on Ofgem's comparative benchmarking process to be considered before allowing mergers to take place. In the central scenario of one merger in electricity distribution and one merger in gas distribution being blocked, the average dual fuel household[36] bill is expected to be around £2 a year lower than it would have been if these mergers were to take place, due to an avoided increase in energy prices, from the mid-2020s[37].

***<u>Non-monetised benefits under the 'Policy Option'</u>***

- In line with HMT Green Book guidance[38], economic transfers between groups are excluded from the overall estimate of Net Present Social Value. Transfers benefit the recipient (in this case, energy consumers) and are a cost to the 'donor' (in this case, energy network companies) and therefore there is no net effect on society. Economic transfers, however, may have distributional impacts. We have not deemed it proportionate to estimate these impacts for the purposes of this Impact Assessment.

- In the central 'Policy Option' scenario, combining the negative NPV value with the excluded avoided transfer provides a net benefit to energy consumers of £420m (benefit, 2020 prices, discounted to 2022). Additional non-monetised benefits are set out below.

***1. Improvements to health and wellbeing***

- **Helping to reduce fuel poverty:** Higher energy bills may lead to increases in fuel poverty, reducing the standard of living and well-being of some household consumers. The 'Policy Option', by helping prevent this unnecessary increase in bills, creates a positive impact for households, allowing more consumers to be able to afford the energy they need to increase their standard of living and well-being.

- **Rebound effects[39]:** As a result of the 'Policy Option' reducing consumer bills, energy consumers will benefit from **a)** financial savings due to lower energy prices in the 'Policy Option' scenario compared to the 'Do Nothing' scenario due to fewer mergers, and **b)** additional utility due to the direct rebound effect. The **direct rebound effect** means that households spend some of the money they save on additional energy in their home (e.g. heating), increasing wellbeing. An **indirect rebound effect** may also occur. This would be through households choosing to spend the avoided extra cost of energy on other goods or services, or alternatively to substitute spending on other goods and services to consume more energy as it becomes cheaper in relative terms.

***2. Improvements to business productivity and Ofgem's comparative benchmarking process***

- **Ability to compare performance and quality of service:** The 'Policy Option' protects Ofgem's ability to regulate network companies comparatively by empowering the CMA to block mergers between energy network companies if a merger would detriment Ofgem's regulatory process. Therefore, Ofgem's ability to comparatively assess network companies is strengthened as they can compare the performance and quality of service of a greater number of energy network companies. This in turn maintains Ofgem's ability to more accurately set price control determinations, enabling Ofgem to continue to protect consumers. Conversely,

[36] A dual fuel household receives their gas and electricity from the same energy supplier.

[37] The avoided bills increase is calculated using the undiscounted avoided transfer from consumers to networks companies of around £270m in electricity distribution and £430m in gas distribution (cost, 2020 prices) in the central scenario.

[38] HM Treasury and Government Finance Function (2020), The Green Book, Chapter 6, https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

[39] BEIS (2021), Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, Background documentation for guidance on valuation of energy use and greenhouse gas emissions, p.13 https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

an increased number of mergers under 'Do Nothing' might enable network companies to increase prices for consumers, increasing their profits above the fair return price.

- **Greater diversity of approaches due to prevented consolidation:** As we assume there will be a greater number of energy network companies under the 'Policy Option' compared to 'Do Nothing' (in which more mergers may be allowed), there will be a larger range of approaches within the gas and electricity sectors to day-to-day operations and problem solving, potentially leading to better outcomes for consumers. These approaches may be specific to the regions in which the companies operate, and therefore of greater value to the respective consumers. Further consolidation in the energy sectors will result in fewer network companies, who may set single policies to cover multiple regions which may not account for the specific requirements of any single region. Ofgem also benefit from a greater diversity of approaches with regards to their benchmarking, as they will use data from network companies taking different approaches to their operations, which helps Ofgem maintain robust comparative analysis and protect consumer interests.

- **Better price discovery:** Though energy network companies operate as regional monopolies, the regulator (Ofgem) engages in a process of 'price discovery' to avoid monopolistic pricing, using data from comparator companies to inform its periodic regulated price controls. These price controls allow the regulator to drive down costs away from the monopoly price and closer towards the 'true' market value. By preventing mergers and maintaining a sufficient number of comparator companies under the 'Policy Option', the regulator is able to to more successfully regulate future prices, ensuring that they move closer to the true market value via more efficient price discovery.

## Conclusion – Net cost / benefit estimates

57. Table 13 presents a summary of the costs and benefits to society of introducing a special merger regime for energy network companies. It shows the totals of admin costs for the min, central and max estimates of proposed mergers, with the totals for other costs and benefits adjusted to fit the assumed numbers of blocked proposed mergers under the 'Policy Option', over the next ten years. All estimates use central estimates for costs[40], elasticity of demand, and the foregone efficiency.

**Table 13: Table of Benefits and Costs for the Energy Networks Special Merger Regime, PV over ten years (2020 prices, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| | **Gas Distribution** | 0 | **1** | 2 |
| **Number of blocked proposed mergers or takeovers** | **Electricity Distribution** | 0 | **1** | 3 |
| | **Gas Distribution** | 0 | **1** | 1 |
| **Benefits (monetised)** | | | | |
| Avoided DWL (domestic and non-domestic consumer gain) | | £0m | <£0.1m | <£0.5m |
| Avoided transfer from consumers to energy network companies (benefit to producers) *Not included in benefits to society* | | £0m | £600m | £770m |
| **Benefits (non-monetised)** | | | | |
| • Helping to reduce fuel poverty. • Rebound effects. • Ability to compare performance and quality of service. • Greater diversity of approaches due to prevented consolidation. • Better price discovery. | | | | |
| **Total Benefits** | | **£0m** | **<£0.1m** | **<£0.5m** |
| **Costs (monetised)** | | | | |
| Administration costs for CMA (including set-up and familiarisation costs) | | <£0.5m | <£2m | £4m |
| Administration cost for Ofgem (including set-up and familiarisation costs) | | <£0.5m | £1m | £2m |
| Administration cost for merger companies (including familiarisation costs) | | £0m | £5m | £15m |
| Loss of efficiencies from mergers not proceeding | | £0m | £65m | £90m |
| Carbon costs of increased demand | | £0m | £105m | £80m |
| Avoided transfer from consumers to energy network companies (cost to consumers) *Not included in benefits to society* | | £0m | £600m | £770m |
| **Costs (non-monetised)** | | | | |
| Additional Costs for CMA | | | N/A | |
| **Total Costs** | | **£1m** | **£180m** | **£190m** |
| **TOTAL NET BENEFIT to society[41]** | | -£1m | -£180m | -£190m |
| TOTAL NET BENEFIT to energy consumers (Not included in total net benefit to society) | | -£1m | £420m | £585m |

[40] As set out at the beginning of the CBA section, the central estimate for gas distribution is equivalent to the high estimate for electricity distribution.

[41] Min, central and max merger scenarios do not directly correlate to the low, best estimate and high NPV shown on the summary page.

# Assumptions and risks

### *General assumptions*

58. It is impossible to say for certain how many energy network companies in the future would seek to merge and how many of those would be blocked. This IA has assumed that as a maximum five mergers can take place in the electricity distribution sector and a maximum of two in the gas distribution sector. This is based on the current number of companies in these sectors. The IA assumes there are no mergers in the electricity transmission as there are already so few operators. There is only one gas transmission owner.

59. Our central estimate assumes that half of the mergers in the electricity and gas distribution sector are blocked. This is based on evidence provided by previous water merger cases where under a special merger regime approximately half of the proposed mergers have not been able to proceed, or in the case where a merger is not blocked, other remedies to compensate consumers were introduced. The IA assumes a 3.5% social discount rate to derive the costs and benefits over a default ten-year time horizon. Note that to back-calculate the annual undiscounted costs underlying the CEPA NPV figures, this IA used the 4.7% discount rate as set out in the CEPA report. Once we have retrieved the annual undiscounted cost figures, this IA consistently applies a 3.5% social discount rate to all costs and benefits to derive (net) present value estimates.

60. The IA is in 2020 prices and all present values are discounted to 2022. The IA uses a 10-year default time horizon as the ‘Policy Option’ does not have an end-date – moreover, there are uncertainties regarding regulatory arrangements and efficiency incentive schemes of future price control periods beyond RIIO-T2 and RIIO-ED2.

61. The IA assumes that the CMA can measure the detrimental impact of mergers or takeovers on consumers. Since they already do so in the water sector, we believe this is a fair assumption.

### *Transfers and deadweight loss (DWL) assumptions*

62. The transfers and DWL calculations rely on findings from a 2010 CEPA report commissioned by Ofgem. While this report is based on the previous price control, Ofgem remain confident that the analysis is applicable to RIIO. If anything, it will underestimate the detriment to consumers and society as under RIIO there are areas in addition to benchmarking that are negatively affected by a reduction in the number of independent groups in the market.

63. The transfer from consumers to producers following a merger in electricity distribution is based on the transfer estimates in the CEPA report. The transfer estimates refer to the loss of *one* licensee, while a merger between groups could result in more than one licensee being lost (different groups own more than one licence). Therefore, the estimates in this IA are likely to be conservative.

*64.* The CEPA report did not quantify the transfer from consumers to producers in the gas distribution sector, due to lack of quantitative evidence. However, due to there being only four independent groups (of which two are majority owned by the same investment funds) it can be argued that the costs to consumers would be larger than in the electricity distribution sector. To approximate potential costs in this sector this IA assumes that the ‘high’ transfer from consumers to producers in the electricity distribution sector is applicable for the gas distribution sector as a central estimate.

*65.* The cost to society (DWL) due to lower electricity consumption has been derived from the transfer values and BEIS’ own projections of electricity demand and retail prices. Further, electricity and gas price elasticities of demand of -0.14 and -0.23 have been assumed, respectively, estimated using BEIS’ Energy Demand Model.

### *Administrative costs*

66. Estimates of additional administrative and set-up and familiarisation costs for the CMA and energy businesses are based on information received from the CMA. Administrative costs for Ofgem are based on estimates from Ofgem.

### *(Foregone) Efficiency gain assumptions*

*67.* To estimate the efficiency gain that a merger might bring, this IA uses evidence from mergers in the water sector. Following a merger between Hastings Luxembourg Water Sarl (the holding company for South East Water Limited) and Mid Kent Water Limited, the merged company's operational expenditure allowance was reduced by around £4m (2020 prices) under the next price control. This represented 3.8% of the pre-efficiency allowed operational expenditure. This percentage has been applied to average allowed operational expenditures under the price control for electricity and gas distribution, following the Annual Iteration Process in November 2020 and November 2021. 3.8% was treated as a high estimate, as savings are likely to be lower in the electricity and gas distribution sector as there are significantly less companies already and firms are larger, which is likely to imply lower benefits from economies of scale. The central estimate is assumed to be a 1.9% efficiency gain. The derivation of the number of blocked mergers is set out in the 'general assumptions' section.

### *Pass-through of network costs and savings to domestic and non-domestic consumers*

68. This IA assumes that retail companies pass on 100% of any costs and savings to domestic and non-domestic consumers.

69. For *pass-through of costs* this assumption implies that energy retail companies pass on 100% of their direct cost relating to the loss of a comparator (transfer) to domestic and non-domestic consumers under 'Do Nothing'. The same transfer to domestic and non-domestic consumers is avoided under the 'Policy Option' (indirect benefit). For *pass-through of benefits* this assumption implies that any efficiency gains shared by network companies with energy retail companies, gas shippers, and distributed generators under 'Do Nothing' are fully passed on to domestic and non-domestic consumers. The same efficiency gains are foregone under the 'Policy Option' should a merger be blocked (direct cost to network companies, indirect cost to retail companies and business consumers).

70. Under 'Do Nothing' there are lower electricity and gas sales due to likely higher prices. This IA assumes that energy retail companies' total revenues and total costs decrease by the same amount due to a loss in sales, therefore keeping profits unchanged (while making a higher profit margin). This loss in sales is avoided under the 'Policy Option'. In reality, energy retail companies might adjust their profit margin. Due to lack of evidence this indirect impact on businesses' profits has not been monetised.

### *Carbon costs*

71. Carbon costs have been estimated by using the change in electricity and gas demand derived for the DWL calculations and then applying the respective long-run marginal emission factors to domestic, public, commercial and industrial electricity demand changes over time, and the gas emission factor to domestic, public, commercial and industrial gas demand changes over time. This provides estimates of emissions for both electricity and gas, which can then be multiplied by the latest published traded sector carbon price for electricity and by the non-traded carbon price for gas, to derive an overall carbon cost.[42]

[42] BEIS (2021), Energy and emissions projections, https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

# Costs and benefits to business

72. The 'Cost Benefit Analysis' section discusses the costs and benefits of the 'Policy Option' to society at large, including businesses. This section draws out the direct and indirect costs and benefits to businesses (in accordance with One in Three Out (OITO) policy).

**Direct**

73. Direct impacts are those that can be identified as resulting directly from the implementation or removal or simplification of regulation. OITO does not consider the potential 'pass-through' of costs. Costs are scored according to where they are directly imposed. Therefore, if a cost is imposed on business, even where there is a strong likelihood that some or all of that cost will be passed on to consumers, the full cost is scored as a direct impact on business for OITO.

*Direct costs to business*

74. The **direct costs** to businesses include;
    - **Administration (including familiarisation) costs** faced by energy network companies associated with undertaking a review with the CMA, with a central estimate over 10 years of **£5m** (cost, 2020 prices, discounted to 2022).
    - **Administration, set-up and familiarisation costs** incurred by Ofgem, the industry-funded regulator, and passed through to businesses. Over 10 years, the central estimate of these costs is estimated to be **£1m** (cost, 2020 prices, discounted to 2022).
    - **Potential foregone efficiency gains** to which network companies could be subject should a merger be blocked. This is considered a direct cost to businesses as the merger would happen under 'Do Nothing' and imposing the policy could potentially prevent the merger from coming forward. The central estimate over 10 years of foregone efficiency gains to energy network companies in cases where they have been prevented from merging is up to **£65m** (cost, 2020 prices, discounted to 2022). Note that network companies will share these direct costs with retail companies, who are assumed to pass them on to consumers (set out in the indirect cost section).

*Direct benefits to business*

75. There are **no direct benefits** to businesses.

**Indirect**

*Indirect costs to businesses*

76. The main indirect cost of the 'Policy Option' is for energy network companies (although being fully offset by an indirect benefit to energy retail companies as set out below) as they will not be able to charge higher network charges in cases where a merger has been prevented or in cases where a merger was allowed to take place but with compensation for consumers. This implies a central estimate indirect cost over 10 years compared to 'Do Nothing' of up to **£600m** (cost, 2020 prices, discounted to 2022). This is classified as an indirect cost as it involves a further step, where Ofgem adjusts its allowed revenues to reflect the continuation of good benchmarking data and therefore causes energy network companies to be able to charge higher network charges.

77. The CMA, which is funded by central Government, will incur additional administration, set-up and familiarisation costs; these are estimated to be around £2m (cost, 2020 prices, discounted to 2022) over a 10-year period. However, network companies continue to pay the same fixed merger fee as set out under 'Do Nothing', irrespective of whether a merger is being referred to a phase 2 investigation. The CMA's higher costs are borne by society as a whole through higher taxation or lower public expenditure. However, this requires HM Treasury to revise its tax rates or public spending plans and is therefore considered to be an indirect cost. This is likely to also affect businesses; however, it is not possible to say by how much due to uncertainty over future fiscal action.

78. The 'Policy Option' could also indirectly lead to higher gas demand by other sectors (i.e. other than energy-intensive industries). This needs to be valued at the central carbon price. Commercial,

public sector, agriculture and transport (which can all be considered as businesses) have a central estimate carbon cost over 10 years of around £105m (2020 prices, discounted to 2022).

79. Network companies will eventually share their direct costs due to foregone efficiency gains with energy retail companies (due to the efficiency incentive rate set by Ofgem under RIIO), who in turn will pass them on to their consumers (including businesses). Assuming the share passed on to energy retail companies is between 30% and 47%[43] in electricity distribution and between 50% and 51%[44] in gas distribution, this implies energy retail companies eventually have to bear up to around £30m (cost, 2020 prices, discounted to 2022) of the £65m (cost, 2020 prices, discounted to 2022) foregone efficiency gain. Retail companies are assumed to fully pass on these foregone efficiency gains to consumers. Non-domestic consumers (businesses) make up 62% and 34% of final electricity and gas consumption, respectively. Therefore, business consumers would eventually have to bear up to £15m (cost, 2020 prices, discounted to 2022).

80. We recognise that many of the network companies are currently owned by international conglomerates. Any measure that places regulatory requirements on these businesses will therefore have some limited impact on international trade and investment. However, we do not anticipate that this impact will be detrimental as noted above in the policy objective box, the aim is to allow more effective checks on mergers in recognition of the unique market conditions of energy networks, and not to prevent them from taking place.

*Indirect benefits to business*

81. The main indirect benefit from the ‘Policy Option’ is that energy retail companies will benefit from lower network charges in cases where a merger has been prevented (i.e. no loss of comparator) or provisions for compensation have been made. This implies a central estimate indirect benefit over 10 years compared to ‘Do Nothing’ of up to **£600m** (benefit, 2020 prices, discounted to 2022). This is fully offset by the indirect cost to energy network companies as set out above. Note that energy retail companies are assumed to fully pass on this benefit to consumers (set out under indirect benefits below). This benefit is classified as indirect as this requires a further step, i.e. a pass-through from energy network companies to energy retail companies and, subsequently, to consumers (which will include businesses).

82. As set out in the *Assumptions and Risks* section, retail companies are assumed to fully pass on their indirect benefit of £600m (benefit, 2020 prices, discounted to 2022) to domestic and non-domestic consumers. As non-domestic consumers (businesses) make up 62% and 34% of final electricity and gas consumption respectively, they would indirectly benefit from around £290m[45] (benefit, 2020 prices, discounted to 2022) of the total benefit passed through. However, this is fully offset within the ‘business’ group by the cost to energy network companies as set out above.

83. Domestic and non-domestic consumers will respond by demanding more electricity and gas than under ‘Do Nothing’. Retailers’ total profits (in absolute terms) are assumed to remain unchanged. This is because energy retail companies’ total costs and total revenues are assumed to increase by the same amount, leaving overall absolute levels of profits unchanged. This is a simplifying assumption and in reality, retail companies might adjust their profit margin, resulting in higher profits (in absolute terms). Due to lack of evidence this indirect impact on businesses has not been monetised.

84. There is also a benefit from network productivity improvements and resource savings from efficiencies (fewer comparators would reduce the incentive for network companies to make productivity improvements). This has not been monetised.

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43 This is based on the efficiency incentive rates set out under RIIO-ED1. The share that DNOs are allowed to or have to keep of any efficient under- or overspend varies between 53%-70%.

44 This is based on the efficiency incentive rates set out under RIIO-GD2. The share that GDNs are allowed to or have to keep of any efficient under- or overspend varies between 49%-50%.

45 Calculated using an average of the non-domestic electricity and gas consumptions as a share of the £580m indirect benefit.

85. The majority of energy network companies are foreign-owned, so a proportion of any additional profits they might receive from a loss of a comparator or a merger is likely to be a cost to GB plc. Avoiding this will be a benefit to GB society. This has not been monetised.

**Table 14: Direct costs and benefits to business, PV over ten years (2020 prices, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| | **Gas Distribution** | 0 | **1** | 2 |
| **Number of blocked proposed mergers or takeovers** | **Electricity Distribution** | 0 | **1** | 3 |
| | **Gas Distribution** | 0 | **1** | 1 |
| **Direct costs to business** | | **£0m** | **£75m** | **£105m** |
| Administration cost (including familiarisation costs) for network companies | | £0m | £5m | £15m |
| Administration cost (including set-up and familiarisation costs) for Ofgem (industry-funded regulator) | | <£0.5m | £1m | £2m |
| Loss of efficiencies from mergers not proceeding | | £0m | £65m | £90m |
| **Direct benefits to business** | | **£0m** | **£0m** | **£0m** |
| **Net present benefit to business** | | **£0m** | **-£75m** | **-£105m** |

**One In Three Out**

86. The central estimate assumes that two mergers in electricity distribution and one merger in gas distribution are considered by the CMA over a ten-year period, with one merger in electricity and zero in gas being allowed (the min and max estimates assume zero and 2 mergers for electricity distribution and zero and one mergers for gas distribution being allowed). This results in a direct net present cost to business of up to £105m, with the central estimate being £75m (2020 prices, discounted to 2022). There is a significant difference between our min and max estimations, which reflects the substantial variation in the number of mergers between these scenarios.

87. This implies an Equivalent Annual Net Cost to Business (EANCB) of between £0m to £12.2m (2020 prices, discounted to 2022), with a central estimate of £8.4m (2020 prices, discounted to 2022). Table 15 presents this process.

**Table 15: Equivalent Annual Net Cost to Business (EANCB) (2020 prices, discounted to 2022)**

| | | Min | **Central** | Max |
|---|---|---|---|---|
| **Number of proposed mergers or takeovers** | **Electricity Distribution** | 0 | **2** | 5 |
| | **Gas Distribution** | 0 | **1** | 2 |
| **Number of blocked proposed mergers or takeovers** | **Electricity Distribution** | 0 | **1** | 3 |
| | **Gas Distribution** | 0 | **1** | 1 |
| **Net present value business costs, over a ten year period** | | £0m | £75m | £105m |
| **Equivalent annual net cost to business (EANCB)** | | **£0m** | **£8.4m** | **£12.2m** |

# Wider impacts

## Distributional Impact

88. The competition authorities have in the past allowed some mergers to proceed with the requirement that the merging companies compensate their customers to offset the cost of the loss of the comparator. This means that the customers of the companies who merged have benefited twice from the merger, once from the merger itself[46] and once from the actual compensation. This comes at the cost to other consumers in the marketplace, since they benefit neither from the merger (which leads to the loss of a comparator) nor the compensation. However, the CMA considers and takes account of this distributional impact when assessing possible remedies.

## Human Rights Impact

89. This measure is compatible with the Human Rights Act 1998 and the European Convention on Human Rights (ECHR). To the extent that legislation to control and potentially prevent mergers between privately owned companies constitutes an interference with the rights to property of the owners and or shareholders under Article 1, Protocol 1 of the ECHR, we consider that the proposals are justified in the public interest and proportionate.

## Public Sector Equality Duty (PSED) Impact

90. The PSED is a duty requiring public authorities and others carrying out public functions to have due regard to:
    a. eliminate unlawful discrimination, harassment, victimisation and any other conduct prohibited by the Equality Act 2010;
    b. advance equality of opportunity between people who share a protected characteristic and people who do not share it; and
    c. foster good relations between people who share a protected characteristic and those who do not.
91. The policy is designed to tackle a technical markets and energy regulation issue. Based on this, we think that there will be very minimal direct impact on individuals. We have undertaken a Justice Impact Test for the Ministry of Justice in relation to the criminal enforcement measures associated with this regime and concluded that the impacts on the justice system will be so minimal as to be negligible and that the extension of the existing criminal enforcement regime should not adversely impact individuals with particular protected characteristics. The policy should indirectly benefit the public through its broader relationship to helping the UK reach net zero and keeping costs to consumers low, whether they possess a protected characteristic or not. Our analysis does not indicate that there are equality issues to address. The focus of the policy and the public-wide impacts of it lead us to conclude that it is not necessary to take any further steps following this analysis.
92. We will proceed as planned with the policy because it should have no adverse or disproportionate negative impacts on people who share a protected characteristic, and it is not a suitable policy opportunity to use for taking steps to advance equality of opportunity or foster good relations.

## Other Impacts

93. There will be no impacts in the following areas:
    - Wider environmental impact
    - Health impact
    - Rural proofing impact
    - Sustainable development impact

46 Pass-through of some efficiency gains realised by network companies through mergers.

# Rationale and evidence that justify the level of analysis used in the IA

94. Where possible, impacts of the proposed measure have been quantified and monetised. It was not possible to quantify every benefit under the proposed 'Policy Option', such as benefits from the competition for innovation initiatives, ability to incentivise quality of service, ability to determine cost of capital and the number of policy ideas.

95. For electricity distribution, relevant evidence from a CEPA report was used. The CEPA report did not quantify the transfer from consumers to producers in the gas distribution sector. However, because there are only four independent groups in this sector (of which two are majority owned by the same investment funds) the IA assumes that the costs to consumers would be larger than those identified for electricity distribution. The IA undertakes scenario analysis to demonstrate the uncertainties associated with the assumptions made in this IA.

# Small and Microbusiness assessment (SaMBA)

96. Small and micro-businesses (SaMBs) are out of the scope of this policy. This is due to the business size of the gas and electricity network companies in terms of turnover, employee numbers and value of mergers. For example, a turnover threshold of at least £70m GB turnover is needed to bring a network company within scope (see 'Network companies' in Table 2). Therefore, we do not believe that any direct impacts of this policy need to be considered on SaMBs.

97. SaMBs which are themselves energy consumers may benefit from lower gas and electricity prices, due to the 'Policy Option' helping prevent an unnecessary increase in bills. Please see paragraph 1 under '*Non-monetised benefits under the 'Policy Option''* on page 34 for further information on the total benefit to energy consumers of this policy. This benefit to SaMBs may create a positive impact for SaMBs by allowing more businesses to be able to afford the energy they need to carry out day-to-day operations.

# Summary and preferred option with implementation plan

98. While mergers or takeovers can bring about benefits including efficiency gains, those involving energy network businesses also reduce the amount of independent data available to Ofgem for comparison, and thus make it harder for them to set benchmarks accurately. This may lead to higher costs and reduced levels of service.

99. The proposed special merger regime does not seek to prevent mergers or takeovers but aims to protect Ofgem's ability to regulate companies. The proposal is estimated to result in a net benefit to society (central estimate) of around -£180m (2020 prices, discounted to 2022) with consumers benefiting from an avoided transfer to energy network companies (central estimate) of up to £600m (2020 prices, discounted to 2022).

100. To extend powers to the CMA for mergers in the energy network industry, primary legislative change is required. We expect that the regime would come into effect after secondary legislation has been introduced, which Parliamentary timetabling pending, will be on Royal Assent of the relevant Bill.

# Monitoring and Evaluation

101. The SMART objectives of this policy are:
    a. To give the CMA the power to block mergers between energy network companies if the merger would impact Ofgem's ability to regulate comparatively.
    b. To protect Ofgem's ability to serve consumer's interests by giving the CMA these additional powers.
    c. To support delivering affordable energy for households and businesses.

102. For policy outcomes 101(a) and 101(b), a post implementation review (PIR) will be carried out after five years following a proportional approach, involving firstly establishing whether there have been any attempted mergers in energy networks over that five-year period. A PIR is required to:

1. set out the objectives intended to be achieved by the regulatory system established by the Regulations;
2. assess the extent to which those objectives are achieved; and
3. assess whether those objectives remain appropriate and, if so, the extent to which they could be achieved with a system that imposes less regulation.

103. To inform this PIR, BEIS may collect evidence from stakeholders, such as the CMA, Ofgem and network companies, to find out how this policy has been implemented into their processes and the effect it has had on how they operate. If any mergers have been attempted in energy networks, we may pose the following questions to stakeholders and collect additional data if necessary:

1. How has the special merger regime impacted the ability to comparatively regulate the sector?
2. Were the extra powers granted by the policy enough to offset the negative effects to consumers that can be caused from energy network company mergers?
3. How do the additional administration costs triggered by the policy compare to our estimates?

104. For policy outcome 101(c), BEIS may evaluate how mergers (if any) may have impacted consumer energy bills, including comparing this to the estimate set out in *Consumer Bills Impact* in paragraph 56.

105. Ofgem's current monitoring and evaluation provisions involve performing comparative benchmarking for each price control period. Mergers may increase information asymmetry between Ofgem and energy network companies, as there would be fewer data points for Ofgem to try and simulate competitively set prices, in turn increasing the probability of allowed revenues being set too generously. Therefore, the new powers introduced by this policy may help consolidate Ofgem's comparative benchmark modelling.

106. The CMA has a bespoke approach to monitoring and evaluation, with it considering each remedy individually and completing reviews on an ongoing basis. In cases of a structural remedy, the CMA monitors the ongoing separation of the business and their owners. In cases of behavioural remedies, aspects of the requirements are monitored depending on factors including: the type of behavioural remedy, the reporting obligations imposed on the merging parties from the remedy, and whether a monitoring trustee[47] has been appointed to monitor compliance.

107. The process of setting price controls through benchmarking is founded on data provided to Ofgem by the distribution electricity and gas operators. This policy will not provide any extra burden on the analytical process behind benchmarking. We may collect some data from stakeholders in the form of responses to questions about the policy – as mentioned in paragraph 103.

108. A PIR may need to be carried out sooner than our planned five-year schedule if our assumption that 50% of mergers getting blocked is found to be an overestimation and if mergers are attempted sooner than anticipated. This would lead to multiple mergers in both the electricity distribution and gas distribution sectors happening ahead of our predicted scenarios in Table 1, and so an extra evaluation into the effects of such an event may be necessary.

109. We do not foresee any major external risks that would impact the success of this policy.

[47] Monitoring trustees are individuals or sometimes businesses appointed by the CMA to verify internal business activity. This is useful for complex cases and where practical monitoring is invasive and costly, so if monitoring trustees are appointed they are usually implemented in behavioural remedies.

# Annex 1 – CEPA's Analysis

Ofgem appointed Cambridge Economics Policy Associates (CEPA) to undertake analysis on the value of a loss in comparators as a result of a merger between two companies in the energy sector. The terms of reference for the analysis were:

- What are the precedents for regulatory approaches to assessing a merger of two companies in industries that rely on competition to set price control?
- What is the potential value of the loss of a comparator company following a merger in sectors that Ofgem regulates using price controls?
- What are the factors considered to determine the minimum number of independent groups that Ofgem should require and what is the minimum number of independent groups in each sector?
- What factors should be considered to determine the maximum number of licences that should be held by any independent group and what is the maximum number of licences an independent group can own in each sector?

**Estimating the loss of a comparator**

CEPA estimate the loss of a licensee in the electricity distribution sector, calculated on a five-year NPV basis with a discount rate of 4.7%, is between £40m and £150m, or £190m to £730m in perpetuity.

The method involves two stages: the first is simulating the loss of a leading comparator at the most recent price control review; and the second uses this estimate to determine a value for each comparator based on their relative importance in setting the efficiency targets. This requires estimating the maximum loss that would arise from the loss of a comparator, either a single DNO or through a group merger, for each of the activities where comparative benchmarking is used.

The first stage requires: re-running the models while excluding, in turn, each comparator for each activity where comparative benchmarking is used. This identifies the leading comparator and the degree to which its removal impacts on the benchmark for each particular activity. The efficiency scores are then benchmarked against the appropriate benchmark. When determining the benchmark, the excluded comparator is returned at the average amount to ensure that the same number of comparators is used.

The resulting efficiency reductions for each of the remaining comparators are applied to the relevant forecast to determine their allowance. The iterative process identifies the maximum allowance for each activity that would result if the leading comparator was lost. The difference between the maximum allowance and the allowance with all comparators included can be monetised to show the cost of losing the leading comparator for each activity.

The second stage of the process involves calculating each comparator's relative importance to Ofgem's modelling based on its efficiency score. The importance of a comparator to Ofgem's modelling can be ascertained from their relative efficiency and position relative to the benchmark. CEPA used a scaling method based on each comparator's relative efficiency score in relation to the benchmark. The scaling process is not a perfect statistical method for determining the importance of the comparators in Ofgem's modelling, although it does assign a higher weight to the most efficient comparators and to those closer to the benchmark, which is indicative of their importance. Weighting the value of the loss of a comparator by their distance to the frontier effectively puts a risk premium on the licensees.

**Relevance of these estimates**

CEPA's analysis for Ofgem concluded in May 2010 and was based on analysis of what were the two most recent price controls (DPCR5 and GDPCR). Ofgem continue to believe that this analysis remains relevant and provides a good guide to the impacts of future mergers. This is for the following reasons:

- There have been further mergers in both electricity distribution and gas distribution since the analysis was completed. This, if anything, is likely to increase the value of the remaining comparators and so does not undermine the case presented in this IA.
- Another price control period has been completed, which is when the analysis could have been updated. In any event, it is difficult to say that any update would change the range of figures materially because the underlying benchmarking techniques are constantly evolving and the underlying costs in the sectors, and the relative differences between the companies, remain stable.

| | |
|---|---|
| **Title:** Energy Industry Code Reform<br>**IA No:** BEIS051(F)-21-ICE<br>**RPC Reference No:** RPC-BEIS-5077(2)<br>(RPC-BEIS-5173(1))<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** Ofgem | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** codereform@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred Option** (in 2020 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status**<br>Non qualifying provision |
| -£16m | -£16m | £2m | |

**What is the problem under consideration? Why is Government action or intervention necessary?**

The CMA and consultation evidence shows that the 10 unique codes that govern the energy system lack strategic direction and are costly for firms to engage with, particularly for SME businesses which are of growing significance in the energy sector. The current arrangements also allow industry participants to delay or water down proposed changes to the codes that are against their private interests despite being in the interest of the market as a whole, competition, or consumers. Together these problems are likely to act as a barrier to achieving Net Zero at least cost. Government intervention is necessary since structural changes to codes governance require primary legislation.

**What are the policy objectives of the action or intervention and the intended effects?**

The aim of the policy is to ensure that the energy industry codes promote effective competition and keep pace with technical and commercial developments in GB energy markets, consistent with BEIS and Ofgem's strategic objectives and policies. Intervention seeks to achieve four key outcomes: (i) Code governance should be forward-looking, informed by, and in line with, wider industry and government strategic direction and the path to Net Zero emissions. (ii) The framework should be able to accommodate a growing number of market participants with effective compliance. (iii) Codes should be agile and responsive to change, while able to reflect the commercial interests of different market participants to the extent that this benefits competition and consumers. (iv) Accessibility to the market should be improved by making it easier for market participants to understand the rules that apply to them and what they entail.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

**'Do nothing':** No changes are made to the existing regulatory framework. Current barriers to competition, participation in code reforms and strategic alignment of reforms remain.

**Option 1 (preferred option)[1]:** Ofgem takes on new strategic functions for codes, with an enhanced code manager function assigned to a separate organisation(s). Code managers will be regulated by Ofgem via licence. Assuming primary legislation is passed in 2023, this could be implemented from 2024. This is the preferred option due to the benefits which include more efficient and dynamic processes that work more effectively in the interest of consumers, competition, and in the wider context of Net Zero.

| **Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:** Multiple dates. | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | No | | | |
| Are any of these organisations in scope? | **Micro**<br>Yes | **Small**<br>Yes | **Medium**<br>Yes | **Large**<br>Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:**<br>NA | **Non-traded:**<br>NA | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

[1] Other reforms to the current operational framework were considered but discounted at previous stages.

# Summary: Analysis & Evidence

Policy Option 1

**Description:**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 12[1] | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | Low: | High: | Best Estimate: -£16m[2] |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Cost (Present Value) |
|---|---|---|---|---|
| Best Estimate | - | | 2 | 16 |

**Description and scale of key monetised costs by 'main affected groups'**

The two major costs posed by this policy option are monetised. First, Ofgem are expected to face increased costs of around £2m per year due to increased resource demands to carry out its new strategic functions. Second, the enhanced code manager functions will pose costs to the licensed organisation or organisations – these are expected to be transitionary and passed down to industry parties and further to consumers. This is estimated as an additional £35m per year from 2024 onward, assuming that primary legislation is passed by 2023. This timeline is due to the time taken for Ofgem to tender for (or otherwise select) the code managers.

**Other key non-monetised costs by 'main affected groups'**

There may be learning and familiarisation costs posed to all participants involved in the codes process which may act to inhibit the rate at which benefits of intervention are realised. For Ofgem and the organisation(s) licensed to carry out the code manager functions, there may be time required before responsible teams have the experience and familiarity with new functions to fully utilise them. For wider industry, time will be required to understand new processes. The time taken to adapt business practices may lead to realised benefits being foregone or delayed.

| BENEFITS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Benefit (Present Value) |
|---|---|---|---|---|
| Best Estimate | - | | - | - |

**Description and scale of key monetised benefits by 'main affected groups'**

Only two minor benefits of intervention are able to be monetised. First, industry is expected to save around £0.3m per year in reduced costs of reading and responding to consultations, due to a more efficient and strategically aligned codes process resulting in fewer proposed code modifications that are subsequently rejected. Second, industry is also expected to save around £1.5m per year in reduced costs of workgroup participation due to the increased preparatory work carried out by the enhanced code manager function.

**Other key non-monetised benefits by 'main affected groups'**

There are several major benefits that have not been possible to monetise. First, a more efficient and strategically aligned code process is likely to reduce the frequency and magnitude of delays to code modifications that are beneficial to consumers, introduce new and innovative technologies, and work towards achieving HMG objectives such as Net Zero. Second, this intervention also intends to reduce the barriers to participation for smaller firms, enabling these firms to better compete in the energy sector.

| Key assumptions/sensitivities/risks | Discount rate | 3.5 |
|---|---|---|

Quantified results are particularly sensitive to the following assumptions estimating the cost of code manager functions: (a) estimates of a current code administrator's (Elexon) costs to perform code manager functions are applicable to other codes and (b) these code manager costs can be isolated from the cost of other activities by assuming costs are uniformly distributed. Finally, (c) it is assumed that a given proportion of code manager activities, illustrated as 30%, are already carried out by code administrators and are non-additional. Implementation of this option is also subject to uncertainty.

**BUSINESS ASSESSMENT (Option 1)**

| Direct impact on business (Equivalent Annual) £m: | | | Score for Business Impact Target (qualifying provisions only) £m: |
|---|---|---|---|
| Costs: NA | Benefits: NA | Net: NA | NA |

[1] A 12 year appraisal period has been used given the base year chosen is 2 years before the expected implementation date, when costs will begin to accrue.

[2] Including illustrative costs of potential secondary legislation decreases the total illustrative NPV to -£280m.

**Contents**

# Evidence Base

## Background

1. Much of the operation of the electricity and gas market is underpinned by technical and commercial codes. This final stage IA provides an assessment of the impact that proposed legislative changes of primary and secondary legislation to the governance structure of these codes (referred to in the IA as "industry codes"), which governs Great Britain's (GB's) electricity and gas market.
2. There are currently 10 industry codes, consisting of more than 10,000 pages of text. They are multi-party agreements, overseen by 6 code bodies with varying governance and ownership arrangements. Broadly, each code has a *code owner*, with responsibility for having the code in place; a *code administrator* responsible for the day-to-day running of the code; and a *code panel*, made up of industry experts and code parties who oversee the operation of the code. This includes any code modifications[1] over time that serve to maintain an efficient industry framework, as well as other functions relating to safety, enabling competition, and legal compliance. The code modification process varies across different industry codes. In order to maintain an efficient industry framework, codes are required to change over time; the change process varies across different codes.
3. The proposed areas within the scope of this reform[2] are the:
    - National Grid Electricity System Operator (NGESO) codes (CUSC, GC, STC) and the non-NGESO codes (BSC, REC, DCUSA, DC, SEC, UNC, IGT UNC)[3].
    - Central system delivery functions underpinning energy systems:
        - Smart Metering (delivered by DCC[4]);
        - Gas (delivered by Xoserve);
        - Electricity (delivered by Elexon); and
        - Data Transfer Service (DTS) (delivered by ElectraLink).
    - Electrical engineering standards set out in the SQSS[5], the DC and GC, as well as their subsidiary documents which include P2 and engineering recommendation G98 and G99.
4. The exact costs of the current code administration system are uncertain. Some code administrators also carry out delivery functions as well as other business aspects, making it difficult to isolate the costs of code administration. External estimates vary slightly. British Gas, in their response to Ofgem's 2015 open letter on the further review of industry code governance[6], estimated that across industries under the code administration of the BSC, DCUSA, UNC, SEC, MRA AND SPAA[7], the costs to customers significantly exceeded £10m in 2015. Based on this estimate, a 2017 research paper from the University of Exeter[8] extrapolated the total cost of running the code administration system to be in the order of £20m-£25m a year. This IA relies on analysis produced by Elexon,

[1] "Change" and "modification" are used interchangeably in this document.

[2] Paragraph 3 includes only the areas directly in scope of reform. There are 10 total energy codes, all within scope of these reforms, but there are additional central system delivery functions and standards which are not included; these may be brought into scope in the future if they are likely to have a material impact on the delivery of the strategic direction or the objectives of code governance reform. Further information can be found within Chapter 2 of the Consultation Document at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1004005/energy-code-reform-consultation.pdf.

[3] Connection and Use of System Code (CUSC); Grid Code (GC); System Operator – Transmission Owner Code (STC), Balancing and Settlement Code (BSC),; Distribution Connection and Use of System Agreement (DCUSA); Distribution Code (DC); Smart Energy Code (SEC); Uniform Network Code (UNC);; Independent Gas Transporter Uniform Network Code (IGT UNC); Retail Energy Code (REC).

[4] Data Communications Company.

[5] Security and Quality of Supply Standard

[6] https://www.ofgem.gov.uk/sites/default/files/docs/2015/07/british_gas_response_2_0.pdf

[7] The Retail Code Consolidation Significant Code Review (SCR) has resulted in the MRA and SPAA no longer being in effect as from 1st September 2021, with certain provisions of the MRA, SPAA and certain other agreements being carried over into the REC. https://www.ofgem.gov.uk/publications/retail-code-consolidation-date-designated

[8] https://ore.exeter.ac.uk/repository/bitstream/handle/10871/28455/Governance%20of%20industry%20rules%20and%20%20energy%20system%20innovation.pdf?sequence=1

which estimates the current cost of code administration to be around £30m. Each of these estimates covers only the direct costs arising from code administration, but not their wider impact on industry participants.

## Rationale for Intervention

5. In June 2016, the Competition and Markets Authority (CMA) published its Energy Market Investigation Final Report[9]. It identified the current system of code governance as a **barrier to pro-competitive changes**, such as faster supply switching for consumers, and concluded that it is inadequate for delivering major reforms that might be necessary to implement policy decisions or support innovation on a timely basis. The report suggests that this holds back energy sector innovation, and the transition to a cleaner, smarter energy system.

6. The need for a responsive and coordinated code governance system has since become more imperative in the context of HMG's commitment to net zero by 2050. Increasingly, policy solutions require a whole-system perspective and changes across multiple codes (e.g., Faster Switching, Half-Hourly Settlement). Further, there is growing industry consensus that action is necessary to create a regulatory framework capable of delivering the changes required to move to a clean, smart, and consumer-led energy system, in line with the Energy White Paper[10] and the Net Zero Strategy[11].

7. During its investigation, the CMA recognised that codes contain technical and commercial provisions which require detailed knowledge of the industry, and therefore that industry-led regulation is appropriate to govern and modify such rules in the majority of cases. However, it also noted drawbacks of how existing arrangements work, including how existing governance and code change arrangements have failed to ensure the implementation of important code changes which benefit consumers and/or competition.

8. The CMA also noted that these existing arrangements have created material burdens on industry participants, particularly smaller ones, and this could undermine their incentives or ability to promote change. All code parties face the cost of monitoring changes in government policy, regulation, and industry code developments. However, the fixed costs of compliance are more of a burden for new entrants and smaller parties with smaller customer bases over which to spread these costs. Further costs are involved if a party wishes to try to influence any such changes. The CMA's evidence found that smaller parties did not have the resources to be involved in every code change or even to suggest code changes themselves. For example, Ofgem has estimated that there are around 150 industry panel-type meetings per year, and on average, each code change proposal may require around four working groups (more complex changes will require significantly more)[12]. These working groups and the appropriate preparatory work to participate in them implies proportionately larger cost to smaller firms.

9. In addition, the CMA found that there were several fragmented, complex sets of rules, each with different and un-coordinated arrangements, **creating a significant barrier to entry** and increasing the cost of participating in the market for new entrants such as small generators, aggregators, and other firms with innovative business models. Responses to the 2021 consultation on Energy Code reform[13] supported the findings from the CMA report. For example, research by Xoserve found that participation in modification processes is "dominated by the larger organisations in the energy

[9] Energy market investigation: Final Report, CMA https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf

[10] See Energy White Paper: https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future/energy-white-paper-powering-our-net-zero-future-accessible-html-version

[11] https://www.gov.uk/government/publications/net-zero-strategy

[12] See CMA working paper on codes: https://assets.publishing.service.gov.uk/media/54f730f140f0b61407000003/Codes.pdf

[13] https://www.gov.uk/government/consultations/energy-code-reform-governance-framework

industry"[14], finding workgroup participation and the raising of proposals is "most prevalent amongst the 'Big 6' supplier / shipper organisations"[15].

10. The code administrators, responsible for code governance, are funded by and accountable to industry. In the CMA's view, they lack powers and incentives to improve the change process and overcome incumbent power. In BEIS's view, the existing arrangement can give rise to a Principal/Agent problem between Ofgem/BEIS (the principal) and industry participants (the agent) who need to implement code changes. The incentives of the agent might not be aligned with those of the principal. This is an example of an **imperfect information market failure**. While a specific policy change requiring changes to industry codes would generate wider benefits to the market, individual industry participants might not directly benefit from such a policy change and therefore have weaker incentives to implement it.
11. The CMA is concerned that under the current regulatory framework, Ofgem has insufficient ability to influence the development and implementation of code change proposals, and that Ofgem is unable to ensure that industry codes keep pace with market developments or wider policy objectives.
12. Without significant reform, changing codes will remain a lengthly process under the current code governance process. The framework was designed around a market structure of the past – where a small number of relatively similar, large, and well-resourced participants were able to reach consensus on rule changes. The benefit of this consensus-based process was that the decision should be acceptable to all group members and have strong support for implementation. But in recent years, particularly with the move to a smarter, more flexible system, the number and diversity of market participants has increased. Conflicting commercial priorities can inhibit the consensus-based decision-making process, meaning that change is slow.
13. In the context of Net Zero and the whole system transformation required in the energy system, the cost of current arrangement may increase due to both the greater magnitude of investment required in the energy system[16] and the increased number of smaller firms[17] entering the market, which are found to be disadvantaged by current governance arrangements which inhibit fair competition. This view was broadly supported in the 2021 consultation, where respondents highlighted the need for policy intervention to enable faster decarbonisation and enable a higher penetration of renewables.
14. These reforms to the energy industry codes are being considered alongside wider changes to the governance of the energy system, such as the creation of a new independent system operator[18] with roles and responsibilities across both gas and electricity. This independent system operator is referred to as the future system operator (FSO).

## Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

15. The approach used in this Impact Assessment is deemed to be proportionate and intends to convey the uncertainty in exact impacts that are inherent to the policy. Detailed consideration has been given to the rationale for intervention and how the options considered meet the policy objectives and key impacts have been identified with their distributional effect considered.

16. The analysis of impacts builds on feedback from both the 2019 and 2021 consultation IAs on codes reform and other sources, to quantify costs and benefits where possible alongside feedback received in the recent 2021 consultation. Where potential impacts remain unquantifiable, we have looked to quote separate analysis, feedback from consultation or referred to existing measures and policies to provide an indication of the potential costs and benefits of the proposed measures and

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14 Included in Xoserve's 2021 consultation response to the previous IA.

15 Ibid.

16 The 2021 Net Zero Strategy estimates investment requirements may be up to £400bn by 2050 for generation alone. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1033990/net-zero-strategy-beis.pdf, pg. 99.

17 This trend in the number of smaller firms participating in the sector is illustrated by tables 8 and 9 below. Looking at electricity in table 8 below highlights that between 2013 and 2020 the number of small and micro businesses each increased by around 300%.

18 See Ofgem's January 2021 review of the GB Energy System Operator: https://www.ofgem.gov.uk/publications-and-updates/review-gb-energy-system-operation and the government response to the 2021 consultation on future system operation arrangements https://www.gov.uk/government/consultations/proposals-for-a-future-system-operator-role.

strengthen our evidence base. We have also provided an initial assessment of risks, uncertainties and the key distributional impacts that are likely to occur.

## Policy objective

17. The aim of this policy is to ensure that the energy industry codes will promote effective competition and keep pace with technical and commercial developments in GB energy markets, consistent with BEIS and Ofgem's strategic objectives and policies. We have identified four key objectives which tackle the fragmentation and lack of coordination between codes, lack of incentive for change, and complexity of the codes landscape:

    - Code governance should be **forward-looking**, informed by, and in line with the Government's ambition and the path to Net Zero emissions, ensuring that codes develop in a way that **benefits existing and future energy consumers**;

    - The framework should be able to **accommodate a large and growing number of market participants** and **ensure effective compliance**;

    - Codes should be **agile and responsive to change**, whilst able to **reflect the commercial interests of different market participants**, to the extent that this benefits competition and consumers; and

    - The framework should **make it easier for any market participant to identify the rules that apply to them and understand what they mean, so that new and existing industry parties can innovate** to the benefit of energy consumers.

18. In addition, the code reform intends to **enable a faster and more effective consolidation of codes** to follow through the prioritisation of code consolidation.

19. To ensure effective monitoring and evaluation, more time-bound sub-objectives are developed below against each objective, outlined in table 10.

## Description of options considered

20. The previous Consultation Impact Assessment discussed two options: Option 1, which installed Ofgem as a strategic body with separate empowered code managers, and Option 2, which created an Integrated Rule Making Body (IRMB) within the FSO, that combined the strategic and code management functions[19]. The 2021 consultation IA concluded Option 1 as the preferred option due to shorter implementation timelines and reduced complexity. Additionally, over 80% of respondents to the 2021 consultation viewed Option 1 as the preferable option with no respondents preferring Option 2. As a result, Option 2 has been discounted from further analysis with more detailed justification to be included in the official Government response to the 2021 consultation published alongside this impact assessment.

21. Therefore, only Option 1 is considered in this IA, compared to our 'do nothing' baseline. For the sake of regulatory and legislative simplicity, we have decided that Option 1 will result in an expansion of Ofgem's existing functions rather than the creation of a distinct entity known as the 'strategic body'. This means that the strategic code functions will constitute new roles for Ofgem, rather than a new body that Ofgem is taking on:

    - **Counterfactual – 'Do nothing':** Under this option, no changes are made to the existing regulatory framework for code governance. Currently, the process for code changes varies across codes and most changes to codes are industry-led. As the status quo would be

[19] Prior options considered before the previous IA also included: (i) Ofgem as the strategic body but with oversight function only, i.e., no ability to get involved in the management or delivery of code changes. This option was disregarded due to a lack of flexibility (limited ability for the strategic body to direct code managers) and similarity with what eventually became our preferred option. (ii) FSO as the strategic body with oversight function only, i.e., no ability to get involved in the management or delivery of code changes. This option was discarded due to lack of flexibility, high complexity, and the inability to meet the reform objectives. (iii) FSO as the strategic body with the ability to get involved in the management or delivery of material code changes (as with our preferred option set out in the consultation). This option was discarded due to high complexity and the similarities to our alternative option, as well as concerns over potential conflicts of interest.

maintained, no additional costs or benefits would be generated from this option. The code modification processes would remain as they currently are.

- **Option 1 – Ofgem takes on new strategic code functions (preferred option):** Under this option, Ofgem will be given new strategic code functions, including the ability to establish and regulate (via licence) one or more code manager(s)[20]. Ofgem would be responsible for setting a strategic direction, based on Government policy priorities and current and future trends in the wider energy market, as well as ensuring that the code managers deliver it. Ofgem would also have the option of modifying the codes directly in a limited range of circumstances and decide on code changes that have a material impact on consumers, competition, and the operation of the market. Code managers will take on most of the responsibilities that are currently held by code panels and industry parties, including proposing code changes, leading most of them, and taking decisions on non-material code changes, although final decisions in this area will be subject to further consultation by Ofgem. Code managers will be appointed by Ofgem once a decision on code consolidation has been made and will be accountable to Ofgem via licence.

  For the purposes of this impact assessment, we assume that this option would be implemented from 2024.

## Description of costs and benefits

### Costs and Benefits of Primary Legislation

22. Primary powers will assign the new strategic code functions to Ofgem and enable it to select and license code managers. However, these powers are enabling and dependent on secondary legislation to enable full implementation of policy reform. Those impacts directly attributable to primary powers and borne before secondary legislation is implemented are detailed below.

Costs

23. Ofgem may incur some initial set up costs associated with its new strategic functions, for example the recruitment of new staff. These are estimated as **up to £2m per year** during set up and are expected to be recouped from industry, in line with Ofgem's current funding system. As there is no strategic function in the current system, the ongoing costs represent additional costs to the status quo.
24. To estimate the additional costs of Ofgem taking on the strategic code functions, we assume, based on consultation with Ofgem, that up to an additional 30 employees are required. This represents an estimated additional 3% of Ofgem's current workforce. Taking the latest available data, we assessed the cost of 30 new Ofgem employees by examining Ofgem's expenditure in February 2015[21], across its Ofgem employees FTE staff, including for external expenditures such as consultancies. Data on Ofgem's full employee costs from its 2014/2015 budget is multiplied by the rate of inflation to give a figure in 2020 terms. The additional 3% rate is applied to Ofgem's budget in 2020 terms to give an estimate of the additional costs to Ofgem of taking on the strategic code functions. We assume that there are no costs associated with procuring additional office space and the grade profile of the additional employees mirrors that of Ofgem as a whole.
25. No other costs were deemed to be attributable to primary powers, however the commitment to new governance arrangements brought forward by primary powers may create some uncertainty for investors.

Benefits

26. There are no major benefits attributable to primary powers given they are primarily enabling. Peripheral benefits may consider improved market confidence given the additional regulatory certainty provided by a decision on policy reform.

Summary

[20] This/these organisation(s) will also take charge of existing roles and responsibilities carried out by current code administrators.

[21] More recent data, e.g. from 2020/21 Annual Reports and Accounts does exist, however this does not offer as good as a breakdown than the 2015 older data. However, at the headline level, the comparison in total expenditure is roughly similar, and thus we assume that using the 2015 would still provide accurate comparison for our analysis.

27. The quantified costs of primary legislation gives a total NPV of -£16 million over a 12-year time horizon beginning in 2022 in the central scenario. Central scenario cost estimates are presented in Table 1.

*Table 1: Central scenario additional cost and benefit estimates of Option 1 (2020£, 2022 discounting perspective, 12-year horizon)*

| Costs | Annual costs, best estimate |
|---|---|
| Ofgem's strategic code function costs | £2m |
| **Total NPV of monetised analysis (12-year horizon)** | **-£16m** |
| **BCR of monetised analysis** | **-** |

*Figures are rounded to nearest 100,000 below £5m, 1m below 50m and for all else above, 5m.*

## Illustrative monetised costs and benefits of secondary legislation

28. Monetised impacts included in this analysis are able to reflect the major costs of policy intervention. However, only smaller, peripheral benefits have been deemed possible to monetise. Therefore, it is important that figures presented here are considered in tandem with the non-monetised impacts below and the strategic case for intervention.

29. A 12-year time horizon has been chosen for analysis, with a base year of 2022, and assuming a 2024 implementation date for Option 1[22].

Costs

*Costs incurred relative to counterfactual estimate*

30. The establishment of a strategic function represents a new cost as no body currently exists to provide a strategic direction and alignment with government objectives, nor carries out the additional responsibilities that Ofgem will hold, including the selection and licensing of code managers.

31. For the code management function, incurred costs correspond to the additional responsibilities taken on by code managers relative to those currently carried out by code administrators. As outlined in the background to this impact assessment, the exact costs of code administration activities are uncertain. This impact assessment relies on analysis by Elexon which estimate the current cost of code administration to be around £30m based on 2019 data. Whilst it is expected that the additional activities carried out by code managers will impose a new cost, part of this cost is assumed to reflect a transfer, with a proportion of code management activities already carried out by code parties or code administrators. The exact proportion deemed to be a transfer is uncertain and tested via sensitivities, with assumptions outlined in Annex 1.

32. There may also be new transitionary costs associated with the set-up and delivery of the new code management functions and the establishment of Ofgem's strategic code functions.

*Option 1: Cost of strategic code functions*

33. The ongoing costs of Ofgem delivering its function are estimated at **£2m per year** incurred from 2024 onwards. These costs will have to be recouped from industry, in line with Ofgem's current funding system. This cost estimate is assumed to accrue from the annual wage and non-wage cost associated with the additional 30 FTE Ofgem employees we have assumed, in consultation with Ofgem, would be required to carry out the strategic code functions.

34. The approach to estimating this cost and attached assumption are detailed above in paragraph 24 on, when considering the initial set up costs associated with Ofgem delivering the strategic code functions.

*Option 1: Cost of code manager function*

[22] Note, this implementation date is illustrative for the purposes of modelling.

35. The shift from code administration to code management will lead to an estimated increase in costs of around £35 million a year from 2024 to the empowered code managers due to the additional responsibilities they will have compared to code administrators[23]. These tasks could include identifying and developing changes to the codes, making recommendations to Ofgem, or prioritising which changes are progressed. These costs are expected to be passed on to industry through charges, with code managers funded in the same way as current code administrators. However, it is expected these charges will be passed through to end-consumers energy bills and not borne by code parties themselves.

36. The enhanced responsibilities of the code managers would help to facilitate change more effectively. Enabling the code managers to propose changes to the code would remove the reliance on industry or on Ofgem initiating ad-hoc Significant Code Reviews (SCRs) to deliver the changes necessary to deliver the energy transition. It would also introduce an explicit role for prioritisation, ensuring a focus on the changes most likely to deliver on the Government's policy or its vision for the energy system. This would speed up the code modification process, more efficiently bringing forward the benefits the code modifications entail.

37. Data provided by a code administrator, Elexon, is used to estimate the additional cost of the code manager function relative to the current system. This data provides a breakdown of Elexon's current costs to carry out roles considered to be code administrator functions and those considered to be code manager functions. However, it is not possible to separate costs considered to be code manager functions from costs considered to be unique to Elexon. In absence of more detailed information, a simplifying assumption is made that costs are spread uniformly between functions considered unique and those considered to be code manager functions. Responses to consultation highlighted the significant uncertainty associated with these cost estimates, which we reflect through sensitivity testing.

38. The current industry-wide costs of code administration, as outlined above, are then scaled by the additional expenditure Elexon spends on its code management functions relative to the expenditure on its code administration functions (158%). This gives an estimate of the additional expenditure required for code management functions to be carried out, provided no code management responsibilities were currently carried out by certain code administrators.

39. However, it is then assumed that a certain proportion of code management responsibilities are already carried out by code administrators, and therefore, intervention would not result in new costs for these. Similarly, the costs could currently be borne by industry and therefore represent a transfer of costs, rather than a new cost. This proportion is illustrated as 30%, however whilst consultation broadly supported this assumption, the testing of this assumption is the focus of sensitivity analysis due to its impact on quantified results. We also intend to use consultation to verify this assumption. The additional costs of the code management responsibilities (£35 million) are reached by applying the 110% multiplier[24] to the estimate of the costs of code administration under the current system.

40. Additional transitionary costs associated with the set-up of code management functions, such as recruitment costs are not fully reflected in this monetised analysis.

<u>Benefits</u>

*Counterfactual estimate*

39. This section outlines the annual estimated cost to industry of participating in the code change process under the current system. These existing costs arise from industry responding to code change consultation and participating in workgroups, with decisions on modifications ultimately made by the code panels. The respective savings rates outlined below are applied to these current cost estimates to give an indication of the benefits to industry which would be expected from code reform.

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[23] Responses to the 2021 consultation found the previous stage IA's estimates to be reasonable and comprehensive, although a number of responses did express views that it was possible that the estimates for code managers may represent a within-industry transfer rather than an additional direct cost from reform. We have tried to mitigate this using a 30% transfer assumption, further tested within sensitivity analysis, however this still reflects a degree of uncertainty surrounding possible overestimate of costs. Given exact arrangements for code managers are yet to be determined until secondary legislation, it is difficult to pin down costs exactly; however, further IAs with accompanying secondary legislation would likely be able to estimate costs with increased certainty.

[24] This figure is achieved by accounting for the 30% transfer costs against the 158% figure of additional costs of code management.

40. We estimate that under the current system, code change consultation responses costs industry around £1.6 million annually. This was estimated by taking data from Ofgem's quarterly Code Administrator reporting metrics to assess the number of consultations for Authority Consent and Self-governance modifications that had occurred in 2019/20 and the average number of respondents for each modification. We then used data provided by code administrators in code change summary reports to estimate the cost of each consultation response by assessing the number of days each consultation response would require and the cost of an industry representative's time to complete the response, with assumed values listed in Table 2. As a simplifying assumption, we assume that effort and costs of consultation responses for all codes other than the Smart Energy Code (SEC) are in line with CUSC, STC, and Grid Code. This has been done due to the availability of data and is tested in the sensitivity analysis. Further, our estimate does not account for time spent by industry engaging with consultations, but which does not lead to a response (e.g., reading consultation documents and choosing not to respond etc.).

41. We estimate that the annual cost to industry of workgroup participation under the current system is around £6.3 million. We assume, in line with the CMA report, that on average each code change requires four workgroups. We also assume, based on Ofgem experience, an average of 10 industry participants per workgroup, though figures do differ across the different codes. These numbers are applied to data provided by Ofgem on the annual number of code change decisions (143 code changes in 2019/2020) to provide an estimate of the total number of workgroup participants per year. This was multiplied by data from code administrators (Table 2) on the effort in days per participant per workgroup and the cost to industry per industry participant per day to give an annual estimate of the current cost to industry for workgroup participation

42. Our estimates do not account for the time spent by industry engaging with consultations which subsequently, do not lead to a response (e.g., those that may read documents, but choose not to respond), given the lack of available data. Similarly, we exclude the costs of those that prepare to participate in workgroups that subsequently do not.

*Table 2: Effort and Cost to industry of Consultation response and workgroup participation*

| Codes | Estimated effort per consultation response (Days) | Estimated effort per workgroup member per workgroup (Days) | Cost per day for industry representative |
|---|---|---|---|
| **SEC** | 3 | 2 | £1,200 |
| **CUSC, STC, Grid Code** | 1.5 | 1.5 | £600 |

*Source: For CUSC, STC and Grid code, data is taken from Final Modification Report of CMP285. For SEC, data is taken from the modification report for SECMP079.*

*Option 1: Illustrative industry savings to consultation costs*

43. Benefits to industry of around £300,000 a year are estimated in the form of savings to current consultation costs. These are expected post-code reform from a more efficient modification consultation process which will lead to savings in effort and cost to industry of engaging in the process. The enhanced role of code managers will relieve some of the material burdens placed on industry as outlined in the CMA report, in the form of reading and responding to modification consultations or contributing to the drafting of legal texts. In addition, it is assumed that modifications which would be rejected or sent back by Ofgem under the current system, would not be proposed under the policy options due to the code manager function ensuring that modifications are aligned with the strategic direction and are of wider benefit.

44. To calculate this saving, the savings rate was applied to current industry consultation costs as calculated above. Our central estimate assumes that code reform results in cost savings compared to the counterfactual, due to a 20% efficiency improvement following intervention. This efficiency improvement is informed by first considering the number of modifications that are currently rejected or sent back to Ofgem, which corresponds to approximately 10% of code modification proposals. It is then assumed that the provision of a clearer strategic direction to codes alongside more preparatory work being carried out by the code management function will reduce the burden on

industry when responding to future consultations. The implications of this figure are tested as part of sensitivity analysis.

*Option 1: Illustrative industry savings to workgroup participation costs*

45. Benefits to industry of around £1.5 million a year are estimated in the form of savings to current workgroup participation costs. Under the current system, workgroups are made up of industry participants who play a large role in the drafting and refining of modification proposals. Post-code reform we expect modifications to require fewer workgroups due to a more efficient modification process in which empowered code managers will carry out much of the drafting and refining of modifications. However, the exact arrangements for the code change process after reform will be decided by the new code managers.

46. To estimate the scale of these savings, the code reform workgroup cost saving rate, 25%, was applied to the current industry workgroup cost estimate to give an estimate of the annual savings to industry from the decreased number of workgroups. The workgroup cost saving rate is calculated based on the assumption that, post-code reform, the average number of workgroups per modification will decrease from 4 to 3 as the code managers will take on much of the work currently carried out by workgroups. This is only one potential improved efficiency from intervention. Efficiency savings may also occur due to the increased preparatory work taken on by the code manager reducing the effort per workgroup per participant. This is a simplifying assumption made for the purpose of this analysis, with arrangements decided by code managers. This assumption is tested in the sensitivity analysis.

### Summary of quantified analysis

47. These illustrative costs and benefits are expected to accrue from 2024. This gives a total illustrative NPV of -£280 million over a 12-year time horizon beginning in 2022 in the central scenario. Central scenario cost estimates are presented in Table 3.

*Table 31: Central scenario additional cost and benefit estimates of Option 1, including illustrative costs of secondary legislation (2020£, 2022 discounting perspective, 12-year horizon)*

| Costs | Annual costs, best estimate | Benefits | Annual benefit, best estimate |
|---|---|---|---|
| Code Manager costs | £35m | Workshop cost savings | £1.5m |
| Ofgem's strategic code functions costs | £2m | Consultation cost savings | £0.3m |
| **Total illustrative costs PV (12 year)** | **£300m** | **Total illustrative benefit PV (12 year)** | **£15m** |
| **Total illustrative NPV of monetised analysis** | | | **-£280m** |
| **Illustrative BCR of monetised analysis** | | | **0.05** |

*Figures are rounded to nearest 100,000 below £5m, 1m below 50m and for all else above, 5m.*

48. As noted above, only the peripheral benefits to intervention have been possible to quantify, whilst all the major costs to intervention have been quantified. Therefore, a full assessment of impacts of policy reform requires non-monetised impacts to be considered in tandem.

## Sensitivities

49. The quantified results discussed above rely on several assumptions, and there remains significant uncertainty around the exact costs and benefits of the intervention. To illustrate this uncertainty, 'high' and 'low' cost scenarios have been developed. The primary driver of differences between these scenarios is the cost of code administrators taking on the enhanced functions of code managers, and therefore sensitivities focus on this assumption. A full description of the impact of this change in assumptions is provided in Annex 1.

Sensitivities – Cost uncertainty

50. As outlined in the assessment of monetised costs, there are several uncertainties in estimating the costs of creating new code managers, with their additional responsibilities, relative to those of the current code administrators. These points were further highlighted via consultation response and are that:

- It is likely that several code management responsibilities are already being carried out by some code administrators, therefore not all code management responsibilities will pose additional costs.
- It is likely that several code management responsibilities (beyond consultation and workgroup participation) are already being carried out by industry participants, therefore a proportion of code management responsibilities represent a transfer from industry to code managers.
- Figures provided by Elexon on the cost of code management responsibilities may be higher or lower for other code administrators[25].

51. The uncertainties presented by code manager responsibilities are illustrated in the high and low scenario.
    - The **low cost** scenario assumes:
        i. 50% of code management responsibilities are already carried out by industry or code administrators.
        ii. Elexon's code management responsibilities costs are 20% higher than other industry codes.
    - The **high cost** scenario assumes:
        i. 10% of code management responsibilities are already carried out by industry.
        ii. Elexon's code management responsibilities costs are 20% lower than other industry codes
52. These scenarios also test the assumptions underpinning benefits modelled, as described in table 11 of the annex.
53. The results of modelled high and low scenarios for total illustrative costs and benefits are presented below in Table 4. The monetised illustrative Net Present Value is a net cost of between around £175m to around £460m over the 12-year period analysed. These costs almost entirely reflect assumptions made on how many new costs are imposed on the industry as a result of the enhanced code manager function carried out. As highlighted above, we have only been able to estimate the major costs of this proposal, while only the peripheral benefits have been estimated – this explains why our illustrative monetised estimates present such negative NPVs and low BCRs.

*Table 42: Total illustrative costs and benefits of Option 1, with sensitivities (2020£, 2022 discounting perspective, 12-year horizon)*

| | Low-cost scenario | Central estimate | High-cost scenario |
|---|---|---|---|
| **Monetised Costs** | £175m | £300m | £460m |
| **Monetised Benefits** | £32m | £15m | £3m |
| **Monetised NPV (illustrative)** | **-£140m** | **-£280m** | **-£460m** |
| **BCR (illustrative)** | **0.18** | **0.05** | **0.01** |

*Figures are rounded to nearest 100,000 below £5m, 1m below 50m and for all else above, 5m.*

<u>Sensitivities – Learning and familiarisation costs</u>

54. The fundamental change to the governance structure imposed by policy intervention is likely to impose learning and familiarisation costs. Ofgem will likely take time to understand how to maximise the effectiveness of their new functions and industry will be required to familiarise itself with how best to engage in new governance structures and understand the content of new governance arrangements. Whilst it is difficult to quantify the familiarisation costs borne by industry, this impact assessment attempts to illustrate the impact of learning costs to monetised analysis via delaying any benefits from

[25] In particular, this was highlighted by consultation respondents operating within the gas sector.

new governance arrangements from accruing for the first 5 years[26] from the assumed 2024 implementation date. Results are shown in Table 5 which indicates a slight worsening in the illustrative NPVs across all scenarios considered.

*Table 53: Impact of Learning and familiarisation on benefits (2020£, 2022 discounting perspective, 12-year horizon), including total illustrative costs of Option 1*

| | **Low-cost scenario** | **Central estimate** | **High-cost scenario** |
|---|---|---|---|
| **Monetised Costs 12-year PV** | £175m | £300m | £460m |
| **Monetised Benefits** | £15m | £7m | £1m |
| **Monetised NPV (illustrative)** | **-£160m** | **-£290m** | **-£460m** |
| **BCR (illustrative)** | **0.09** | **0.02** | **0** |

*Figures are rounded to nearest 100,000 below £5m, 1m below 50m and for all else above, 5m.*

55. Quantified benefits also vary significantly depending on assumptions of learning costs and other assumptions; however, these are small when compared to costs quantified in each scenario, and as a result are not the focus of discussion here. Further, while the quantified costs outweigh quantified benefits in each sensitivity scenario, it is important to note again that the major benefits from these reforms are still left unquantified. These are discussed in the section below.

## Non-monetised costs and benefits

Non-monetised costs

*Learning and familiarisation costs*

59. There would likely be some costs involved with industry and code managers familiarising themselves with the new framework and adapting business practices to the new arrangements. It is expected learning and familiarisation costs may arise via two main channels:

a) Foregone benefits if there are delays to the establishment or adaptation to the new arrangements. These have been illustrated above in the Sensitivities section, where the assessment of costs and benefits have been analysed where no benefits accrue to industry for the first 5 years following implementation of these regulations.

b) Costs incurred to industry and code managers, as these parties familiarise themselves with the new regulations and acclimatise to new responsibilities. These are dependent on the detail of future documentation such as those detailing how Ofgem will appoint code managers. To illustratively assess what the costs to industry participants may look like, given average costs per day for industry representatives can fall in the range between £600 and £1,200 (see Table 2), assuming that it would take 16 total staff hours for companies to read and familiarise themselves to the new regulations, the potential costs may be in the range of £1,200 to £2,400 per company.

Non-monetised benefits

60. The primary benefit of these reforms is the reduced time and effort taken for the implementation of modifications. This also has significant second-order benefits, as the more efficient and effective code modifications will allow the benefits of individual code modifications to be achieved more fully and realised faster. This is thus beneficial for the wider context of Net Zero, whereby current arrangements could result in an increase in the magnitude and frequency of delayed benefits due to the whole system change required in industry, and in the interest of the consumer, even in cases where these interests are not aligned to those of parts of industry. This is because delayed and inhibited code changes under the current system would result in a direct cost to

[26] 5 years has been selected as an illustrative assumption.

industry from increased costs involved in the process, pushing an indirect cost to consumers from relatively higher energy bills.

61. There are also benefits to competition. This proposal should enhance the functioning of code governance arrangements so that code changes that are considered beneficial to the market are not delayed by incumbent firms that would not directly benefit from such changes. This proposal would also reduce the complexity of code governance arrangements, reducing the material burden that currently falls disproportionately on smaller firms. This should lower barriers to entry and participation in the market and give smaller firms more power to influence change.

62. The section on switching values below addresses this by providing an indication of the annual scale of the unmonetised benefits which would be required to outweigh the costs of code reform.

*More efficient and consolidated processes*

59. The enhanced responsibilities that code managers would be given under these reforms would help to facilitate change more effectively and efficiently. Enabling the code managers to propose changes to the industry codes would remove the reliance on industry or on Ofgem initiating ad-hoc Significant Code Reviews (SCRs) to deliver the changes necessary to deliver the energy transition. This can be expected to speed up the code modification process, bringing forward the benefits that code modifications can generate.

60. Further, generally under the current system any code party is allowed to introduce as many modifications as desired. However, this can often result in multiple modifications being proposed which are very similar, or proposals introduced which are non-compliant or inconsequential. This can slow down processes and result in delays to implementation, leading to foregone benefit. The reforms are expected to introduce an explicit prioritisation function, that would ensure a focus on changes most likely to deliver benefits in line with Government objectives or for consumers. This would facilitate more timely and coordinated change, increasing efficiency by reducing the sometimes significant delays arising from excessive modification proposals.

61. To illustrate the impact of the delays that could occur under the current arrangements, two case studies are provided. Case studies are used as it is not possible to quantify the industry-wide cost of delayed code changes under the current system. This is due to difficulty in quantifying the total number of code modifications with delays due solely to the current code change process, the scale of the benefits delayed, and the length of the delays.

*Case Study 1: P272*

63. The CMA Report details code modification ‘P272’[27]. This is an example of a code modification with clear principles, but which was slow to be enacted. The case study highlights that the current system of constrained self-regulation of the industry codes is likely to inhibit change when modifications are not in the financial interests of larger parties, despite being in the interest of consumers and the market as a whole.

64. Process summary: SmartestEnergy, a small electricity supplier to large industrial and commercial organisations, proposed this modification in 2011, which was approved in 2014, but was not implemented until 2017. The modification was dependent on the implementation of changes to the half-hourly distribution use of system (DUoS) charging regime being completed before April 2014. Before the modification was raised, a subcommittee of the BSC panel[28] estimated that if mandated by 2014, the modification would incur a net benefit of around £50m over the first 5 years.

65. In June 2011, a working group was set up by the BSC panel to consider P272. It carried out an industry impact assessment and held two working group assessment consultations. An alternative proposal was raised by the working group, which was identical to the original, apart from a later implementation date. On 12 January 2012, the working group stated that it was supportive of P272 but concluded that until the issues with DUoS were resolved, implementing

[27] https://www.gov.uk/cma-cases/energy-market-investigation

[28] Balancing and Settlement Code. Under the current system, code panels are responsible for managing codes.

P272 would not be viable. It therefore recommended that P272 and its alternative should be rejected.

66. In March 2012, Ofgem asked the working group to undertake further scenario modelling and provide additional information to better understand and quantify the costs and benefits associated with P272. Based on responses to two consultations, the working group delivered a cost-benefit analysis report of P272 in November 2012. This estimated that the costs would range from around £46 million to £199 million by the end of 2020 and that in the same period benefits of between £71 million and £198 million could be realised by industry.

67. The report said the wide spread of costs was due to the range of costs submitted by suppliers and, to a lesser extent, distribution businesses. The broad range of benefits was due to the uncertainty surrounding the hypotheses and the sensitivity to their assumptions in the cost benefit analysis model. Given the uncertainty surrounding costs and benefits of P272, the BSC panel made its final recommendation that P272, and its alternative, should be rejected at its meeting on 13 December 2012.

68. Following the BSC's panel recommendation to reject both proposals, Ofgem decided to undertake its own regulatory impact assessment and said, in October 2013, that it was 'minded to' approve the alternative modification. Ofgem concluded that, for those impacts it quantified, the proposal was 'broadly cost-neutral' for consumers. However, it considered that its quantitative analysis provided a conservative estimate of the cost savings for consumers, particularly those from demand side response.

69. Issues faced with P272: The modification was likely to have different commercial impacts on different players simply because of the composition of their customer portfolios. One supplier might by chance find itself with a high proportion of customers that are more expensive to serve on a half-hourly settlement basis. Additionally, the costs of the changes might be large and unevenly distributed between suppliers. Incumbents are likely to incur larger direct costs as their IT systems are older and will require major upgrades.

70. The slowing-down of the modification disadvantaged new entrants and small players, whose business models are built on providing new and innovative products, which require settlement processes based on actual data from smart meters.

71. Lessons learned: The modification was dependent on the implementation of changes to the half-hourly distribution use of system (DUoS) charging regime being completed before April 2014. As such P272 may have been proposed too early. More strategic oversight across all codes could have led to better alignment between P272 and related changes in the market and this modification may have been proposed at a more appropriate time.

72. Further along the modification process, workgroups twice recommended rejecting the modification, but Ofgem requested further modelling. This suggests Ofgem and the workgroups were working from different objectives. More alignment between Ofgem and the workgroup could have led to fewer consultations.

73. The current system of constrained self-regulation of the industry codes is likely to inhibit change when modifications are not in the financial interests of larger parties, despite being in the interest of consumers and the market as a whole.

*Case study 2: Gas Transmission Charging Review (GTCR)*

74. This case study provides an example of a series of modifications in which there are clear misaligned incentives and objectives between Ofgem and the industry parties proposing modifications. Under the current code governance system, industry parties are able to either delay modifications or put forward aspects which are self-interested.

75. Process summary: Ofgem launched the GTCR in June 2013 with a call for evidence to look at the structure of GB gas transmission charging regime. Ofgem completed the review in 2015 and concluded that fundamental changes to the charging arrangements were required to reflect the changing use of the transmission network. Ofgem asked industry to take forward its recommendations for reform alongside implementing the European network code on Gas Tariffs (TAR NC). This culminated in Uniform Network Code (UNC) modification 621 'Amendments to Gas Transmission Charging Regime' being raised. Alongside the original proposal, industry also

raised 10 alternative proposals, resulting in 11 different proposals captured under this modification (UNC621/A/B/C/D/E/F/H/J/K/L). On 20th December 2018, Ofgem rejected the modifications[29], concluding that none were compliant with TAR NC and therefore could not be implemented.

76. In May 2019, 11 new modification proposals under UNC678 were submitted to Ofgem for consideration. Ofgem approved UNC678A 'Amendments to Gas Charging Regime (Postage Stamp (PS))[30] on 28th May 2020.

77. Issues faced with UNC621: The UNC621 process was initiated based on Ofgem direction in November 2015 for industry to fundamentally reform the gas charging methodology to reflect the changing use of the system and implement new EU regulations which had to be implemented by the end of May 2019. After a lengthy industry-led process, 11 proposals were sent to Ofgem and all 11 were rejected on compliance grounds.

78. Several key issues arose with UNC621. While some aspects of the proposals had merit, the non-compliance of any aspect would render the whole proposal non-compliant. In addition, the relevant areas of compliance were arguably open to legal interpretation, resulting in industry participants strategically interpreting different legal provisions to promote commercial interests, though the legal interpretations provided were of little substance. Finally, the non-compliant aspects (e.g., creation of 'interim contracts'; 'transition period'; and 'NTS Optional Charge'), resulted from an industry-wide preference to favour proposals which protected their vested interests (either through delay or implementation of beneficial aspects), at the risk of being deemed non-compliant.

79. Issues faced with UNC678: Of the 11 proposals submitted under UNC678 in May 2019, all but two were rejected on compliance grounds. These were deemed non-compliant despite the reasons for the rejection of the UNC621 proposals being communicated and despite Ofgem stressing the importance of legal compliance. The non-compliance of 9 of the 11 proposals limited Ofgem's scope of options to two, despite extensive industry input into the remaining 9 proposals. Ofgem, however, was still required to spend considerable resource to assess all 11 proposals. Ultimately, the two compliant proposals lacked certain aspects of a charging regime which Ofgem considered of merit, but the modifications could only be approved or rejected as presented.

80. As the whole package of proposals contained in UNC678A was implemented, some areas that Ofgem had signalled as worthy pursuing in its UNC678 decision (e.g., short-haul, higher storage discounts) remained unaddressed and would be subject to future UNC mods. This resulted in a suite of "follow-on" modifications (e.g., UNC727, UNC728, UNC729). The effect has been that users of the NTS have been subject to a significant change in charging methodology between 2019-20 and 2020-21 as UNC678A was implemented, and further significant changes between 2020-21 and 2021-22, as "follow-on" modifications are implemented.

81. Lessons learned: There is no filter to prevent non-compliant modifications from being proposed, increasing the burden to Ofgem, the code administrator, and wider industry. Ofgem is also unable to incentivise industry to develop and raise proposals when deemed necessary for consumers; power is limited to instructing Gas Transporters, but this does not necessarily result in proposals of appropriate quality.

62. These case studies have been chosen to highlight the risks and potential inefficiencies that exist under current market arrangements. As highlighted by consultation response, these do not reflect all code modifications[31].

*Greater alignment with HMG strategic direction, consumer interests, and Net Zero ambitions*

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29 https://www.ofgem.gov.uk/publications-and-updates/uniform-network-code-unc-621abcdefhjkl-amendments-gas-transmission-charging-regime

30 https://www.ofgem.gov.uk/publications-and-updates/amendments-gas-transmission-charging-regime-decision-and-final-impact-assessment-unc678abcdefghij

31 For example, industry highlighted several examples of strong governance performance under current arrangements. These were CMP373, UNC0748, P379, the electricity charging SCRs, and the industry's response to the COVID pandemic

63. The proposed policy options address the current inability for Government to ensure codes are strategically aligned with overarching policy objectives in the energy sector, such as achieving Net Zero and delivering benefits to consumers. Without reform, current code processes are likely to either act as a barrier to achieving such policy goals or raise the cost of meeting them relative to intervention.

64. While tools such as the Significant Code Review (SCR)[32] have been used in the absence of alternatives for delivering strategic code change, the SCR process is heavily resource intensive and has been used sparingly as a result. Granting Ofgem new strategic functions for codes would enable industry codes to align with consumer interests and Government policy more closely, delivering, for example, decarbonisation and consumer protection objectives by proactively identifying and prioritising relevant modification changes. Ofgem could also help co-ordinate and lead cross-sector reforms, where strategic priorities are complex and cut across multiple areas of the energy system.

65. The enhanced responsibilities of the code management function is also intended to introduce an explicit role for prioritisation, ensuring a focus on the changes most likely to deliver benefits in the interest of the consumer, or on Government policy and its vision for the energy system. This would allay delays resulting from focus on modifications made with vested industry interests. This function would also increase the dynamism of the governance arrangements, and alongside a reduction in costs for industry participants, allow for faster diffusion and enable access for new, innovative technologies and markets necessary to meet Net Zero in a more timely and coordinated way.

*Lowering costs of participation for small firms*

66. Under the current system, we expect costs to fall disproportionately on smaller firms due to the high fixed cost of participation in the code modification process; small firms currently have less ability to shape the regulations which govern them.

67. This proposal is expected to strengthen the ability of all parties to compete, irrespective of size. As the CMA noted, the current framework creates significant compliance costs to industry due to the complexity of codes arrangements. The CMA considers that these costs fall disproportionately on smaller parties and hinder their ability to compete and generate innovation in the industry. As set out in the monetised costs section of this IA, code reform will lower some of the costs of participation (i.e., through reduced workgroup and consultation costs) which currently exist as part of the modification process. This should lead to greater code modification participation from small firms and greater competition in the energy industry, and in turn to lower costs to energy consumers.

68. This benefit of code reform should increase in the future as small and micro businesses are expected to play an increasing role in the delivery of a smarter, more flexible energy system.

*Enabling new market entrants and increased competition*

69. New arrangements intend to reduce the material burden of participating in governance processes and reduce the risk of large incumbent firms slowing code changes against their commercial interests, such as those enabling greater competition. Through achieving these intended outcomes, it is expected that a greater number and variety of participants will be able to participate in the codes process, allowing for modifications supportive of competition and market entry.

Switching values

70. The unquantified benefits of code reform need to amount to at least £33m per year in order for the intervention to have a BCR of 1.

71. It is likely that the majority of benefits will come from reduced delays to code modifications, as illustrated by the case studies outlined above, although other channels such as increased competitiveness within energy markets and greater alignment of strategic goals would also have

[32] The Significant Code Review (SCR) process provides a tool for Ofgem to initiate wide ranging and holistic change and to implement reform to a code-based issue. Further guidance on the SCR process can be found here https://www.ofgem.gov.uk/publications-and-updates/ofgem-guidance-launch-and-conduct-significant-code-reviews

strong effects. High-level analysis based on estimates put forward during the P272 code change process suggests that the delayed benefits of this case study only are likely to be in the millions of pounds per year. Given the overall cost of delays and the burden to society may be likely to increase in the context of Net Zero, it is expected that the aggregate impact of delays, and therefore the benefit of reducing such delays, exceeds the £33m per year required for the BCR to exceed 1.

72. Further, this proposal is pro-competition as it would enable firms to enter the market, break the dominance of larger industry players, and reduce the costs of participating in the code change process. Overall, this would likely reduce the costs to consumers through competition effects. This increased competitive pressure can also likely be expected to increase the number of bidders for competitively tendered projects, increase opportunities for output competition in the wholesale and supply markets and provide a greater incentive to innovate, all of which can be expected to reduce costs compared to the counterfactual.

## Risks and uncertainties

73. There are potential risks and uncertainties with the policy and the economic assessment. These are discussed in turn.

Potential policy risks and uncertainties

*Risk of inadequate funding to Ofgem*

74. Current Ofgem funding is determined via HMG and paid for end users energy bills. The effectiveness of Ofgem in its new strategic role is likely to be dependent on adequate funding to ensure sufficient resources are devoted to this function. In the event Ofgem does not secure sufficient funding from HMG, their performance in this new capacity may be impacted.

75. This risk was highlighted as a concern by a number of respondents to the 2021 consultation, who cited previous code modifications where Ofgem's resource constraints had slowed processes or resulted in strategic inefficiencies, such as Ofgem raising concerns late on during the code modification process[33]. This risk is intended to be mitigated by ensuring adequate funding is provided for Ofgem to deliver its new strategic role.

*Risk of delays*

76. There is a risk that the cost of implementation and delivery timelines may overrun. This could be in the form of delays to the selection of code managers delaying the system by several months. If this materialises, this could lead to foregone benefits, which has been assessed in the Sensitivities section. Work on the development of a clear and robust implementation delivery plan is intended to mitigate this risk.

*Unknown risks*

100. The energy system is undergoing a period of rapid transformation and as such, there are likely to be risks that are currently unknown. This is especially pronounced given developments surrounding the major expansion and decarbonisation of the electricity system. To mitigate this uncertainty, careful consideration will be given as to how Ofgem can be equipped and incentivised to address new challenges.

*Development of code manager function and/or governance arrangements*

101. A change in governance framework is likely to create uncertainty to affected firms which may inhibit or delay investment and strategic decisions. This may also include future development of the code manager function, which may lead to a regulatory risk and higher capital cost for investors.

## Assumptions used

102. Several simplifying assumptions are made throughout the quantified analysis. Where possible, we have used sensitivity testing to inform ranges and rounding to ensure that the broad figures

[33] These examples include modifications: CMP317 (by 5 respondents) and UNC621 (by 3 respondents). Further, consultation responses highlighted modifications P390 (by 4 respondents), UNC696 (by 2 respondents), and GC0137 (by 2 respondents).

presented are still accurate. These assumptions have had to be made to ensure meaningful analysis within possibility parameters; however, we do expect that these assumptions may present a slightly downwards bias on results.

103. When calculating the benefits of code reform to industry in savings to consultation response costs:

- Assumption 1: For the current costs to industry of responding to consultations, it is assumed that for all codes other than SEC, effort and cost are in line with CUSC, STC, and Grid Code effort and cost. This is a simplifying assumption based on available data.
- Assumption 2: For the consultation response savings rate of code reform, it is first assumed that the savings arise from modifications which are rejected or sent back no longer being proposed. We assume that all modifications of this type would not be proposed under the new arrangements, given empowered code managers would ensure from the outset that modifications are as aligned with Ofgem's strategic priorities as possible. However, these are likely to not be eliminated completely under the new arrangements. This is a simplifying modelling assumption used to aid analysis.
- Assumption 3: It is assumed that proposals which do not receive a formal response do not account for a hidden cost of industry engaging in code modifications. Along with Assumption 2, this provides the rationale for our central efficiency scenario of 20% consultation cost savings.

104. When calculating the benefits of code reform to industry in savings to workgroup participation costs:

- Assumption 4: For the current costs to industry of workgroup participation, it is assumed that, for all codes other than SEC, effort and cost are in line with CUSC, STC, and Grid Code effort and cost. This is a simplifying assumption based on available data.
- Assumption 5: It is assumed that there are an average of 4 workgroups per modification, as estimated by the CMA. We assume, based on an assumption setting workshop with Ofgem, an average of 10 participants per workgroup in our central scenario. We accept that the exact modification processes of different codes under the current system varies and these are indicative numbers. This assumption is a key focus of sensitivity testing.
- Assumption 6: For the workgroup participation savings rate of code reform, we assume that there would be 3 workgroups per modification, equating to a 25% savings rate. This is an indicative estimate as it is not possible to predict exactly how many workgroups will be needed after code reform, savings may also occur through alternate mechanisms to a reduction in the 'number' of workgroups[34] which are not formally included here. This assumption was tested through sensitivity analysis. It is assumed that code managers may still use workgroups to engage with industry over modification proposals.

105. When calculating the cost of the strategic function:

- Assumption 7: In discussion with Ofgem, we assume that carrying out its new strategic code functions would require an additional 30 FTE staff, based on Ofgem estimates. The additional cost is estimated by taking this as a share of total Ofgem costs. This is based on data from Ofgem's expenditure in February 2015, which was the latest readily available[35].

106. When estimating the costs of the additional code manager responsibilities:

- Assumption 8: It is assumed that:
    i. Estimates of Elexon's costs to carrying out code manager functions is applicable to other codes.

[34] For example, through shorter workgroups or workgroups requiring less preparatory work.

[35] As before, more recent Annual Reports do exist, however not to the same granularity required for our analysis. Comparisons at the headline level in total expenditure gives roughly similar results, and therefore we assume that using the 2015 data would still provide accurate estimates.

ii. Elexon's costs for activities considered "unique" to Elexon can be separated out from activities labelled as "code manager" by assuming costs are uniformly distributed across each activity. This is due to the granularity of available data.

iii. 30% of activities labelled as "code manager" are already carried out by either industry or code administrators. This assumption will be tested through consultation and its uncertainty is reflected in sensitivity analysis.

107. Other assumptions made:

- Assumption 9 For the cost estimates for both the set-up of Ofgem's new strategic functions, and for the additional costs for code managers, we make the following simplifying functions for analysis:

  i. We do not include any start-up costs relating to the costs of recruitment or of building up expertise.

  ii. We assume that the new employees can be accommodated within current offices and that no new office space is required.

  iii. We assume that the grade profile of the additional employees' mirrors that of Ofgem/current code administrators as a whole.

- Assumption 10: Costs are assumed equal for code administration systems, central delivery body functions and engineering standards under the new governance arrangements.
- Assumption 11: It is assumed that all costs associated with Ofgem's new strategic functions and the code manager(s) are passed through to end consumers of energy via industry participants passing through any increases in their license payments.
- Assumption 12: It is assumed for the purposes of modelling that all code managers will be established at the same time. In reality, this process is likely to take place over a period of several years, with some codes receiving a code manager towards the beginning of the transitionary period and others towards the end.

## Wider impacts

108. We have considered wider impacts on competition and consumer confidence in the market which we consider to be the most relevant ones for this analysis.

109. The wider impacts we have considered are:

- **Competition:** The current code governance approach makes sense where only small-scale changes are needed to keep the rules and systems fit for purpose, where the composition of the industry is homogenous, and interests are largely aligned. However, the significant industry change that we anticipate in the years ahead calls this model into question. New technologies, new business models, and new ways of running the energy system are emerging. These innovations may help us move to a low carbon system that is both secure and affordable. They will also be important for enabling our vision for smarter markets where consumers are more engaged and empowered. But the existing industry code governance framework may be preventing these innovative ideas from coming to fruition, especially where they require significant changes to existing arrangements, or where they are not aligned with certain industry interests. This proposal should enhance the functioning of code governance arrangements so that code changes that are considered beneficial to the market are not delayed by incumbent firms that would not directly benefit from such changes. This should have a beneficial effect on competition and lower barriers to entry in the market.
- **Price and Bill impact:** This policy intends to contribute towards reducing the costs of enabling Net Zero alongside allowing for increased competition and innovation across the energy system. These are expected to translate into reduced costs of energy price and bills out until 2050, which can be expected to support all end users of energy.

  However, these benefits are expected to accrue over the long term and are harder to pin down, whilst the direct costs of policy intervention – namely the learning and familiarisation costs involved, and costs to industry from higher charges to code managers – are borne in the near term. An internal assessment of price and bill impacts concluded that this direct temporal cost would have no significant impact on end consumers bills, with a bill impact for this cost is estimated at below £1 per year across all sensitivities tested. The long term benefits to consumers are therefore expected to outweigh this effect.

- **Environmental:** The delivery risk associated with achieving the UK's Carbon Budgets and Net Zero is reduced through policy intervention helping to enable timelier and cost-effective decisions to be made across the energy system.
- **Ensuring safe operation and security of supply:** The proposals will ensure that the codes can continue to work effectively, while seeking to improve and strengthen the code regime by ensuring the codes work better for all parties involved, especially for those that will see an increased ability to propose modifications to arrangements. Respondents to the 2021 consultation noted that having more effective codes would ensure safer operation within the energy market, and bolster security of supply through clearer and more appropriate technical standards for a high renewable energy system.

Statutory Equality Impact

110. We do not expect any direct impact on the Convention Rights of any person or class of persons arising from the measures assessed in this IA. Our view is that there would be no impact on race, disability, gender or any other protected characteristic from any of the measures in this IA. These regulations will not target persons but companies in scope. In addition, these regulations will be of general benefit to everyone in the UK, regardless of whether they have one or more protected characteristics.

111. Similarly, we do not expect any direct impact given our analysis of potential price and bill impacts was found to have no significant impact on annual bills.

Justice Impact Test

112. This intervention does not expect to impact on the justice system. An internal assessment of the measures taken found it was unlikely that Code Reform would result in any implication on the justice system.

Human Rights Impact Test

113. We note that the power for Ofgem to make direct changes to codes potentially impacts on the property rights of code parties and others as it is effectively a statutory requirement to change a private law contract (albeit one which is linked to licence conditions). Ofgem will also be granted transitionary powers to modify codes, licences and contracts for the purposes of implementing code reform, in addition to the power to establish transfer schemes to set up the new code managers. We intend to mitigate this by ensuring a fair price is paid for property that is impacted, as well as by building robust checks and balances into the required enabling legislation.

## Distributional effects

119. An assessment of the distributional impacts across groups and time is detailed in Table 6. Impacts on business are then considered in more detail in the following sections, splitting out the overall impact to business and the impact on small and micro businesses.

*Table 64: Distribution of impacts over groups and time*

| Group | Costs | Benefits | Time-horizon for costs and benefits[36] |
|---|---|---|---|
| **HMG** | Internal costs of Codes Reform project<br><br>Learning and familiarisation costs | Greater strategic alignment of energy sector | Internal costs of code reform expected to occur 2021-2023<br><br>Benefits and familiarisation costs begin in 2024 |

[36] Implementation timelines are subject to Parliament passing the necessary primary legislation.

| | | | |
|---|---|---|---|
| | | More flexible, responsive, and innovative energy system. | |
| **Ofgem** | Cost of new strategic functions (central estimate of around £2m per year)<br><br>Internal resource to participate in Codes Reforms project<br><br>Learning and familiarisation costs | Greater strategic alignment of energy sector<br><br>More flexible, responsive, and innovative energy system. | Internal costs to Ofgem begin in 2023 with additional costs of operating the strategic code functions beginning 2023.<br><br>Benefits are expected to begin in 2024. |
| **Code Administrators** | Cost of code manager responsibilities<br><br>Internal costs of participating in code reform project.<br><br>Learning and familiarisation costs | Reduced workgroup costs<br><br>Reduced consultation costs<br><br>Greater control over code administered. | All benefits will begin in 2024.<br><br>Costs of code management activities are assumed to begin in 2024. |
| **Industry (***Generation, transmission, distribution, supply firms***)** | Increased fees to code administrators<br><br>Internal costs of participating in code reform project.<br><br>Learning and familiarisation costs | Reduced workgroup and consultation costs<br><br>Reduced requirement to carry out code manager responsibilities.<br><br>Faster codes process increasing market flexibility.<br><br>Reduced barriers to participating in code modification process. | All benefits will begin in 2024.<br><br>Costs may begin in 2023 when Ofgem's new strategic functions come online, which will be funnelled down to industry. Other costs will begin in 2024. |
| **SME energy firms** | Increased fees to code administrators<br><br>Learning and familiarisation costs | Reduced barriers to participating in code modification process.<br><br>Reduced requirement to carry out code manager responsibilities.<br><br>Faster codes process increasing market flexibility.<br><br>Reduced workgroup and consultation costs | All costs and benefits will begin in 2024.<br><br>Costs may begin in 2023 when Ofgem's new strategic functions come online, which will be funnelled down to industry. Other costs will begin in 2024. |
| **Energy end users (***Industrial and household consumers***)** | Costs per annum estimated as minimal | Increased number of code modifications prioritising consumer interests.<br><br>Reduced energy bills relative to baseline in long-run. | Benefits may begin to accrue from 2024. |

120. Table 7 illustrates the distribution of costs and benefits from monetised analysis. Costs of code manager functions and setting up the strategic code functions within Ofgem are highlighted in (a) and (c). These are expected to be passed on to end users of energy, which as discussed above is not expected to result in a material impact on end user bills, including both business and consumers. As a result, only the monetised benefit to code parties in (b), via reduced consultation and workgroup costs, is expected to accrue to business. Analysis also assumes a transfer of costs for code management activities currently carried out by code parties, that under new governance arrangements, will instead be carried out by code managers. This results in

an additional benefit to code parties; however these are not included below due to uncertainty as to what proportion of code management activities are currently carried out by code parties.

121. As noted throughout this IA, these monetised benefits only capture peripheral benefits of policy intervention. It is expected that unmonetized benefits will benefit the system as a whole alongside end consumers.

*Table 75: Distribution of total monetised impacts of Code Reform (£m) (2020£, 2022 discounting perspective, 12-year horizon)*

| Scenario | (a) Monetised Code Manager costs to pass on | (b) Monetised benefit to code parties | (c) Monetised costs to Ofgem to pass on | (d) Monetised costs passed through to energy end users (a) + (c) |
|---|---|---|---|---|
| **Low** | 435 | 3 | 26 | 460 |
| **Central** | **280** | **15** | **16** | **300** |
| **High** | 160 | 32 | 12 | 175 |

*Figures rounded to nearest 10m for costs above 50m, to nearest 1m for costs below*

## Business Impact Assessment

122. BEIS considers these measures to be pro-competition and therefore to fall out of scope of business impacts. According to the Better Regulation manual[37], a regulatory measure needs to satisfy four conditions in order to be considered to promote competition. In the following section we list the four conditions and provide a comment for each of them to explain how the proposed measures meet them.

a) *The measure is expected to increase, either directly or indirectly, the number or range of sustainable suppliers; to strengthen the ability of suppliers to compete; or to increase suppliers' incentives to compete vigorously.*

**Comment**: The measures are expected to strengthen the ability of all industry parties to compete. As the CMA noted, the current framework creates significant compliance costs to industry due to the complexity of codes arrangements. The CMA considers that these costs fall disproportionately on smaller parties and hinder their ability to compete and generate innovation in the industry. The measures proposed would simplify the code governance arrangements, strengthening the ability of all parties (in particular smaller firms) to engage in the code modification process, and along with more efficient processes that reduce the material burden arising from consultation and workgroup costs, allow these smaller firms to compete more effectively in the industry. The proposals will also mean that code parties will no longer have to bear the cost of responsibilities due to be transferred to code managers.

Businesses may also incur costs from learning and familiarisation to the new code management arrangements, as well as higher incurred costs through increased charges designated for the increased costs for code management. However, it is expected that all costs incurred can be passed onto energy end consumers[38]. As a result, we do not expect code reform to have an indirect cost on wider industry.

Overall, we would expect the small familiarisation costs (likely not incurred by business) to be outweighed by ongoing benefits from lower costs of interacting with the codes, strengthening code parties' ability to participate and compete. Table 7 above outlines estimates for code parties of benefits ranging from £3 million to £32 million per year, due to reduced responsibilities and savings from costs of consultation and workgroup participation.

b) *The net impact of the measure is expected to be an increase in [effective] competition (i.e. if a policy fulfils one of the criteria at (a) but results in a weakened position against another) and the overall result is to improve competition.*

**Comment**: The policy is likely to have positive impacts on all criteria listed under a), although the evidence described above is considered to be the most relevant and most likely to materialise in this context, given

[37] https://www.gov.uk/government/publications/better-regulation-framework

[38] For end consumers of energy, the price and bills impact finds that these costs will be marginal and have no material impact on final energy bills.

the current arrangements disproportionately affect small firms more, harming competition. With regards to other criteria, by making the market more transparent and enabling the timely and effective introduction of policy changes that meet BEIS and Ofgem's strategic objectives, the policy should increase incumbent firms' incentives to compete, particularly smaller players who would benefit more than larger players from increased pro-competitive changes to codes. More streamlined code governance arrangements could also have an impact on barriers to entry in the market, as operating in the industry might be perceived as less complex by potential new entrants, possibly leading to an increase in the number of firms competing in the market.

Further, the current system also favours larger firms, as it is based upon an arrangement where only small-scale changes are needed to keep the rules fit for purpose, where the composition of the industry is homogenous, and interests are largely aligned. Given the shift to a more diverse market, smaller firms are currently left with disproportionately low levels of power and influence, especially given the resources required to participate negatively affects smaller firms more. This measure would allow smaller firms to more easily bring forward and expediate code modifications that are considered a benefit to themselves, or the wider market, without fear of processes being delayed by incumbent firms that would not directly benefit from such changes. Therefore, this proposal would allow the smaller suppliers within the existing market to more effectively participate in market, and align it with a more holistic view of objectives and incentives – increasing competition by allowing small firms to more effectively compete in the future.

c) *Promoting competition is a core purpose of the measure.*

**Comment**: The CMA has found that the existing code governance arrangements prevent the effective implementation of code modifications that would promote competition, as well as place a large administrative material burden disproportionately upon smaller firms. The proposed package will enable modifications to industry codes to happen quicker, and more in line with the entire market's objectives and incentives. This should allow for greater competition as barriers to entry and participation for small firms are reduced, and enable markets to cope with new technologies, new business models and emerging ways of running the energy system. These innovations are important for enabling our vision for smarter markets where consumers are more engaged and empowered, which is in the interest of both consumers and competition.

d) *It is reasonable to expect a net social benefit from the measure (i.e. benefits to outweigh costs), even where all the impacts may not be monetised*

**Comment**: As discussed in the previous section on overall impact, it is expected that the administrative costs of changing the governance system are less than the benefits of the code modifications these changes will enable. The proposed reform will enable the timely implementation of policy changes in line with BEIS's strategic objectives, providing benefits to society such as reducing the time for innovation within the market, expediting the move to a low carbon system that is both secure and affordable. Further, a greater strategic vision in line with BEIS and Ofgem objectives will also ensure that the incentives in the market are aligned with those of the Government's, allowing for the prioritisation of modifications that are in the interest of consumers, as well as those that enable more rapid implementation of new, innovative technologies required to meet Net Zero. This in turn also helps consumers and the wider public, as the decarbonisation process is sped up, and the deadweight loss involved with the current slow governance arrangements is removed.

## Impact on small and micro businesses (SaMBA)

119. BEIS's Business Population Estimates[39] provide the combined number of employers in the 'Electric power generation, transmission and distribution' and the 'Manufacture of gas; distribution of gaseous fuels through mains' sectors. In 2020 there were 2,060 micro businesses in the electricity sector and 55 in the gas sector. There were 415 small businesses in the electricity sector and 15 in the gas sector. There has been a particularly large increase in the number of micro and small businesses in the electricity sector since 2013 – around a 300% increase in the number of micro and small firms, compared to rises of around 175% and 65% for medium and large businesses' respectively. These figures show that micro and small businesses already play an important and significant role in the electricity sectors, which will be

[39] https://www.gov.uk/government/statistics/business-population-estimates-2020

expected to increase further in the future, as more decentralised systems allow for a greater degree of small-scale generation.

120. For gas, the role of micro and small firms appears more stable with no rise in the number of small firms and about a 50% increase in the number of micro firms, roughly comparable to the 100% increase in the number of large firms.

*Table 86: Number of employers in the private sector, Electric power generation, transmission and distribution industry group, UK, beginning of 2020*[40]

| | **Firms (*number*)** | **Employment (*'000s*)** | **Turnover (*£m*)** | **Firms (%)** | **Employment (%)** | **Growth in firms since 2013** |
|---|---|---|---|---|---|---|
| **All employers** | 2,555 | 101 | 101,065 | *100.0* | *100.0* | 296% |
| **Micro (1 - 9 employees)** | 2,060 | 8 | 6,898 | *80.6* | *7.9* | 308% |
| **Small (10 - 49 employees)** | 415 | 6 | * | *16.2* | *5.9* | 295% |
| **Medium (50 - 249 employees)** | 55 | 6 | * | *2.2* | *5.9* | 175% |
| **Large (250+ employees)** | 25 | 82 | 85,319 | *1.0* | *81.2* | 67% |

*Key: * - denotes to unavailable data*

*Table 97: Number of employers in the private sector, Manufacture of gas; distribution of gaseous fuels through mains, UK, beginning of 2020*[41]

| | **Firms (*number*)** | **Employment (*'000s*)** | **Turnover (*£m*)** | **Firms (%)** | **Employment (%)** | **Growth in firms since 2013** |
|---|---|---|---|---|---|---|
| **All employers** | 85 | 44 | 40,845 | *100.0* | *100.0* | 42% |
| **Micro (1 - 9 employees)** | 55 | * | * | *64.7* | * | 57% |
| **Small (10 - 49 employees)** | 15 | 0 | * | *17.6* | *0.0* | 0% |
| **Medium (50 - 249 employees)** | 5 | * | 1,229 | *5.9* | * | 0% |
| **Large (250+ employees)** | 10 | * | * | *11.8* | * | 100% |

*Key: * - denotes to unavailable data*

121. All parties in these sectors face the cost of monitoring changes in Government policy, regulation, and industry code developments. While this regulatory environment is a cost of doing business applicable to all parties, the fixed costs of compliance are more of a burden for new entrants and smaller parties with smaller customer bases over which to spread these costs. Further costs are involved if a supplier wishes to try to influence any such changes. The CMA's evidence found that smaller parties did not have the resources to be involved in every modification or even to suggest modifications themselves[42].

122. Beyond small businesses already participating in the sector, there could also be small innovative companies who are finding it difficult to enter the sector due to the complexity of the codes or the codes' inability to keep up with innovation. In the first two and a half years of Ofgem's innovation hub, the scheme engaged with 274 innovators seeking to understand the regulatory implications of their propositions. Of these, Ofgem gave substantive support to 81 businesses looking to innovate in the electricity retail and flexibility markets. Of the 81, 36 (44%) sought feedback that covered code requirements. This demonstrates that codes are an important issue

[40] https://www.gov.uk/government/statistics/business-population-estimates-2020

[41] https://www.gov.uk/government/statistics/business-population-estimates-2020

[42] See CMA working paper on Codes: https://assets.publishing.service.gov.uk/media/54f730f140f0b61407000003/Codes.pdf

for innovators. These figures are the lower bound of the number of affected organisations; there may be other innovators facing issues with code requirements who have not been in contact with Ofgem and, of those who were in contact, code requirements may have become material considerations in later stages of their development.

123. Further, research by Xoserve found that the raising of modification proposals and participation in Workgroups is still dominated by the larger organisations in the energy industry. Across all Codes, "Modification Proposals are most commonly raised by Supplier / Shipper organisations (39%) and by Network businesses (including the TO/SO functions) (32%)"[43]. Workgroup participation is also "most prevalent amongst the 'Big 6' Supplier / Shipper organisations, who have attended an average of 51% of all Workgroup meetings"[44]. This shows that micro and small firms still have relatively little power to influence and enact change in line with their objective within the system.

*Effect of this proposal*

124. Costs directly attributable to policy reform and borne by small and micro businesses within the energy sector are the learning and familiarisation costs associated with understanding the new governance process. Under paragraph 59, we assume that these learning and familiarisation costs could accrue to around £1,200 to £2,400 per company at minimum. Given that familiarisation costs are inevitable with any new measures, it is not possible that micro and small firms could be exempted from these costs. However, we expect these familiarisation costs to be transitionary costs, passed down to end consumers (again, with marginal material impact on energy bills), and therefore do not expect these costs to be incurred by micro and small businesses.

125. Small and Micro firms may also face an increase in industry charges due to the new costs associated with the creation of Ofgem's new strategic functions and the new code manager(s). However, it is expected that these costs will be able to be passed through to customers and eventually to the energy bills of energy end consumers and therefore not impact on these firms. Moreover, in most instances, industry charges are proportional to the size of firm, mitigating the impact of any increase in industry charges under scenarios in which costs are not able to be passed through to their customers. It is also not anticipated that this cost pass through of industry charges will significantly increase the cost of energy bills, minimising any potential impact on small and micro businesses outside of the energy sector.

126. There are also a large number of benefits that may accrue to small and micro businesses as a result of code reform. Rationalising and simplifying the codes should lead to lower ongoing administrative burden for businesses in terms of understanding and ensuring compliance with the codes. The introduction of Ofgem's strategic code functions and the move away from industry control should ensure the timely delivery of modifications to industry codes that generate wider benefits to the market, even if they do not directly benefit large, incumbent industry participants individually. Therefore, the material burdens overall will be reduced, removing a significant barrier to participation for micro and small firms, while Ofgem's new strategic function will allow them to have more power and influence in processes, enabling them to enact more change in the system. Table 7 above shows that these code parties could see benefits ranging from £3 million to £32 million per year.

127. Overall, we would expect the small familiarisation costs (likely not incurred by business) to be outweighed by ongoing benefits from lower costs of interacting with the codes, and the code changes that the proposals enable should progress quicker, to help level the playing field for smaller businesses.

## Monitoring and Evaluation

128. This impact assessment outlines how we intend to use monitoring and evaluation (M&E) to inform this policy intervention alongside the likely data requirements and approach we expect to take.

[43] Included in Xoserve's consultation responses to the previous IA.

[44] Ibid.

Policy Objectives

129. Policy intervention intends to achieve the objectives established through consultation and as set out above, in paragraph 17. Ensuring that these objectives can be interpreted in a SMART[45] manner is important for enabling effective M&E. However, Energy Code Reform is a market-enabling policy which intends to help the energy system achieve Net Zero out to 2050 at least cost. As such, there is no clear 'completion date' by which we expect objectives to have been fully realised. This makes it difficult to reflect the objectives of policy intervention in a time-bound and measurable manner.

130. As a result, a series of sub-objectives which are more time-bound and measurable in mature have been developed to track progress against each of our overall objectives. Time periods considered for these sub-objectives come from discussions with BEIS and Ofgem, dictated by both the date at which we expect to observe early signs of our policy to come into effect and when monitoring results may be informative to future decisions.

131. These sub-objectives are mapped out against overarching policy objectives in Table 10 and are compared to our 'do nothing' baseline. They represent an attempt to rework the objectives into smaller components which are SMART. They do not represent an exhaustive list of all possible sub-objectives related to the policy objectives. Therefore, in tandem with the achievement of these sub-objectives, the performance of Codes Reform is expected to be assessed through monitoring whether outcomes aligned with the intentions of Code Reform are observed in the market.

*Table 108: Policy objectives of Energy Code Reform and supporting sub-objectives*

| Policy Objective | Supporting Sub-Objectives |
|---|---|
| **Objective 1:** Code governance should be forward-looking, informed by and in line with the government's ambition and the path to Net Zero emissions, and ensure that codes develop in a way that benefits existing and future energy consumers. | 1. An annual strategic direction which takes into account government policy and wider industry developments should be developed from within 12 months of the strategic body being established.<br>2. Code managers should subsequently develop annual delivery plans aligned to the published strategic direction and manage the code change process to enable their delivery. |
| **Objective 2:** The reformed energy code framework should be able to accommodate a large and growing number of market participants and ensure effective compliance. | 1. The total number of market participants, given by the total number of code parties across all codes, should begin to increase within 12 to 24 months before levelling out[46].<br>2. Code managers should have sufficient regulatory capacity to fulfil code management duties despite the large number of market participants.<br>3. The compliance framework should remain as or more effective, both in terms of level of compliance and time taken to enforce compliance.<br>We expect impacts for sub-objectives are likely to be observable from 1-2 years following implementation, with impacts continuing on an ongoing basis. |
| **Objective 3:** The reformed energy code framework should be agile and responsive to | 1. The code change process should be efficient and effective, with the average time taken for code changes decreasing |

[45] Specific, Measurable, Achievable, Realistic and Timebound

[46] It is noted that this indicator is sensitive to external factors such as market shocks. However, we aim to compare each indicator to a relative to our 'do nothing' baseline, where it is assumed the external factors would still impact on energy firms.

| | |
|---|---|
| change whilst able to reflect the commercial interests of different market participants to the extent that this benefits competition and consumers. | across all types of code change within 12 to 24 months of implementation.<br>2. There should be an increase in the number and type of different code parties proposing code changes.<br>We expect measurable impact across both sub-objectives from 1-2 years after the new framework is in place, following a transition to code managers. |
| **Objective 4:** The reformed energy code framework should make it easier for any market participant to identify the rules that apply to them and understand what they mean, so that new and existing industry parties can innovate to the benefit of energy consumers. | 1. Code consolidation is delivered.<br>2. Code managers should be empowered to carry out an enhanced set of roles supporting accessibility[47], transferring complexity and burden away from individual code parties within 6 months of appointment.<br>3. Code managers should facilitate all code parties' understanding of the code and related processes, taking a role to educate code parties. This role should be taken from the outset of appointment. |

Theory of Change

132. The theory of change for how policy intervention intends to achieve objectives 1 to 4 is set out in annex 2, in **Error! Reference source not found.**, with objectives denoted D8 to D11. This mapping emphasises which outcomes contribute to which objectives through the inclusion of bracketed text in bold, illustrating which objective is being contributed to. This is in addition to the arrows included throughout the mapping.

133. The achievement of the impacts in the theory of change is dependent on a number of assumptions linking actions, outputs, and outcomes in **Error! Reference source not found.Error! Reference source not found.** above. These assumptions relate to external factors, outside the control of policy intervention, however likely to influence results. For example, the recent rise in gas prices and its impact on the number of energy suppliers in the system. Internal to government, this includes ensuring there is adequate resourcing across Ofgem and BEIS and available parliamentary time to deliver on actions according to timelines. More widely, it is also assumed that market participants are adequately equipped to participate in the code change process, including the correct resourcing and expertise. It is also assumed that the wider market environment allows for actions listed to take place. For example, for actions such as 'B6: Appointment and licencing of CMs', it is assumed that there is a sufficiently competitive market to support tendering.

134. The need for adequate skills, resourcing and time across government, code managers and code parties is a continued need across actions, outputs and outcomes contributing towards the achievement of objectives. It is also assumed that policy intervention will work as intended and the new arrangements will result in the achievement of objectives whilst not also producing any unintended consequences. The impact of wider contextual arrangements such as the rate of power sector decarbonisation, the emergence of new technologies and the existence of new bodies such as the FSO will also need to be considered.

Aims of Monitoring and Evaluation

[47] For example, improving the ability for code parties to navigate the websites of code managers.

135. Ensuring that the governance of the energy system is fit for purpose is crucial to the achievement of Net Zero, whilst ensuring security of supply and universal access to affordable energy. This creates two key objectives for M&E:

136. **Aim 1: To provide clear, impartial and robust evidence to demonstrate the intervention's impact or wider outcomes:** It is important that robust M&E is available in a timely manner in order to help ensure that governance arrangements are fit for purpose and highlight where additional action may be required. This need for M&E is heightened by the uncertainties and assumptions illustrated of the future state of the world and energy system needs, illustrated in the narrative supporting our theory of change above.

137. **Aim 2: To provide useful and timely learning about the roll-out and performance of the code reform:** This policy intends to leverage M&E to highlight early signs of both good and poor performance in both the process of delivering code reform and subsequent performance of governance arrangements in achieving policy objectives.

138. In the event that M&E highlights shortcomings in the delivery of code reform, evidence may then inform decisions on how these shortcomings may be appropriately addressed. In all eventualities, evidence provides learning useful for other wide scale governance reform projects and helps ensure BEIS is accountable to policy customers and tax-payers.

<u>Monitoring and data requirements</u>

139. At this stage, we anticipate that monitoring the performance of policy intervention in achieving its objectives and attached sub-objectives will be informative of overall performance however only partly able to provide the evidence required to draw conclusions on the effectiveness of intervention. More complete conclusions will be dependent on evaluation of the policy, detailed below.

140. To assess the performance of this policy intervention against the four policy objectives listed above and their attached sub-objectives, it is likely that a mix of quantitative and qualitative indicators will be required, some of which may require additional data collection. Finalised indicators are still being developed therefore this section provides a discussion of potential indicators.

141. For policy objective 1, and attached sub-objectives, measurement of performance is likely to rely on the perceptions of industry participants, government, and regulators. Measuring the number of code modifications that are developed and then subsequently rejected may also provide an indication of the forward-looking strategic alignment of code governance, with fewer code modifications rejected by Ofgem suggesting greater strategic alignment. Sub-objective 2 may be captured via monitoring whether or not annual delivery plans have come forward from each code manager.

142. For policy objective 2, and attached sub-objectives, it is likely that quantitative measurements on the 'number of market participants' and 'number of enforcement actions taken' is likely to indicate the performance of sub-objectives 1 and 3 respectively. Sub-objective 2 is likely to rely on more qualitative approaches such as via survey or interview methods.

143. For policy objective 3, the responsiveness of codes to changing market needs could be informed by a mix of qualitative and quantitative measures. Quantitatively, measuring the average time of code modifications is likely to capture sub-objective 1 whilst sub-objective 2 is likely to be well captured via monitoring the number and type of code party proposing code changes.

144. For policy objective 4, the accessibility of the market is likely to be measurable using both quantitative and qualitative indicators. For sub-objective 1, monitoring the progress of code consolidation will be dependent on agreeing what a finalised set of consolidated codes will look like. For sub-objective 2, indicators such as 'number of roles carried out by the code manager' may be informative of success however it is likely that code parties will need to be surveyed to

understand whether these additional roles have removed complexity away from individual code parties. Similarly, sub-objective 3 may be informed by indicators such as 'number of educational events hosted by code managers', but survey data will likely be required on how impactful actions to educate code parties have been. More widely, additional indicators may include the number of market entrants, velocity of entry and exit dynamics or estimating costs for market entry and participation in code reform procedures.

145. Across all four policy outcomes, it is difficult to assess the timelines over which the performance of the policy should be measured. It is likely that benefits from each outcome should begin to accrue shortly after the policy option is implemented and operable, with listed sub-objectives detailing the earliest dates we expect potential impacts to materialise.

Evaluating performance

146. To provide a full understanding of policy intervention, and, given the difficulties in effectively monitoring the performance of intervention on an ongoing basis, it is deemed proportional to carry out two evaluations; a lighter-touch process evaluation at the time of implementation[48] followed by a value-for-money performance evaluation 5 years following implementation, when it is expected there will be sufficient experience of the new governance arrangements to assess their performance and desirability.

Process evaluation (expected 2027):

147. We intend to conduct a process evaluation around 2027, when the implementation of Ofgem's new strategic code functions, and at least some code managers, have been completed. This process evaluation would focus on understanding how implementation arrangements have performed in establishing new energy code governance arrangements and assess how the theory of change, and its underpinning assumptions may be updated in light of new evidence.

148. Thematic questions this evaluation will look to address are:

a) Was the reform to energy codes governance structure delivered as intended? What lessons can be learned from implementation?
   i. Were timelines realistic?
   ii. Were there any unexpected or unintended issues in the delivery of the intervention?
   iii. Was security and stability maintained during the transition?
   iv. Did the change create regulatory uncertainty for investors?

b) Is the theory of change still reflective of our policy intervention? How have wider contextual factors or unforeseen dependencies influenced our understanding of the intervention?
   i. Is the governance structure still equipped with the right skills, roles and resources to meet our objectives in light of this new information?
   ii. Has the development of wider factors influenced the requirements of this policy intervention to meet its objectives? These factors could include the number and characteristics of code parties, the implementation of the FSO and the development of code simplification.

149. Evidence from this process evaluation intends to provide early signs on whether this policy intervention is on track to meet objectives and sufficient to meet the needs of power sector decarbonisation and Net Zero more broadly.

Impact and value-for-money evaluation (expected 2032):

150. We plan to carry out an evaluation of the implementation's impact and value for money however in order to do this we need to allow some time for the changes to be established. As described

[48] Measured as the point by which all code managers are in place.

above we will carry out monitoring and a process evaluation early on and expect this to be followed by an impact evaluation 5 years following the process evaluation, when we expect most or all code managers to be in place and significant experience with the new governance process. This timeline for evaluation is chosen to balance an early date, where sufficient experience with the new governance structure enables strong evidence to be drawn, whilst also enabling timely evidence to correct for any shortcomings that may be slowing down or, adding complexity to achieving Net Zero.

151. Thematic questions this evaluation will look to address are:

a) Did delivering energy code reform achieve the expected outcomes and objectives of intervention? To what extent are these attributable to this policy intervention?
b) How cost-effective was the intervention to energy code reform? Have different groups been affected in different ways, how, why, and in what circumstances?
c) Are governance arrangements fit for purpose into the future? Does the emergence of unintended consequences, new energy system challenges or wider contextual factors require reform to current arrangements?

    i. Does the governance structure provide the correct roles and responsibilities? Are these carried out by the correct bodies?
    ii. How can governance structure account for new challenges to better achieve the objectives of intervention?

Approach to evaluation and additional data requirements

152. We anticipate that the evaluations will be theory-based and incorporate evidence from qualitative and quantitative sources, using a range of expert interviews alongside surveys to capture the views of relevant parties across the energy system, ensuring a sufficient range of relevant parties are reflected. This approach is preferred due to both the highly bespoke nature of GB energy code governance arrangements and the pace of whole system change in the energy sector making it difficult to establish a counterfactual by which experimental or quasi-experimental approaches to evaluation could be compared. Similarly, the multitude of interdependencies and supporting policy interventions in the energy sector makes it difficult for quantitative analysis to identify the causal impacts of this intervention. Additionally, the energy code governance arrangements being universally applied to all sector participants, results in no valid control group for other quantitative methods of evaluation such as difference in differences or randomised control trials.

153. For the above reasons we do not anticipate a need for further monitoring data requirements in future years, however the evaluations themselves will likely collect further data. We do however expect that data collected as part of the monitoring framework will be informative of evaluation.

## Justification of Preferred Option

154. The 2021 consultation on energy code reform presented two options for delivering code reform that were compared to our 'do nothing' counterfactual. Option 1 created a strategic body function within Ofgem, whilst delegated code managers carried out an enhanced set of responsibilities. Option 2 merged these functions into one IRMB, which would ensure both the strategic direction and delivery of the code manager responsibilities was carried out.

155. The 2021 consultation stage IA published alongside consultation concluded support for Option 1. This IA concluded that the magnitude of annual impacts was likely to be similar under both options, with both preferable to the 'do nothing' counterfactual, however the shorter implementation timelines and reduced complexity of Option 1 provided a clear basis for its preference over Option 2. This support for Option 1 was also reflected throughout consultation

responses, where no respondent preferred Option 2 over Option 1. Therefore, this final stage IA considered only Option 1 in analysis.

156. We conclude that Option 1 can be expected to have an overall positive impact relative to our ‘do nothing’ counterfactual, despite the negative NPV of quantified analysis, estimated at -£16m in our central scenario over a 12-year time horizon. Including potential secondary impacts results in a total illustrative NPV of -£280m. When considering non-monetised analysis in tandem, the potential benefits of a more efficient, agile and pro-competitive codes process aligned with governments strategic direction is deemed likely to outweigh costs. This view was broadly supported by consultation respondents.

157. Option 1 is also not expected to result in significant distributional concerns. We expect the major costs of delivering the new strategic code functions by Ofgem and the enhanced roles and responsibilities of code managers will be passed through to end users of energy via energy bill. These costs were considered to have only a small impact on energy bills estimated at below £1 across all scenarios and sensitivities considered.

## Annex 1

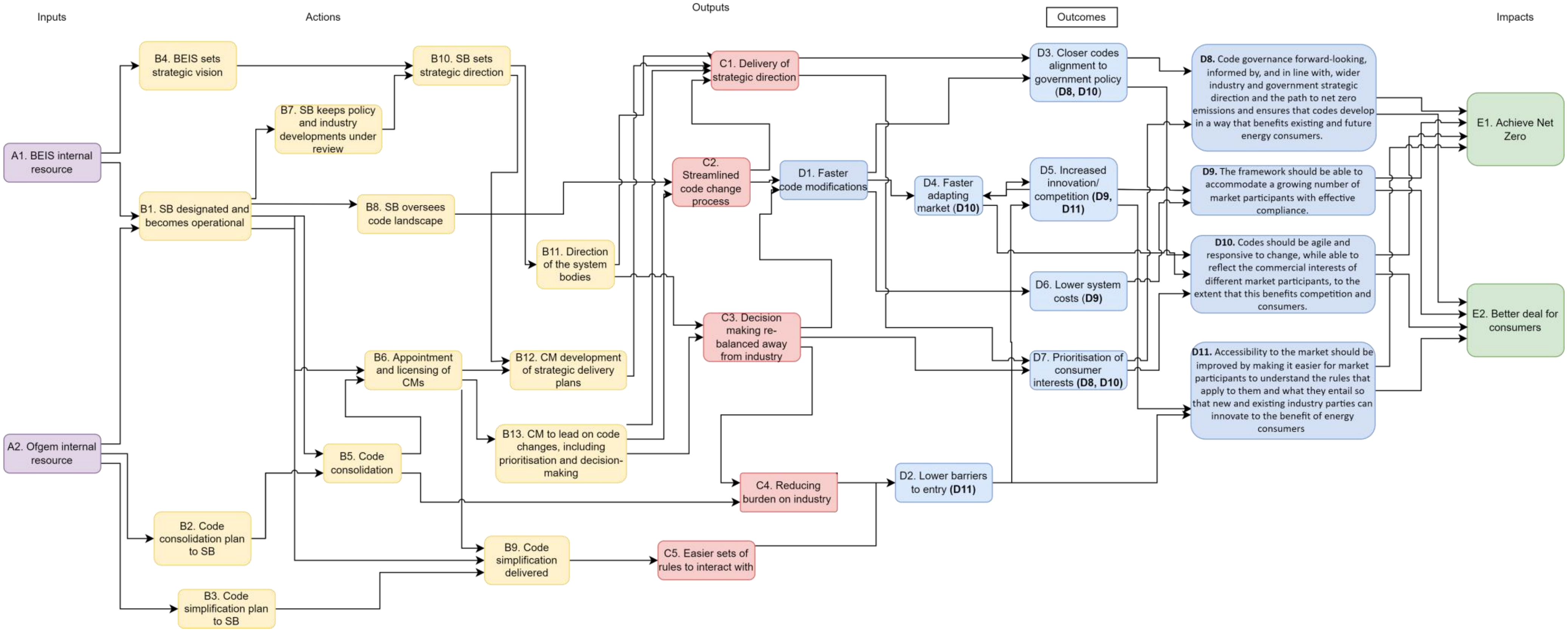
*Table 119: Scenarios to test assumptions*

| Calculation | Parameter | Low-cost scenario | Central estimate | High-cost scenario | Description of assumption scenarios |
|---|---|---|---|---|---|
| **Consultation cost savings** | Code reform efficiency savings | 50% | 20% | 10% | Low: Based on the proportion of code modifications rejected by Ofgem in 2018-2019 (~9%). Central: assumes low does not capture all efficiency gains, doubling estimate to appreciate wider gains from intervention (i.e., incorporates the hidden cost of consultations such as internal resource to develop and review proposals). High: extends this central by assuming a higher unhidden (i.e., send-backs) and hidden cost due to the increasing complexity of energy system in future years. |
| **Consultation cost savings** | Cost per industry participant | increased by 50% | as given | halved | Illustrative +-50% to provide a range. |
| **Workgroup costs savings** | Participants per workgroup | 12 | 10 | 8 | Range of +-2 |
| **Workgroup costs savings** | Efficiency savings (i.e. reduced workgroup requirements) | 25% | 25% | 13% | Central and high scenario assumes number of workgroups required per modification falls from 4 to 3, low assumes fall from 4 to 3.5. Based on discussions with Ofgem, first workgroup consists of preparatory work that is expected to be carried out by enhanced code manager functions. |
| **Workgroup costs savings** | Cost per industry participant | increased by 50% | as given | halved | Illustrative +-50% to provide a range. |
| **Cost to code administrators of taking on code manager functions** | Code management multiplier | Costs of code management functions are 20% lower for other code administrators than Elexon. 50% of code management activities currently carried out by industry or code administrators. | Costs of code management functions are the same for other code administrators as Elexon. 30% of code management activities currently carried out by industry or code administrators. | Costs of code management functions are 20% higher for other code administrators than Elexon. 10% of code management activities currently carried out by industry or code administrators. | Discussed in detail under sensitivities. Key assumption of quantified analysis. |
| **Option 1 - Cost to Ofgem's new** | Ofgem's strategic code functions: number of employees | 20 | 30 | 45 | Central estimate based on discussion with Ofgem. High assumes fewer staff needed by 33%, low assumes 50% increase in staff. Asymmetric due to expected lower bound of staff feasible to deliver function but no upper. |

| | | | | | |
|---|---|---|---|---|---|
| **strategic code functions** | | | | | |

## Annex 2

*Figure 1: Energy Code Reform theory of change*[1]

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[1] Within Figure 3, 'SB' refers to Ofgem and its planned new strategic code functions for simplicity.

| | |
|---|---|
| **Title:** OTNR – Multi-Purpose Interconnectors IA<br>**IA No:** BEIS037(F)-22-ESNM<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** offshore.coordination@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| > −£0.1m | > −£0.1m | < £0.1m | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

Interconnectors are used to convey electricity between GB and other jurisdictions, and multi-purpose interconnectors (MPIs) combine traditional interconnector functionality with the transmission of electricity from offshore generation. However, existing legislation was not designed for the multi-functional nature of MPIs as they are a new type of asset. This presents challenges to how their activities should be licenced, creating legal uncertainty which could be a barrier to the development of MPI projects. MPIs are expected to help reach net zero since interconnection helps integrate renewable electricity onto the grid and MPIs can help coordinate offshore transmission networks, reducing the amount of offshore transmission assets required.

**What are the policy objectives of the action or intervention and the intended effects?**

The objective of the intervention is to improve legal clarity for MPIs by introducing a new licensable activity specific to MPIs within the existing regulatory regime. The Electricity Act 1989 regulates electricity assets based on their licensable activity, with the existing legislation treating interconnectors and transmission systems as separate and distinct assets, while MPIs will be fundamentally a combination of both. Improving legal clarity supports investment in MPI projects, contributing to the development of interconnection and, through coordinating offshore transmission infrastructure, supports the deployment of offshore wind to deliver on Government's Net Zero ambitions.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

The preferred option is to introduce a new licensable activity for MPIs under the existing regulatory regime in primary legislation, resulting in potential MPI developers obtaining MPI licences from Ofgem for the operation of MPIs as interconnectors and transmission network operators do currently. This provides legal clarity to MPI investors and developers, providing a clear route-to-market.

We considered a do minimum option by making amendments to the standard licence conditions for interconnection and/or transmission, however, this would not a suitable solution in the longer term as legal uncertainty would remain and it could be prohibitive if the primary purpose of an MPI changed over time.

A secondary legislation option was also explored, but this would involve making changes using delegated powers in an untested way, adding complexity to the legislative process, with no time benefit.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date: N/A**

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | Yes | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** N/A | **Non-traded:** N/A | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

## Summary: Analysis & Evidence

Policy Options 1 & 2

**Description:**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period 10 Years | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low: −£0.1m** | **High: > −£0.1m** | **Best Estimate: > −£0.1m** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | < £0.1m | 1 | N/A | **< £0.1m** |
| **High** | < £0.1m | | N/A | **< £0.1m** |
| **Best Estimate** | < £0.1m | | N/A | **< £0.1m** |

**Description and scale of key monetised costs by 'main affected groups'**

The UK currently has no operational MPI projects, however we estimate there to be potential one-off familiarisation costs to existing electricity licence holders. While the majority of licensees will not be affected by the changes, because the functionality of MPIs straddle two existing electricity licence categories, licensees may need to familiarise themselves with the new activity and confirm there are no impacts to how their business operates. We expect these impacts on licence holders to be less than £100,000 in total.

**Other key non-monetised costs by 'main affected groups'**

Offshore transmission assets require an onshore landing point, which may impact on local residents, and can affect coastal environments. While constructing MPIs could have similar impacts, the number of landing points can be lower when compared to traditional interconnectors. Further, we expect MPIs will have a role in coordinating offshore transmission infrastructure, reducing the local community and environmental impacts, by reducing in the number of substations and length of cables required to connect offshore generation.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | N/A | | N/A | **N/A** |
| **High** | N/A | | N/A | **N/A** |
| **Best Estimate** | 0 | | N/A | **0** |

**Description and scale of key monetised benefits by 'main affected groups'**

No monetised benefits.

**Other key non-monetised benefits by 'main affected groups'**

The key non-monetised benefit from the changes is improving legal clarity. Through that impact, it may help to support potential MPI projects by providing confidence that the assets can continue to operate lawfully in the medium to long term. MPIs can support wider benefits associated with offshore transmission network coordination. Coordinating offshore developments can enable a reduction in the number of landing points required, reducing the number of substations and cable corridors, to reduce the impact they may have on the environment and local communities – so to the extent that this legislation helps to enable MPI development, it may also enable these benefits.

| **Key assumptions/sensitivities/risks** | **Discount** | 3.5% |
|---|---|---|

The overall impact from the legislative change on MPI deployment is uncertain. While legal clarity is expected to encourage investment in MPIs, as it may be possible for MPIs to be accommodated within the existing regulatory framework without legislative change, the extent to which additional MPI projects would be realised is unclear.

**BUSINESS ASSESSMENT (Option 1 & 2)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** < 0.1 | **Benefits:** 0 | **Net:** > −0.1 | 0.0 |

# Evidence Base

## Problem under consideration and rationale for intervention

1. In very broad terms, a multi-purpose interconnector ('MPI') is equipment which can be used to convey electricity produced by a generator in GB offshore waters to any other place (referred to as 'transmission'), whilst also being involved in the conveyance of electricity between GB and another jurisdiction (referred to as 'interconnection'). There are currently no operational MPIs involving GB but, should they be developed, in the future the equipment might additionally be used to support the coordination of other assets and activities offshore, for example the electrification of oil and gas platforms by connecting them into the MPI system to decarbonise their power supply.[1]

2. An MPI activity is fundamentally a combination of licensable activities presently described in the Electricity Act 1989 ("the Act") – offshore transmission and interconnection. As MPIs are a new type of asset, the Act does not provide for a specific MPI activity and their multi-functional nature presents challenges to how their activities should be licensed, acting as a barrier to nascent and future projects securing investment. For an MPI to be licensable under the current regime, the activity and asset must develop in such a way as to be eligible to be granted an offshore transmission licence or an interconnector licence. The problems this poses are:

   a) Where assets subsist "wholly or primarily" for the purpose of conveying electricity between GB and another jurisdiction, or dispatching electricity directly from an offshore wind farm in GB's offshore waters, an interconnector licence is appropriate.

   b) However, depending on the capacities and configurations of the activity being undertaken at a particular time, an interconnection licence would not be appropriate for that activity. For example, where a greater proportion of the electricity conveyed is from offshore wind then arguably the asset does not subsist "wholly or primarily" for the purpose of conveying electricity between GB and the other jurisdiction.

   c) The Act prevents an interconnector licensee from simultaneously holding a transmission licence so it would not be possible for the same person to hold a licence for each activity.

   d) The activities cannot therefore be regulated through separate licences for the assets held by the same person.

3. BEIS is guided by an approach which seeks to reduce the amount of offshore transmission infrastructure and increase coordination between interconnector and offshore wind developers. Removing the legal barrier of how MPIs are classified in the existing legal framework of the Act can enable this to happen. There are other perceived barriers to the development of MPIs in GB including EU policy direction and market arrangements, post EU-exit electricity trading arrangements, planning and consenting, anticipatory investment challenges, geography, and coordination with other developers. However, the primary consideration of this policy is how MPIs are licensed in the Electricity Act.

4. Introducing a new licensable activity into the Act for MPIs, with an associated definition of an "MPI asset" (as opposed to separate interconnection and transmission assets), would mean that the operation of an MPI would be licensable under the Act, and would provide investors greater certainty on the legal criteria for an MPI asset over the lifetime of their project.

[1] Offshore oil and gas platforms have significant power requirements to extract and process fossil fuels. This is typically provided by on site gas/oil generation. Supplying these platforms with renewable electricity could significantly reduce operational emissions.

## Policy background and objectives

5. The UK government has set targets to achieve 40GW of offshore wind capacity by 2030,[2] and net zero emission by 2050,[3] which may result in up to 100GW of offshore wind capacity (from c.10GW today).[4] Simultaneously, the Government has the ambition to increase the level of interconnection between GB and other countries to 18 GW by 2030[5] from c.7.4GW of installed point-to-point[6] interconnector capacity at the end of 2021.[7]

6. The current approach to designing and building offshore transmission was developed when offshore wind was a nascent sector and industry expectations were as low as 10GW by 2030. It was designed to de-risk the delivery of offshore wind by leaving the project developers in control of building the associated transmission assets to bring the energy onshore. This approach has contributed to the maturing of the sector, the significant reduction in costs of offshore wind energy and has helped position the UK at the forefront of global offshore wind deployment. However, in the context of increasingly ambitious targets for offshore wind, constructing individual point to point connections for each offshore wind farm may not be the most efficient approach and could become a barrier to the delivery of offshore wind.

7. The Offshore Transmission Network Review (OTNR) was launched in July 2020 to ensure future transmission connections for offshore wind are delivered with increased coordination while ensuring an appropriate balance between environmental, social and economic costs.[8] The OTNR comprises four workstreams to design effective interventions that target offshore transmission and interconnection projects at different stages of the development journey:

    a) 'Early Opportunities' focuses on in-flight projects;[9]
    b) 'Pathway to 2030' focuses on projects connecting until around 2030;
    c) 'Enduring Regime' (ER) focuses on a new post-2030 framework; and
    d) Multi-Purpose Interconnectors

8. The MPI workstream works across all three temporal OTNR workstreams to make tactical changes that will enable the delivery of MPIs, including those already in-flight. BEIS is leading on considering the enduring solution for the onset of MPIs, and the energy market regulator, Ofgem, is leading on MPI considerations as part of the OTNR early-opportunities work-stream.

9. The objective of this policy is to remove the potential legal classification barrier around how an MPI is licensed which may affect whether or not MPIs are developed.

## Policy options and assessment

10. BEIS and Ofgem identified three categories of potential solutions for the licensing of MPIs:

    a. **Option 0: The non-legislative approach** (the do minimum option) would rely on Ofgem using existing licensing powers to include special licence conditions in the 'primary' activity licence to regulate a secondary activity. It would mean an MPI receives either an Offshore Transmission Owner (OFTO) licence (OFTO led) or an interconnector licence (interconnector led) with altered licence conditions, transposing conditions onto each other to facilitate these two models. The problems here are:

[2] Set out in the Prime Ministers Ten Point Plan for a green industrial revolution.
[3] A target of at least 100% reduction of greenhouse gas emissions (compared to 1990 levels) (Climate Change Act 2008 Part 1 as amended by the Climate Change Act 2008 (2050 Target Amendment) Order 2019 (S.I 2019/1056)).
[4] https://www.theccc.org.uk/publication/sixth-carbon-budget/
[5] Energy white paper https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf
[6] Point-to-point is used to describe interconnector connections which are a direct high voltage electrical transfer wire between two jurisdictions or nations which can convey electricity in both directions.
[7] There are currently operational connections from GB to France (IFA 1 and 2), Norway (NSL), Belgium (NemoLink), the Netherlands (BritNed), Ireland (EWIC) and Northern Ireland (Moyle).
[8] https://www.gov.uk/government/groups/offshore-transmission-network-review.
[9] Projects (OSW, offshore transmission or interconnection) which are already under development intending to coordinate infrastructure in offshore transmission and interconnection.

i. The primary activity being licenced would need to be, somewhat artificially, defined and identified for the MPI. However, it would be artificial / inaccurate to identify a primary purpose of either interconnection or offshore transmission for each MPI.

ii. If an MPI could be said to have a primary purpose, additional considerations from pursuing this approach could cause complications for MPI owners. For example, MPI owners may need to demonstrate, with evidence, the primary usage of an asset to be granted the requested licence, but there are currently no agreed criteria for determining whether the primary function is either an offshore transmission asset or interconnector. Even if such criteria were agreed, the licence issued by Ofgem may not remain appropriate over time due to the multi-purpose nature of MPI assets. If the primary function of the MPI changed over its lifetime, this may cause complications for MPI owners who could find their licence no longer serves its purpose for its associated asset, and risk engaging in a licensable activity without a licence.

iii. Regulatory control by including special licence conditions in an OFTO licence or interconnection licence is only available if Ofgem can justify such conditions are necessary for it to fulfil its duties as the energy regulator. This creates a potential complexity to implementing this approach.

Ofgem is considering whether an interconnector or transmission licence with special licence conditions could be used,[10] however this will not provide sufficient certainty to potential MPI developers for an enduring regime. In the Enduring Regime consultation published in September 2021,[11] industry stakeholders broadly agreed the existing regulatory regime was not suitable for an enduring solution to MPIs.

b. **Option 1: The secondary legislation approach** considered the creation of a new licensable activity via a statutory instrument using the power under section 56A[12] of the Act. It would mean introducing MPI activity as an additional and distinct activity from interconnection and offshore transmission, with operators holding one licence for each activity. The section 56A power is available where the new activity is *"connected with the generation, transmission, distribution or supply of electricity*...".[13] However, 'interconnection' is not listed so BEIS concluded introducing a new MPI activity as "connected with" interconnection was not possible. In order to be connected to 'transmission', the MPI activity would need to be distinct from the existing transmission activity. This approach was deemed not to be viable due to MPIs inherently being connected with both transmission and interconnection. The omission of "interconnection" in the language of the order was prohibitive with early models being "interconnector-led", and therefore use of the power would not be a satisfactory enduring solution.

c. **Option 2: The primary legislation approach** (the preferred option) seeks to define a new licensable activity in relation to MPI activity that is a combination of interconnection and offshore transmission via amendments to the Act and would mean operators hold one licence for one activity. This will enable the creation of a bespoke regime, under licence, by Ofgem for the regulation of this new asset class.

11. In the medium and longer term it may not be possible to rely on the existing regime or non-legislative changes as market conditions could change. For example, more electricity may be imported and exported via the connection with another jurisdiction, which changes the primary activity of the asset. This could occur simply if, for example, greater than 50% of the capacity across the OFTO-led MPI was through interconnection. Therefore, opting for the non-legislative route of replicating certain licence conditions from the OFTO licence onto the interconnector licence, or vice versa, does not provide investors with the certainty required about the legal standing of their asset due to the lack of flexibility in these definitions. Specifically for an interconnector-led model, it is expected a viable MPI

[10] Over short time horizons and for specific capacities and configurations of MPIs, it is conceivable that an interconnector or offshore transmission led MPI model could satisfy the respective definition (interconnection or transmission) within the Act. The operation of the asset could be predicted based on modelling of future market conditions at the time of investment.

[11] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1021040/offshore-transmission-enduring-regime-condoc.pdf

[12] Section 56A – Power to alter activities requiring a licence – was introduced into the Act in 2000. See section 43 of the Utilities Act 2000 c.27.

[13] See section 56A(4) of the Act.

must allow priority dispatch for offshore wind generators,[14] which would then cast doubt on a primary purpose of interconnection.

12. Introducing a new licensable activity by way of primary legislation would create a clear legal basis for regulating a multi-purpose asset performing a role which comprises of interconnection and offshore transmission, as the existing activities within the Act are not suitable. MPIs are operationally different to interconnectors, and therefore having OFTO-led and interconnector-led assets operating under one licence would create complexity and confusion. In the September consultation, stakeholder responses were broadly in support of there being a necessity for a new MPI definition as an enduring solution for MPIs.

13. We have considered whether exemptions under section 5 of the Act could be used to enable a single owner or operator of an interconnector and transmission assets to hold more than one licence, to overcome the hurdle of section 6(2A) of the Act. Again, whilst this would be a technical solution to enable the legal standing of the asset to be secured, it would create a more complicated regime, as it would acknowledge that different licences are required for an asset which will operate as one. This would in practice mean that Ofgem would still have to regulate for both interconnection and transmission at once, which is not deemed feasible by Ofgem.

## Analytical approach

14. The only monetised impact from the preferred option are potential familiarisation costs to existing electricity licence holders to consider the new activity. While legal clarity around the regulation of MPIs is expected to support investment in MPI projects and increase the likelihood that they are realised, an overall monetised impact from the changes due to MPI deployment is not presented due to challenges quantifying the impact of introducing the new licensable activity given MPIs could potentially be accommodated and operate within the existing regulatory framework without legislative change. The level of MPI deployment is also inherently uncertain and further steps are required before they can become operational, including establishing the full regulatory regime and potentially further support for their deployment.

15. This impact assessment expands on the analysis from the enduring regime consultation IA by presenting further evidence on the impacts of MPIs.[15] More detail is provided on the illustrative impacts of MPIs as well as further qualitative discussion on the non-monetised wider impacts of MPIs. The impact of legal clarity is also difficult to monetise, so a qualitative discussion is provided.

16. It is important to note this final stage IA has a more limited scope than the consultation stage IA because facilitating MPIs is only a subset of the policies covered by the enduring regime consultation. While MPIs have a role to play in coordinating offshore electricity transmission networks, most of the impacts presented there relate to coordination of transmission infrastructure for offshore wind generation rather than specifically on MPIs.

## Monetised impacts

17. The new licensable activity of multipurpose interconnection straddles the licensable activities of electricity generation, transmission, and interconnector licences, so licensees may need to read the newly introduced definition in case it affects how their business operates. While the vast majority of licensees will not be affected by the changes because they are not developing MPI projects, relevant individuals in these organisations would be reading the new guidance, interpreting its implications, and disseminating to the organisation that there are no impacts to how the business operates.

18. We estimate one-off familiarisation costs are minor and total £4,100 in the central estimate (2020 prices), with a range of £1,900 to £33,300 representing uncertainty around the number of licensees who would be affected. The central estimate assumes all 45 current transmission and interconnector

[14] Priority dispatch for an offshore generator connected to an MPI would mean that whenever the plant is generating, it has priority use of the capacity of the MPI to access the market.

[15] Developing an enduring regime for offshore transmission Consultation Impact Assessment https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1021063/enduring-regime-consultation-impact-assessment.pdf

licensees will individually familiarise themselves with the changes.[16] The low estimate assumes licensees owned by the same groups of investors in the central estimate would have shared resource so would not duplicate the familiarisation activities, for which we estimate there to be around 21 separate groups.[17] The high estimate represents all 364 generation, 27 transmission and 18 interconnection licensees individually familiarising with the changes; while some offshore wind generators considering joining an MPI are likely to familiarise with the changes, this high estimate is likely to be a significant overestimate of familiarisation costs because it includes onshore generators who are clearly unaffected by the changes.

19. We estimate it takes one corporate manager or director for each licensee approximately 1.5 hours to consider the new licensable activity and disseminate (the lack of) implications back to the organisation. The relevant explanatory notes to the legislation and legislative clauses are expected to total around 1,500 words, and it is assumed the corporate manager or director will read these texts three times at a reading speed of 50 words per minute to fully understand the content. The assumed reading speed is at the low end the range for technical texts to account for the higher level of language complexity in these documents.[18] Labour costs are estimated to be around £60 per hour, including both wage and non-wage costs.[19]

*Table 1: Number of electricity licences and number assumed to incur familiarisation costs*

| Number of electricity licences | Interconnection licences | Transmission licences | Generation licences | Licensees incurring familiarisation costs |
|---|---|---|---|---|
| | 18 | 27 | 319 | |
| **Central estimate** | ✓ | ✓ | | 45 |
| **Low estimate** | ✓* | ✓* | | 21* |
| **High estimate** | ✓ | ✓ | ✓ | 364 |

**Low scenario merges licensees owned by the same groups of investors.*

20. Informal engagement with Ofgem has indicated the regulator’s costs from these changes are likely to be broadly net neutral. They are a partner of the OTNR and are already actively participating in the MPI workstream. In future, the volume of regulatory activity relating to MPIs is unlikely to be significantly affected by whether a new licensable activity is introduced. While the issuance of MPI-specific licences may mean fewer licences in total need to be issued and overseen compared to separate offshore transmission and traditional interconnector assets, accommodating MPI projects via separate amended transmission or interconnector licences leads to no reduction in the number of licences.

## Illustrative impacts of multi-purpose interconnectors

21. Introducing a new licensable activity for MPIs is expected to improve legal clarity such that the following potential benefits and wider impacts of MPI deployment are more likely to materialise. While MPIs could be deployed under the existing license categories available, removing uncertainty around how MPIs are regulated helps support investment in new MPI projects. However, the extent the change clarifies legal is unclear and the ultimate impact on MPI deployment will also depend on how the full regulatory regime for MPIs develops. Further, it is not possible to estimate the overall impact

[16] List of all electricity licensees available from Ofgem: https://www.ofgem.gov.uk/publications/list-all-electricity-licensees-including-suppliers (retrieved January 2022)

[17] Licensees owned by consortia of investors were mostly identified by name since the name of the parent company is part of the registered name of the licensee. This information was supplemented by accessing licensees’ websites to identify any consortia which did not follow this naming convention and verified by accessing the consortia websites and other public documents which list their investments.

[18] Business Impact Target: appraisal of guidance, BEIS (2017) (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/609201/business-impact-target-guidance-appraisal.pdf)

[19] Hourly gross wages from ONS Annual survey for Hours and Earning (ASHE) Table 14: 2020 (11: Corporate managers and directors, at the 90th percentile) and private sector non-wage costs from ONS Index of labour costs per hour (Non-seasonally adjusted) Q1 2020.
https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/datasets/occupation4digitsoc2010ashetable14
https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/datasets/indexoflabourcostsperhourilchnonseasonallyadjusted

of MPIs deployed under a distinct MPI license because, apart from uncertainty around how many projects will materialise, the appropriate counterfactual for individual projects will differ. Some interconnection projects may deploy as MPIs instead of traditional interconnectors, but where traditional interconnectors were not feasible or were not being planned, MPI projects may provide new interconnection capacity that wouldn't otherwise be built. This introduces a further level of complexity and uncertainty in any attempt to quantify the impact of this change.

### *Impact on capital and operating costs*

22. MPIs can offer additional interconnection capacity at lower capital and operating costs through shared utilisation of transmission infrastructure. By coordinating interconnection and offshore wind generation, MPIs can reduce the total number of onshore and offshore substations and length of cabling required to reduce the total capital cost of installations and operating costs. A study of 10 potential European MPI ('hybrid') projects considered by the Roland Berger consultancy found capex savings for projects ranged from €300m and €1500m when compared to counterfactual scenarios using traditional interconnectors.[20]

23. Phase 1 outputs from the Offshore Coordination Project set up by National Grid Electricity System Operator (NGESO) indicated adopting an integrated approach to offshore transmission from 2025, including the use of MPIs, could reduce lifetime transmission costs by around £6bn.[21] The consultation IA was for the longer-term approach to coordinating offshore transmission so used a lower figure of up to £3bn based on coordinating offshore wind connections from a later date of 2030 onwards instead. In addition to reducing offshore transmission infrastructure by half (or 30% if coordinating from 2030), these savings also include onshore transmission cost reductions as a result of coordination reducing the need for onshore grid reinforcements. A reduction in transmission infrastructure has environmental and community benefits, discussed under Wider Impacts, while transmission cost savings are assumed to be ultimately passed onto end consumers through lower electricity transmission charges.

24. Coordinating offshore wind transmission infrastructure and interconnectors by way of MPIs could enable and accelerate the deployment of offshore wind capacity. Increased coordination can reduce opposition and delays during the planning process for constructing new infrastructure as fewer individual assets need to be approved, cumulative impacts on the local area are reduced. This can mean offshore wind is deployed earlier and brings forward the carbon savings from renewable electricity.

25. The dual interconnection and offshore transmission functionality associated with MPIs also increases asset utilisation, helping to a achieve a more efficient use of infrastructure. When offshore wind is generating below full capacity, point-to-point transmission cables for offshore wind are underutilised. Asset utilisation is higher with an MPI because when wind generation is low, the spare transmission capacity can be used for interconnection purposes. An unpublished study on connections between GB and the Netherlands conducted for The Crown Estate and TenneT suggests under half of the total flow potential of offshore wind transmission assets are used currently, but utilisation can be one fifth higher for hybrid technologies.

### *Wider impacts*

26. MPIs can play a role in coordinating offshore transmission infrastructure with wider benefits beyond infrastructure costs savings. Based on grid agreement to develop 6.4GW of interconnectors, National Grid estimates adopting MPIs instead could reduce the total number of landfall points in GB and EU by over 50% from 18 to 8.[22] For the wider offshore transmission network, based on results from the NGESO Offshore Coordination Project, the consultation IA presented estimates that greater offshore coordination from 2030 could reduce negative environmental and local social impacts by around 30%. Compared to a counterfactual with traditional interconnectors and radial point-to-point

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[20] 'Hybrid projects: How to reduce costs and space of offshore development' Roland Berger: 2018

[21] 'Offshore coordination phase 1 final report' National grid ESO: 2020
https://www.nationalgrideso.com/news/final-phase-1-report-our-offshore-coordination-project

[22] Summary results from analysis on National Grid Ventures MPI pathfinder projects presented at UK Hybrid Project Forum on 10 March 2021, slide 36

connected offshore wind farms, adopting a coordinated offshore network could reduce the number of onshore landing point for cables by 40%, total transmission cable length by 27%, and seabed trenches by 10%. Earlier coordination from 2025 increases the reduction in negative environmental and local social impacts to half.

27. Coordinating offshore developments can have positive impacts on marine and coastal environments by reducing the amount of offshore infrastructure required. It is expected to have a positive effect on natural capital by reducing the number and area of installations placed in marine and coastal ecosystems and reduce the impact of their construction on the environment. However, the extent of these benefits is uncertain because and would depend specific location of projects agreed upon during the planning and consenting processes, the construction methods used, and other factors such as the effectiveness of any environmental risk mitigations.

28. Reducing the placement of substations and cable corridors on the seabed has the benefits of reducing the cumulative impact on habitats and ecosystems. Preparatory works for installing foundations of structures such as substations may require material to be dredged or excavated from the seabed, and habitats can also be changed by materials deposited for the external protection of cables, such as concrete mattresses or rock bags.[23] While individual projects currently already undertake environmental impact assessments and adopt mitigations where appropriate, especially within designated Marine Protected Areas, coordination could allow a more holistic examination of the total cumulative impacts offshore developments have on the natural environment.

29. The wider evidence on natural capital impacts from offshore developments can also be mixed or unclear, with evidence constantly developing and often highly location or species specific. Some environments seem resilient to disruption while the research on the impact on marine mammals is inconclusive. Artificial reef effects are potentially beneficial for commercial species, but there is also concern over the role of developments in assisting with the spread of invasive species.[24] This emphasises difficulties in estimating an overall environmental impact coordinating offshore transmission infrastructure at a high level, and conservation issues may be more appropriately addressed at a local level. Biodiversity impacts aside, a reduction in construction activity would be expected to reduce potential environmental risks associated with construction of offshore infrastructure such as the release of pollutants and accidents involving wildlife.

### *Greenhouse gas emissions*

30. MPIs can reduce carbon emissions in the power sector by increasing the level of interconnection with neighbouring markets, supporting the integration of renewable generation into the energy system, or by bringing forward the deployment of offshore wind. A study commissioned by BEIS found that an increase in interconnector capacity between GB and EU would likely lead to both a reduction in carbon emissions and the curtailment of offshore wind in both GB and the EU.[25] Total cumulative GB emissions from 2020 to 2050 were estimated to be around 200mtCO2e lower in the high interconnection scenario compared to the low interconnection scenario, against existing and known decarbonisation policies at the time of analysis. While emission savings would be lower with further net zero policies as marginal grid carbon intensities fall, interconnection is still useful for integrating intermittent renewables into the system.

31. Interconnectors are generally understood to increase system flexibility and help integrate intermittent renewable power generation. If MPIs are deployed in addition to traditional interconnectors, the increase in interconnection capacity can maintain higher levels of generation from renewables instead of curtailing the excess supply to maintain grid stability and allows lower cost power to be imported when supply margins are tight. Although the direction of electricity flows on interconnectors depends on trading based on the price differentials between markets, importing power when prices

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[23] Marine Pressures-Activities Database (PAD) v1.4 | JNCC Resource Hub

[24] Understanding the Impacts of Offshore Wind Farms on Well-Being, The Crown Estate (2015) (https://www.offshorewindindustry.com/sites/default/files/ei-understanding-the-impacts-of-offshore-wind-farms-on-well-being.pdf)

[25] The impact of interconnectors on decarbonisation (https://www.gov.uk/government/publications/impact-of-interconnectors-on-decarbonisation)

are high could reduce overall emissions by allowing excess renewable power in Europe to be exported to GB instead of being curtailed.

32. As mentioned above, coordination of offshore transmission with MPIs can reduce delays to planning processes and bring forward offshore wind deployment. Based on grid agreement to develop 6.4GW of interconnectors, analysis produced for National Grid estimates MPIs could provide 21mtCO2e additional carbon savings compared to point-to-point connections over 2030-2050. Much of these savings are due to earlier assumed offshore wind deployment following an analysis of the difficulties connecting at different grid connection locations, for which MPIs reduce the connection time when compared to radial point-to-point radial transmission connections.

33. Coordinating offshore transmission infrastructure using MPIs can also have wider impacts on greenhouse gas emissions beyond direct emissions from the power sector. Reducing the amount of transmission infrastructure being built is expected to reduce their impact on natural habitats surrounding ecosystems. Coastal and marine habitats which act as carbon stores and sequester carbon may otherwise have been disturbed. 'Blue carbon' refers to atmospheric CO2 sequestered by vegetated coastal and marine habitats, storing carbon in soils and sediments,[26] and the Office for National Statistics estimate UK saltmarshes, sublittoral (sub-tidal) sands and sublittoral muds alone sequestered between 10 and 60 MtCO2e in 2018.[27] While coordination offshore infrastructure is not expected to have a significant impact on carbon emissions, reducing habitat loss would help maintain the size of the carbon sinks.

34. MPIs could reduce the number of landing sites compared to separate landing points for offshore wind transmission and traditional interconnector infrastructure, reducing the disturbance of coastal and marine habitats. Sand dunes, saltmarshes and machair dune grassland make up around 93% of UK coastal margin habitats, and saltmarsh and seagrass represent the largest sedimentary carbon store. However, the most recent estimates indicate saltmarshes sequester 2 to 8 tCO2e per hectare per year.[28] Reducing the number of landing sites reduces the re-release of emissions and maintain their ongoing ability to sequester carbon dioxide.

### *Spatial impacts*

35. Increasing coordination in offshore transmission can have nuanced effects on local communities, although the impact from MPIs specifically is likely to be limited because significantly fewer projects relative to the number of offshore wind farms means fewer areas may be affected. Reduced infrastructure building would be expected to alleviate concerns amongst local communities around the cumulative impacts of offshore cables and onshore landing points near coastal locations, however, it may have an uncertain impact on local economies and jobs. Overall, coordination may better enable local communities to have their views represented in planning processes by reducing the number of individual applications to respond to.

36. Coastal communities in England and Wales could benefit from offshore coordination more than the wider economy because they have a different sectorial composition which may make their local economy more vulnerable. Coastal communities are more orientated towards providing leisure and hospitality services and may be more adversely impacted by the visual impact of transmission infrastructure development. In 2018, the accommodation and food services sector had the highest share of employment amongst small seaside towns, with 19%, compared to just 7% for this sector in non-coastal small towns. Coastal towns are more likely to be deprived than non-coastal towns and resident populations less likely to have degree-level qualifications.[29]

37. Reduced opposition to offshore wind development during planning can accelerate the delivery of offshore wind capacity and bring forward additional high value jobs. The offshore wind sector directly

[26] Carbon Storage and Sequestration by Habitat, Natural England (2021) (http://publications.naturalengland.org.uk/publication/5419124441481216)

[27] Marine accounts, natural capital, UK: 2021, ONS (https://www.ons.gov.uk/economy/environmentalaccounts/bulletins/marineaccountsnaturalcapitaluk/2021)

[28] NatureScot Commissioned Report 957 (2017) (https://www.nature.scot/naturescot-commissioned-report-957-assessment-blue-carbon-resources-scotlands-inshore-marine)

[29] Coastal towns in England and Wales: October 2020, ONS (2020) (https://www.ons.gov.uk/businessindustryandtrade/tourismindustry/articles/coastaltownsinenglandandwales/2020-10-06)

employed approximately 7,200 full-time equivalent employees in 2019,[30] and some local areas are supporting offshore wind development as part of their local economic strategies. While reductions in capital spending resulting from MPIs supporting the coordination offshore wind infrastructure may reduce the number of jobs directly involved in delivering transmission infrastructure, any reduction in total jobs is likely to be small and could be offset by increased delivery rates. Offshore cable installation typically represents 6% of total offshore wind costs, while cables represent 5%.[31]

38. Less infrastructure placement may be beneficial for employment in other sectors. MPIs can help to deliver fewer, larger developments instead of more, smaller developments, which may be beneficial from a tourism perspective. The need to build less infrastructure such as substations could reduce noise and traffic from construction processes. This could reduce potential negative impacts on tourism which are often cited as reasons for objections to offshore infrastructure. However, the evidence on local impacts is mixed. It is unclear whether these issues would materialise had they not been considered as part of planning and consenting processes.

### *Competition and innovation impacts*

39. The development of MPI projects and coordination of offshore transmission networks has a positive impact on innovation. There are currently no operational MPI projects in GB so project development will require innovations to make these projects operational from design to delivery. Coordinated network designs are more complex and are likely to require technological innovations. The foundations of MPI substations, for example, may require new convertor technology to integrate with offshore wind generation. Other technological developments which are required facilitate the connection of offshore wind farms to more complex coordinated networks includes subsea connectors and subsea switching devices.[32]

40. Competition in delivering offshore transmission networks may increase or decrease with increased coordination. More integrated networks are larger and more complex than radially connected offshore transmission so could raise barriers to entry to infrastructure delivery and reduce competition, but since there are fewer projects to bid for and work on, competitive pressures between firms may increase if the number of bidders per project increases. Higher levels of competition would be expected to increase the level of innovation as competing firms seek to deliver infrastructure more efficiently at lower cost.

## Risks and assumptions

41. Introducing the operation of MPIs as a new licensable activity is expected to reduce the perceived legal risk with developing MPI projects. As explained above, the current legal framework for MPIs is challenging because it is not possible to hold more than one electricity licence, but the functionality of MPIs straddles at least two license types. While it may be possible to accommodate MPIs within existing licence categories by amending standard licence conditions, consultation responses and stakeholder engagement have indicated this may not provide sufficient legal clarity and may not be a sustainable position in the medium to long term. The extent of this legal clarity and how much more investment in MPIs it encourages is uncertain and will also depend on how the full regulatory and support landscape for MPIs develops.

42. Evidence around the impact of MPIs on the wider energy system is often intertwined with the impacts of additional interconnection capacity, and the most appropriate counterfactual would differ between specific projects and the timing at which an assessment is made. For example, MPIs could lead to less interconnection capacity being available if a traditional interconnector project in the processes of planning is adapted to become an MPI project instead. The Roland Berger study identifies a conflict exists between available interconnection capacity and transmission of offshore wind generation. That is because the infrastructure sharing made possible by MPIs creates a competition for capacity between its dual interconnection and offshore transmission functionality. This leads to lower trading

[30] Low carbon and renewable energy economy estimates, ONS (2021) (https://www.ons.gov.uk/economy/environmentalaccounts/datasets/lowcarbonandrenewableenergyeconomyfirstestimatesdataset)
[31] https://guidetoanoffshorewindfarm.com/wind-farm-costs
[32] 'HVDC supply chain overview', The national HVDC centre: 2021 https://www.dnv.com/article/floating-substations-the-next-challenge-on-the-path-to-commercial-scale-floating-windfarms-199213

compared to traditional interconnectors and/or requires the curtailment of renewables generation, leading to smaller efficiency gains from cross-border electricity trading. However, depending on individual project characteristics, it may be outweighed by reductions in capex and opex costs.[33] Conversely, MPIs would increase interconnection capacity if previously uneconomical traditional interconnector projects could become viable with capex and opex reductions made possible as an MPI instead. In these instances.

43. The impacts of MPIs compared to traditional interconnectors or no interconnection would also depend on specific market arrangement on the MPI. How competing flows are prioritised, both on the GB side of the MPI and perhaps the foreign side of the connection if also an MPI, will determine the level of offshore wind curtailment and how much capacity is used for interconnection. Currently the assumed market model going forward is transmission for offshore wind generation takes precedent, avoiding curtailment due to MPIs compared to traditional interconnectors. The extent of offshore transmission network coordination also affects MPI outcomes because greater offshore coordination could enable alternative routing of offshore wind generation to avoid instances where capacity constraints on MPIs cause generation to be curtailed.

## Direct costs and benefits to business

44. The UK currently has no operational MPIs and introducing the operation of MPIs as a new licensable activity is not expected to directly impact on the vast majority of businesses in the power sector. Further, regulatory costs on these projects if they come to fruition are expected to be similar to costs they would face if MPIs were accommodated within the current licensing regime because the underpinning activities being regulated would be the same. Through the OTNR, we are aware of several potential MPI projects being explored by interconnector developers and offshore wind developers who would be affected by the clarification to the legal framework in which MPIs would operate. Developers of these MPI projects would directly benefit from the legal clarity, but these impacts are challenging to monetise, and their costs from contributing to the OTNR are assumed to be part of business-as-usual regulatory engagement costs and so not included in this assessment.

45. We estimate the only direct costs on business from the changes are the potential one-off familiarisation costs to existing electricity licence holders. As explained above, these are estimated to total £4,100 in the central estimate, with a range of £1,900 to £33,300 to cover different combinations of electricity license holders who perform activities remotely like that of MPIs. In practice, familiarisation costs are unlikely to fall towards the high estimate because this includes all generation license holders so includes a significant number of non-offshore wind generators who would clearly not be expected to be affected by changes to how MPIs are regulated and offshore wind farms which are not suitable and/or not seeking to become to MPIs.

46. Over a default appraisal period of 10 years the familiarisation costs have a negligible equivalent net direct cost to business (EANDCB) significantly less than £0.1m. Informal engagement with Ofgem have indicated the regulator’s costs from these changes are likely to be broadly net neutral.

47. The role of MPIs in supporting the coordination offshore wind transmission infrastructure would indirectly benefit electricity generators and suppliers. As mentioned above, adopting an integrated approach to offshore transmission from 2025, including the use of MPIs, could reduce lifetime transmission costs by around £6bn. This would reduce costs recovered from generators, including offshore wind farms connected to the more coordinated network, and electricity suppliers, through the Transmission Network Use of System (‘TNUoS’) charging system. However, these savings are ultimately assumed to be passed on to end consumers.

## Small and micro business assessment

48. There are no licensees of operational interconnectors, offshore transmission assets, or offshore wind generators which are small or micro businesses. These are significant assets and licensees operating them generally consist of consortia of large businesses, including parent companies and

[33] Hybrid projects: How to reduce costs and space of offshore development’ Roland Berger: 2018

institutional investors. The value of offshore assets being owned and operated are typically valued in excess of hundreds of millions of pounds.

49. While there are currently holders of electricity interconnector or transmission licences which are technically defined to be businesses which are small or micro in size – with up to 49 employees – these are developers of potential projects and would not remain as small businesses by the time they are operational because significant investment would have been required. A greater proportion of electricity generation licensees may be small businesses because this group includes operators of smaller onshore generators but, like interconnectors and offshore transmission networks, offshore wind generators require significant investment to bring online so would not remain small.

50. The introduction of MPIs as a new licensable activity will benefit small and microbusinesses by improving legal clarity. The changes will not introduce new barriers to entry for small businesses because the functions performed by MPIs, interconnection and transmission of electricity, are already separately licensable activities under the current regulatory regime. However, improving legal clarity around the regulation of MPIs could support small businesses proposing MPI projects in attracting investment to develop and operationalise their plans. Small businesses with proposals to develop traditional interconnectors may also benefit. The legal clarity around MPIs could make the option to adapt existing plans for them to become MPIs more feasible, providing an alternative route to attracting investment to scale up and increase the likelihood of becoming an operational project.

51. While the time taken for small business licensees to familiarise might be more burdensome than for larger businesses because they are less likely to have dedicated legal resource, these familiarisation costs are insignificant compared to the typical capital investment of over £1bn required deliver an operational project. Given the benefits of legal clarity provided to small businesses it would not be appropriate to exempt them from the changes. Further, most businesses in the power sector would not need to familiarise so we would expect total familiarisation costs to fall towards the central and low estimates. As explained above, the high estimate assumes all generation licence holders familiarise with the changes, but the majority are not offshore wind generators and would clearly not be affected by changes to how MPIs are regulated so would not be expected to familiarise with the introduction of the new licensable activity.

52. More widely, MPIs helping to coordinate offshore transmission networks is expected to have a positive indirect impact on small and micro businesses through a reduction in energy bills. Transmission cost savings are ultimately assumed to benefit energy consumers. Smaller businesses in coastal locations are also expected to be impacted less by the construction of a more coordinated offshore network and face lower burdens responding to planning applications as these can be managed in a more coordinated way.

## Potential trade implications of multi-purpose interconnector deployment

53. Introducing the operation of MPIs as a new licensable activity is not expected to have trade implications unless there is an impact on the deployment of interconnection capacity. The deployment of additional interconnection capacity using MPIs would be expected to facilitate increased electricity trading across borders, increasing both import and export volumes. This increased interconnection capacity increases economic efficiency by allowing more lower cost electricity to be imported when prices in GB are higher than connecting countries and allows more electricity to be exported when GB prices are lower than connecting countries.

## Equalities assessment

54. The introduction of MPIs as a distinct licensable activity does not have any equalities impacts. Evidence from public responses to our Enduring Regime consultation, published in September 2021, did not raise any concerns relating to the equalities impact of MPIs. Offshore wind developers, who would typically also build offshore transmission networks, also conduct extensive stakeholder when developing their projects. Any disproportionate impacts from individual projects would be expected to be mitigated through local planning and consenting processes.

55. The deployment of MPIs and the support for coordinating offshore transmission networks this can provide may have a small net positive impact on those with protected characteristics. While there is a

small risk the construction of MPI assets may disproportionately impact individuals with mobility challenges by temporarily impeding road access and use of clear footpaths, preventing access to public spaces and services, the overall coordination of offshore transmission networks is expected to reduce instances of unmitigated disruptions by reducing the number of installations which are built. Individuals with mobility issues may be overrepresented in groups such as the disabled and elderly, and coastal areas which would be impacted by offshore transmission infrastructure development tend to have older demographics and higher levels of health deprivation and disability.

## Monitoring and evaluation

56. Given the relatively small number of MPI projects in development currently, it is envisaged BEIS will continue engagement with all relevant stakeholders to understand the impact of introducing MPIs as a new licensable activity. At present it still premature to develop detailed monitoring and evaluation plans for MPIs policies because the full regulatory framework is not yet complete. While the need for legal clarity around the operation of MPIs was identified in responses to the enduring regime consultation and during stakeholder engagement as part of the OTNR, further steps are also required before can MPIs deploy. This includes establishing the licensing regime and standard licence conditions for MPIs in full, and potentially developing a mechanism to support the development of MPI projects.

**Title:** Defining electricity storage in legal text
**IA No:** BEIS013(F)-22-ICE

**RPC Reference No:** **RPC-BEIS-5173(1)**

**Lead department or agency:** BEIS

**Other departments or agencies:**

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage:** Final

**Source of intervention:** Domestic

**Type of measure:** Primary legislation

**Contact for enquiries:**
smartenergy@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred Option** (in 2020 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| >£-0.1m | >£-0.1m | <£0.1m | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

Research indicates that smart and flexible technologies, including electricity storage, could reduce system costs between £30-70bn from 2020 to 2050[1]. However, electricity storage is not currently defined in primary legislation, as the regulatory framework was not built with technologies such as electricity storage in mind. Whilst the Government has tried to clarify the treatment within the framework through guidance and licence conditions, without a formal definition there is a lack of legal clarity and certainty over its treatment creating a risk of legal challenge and disincentivising investment in the technology. This risks stifling the deployment of electricity storage in GB and missing out on the benefits it can bring to the electricity system and consumers.

The Government has previously committed to formalise this official definition within the 2017 Smart Systems and Flexibility Plan, 2020 Energy White Paper and 2021 Smart Systems and Flexibility Plan.

**What are the policy objectives of the action or intervention and the intended effects?**

The key policy objective is to provide the sector with legal clarity and certainty over the regulatory treatment of electricity storage. The intended outcomes are to increase investor confidence in the sector, reduce the risk of legal challenge, ensure savings to business from no longer having to procure legal services, ensure consistency in the treatment of storage in the licencing and planning frameworks, and provide a clear basis for future regulatory changes to consistently refer to. In turn, supporting the deployment of electricity storage needed to meet our decarbonisation targets cost-effectively.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

**'Do nothing':** No further changes are made to the existing legislation. Electricity storage continues to have no formal definition, and the Government fails to keep to its list of intended actions in the 2017 Smart System and Flexibility Plan and 2021 Smart Systems and Flexibility Plan. Investment in electricity storage could be stifled by lack of legal clarity and certainty. Storage providers continue to procure legal services surrounding definition.

**Option 1 (preferred option):** Define electricity storage in the Electricity Act 1989 as a distinct subset of generation. This provides clarity in the quickest possible timeframe and consistency with the status quo but also allows storage to be treated differently to other forms of generation where appropriate, recognising its differences to provide greater regulatory certainty for current and future projects. There is not expected to be any reclassification of current assets, or any significant deviation in the financial value of such assets, as a result of these regulations. The proposed definition has received support through public consultation and has been developed through close engagement with industry.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:** NA

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** N/A | **Non-traded:** N/A | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003787/smart-systems-appendix-i-electricity-system-flexibility-modelling.pdf

## Summary: Analysis & Evidence

Policy Option 1

**Description:**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 10 | Net Benefit (Present Value (PV)) (£) | | |
|---|---|---|---|---|---|
| | | | **Low:** >-0.1m | **High:** >-0.1m | **Best Estimate:** >-0.1m |

| **COSTS (£)** | **Total** (Constant Price) | **Transition** Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | <0.1m | 1 | 0 | <0.1m |
| **High** | <0.1m | | 0 | <0.1m |
| **Best Estimate** | **<0.1m** | | **0** | **<0.1m** |

**Description and scale of key monetised costs by 'main affected groups'**

Transitionary learning and familiarisation costs may be incurred to those companies who currently hold storage assets. It is envisaged that they would read and take time to understand the new definition which would involve legal and managerial resource. In our central estimate, we estimate that this additional resource would cost £270 per company; for all those companies we expect the total additional cost as around £27,000.

**Other key non-monetised costs by 'main affected groups'**

There are no other costs expected to arise from this proposal.

| **BENEFITS (£)** | **Total** (Constant Price) | **Transition** Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | N/A | | N/A | N/A |
| **High** | N/A | | N/A | N/A |
| **Best Estimate** | **N/A** | | **N/A** | **N/A** |

**Description and scale of key monetised benefits by 'main affected groups'**

There are no quantifiable benefits expected to arise from this proposal.

**Other key non-monetised benefits by 'main affected groups'**

The non-monetisable benefits include increased investor confidence from increased clarity and consistency for the sector, through sending a strong positive signal on the regulatory position of storage, and providing a considerably clearer basis for future regulatory changes. Further, we expect there to be a reduction in the risks of legal challenge related to the definition of storage for planning and licensing purposes, and cost savings to industry from no longer having to hire lawyers to help clarify the legal position of storage.

**Key assumptions/sensitivities/risks** | **Discount rate (%)** | 3.5

We assume that learning and familiarisation costs can be illustrated fairly by assuming that the time to read and understand legislative changes is around 4.5 hours (based on reading time assumptions and consultation with external stakeholders) at an assumed cost of £60 an hour, and that all current storage providers would take the time to read and familiarise themselves with the new regulation.

We have performed sensitivity analysis around both the time and number of firms required to familiarise themselves to the new regulations, introducing a range of total costs of between £12,500 and £54,000.

There is a potential policy risk wherein the new storage definition is defined poorly – this is mitigated as the definition has been under intense scrutiny and consultation with both internal and external stakeholders. The definition is also in effect the same as that included in Ofgem's modified generation licence for storage which

**BUSINESS ASSESSMENT (Option 1)**

| Direct impact on business (Equivalent Annual) £m: | | | Score for Business Impact Target (qualifying provisions only) £m: |
|---|---|---|---|
| **Costs:** <0.1 | **Benefits:** 0 | **Net:** >-0.1 | 0.0 |

# Evidence Base

## Background

1. The concept of electricity storage involves the conversion of electrical energy into a form of energy that can be stored, the storing of that energy and its subsequent reconversion into electricity. Electricity storage therefore allows the time-shifting of energy use, a valuable property within a system with variable demand which must be met precisely across the day and through all seasons.
2. There is a range of electricity storage technologies at various stages of development which are suited to different applications at different scales. These include batteries, compressed air, flywheels, and pumped-hydro systems. They have different technical characteristics (power, capacity, and response time), efficiency and cost, and can be deployed at all levels of the electricity system. The UK currently has around 4 gigawatts (GW) of storage on the system, made up of 3GW of pumped hydro and 1GW of newer lithium-ion battery storage that has been built since 2017.
3. The Government supports the deployment of storage within the electricity system, because of the flexibility it provides. Electricity storage helps the (Transmission) System Operator and Distribution Network Operators balance electricity supply and demand, and manage constraints on their systems. It also benefits consumers by reducing the need for investment in new conventional generation, by avoiding or deferring network reinforcements, by maximising the usable output from intermittent renewable generation (e.g. solar and wind), and by operating the electricity system more efficiently. It is a critical technology for meeting Net Zero.
4. Recent analysis published for the 2021 Smart System and Flexibility Plan[1] estimated that smart and flexible technologies, including storage, could reduce system costs between £30-70bn from 2020 to 2050[2]; and that around 30GW of low carbon flexible assets (including electricity storage) may be needed by 2030 to maintain energy security and cost-effectively integrate high levels of renewable generation. This represents a three-fold increase on today's levels.
5. In the 2021 Smart System and Flexibility Plan, the Government and Ofgem, set out a vision, analysis, and work programme for delivering a smart and flexible electricity system that will underpin our energy security and the transition to net zero. For electricity storage, the approach is centred on creating a best-in-class regulatory framework by removing regulatory and policy barriers to the implementation of storage, ensuring that markets reflect the value of flexibility to system, and investing in innovation.
6. A key action from the 2021 Smart System and Flexibility Plan, is the re-iteration of a commitment made in the 2017 Smart System and Flexibility Plan to define electricity storage as a distinct subset of generation in primary legislation.

## Problem under consideration

7. Electricity storage is currently not defined in primary legislation. However, the Government's position[3] is that it constitutes a distinctive subset of the generation asset class – and this is generally considered to be the status quo. Electricity storage is already being treated in this way within the planning and licencing frameworks.
8. Calls for a formal definition have been recommended since 2016, such as in the House of Common's Energy and Climate Change Committee's final report of session 2016-7[4], and the National Infrastructure Commission's 2016 *Smart Power* report[5]. Formalising an official definition was also introduced as one of 29 proposed actions that the Government and the Regulator

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[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003778/smart-systems-and-flexibility-plan-2021.pdf
[2] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003787/smart-systems-appendix-i-electricity-system-flexibility-modelling.pdf
[3] This position has been agreed between BEIS, the Scottish Government, and the Welsh Government.
[4] HC 705. https://publications.parliament.uk/pa/cm201617/cmselect/cmenergy/705/705.pdf
[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf

committed to in the 2017 Smart Systems and Flexibility Plan[6], and re-iterated in the 2021 Smart System and Flexibility Plan.

9. The lack of formal definition means that its regulatory status within the electricity system is not completely clear, leading to unnecessary legal costs and risks around legal challenge which could stifle investment. In the past this has resulted in: storage being treated inconsistently as generation, demand, or both; discrepancies in network charges for storage; contradictory rules being applied to developers; uncertainty for investors; and barriers to new storage technologies participating in electricity markets, thereby hindering their deployment.

10. In lieu of primary legislation (which was first committed to in 2017), the Government has taken actions to provide clarity within the planning and licensing framework reducing the uncertainty for investing in storage. However, using primary legislation will provide much greater legal clarity, and help to future proof the framework.

## Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

11. This Impact Assessment is deemed proportional given the small magnitude of impact policy is estimated as having, with central estimates evaluating costs as a one-off familiarisation cost of £27,000. Whilst remaining unmonetised due to data availability constraints, important material benefits are expected to accrue to industry and wider society, justifying a thorough assessment of impacts – although these impacts are not deemed sufficiently substantial to warrant additional resources such as specific Monitoring & Evaluation (M&E) spending. This is further justified given the informal M&E expected to occur via stakeholder feedback to BEIS and our Smart Systems and Flexibility Monitoring Plan, which will holistically consider the impact of policy interventions within the contextual environment electricity storage operates within.

12. Further, this measure is also not expected to be politically sensitive. It is being introduced to fulfil one of the key actions presented in the 2017 Smart Systems and Flexibility Plan, and the subsequent 2021 Smart Systems and Flexibility Plan, to remove barriers for smart technologies such as storage. The definition has been developed on the basis of close engagement with industry and informed by both policy and stakeholder views, including views collated through a call for evidence in 2016. While some stakeholders would prefer it to be defined as a separate asset class (rather than a subset of generation), we have worked through the arguments, and we are confident in our approach.

## Policy objectives

13. The key policy objective is to provide the sector with legal clarity and certainty over the regulatory treatment of storage. The intended outcomes are to increase investor confidence in the sector, to reduce the risk of legal challenge, ensure consistency in the treatment of storage in the licencing and planning frameworks, and provide a clear basis for future regulatory changes to consistently refer to.

## Description of options considered

14. This IA only considers the single policy option of defining storage as a distinct subset of generation. This proposal is expected to achieve the key objectives outlined above, and is assessed relative to the 'do nothing' counterfactual.

    - **Counterfactual – 'Do nothing':** Under this option, no further changes are made to the existing legislation. Electricity storage continues to have no formal definition, keeping regulatory uncertainty, and the Government fails to keep to its list of intended actions in the 2017 and 2021 Smart Systems and Flexibility Plans.

    - **Option 1 (preferred option):** To define storage in the Electricity Act 1989, as a distinct subset of generation[7]. Reference to a person who generates electricity will include a

[6] HM Government & Ofgem. 2017. *Upgrading our Energy System – Smart Systems and Flexibility Plan.* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/633442/upgrading-our-energy-system-july-2017.pdf [ONLINE]

[7] No change to the treatment within the regulatory regime is planned. Given this, and the fact this has generally been treated as the *de facto* definition since 2017 (when it was introduced as an action within the Smart Systems and Flexibility Plan), we do not expect any reclassification of current assets, or any significant deviation in the financial value of such assets, as a result of these regulations.

reference to a person who generates electricity from stored energy, whereby 'stored energy' means energy which is converted from electricity, and is stored for the purpose of its future reconversion into electricity.

One previously considered alternative option included defining electricity storage as an entirely new asset class. However, following a call for evidence and analysis of these options, defining it as a distinct subset of generation is preferable. This is because electricity storage is similar to generation in many ways, and therefore including it as a distinct form of generation would avoid the disproportionate burden arising from unnecessary duplication of regulation, while still allowing specific regulations to be determined for storage assets. This alternative option would also be expected to lead to higher overall costs as it would represent a larger departure from the status quo, necessitating increased familiarisation costs. Our preferred option would also ensure implementation within the shortest possible timeframe, allowing for benefits to accrue sooner. It will also provide certainty for storage developers that already hold a generation licence.

## Summary and preferred option with description of implementation plan

15. The Government wants to provide regulatory clarity and certainty for electricity storage and to that end, to define electricity storage as a distinct subset of generation in the Electricity Act 1989. This will ensure continuity with the current approach yet allow flexibility for treating storage differently to other forms of generation where it is appropriate to do so.
16. As the measure will simply serve to clarify the Government's position formally, it will not give rise to any changes in regulation for the sector. The new definition is expected to be implemented from the moment the legislation comes into force. There is no need for enforcement or ongoing operation.

## Monetised costs and benefits

17. This section sets out the quantified costs of the proposed measure. Where evidence allows, we have quantified the major costs of the measure, and provided evidence of the direct benefits to industry.
18. The quantified costs are the learning and familiarisation costs to industry from reading and understanding the new definition.
19. It has not been possible to quantify the wider benefits which arise from the measure, such as the increased clarity and consistency for industry. These are discussed further in the non-monetised benefits section.

<u>Costs</u>

*Learning and familiarisation costs (Transitionary)*

20. This proposal may incur a transitionary familiarisation cost for market participants to read and understand the new definition. This would be a wholly additional cost arising from the measure relative to the counterfactual. To formulate this cost, the number of interested parties in 2022 (who would likely read the new legislation) has been estimated based on the National Grid's Capacity Market Registers[8]. The number of unique applicant companies with a Capacity Market Unit categorised as 'Storage' is centrally estimated as 100. However, given the uncertainty around the potential number of businesses who are likely to read the proposed definition (i.e. incur additional familiarisation costs) in 2022, we also examine low- and high-cost sensitivities using a range of 70-150 businesses.
21. Only the current number of unique applicant companies with storage has been used for this analysis. Familiarisation to the new definition for future storage companies is expected to become part of the routine planning and start-up costs of creating new unique applicant companies. Further, as this effectively replaces the costs of businesses having to currently familiarise themselves with the present legal status of energy storage, these costs to future businesses do not represent an additional cost.

[8] National Grid, Electricity Market Reform Delivery Body. 2018. Capacity Market Registers. https://www.emrdeliverybody.com/CM/Registers.aspx [ONLINE]

22. It is assumed that in the initial year of the definition being introduced (year 2022), each developer will require additional (legal and managerial) resource to read and understand the legislation, centrally estimated as 4.5 hours (from reading time assumptions and consultation with external stakeholders)[9], at a cost of £60 per hour[10]. However, given uncertainties, we also examine low- and high-cost sensitivities using a range of 3 to 6 hours of additional resource time.

23. These figures give a total additional familiarisation cost to businesses in the year of implementation is estimated to be in the range of £12,500 to £54,000, with a central estimate of around £27,000.

Summary of quantified analysis

24. The transitionary cost is expected to occur in the first year following implementation. This cost does not recur and therefore gives a quantified NPV of -£27,000 over a 10-year time horizon in the central scenario. Estimates are presented in Table 1 below.

*Table 1: Summary of quantified analysis*

| **Costs** | Transitionary cost, low-cost scenario | **Transitionary cost, best estimate** | Transitionary cost, high-cost scenario |
|---|---|---|---|
| **Learning and familiarisation cost** | £12,500 | **£27,000** | £54,000 |
| **Total NPV (best estimate)** | | | **-£27,000** |
| **BCR (best estimate)** | | | **-** |

*Costs are rounded to nearest £1,000.*

25. As noted above, only the costs of the measure have been possible to quantify, whilst it has not been possible to quantify any of the benefits. This explains why our central monetised estimates presents a negative NPV.

## Non-monetised costs and benefits

26. Due to the barriers in quantifying benefits, the monetised costs must be evaluated in tandem with the non-monetised benefits. The primary benefit of this measure is the increased ease of use to industry, through better clarity and consistency of regulations, with a secondary benefit from reduced risk of legal challenge and legal savings to industry.

27. Given this is a legal clarification of the definition of storage assets, rather than a change in the regulatory regime, and that the definition has generally been treated as the *de facto* definition since when it was first proposed in 2017, there is not expected to be any reclassification of current assets, or any significant deviation in the financial value of such assets, as a result of these regulations.

28. There are not expected to be any significant additional costs or benefits to the Government, and any costs associated with developing primary legislation will be absorbed within existing resources and will not be passed through to businesses or consumers. This measure is also not expected to result in any significant additional costs or benefits to the Regulator, however they are very supportive of the measure in helping to future proof the framework.

Benefits

*Increased clarity for the sector*

29. This measure has the potential to result in an indirect benefit in the form of increased investor confidence for the storage sector. This is through sending a positive signal to stakeholders on the

[9] This time assumption is based on the length of the relevant explanatory notes to the legislation and legislative clauses, which are expected to total around 9 pages, or 2,300 words – where it is assumed the corporate manager or director will read these texts three times over at a reading speed of 50 words per minute, to fully understand the technical content. This is then uplifted to account for any additional direct thinking those persons may have with regards to how these new regulations may then affect their businesses, based on informal discussions with internal and external stakeholders with relevant industry expertise – this is estimated by a further 2 hours. Given uncertainties, however, this assumption is subject to sensitivity analysis – this is found not to dramatically affect the impact upon businesses. This time period is treated as consistent across all business sizes, given any relevant changes in the cost of business operations as a result of this regulation are expected to be embedded into wider planned business expenditures – however it is appreciated that a larger-sized business may require relatively greater resource in familiarisation. It is expected that sensitivity analysis would also account for this.

[10] 2020 prices. Wage costs based on ONS – Revised 2020 ASHE: Table 14.5 a (11: Corporate managers and directors at the 90th percentile; 241: Legal professionals at the 80th percentile. To ensure that the costs are as representative as possible we used the highest percentile costs for that were available, given sample sizes, for these professions). Includes non-wage-costs of around 20% (EUROSTAT, 2016)

stability of the regulatory position for storage – something the majority of Call for Evidence[11] responses supported the use of primary legislation to achieve – and demonstrating that the Government is committed to developing a best-in-class regulatory framework for storage in Great Britain.

*Greater consistency*

30. This measure will help to ensure consistency and certainty in the treatment of electricity storage in legislation and provide a clear basis for future regulatory changes to consistently refer to. This is especially relevant for planning and licensing.

*Cost savings to industry for legal advice*

31. This measure will reduce cost requirements on developers who currently have had to seek legal advice for projects to clarify the treatment of storage as a subset of generation, given the current lack of a formal legal definition.

*Reduced risk of legal challenge*

32. This measure will reduce the risk of legal challenge relating to the approach to define storage for planning and licencing purposes. The Department's legal view on the risk of legal challenge from storage developers stemming from the lack of a legal definition (e.g. challenge from storage developers who disagree with the position that storage should be treated as a distinct subset of generation) is 'low' as no legal challenges have been brought forward to date in Great Britain and there is no evidence to suggest that any are imminent. However, the likelihood of a successful challenge at court is estimated to be 30-50% (medium-low) without the definition in primary legislation; introducing the proposed measure reduces this risk to below 30% (low).

## Summary of monetised and non-monetised costs and benefits

33. This measure is expected to have quantified costs in the range of £12,500 to £54,000 with a central estimate of around £27,000 from the learning and familiarisation costs to industry. The primary benefit of this measure is the increased ease of use to industry, through better clarity and consistency of regulations, with secondary benefits from reduced risk of legal challenge and savings from industry from having to procure additional legal advice.

## Risks and assumptions

Risks

34. A risk arises if the formal definition is inaccurate, or requires further adjustments down the line. As we move towards net zero, new technologies may enter the market and be able to qualify as electricity storage while not necessarily providing electricity storage as we currently understand it. For example, synchronous compensators have been able to make this case to secure an electricity storage license. However, the extent to which this would need to reflected in a definition is unknown and this risk is seen as generally small given the proposed definition is being used in Ofgem's modified generation licence for storage, has received support from industry through a call for evidence, and has been developed on the basis of close engagement with industry[12]. Any amendments to the definition in the future would likely require additional primary legislation.

Assumptions

35. Quantified analysis assumes that familiarisation costs can be illustrated fairly by assuming time to read and understand legislation changes is around 4.5 hours at an assumed cost of £60 per hour.[13]

36. Quantified analysis assumes that all current storage providers would take the time to read and familiarise themselves with the new regulations. Given the new definition is a simple clarification of the status quo, it is possible that not all companies would find this necessary; further, the Government's position and intended definition has been clear since 2017, and therefore this information may already be known to companies. If less companies must familiarise themselves to

[11]HM Government & Ofgem. 2016. *Smart Systems and Flexibility Plan - Call for Evidence.* https://www.gov.uk/government/consultations/call-for-evidence-a-smart-flexible-energy-system [ONLINE]

[12] HM Government & Ofgem. 2017. Smart Systems and Flexibility Plan - Call for Evidence Question Summaries and Response from the Government and Ofgem. Page 15. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/631656/smart-energy-systems-summaries-responses.pdf [ONLINE]

[13] The explanation for these is included in footnotes 9 and 10.

the new definition, this situation would lead to lower total overall costs, more in line with the low-cost scenario, analysed within sensitivities, of £12,500. On the other hand, it is also possible that non-storage providers may also seek to familiarise themselves with the new definition, which would drive costs up and may counteract the former effect.

## Wider impacts (consider the impacts of your proposals)

Enabling flexibility

37. Electricity storage is a critical technology for meeting Net Zero. Recent analysis published for the 2021 Smart System and Flexibility Plan estimated that smart and flexible technologies, including storage, could reduce system costs between £30-70bn from 2020 to 2050; and that 30GW of low carbon flexible assets (including electricity storage) may be needed by 2030 to maintain energy security and cost-effectively integrate high levels of renewable generation. This represents a three-fold increase on today's levels.
38. This measure reduces barriers to the deployment of storage to help achieve these savings and targets, and improves our ability to meet our decarbonisation targets cost-effectively.

Justice Impact Test

39. As the measure formalises the Government's existing position, it is not expected to increase or decrease the volume of cases going through the courts or tribunals, or change the way that cases are delt with by the justice system. This measure is not expected to have an impact.

Equalities Assessment

40. We do not expect any impact on the Convention Rights of any person or class of persons arising from the measure assessed in this IA. Our view is that there would be no impact on race, disability, gender or any other protected characteristic from the measure in this IA. These regulations will not target persons but companies in scope. In addition, this measure will be of general benefit to everyone in the GB regardless of whether they have one or more protected characteristics.

Price and Bills impact

41. We do not expect there to be any implications on energy bills from this measure.

Potential trade implications

42. We do not expect there to be any direct implications on trade from our measure. This measure may however contribute to greater regulatory clarity for the electricity storage sector, which may contribute to increased confidence in UK investments for international electricity storage investors, though it is expected that this policy may only contribute towards investor confidence in a small way.

## Direct costs and benefits to business calculations

43. Relative to the counterfactual (i.e. the 'Do nothing' option) and aside from monetised one-off familiarisation costs and unquantified savings from legal procurement, this measure is not expected to result in any immediate additional quantifiable direct costs or benefits to businesses. This is because the Government's existing position – as set out in the Smart 2017 Systems and Flexibility Plan, prior Call for Evidence, and 2021 Smart Systems and Flexibility Plan – is that electricity storage constitutes a distinct subset of generation for licencing and planning purposes. As such, the measure will simply serve to clarify this position formally in the Electricity Act 1989 and will therefore not give rise to any change in regulation for the sector.
44. As a result this gives an expected EANDCB to be in the range of £12,500 to £54,000 with a central estimate of around £27,000.

## Impact on small and micro businesses (SaMBA)

45. This definition will apply to all electricity storage developers regardless of size. Relative to the counterfactual, this measure is not expected to result in any direct costs or benefits to businesses apart from potential one-off familiarisation costs. On a per company basis, our central estimate assumes that the additional cost incurred to business will amount to £270. Sensitivity analysis determined low- and high-cost estimates per business within a range of £180 and £360. This cost

is overall insignificant and is unlikely to impact business operations, regardless of company size – however, it is still expected that this would represent relatively larger proportions of micro and small business' turnover[14].

46. However, potential mitigations for small and micro businesses were explored (e.g. exemptions) but this was not considered compatible with the aim for the definition to be applied uniformly. Subsidy schemes were also not considered justifiable, to warrant additional Government spending, given the small scale of the expected burden from these regulations. It is considered that there is no reasonable scope for the familiarisation costs to be avoided for small and micro businesses.

47. Having said this, these small and micro business are likely to receive benefits from the savings gained from no longer having to procure legal services relating to the definition of storage. This benefit has not been able to be monetised.

48. Table 2 below shows the number of firms spread across the electricity sector in 2020. This shows that micro and small businesses already play an increasingly important and significant role in the electricity sector. However, not all of these firms are expected to face additional costs from familiarising themselves to this proposal, as they may not have an explicit focus in electricity storage. In addition this measure is a clarification of the status quo rather than a new regulation.

*Table 2: Number of employers in the private sector, Electric power generation, transmission and distribution industry group, UK, beginning of 2020*[15]

| | **Firms (*number*)** | **Employment ('*000s*)** | **Turnover (*£m*)** | **Firms (%)** | **Employment (%)** | **Growth in firms since 2013** |
|---|---|---|---|---|---|---|
| **All employers** | 2,555 | 101 | 101,065 | *100* | *100* | 296% |
| **Micro (1 - 9 employees)** | 2,060 | 8 | 6,898 | *81* | *8* | 308% |
| **Small (10 - 49 employees)** | 415 | 6 | * | *16* | *6* | 295% |
| **Medium (50 - 249 employees)** | 55 | 6 | * | *2* | *6* | 175% |
| **Large (250+ employees)** | 25 | 82 | 85,319 | *1* | *81* | 67% |

*Key: * - denotes to unavailable data*

## Monitoring and Evaluation

49. It is not deemed proportional to carry out Monitoring and Evaluation (M&E) specific to this intervention given both the small scale of impacts expected and minimal opportunity for this policy intervention to provide M&E learning opportunities or inform future electricity storage decisions.

50. Instead, M&E will be carried out informally via stakeholder feedback to BEIS and our Smart Systems and Flexibility Monitoring Plan, the first iteration of which was published in 2021[16]. Both of these will enable the impact of policy intervention to be considered holistically against the range of other measures we are taking and the contextual environment electricity storage operates within.

[14] It is important to note however that, for ease, a single time assumption within analysis of familiarisation costs was used, consistent across business sizes. While additional assumptions for familiarisation by company size would have likely drawn out additional context, estimating and applying such assumptions were seen as adding potentially misleading spurious accuracy to the calculations.

[15] https://www.gov.uk/government/statistics/business-population-estimates-2020

[16] Annex 2 to BEIS' Smart Systems and Flexibility Plan https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

| | |
|---|---|
| **Title:** Smart Metering Rollout<br>**IA No:** BEIS048(F)-22-SMIP<br>**RPC Reference No:** **RPC-BEIS-5173(1)**<br>**Lead department or agency:**<br>**Other departments or agencies:** | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage: Final**<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** smartmetering@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| Not quantified | Not quantified | Not quantified | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

This intervention is to extend the duration of the Secretary of State's powers in the Energy Act 2008 (and associated powers in the Electricity Act 1989 and Gas Act 1986) to make licence and industry code modifications for the purposes of the roll out of smart meters in Great Britain. These powers currently expire on 1 November 2023. This intervention would extend them to 1 November 2028. Due to the likely need to make changes to the smart metering regulatory framework throughout the period of the new policy framework (1 January 2022 to 31 December 2025) and the potential for necessary regulatory changes arising from the subsequent post-implementation review, it is not feasible to anticipate and to make all the required regulatory changes prior to November 2023. If the Secretary of State was not able to act in such circumstances, we consider that it is likely that there would be a significant risk to achieving the overall Smart Metering Implementation Programme (SMIP) benefit case.

**What are the policy objectives of the action or intervention and the intended effects?**

Smart meters will make our energy system more efficient and flexible, which will cut costs for consumers whilst also underpinning the cost-effective delivery of the government's commitment to net zero emissions by 2050, enabling renewable energy sources and new technologies to be integrated into the energy system. Without this flexibility, the costs of delivering net zero by 2050 could be up to £16 billion higher each year. The government is committed to achieving market-wide rollout of smart meters by the end of 2025. This intervention will ensure that the Secretary of State is able to make licence and industry code modifications for the purposes of the roll out of smart meters in Great Britain. Any licence and industry code modifications in the period of extension (1 November 2023 to 1 November 2028) would be subject to consultation and, as needed, specific Impact Assessments will be submitted to assess their related impacts.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Do nothing – This would see the Secretary of State's powers expire in November 2023. Ofgem has powers under the Electricity and Gas Acts (as the named 'Authority') to amend licence conditions beyond November 2023. However, as an independent regulator it is not their responsibility to preserve SMIP's benefits case which potentially risks £7.7bn of potential net benefit. Furthermore, the Authority is reliant on industry parties to raise code changes themselves, or to conduct a significant code review itself, which can take a considerable amount of time.

Option 1 (preferred) - Extend the duration of the Secretary of State's powers in the Energy Act 2008, will enable the Secretary of State to, as needed, make licence and industry code modifications to preserve SMIP benefits for the remainder of the smart rollout, ensuring the delivery of £7.7bn of net benefit.

**Will the policy be reviewed?** It will/will not be reviewed. **If applicable, set review date:** Month/Year

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | No | | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** N/A | **Non-traded:** N/A | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

## Summary: Analysis & Evidence

Policy Option 1

**Description:**

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Years** | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** | **High:** | **Best Estimate: Not quantified** |

| **COSTS (£m)** | **Total Transition** (Constant Price) Years | | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | **Not quantified** | | **Not quantified** | **Not quantified** |

**Description and scale of key monetised costs by 'main affected groups'**

The main monetised costs areas arising from smart metering are identified in the 2019 CBA (and are those most likely to be affected by this legislation). The majority of these costs are those incurred by energy suppliers for (a) the purchase of metering assets (smart meters, in-home displays, and communications hubs); and (b) the installation of these meters. Combined these areas make up around 80% of the total cost. Other costs include operational and maintenance costs, supplier IT costs, pavement reading inefficiencies and disposal costs, which are all incurred by suppliers. These costs are likely to be passed through to consumers through impacts on energy bills.

**Other key non-monetised costs by 'main affected groups'**

While we have monetised the time cost to consumers resulting from the typical duration of an installation visit (around two hours to complete), consumers will also incur a non-monetised opportunity cost relating to the time that they may stay at home prior to and following this installation visit.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) Years | | **Average Annual** (excl. Transition) (Constant | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | Not quantified | | Not quantified | **Not quantified** |

**Description and scale of key monetised benefits by 'main affected groups'**

The main monetised benefits arising from smart metering are identified in the 2019 CBA (and are those most likely to be affected by this legislation). Consumers will benefit through energy savings that smart meters enable them to realise. This makes up around a third of the total benefits. Most of the remaining benefits are to energy suppliers, including avoided site visits (e.g., for meter reading), reduced customer service enquiries, and lower costs to serve prepayment customers. We expect these savings to be passed on to consumers through lower bills. There are also environmental benefits from reduced energy usage and benefits to electricity network operators through improved fault detection and better-informed investment decisions.

**Other key non-monetised benefits by 'main affected groups'**

Smart meters are an important upgrade to our national energy infrastructure that will enable the creation of a more flexible and more resilient energy system benefitting both consumers and suppliers. They will enable suppliers to offer innovative new tariffs, including smart tariffs which charge consumers different prices for electricity at different times of the day.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | N/A |
|---|---|---|

This Impact Assessment is based on the latest Cost-Benefit Analysis model for the smart meter rollout, which was published in September 2019. The recency and comprehensive nature of that assessment gives confidence that it remains suitable for the purposes of this impact assessment.

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m: N/A** | | | **Score for Business Impact Target (qualifying provisions only) £m: N/A** |
|---|---|---|---|
| **Costs: N/A** | **Benefits:** N/A | **Net:** N/A | N/A |

# Evidence Base

## Problem under consideration and rationale for intervention

1. Smart meters are replacing traditional gas and electricity meters across Great Britain and are a vital upgrade to our national energy infrastructure. They will make our energy system more efficient and flexible, enabling the use of more renewable energy in a more cost-effective manner, whilst also enabling new technologies to be integrated into the energy system. Smart metering will cut costs for consumers (in the form of energy savings) whilst also underpinning the cost-effective delivery of the Government's net zero commitment; without the flexibility afforded by smart metering, the cost of delivering net zero will increase by up to £16 billion per annum according to a Climate Change Committee report[1]. On 1 January 2022 a new four-year regulatory framework with fixed annual installation targets for energy suppliers came into force. The government is committed to achieving market-wide rollout of smart meters by the end of this framework (end 2025).

2. Under the Energy Act 2008, the Secretary of State has powers to make licence and industry code modifications to require electricity and gas licensees to roll out smart meters to electricity and gas customers. Originally under Section 88 of the 2008 Energy Act, the Secretary of State's powers to make licence and code modifications were to expire on 1 November 2013 (together with section 56FA Electricity Act 1989 and section 41HA Gas Act 1986). The Energy Act 2011 extended that period (together with the expiry date for section 56FA Electricity Act 1989 and section 41HA Gas Act 1986) to 1 November 2018 and the Smart Meters Act 2018 further extended it (together with the expiry date for section 56FA Electricity Act 1989 and section 41HA Gas Act 1986) to 1 November 2023.

3. The expected timeframe for the roll out of smart meters have changed since this previous extension. The target date for the completion of the smart metering roll out has been extended from the end of 2020 to the end of 2025.

4. While it is expected that by November 2023 (when current powers expire) most of the regulatory framework will be delivered and the need for the Secretary of State to make modifications will be substantially reduced, it is likely will still be some areas where the Secretary of State might need to intervene given the timeframe of the rollout, as outlined above. If the Secretary of State was not able to act in such circumstances, it is possible that there would be a significant risk to delivering the overall Smart Metering Implementation Programme (SMIP) business case. A recent example of the effective use of these powers was seen during the COVID-19 pandemic, where the previous policy framework was extended by 12 months (in two, six-month increments) to provide regulatory certainty regarding the smart meter rollout whilst nationwide restrictions were in place. While it is not possible to foresee all of the possible policy scenarios that a programme of this scale and complexity may encounter after November 2023, there are some known instances where the Secretary of State may need to take steps at around or beyond the expiration of the Section 88 powers. For example:

   - On 1 January 2022 a new four-year regulatory framework with fixed annual installation targets for energy suppliers came into force[2]. The government is committed to achieving market-wide rollout of smart meters by the end of this framework (end 2025). This Framework sets energy suppliers' minimum, annual installation targets to deliver market-wide rollout. Currently these targets have been set for only Year 1 (2022) and Year 2 (2023) of the Framework. Installation targets for years 3 and 4 will need to consider the most relevant (and emerging) evidence when the mid-point review of the Policy Framework takes place in 2023. Extension of the Section 88 powers beyond November 2023 is, therefore, needed to enable the Government to implement any regulatory changes that may prove necessary following the findings of the mid-point review. For example, in November 2021 the Government consulted on a technical amendment to the formula used to

[1] Net Zero Technical Report May 2019

[2] https://www.gov.uk/government/consultations/smart-meter-policy-framework-post-2020-minimum-annual-targets-and-reporting-thresholds-for-energy-suppliers

calculate annual installation targets to adjust for churn in smart meter customers. Similar adjustments may need consultation and amendment following the mid-point review.

- At the end of the new four-year regulatory framework, a post-implementation review of the smart meter rollout will be conducted. This may identify the need for further regulatory changes to ensure consumers continue to be protected and benefit from smart metering. Extension of the Section 88 powers beyond November 2023 is, therefore, needed to enable the Government to implement any regulatory changes that may prove necessary following the post-implementation review.

## Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

5. In 2019, the Smart Metering Implementation Programme produced and published a revised cost benefit analysis[3] which is a comprehensive and extensively quality assured assessment of the costs and benefits of the programme. This analysis suggests that the programme will deliver a net societal benefit of £6bn from the start of the rollout through to 2034. Renewing the powers to modify licence conditions and industry code ensures that the programme remains responsive to developments and changes in the energy system, safeguarding the cost-effective and timely delivery of the programme. However, given the inherent uncertainty around the necessity for any future policy intervention (and the nature of any potential intervention) plus the pre-existence of a comprehensive cost-benefit analysis, we do not consider additional analysis to be proportionate at this stage and have not quantified the benefits related to these potential interventions. Any future interventions will work to deliver the £6bn of net benefit to society and will be assessed in line with the Better Regulation Framework and guidance published by the Regulatory Policy Committee.

## Description of options considered

6. In addition to our preferred option, we have considered the alternative approaches available for safeguarding SMIP's benefits including, Ofgem's power to modify licence conditions. However, we have concluded that these will not deliver the required changes in a timely enough manner during the roll out phase of the programme and may risk some of the SMIP benefits case. Whilst Ofgem does have the power under the Electricity and Gas Acts (as the named 'Authority') to amend licence conditions, they, as an independent regulator, it is not their role to preserve the SMIP benefits case for which BEIS is responsible and is estimated to deliver a net benefit of £7.7bn from 2024 through to 2034. Furthermore, the Authority is reliant on industry parties to raise code changes themselves, or to conduct a significant code review itself, which can take a considerable amount of time. This process cannot be relied upon to make important cross-cutting changes that are likely to be required in shorter timeframes.
7. We therefore have only proposed one policy option in addition to the status quo counterfactual. Our policy options are as follows:
   - Option 0 – This is the scenario that we would expect to prevail in the absence of any policy intervention. Government has less scope (than at present) to effectively intervene with respect to smart metering. This represents a strategic delivery risk given the ongoing nature of the smart metering rollout. This option is not considered viable for the reasons given above and is included in line with HMT Green Book[4] guidance.

   - Option 1: Extension of legislative powers – This is our preferred policy option. Whilst the costs and benefits for this option have not been quantified as explained elsewhere in this assessment, it will, by nature, allow for the delivery of additional net benefit compared to option 0 (any policies

3 https://www.gov.uk/government/publications/smart-meter-roll-out-cost-benefit-analysis-2019

4 https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

implemented as a result of the powers from this intervention will be assessed and proceed if they deliver a net benefit to society.) Under this option, legislation pertaining to smart metering is quicker to implement and Government are more responsive to changes in the energy system that could affect smart metering and energy consumers. Existing powers have already been used to the benefit of society; for example, the implementation of the Targets Framework in June 2021 will deliver an estimated net benefit of £1.2bn to society between 2021 and 2034.[5]

## Policy objective

8. On the 1 January 2022 a new four-year regulatory framework with fixed annual installation targets for energy suppliers came into force. This Framework sets energy suppliers' minimum, annual installation targets to deliver market-wide rollout.
9. The objectives for this new four-year framework (based on engagement with energy suppliers, Ofgem and Citizens Advice) are:

- To encourage consumers to benefit from the rollout of smart meters, including how to use the data from their smart meters;
- To deliver a market-wide rollout of smart meters as soon as possible, that ensures value for money and maintains installation quality so that consumers can derive maximum benefit and have a good experience;
- To normalise smart meters so they are the default meter used in Great Britain; and
- To give certainty to the whole sector to invest and plan, ahead of and beyond 30 June 2021.

10. This particular intervention (to extend the duration of the Secretary of State's powers in the Energy Act 2008 and associated powers in the Electricity Act 1989 and Gas Act 1986) will ensure that the Secretary of State is able to make any necessary changes to licence conditions and industry codes between November 2023 and 2028.

## Summary and preferred option with description of implementation plan

11. As discussed in paragraph 7, option 1 is our preferred policy option. The intervention would be implemented via the Energy Bill and is intended to come into effect by November 2023, and no additional operational changes will be required.

## Monetised and non-monetised costs and benefits of each option (including administrative burden)

12. As discussed in the paragraph 5, no additional analysis of costs and benefits beyond the 2019 Smart Metering CBA has been undertaken for this assessment given the uncertainty about potential measures needed at the point of secondary legislation. As such, we have categorised the costs and benefits of this measure as "not quantified." Any additional policy interventions that result from this measure will:

- Assessed appropriately in accordance with the Better Regulation Framework.
- Be expected to contribute to the previously published £6bn net benefit to society or deliver additional net benefit to society.

[5] https://www.gov.uk/government/consultations/smart-meter-policy-framework-post-2020-minimum-annual-targets-and-reporting-thresholds-for-energy-suppliers

13. The 2019 CBA identifies total costs and benefits as shown in Table 1 below (these are in 2011 prices with a 2019 present value base year.) The same analysis also found that the programme has reached a point where each additional smart meter installed delivers a net benefit to society[6].

| **Total Costs** | **13,687** | **Total Benefits** | **19,348** |
|---|---|---|---|
| | | | |
| *In Premises Costs* | *7,706* | *Consumer Benefits* | *7,502* |
| Installation of Meters | 3,165 | Energy Savings | 6,129 |
| Meters & IHDs | 2,345 | Time Savings | 1,373 |
| Communications Hubs Capital Costs | 1,246 | | |
| Operations and Maintenance of Meters | 646 | *Supplier Benefits* | *8,035* |
| Communications Hubs Operations Costs | 304 | Avoided Site Visits | 2,303 |
| | | Customer Switching | 1,251 |
| *DCC Related Costs* | *2,900* | Customer Calls | 1,234 |
| DCC Licensee Costs | 539 | Avoided PPM Premium | 1,116 |
| External Service Provider Costs | 2,361 | Debt Handling | 1,051 |
| | | Reduced Theft and Losses | 911 |
| *Suppliers' and Other Participants' System Costs* | *1,169* | Remote Change of Tariff | 170 |
| Supplier Capital Costs | 494 | | |
| Supplier Operating Costs | 346 | *Demand Shifting Benefits* | *1,363* |
| Industry Capital Costs | 57 | | |
| Industry Operating Costs | 118 | *Network Benefits* | *424* |
| DCC Adaptor Services | 155 | Better Informed Investment Decisions | 259 |
| | | Outage Detection and Management | 164 |
| *Other Costs* | *1,720* | | |
| Energy Consumption by Smart Metering Assets | 654 | *Carbon and Air Quality Benefits* | *2,024* |
| Organisational Costs | 280 | Reduced GHG Emissions | 1,636 |
| Alt-HAN Direct Costs | 288 | Air Quality Impact | 388 |
| Pavement Reading Inefficiency | 250 | | |
| Smart Energy GB Costs | 230 | **Net Present Value** | **5,977** |
| Disposal Costs | 18 | | |
| | | | |
| *Projected Future Costs* | *192* | | |

**Table 1 – Summary of costs and benefits and total NPV (all figures in £m)**

## Direct costs and benefits to business calculations

14. As discussed in paragraph 5, we have not sought to quantify costs and benefits relating to this intervention given the aforementioned uncertainty around future policy proposals. These powers do not directly result in any costs and benefits and an appropriate assessment of direct costs and benefits to business will be undertaken for all future policy appraisal resulting from this intervention, in line with Regulatory Policy Committee guidance.

## Risks and assumptions

15. There are no additional risks resulting from the proposed policy measure which works to mitigate against any risks which could impact the successful delivery of the smart meter rollout and associated benefits. For risks and assumptions relating to the programme, see the 2019 cost benefit analysis[6].

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[6] https://www.gov.uk/government/publications/smart-meter-roll-out-cost-benefit-analysis-2019

## Impact on small and micro businesses

16. The smart meter rollout includes within scope all domestic and non-domestic metering points within electricity profile classes 1 to 4 and with gas consumption below 732MWh per annum. This covers the vast majority of British business metering points and would be expected to include the vast majority of small and micro-businesses (as these are likely to be smaller energy consumers). To exclude these metering points from the policy measure would deny a significant proportion of consumers many of the benefits resulting from smart metering.

17. Responsibility for the rollout sits with energy suppliers, a small proportion of which are small and micro businesses. Given that the above measure imposes no costs at present, we will look to assess the impacts of any future interventions on small and micro energy suppliers on a policy-by-policy basis.

## Wider impacts (consider the impacts of your proposals)

18. It is our view that there are no additional wider impacts from these proposals. However, we shall continue to assess these as necessary for any new measures resulting from this intervention. The rollout of smart meters is an enabling programme that will assist in the transition to a flexible energy system and is integral to the cost-efficient delivery of net-zero. The market-wide rollout of smart meters will also be necessary to help maximise the benefits of half hourly settlement, which Ofgem is considering in respect of domestic and smaller non-domestic consumer segments7 (larger non-domestic consumers are already subject to half-hourly settlement).

## A summary of the potential trade implications of measure

19. The Smart Metering rollout covers Great Britain, and it is our view that there will be no impact on trade or investment from the policy measure.

## Monitoring and Evaluation

20. The Programme undertakes extensive monitoring and evaluation activities and will continue to do so following the renewal of our legislative powers. Activities to monitor the progress of the smart meter rollout and identify the potential need for policy intervention, include (but are not limited to):

    - The production of quarterly and annual statistical releases, making transparent the progress of the rollout.
    - Holding regular bilateral meetings with energy suppliers to identify issues, promote best-practice, and monitor developments within the industry.
    - Working with specific business sectors to ensure that they can maximise their benefits from smart metering.
    - Reviewing the benefits being delivered by smart meters, as part of ongoing benefits realisation activity within the Smart Metering Implementation Programme.

21. We expect that no additional information, beyond that which is collected from the activities listed above, will need collecting as a result of this measure. Where there is further need for additional monitoring and evaluation of specific metrics (or the like), we will first look to adapt our existing activities.

22. In the event that the legislative powers are used to amend license conditions, we will develop robust monitoring and evaluation plans to assess how effective any policy measures have been at delivering the specified objectives of the policy intervention and how they have contributed to the delivery of the programme's wider, strategic objectives.

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[7] https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement-reform

## Public Sector Equality Duty Assessment

23. The Smart Metering Implementation Programme has undertaken assessments of this nature for previously policy interventions in line with the requirements of the Public Sector Equality Duty (the equality duty) as set out in section 149 of the Equality Act 2010. Whilst we do not believe that this primarily legislation will have any impacts in this space, we will continue to consider PSED implications alongside any legislative proposals resulting from this policy.

24. In June 2021, we implemented our new post-2020 policy framework (which underpins the rollout of smart meters.) In doing this, we completed a PSED assessment in line with the aforementioned requirements. The impact of smart metering on statutory equality duties (including our obligations under the Public Sector Equality Duty) is considered on pages 67-72 of the 2019 Smart Metering Cost-Benefit Analysis. Since the purpose of the post-2020 policy framework is to maintain the momentum in the smart meter rollout to help ensure that it can be delivered to completion, the impacts studied in that document are also applicable here. We do not consider that any of the social impact tests available are relevant to this assessment

25. The Government and Ofgem have worked with a range of consumer and other organisations to use the opportunities created by smart metering to protect and provide benefits for those in vulnerable circumstances and to avoid possible disbenefits. The Programme has put in place measures designed to ensure that consumer interests are fully protected. These measures include a Code of Practice covering the necessary steps required during installation; and a Data Access and Privacy Framework, which sets out the purposes for which energy consumption data can be collected and the choices that consumers have about access to their data. The Smart Metering Implementation Programme will continue to monitor consumer protection policy to ensure appropriate safeguards are in place, including for vulnerable consumers and consumers with protected characteristics.

| | |
|---|---|
| **Title:** Future of the System Operator<br>**IA No:** BEIS050(F)-21-ICE<br>**RPC Reference No:** RPC-BEIS-5076(2)<br>(RPC-BEIS-5173(1))<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** Ofgem | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>Source of intervention: Domestic<br>Type of measure: Primary legislation<br>**Contact for enquiries:**<br>EnergyBill2021@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2020 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status**<br>Non qualifying provision |
| NA | NA | NA | |

**What is the problem under consideration? Why is government action or intervention necessary?**

Achieving net zero will require a transformation of both the energy system and its governance structure. The unique position of the System Operator (SO) at the heart of the energy system makes it well placed to take on enhanced roles and responsibilities for achieving net zero at least cost whilst ensuring a secure and stable energy system. However, the current ownership of the SO by National Grid Plc, creates a potential or perceived conflict of interest. While there is no evidence that this has been acted upon, it nevertheless inhibits the SO from taking on the enhanced roles desirable to reach net zero. To overcome this potential conflict of interest, the 2021 Ofgem Review of GB Energy System Operation concluded the need for government to create a new independent future system operator (FSO).

**What are the policy objectives of the action or intervention and the intended effects?**

This intervention intends to remove the current potential conflict of interest by creating an independent FSO able to drive progress towards net zero while maintaining energy security and minimising costs for consumers. To do this, the FSO will need new roles and responsibilities in the electricity and gas systems and will need to have the following characteristics outlined in the Ofgem report and further developed by BEIS: (i) Technically expert, (ii) Operationally excellent, (iii) Accountable, (iv) independently minded and (v) resilient. This intends to enable FSO to provide improved advice to government and Ofgem and to take a “whole system” view in areas such as network planning. As a result, intervention intends to reduce the overall system cost required to meet net zero while maintaining energy security and minimising costs for consumers.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Options presented in this Impact Assessment are stylised and used to illustrate the magnitude of impact this policy may have based on the scale of intervention. Final options are subject to a sale process with National Grid Plc and the views collected at consultation. Illustrative options presented in this impact assessment are: (1) **Do nothing:** National Grid Plc continues to operate the electricity system operator. National Grid Plc continues to undertake the gas system balancing and operating role, with a new private investor after the sale of the majority stake of NGG is completed. Expected higher energy system costs of reaching net zero against policy options. (2) **Option 1:** The FSO undertakes day-to-day operation of the electricity system operator and takes an increased role in planning the electricity system and facilitating competition. No formal gas roles performed by FSO. (3) **Option 2: (Preferred):** In addition to roles included in option 1, the FSO also undertakes increased coordination and advice on rulemaking responsibilities. The FSO is responsible for long-term planning and forecasting for the gas National Transmission System (NTS). (4) **Option 3:** The FSO is responsible for the day-to-day operation of the gas NTS in addition to all functions listed in option 2. Under Options 1-3, the FSO is a highly independent publicly owned body. The preferred option was broadly supported at consultation and found to have the strongest economic case assessed below.

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:** to be confirmed

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro**<br>Yes | **Small**<br>Yes | **Medium**<br>Yes | **Large**<br>Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions?<br>(Million tonnes $CO_2$ equivalent) | | **Traded:**<br>NA | **Non-traded:**<br>NA | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ____________ Date: 24/06/2022

## Summary: Analysis & Evidence — Policy Option 1

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 10 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** | **High:** | **Best Estimate: NA** |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Cost (Present Value) |
|---|---|---|---|---|
| **Best Estimate** | | | | |

**Description and scale of key monetised costs by 'main affected groups'**

Across all options there are no material costs of primary legislation which are deemed enabling only. All costs of secondary are given as a range due to the uncertainty of estimates. The costs to implementing the FSO under this option are estimated as between £50m-£140m. This includes one-off separation costs incurred by the current and new owner of FSO functions, on-going costs due to the duplication of corporate services, legal, financial and consultancy costs. Any capital costs associated with FSO implementation are commercially sensitive and therefore removed. These costs may be recouped against the future guaranteed revenue streams available to the FSO.

**Other key non-monetised costs by 'main affected groups'**

There may be significant learning and familiarisation costs to all stakeholders. These costs are likely to be largest for the FSO, since internal learning costs will also be incurred as the newly created body adjusts to its organisational design and internal processes.

| BENEFITS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Benefit (Present Value) |
|---|---|---|---|---|
| **Best Estimate** | | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

There are no material benefits of primary legislation across any option considered. For secondary impacts, the improved "whole system" view of the FSO is illustrated as reducing the future costs of the electricity system by between £210m-£2,500m across generation, network development and system balancing, though this is highly uncertain. This is in part, due to the reduced potential and perceived of conflicts of interest in network development as well as increased co-ordination of investment decisions across the sector and across energy vectors. An independent FSO is also expected to better facilitate competitions for third parties to provide assets for pre-identified system needs, this is estimated to save between £80m-£300m compared to if the current SO facilitated competition.

**Other key non-monetised benefits by 'main affected groups'**

The removal of potential conflicts of interest in the FSO is likely to reduce the perception of conflicts of interest in their expert advice provided to government, Ofgem and energy participants, improving technology decisions. For government and Ofgem, this is also expected to reduce the level of internal scrutiny required allowing for more timely decisions. Improved co-ordination across the energy system may lower the risk of unplanned outages and system failures, particularly during periods of system stress.

**Key assumptions/sensitivities/risks** — **Discount rate (%)** 3.5

Quantified results are sensitive to two key assumptions. Firstly, is assumed that the reduced costs as a result of the FSO's "whole system" view can be fairly illustrated by a range of between 1% to 5%. Secondly, it is assumed that the FSO will improve facilitation of network competition by an illustrative range of 25%-50%. These illustrative ranges are not distinguished across policy options due to the uncertainty in assessing the magnitude of benefits. Several key risks exist including reduced efficiency under the FSO, increased uncertainty to energy system participants and the creation of a "single view" of the energy system which could worsen decisions made.

**BUSINESS ASSESSMENT (Option 1)**

| Direct impact on business (Equivalent Annual) £m: | | | Score for Business Impact Target (qualifying provisions only) £m: |
|---|---|---|---|
| **Costs:** NA | **Benefits:** NA | **Net:** NA | NA |

## Summary: Analysis & Evidence                    Policy Option 2

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Year** 10 | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** | **High:** | **Best Estimate:** NA |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Best Estimate** | | | | |

**Description and scale of key monetised costs by 'main affected groups'**

The cost of implementation is higher compared to Option 1, amounting to an expected £90m-£270m due to the additional gas and electricity roles and responsibilities taken on by the FSO. Primarily, this rise in implementation costs is a result of higher expected separation and/or duplication costs of gas functions due to their current integration with the gas transmission operator. As above, any capital costs associated with FSO implementation are excluded due to their commercial sensitivity.

**Other key non-monetised costs by 'main affected groups'**

Non-monetised costs are the same as those listed in Option 1. The magnitude of these costs is expected to be larger under this option due to the increased number of roles and responsibilities for gas and electricity taken on by the FSO.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Best Estimate** | | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

In addition to Option 1, the increased gas forecasting and planning functions are expected to enable further cost reductions across the energy system of between £80m-£600m, due to improved "whole system" decision making now also applying to natural gas and hydrogen, reducing future network development, balancing and potential decommissioning costs.

**Other key non-monetised benefits by 'main affected groups'**

The key non-monetised benefits are expected to be the same as those in Option 1. It is expected that the greater number of gas roles and responsibilities taken on by the FSO will increase the magnitude of benefits accruing from improved trusted advice and system co-ordination.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | 3.5 |
|---|---|---|

Quantified results are sensitive to two key assumptions. Firstly, is assumed that the reduced costs as a result of the FSO's "whole system" view can be fairly illustrated by a range of between 1% to 5%. Secondly, it is assumed that the FSO will improve facilitation of network competition by an illustrative range of 25%-50%. These illustrative ranges are not distinguished across policy options due to the uncertainty in assessing the magnitude of benefits. Several key risks exist including reduced efficiency under the FSO, increased uncertainty to energy system participants and the creation of a "single view" of the energy system which could lead to poorer decisions being made by the FSO than currently.

**BUSINESS ASSESSMENT (Option 2)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs: NA** | **Benefits:** NA | **Net:** NA | NA |

## Summary: Analysis & Evidence — Policy Option 3

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Years** 10 | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** | **High:** | **Best Estimate:** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Best Estimate** | | | | |

**Description and scale of key monetised costs by 'main affected groups'**

The costs of implementation are estimated at between £260m-£790m, substantially higher than Option 2 due to the high separation and on-going costs incurred by carrying over the day-to-day operations of the gas system operator. Separating day-to-day gas operations from the transmission owner is also expected to introduce a loss of operational synergies, increasing the costs of balancing the gas system. This loss of synergies exposes the FSO to cost uncertainty, with estimates ranging between a net-cost of between £410m and £70m.

**Other key non-monetised costs by 'main affected groups'**

Non-monetised costs are the same as those listed in Option 1 and Option 2. The magnitude of these costs is expected to be larger than both options due to this option carrying over day-to-day gas functions into the new FSO.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Best Estimate** | | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

It is expected that carrying over day-to-day gas operations will not improve "whole system" decision making compared to Option 2, resulting in no further cost reductions expected.

**Other key non-monetised benefits by 'main affected groups'**

The key non-monetised benefits are the same as those under Option 1 and Option 2.

**Key assumptions/sensitivities/risks** — **Discount rate (%)** 3.5

Quantified results are sensitive to two key assumptions. Firstly, is assumed that the reduced costs as a result of the FSO's "whole system" view can be fairly illustrated by a range of between 1% to 5%. Secondly, it is assumed that the FSO will improve facilitation of network competition by an illustrative range of 25%-50%. These illustrative ranges are not distinguished across policy options due to the uncertainty in assessing the magnitude of benefits. Several key risks exist including reduced efficiency under the FSO, increased uncertainty to energy system participants and the creation of a "single view" of the energy system which could lead to poorer decisions being made by the FSO than currently.

**BUSINESS ASSESSMENT (Option 3)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs: NA** | **Benefits:** NA | **Net:** NA | **NA** |

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# Evidence Base

## Background

1. Delivering net zero will bring significant challenges for the electricity and gas systems. Not only does it require the decarbonisation of the electricity system, but also greater integration with, and electrification of, the transport and heat sectors. This change is in turn making operating the energy system more challenging and brings potential new roles and responsibilities to the system, all of which will need to be delivered in a coordinated and efficient way. To perform these roles effectively, the system operators (SO) will require both high levels of engineering capability, and the organisational design, incentives and accountability to act in the best interests of consumers free of commercial or other interests.

2. The gas and electricity system operators have a unique position at the heart of their respective systems. At their core, their responsibility is to keep each system operating in real time. This role gives them unparalleled insight into how each system operates, which makes them very well placed to fulfil wider, longer term roles on behalf of the system. The gas and electricity system operators are currently part of National Grid Plc, which also owns and maintains gas and electricity transmission assets. This creates the potential for conflict of interest between National Grid Plc's role as the SO in recommending changes to the system to support system operability, and National Grid Plc's role as a transmission company whose remuneration comes from building additional network to support these needs. While there is no evidence of this conflict being acted upon, the perception and potential for conflicts can nevertheless make it challenging for the system operators to fulfil their existing roles, and it would be even more challenging to give them some of the potential new roles needed to fulfil net zero. Following an assessment of the system operator, Ofgem have recently published a report[1] ("the Ofgem report") recommending the creation of a fully independent system operator, separate from National Grid Plc. The 2020 Energy White Paper stated that 'we will ensure that the institutional arrangements governing the energy system are fit for purpose for the long term, consulting in 2021 over organisational functions, including system operation and energy code governance.'[2]

3. In Great Britain, National Grid Electricity System Operator (NGESO) is responsible for ensuring the stable and secure operation of the national electricity transmission system (NETS). NGESO is legally separated from the electricity transmission owner (TO), National Grid Electricity Transmission (NGET). Gas System Operator (GSO) functions, including operation of the National Transmission System (NTS), are performed by National Grid Gas Transmission (NGG). NGG is also the transmission operator (TO) and owner across GB. The electricity and gas systems are governed by separate legislative and regulatory arrangements meaning NGESO and NGG only have roles and functions in their respective sectors. Both NGESO and NGG are part of National Grid Plc, one of the world's largest investor-owned energy companies that operates in the UK and US. National Grid Plc also has a range of other subsidiary companies. Throughout this document, SO is used to refer to both the GB gas and electricity system operator. When referring to the future state of the electricity system operator we use the term "Future System Operator" (FSO) which includes for some GSO functions.

4. Northern Ireland is excluded from this analysis as the scope of this policy is GB, and system operator functions for both gas and electricity in NI are carried out by separate system operators which are not considered in scope.

## Rationale for Intervention

[1] https://www.ofgem.gov.uk/publications-and-updates/review-gb-energy-system-operation

[2] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

5. The challenge of governing the energy system is an example of a 'principal-agent problem'. The system operator (the agent) makes decisions on behalf of energy consumers (the principal via Ofgem), but the system operators can be motivated to act in their own best interests which is contrary to the best interest of energy consumers. In the absence of full information, the principal can often only partly mitigate the agent's incentive to act in their own best interests.

6. For the energy system, both conditions are present for the principal-agent problem to occur. There is:
   i. **A Misalignment of incentives**: The commercial interests of the SOs (as part of National Grid Plc) may not be fully aligned with the interests of energy consumers. National Grid Plc's other business interests include the ownership of the electricity and gas transmission networks[3]. The SOs could be incentivised to make decisions that increase the revenue of National Grid Plc's profit-making assets (e.g., transmission network assets) and avoid outcomes that negatively affect their commercial interests, even if these outcomes would be in the best interests of consumers. The SOs may also lack the incentive to ensure sufficient scrutiny of their own processes[4] or data and advice provided by the TO. Further, annual corporate reporting and shareholder reporting cycles can drive a short-term focus on within-year performance.

      i. In gas, the SO and TO functions are carried out by an integrated company, NGG. There are no limitations in the interactions between these parts of the business in order to mitigate potentially misaligned incentives.
      ii. In electricity, NGESO has been legally separated into a separate company from National Grid Plc and there are licence conditions to support this separation. However, the Ofgem report concluded that despite legal separation, a perceived conflict of interest within NGESO remains, due to for example, senior governance interactions within National Grid Plc.

   ii. **Asymmetric Information**: The SOs hold significantly more information than Ofgem and could leverage this information to their advantage. The SOs' unique position in the energy system requires considerable technical expertise and gives them access to substantial data and information. It is unlikely to be possible for Ofgem to fully mitigate these information asymmetries. For example, the SOs have no competitors, therefore it is difficult to create a counterfactual against which performance can be benchmarked. This makes it challenging to set quality of service or consumer benefit performance targets to correct the misalignment of incentives.

7. Together this creates a **potential or perceived conflict of interest** that cannot be fully mitigated through the current regulatory framework. While there is no evidence of National Grid Plc acting in a way that deliberately exploits any potential conflicts of interest, this nevertheless results in a '**market failure'**, since Ofgem are unable to fully mitigate against the risk of sub-optimal outcomes, such as:
   i. **Potential conflict of interest in transmission network development:** The SO's decisions could lead to an inefficient (increased) level of transmission network investment. The SO could inflate long-term forecasts of the need for network assets[5] or fail to appropriately challenge the TO's investment proposals. The SO could also

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[3] Note in March 2021, National Grid announced its intention to sell National Grid Gas Transmission in the second half of 2021 with a view to complete the transaction within 2022: https://www.itv.com/news/2021-03-18/national-grid-agrees-78bn-electricity-deal-and-set-to-offload-gas-business

[4] For example, Ofgem recently fined NGESO £1.5m for failure to provide accurate and unbiased seven day ahead electricity demand forecasts over periods of 2017. This failure was found to have financially benefited NGESO by around £130,000. Whilst Ofgem concluded that NGESO did not deliberately set out to breach the conditions of Standard Condition C16 of its electricity transmission licence, inadequate oversight and compliance controls were in place to mitigate the behaviour.

[5] For example, by understating the existing network capabilities.

fail to take on the views of other energy system stakeholders, likely resulting in an informational bias towards SO network solutions.

ii. **Potential conflict of interest in facilitating network competition:** The SOs may limit the role of competitive pressures to reduce system costs where this would reduce the return of National Grid Plc's profitable assets. For example, NGESO could be potentially conflicted in establishing the rules for competitive tenders for network build in order to limit the role for third parties to provide network or non-network solutions.

iii. **Potential conflict of interest in advice:** A perceived lack of independence may limit the extent to which stakeholders (including government and Ofgem) trust the SOs' advice. At an industry level, commercial stakeholders may be unwilling to fully collaborate with NGESO, leading to less competitive and less efficient outcomes. Government may delay or be unable to take important policy decisions due to concerns with the SO recommendations. This prevents the SO's considerable technical and operational expertise being fully utilised. In the context of climate change, this could affect the UK's ability to meet its net zero target on time[6].

8. In addition to these existing potential consequences, the potential conflicts of interest are likely to be barriers to the SOs taking on the enhanced roles needed for the transition to net zero. The enhanced roles include greater coordination, network planning and strategic and advisory roles. Enhanced co-ordination and network planning roles are likely to increase the existing information asymmetry exacerbating the perceived or actual conflict of interest faced by the SO.

9. The FSO will need to be deemed impartial to carry out these enhanced roles and responsibilities, and will also need to have the following characteristics outlined in the Ofgem report and further developed by BEIS:

   i. **Technically Expert**: able to attract and retain world class technical capability and utilise sector-wide knowledge to provide definitive analysis of the energy system;

   ii. **Operationally excellent**: Able to operate at the pace necessary to deliver change, with a clear understanding of the way in which industry operates;

   iii. **Accountable**: to citizens/consumers today, and to those of tomorrow;

   iv. **Independently minded**: Not conflicted or occupied by other commercial interests and government influence over the system operator is strategic and not short-term; and

   v. **Resilient**: Both in times of system stress and in proactively responding to new challenges.

10. Overall, by addressing the perceived or potential conflicts of interest faced by the SO this intervention looks to increase the trust that the SO acts impartially in its decision making and advice. In turn, this increased trust in the impartiality of the SO looks to overcome existing market failures and enable enhanced roles to be assigned to the SO. Together, and alongside equipping the FSO with the characteristics listed in paragraph 9, these intend to maximise the value of the SO's unique position in the energy system in order to help realise government's strategic aim of delivering net zero at least cost through reduced energy system costs[7] whilst maintaining security of supply and improved advice to government.

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[6] To note that even if the SO never behaves as though there were a conflict as set out in 7.i and 7.ii, the perceived risk of one is likely to be sufficient to cause problem 7.iii.

[7] It is expected that these reduced costs could extend across the whole system from generation, transmission, distribution and system balancing.

**Updates since consultation IA:**

11. Consultation responses and further policy development have resulted in a number of changes to the options considered and supporting analysis included at consultation IA stage[8].

12. Those impacting the stylised options analysed here are summarised as:
    - **A privately operated and shareholder owned FSO was found to be less effective at achieving our objectives:** A private sector FSO would be challenged by an inability to completely remove or mitigate conflicts of interest arising from ownership, the inability to completely align shareholder and consumer interests, particularly around many of the new and enhanced roles, and the potential risk of reclassification to the public sector. It was also very unclear whether there would be any meaningful appetite for ownership of a private sector FSO.

    - **Consultation and policy development indicate greater FSO electricity system roles and responsibilities may be required to achieve objectives:** This reduces the likelihood of stylised Option 1, detailed below.

    - **Consultation and policy development indicate carrying over day-to-day gas functions of the GSO is unlikely at this time:** This reduces the likelihood of stylised Option 3, detailed below.

13. Whilst Option 1 and Option 3 no longer appear viable options, in light of policy development and consultation feedback, they are included to illustrate the magnitude of impact policy intervention may have and help to illustrate the economic case for why Option 2 performs comparatively well against them.

14. Key changes to the analysis are:
    - **Increased range of sensitivity scenarios tested:** A greater number of uncertainties in the implementation and performance of the FSO are now included in sensitivity analysis, including learning and familiarisation costs and potential benefits the FSO may have across the entire energy system. These were chosen to reflect consultation responses and points highlighted during the internal governance process.

    - **Inclusion of 'onshore transmission network competitions' benefits into the 'improved whole system view' benefit:** Analysis at consultation stage monetised the potential benefits the FSO may have via an improved facilitation of onshore network competition. Consultation responses highlighted the uncertainties in the analytical approach taken, and as such, this IA chooses to no longer explicitly quantify these benefits and instead, to group these under the 'improved whole system view' benefit.

    - **Greater appreciation of wider costs, benefits, and risks:** Consultation responses and subsequent policy and analytical work have enabled a more detailed assessment of the potential wider impacts and risks of this intervention.

    - **Additional detail on our Monitoring and Evaluation plan is now included**

**Policy Objectives**

[8] A link to the consultation and attached consultation IA can be found here: https://www.gov.uk/government/consultations/proposals-for-a-future-system-operator-role

15. Our objective is to establish an FSO able to drive progress towards net zero while maintaining energy security and minimising costs for consumers. An FSO able to do this will need to be given appropriate roles in the energy system and have the necessary characteristics to fulfil them effectively. These roles, functions and characteristics are summarised in brief in paragraphs 8 and 9 above, and are described more fully in the consultation response.

    We believe that an independent FSO that has such roles, functions and characteristics should help us realise the four key intended outcomes:

    i. **optimised reductions in network and balancing costs**: by supporting Ofgem and industry in using investment optimally to deliver a secure electricity and gas supply with net zero emissions at least cost;

    ii. **efficient technology decisions**: by providing engineering insights to government, Ofgem and industry into the fundamental system operability challenges presented by new technologies, so that government, Ofgem and industry can better identify lower cost technology mixes to reach net zero;

    iii. **co-ordinated system development**: by ensuring that decision-makers (such as government and Ofgem) understand impacts across the energy system, so that we can ensure that decisions taken in one area actively support, rather than hinder, decarbonisation of other sectors; and

    iv. **increased innovation**: by supporting the development of rules and standards that remove barriers to new technologies and business models, so that lower cost pathways to net zero will become available to us while maintaining a resilient system.

**Options under consideration**

16. As set out above, there is no evidence of National Grid Plc acting in a way that deliberately exploits any potential conflicts of interest. Nevertheless, the perception of and potential for conflicts nevertheless creates barriers to fulfilling our policy objectives. All options considered therefore look to reduce the perceived or potential conflict of interest faced by the SO. Ofgem has already implemented initial efforts to help achieve this, primarily through requiring National Grid Plc to legally separate NGESO from National Grid Electricity Transmission, which came into effect on April 1st 2019. However, the Ofgem report found that some features of the current energy systems governance arrangements, such as potential asset ownership conflicts of interest, were expected to limit the SOs' ability to perform new and enhanced roles required (e.g. network planning and competition) to achieve net zero effectively at least cost. Furthermore, the report also outlines the case for addressing the potential conflicts of interest in the GSO, whilst appreciating the additional complexities in separating the current fully integrated SO-TO model NGG operates under due to the physical characteristics of the gas system. To overcome the perceived conflicts of interest that exist under the current ownership structures of both NGESO and GSO, the report recommended a new independent system operator with enhanced electricity and gas functions.

17. Government agrees with Ofgem's findings and therefore this Impact Assessment only considers options for the roles and responsibilities that could be carried out by a new independent FSO. Alternative options to overcome the perceived or potential conflict of interest faced by the SO such as the creation of a new 'Energy Agency' responsible for the

new and enhanced functions proposed were considered and deemed less desirable in the Ofgem report[9].

18. Additional to this policy intervention, reform is also being considered to other aspects of energy system governance, as outlined in Section 2.5 of our 2021 consultation document[10]. This is to help ensure that the institutional framework of the energy system remains fit for purpose as we transition to net zero.

19. There are five broad categories of choice in designing and delivering the FSO, these are:
    a. **electricity system operator roles and responsibilities:** this considers the range of roles an electricity Future System Operator (FSO) would be responsible for;
    b. **gas functions:** this considers the functions of the existing Gas System Operator (GSO) that the FSO would be responsible for;
    c. **organisational design:** this considers what type of organisation would be best placed to deliver the FSO's roles and responsibilities;
    d. **implementation:** this considers how the proposal will be delivered in terms of the transition from existing SOs to a new FSO; and
    e. **funding:** this considers how the on-going expenditure of the FSO will be funded.

20. Longlisted options under each category of choice were assessed against the overarching spending objective to achieve net zero at least cost whilst maintaining security of supply alongside the relevant critical success factors listed in the Green Book[11]. Following this internal assessment, the suitable options identified were carried forward into the short list for further appraisal.

21. There are a large number of possible combinations of short-listed options across each category of choice outlined in paragraph 19. Therefore, options considered in this Impact Assessment present 'stylised combinations' of the short-listed options across each category in order to assess their impacts. As noted in paragraph 12, all options have been revised since Consultation IA stage to reflect our refined understanding of what options are both feasible and desirable.

22. Note that all options are subject to a sale process with National Grid Plc and therefore those included here are illustrative. It is also noted that National Grid have not had any input on the assessment of any costs included in this IA.

These options are as follows:

**'Do minimum' Counterfactual – Status Quo (including RIIO-2 changes)**

The short-listed options are compared to a 'do minimum' baseline option. This option reflects the existing structure of the SOs but includes the changes Ofgem are planning to make to NGESO in the RIIO-2 period (2021-2026), These changes[12] aim to further mitigate any conflicts of interest, however there is limited further separation of functions in NGESO and limited changes to the GSO.

**Option 1: 'Lower Intervention'**

[9] The Ofgem report writes "We consider that the SOs would be better positioned than an Energy Agency to take on new and enhanced functions beyond real-time system operation given the importance of real-time system balancing experience for effective system planning."

[10] https://www.gov.uk/government/consultations/proposals-for-a-future-system-operator-role

[11] The 2020 Green Book, page 32, Box 9 - https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent. Critical success factors considered relevant are (i) strategic fit, (ii) value for money, (iii) organisational capability, (iv) Resilience and (v) achievability.

[12] This includes stronger restrictions on ESO's use of shared services provided through National Grid Plc; stronger restrictions on day-to-day governance interactions with National Grid Plc and its affiliated companies; changes to NGESO board's role and structure to increase the role of the independent directors' and removal of any scope for 'dual fuel' employees to exist.

a. Electricity Roles: Day-to-day operation + advising + planning and competition
b. Gas functions: No roles transferred
c. Organisation Design: Highly independent public sector entity
d. Funding: Consumer funding (i.e. BSuoS[13])
e. Implementation: Existing organisation, phased transition

**Option 2: 'Preferred Way Forward'**

a. Electricity Roles: Day-to-day operation + advising + planning and competition + co-ordination + data and standards
b. Gas functions: Long-term forecasting & network planning + strategic market functions
c. Organisation Design: Highly independent public sector entity
d. Funding: Consumer funding (i.e. BSuoS)
e. Implementation: Existing organisation, phased transition

**Option 3 'Greater Intervention':**

a. Electricity Roles: Day-to-day operation + advising + planning and competition + co-ordination + data and standards
b. Gas functions: Long-term forecasting & network planning + strategic market functions + day to day operation
c. Organisation Design: Highly independent public sector entity
d. Funding: Consumer funding (i.e., BSuoS)
e. Implementation: Existing organisation, phased transition

23. For electricity roles (a):

- in option 1, the FSO is responsible for the real time system balancing of the electricity system and also undertakes advisory, enhanced planning and competition roles. This could include holistic and coordinated onshore and offshore network planning, enhanced NOA process, and running tenders for electricity network competition. All of these roles would be subject to further consultation; and
- in option 2 and 3, in addition to the functions taken on in option 1, the FSO would also be responsible for co-ordination, engineering standards and data. For co-ordination, the FSO could be responsible for taking greater roles in coordinating elements of heat and transport decarbonisation, for example in local energy mapping and planning. It could also have responsibility for co-ordinating across organisations (e.g. DNOs, TOs, gas networks and government departments) to ensure that there is a consistent strategic direction. This option could also include functions in energy code governance, engineering standards and data. All of these roles would be likely to be subject to further consultation.

24. For gas roles (b):

- in option 1, the FSO would not undertake any formal role in gas, however capability would be built up within the FSO to contribute to long-term forecasting and some strategic gas functions. This builds on the limited gas strategic thinking and work that NGESO already does through the future energy scenarios (FES), including input into FES, Gas 10-year statements and Gas Markets Actions Plan[14];
- in option 2, the FSO would undertake long-term strategic planning, markets and forecasting functions. This would include network capability planning (which could be formalised into a Gas Network Options Assessment process analogous to that already performed by NGESO for electricity networks) and strategic capability assessment for

[13] https://www.nationalgrideso.com/industry-information/charging/balancing-services-use-system-bsuos-charges

[14] To note, the option to carry over no gas roles is not included as a policy option in the consultation document. The primary purpose of including no gas roles in Option 1 is to illustrate the impact of a wider range of example interventions, helping facilitate discussions on the value of carrying over gas roles.

new connections, asset replacement and decommissions, and medium to long-term forecasting; and

- in option 3, the FSO would undertake the roles outlined in option 2 but additionally take on control room functions, including day-to-day network balancing, operational planning (2 weeks ahead) and both emergency response and outage co-ordination.

25. Note that in March 2021, National Grid Plc announced its intention to sell National Grid Gas Transmission in the second half of 2021 with a view to completing the transaction within 2022[15]. We do not consider that the intention of this sale impacts the feasibility of the options considered.

26. For organisational design (c), funding (d) and implementation (e), all three options present the same choices which are assessed qualitatively and do not feature as part of the quantified analysis.

27. Under organisational design (c), only one viable option is considered, that is deemed both achievable and able to meet the required characteristics described above in section 2. This is a highly independent public sector entity; a corporate body model classified within the public sector, but with statutorily assured operational independence. Unbound by day-to-day government operational control but operating within the strategic framework set out by Parliament.

28. Under funding (d), it is assumed that the FSO will be paid for through charges on users of the system that will eventually be passed on to consumers[16], similar to current ESO and GSO arrangements. Options for central funding by government are unlikely due to both the political challenge and risk that central government involvement with budget setting could compromise the independence of the FSO.

29. Under implementation (e), the FSO will be founded on the existing capabilities (including people, processes, systems and assets) of NGESO, and where appropriate NGG, followed by phased introduction of any further roles to the FSO. (The functions of NGESO may also continue to evolve to include some of the proposed functions of the FSO, in the period after the Government's response to this consultation and prior to transition to an FSO, where appropriate and subject to feasibility under existing licencing, codes and price control arrangements).

30. All options considered would require primary legislation taking place as part of the 2022 Energy Bill.

**Rationale and evidence to justify the level of analysis used in the Impact Assessment (IA)**

31. The approach used in this Impact Assessment is deemed to be proportionate and intends to convey the uncertainty that is inherent to the policy at this stage. Detailed consideration has been given to the rationale for intervention and how the options considered meet the policy objectives and key impacts have been identified with their distributional effect considered.

32. This analysis builds on the 2021 Consultation Stage IA and has incorporated responses from both internal governance stakeholders and consultation respondents. Where impacts have remained unquantifiable, we have drawn from wider evidence sources such as the academic literature.

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[15] https://www.nationalgrid.com/proposed-acquisition-western-power-distribution-and-strategic-portfolio-repositioning

[16] This is likely to exclude the cost of purchase of SO assets from National Grid Plc, which are discussed separately under costs beginning paragraph 34.

33. We have also provided an initial assessment of risks and uncertainties and the key distributional impacts that are likely to occur. This policy is dependent on subsequent secondary legislation or other provisions, such as changes to license conditions.

## Description of Costs and Benefits

### Costs and Benefits of Primary Legislation

34. Primary Powers are not expected to have any substantial impacts given these are enabling powers. Whilst primary powers also include the ability for government to mandate the purchase of SO assets, this would not take place until secondary legislation was implemented, nor would the creation of the FSO envisaged be possible without subsequent secondary legislation.

### Illustrative Monetised Costs and Benefits of Secondary Legislation

35. The timeframe for analysis is 2022-2050, representing the earliest stage at which the costs of options may begin to incur[17], until the 2050 legislated target of reaching net zero emissions. Several key benefits of intervention are deemed unquantifiable such as the value of impartial advice to government. Therefore, the quantified net present value (NPV) should be viewed as a partial NPV and considered in tandem with the non-monetised costs and benefits to fully assess the impact of proposed options. It is also noted that the quantified impacts are illustrative with the views of stakeholders on how analysis can be improved sought as part of consultation.

Costs

Capital cost of implementation: (*Numbers redacted for commercial reasons*)

36. A significant cost in the establishment of a new FSO will be the capital cost to Government associated with implementation. The nature of the outlay required will depend heavily on the outcomes of negotiations with National Grid plc.

37. Any estimate of capital costs associated with the FSO implementation are commercially sensitive and therefore removed. The initial capital cost might be repaid through the guaranteed revenue stream taken on by the government. The underlying assets of the ESO are also likely to be transferred to HMG. It is expected that these two factors result in the exclusion of these costs having minimal impacts on the conclusions of this IA.

Cost of implementing the FSO:

38. Implementation costs included in our estimate are:
    - **legal, financial and consultancy costs:** the FSO will be founded on the capabilities and functions of NGESO and (where appropriate) NGG. The process of achieving this will involve costs, including legal, financial and consultancy costs;
    - **separation costs:** These are one-off project costs incurred by National Grid Plc (and any future owner of NGG) and the FSO (or government) in separating the roles and capabilities of NGESO and relevant functions of NGG from their current situation, such as recruitment, property and IT systems separation costs incurred in separation; and
    - **on-going costs:** These are ongoing costs incurred by National Grid Plc (and any future owner of NGG) and the FSO (or government) as a result of separation the roles and capabilities of NGESO and relevant functions of NGG from their current situation (i.e., the duplication of corporate services). These may include the costs of additional personnel

[17] Some administrative costs have already been incurred such as internal government resource, however since these are sunk costs under all scenarios they are excluded from analysis. This is a modelling assumption and not a policy decision.

for roles that are currently shared, duplicate licences for IT and technology, and duplicate services.

39. For all three options, legal, financial and consultancy costs are assumed to be incurred between 2020-2025 whilst the separation costs take place between 2024-2026 with the costs of separation assumed to be spread evenly over the three years. On-going costs are also assumed to begin in 2024 and continue at a constant annual cost over the timeline of analysis. Administrative costs occurred before 2022 are deemed to be sunk costs and therefore removed from analysis[18]. To note, these dates included are modelling assumptions and not policy positions.

40. Legal, financial and consultancy costs incurred from 2022 onwards are estimated using internal estimates of BEIS and Ofgem project budgets. Separation and on-going cost estimates are produced by FTI Consulting[19]. In all options, the full costs of separating NGESO are assumed to apply, which we have estimated as a one-off cost of separation of £22m (2020 prices) based on FTI's analysis, however these are expected to be substantially lower than the cost of fully separating the GSO. This is because much of the costs of separating NGESO occurred during the 2019 legal separation of NGESO from NGET[20]. For the GSO, we estimate the implementation cost of full separation as a one-off cost of £100m[21]. In option 1, no formal gas roles are carried over to the FSO, instead, capability is expected to be built up within the FSO to assess and forecast strategic gas capabilities and requirements. It is assumed that this would cost an illustrative 1% of the total cost of full separation. For option 2, modelling assumes transition of network planning roles to the FSO increase these costs to 20% of the £100m. Option 3 assumes 100% of the costs apply since day-to-day operation and all supporting functions transition to the FSO.

41. Estimates for each option are described in table 1. To emphasise the uncertainty in these figures high and low estimates are also presented in the table by increasing and decreasing the central estimate by 50%. This is purely to provide an illustrative range. Actual costs could fall significantly outside of the numbers presented as highlighted in consultation response by National Grid ESO. As a result, these figures are further tested through sensitivities.

*Table 1: Costs of implementation for options (rounded to nearest £10m)*

| £ (Present Value, 2020£), 2022-2050 | Low | Central | High |
|---|---|---|---|
| Option 1 - 'Low Intervention' | 50 | 100 | 140 |
| Option 2 - 'Preferred Intervention' | 90 | 180 | 270 |
| Option 3 - 'Greater Intervention' | 260 | 520 | 790 |

<u>Loss of operational synergies (*gas only*)</u>

[18] These costs range from around £1m (2020 prices) in Options 1 and 2 to around £1.5m (2020 prices) in Option 3 and therefore make no substantial difference to the benefit to cost ratio of any option considered. The figure of £100m is arrived at by using FTI's estimate of £89m and adjusting upwards to remain conservative. (i.e., accounting for any potential optimism bias).

[19] Taken from Annex 1 of Ofgem's Review of the GB energy system operation. https://www.ofgem.gov.uk/system/files/docs/2021/01/final_-_fti_consulting_-_ofgem_gb_so_review_2021-01-22_0.pdf

[20] For outstanding costs of ESO separation, such as the costs of IT separation, these are assumed to take place in the 'do nothing' counterfactual and are therefore deemed appropriate to exclude from analysis. The rationale for this assumption is based on the RIIO-2 Final Determinations – Electricity System Operator report, page 89, section 8.6 and 8.7. This outlines Ofgem's view that full IT separation is desirable and key to delivering net zero.

[21] This is assumed to be lower at £50m in FTI's high case outlined in table 4.4 of their report, however the low estimate was chosen to remain conservative.

42. Unlike in electricity where NGESO is a legally separate entity, the GSO and GTO functions are currently integrated within the same company (National Grid Gas Plc) due to the different physical characteristics of the gas system. Under the integrated SO-TO structure of NGG, the GSO control room uses transmission network assets (network control) to operate and control the network, manage constraints and ensure system safety. For example, the GTO may delay the planned maintenance of a compressor to reduce the likelihood of a network constraint. The alternative to using network assets, is to balance the system by taking commercial actions to adjust the flows of gas across the network, however these actions are often more expensive and have an indirect effect on consumers through changing the price of gas.

43. Under the current regulatory arrangement, the GSO and GTO have the incentive to minimise the combined cost of operational and commercial actions (the Constraint Cost Management (CCM) Scheme[22]), therefore the GTO may be willing to incur the additional cost of an operational action if the cost was less than the potential reward to the GSO. While the GTO is willing to take these short-term operational actions, the GSO is required to take fewer, more costly, commercial actions to balance the network. This reflects the operational synergies of the two bodies while they are integrated within NGG.

44. We assume that if the GSO control room were separated from the GTO, the GTO would be less willing to take operational actions for balancing[23] and therefore the GSO would have to take more commercial actions. Following the approach set out in FTI analysis[24] we assume the GSO would take around 3 actions per year, compared to an historical average of 0.4.

45. This would increase the cost of balancing actions, it is difficult to forecast the cost of commercial actions but based on FTI analysis of an oversupply event in 2016, we assume the cost of location trades to be around £80k, and commercial buybacks to between £3.5 and £11.6m. However, we assume that the current CCM incentive that costs around £5.2m[25] per year would be removed as NGG would no longer have an active role in balancing. This could partly offset the expected increase in costs of balancing the gas system.

46. Based on the assumptions outlined above, the loss of operations synergies could range from a cost of around £410m[26] if the cost of commercial actions are high, to a cost of around £70m[27] if the cost of commercial actions is lower than the cost of the CCM incentive (present value). The additional exposure to cost uncertainty for the GSO may present an additional cost.

47. For NGESO, we assume loss in operational synergies has already occurred due to the 2019 legal separation of NGESO from NGET. No further losses in operational synergies are considered in modelling however this remains an uncertainty.

Benefits

[22] To encourage NGGT to resolve this congestion efficiently, Ofgem developed the Constraint Cost Management ("CCM") incentive scheme (or "CCM incentive") as part of the RIIO-T1 price control. This is assumed to cost £12m per year.

[23] The cost of capacity buybacks is higher as such operations can have an indirect impact on consumers as the restriction in the volume of gas on the network can translate into an increase in the wholesale price (or National Balancing Point) of gas as a result. The Ofgem paper notes that there are a few reasons to believe this assumption may be conservative.

[24] See Section 4 and annex beginning paragraph A1.22. https://www.ofgem.gov.uk/system/files/docs/2021/01/final_-_fti_consulting_-_ofgem_gb_so_review_2021-01-22_0.pdf

[25] £5.2m reflects the recently announced cap on the CCM of £5.2m per year under RIIO-2. Conversations with Ofgem reveal that we expect the actual annualised cost of the CCM to be lower than the cap. This is significantly below FTI's annual cost saving estimate of the CCM at £12m per yar.

[26] Cost is calculated as increased cost = ('estimated increased in number of locational actions'*'cost of locational trade') + ('estimated increase in capacity buy backs'*'cost of capacity buy backs')-('estimated reduction in short-term asset optimisation'*'cost of short-term asset optimisation)-'annual cost of CCM incentive'

[27] These figures also differ to FTI's analysis due to the higher discount rate used (i.e., FTI used a discount rate of 2.88% compared to the Green Book aligned 3.5% used in this appraisal).

Reduced potential conflicts of interest in transmission network development

48. Under existing arrangements, while there is no evidence of such a conflict being acted upon, there is nevertheless the potential for the SO to overestimate network transmission needs in long term forecasts or fail to properly scrutinise the TO assessment of network needs.

49. There are several mechanisms by which this could occur, each of which may not be unique to the current energy system governance structure. Those considered here are:

i. interruptions and outages on the energy system may result in reputational and financial damage to the SO[28]. Given the SO is risk-averse, the SO may be incentivised to overstate the future needs for network assets, "overengineering" the system beyond what is required to lower their exposure to risk below what is the social optimum. (Applicable to all SO governance models)

ii. the common ownership of the SO and TO may result in overstating[29] the need for network assets due to an informational or financial potential conflicts of interest towards transmission network asset solutions to energy system problems[30]. (National Grid Plc specific)

iii. the RIIO-1 framework rewarded National Grid Plc for meeting energy system needs at a lower cost than forecast, by allowing National Grid Plc to retain a proportion of the 'cost-saving' as additional profits via the Totex Incentive Mechanism (TIM). This was likely to incentivise National Grid Plc to 'overstate' their future expenditure[31] on network assets in forecasts. Retaining underspend as profits via TIM has now been removed under RIIO-2[32] reducing the potential for conflicts of interest in forecasts. (National Grid Plc specific, no longer applicable)

50. Of the two mechanisms considered, only mechanism ii. is specific to the current SO-TO ownership structure operated by National Grid Plc, however this more closely aligns with the benefit of "improved whole systems thinking", which is considered below. For mechanism i., it is not clear that any option considered would resolve the mechanisms by which the SO has the potential to overestimate network asset requirements and mechanism iii. is no longer applicable. Furthermore, the costs of underestimating future network needs are likely to be asymmetrically greater to the consumer than overestimating future network needs. Given the significant uncertainty that exists in all long-term forecasts and in light of these asymmetric costs, it is assumed that the FSO would also be incentivised to "overengineer" the system.

51. For these reasons, the reduction in transmission network development costs from mechanism i. are assumed to be zero[33]. There may however be savings due to mechanism ii., which is considered as part of the potential for improved "whole systems" decision making.

Improved 'whole systems' decision making

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[28] As illustrated by the financial and reputational damage taken on by the companies found responsible for 9th August 2019 Power Outage. Detailed here https://www.ofgem.gov.uk/publications-and-updates/investigation-9-august-2019-power-outage.

[29] This is only a direct cost to the system if National Grid choose to act upon this conflict of interest, of which there is no evidence.

[30] For example, all of the Future Energy Scenarios (FES) developed by NGESO see a prominent role for hydrogen in achieving net zero. Whilst hydrogen is an important technological solution to decarbonisation, it also creates the need for retrofitting gas networks and reinforcing gas transmission network infrastructure. This perception that NGESO could be subject to potential conflicts of interest towards hydrogen solutions may reduce trust in the FES scenarios and the credibility of NGESO advice, or offer as an example of potential conflicts of interest towards transmission network solutions, since no solution is offered without a prominent role for hydrogen.

[31] To note, the informational asymmetry between National Grid and Ofgem may have limited mechanisms included in TIM designed to limit the 'overstating' of future costs.

[32] 7.38 in RIIO-2 final determinations: https://www.ofgem.gov.uk/system/files/docs/2020/12/final_determinations_-_core_document.pdf

[33] A significantly different assessment of potential cost savings from reduced asset ownership conflicts of interest is offered by FTI in their analysis for Ofgem's review of the GB energy system operator. Here they estimated savings to be between 1%-10% of total network costs. These differ with analysis included in this assessment because potential cost savings included in FTI analysis are considered as part of cost savings due to "whole systems" decision making.

52. A significant benefit that a new FSO could deliver is an improved “whole systems” approach to network development and assessing energy system needs. These benefits are directly related to the reduction in the perceived or actual conflicts of interest faced by the SO under current arrangements. While there is no evidence of such a conflict being acted upon under the current arrangements, removing this potential conflict of interest nevertheless enables the FSO to take on enhanced roles and responsibilities which will help to ensure that decisions made across the system work together to meet decarbonisation and security of supply goals at least cost.

53. Dependent on the option taken[34], the improved whole systems insight under an FSO would be expected to:

- improve network planning through removal of the current informational and financial potential conflicts of interest the SO has towards transmission network solutions as outlined in Paragraph 49. (ii)[35]. For example, free of potential asset ownership conflicts of interest, the FSO could better identify efficient investments in assets located in National Grid Plc asset locations that might alleviate the need for reinforcements;
- better identify and promote cost-effective and innovative solutions. These solutions may be found across areas such as technology, logistics as well as market design and business models;
- better identify challenges to system operability and take the steps to address them;
- better co-ordination of investment decisions to ensure alignment with whole system needs and policy goals. For example, an integrated FSO with responsibility for both GSO and ESO functions may have increased flexibility to meet network development and system balancing needs across fuels, minimising costs across infrastructure projects across energy, heat and transport networks that would otherwise be siloed; and
- better co-ordination and promotion of innovation projects involving actors from across the energy system. The improved perception of impartiality of the FSO is expected to increase energy actors’ willingness to participate in joint-innovation projects.
- Improved facilitation of competition: As noted in our consultation IA, the FSO may be well placed to identify, develop and facilitate competitive tenders across the energy system. For example, competition in onshore electricity networks[36].

54. These benefits are likely to result in reduced costs across the entire energy system including generation, system-balancing and policy costs passed through to consumers via energy bills[37]. Given the variety of sources cost savings could come from, this analysis chooses to quantify savings that occur due to transmission network cost savings only. This analysis only considers the potential cost savings in future transmission network development. The reasons for doing this are two-fold. Firstly, these costs are more easily quantifiable than the costs of other aspects, such as future policy costs. Secondly, these costs also help to illustrate the potential benefits a reduced information or financial potential conflicts of interest to transmission asset-oriented solutions may have.

55. Estimating the magnitude of the quantified benefits relies on forecast total expenditure (totex) on the transmission network to 2050 across a range of net zero and Carbon Budget compatible scenarios. This total expenditure estimate is based on the existing TO costs in

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[34] All benefits are expected to accrue under options 2 and options 3 given the greater number of roles and responsibilities within gas and hydrogen. Option 1 is modelled as only allowing benefits to accrue from the electricity. It is likely that the extent to which the FSO could be expected to achieve these benefits would be larger under option 2 and option 3 given the greater oversight of the energy system.

[35] As stated above, this is only a direct cost to the system if National Grid choose to act upon this conflict of interest, of which there is no evidence.

[36] This potential benefit was included separately at consultation stage. Consultation respondents broadly agreed that this the FSO may better facilitate network competition however disagreed with analysis’ approach to quantification. These benefits are therefore removed at final IA stage.

[37] This could occur for several reasons, for example, improved advice to government enabling better decision making or the identification and promotion of more cost-effective solutions reducing policy costs.

the RIIO-2 business plan. For years beyond RIIO-2 the expenditure estimates are then scaled based on the possible development of the transmission network. For electricity, we scale total expenditure based on the Allowed Revenues forecast using the Dynamic Dispatch Model (DDM) under the 2019 high and low reference case scenarios, which was used to inform the Carbon Budget 6 Impact Assessment and are described at a high level in Annex 2 of the report. For natural gas, we scale total expenditure based on consumption estimates in UK Times Carbon Budget 6 (CB6) scenarios. For hydrogen there is no existing transmission network costs to base the estimate from, instead we use an estimated network cost of £2.2m/TWh and apply this to the UK Times final energy consumption estimates for hydrogen under different CB6 scenarios.

56.

57. We then assess the potential savings in network costs by assuming a proportion of this total expenditure could be saved as a result of improved whole systems decision making. It is difficult to determine the proportion of transmission network costs that could be saved. As an illustrative assumption we consider a proportion between 1-5%.

58. This calculation gives an estimate of the potential savings in transmission network development as follows: Electricity: £210m to £2500m, Natural Gas: £50m to £300m, Hydrogen £30m to £300m (present value, 2020 prices). The potential cost saving in the electricity transmission network is higher than natural gas and hydrogen. This is due to i) the existing network being more expensive (electricity Totex in the RIIO-2 is around £1.3bn per annum, compared to around £550m in natural gas) and ii) that we forecast the electricity network to increase in size out to 2050, while the natural gas network is expected to decline across all scenarios considered.

**Summary of monetised costs and benefits**

59. The results of quantified analysis are presented in table 2, illustrating a less favourable "low" and more favourable "high" scenario to create a central range.

60. In option 1, implementation costs are assumed to be lowest due to NGESO already having incurred many of the costs of separation during legal separation in 2019. Under this scenario quantified benefits are assumed to accrue from electricity only. Whilst the full range of benefits has been appreciated below, it is likely that option 1 will be less likely in achieving the 'high' outcomes than options 2 and 3, where the enhanced roles and responsibilities are assigned to the FSO enabling greater "whole system" decision making.

61. In option 2, the greater number of GSO functions and enhanced roles of the FSO raise implementation costs compared to option 1; however, since day-to-day operations are retained within NGG, it is assumed that there is no loss of operational synergies in balancing the gas system. The greater gas roles taken on by the FSO enable the realisation of improved "whole system" decision making across both gas and hydrogen.

62. In option 3, these benefits are assumed to be the same despite day-to-day operation of the gas system being transferred over to the new FSO. This is based on the assumption that system balancing requirements are simpler on gas when compared to electricity, therefore the feedback loop between efficient network planning and experience of balancing the system is less of a concern for gas than electricity and benefits can be achieved without taking charge of day-to-day system balancing. Instead, carrying over the day-to-day system balancing costs is likely to pose significantly higher costs for both implementation and system balancing, due to the loss of operational synergies[38].

*Table 2: Summary of high-level quantified analysis (£m, present value, 2020£)*

[38] Under scenarios with high hydrogen uptake and electricity/hydrogen linkages, there may be a case to take over day-to-day gas functions in the future. This is not modelled in options for this IA and future analysis (once there is greater certainty in the role for hydrogen) may find it valuable to carry over day-to-day gas functions to the FSO.

| | Option 1 | | Option 2 | | Option 3 | |
|---|---|---|---|---|---|---|
| Scenario | **Low** | **High** | **Low** | **High** | **Low** | **High** |
| **Costs** | | | | | | |
| Cost of asset purchase | (t) | (t) | (t) | (t) | (t) | (t) |
| Implementation Costs | -140 | -50 | -270 | -90 | -790 | -260 |
| Loss of operational synergies (*gas only*) | 0 | 0 | 0 | 0 | -410 | -70 |
| **Benefits** | | | | | | |
| Reduced potential conflicts of interest in transmission network development | 0 | 0 | 0 | 0 | 0 | 0 |
| Improved "whole system" decision making (*electricity*) | 210 | 2,500 | 210 | 2,500 | 210 | 2,500 |
| Improved "whole system" decision making (*natural gas*) | 0 | 0 | 50 | 300 | 50 | 300 |
| Improved "whole system" decision making (*hydrogen*) | 0 | 0 | 30 | 300 | 30 | 300 |
| **Net Present Value (£m)** | **60** | **2,400** | **10** | **2,900** | **-900** | **2,800** |

*Note: (1) For transmission costs:  Low scenario represents the lowest available demand projection and 1% reduced costs due to the improved "whole system" decision making. High scenario represents the highest available demand projection and a 5% reduced costs assumption. (2) Results presented are rounded to the nearest 10 for costs below 1bn and 100 for those above.*

**Sensitivities**

<u>Uncertainty over benefits</u>

<u>Improved 'Whole System' decision making</u>

63. Sensitivity analysis focuses on testing the quantified benefits from improved "whole system" decision making and facilitation of electricity network competition. This is because these benefits represent the greatest overall impact on quantified analysis however rely on illustrative scenarios to assess the magnitude of impact. There are also reasonable chains of reasoning to suggest that quantified benefits may be lower or higher than the scenarios currently included in core analysis. For example:

- the role proposed to be given to the FSO may reduce the role for TOs and DNOs in assessing future investment needs resulting in a "single worldview" of energy system needs. If contracts between the FSO and network operators are difficult to define, this may result in energy system needs being determined by an FSO that has less information available than TOs and DNOs. Under this scenario there may be **fewer benefits from the improved "whole system" decision making**. Conversely, however, the positive benefits from improved whole system decision making may be even greater than expected; and
- efficient network competitions may be achievable under the status quo through adequate design of competitive processes. For example, National Grid Plc and now NGESO has successfully run the Contracts for Difference allocation process since 2014. In this time there has been no clear evidence of conflicts of interest or insufficient competitive pressure due to NGESO's ownership structure. Conversely, greater co-ordination across the system and the enhanced responsibilities of the FSO may enable new opportunities for competition that would not otherwise be identified.

64. In central analysis, we assumed the improved "whole system" decision making would result in savings of between 1% to 5%. To test the chains of reasoning included above, an illustrative "worst-case" scenario is presented where: there are no benefits from whole system decision making; and demand for network development is low, decreasing the scope

for potential benefits. An illustrative "best case" scenario is also presented where there is a 10% reduction in transmission network costs due to improved whole system decision making, moreover, demand for network development is high. These are illustrated below in table 3.

Table 3: Summary of sensitivity analysis (£m, NPV, 2020£)

| ***Scenario*** | **Worst Case** (Low demand, 0% whole system saving) | **Central: Low** (Low demand, 1% whole system saving) | **Central: High** (High demand, 5% whole system saving) | **Best Case** (High demand, 10% whole system saving) |
|---|---|---|---|---|
| **Option 1** | -140 | 65 | 2,400 | 5,400 |
| **Option 2** | -270 | 15 | 2,900 | 6,400 |
| **Option 3** | -1,200 | -900 | 2,700 | 6,200 |

*Results rounded to nearest 10 below 1bn and 100 above.*

65. In the 'worst case' scenario, the net-present value is negative across all three options considered. Implementation costs (and loss of operational synergies in option 3) are incurred with no quantified benefits. In the 'best case' scenario, the quantified net-present value almost doubles compared to the central high scenario, increasing from between £2,400-2,900m to £5,400-6,400m. This reflects the sensitivity of quantified results to assumptions made about the magnitude of potential benefits, particularly, the assumed benefit that improved "whole system" decisions will bring.

66. Given the significant uncertainty and impact of this assumption we tested the 'breakeven' point to assess how large the benefits from an improved "whole systems" view would need to be for the project to have an NPV of zero. In both the high and low scenario included in table 4.

*Table 4: Summary of breakeven analysis (Savings as a % of total expenditure required)*

| ***Scenario*** | ***Low*** (Low demand, High implementation costs) | ***High*** (High demand, Low implementation costs) |
|---|---|---|
| **Option 1** | 0.4% | 0.1% |
| **Option 2** | 0.8% | 0.1% |
| **Option 3** | 3.6% | 0.5% |

67. Assessing the results presented in table 4, the improved "whole system" view taken by an FSO would need to result in reduced costs of transmission network developments between 0.1 – 3.6% to break even. Under the preferred option, this benefit would need to be greater than 0.1-0.8% in order for benefits to exceed the costs of creating an independent FSO. Furthermore, these "whole system" savings are only quantified from one aspect of the energy system (i.e., transmission networks).

Inclusion of wider energy system benefits

68. When considering the potential for cost savings that could occur elsewhere in the energy system due to a "whole system" view, the breakeven point at which a positive NPV occurs is likely to be even lower. This highlights that whilst there is significant uncertainty in estimating the magnitude of potential benefits, the range of uncertainty over which benefits could occur is asymmetrically skewed towards outcomes resulting in a positive NPV given only a relatively small benefit is required to materialise to overcome the quantified costs of intervention.

69. As highlighted throughout consultation response, there is likely to be additional benefit from the "Whole Systems" view taken by the FSO beyond the transmission network, including for

generation, distribution and system balancing and stability services, each of which are excluded from core economic analysis.

70. Governments recently published Net Zero Strategy[39] estimates that achieving Net Zero and our Carbon Budgets could require between £280-£400bn in generation capacity alone. Assuming the same 1% to 5% range of potential cost reductions enabled by the “whole system” view taken by the FSO, it is estimated that the FSO could generate additional benefits of between £3bn (1% saving, low) to £20bn (5% saving, high) in generation costs, (undiscounted, 2020£). We anticipate that the future total expenditure requirements on the distribution network out until 2050 may be broadly similar to that of the transmission network and therefore assume a similar scale of potential of cost savings, resulting in a further range of additional FSO ‘whole system’ net benefits from between around £200m to £2,500m. Together with quantified transmission savings, this could take the benefit of the FSO providing a whole system view to a lower estimate of around £3-4bn to an upper estimate of around £25bn. Though these figures are illustrative, we have more confidence around the order of magnitude of the costs than the benefits. There is the potential that the benefits could be an order of magnitude larger than the costs and so it highlights the potential ‘size of the prize’.

71. We also do not appreciate balancing and system stability services in these costs, these represent a further additive saving which the creation of an FSO may unlock.

<u>Uncertainty over costs</u>

<u>Greater costs of implementation</u>

72. As noted in consultation responses, the costs of implementation may be greater than our upper estimates included in core analysis. To reflect this, we include an additional sensitivity in table 5 below, in which all implementation cost estimates are doubled. This highlights that whilst there is cost uncertainty around the cost of implementation, when balancing the potentially large benefits described in the paragraph above, the creation of an FSO is still likely to have an overall positive NPV.

<u>Familiarisation and learning costs</u>

73. The creation of any new entity is likely to pose significant learning and familiarisation costs. In the case of the FSO:
   - learning costs to the FSO are likely to be both internal and external. Internally, the FSO’s organisational design and processes may require several adjustments before working as intended. Also, time may be required until the FSO is able to maximise the enhanced roles and responsibilities assigned to them, particularly in cases where the reassignment of roles to the SO and away from others in the energy system results in a loss of corporate memory. Externally, the FSO will require time to establish the correct lines of communication;[40]

   - familiarisation costs are posed to Ofgem, HMG and National Grid Plc (discussed above) and all other energy industry participants. For Ofgem and HMG, given the system operator sits at the heart of the energy system, the creation of a new FSO is likely to impact almost all policy areas related to energy. This may create significant adjustment costs. For all other energy system participants, the significant change to the system may require firms to understand the new market structure. The increased co-ordination function of the FSO may require firms to hire new employees to engage with the FSO. In options where the FSO takes an increased role in network planning across the whole

[39] Page 99, paragraph 18, https://www.gov.uk/government/publications/net-zero-strategy

[40] The Transfer of Undertakings (Protection of Employment) Regulations 2006 (TUPE) are designed to minimise the impact of these learning costs, helping enable a smooth transition and the retainment of corporate memory.

system, firms may have to adjust their own planning functions to co-ordinate effectively with the FSO; and

- the impact of these costs is intended to be minimised through the approach to implementation of an FSO as well as its organisational design, however some costs are unavoidable. Whilst it is not possible to quantify the multitude of learning and familiarisation costs it is likely that these costs will be substantially higher in GSO functions compared to ESO functions. This is because NGESO is currently a legally separate entity whilst the GSO is currently integrated within NGG.

74. These costs are illustrated in sensitivity analysis by delaying benefits from the creation of the FSO by a 5-year period. This is considered to capture the core risk associated with learning and familiarisation costs however, there may be additional costs incurred by industry in understanding how to interact with the newly created FSO. Table 5 below illustrates these costs. These highlight a high potential downside risk under Option 3, whilst only a small downside risk exists under Option 1.

*Table 5: Options under higher costs (NPV, 2020£m, 2022 discounting perspective).*

| | Option 1 | | Option 2 | | Option 3 | |
|---|---|---|---|---|---|---|
| Scenario | **Low** | **High** | **Low** | **High** | **Low** | **High** |
| **Higher implementation costs** | **-70** | **2,400** | **-300** | **2900** | **-1300** | **2600** |
| **High learning and familiarisation costs** | **10** | **2,100** | **-70** | **2,500** | **-1100** | **1,800** |

75. However, a substantial amount of costs and benefits remain unquantified. Therefore, the quantified NPV is only one aspect of this Impact Assessment and must be considered in tandem with the unmonetized costs and benefits considered below.

**Illustrative unmonetised Costs and Benefits of secondary legislation**

<u>Costs</u>

76. Note, given the remaining uncertainties in the implementation of options and performance of policy design, several costs are considered under “risks and uncertainties” since effective policy design intends to mitigate them. Those costs included here are assumed to apply in all scenarios. However effective policy development can limit the magnitude of impact.

<u>Increase SO to TO transaction costs</u>

77. The separation of ownership of the SO and TO functions in gas is likely to result in a loss of operational synergies not captured in quantified analysis. These costs may include:
    - replication of roles across FSO and TO to ensure effective communication and collaboration; and

    - contractual agreements allowing the FSO to operate TO assets may be difficult to establish. A 2013 report to Ofgem[41] notes that these difficulties currently exist between NGESO and both the Scottish TOs and OFTOs and may be significant. However, the report also notes that some of these costs may also occur under the counterfactual in electricity where TOs outside of England and Wales are beginning to play a larger role in the electricity system.

[41]Page 35; Strbac, G., Konstantinidis, C.V., Konstantelos, I., Moreno, R., Newbery, D., Green, R. and Pollitt, M. (2013), Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery, Final Report to Ofgem, May.

78. These costs are expected to be increasing in the number of roles and responsibilities carried over to the FSO and therefore highest in Option 3 and lowest in Option 1.

Learning and familiarisation costs

79. Whilst above sensitivity analysis captures the core of the uncertainty created by learning and familiarisation costs, additional costs remain unmonetized. Principally, the costs to business of becoming familiar with the new roles, responsibilities and opportunities to engage with the FSO. These costs are likely to be in part proportional to the size of the energy market participant and the extent to which their business chooses to engage. Therefore, these costs are deemed inappropriate to cost.

80. However, to provide an indicative sense of the minimum cost these unmonetized learning and familiarisation costs may pose, analysis assumes a ‘cost per day of an energy sector representative’ to be within £600-£1200. This is based upon data provided by code administrators as part of our 2021 Energy Industry Code Reform IA[42]. At a minimum, we assumed that all energy industry participants will need to spend 1 working day per year during the transitionary period as the FSO is implemented and begins to perform new roles and responsibilities. Whilst we assume this captures an effective minimum cost, some firms with more engagement with the SO function, such as DSOs may have substantially higher familiarisation costs including potential costs such as upskilling.

Benefits

Improved advice to government

81. Benefits from this improved advice may come from two key sources.

82. Firstly, the greater trust in the impartiality of the FSO will enable government and Ofgem to act more quickly upon advice provided by the FSO, requiring less internal scrutiny before making decisions. A small benefit may come from the reduced resource requirements on Ofgem and HMG however the largest benefit is expected to come from a greater ability to make timely and robust policy decisions in the energy system.

83. Secondly, the enhanced roles and responsibilities of the FSO enable an improved whole system oversight, which in turn, is likely to increase the value of advice provided by the FSO. For example, this improved whole system oversight may enable the FSO to advise on developments in different areas of the energy system that misalign with policy objectives or each other. This may enable better government decision making and in turn reduce the costs of government interventions.

84. The magnitude of these benefits would be likely to increase in relation to the size and scope of the FSO. Therefore, the greatest benefits are expected in Option 3. Benefits are likely to be further increased if GSO and ESO functions were integrated within the same entity. This would enable advice to be made across energy vectors.

Improved “whole system” decision-making

85. Improved decision making across the “whole system” is the largest quantified benefit and is also pivotal in the FSO being able to provide improved advice to government, however there are several aspects of this benefit that are not mentioned elsewhere.

86. Firstly, monetised values only considered reduced costs in transmission network development. These reductions in costs may also occur elsewhere in the energy system due to a “whole systems” view. For example, system balancing, and network costs (including the

[42] https://www.gov.uk/government/consultations/energy-code-reform-governance-framework

distribution network) may be reduced under an integrated FSO able to co-optimise across both gas and electricity requirements. This benefit is likely to be substantially larger under future scenarios with a greater role for hydrogen. This is partly appreciated in sensitivity analysis above.

87. Secondly, a greater harmonisation of operational and investment decisions across the entire energy system may lower the risk of unplanned outages and system failures through greater co-ordination of energy system participants. The added gas roles and responsibilities taken on by the FSO under Option 2 are likely to increase the size of this benefit under Option 1. Benefits under Option 3 are expected to be comparable to Option 2 since it is unlikely that day-to-day gas functions will be required to enable a "whole system" view to be taken for gas.

Increased adaptability

88. The increased roles and responsibilities of the FSO could enable the FSO to both better predict and better respond to changing energy system needs. For example, an increased role in co-ordination could allow greater responsiveness of the energy sector during periods of extreme weather, such as the 2018 'Beast from the East'. Option 2 and Option 3 are likely to better adapt to challenges requiring cross-vector adaptability.

Increased innovation

89. The FSO will have a clear focus on innovation and could help to remove barriers to new technologies and business models, meaning that lower cost pathways to net zero may become available to us that would be otherwise shut down by prescriptive system rules that do not leave room to try new things.

90. This remit would be supported by the potential benefits to innovation brought about by improved "whole system" decision making enabling new opportunities for innovation and improved co-ordination facilitating its delivery. These supporting roles are present or likely to be larger under Option 2 and Option 3, compared to Option 1.

Introduction of competition on gas/hydrogen network assets

91. There may also be future benefit in introducing competition for large and separable gas or hydrogen projects in the future, and if so, whether the FSO is appropriately placed to identify, facilitate, and advise on these projects. Given natural gas networks are expected to decline across most net zero pathways[43], it is expected that the potential cost reductions as a result of input competition would be largest under pathways with significant scale up in the use of hydrogen. It is likely Option 2 and Option 3 will better deliver this benefit compared to Option 1 due to their great roles and responsibilities in the gas system.

## Risks, Uncertainties and Assumptions

Risk and Uncertainties

Increased inefficiency of the SO under the FSO

92. There is a risk that the FSO could be less efficient than the status quo resulting in higher internal costs and more importantly higher costs required to balance system balancing costs. This is likely to occur if the organisational design and resulting incentive structure applied to the FSO cannot create the same pressure to minimise costs.

[43] For example, the use of natural gas declines across all scenarios considered in the Carbon Budget 6 Impact Assessment: https://www.legislation.gov.uk/ukia/2021/18/pdfs/ukia_20210018_en.pdf

93. A 2019 paper by NERA[44] compared the performance of network operators based on their organisational design (i.e., public vs private) and found evidence that private firms have historically been more efficient in meeting energy needs with fewer unplanned outages and lower costs. However, there is less evidence that examines the SO function specifically, which may be effectively incentivised under a range of organisational design structures. The development of a strong organisational design model for the FSO is necessary to mitigate this risk. Moreover, there is a risk of inefficiency created by decision making and delivery being linked within a single organisation. Some consultation respondents highlighted that this could potentially leading to operational delivery being prioritised ahead of strategic decisions.

94. However, the removal of a profit incentive may also benefit non-profit or public organisational models by allowing greater focus to be given to softer, less profit-making areas important to overall system performance. This is likely to exist across all options, however, the magnitude of any potential inefficiencies is increasing in the size of the FSO, and therefore largest in Option 3.

<u>Increased uncertainty in governance structure</u>

95. The transition to an FSO creates uncertainty to the energy industry which may inhibit or delay investments. For example, distribution network operators (DNOs) may be uncertain what their future role in energy system planning and delay investments into new modelling capabilities as a result. Delaying planned investments to the electrification network may pose risk to the electrification pathway required under future scenarios. This is likely to be largest in Option 3 given the larger impact on the gas system, and in turn those operating in the gas sector. Conversely, this is likely to be smallest in Option 1 due to the FSO taking no formal roles and responsibilities for gas.

<u>Cost overrun and delays</u>

96. There is a risk the cost of implementation and delivery timelines may over run. Work on the development of a clear and robust implementation delivery plan is intended to mitigate this. This is likely to exist across all options with increasing costs under options in which more roles and responsibilities are carried over, and therefore largest in Option 3.

<u>Reduced accountability</u>

97. The increased number of responsibilities attached to the FSO for the delivery of outcomes in the energy system may reduce the accountability for the delivery of these outcomes to any one body. This risks creating a "*blame game*" across HMG, Ofgem and the FSO. Developing clear roles and responsibilities and a transparent decision-making process is intended to mitigate this risk.

<u>Increased risk of health and safety issues under the FSO transition</u>

98. Gas transmission in the UK is currently subject to a "Safety Case" owned by the Health and Safety Executive (HSE). The increased loss of operational synergies in gas between SO and TO functions may increase the risks to the system and require a review of the Safety Case. This risk principally applies to Option 3.

<u>Creation of a "single view" of the energy system</u>

99. Whilst it is expected that an increased "whole system" view will result in improved decision making across the energy system there is also a risk of creating a single view of the energy system and limiting diffuse decision making based on those with the best information. This could create inefficiencies in the delivery of policy objectives and raise costs to consumers.

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[44] https://www.nera.com/content/dam/nera/publications/2019/NERA%20Economic%20Consulting%20Public%20Private%20Energy%20Networks%20UK%20July%202019.pdf

100. In the context of net zero, the increasing complexity of the energy system is likely to limit the effectiveness of any single entity from having the necessary information to make informed decisions across the whole system. The design of roles and responsibilities taken on by the FSO look to limit this and ensure the active participation of stakeholders in the design of future system needs. This risk exists most strongly under Option 3 where the GSO as a separate entity is entirely removed.

Optimism bias

101. The cost of implementing the FSO is likely to be subject to optimism bias, with costs larger than expected and benefits smaller than expected. This applies to both monetised and non-monetised costs and benefits. This risk exists under all options.

Unknown uncertainties

102. The energy system is undergoing a period of rapid transformation and as such, there are likely to be risks that are unknown currently. To mitigate this uncertainty, careful consideration will be given as to how the FSO can be equipped and incentivised to new challenges.

Assumptions

103. There are several assumptions made throughout quantified analysis.

104. When calculating the benefit that improved “whole systems” decision making could have on reducing transmission network costs:

- **Assumption 1:** For electricity, it is assumed that future total expenditure on electricity transmission can be calculated by scaling current costs by the growth rate in allowed revenues used in BEIS’ Dynamic Dispatch Model reference cases.

- **Assumption 2:** For natural gas, it is assumed that future total expenditure on gas transmission can be calculated by scaling current costs by the growth rate of natural gas and hydrogen production in BEIS’ UK Times internal Carbon Budget 6 runs. i.e., assumes that network costs scale linearly with demand.

- **Assumption 3:** For hydrogen, it is assumed that the cost of the hydrogen network is £2m/TWh, this is based on a previous Baringa model[45].

- **Assumption 4:** For all three fuels, it is assumed that the reduced costs as a result of the FSO’s “whole system” view can be fairly illustrated by a range of between 1% to 5%. Given there is little evidence for this range, this assumption is the key focus of sensitivity testing.

105. When considering the loss of operational synergies that would occur in gas between the GSO and GTO under option 3:

- **Assumption 5:** This analysis directly replicates FTI analysis produced for Ofgem and therefore inherits their assumptions, listed in their report[46]. Broadly this assumes that the existing operational synergies allow the TO to use network assets to manage constraints and balance the system. If these options were lost, the GSO would need to take more commercial actions which would increase the cost.

106. Across all options:

[45] Not publicly available

[46] https://www.ofgem.gov.uk/system/files/docs/2021/01/final_-_fti_consulting_-_ofgem_gb_so_review_2021-01-22_0.pdf

- **Assumption 6:** It is assumed that all costs and benefits (excluding implementation costs) start in 2026 and continue out until the end of the timeline for analysis, in 2050.

107. There is also an assumption across all benefits listed this:
- **Assumption 7:** The FSO's risk appetite for trying new things is at least as great as under the status quo. This assumption is important to realising the benefits of a more innovative and flexible system.

## Wider Impacts and Distributional Effects

### Wider impacts

108. Beyond the quantified and unquantified costs considered so far, the creation of a new FSO may have several environmental, social and reputational impacts.

109. The creation of a new FSO represents a significant action to facilitate the enabling environment required to meet both domestic (UK Carbon Budgets, net zero) and international climate (UK Nationally Determined Contribution (NDC), net zero) commitments. This may increase the UK's credibility and provide lessons learning opportunities when influencing other countries to raise ambition on climate. This may contribute to ensuring the success of COP26, when countries NDCs will come into effect under the Paris Agreement.

110. The FSO is also likely to contribute to enabling the uptake of a Smart Grid and low carbon flexible assets. This supports the vision set out in the recently published 2021 Smart Systems and Flexibility Plan[47]. Similarly, the FSO may also be well positioned to support the decarbonisation of inter-related sectors such as heat and transport. For example, for advising on the optimal integration of electric vehicle charge points and ensuring the grid remains stable whilst doing so.

111. This policy intervention is also likely to contribute towards achieving governments objectives in sectors dependent on the electricity sector, such as the UK's target to rollout 600,000 heat pumps per year by 2028. Similarly, the creation of the FSO may help to enable governments Data and Digitalisation Strategy[48]. Therefore, the creation of an FSO may reduce the delivery risk associated with achieving Net Zero and our Carbon Budget pathway.

### Equalities Assessment

112. The transition to a FSO may have differing impacts on current employee's dependent on their protected characteristics. Ensuring full compliance with both the Transfer of Undertakings (Protection of Employment) Regulations 2006 (TUPE) and Public Sector Equality Duty set out in the Equality Act 2010 are critical to mitigate this. There are also potential opportunities in the creation of new roles and capabilities within the System Operator for wider social impacts through high-quality job creation. Preventing any adverse impacts and amplifying the potential opportunities outlined above will be kept under review as the implementation proposals are developed. We are also considering the wider societal impact that the FSO will have through its future roles and the extent of its advisory and decision-making responsibilities and have developed proposals to place a statutory duty on the FSO to consider the impact on consumers.

### Justice Impact Test

[47] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[48] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1004011/energy-digitalisation-strategy.pdf

113. [to be confirmed by MoJ – impact assessment submitted] This intervention does not expect to impact on the justice system. An internal assessment of the measures taken found it was unlikely that the creation of an FSO would result in any implication on the justice system.

Human Rights

114. [to be confirmed by lawyers] The power to force the sale of National Grid assets to government may impact on property rights. We intend to mitigate this by ensuring a fair price is paid for these assets.

Price and Bill Impacts

115. The creation of an FSO is likely to have upfront and ongoing costs of implementation which are likely to be passed onto end consumers of electricity, and under option 3, there is also additional costs via the potential loss of operational synergies. Whilst it is expected that benefits of intervention will also be passed onto consumers in the form of lower prices, the temporal effect of more near term costs before benefits are incurred could risk higher bills for end users of energy.

116. Internal analysis concluded that the size of costs incurred across all options would not result in any substantial increase in end user bills. However, over the longer term, the potential for more substantial cost reductions could have scope to reduce the bills of end users. This is not modelled given the illustrative nature of quantified benefits.

**Distribution of Impact**

117. A high-level assessment of the distributional impacts across groups and time is detailed in table 6 for our preferred option. Impacts on business are then considered in more detail in the following sections, splitting out the overall impact to business and the impact on small and micro businesses. Whilst no assessment of distributional impacts is exhaustive, consultation responses broadly agreed that the distribution of costs illustrated below was correct.

Table 6: *Distribution of impacts over groups and time – option 2*

| **Group** | **Costs** | **Benefits** | **Time-horizon for costs and benefits** |
|---|---|---|---|
| **National Grid Plc** | Internal resource costs (i.e., costs of sale process), separation.<br><br>Loss of revenue streams. (i.e., BSUoS)<br><br>Loss of incentive scheme revenues (i.e., Information Quality Incentive)<br><br>Loss of corporate memory and employee talent.<br><br>Loss of SO-TO operational synergies.<br><br>Loss of future RAV growth. | Capital cost associated with sale of SO assets. | For the purposes of our assessment, we assume that National Grid Plc faces internal resource costs to enable the establishment of a new FSO from 2022-2026.<br><br>For the purposes of our assessment, we assume that in 2026, National Grid Plc will receive the capital cost associated with implementation, however we also assume that it incurs all |

| | | | |
|---|---|---|---|
| | Reduced decision making in network planning.<br><br>Familiarisation and learning costs. | | remaining costs at this time. [49] |
| **FSO** | On-going costs<br><br>Familiarisation and learning costs<br><br>Potential capital cost of implementation (if the FSO is to be privately owned) | Revenue streams (i.e., BSUoS)<br><br>Incentive scheme revenues (i.e., Information Quality Incentive)<br><br>Future RAV growth.<br><br>Enhanced roles and responsibilities | For the purposes of our assessment, benefits are assumed to begin in 2026. |
| **HMG** | Legal, financial and consultancy costs<br><br>Capital cost of implementation (if the FSO is to be non-private)<br><br>Familiarisation and learning costs | Improved impartial advice provided by the FSO to government enabling better decisions and reduced policy costs.<br><br>Greater ability to meet policy goals (i.e., net zero, reduced fuel poverty) and ensure strategic alignment with them in the energy system.<br><br>Greater transparency in decision making. | Costs of implementation and capital cost of implementation are assumed to take place 2021-2026.<br><br>Benefits expected to accrue over longer timeframe, post 2026. |
| **Ofgem** | Internal resource costs to make appropriate adjustments in regulation for new FSO.<br><br>Familiarisation and learning costs | Improved trust in SO decisions.<br><br>Improved trust in SO advice. | Costs assumed to take place pre-2026.<br><br>Benefits expected to accrue over longer timeframe, post 2026. |
| **Energy firms (***Generation, transmission, distribution, supply***)** | Loss of some decision-making abilities due to increased role for FSO.<br><br>Increased uncertainty in system governance structure.<br><br>Internal resource to participate in government policy consultation process.<br><br>Familiarisation and learning costs. | Improved trust in SO decisions.<br><br>Increased opportunities to participate in competitions.<br><br>More belief in fair consideration of their network solution proposals.<br><br>Increased opportunities for innovation. | Costs illustrated as accruing from 2026, during transition to new FSO.<br><br>Increased uncertainty in system governance structure may be incurred from present until 2026.<br><br>Benefits accrue over longer timeframe, post 2026. |

[49] These assumptions are for the purpose of the IA and producing quantified results only and do not constitute policy decisions.

| | | | |
|---|---|---|---|
| | | More responsive energy system to changing needs. | |
| **SME energy firms** | Increased uncertainty in system governance structure.<br><br>Internal resource to participate in government policy consultation process.<br><br>Familiarisation and learning costs | Improved trust in SO decisions.<br><br>Reduced barriers to participation<br><br>More belief in fair consideration of their network solution proposals.<br><br>Increased opportunities for innovation.<br><br>More responsive energy system to changing needs. | Familiarisation and learning costs illustrated as occurring from 2026[50], during transition to new FSO.<br><br>Increased uncertainty in system governance structure may be incurred from present until 2026.<br><br>Benefits accrue over longer timeframe, post 2026. |
| **Energy end users (***Industrial and household consumers***)** | New FSO roles and responsibilities passed through to consumers' energy bills (expected to be negligible)<br><br>Risk of outage during SO ownership transition (particularly gas)<br><br><u>No substantial bill impact</u> from capital and implementation costs identified | Reduced energy bills<br><br>Potential for increased future system reliability<br><br>Increased number of innovative opportunities for participation (i.e., Demand Side Management, Prosumers) | Risks associated with transition to new FSO expected in 2026[51] with on-going costs of new FSO roles and responsibilities passed through to consumers thereafter.<br><br>Benefits expected to accrue over longer term, beginning 2026 but predominantly 2030 onwards. |

**Additional detail on distribution of costs and benefits**

### Direct Business Impact

118. As noted in table 6, in the energy sector, direct costs to business are likely to be limited to learning and familiarisation costs alongside the internal resource costs required to participate in subsequent government consultations. However, BEIS considers these impacts to be pro-competition and therefore to fall out of scope of a more detailed assessment of business impacts. According to the Better Regulation manual[52], a regulatory measure needs to satisfy all of four conditions to be considered to promote competition. In the following section we list the four conditions and provide a comment for each of them to explain how the proposed measures meet them:

    a. *The measure is expected to increase, either directly or indirectly, the number or range of sustainable suppliers; to strengthen the ability of suppliers to compete; or to increase suppliers' incentives to compete vigorously.*

**Comment:** This intervention looks to remove the perceived or potential conflict of interest in SO decision making. This intends to enable greater competition through two means. Firstly, the

[50] Given these costs are not monetised, no assumptions are made over how long these learning and familiarisation costs will last.
[51] Given these costs are not monetised, no assumptions are made over how long these learning and familiarisation costs will last.
[52] https://www.gov.uk/government/publications/better-regulation-framework

enhanced roles and responsibilities of the FSO will enable a "whole system" view which may result in realising new opportunities to create competition. Secondly, the current perception of conflicts of interest in SO decision making may act as a barrier to entry for firms looking to enter competitions. By creating an impartial FSO, this barrier of entry is reduced since firms are likely to have greater trust that they will be treated fairly throughout the competitive process. These two policy aims intend to meet all four criteria, listed under paragraph 118.

b. *The net impact of the measure is expected to be an increase in [effective] competition (i.e., if a policy fulfils one of the criteria at (a) but results in a weakened position against another) and the overall result is to improve competition.*

**Comment:** At its core, this intervention intends to remove the perceived or actual conflict of interest that exists under the current ownership arrangements, under National Grid. This is because National Grid are a profit-making company with business interests in other areas of the energy system such as interconnectors[53]. As noted throughout supporting literature[54], this has the potential to limit effective competition by favouring system solutions supporting their business interests or disfavouring (via delays, higher connection charges, etc.) competitive rivals.

It is also expected that the FSO will identify new opportunities for competition across the energy system and act as an impartial facilitator of these competitions. These may also extend to gas and hydrogen networks in the future. Respondents at consultation stage broadly agreed the creation of the FSO would result in improved facilitation of network competition however disagreed with our approach to quantifying impacts, therefore no quantified impacts are explicitly included. These benefits do contribute towards our 'whole system' view benefit quantified above.

c. *Promoting competition is a core purpose of the measure.*

**Comment:** Yes. The overarching strategic aim of this intervention is to contribute to delivering net zero at least cost to consumers. A core part of the intervention achieving this will be through the FSO increasing the frequency and intensity of competition across the energy system. This is informed by the conclusions of the 2021 Ofgem Review of the GB Energy System Operator, who found that stakeholders viewed current arrangements as inhibitive of fair competition, acting as a barrier to entry.

d. *It is reasonable to expect a net social benefit from the measure (i.e., benefits to outweigh costs), even where all the impacts may not be monetised.*

**Comment:** Yes. Central estimates included under monetised impacts find that the three options assessed result in net present values of between a net cost of £900m to a net benefit of £2,900m. However, the preferred option is expected to result in a net benefit of between £10m to £2,900m. When also considering non-monetisable impacts, the learning and familiarisation costs are only expected to be transitionary whilst benefits such as the improved value of advice to government is expected to be on-going. Overall, it is reasonable that intervention will present a net social benefit.

### Small and Micro Business Assessment (SaMBA)

119. BEIS's Business Population Estimates[55] listed in tables 7 and 8 provide the combined number of employers in the 'Electric power generation, transmission and distribution' and the 'Manufacture of gas; distribution of gaseous fuels through mains' sectors. In 2020 there were 2,060 micro businesses in the electricity sector and 55 in the gas sector. There were 415 small businesses in the electricity sector and 15 in the gas sector. There has been a

[53] As noted here, National Grid owns several of the current interconnectors. https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors

[54] An early example of this is supporting analysis undertaken by Imperial College and Cambridge University as part of Ofgem's 2013 Intergated Review of Planning and Regulation (page 16, https://www.ofgem.gov.uk/sites/default/files/docs/2013/06/imperial_cambridge_itpr_report_0.pdf)

[55] https://www.gov.uk/government/statistics/business-population-estimates-2020

particularly large increase in the number of micro and small businesses in the electricity sector since 2013, the earliest year for which data is available, there has been around a 300% increase in the number of SME firms, compared to rises of around 175% and 65% for medium and large businesses respectively. These figures show that micro and small businesses already play an important and significant role in the electricity sector, which will be expected to increase further in the future, as more decentralised systems allow for a greater degree of small-scale generation.

120. For gas, the role of SME firms appears more stable with no rise in the number of small firms and about a 50% increase in the number of micro firms, roughly comparable to the 100% increase in the number of large firms.

Table 7 - Number of employers in the private sector, Electric power generation, transmission and distribution industry group, UK, start 2020

| | Firms (*number*) | Employment ('*000s*) | Turnover (*£m*) | Firms (%) | Employment (%) | Growth in firms since 2013 |
|---|---|---|---|---|---|---|
| All employers | 2,555 | 101 | 101,065 | *100.0* | *100.0* | 296% |
| Micro (1 - 9 employees) | 2,060 | 8 | 6,898 | *80.6* | *7.9* | 308% |
| Small (10 - 49 employees) | 415 | 6 | * | *16.2* | *5.9* | 295% |
| Medium (50 - 249 employees) | 55 | 6 | * | *2.2* | *5.9* | 175% |
| Large (250+ employees) | 25 | 82 | 85,319 | *1.0* | *81.2* | 67% |

*Key: * refers to missing data*

Table 8 - Number of employers in the private sector, Manufacture of gas; distribution of gaseous fuels through mains, UK, start 2020

| | Firms (*number*) | Employment ('*000s*) | Turnover (*£m*) | Firms (%) | Employment (%) | Growth in firms since 2013 |
|---|---|---|---|---|---|---|
| All employers | 85 | 44 | 40,845 | *100.0* | *100.0* | 42% |
| Micro (1 - 9 employees) | 55 | * | * | *64.7* | * | 57% |
| Small (10 - 49 employees) | 15 | 0 | * | *17.6* | *0.0* | 0% |
| Medium (50 - 249 employees) | 5 | * | 1,229 | *5.9* | * | 0% |
| Large (250+ employees) | 10 | * | * | *11.8* | * | 100% |

121. The main cost borne by SME firms in the energy sector is likely to be learning and familiarisation costs, such as administrative costs of understanding the new roles taken on by the FSO. Whilst these costs will be felt across all stakeholders it is likely that the fixed costs of this administrative burden are likely to have a larger impact on SME firms, who are likely to have both a smaller revenue base to absorb these costs and fewer internal resources to fully adjust to operation under the FSO.

122. There may also be secondary impacts to SME firms that are subject to further consultation. SME firms may also feel the impact of new roles and responsibilities assigned to the FSO if they are license holders or signatories of energy codes. This is because their obligations under these licenses or codes may change. Given these are subject to consultation, SME firms will also have the opportunity to make representation on any specific elements of new FSO roles that have an effect on them, prior to those roles coming into effect. As stated in

the 2021 consultation, we intend to make sure that SME industry participants are appropriately represented in any forums that contribute to that overarching governance helping to ensure impacts to SME firms can be mitigated.

123. A core purpose of intervention is to enable an improved facilitation of competition and reduced potential for conflicts of interest towards transmission network solutions. Currently, the fixed costs of participating in competitions is likely to represent a greater burden on SME firms than larger firms, for example the cost of developing formal bids. The perception of conflicts of interest in competition is therefore more likely to deter SME firms from participating since the cost of participating is relatively higher. By ensuring SME firms feel competitions are facilitated fairly, the barriers to participation are then lowered. Similarly, given its economies of scale, the transmission network in operated by large firms only. Therefore, the perception of conflicts of interest towards transmission network solutions is likely to act as a barrier to entry for SME firms since these solutions exclude SME solutions. Removing the perceived or potential conflicts of interest towards them is likely to increase the willingness of SME firms to enter the energy market by increasing the perceived or actual benefit of doing so.

124. For SME firms outside of energy, any additional costs passed through to energy bills are likely to be small and have no significant impact on firm productivity, as confirmed by our price and bills assessment above. The long run impact of intervention is intended to facilitate net zero at least cost meaning a lower bill impact to all end users.

## Monitoring and Evaluation

125. Monitoring and Evaluation (M&E) in this impact assessment outlines the objectives of M&E for this policy intervention and outline the likely data requirements and approach that may be taken. Additional detail will be required to refine the plan and ensure proportionality to be developed alongside implementation.

### Policy Objectives

126. Policy intervention intends to achieve the objectives established through consultation and as set out above, in paragraph 15. Ensuring that these objectives can be interpreted in a SMART[56] manner is important for enabling effective M&E. However, the Future System Operator is a market-enabling policy which intends to help the energy system achieve net zero out to 2050 at least cost. As such, there is no clear ‘completion date’ by which we expect objectives to have been fully realised. This makes it difficult to reflect the objectives of policy intervention in a time-bound and measurable manner.

### Theory of Change

127. The theory of change for how policy intervention intends to achieve objectives is set out in annex 1, figure 1. This process chart outlines how we expect intervention to achieve our intended outcomes and contribute towards our overarching policy objective of helping to achieve Net Zero at least cost whilst ensuring security of supply.

128. The achievement of this theory of change is dependent on a number of assumptions linking actions, outputs and outcomes in the figure above. These assumptions relate to external factors, outside the control of policy intervention and reflected in the risks section above.

129. It is also assumed that policy intervention will work as intended and the new arrangements will result in the achievement of objectives whilst not also producing any unintended consequences. The impact of wider contextual arrangements such as the rate of power sector decarbonisation, the emergence of new technologies or the existence of new bodies

[56] Specific, Measurable, Achievable, Realistic and Timebound

such as a Strategic Body overseeing Energy Codes is important to consider alongside this policy intervention.

Objectives of Monitoring and Evaluation

130. Ensuring that the governance of the energy system is fit for purpose is crucial to the achievement of Net Zero, whilst ensuring security of supply and universal access to affordable energy.

131. **Aim 1: To provide clear, impartial and robust evidence to demonstrate the intervention's impact or wider outcomes:** it is important that robust M&E is available in a timely manner in order to help ensure that governance arrangements are fit for purpose and highlight where additional action may be required. This need for M&E is heightened by the uncertainties and assumptions illustrated of the future state of the world and energy system needs, illustrated in the narrative supporting our theory of change in paragraph 127.

132. **Aim 2: To provide useful and timely learning about the roll and performance of the FSO:** This policy intends to leverage M&E to highlight early signs of both good and poor performance in both the process of delivering the FSO and subsequent performance of governance arrangements in achieving policy objectives.

133. In the event that M&E highlights shortcomings in the delivery or performance of the FSO, evidence may then inform decisions on how these shortcomings may be appropriately addressed. In all eventualities, evidence provides learning useful for other wide scale governance reform projects and helps ensure BEIS is accountable to policy customers and tax-payers.

Monitoring and data requirements

134. Monitoring requirements are under development. An update will be provided in subsequent IAs produced at secondary legislation stage.

135. Stakeholder feedback on the performance of the existing ESO has been collected through consultation and through stakeholder engagement. There is also an existing annual ESO performance panel[57] which challenges the ESO's plans before the start of the year, evaluates the ESO's performance after six months (mid-year review) and performs an end of year assessment, as part of Ofgem's RIIO framework.

136. It is expected that monitoring the performance of the FSO will look to utilise these existing performance panels, with additional indicators requested in order to ensure as many relevant indicators are captured as possible. This work is ongoing and will continue to be developed ahead of the implementation of the FSO and before outcomes of the policy intervention are observable.

Evaluating performance

137. To provide a full understanding of policy intervention, and, given the difficulties in effectively monitoring the performance of intervention on an ongoing basis, at this stage, it is deemed likely to be proportionate to carry out two evaluations; a lighter-touch process evaluation at the time of implementation followed by a value-for-money performance evaluation 5 years following implementation, when it is expected there will be sufficient experience of the new governance arrangements to assess their performance and desirability.

[57] https://www.ofgem.gov.uk/publications/eso-performance-panel-end-year-review-2020-21

Process evaluation (within 1 year of implementation):

138. To complement the monitoring approach, we might expect to carry out a light-touch process evaluation to explore the implementation of the proposed changes. Given the robust nature of the monitoring process, the process evaluation will be relatively light-touch and explore the following thematic questions:

a) Was the intervention to establish a Future System Operator delivered as intended? What lessons can be learned from the implementation of the FSO? (Process evaluation)
   - Were there any unexpected or unintended issues in the delivery of the intervention?
   - Was security and stability maintained during the transition?
   - Did the change create regulatory uncertainty for investors?
   - Were timelines realistic?

b) Is the theory of change still reflective of our policy intervention? How have wider contextual factors or unforeseen dependencies influenced our understanding of the intervention?
   - Is the governance structure still equipped with the right skills, roles and resources to meet our objectives in light of this new information?
   - Has the development of wider factors influenced the requirements of this policy intervention to meet its objectives?

Impact and value-for-money evaluation (5-years post implementation):

139. We may also expect to carry out a robust evaluation of the impact and value for money of establishing the FSO five years post implementation. This evaluation would make use of the monitoring data collected over time and supplement this with new data and analysis.

Thematic questions this evaluation will look to address are:

a) Did delivering an FSO achieve the expected outcomes and objectives of intervention? To what extent are these attributable to this policy intervention?

b) How cost-effective was the intervention to FSO? Have different groups been affected in different ways, how, why, and in what circumstances?

c) Are governance arrangements and the FSO' role within it fit for purpose into the future? Does the emergence of unintended consequences, new energy system challenges or wider contextual factors require reform to current arrangements?
   i. For example, Does the FSO hold the correct roles and responsibilities?

Approach to evaluation and additional data requirements

140. We anticipate that any evaluations would be largely survey and interview based, using a range of expert interviews alongside surveys to capture the views of relevant parties across the energy system, ensuring a sufficient range of relevant parties are reflected. This approach is preferred due to both the highly bespoke nature and universal application of the Future System Operator and the pace of whole system change in the energy sector making it difficult to establish a counterfactual by which quantitative or experimental approaches to evaluation could be compared. Similarly, the multitude of interdependencies and supporting policy interventions in the energy sector makes it difficult for quantitative analysis to identify the causal impacts of this intervention.

141. Data collected by the FSO performance panel could also be used to evaluate the intervention. This data will be collected on an annual basis. We will review the evidence that is collated through the existing process and identify any gaps in the monitoring which could

be filled with existing administrative data or, if needed, primary research (e.g., surveys). Data will also be collected from individuals involved in the intervention to answer the process evaluation questions. Data on the cost of the intervention will also be collected.

**Justification of preferred Option**

142. **The preferred option in this IA is Option 2, which designs a highly independent but publicly owned FSO to carry out all electricity roles and all gas roles excluding day-to-day operations**. This preferred option has been informed and chosen based on the analysis presented in the economic case, alongside detailed policy analysis and overarching strategic considerations which are not able to be fully reflected in the economic case.

143. The analysis in this impact assessment concludes support for the preferred option via:

- **Quantified analysis concluding that Option 2 presented the highest net-present value:** Whilst there is significant uncertainty about both the potential costs and benefits of an FSO, quantified analysis concludes that Option 2 is the preferred option, since Option 2 is able to achieve the same benefits as Option 3 whilst not incurring the additional costs. Compared to Options 2 and 3, Option 1 achieves significantly fewer benefits whilst only incurring small cost savings relative to Option 2.

- **Sensitivity analysis highlighting that benefits would only need to be small in order for intervention to 'break even':** There is significant uncertainty in the effectiveness of the FSO in reducing costs across the energy sector. Sensitivity analysis highlights that under Option 2, the FSO would be required to reduce the costs of delivering a Net Zero energy sector by a fractional amount compared to Options 3. Looking at the future transmission costs alone, the FSO under Option 2 would only need to reduce transmission network costs by 2%, compared to over 5% under Option 3.

- **The non-monetised risks associated with Option 3 are significantly higher than other options:** Carrying over day-to-day functions of the GSO to the FSO creates greater safety risks. Given the probability of a safety event occurring is unknown, costs are not monetized, however, these could be significant. It is also reasonable to expect higher learning and familiarisations costs alongside greater risk of delay to implementation timelines, eroding benefits.

144. In addition to the analysis included in this impact assessment, there are also strategic policy considerations in support of the preferred option are:

- **Implementation timeline risks:** The greater risk of delay to implementation timelines under Option 3 may inhibit the FSO from supporting key decarbonisation decision points, such as CB6. This may occur directly via delayed FSO advice or decision making, but also indirectly, via increased investment uncertainty for industry. This preferences Option 2, which is found to have similar implementation risks as Option 1 however a greater achievement of this business cases policy objectives.

- **Safety risks**: Option 3 raises concerns over the HSE Safety Case for gas which would need to be revisited.

145. On balance, these considerations indicate that roles prescribed to the FSO under Option 1 would not fully capitalise on the potential strategic and economic benefit of the FSO. Roles prescribed under Option 3 would allow for these benefits to be realised however present significantly higher costs associated with implementation, alongside new costs and risks due

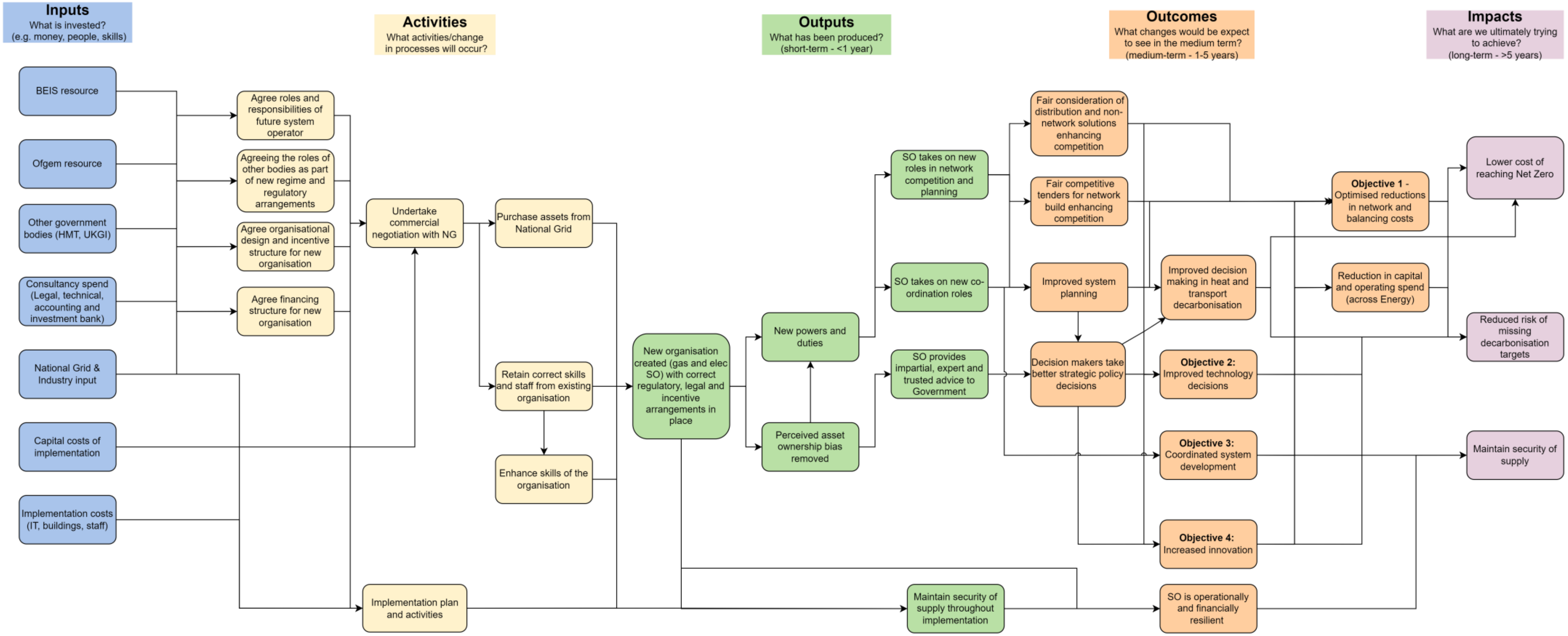
to the loss of operational synergies expected to occur in gas. To cover these increased costs, sensitivity analysis highlights those benefits would have to be substantially higher under Option 3 compared to Options 1 or 2, which policy development and consultation did not indicate would be the case.

146. As a result, Option 2 is the preferred option, since it is expected to maximise the economic and strategic benefit an FSO can have whilst minimising the downside risks highlighted. These conclusions and the underpinning economic analysis were broadly supported via consultation feedback, providing a further form of evidence for the above conclusions.

147. Across all options, a highly independent but publicly listed company was found to be most viable. If any option is implemented, Monitoring and Evaluation will play an important role to ensure that the process of implementing the FSO and it’s performance are in line with expectations. Similarly, Monitoring and Evaluation may also assess whether the roles and responsibilities carried out by the FSO are sufficient, or whether further roles, such as planning responsibilities for CCUS networks, are required. Further details of this are presented in the Monitoring and Evaluation section.

## Annex 1:

## *Figure 1: Future System Operator theory of change*



| | |
|---|---|
| **Title:** Regulation of Load Controlling entities<br>**IA No:** BEIS045(F)-22-ESNM<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business Energy and Industrial Strategy<br>**Other departments or agencies:** | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Development/Options<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** smartenergy@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status**<br>Non qualifying provision |
| £0m | £0m | £0m | |

**What is the problem under consideration? Why is government action or intervention necessary?**

Demand Side Response (DSR) is expected to contribute to reducing the costs of achieving Net Zero and legislated Carbon Budgets whilst also enabling consumers to participate in the energy transition and reduce their energy bills. New business models and markets are emerging that enable 'load controlling' organisations to remotely manage consumers' energy smart appliances, reduce consumer bills and provide DSR flexibility to the grid. In the absence of intervention, consumers may be exposed to several risks including the mis-selling of products, unfair lock-in or compromise of personal data. There may also be greater costs to the energy system, including an increased likelihood of system outage or increased costs of maintaining grid stability. Government intervention intends to mitigate these risks, enabling the scale-up of competitive markets for DSR and energy smart appliances whilst protecting consumers and the energy system.

**What are the policy objectives of the action or intervention and the intended effects?**

The Government's aim is to maximise the use of Demand Side Response, to benefit both consumers and the electricity system, whilst supporting the transition to Net Zero. This aim will help meet the BEIS objectives of achieving net zero, maintaining security of supply, and helping reduce fuel poverty. To meet this aim, we need to facilitate greater consumer uptake of DSR through providing appropriate protection for consumers and the energy system. More specifically, these interventions intend to meet the objectives of consumer protection, interoperability, grid stability, cyber security and data privacy.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

This impact assessment considers our **'Do Nothing' counterfactual** where load controlling organisations remain unregulated, against **designating 'load control' as a licensable activity (preferred option)**; here, the government would require organisations undertaking relevant activities to obtain a licence from Ofgem and comply with any licence conditions and codes attached to that licence. The significant risks posed by the counterfactual, such as widespread consumer harm, increased cost of maintaining energy system stability, or leaked consumer data incidents are deemed to justify the creation of a licence, which is a well understood and commonly adopted approach within the energy system. Alternatives to regulation via Government encouraging voluntary compliance of industry standards, and alternative forms of regulation via mandating legislative requirements in statutory instruments (rather than in a licence), were also considered. Neither were taken for more detailed scrutiny due to not addressing the technical and flexibility needs required to solve the market failures and mitigate identified risks.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:**

| | | | | | |
|---|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | Yes | | | |
| Are any of these organisations in scope? | **Micro**<br>Yes | **Small**<br>Yes | **Medium**<br>Yes | **Large** Yes | |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:**<br>0 | **Non-traded:**<br>0 | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

# Summary: Analysis & Evidence

Policy Option 1

**Description:**
**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** NA | **PV Base Year** NA | **Time Period Years** | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** 0 |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | 0 | | 0 | **0** |

**Description and scale of key monetised costs by 'main affected groups'**

There are no costs expected from primary legislation. Impacts arising from secondary legislation are discussed qualitatively and are unmonetised in this impact assessment. There will be further impact assessments with more detailed quantification of impacts to accompany a consultation on the detail of the licensing regime for load controllers, which will precede the full implementation of the regime through secondary legislation.

**Other key non-monetised costs by 'main affected groups'**

There are no costs expected from primary legislation. The creation of a licensable activity under secondary legislation may pose several costs. Licensees will incur compliance costs, which may involve changes to internal processes and technical infrastructure, or recruitment costs to ensure compliance, though some of these costs may be passed onto customers. There will also be new costs to Ofgem to enforce the license and costs associated with any entity designated with the role of a central body, which may be required to deliver technical infrastructure.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | 0 | | 0 | **0** |

**Description and scale of key monetised benefits by 'main affected groups'**

There are no benefits expected from primary legislation. Impacts arising from secondary legislation are discussed qualitatively and are unmonetised in this impact assessment.

**Other key non-monetised benefits by 'main affected groups'**

There are no benefits expected from primary legislation. The achievement of policy objectives through secondary legislation is likely to increase the uptake of DSR, reduce the costs of maintaining energy system stability and protect against the unfair treatment of consumers. This is likely to decrease the costs of operating and decarbonising the energy system as a whole, likely resulting in reduced energy bills for end consumers. Greater competition among providers of DSR services may also increase innovation and the accessibility of DSR services.

| **Key assumptions/sensitivities/risks** | **Discount rate** | NA |
|---|---|---|

There are no risks expected from primary legislation.  For secondary legislation, there is large uncertainty over how future markets for DSR services will develop. Policy intervention may also create risks, including greater barriers to entry for organisations and regulatory uncertainty for investors. Intervention itself may also risk timeline delays which would delay the benefits of intervention. Policy design intends to mitigate these risks, and further consideration to these will be given in subsequent impact assessments on the detail of implementation.

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** NA | **Benefits:** NA | **Net: NA** | NA |

# Contents

# Evidence Base

## 1. Background

1. Smart and flexible energy solutions, such as storage and demand side response, can enable us to use energy more flexibly and de-carbonise our energy system cost-effectively. Deployment of electricity storage and smart technologies in homes and businesses will reduce energy bills and system costs.[1] The Smart Systems and Flexibility Plan[2] highlights that up to 60GW of low carbon flexibility may be needed by 2050, saving as much as £10bn per year by 2050 (2012 prices)[3]. This low carbon flexibility is likely to be met through a combination of different solutions, such as electricity storage (e.g. batteries), interconnectors with surrounding countries and **Demand Side Response** (DSR).

2. **Demand Side Response** refers to actions taken by consumers to shift the time of their electricity use, typically to minimise impact on the energy system. DSR offers flexibility to the energy system by rewarding consumers for using (or not using) electricity at times that are beneficial for the electricity system. By shifting non-time sensitive electricity demand away from peak periods and towards periods of low demand and plentiful supply of renewables, we can reduce the amount of generation and network capacity necessary to meet our net zero targets. This reduces the cost of our energy system for all consumers.

3. Increasingly, energy consuming devices, such as EV chargepoints, that are in or around premises include “smart” functionality. This allows these energy smart devices to change their energy consumption in response to communications signals. Smart tariffs and DSR services allow consumers with these devices to participate in Demand Side Response, by indirectly or directly rewarding consumers for shifting their demand. For example, time-of-use tariffs already offer EV drivers much cheaper electricity prices if they charge overnight when demand is lower. We expect increasing numbers of other high-load devices, such as heat pumps, to be sold with smart functionality in the coming years.

4. As Energy Smart Appliances become more common, and the need for flexibility in the energy system grows, we expect consumer propositions involving DSR to become increasingly attractive to domestic and small business energy consumers. This DSR in domestic and small business premises is expected to be delivered through a range of new business models whereby ‘load controlling’ organisations enter into arrangements with consumers to remotely control or configure the load (or export from battery storage) consumed by devices.

5. These ‘load controlling’ organisations are diverse and referred to in many ways, such as Demand Side Response Service Providers (DSRSPs)[4], Home/Buildings Energy Management System (HEMS/BEMS) Providers, aggregators, flexibility service providers and charge point operators (CPOs), amongst others. These organisations sometimes also have other roles in the energy system (e.g. they may also be energy suppliers).

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[1] https://www.gov.uk/government/publications/sustainable-warmth-protecting-vulnerable-households-in-england/sustainable-warmth-protecting-vulnerable-households-in-england-accessible-web-version

[2] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

[3] This is £12bn per year by 2050 in 2020 prices.

[4] Other non-DSRSP organisations also meet the definition of a ‘load controller’, such as home management services offered by virtual assistant technologies such as Amazon Alexa. These are not the focus of this policy intervention.

6. DSR takes many different forms. Some DSR services will involve the direct remote control of electrical load to provide flexibility services to system operators, while others will allow consumers to automate their device's usage against price or other signals. DSR can also be delivered at the local level through home/Building energy management (HEM/BEM) systems, through which demand from devices such as chargepoints or heat pumps is shifted to allow the usage of local generation and storage. Similarly, consumer propositions for DSR can take multiple forms, such as time-of-use tariffs, smart tariffs requiring automated demand response, or direct revenue incentives.

## 2. Problem under consideration

7. The Government has identified a number of risks and challenges that load controlling organisations participating in DSR could bring for both consumers and the energy system. The five sets of risks that have been identified relate to:

    - **Consumer protection:** the control and configuration of consumer devices for DSR by a load controlling organisation will present new issues relating to consumer protection, including fair contractual terms.

    - **Cyber security:** a cyber attack on organisations controlling load to provide aggregation and demand management services could lead to consumer detriment, and put consumers off use of DSR, undermining its uptake and subsequent benefits to consumers and the energy system. At scale, cyber attacks could also disrupt grid stability and lead to wider social and economic harm (e.g. by causing blackouts).

    - **Interoperability:** in absence of intervention, coordination failures may mean organisations are not incentivised to develop and put in place the interoperable systems and processes that enable consumers to switch service providers. Furthermore, the value of flexibility may incentivise organisations to unfairly lock-in consumers to their services or devices, deterring or blocking them from freely switching in search of better offerings, or from using their devices for DSR at all.

    - **Grid stability:** the connected nature of Energy Smart Appliances could mean that load control or DSR leads to sudden spikes or drops in electricity demand. For example, when large numbers of load controlling organisations make household devices simultaneously respond to the same price signal.

    - **Data privacy:** Energy Smart Appliances and DSR will generate large amounts of data relating to consumers' energy consumption and usage patterns. The improper storage, use or sharing of this data will lead to data privacy risks.

8. The risks identified are expected to grow in significance as we increasingly use devices with smart functionality such as heat pumps and electric vehicles chargepoints. The Government's target is to install 600,000 heat pumps every year from 2028 under the 10-point-plan for a green industrial revolution[5]. Further, the Climate Change Committee suggests there could be around 28 million EVs on the road, comprising 25 million BEVs and 3 million PHEVs by 2035[6].If these risks are not resolved, it could limit use of DSR. This would undermine the BEIS objectives such as meeting net zero, increasing energy security

[5] BEIS, Prime Minister's Office, 10 Downing Street (2021), PM outlines his Ten Point Plan for a Green Industrial Revolution for 250,000 jobs, https://www.gov.uk/government/news/pm-outlines-his-ten-point-plan-for-a-green-industrial-revolution-for-250000-jobs

[6] https://www.theccc.org.uk/publication/sixth-carbon-budget/

and reducing fuel poverty. Specifically limited use of DSR could both undermine and increase the costs of achieving our net zero energy system by 2035 ambition[7], via increased reliance on more capex intensive forms of low-carbon flexibility, and greater need for network reinforcement and generation assets that could increase consumer bills.

9. By taking powers to make load controlling a licensable activity, alongside complementary proposals being taken forward to establish device level requirements for energy smart appliances, the Government will have the tools it needs to be able to tackle the above issues. Energy Smart Appliances and load controlling organisations are currently not subject to regulatory requirements relating to their delivery of DSR, except for private EV chargepoints, which are subject to device-level regulations which come into force later this year[8]. Proposals to take enabling powers to set manufacturing standards on devices with smart functionality will address some of the above risks in relation to use of ESAs. These proposals to take enabling powers to licence load controlling organisations, alongside others, will add to these assurances by helping mitigate cyber security incidents, as well as ensuring consumer issues related to switching DSRSPs can be addressed.

## 3. Policy objective

10. The government's aim is to maximise the growth in the market for DSR to the benefit of both consumers and the electricity system. To meet this aim, we have five core objectives:

- **Consumer Protection:** Consumers should be treated fairly, and protected from unfair terms, mis-selling or unacceptably poor service
- **Cyber security:** Organisations providing load controlling services must have appropriate and proportionate cyber security in place, to mitigate risks to the stability of the grid, in addition to protecting individual consumers.
- **Interoperability:** interoperability is essential for a competitive market for DSR services and helping ensure cyber security. Consumers should not be unfairly locked in to organisations' services or devices, deterred or blocked from freely switching in search of better offerings, or from using their devices for DSR at all.
- **Grid stability:** Load controlling entities should have controls to prevent of negative impacts on the grid caused by inappropriate smart operation.
- **Data privacy**: Load controlling entities should minimise collection of personal data and protect against mis-use

11. The ability to make these policy objectives SMART[9] is subject to further policy development and consultation on the detail of specific requirements under the future licencing framework. For example, more detailed work to establish what actions load controlling organisations will need to take under the licence to ensure interoperability of their service with smart devices and vice versa, will be a pre-condition to assessing whether this action has met our interoperability policy objective. A further consultation will set out the details of the proposed licence for load controlling organisations, and subsequently consider SMART impacts of these policy objectives to inform monitoring, compliance, and enforcement processes for the licence.

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7 https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035

8 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1015290/electric-vehicles-smart-charge-points-regulations-2021-impact-assessment.pdf

9 Specific, Measurable, Achievable, Realistic and Time-bound

## 4. Policy context and actions

12. The government is seeking enabling powers in the 2022 Energy Bill to help achieve its policy objectives. To enable sufficient scrutiny of these proposed powers, four impact assessments have been developed, assessing the impact that each of the three major strands of our enabling powers entail.

13. This impact assessment considers enabling powers to (i) establish a licensing regime, to be enforced by Ofgem for organisations providing applicable load control services; (ii) to create one or more central bodies to help ensure the safe operation of DSR, and (iii) to amend any existing licenses and codes impacted by our interventions. The remaining three impact assessments are:

   - **Energy Smart Appliances (ESAs):** The Government is proposing to enact enabling powers to set regulatory requirements for domestic energy smart appliances in Great Britain.[10] The regulation will set requirements on smart functionality, interoperability, data privacy, cyber security, grid stability and consumer protection. This will ensure smart appliances can provide DSR and allow consumers to shift their electricity demand to cheaper times of the day in a safe and secure way. The technical requirements with which smart appliance manufacturers will have to comply will be specified at the secondary legislation stage.

   - **Energy Smart Appliances (ESAs) –** Smart Electric Vehicle Charge points: the powers being sought to set requirements on ESAs will also apply to smart charge points so that all ESAs are regulated under one coherent regime. These changes are assessed in a separate impact assessment given there is existing regulation in place for charge points.

   - **Mandating electric heating appliances are smart:** The Government is also proposing to take enabling powers to mandate that electric heating appliances must have smart functionality, with requirements specified at secondary legislation stage. Subject to consultation, it is proposed that the requirements will be introduced initially for electrical heating appliances with the greatest potential to be used flexibly, including heat pumps, as well as storage heaters and heat batteries.

14. The market for DSR is also supported by a number of other policies and actions. Those which are most relevant are detailed in annex 1 of this impact assessment and include Ofgem's decision to implement half-hourly settlement by 2025, the development of technical standards for energy smart appliances, changes to regulation to ensure UK cyber security and a number of actions set out in the Smart Systems and Flexibility Plan.

## 5. Rationale for intervention

15. Without regulation, there are several market failures that are likely to materialise across each of the Secure Smart Energy System (SSES) project's areas of concern highlighted in paragraph 7 (*cyber security, grid stability, interoperability, data privacy and consumer protection*). Whilst these areas of policy development are highly intertwined, their potential market failures differ between areas. These are therefore discussed separately below before the strategic rationale across all options is summated. Collectively these market failures would undermine BEIS objectives related to achieving net zero, increasing security of energy supply, and reducing fuel poverty.:

[10] Energy Smart Appliances (ESA) refer to large domestic appliances with the ability to provide DSR services: Heating, ventilation, and air conditioning, wet and cold appliances, and battery storage.

### 5.1.1 Market failures – interoperability

16. In many industries, the technical standards required to deliver interoperability are often industry led, delivered through competitive forces or Standard Setting Organisations (SSOs)[11] which enable industry to collaborate in order to agree a common technical approach to enabling interoperability. For example, these SSOs have successfully delivered several industry led interoperability standards in telecommunications such as 4G (albeit in a sector which is subject to significant regulation, including regulatory oversight from Ofcom) and the development of Unicode text standards. Market failures may occur however under certain market conditions.

    Interoperability standards are characterised as being subject to strong network effects. This means that the more customers that use a particular interoperability standard the greater the value for that interoperability standard. For example, the value of social media platforms increases exponentially the more people that you know on the platform. This has implications for the related market failures.

17. Potential market failures are:

    - **Market power** – In the presence of a clear dominant firm (i.e., a firm with a significant market share or cost advantage), it is likely that network effects will create significant barriers to firms implementing new approaches. These network effects act as a barrier to entry for new firms and results in interoperability solutions being restricted to following the standards of the dominant firm, which will often result in lost efficiencies.
        - Organisations with sufficient **market power** may also deliberately prevent rival firms from being interoperable with its products or services, in order to sell more products or maintain services over a longer period of time which may introduce barriers to interoperability. Under competition law, this does not necessarily constitute uncompetitive practices[12].

    - **Natural monopoly** – When these network effects are sufficiently strong, it is possible that interoperability standards can reflect the properties of a natural monopoly[13]. Under this state of the world, the first approach to gain traction will rise to become the dominant standard for interoperability. Competition will not be able to occur for sufficiently long to deliver the potential, more efficient approach to interoperability.

    - **Information asymmetry** – Some organisations may not have the incentive, capability, or mechanism to effectively co-ordinate to deliver interoperability.

    - **Coordination failures** – for example, while consumers and the overall system may benefit from a standardised approach to DSR, companies may fail to coordinate effectively leading to less optimal outcomes.

    - **Externalities**– the benefits to the energy system and consumers as a whole from maximising uptake of flexibility are felt regardless of whether consumers use an individual companies devices or services, or even whether an individual owns any smart

[11] For a detailed discussion of mechanisms by which digital standards may emerge please see Kerber and Schweitzer 2017 - https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2922515

[12] A commonly cited example of this is the case of Virgin and Apple's iTunes platform. At the time, almost all music downloads were made via iTunes, however it was still possible to sell downloadable music online without iTunes. As a result, Apple's decision to not licence out the iTunes platform was not seen as anticompetitive.

[13] This represents a case where lowest production costs can only be achieved under the existence of one standard, due to the significant economies of scale that a high number of users may achieve.

appliances. These wider benefits are far greater than the private benefit a firm perceives for investing in interoperability, leading to a tendency to underinvest. This may be more prevalent in the absence of more developed markets for DSR services and energy tariffs, where there may be little incentive for companies developing products to invest additional time and energy in standardisation. This in turn may hinder those markets for services and tariffs from emerging.

While DSR markets are nascent, there is already emerging evidence of coordination failures – for instance, consumers may require a bespoke product in order to access a certain energy tariff. The likelihood of these market failures resolving in time without intervention is dependent on the strength of network effects in DSR standards and the number of competitors operating in the market. Intervention helps to mitigate the risk of these potential market failures from materialising across all future markets. For instance, interoperability gives consumers choice about who they use their ESAs for DSR with. This provides an incentive for organisations to develop compelling consumer propositions for DSR, and makes it easier for consumers to participate in DSR. Overall, this should promote uptake of DSR, for the benefit of consumers and the wider energy system.

### 5.1.2 Market failures – Consumer Protection and Data Privacy

18. Unregulated, consumers may be exposed to the mis-selling of services, contract-lock in or the mishandling of personal data. These are likely to occur due to:
    - An **information asymmetry** between load controllers and consumers, regarding their understanding of services offered, internal data practices and contract detail. This may lead to consumers engaging with load controlling firms without fully understanding the risks or impacts of their relations. This risk is particularly acute for services involving DSR, due to the complex nature of the consumer relationship and the financial value associated to the device's energy usage (whereby a load controlling firm is controlling how a smart appliance in a consumer home uses energy, in exchange for remuneration). Vulnerable consumers in particular may not have information to make informed choices.

    - A **misalignment of incentives** where load controllers may be exposed to incentives to mis-sell services or contracts, or to mishandle personal data.

        - Specifically, load controlling entities may not have commercial incentives to develop arrangements for vulnerable consumers who may stand to benefit from these services. **Asymmetric information** may mean these vulnerable consumers are not aware of such arrangements, particularly due to the complexity of contracts and data privacy rules and are therefore exploited.

19. Whilst both consumer protection and data privacy regulations are in place, we expect that more specific requirements could be needed to clarify the application of regulations in the context of DSR and to ensure sufficient protections are applied. For example, under GDPR sector-agnostic, over-arching legal protections for Data Privacy are already in place, government intends to ensure sufficient protection is applied to data that is not in scope of GDPR.

### 5.1.3 Market failures– cyber security and grid stability

20. The energy system is critical national infrastructure, and is undergoing transformation due to rapid decarbonisation and deployment of high-load, smart appliances such as EV chargepoints and electric heating. The stability of the energy system could be impacted by inappropriate actions of load controlling firms, or significant cyber-attack. At certain scale or

in vulnerable conditions, the costs of impacts (i.e. loss of supply) could be significant. Without additional regulation, firms may underinvest in cyber security[14] or grid stability due to the existence of the following market failures:

- **Externalities** – it is likely the private firms do not fully capture the wider societal benefits of investing in cyber security or grid stability, and as such, don't fully weigh their value This can be caused by:
    - Cyber security and grid stability at the system level is a **public good**, where the benefits of security or stability are borne by society as a whole, and ESO/DSOs in the form of a more stable and lower cost energy system. These benefits are non-rivalrous and non-excludable[15]. Equally, the costs of insecurity or instability are also borne by the system. Both cyber security and grid stability are therefore subject to the **free-rider problem[16]**, as load controlling entities who operate relatively insulated from these benefits/costs have a weakened incentive to invest in the levels of cyber security or device hardware/software required by the system.

- **Information Asymmetry**– individual firms may not be sufficiently equipped to identify, understand, and implement sufficient cyber security or grid stability solutions due to their perceived complexity or impact at system level. This informational gap may be worsened by firms subject to cyber-crime facing an incentive not to report or to play down the severity of cyber security attacks due to the potential for reputational damage. Further, the aggregate impact of many load controlling devices optimising across the same time of use tariff could be greater grid instability, however no individual device is likely to have the necessary information to be aware of this

### 5.2 Strategic case for change

21. In addition to the market failures identified above, there is also a clear strategic case for change across all options. These include:

- **Enabling the achievement of wider HMG objectives**: A government led approach to promote secure, interoperable DSR is likely to enable wider gains across the energy system, such as allowing for more timely policy and investment decisions by government in line with decarbonisation and power sector needs.

- **Creating a market for DSR service provision:** This market is currently nascent. Providing clear regulations may improve consumer confidence in participating in these markets (i.e., via the ability to switch DSRSPs). Similarly, interoperability standards also enhance DSRSP businesses' customer base over which they can compete, increasing the returns from participating in DSR markets. There is a 'chicken and egg' problem here, insofar as effective standardisation can enable the development of new products and services – however, in the absence of those products and services there may be little incentive for current manufacturers of ESAs to invest in standardisation or for consumers to demand it.

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[14] These risks are informed by the academic literature, for example here, and a DCMS IA on cyber security for consumer products, with both concluding the same market failures.

[15] Non-rivalry suggests the benefit one energy market participant receives from having a stable grid does not reduce the amount of benefit another can receive from having a stable grid. Non-excludability suggests that all energy market participants receive the benefit of a stable grid.

[16] The free rider problem is the burden on a shared resource that is created by its use or overuse by people who aren't paying their fair share for it or aren't paying anything at all.

- **Reduced risks of DSR uptake:** The risks of operating an electricity system with a high DSR capacity is reduced by intervention, for example, via more stringent cyber security requirements. This helps to avoid these risks from materialising, which are likely to pose both high direct costs alongside damage to consumer confidence.

- **Improved attractiveness of DSR solutions to the ESO:** Reduced risks of DSR uptake may also reduce ESO stability service requirements relative to a counterfactual without SSES regulation and increase the attractiveness of DSR solutions to the ESO in the options assessment process.

- **The UK as a market leader**: The UK is well positioned to help industry create an international standard for DSR services and develop innovate consumer propositions. This may present benefits to both UK trade as well as enhance the UKs reputation as a market leader in green technologies.

- **Ensuring cyber security for critical national infrastructure.** Cyber security presents a key risk to our essential services such as energy. As the DSR market develops, it will become increasingly important for these services to be cyber secure. Whilst the risk of an attack is likely to be low, the potential costs of non-action and not-protecting against one is potentially far greater. Therefore, committing to proactively managing this risk is vital.

## 6. Entities under consideration

22. This impact assessment considers the organisations that provide ‘load controller’ services which is defined alongside a list of other working definitions used in this IA below in table 1. In practice, "load controller” is a broad term, reflecting the wide and diverse nature of organisation in scope and the pace of change in the market.

*Table 1: List of working definitions used in this impact assessment*

| Term | Working definition |
|---|---|
| Load controller | A person who enters into an arrangement with a consumer to be able to remotely control or remotely configure the electricity consumption of, or the production of electricity from energy stored within, devices that consume electricity. |
| Remotely | By remotely, we mean by some long-distance telecommunications network, not local short range communications such as Bluetooth. |
| Demand Side Response (DSR) | The alteration of the rate of electricity flowing in the electric circuits of network-connected devices in response to a remote electronic communication, wholly or primarily for the benefit of the electricity system and resultant consumer benefits. |
| Energy smart appliance (ESA) | An appliance which is communications-enabled, and able to respond automatically to price and/or other signals by modulating their electricity consumption. |
| DSR service provider (DSRSP) | An organisation with the ability to alter the rate of electricity flowing in the electric circuits of network-connected devices via remote electronic communications, wholly or primarily for the benefit of the electricity system and resultant consumer benefits. |

| | |
|---|---|
| Home Energy Management (HEM) System / Building Energy Management System (BEM) | A Home Energy Management (HEM/BEM) system autonomously monitors, controls and optimises the timing, volume and mix of energy flows within the home/Building, in order to minimise customers' energy costs while meeting customers' preferences (such as comfort, EV use, carbon emission, cost, etc.). |

23. Our primary powers also include enabling powers to mandate that all electric heat appliances are smart enabled and set out the device requirements for ESAs. Products and entities impacted by these aspects of our policy are discussed separately in the accompanying impact assessments.

### 6.1 Current firms on the market within scope

24. The scope of this impact assessment is load controlling organisations who **remotely control or remotely configure** the electricity consumption of, or the production of electricity from energy stored within, devices that consume electricity, or enter into arrangements with consumers for the purposes of load control. This could be for the purposes of:

- Providing a flexibility or grid service (such as Short-Term Operating Reserve or Frequency Response), to the Transmission System Operator, a Distribution System Operator or another Balancing Responsible Party;
- Optimising energy usage against a Time of Use Tariff;
- Optimising energy usage against an external data source, related to the costs of energy supply (such as network charges or wholesale costs); or
- Optimising energy usage against an external data source, connected to the performance of the wider energy system (such as carbon intensity of the energy system, provided by National Grid); or
- Optimising energy usage against another data source related to energy usage within the consumer premises (such as energy generation of photovoltaic solar panel in the consumer's home)

25. In practice, these firms are diverse and fast-changing, and may identify themselves in different ways – including DSR Service Providers, Home/Building Energy Management System Providers, Aggregators, or Charge Point Operators, amongst others. They may also take other related roles, such as an energy supplier providing 'smart tariffs' (whereby the consumer pays a reduced tariff in exchange for allowing their supplier to use their appliance for DSR). We expect that increased uptake of ESAs over the coming years will lead a significant increase in the type and scale of organisations providing these services, and consumer demand changes and new propositions emerge.

26. The market is evolving rapidly with mergers, acquisitions, new entrants and uncertainty around players in the market but we estimate approximately 30 firms, excluding chargepoint operators, participating within the UK DSRSP market meeting the above definition.[17] This includes aggregators, home/building energy management service providers and energy

[17] Based upon internal desk research from sources by Delta-EE and Energy Systems Catapult.

suppliers. Based upon DfT estimates, we would expect an additional 47 chargepoint operators in the market, who could also fall within scope.[18] This does not include private chargepoint operators. However, there remains uncertainty over how this market will grow out to 2050, and this therefore represents a current best estimate. A non-exhaustive list of current firms identified to be in scope, based upon our analysis, is listed below in table 2.

*Table 2: Non-exhaustive list of current firms within scope, split by main activity:*

| **Type of firm** | **Firms in scope** |
|---|---|
| Aggregators | Ameresco, Centrica, Schneider Electric, Enel X UK, Flexitricity, Engie, KiWi Power, Limejump, Open Energi (bp), Origami Energy. Pearlstone Energy, Reactive Technologies, AMPX, Kaluza |
| Home / Building Energy Management Service Providers | Dcbel, Evergreen, Solo Energy, Tribe, Wondrwall, Homely, Fenecon, Moixa, Sonnen, Hive, Solaredge, Kostal, Social Energy |
| Chargepoint Operators | DfT have identified 47 CPOs in their Consumer Experience IA, based on data from Zap-Map, including some firms such as: Osprey, Electric Blue, Instavolt, BP Pulse, Charge your car, Genie Point, Source London, ESB, Pod Point, Tesla, Shell Recharge, ChargeNet, Zero Carbon World, Ubitricity, Alfa Power, Energise, EV Driver, Ecotricity, RAW Charging, New Motion, Char.gy, Grid Serve |
| Energy Supplier | EDF Energy, Centrica, Octopus, Ovo, E.On, |

27. Of those firms currently operating within the UK DSRSP market, Delta-EE estimate around 60%[19] of the market is delivered by integrators/aggregators or energy suppliers. Traditionally, aggregators focused on combining backup generation and industrial loads to sell to National Grid. More recently, many have diversified their business into software or hardware as aggregation in isolation has in many cases, not historically been profitable. Energy Suppliers are catching up by acquiring or partnering with aggregators, developing their own DSR capabilities and purchasing enabling technologies from smaller software providers. Most of the innovation in the DSR market is coming from technology providers and battery providers via both enabling software such as energy management platforms, and hardware such as lower cost controls.

### 6.2 Future development of the DSR market and potential firms within scope

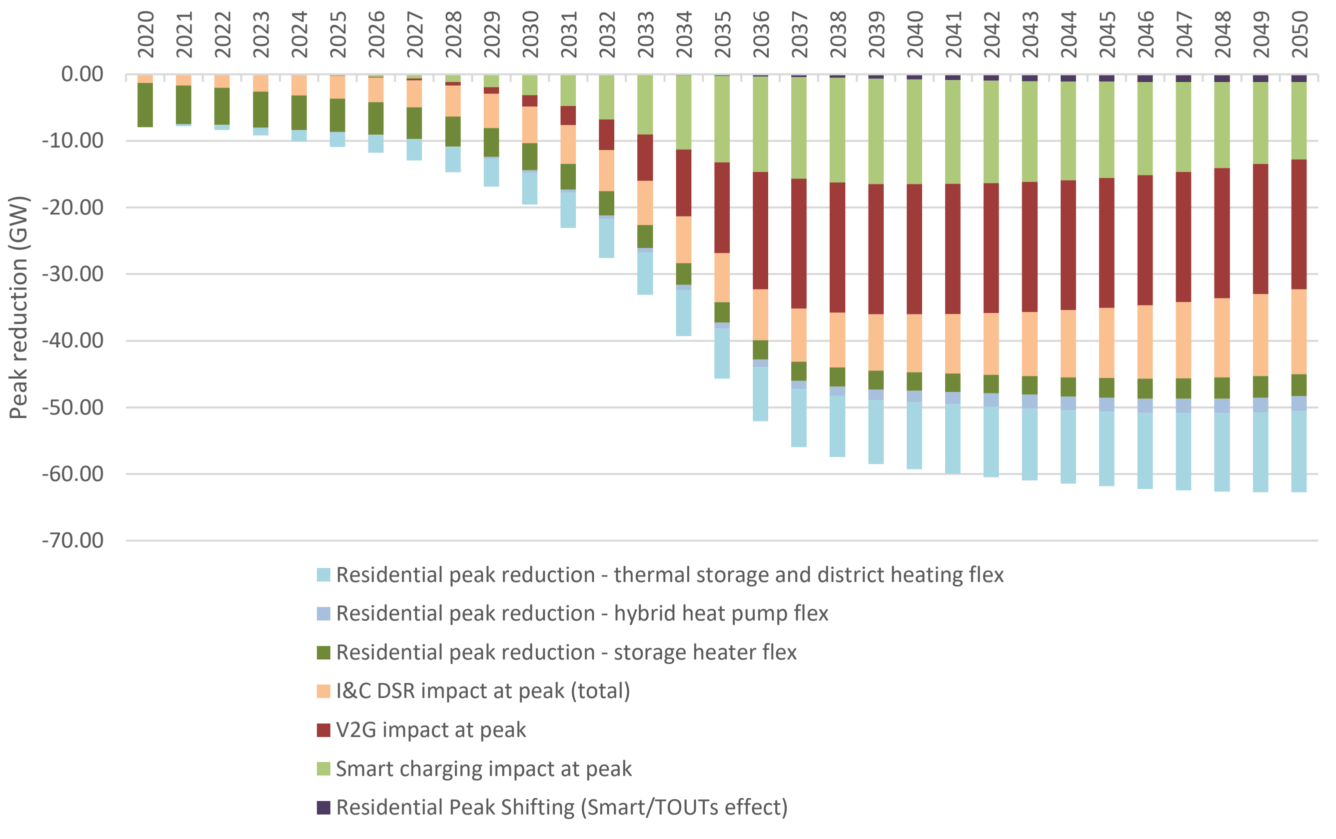
28. The market for load control services and DSR is expected to grow significantly over the coming decade. This will be accelerated by government promoting low-carbon technologies, such as electric vehicles and heat pumps, and measures to promote these technologies being ‘smart’, such as government’s ‘phase 1’ measures to ensure all private EV

[18] As referenced in the Consumer Experience at Public Chargepoints Impact Assessment. Based on data from Zap-Map.
[19] Delta-EE, GB demand response report (2019).

chargepoints are smart. These measures will necessarily lead to an increase in total load controlled, consumers using services involving load control, and firms offering services requiring load control.

29. DSR capacity is expected to increase from 8GW in 2020 to 19-44 GW in 2050.[20] Figure 1 shows the technical feasible capacity of DSR growing substantially by 2050, as estimated by the National Grid ESO.[21] This shows the potential for growth in markets for technologies such as EVs, heat pumps, smart appliances and I&C DSR. As the market grows, the number of consumers, firms potentially in scope and energy system risks will increase in line with these proportions. These measures are proposing an approach to protect them from increased risk.

**Figure 1: Technical electricity peak reduction capacity from DSR technologies**




### 6.3 Other entities in scope

30. Additional to the regulation of load controlling entities, our policy also seeks enabling powers to establish one or more central bodies to support or lead in the delivery of our policy requirements. Enabling powers are also sought to amend GB energy codes[22] or GB energy licenses[23] that could be interdependent or impacted by our interventions. These will be discussed in more detail during our 2022 consultation on secondary legislation.

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[20] This range is across the four respective scenarios run in the FES 2021 analysis and excludes V2G.

[21] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021 Figure 1 uses the Leading the Way scenario and includes V2G technology, which has the potential to offer substantial additional peak reduction.

[22] There are 12 GB Energy Codes listed here: https://www.ofgem.gov.uk/energy-policy-and-regulation/industry-codes-and-standards

[23] There are 11 GB energy licenses listed here: https://www.ofgem.gov.uk/industry-licensing/licences-and-licence-conditions

## 7. Defining the counterfactual

31. Without policy intervention, the combined effect of the five risk groups identified (interoperability, cyber security, grid stability, data privacy and consumer protection) are likely to limit uptake of DSR. This would undermine BEIS objectives related to achieving net zero, increasing security of our energy supply, and help reduce fuel poverty. Specifically, the lack of policy intervention could lead to the following:

(i) *Inhibit the rate of growth of the UK market for DSR; and*,

- *Interoperability* – Increased risk of consumer lock in; reduced competitive pressure from no or sub-optimal interoperability[24] would be likely to worsen consumer offers.
- *Data Privacy and Consumer Protection* – Consumers concerned with the misuse of data generated from products or mis-selling of DSRSP service may be deterred from using low carbon technology or participating in DSR[25].
- *Cyber Security and Grid Stability* – Consumers may also be deterred from participating in DSR services due to the perceived or actual cyber risks[26]. These vulnerabilities may also make it more difficult for load controlling entities to provide services lowering the attractiveness of competing in these markets.

*(ii) Increase the risks and costs associated with maintaining energy system stability.*

- *Cyber Security, Grid Stability and Interoperability* – The likely increased vulnerability of the system to cyber-attacks and grid instability may require the system operator to procure additional and costly system stability services and operational reliability resources. There could also be easier routes for malicious actors to disrupt energy supply and make it a more attractive target for cyber criminals, risking knock on effects to end customers and other essential services such as gas, healthcare and transport. To ensure the integrity of the system, the system operator may also be required to limit the role of DSR, creating a potentially large indirect cost, as alternate, more expensive forms of flexibility would be required. The increased investment costs could increase pressure on consumer bills, undermining fuel poverty objectives. No or sub-optimal may worsen this due to lower visibility of DSR on the system due to less consistent and interoperable data.

32. The combined impact of this reduction in the rate of growth in the availability of DSR capacity matched with higher associated costs would be an increased cost and delivery risk to achieving Net Zero and the UK's legislated Carbon Budgets.

33. This likely reduction in the growth of the UK market for DSR service provision may also result in missed UK export potential and fewer opportunities for consumers to participate in proactively managing their energy bills. There is also an increased risk that more consumers that do choose to purchase DSRSP products may be mis-sold or vulnerable to improper use of their data.

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24 Note – high levels of interoperability may be achievable under the counterfactual via a competitive process or SSOs. There is however an increased risk of no or sub-optimal interoperability outcomes under the counterfactual as illustrated by the aforementioned market failures.

25 For example, a 2016 report by Deloitte, 'Switch on the connected home', found that 26% of consumers were deterred from purchasing 'in the home' connected devices due to the perception that the technology still needs to develop.

26 For example, well publicised stories such as the 2021 BBC article exploring EV home charge point vulnerabilities may reduce the number of consumers willing to participate in these services.

34. In addition to this, the increased cyber vulnerabilities and risk to grid stability may also result in a greater risk of highly costly system outages. A case study is offered to illustrate the consequences of these system outage events and help to underpin our case for change:

***Case study 1:*** *The August 9th 2019 power outage*[27]*:*

On 9th August 2019, a power outage caused interruptions to over 1 million consumers' electricity supply and 892 MW of net demand was disconnected from distribution networks as a result of low frequency demand disconnection, representing around 4% of national demand. A lightning strike caused a fault on the transmission network, disconnecting a number of small generators and two large generators. This led to a fall in system frequency and further generation disconnects beyond the back-up power arrangements, and therefore demand disconnection was required. Ofgem report that the major impacts of the event were faced by other sectors, resulting from the lack of resilience to the disturbance of the affected service providers. This included predominantly transport with over 500 rails services disrupted and Newcastle airport being disconnected. Other essential services such as hospitals and water pumping stations were also disconnected as a result of the outage, and several thousands of customers experienced disruption to their water supply. Ofgem concluded that whilst the actions of the ESO were effective to restore the system within 45 minutes, this outage highlighted the risks of managing system security and stability in a developing electricity system. They further concluded that the cost to increase the ESO's frequency response would not be value for money considering the knock on impact to consumer bills, which might limit the extent to which the additional investment occurs.

## 8. Description of options considered

### 8.1 Longlist of options considered

35. To mitigate the risks posed by our counterfactual, government considered a range of high-level options which were assessed internally and are described below. These were:

Option 0 – Do nothing (counterfactual): The market for DSR services is exposed to the risks described above in section 7. These risks are likely to reduce the rate of consumer uptake of DSR services and increase the costs and risks of managing DSR on the electricity system.

Option 1 – Encourage voluntary compliance with standards: Under Option 1, the Government encourages relevant organisations to comply with one or more standards, such as BSI's PAS 1879 or the Association of Decentralised Energy's FlexAssure Code of Conduct. This option would see Government indicate which standards it considers supportive of its policy objectives but would have no regulatory or legislative backing. Compliance would remain optional making uptake rates uncertain.

Option 2 – Mandate legislative requirements via regulations: Under Option 2, the Government would mandate compliance with a set of legislative requirements set out in primary or secondary legislation. These requirements would apply to any organisations undertaking relevant activities and would be backed by appropriate assurance and enforcement.

Option 3 – Licence (*Preferred option with detailed analysis in this IA*): Under Option 3, the Government would require organisations undertaking relevant activities to obtain a licence from Ofgem and comply with any licence conditions and codes attached to that licence. This would

[27] https://www.nationalgrideso.com/information-about-great-britains-energy-system-and-electricity-system-operator-eso

be backed by appropriate assurance and enforcement under Ofgem's powers in the Electricity Act 1989.

The Government has considered the range of options set out above and assessed them against their ability to deliver policy objectives.

36. Considering the risks posed by load controlling organisations, the government believes it is essential that any approach to mitigating the 5 identified risks must ensure that:
    - Changes to regulatory requirements can be **made rapidly**, to keep pace with emerging cybersecurity threats and to ensure that interoperability endures as the market for load control services evolves;
    - The regulator is able to specifically **identify and actively monitor** the compliance of organisations undertaking relevant activities, and
    - **Unnecessary new complexity is avoided** for the regulator and the sector, by ensuring the chosen option is in line with the approach taken to regulation in the wider energy sector.
    - Once a licensing regime is established, the **regulator** is able to act independently, within the policy constraints set by government and the legislative framework provided by parliament, which gives it greater political independence. This can give consumers and industry greater confidence in the stability of the licensing framework than may be the case with regulations led by Government.

37. When considering Option 1, voluntary standards are unlikely to result in full uptake of any one single approach or deliver robust protections for consumers or the energy system. This maintains the significant risk that identified market failures may still emerge.

38. We therefore determine that a regulatory intervention in this market is required, so the merits of option 2 and option 3 were considered. It was determined that licensing is the most appropriate approach, for four key reasons.

    a. First, the risks to grid stability and cyber security posed by load control are significant and could in the future be at a similar order of magnitude to the risks posed when supplying, distributing, or transmitting energy. Placing load controllers within the same licensing framework as that which applies to suppliers, DNOs and TOs will ensure that our approach is consistent with the wider energy regulatory regime, and will more easily facilitate the delivery of these regulatory changes within the sector. Some load controllers may also be already licensed as suppliers, so adopting licensing for load control will enable greater consistency and many in the industry will already be familiar with the approach.
    b. Second, load controllers are expected to directly control consumers' devices in homes, for example to deliver DSR, so we must ensure that the relationship with consumers, too, is appropriately regulated: for example, to ensure that consumers are not locked into specific providers, insufficiently protected from unfair commercial practices, or have their devices controlled outside of their agreed consumer preferences. We consider licensing to be the best approach to delivering consumer protections – it's used to this effect across the energy sector already and so, as set out above, will provide for greater consistency for consumers and industry.
    c. Third, the range of requirements needed to deliver our policy objectives (specifically for interoperability) in practice could be extensive and prescriptive in some areas. These requirements may include interactions with central bodies, compliance with technical specifications, execution of specific industry processes

and a comprehensive enforcement regime. Setting out these requirements in regulations, compared to licenses or codes, is expected to introduce complexity and constraints. These would be more easily avoidable through an appropriately designed licensing regime that makes use of the existing licensing framework under the Electricity Act 1989 and Gas Act 1986.

d. We expect the market for load control service to grow and change rapidly over the next decade, driven by the Government's net zero commitments. As the market changes, we expect the types of services offered will change rapidly, and a range of risks will emerge. The flexibility offered by licensing, compared to editing regulations under option 2, will allow the Government and/or Ofgem to more easily adapt the requirements which load controllers are subject to, to keep pace with market changes. Government's long-term aim is for Ofgem to maintain the future regulatory framework, which also makes licensing a more appropriate tool for an independent regulator.

e. Finally, the concept of licensing captures a full range of possible approaches. For example, licences can include a limited number of conditions, or be used to set more extensive requirements. It can accommodate both 'outcome' based requirements as well as more prescriptive requirements, and different pre-conditions to be granted a license. This will allow conditions to be kept proportionate, targeted to specific risks and adapted as the market develops.

### 8.2 Shortlisted option for appraisal

39. This impact assessment analyses the performance of government's proposed primary powers, to create a new license from Ofgem to regulate load controlling entities (Option 3), against the counterfactual (Option 0).

40. Additional policy detail building on these primary powers will be set out in our 2022 consultation,[28] which will then inform the detailed design of secondary legislation. At this stage however, given that detail of policy implementation is still in development, analysis illustrates costs, benefits and their distribution in a high-level qualitative manner.

## 9. Costs and Benefits

### 9.1 Primary legislation

41. The primary powers sought are enabling powers and therefore do not impose any direct or substantial costs or benefits. A small impact may result from enabling powers signalling future changes to the regulatory landscape on DSR. Whilst this has the potential to create increased regulatory uncertainty to firms within scope, this signalling effect may also improve industry confidence knowing that regulation to achieve outcomes such as interoperability are expected to create more competitive opportunities within the UK DSR market. These competing effects make any net impact difficult to infer and because they are both small, difficult to quantify, and likely to be acting in opposite directions, we have not attempted to quantify them here.

### 9.2 Illustration of potential costs and benefits of secondary legislation

42. Policy is subject to further development with greater detail provided in a subsequent consultations and secondary legislation. Therefore, it is not possible to fully quantify the costs and benefits from secondary measures, until this policy detail is developed.

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[28] As committed to in the government's 2021 Smart Systems and Flexibility Plan, commitment 1.4. https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

43. The impacts considered here are discussed at a high level with a focus on identifying the correct potential impacts and their distribution. Where possible, we have attempted to indicate the potential scale of some costs by referencing figures from other similar interventions. However, due to the very early stage of policy design around these measures, there is a large amount of uncertainty associated with these illustrative impacts. Where it has not been possible to provide an indicative scale of the potential costs, justification for this has been provided. This will be reviewed for any secondary stage impact assessments.

### 9.2.1 Costs

### Costs to load controlling entities

44. Under our proposed policy option, firms will be expected to adhere to a new license creating several potential costs such as changing practices. For example, at the organisational level, this could include changes in management practices to adhere to certain cyber security requirements. The magnitude of additional impact of these costs is dependent on future more detailed policy design, and likely to differ on a firm by firm basis, differing by level of existing professional expertise, business practices, products offered and the extent to which the in-scope firms already meet the levels specified by the licence. It is assumed these costs will be passed through to consumers. These requirements have not yet been quantified in large part because the exact regulatory requirements are not clear, at this stage. For example, it is not certain what will be in licence conditions and any requirements they may impose. The details of the requirements of the licence and the size of any related impacts will be determined following development of secondary legislation. Despite this, we have attempted to provide some illustrative estimates of potential costs to firms in scope using a range of sources, for example from the heat networks market reform consultation IA. This source represents the best and only example of a new licensing regime in the energy sector for a nascent consumer sector. Whilst these illustrative costs are useful, they should not be taken as an exact measure for the costs associated from the licence proposed here. For this reason, we have not aggregated them as they do not pre-judge secondary legislation. The potential costs faced by firms in-scope may include the following:

    i. **Transitional - Organisational costs:** The creation of a new policy regime will introduce learning costs and familiarisation costs. Initial familiarisation costs include time spent engaging and understanding new legislation and interpreting how it affects current business practices[29]. Learning costs may include time spent recruiting additional staff and adjusting products and processes to meet with new license requirements. Alongside these costs, policy development may also introduce regulatory uncertainty for firms. This may make near term investment decisions before a finalised policy position is reached more difficult. However, it has not been possible to quantify these impacts at this stage, as the precise details of the policy and the extent firms may delay investment is uncertain. This will be informed by consultation to support secondary legislation.
    There will also be the direct, one off cost of applying for a licence. This will include time taken for a firm to read the licence application form and submit the required information and any licence fees. As the terms of the licence will be determined at the secondary stage, following consultation, it is not possible to provide a full assessment of the costs

[29] This will be dependent on assumptions made in applying a standard cost model. Typically, this includes length of time to read guidance, wages and number of firms in scope, for example. Given the uncertainty around licence design, it is not possible to provide a precise calculation at this stage, and this will be informed in the design of secondary legislation. However, some indication of potential ongoing familiarisation costs, including the first year, is provided in paragraph 44iii.

resulting from the specific application process for the licence proposed here. Costs may also vary depending on the scale and complexity of the licensable activity being carried out. Despite this, to attempt to illustrate the potential scale of these costs, the 2020 consultation IA on heat networks future market reform estimated the costs of applying for a licence to a heat network firm to be a one-off cost of £634[30]. Scaling this by the number of firms identified in the DSR market, this would represent a one of cost of c. £50,000. However, this assumes a senior manager taking on average 24 hours to apply for the licence, at a wage of £26 per hour. It is not clear the extent to which these assumptions and the resulting costs translate to the licence application process resulting from these primary powers. Therefore, these costs are purely illustrative at this time and doesn't pre-judge secondary legislation.

ii. **Transitional - Device level costs:** Devices operated by load controlling entities could be indirectly required to install additional hardware/software updates, in order to comply with future license conditions introducing a potential transitional cost. For example, this could be to ensure the latest software updates are installed, to mitigate cyber risk. The details of the requirements of the licence will be determined following development of secondary legislation, and given the uncertainty of the frequency and size of any potential additional software updates required by the licence, it is not possible to provide an indicative scale of these costs here. However, similar device level costs are considered in greater detail in the Energy Smart Appliances impact assessment, within the Energy Bill[31]. Future consultation on secondary legislation will be used to acquire additional evidence around these costs.

iii. **On-going - Organisational costs:** There may also be ongoing costs to firms of familiarising themselves with changes to the terms of the licence and demonstrating compliance. Compliance costs may be associated with delivering monitoring, verification and enforcement requirements. To illustrate the potential scale of these costs, the 2020 consultation IA on heat networks future market reform suggested the familiarisation and compliance costs from a licence per heat network firm to be £740 per year. Scaling this to the number of firms in scope of this IA, this would represent an ongoing cost of c. £57,000 per year. However, this assumes a senior manager, with an average wage of £26 per hour, takes 28 hours each year to familiarise and comply with the licence. In practice, these costs represent the transitional costs in the first year, and the ongoing costs in each subsequent year. It is not clear at this stage, how these assumptions and the resulting costs translate to the potential familiarisation and compliance costs from the powers in this IA, given the differences in scope. Therefore, these costs are purely illustrative at this time and doesn't pre-judge secondary legislation.
Adhering to the license regime set out by this policy may require organisational changes to incumbent firms. For example, enhanced cyber security requirements for firms may require the recruitment of new cyber expertise in-house or the procurement of business services to ensure cyber compliance. This has not been quantified as there is a lack of information about the extent to which DSR firms are already investing in cyber security and the requirements of the licence which is to be determined at secondary stage. The latest Cyber Security Breaches Survey reports 96% of business surveyed had at least one technical rule or control in place already, but only 23% businesses had a formal cyber security strategy, with 39% of businesses outsourcing their cyber-security[32]. This

[30] Heat Networks Market Framework consultation IA, 2020: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/863855/heat-networks-market-framework-consultation-impact-assessment.pdf

[31] To be published alongside this IA, within the Bill.

[32] National Cyber Security Breaches Survey, 2022: https://www.gov.uk/government/statistics/cyber-security-breaches-survey-2022/cyber-security-breaches-survey-2022

evidence provides an illustrative scale of the extent firms are already investing in cyber security, however these figures are for multiple business sectors, and not specific to the DSR market, and therefore may not translate directly. We will look to gather additional evidence around these costs at consultation for secondary legislation.

The introduction of potential new licenses and any subsequent energy industry codes will also introduce new costs to firms. For example, there may be the additional cost on firms from increased complaints, if replying to complaints within a certain timeframe is made easier for consumers as part of the licence. To provide an illustrative example of these costs, the heat networks future market framework consultation IA suggests an increase in complaints of 10% compared to the counterfactual, with an average cost to business of £300 per complaint. The resulted in a total discounted cost of £2.5m over the 10 year appraisal period[33]. These costs are illustrative and do not pre-judge secondary legislation.

The cost of license fees and paying for governance arrangements is expected to be proportional to the size of the firm and diminishing in the number of firms operating within the DSR market, minimising potential barriers to entry. To illustrate the potential size of these costs, the 2021 consultation IA on energy industry code reform estimates that if the 12 existing code administrators were to operate the enhanced code manager functions, the total cost of industry code governance would be around £70m per year. Assuming a new DSR focused code was of average size, this would give the code an annual on-going cost of around £6m[34]. These costs may also be passed through to consumers and not borne by organisations themselves.

Additional costs may also accrue from participating in the license development and maintenance process. The 2021 consultation IA on energy industry code reform estimates the cost of engaging in a code modification process as between £1800 and £3600 (assuming 3 days of workshop participation and a day-rate of highly specialised employees of between £600-£1200)[35].

To provide an illustrative example of total burden, the heat networks market framework cost recovery consultation suggests a central estimate of total ongoing costs of regulating the market would be £6.5m per year to Ofgem, over the 10-year appraisal period. If these costs fell solely on heat network regulated entities, then assuming regulated entities would then recover those costs through heating bills, it would effectively be heat network consumers only funding the costs of regulation[36].

### Costs to consumers

45. The introduction of license requirements on firms may also result in direct or indirect costs on current or future consumers. Direct costs may result from firms passing through the costs of new license fees and complying to consumers, resulting in higher costs or lower benefits associated with products. The heat networks cost recovery consultation suggests provisional estimates that spreading the costs only across heat network customers would result in heat network consumers paying an extra £10 or more per consumer bill per year to fund regulation. In comparison, they estimate that gas and electricity consumers pay less than £2 per consumer per year towards regulation. This case study examples provides some illustration of potential costs, but it assumes c. 600k customers of heat networks, and it is uncertain at this stage how close the resulting costs translate to our policy area[37].

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33 See footnote 29 for reference and link to heat networks consultation IA.

34 Energy Industry Code Reform Consultation IA, 2021 (2020 prices): https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1004010/energy-code-reform-consultation-impact-assessment.pdf

35 See footnote 29 for reference and link to heat networks consultation IA.

36 Recovering the costs of heat networks regulation, 2021: https://www.gov.uk/government/consultations/recovering-the-costs-of-heat-networks-regulation

37 See footnote 35 for reference and link to cost recovery consultation IA.

Setting out an approach to DSR may also close off some potential innovative business models and products, resulting in a potential reduction in future product diversity. It is not possible to fully quantify these impacts at this stage, as there is a lack of information to determine how these costs will be passed through, and the likelihood and form of any reduction in product diversity. However, the future potential costs to wider electricity users are discussed in a later section. We will look to gather additional evidence on these costs from future consultations on secondary legislation.

### Costs of central bodies

46. A central body may be required to deliver responsibilities relating to the cyber security, interoperability, and grid stability outcomes this policy seeks to achieve. This central body function may be carried out by a new or existing entity, with the exact roles and responsibilities carried out subject to further technical development and industry consultation. Likely costs in the design, implementation and delivery of a central body function are dependent on if a central body is required, its role and functions, whether it is new or existing - none of which is decided in these primary powers. However, illustrative potential costs are discussed below:

    i. **Transitionary costs:** There could be set-up costs associated with a new central body function including costs of recruiting staff, procuring technical services associated with the delivery of requirements and potential legal, consulting and business services to ensure full compliance with roles and responsibilities. Learning and familiarisation costs could also apply to any entity delivering central body functions. For example, it may take time for new staff to understand how to effectively deliver their roles, or for governance processes to be established. These transitionary costs could be lower if central body functions are awarded to an existing organisation rather than a new entity that is yet to be formed, or if the service required is already well-established in the market. It has not been possible to illustrate the scale of these transitional costs, as they are highly dependent on whether an existing organisation or new entity would fulfil this role, and what additional requirements would be asked of them. This will be the subject of further consultation and secondary legislation.

    ii. **On-going costs:** The on-going operation of the central body will create staff costs, system costs, contracted service costs and administrative costs alongside governance and industry engagement costs. Case studies of other bodies within the energy system show that the magnitude of these costs are very dependent on the roles and responsibilities carried out. To provide an illustrative example of the range of these costs, the 2021/22 operational costs for the Low Carbon Contracts Company are estimated at around £20m (2020 prices)[38] whilst the 2020 administrative expenses of the Data and Communications Company exceeded £100m[39] (2020 prices)[40]. However, the exact scale of costs incurred by any central body is highly dependent on the exact function it delivers, which we are not in a position to specify at this stage.

47. These costs could be paid for via a cost recovery mechanism for service users, which would likely be passed on to load controllers' customers or the end users of electricity.

### Costs to government and Ofgem

[38] LCCC Annual Report and Accounts 2020/21, table 4. (https://www.lowcarboncontracts.uk/annual-reports)

[39] DCC Annual Report 2020, slide 85, heading 6.https://www.smartdcc.co.uk/media/1060/20204_dcc_report_and_accounts_9.pdf

[40] However, the estimate presented by the DCC here could be significantly higher than proposals sought at secondary legislation.

48. These costs may include:
   i. **Transitionary and on-going costs - government:** Costs to government are likely to be associated with legal, financial and consulting services used during policy development or any future monitoring and evaluation required by policy intervention. Due to the uncertainty of subsequent policy design, it has not been possible to provide an indication of the scale of these costs, but this will be determined at secondary stage. There are no substantial on-going costs expected to accrue to government.

   ii. **Transitionary costs - Ofgem:** Ofgem are likely to face legal, financial and consultancy costs when contributing to policy development and it's implementation. There may also be learning and familiarisation costs associated with the monitoring, promotion and enforcement of compliance with any new license. For example, given the relatively nascent status of the current UK market for DSR-related products, it may take time to understand the most effective way to ensure compliance with any new license developed. The amendment of current industry governance codes may also create incremental costs to Ofgem via a greater number of proposed code changes. The estimated one-off cost to Ofgem of regulating a general licence in the heat networks market framework impact assessment was £2.5m[41]. This provides some case study evidence on the potential magnitude of costs, however, the exact size of costs and the extent to which they are passed onto consumers will be dependent on subsequent policy development limiting the extent to which this case study can be informative.

   iii. **On-going costs – Ofgem:** The costs monitoring, promoting and enforcing new licenses for firms will create an on-going incremental increase in the operational costs of Ofgem, which totalled around £120m in 2020/21[42]. This cost to Ofgem of administering the Renewables Obligation scheme was around £7m in 2020/21[43]. This provides some case study evidence on the potential magnitude of costs, however, the exact size of costs and the extent to which they are passed onto consumers will be dependent on subsequent policy development limiting the extent to which this case study can be informative. An example of scale of costs which could be passed through to consumers is discussed in paragraph 45. In practice, many of the ongoing operational costs to Ofgem could be recovered by licence fees.

### Costs to other actors within the Energy System

49. Policy intervention may require modifications to existing energy system licenses to achieve policy objectives[44]. For example, placing obligations on firms that interact with DSRSP firms could be required to ensure desired cyber security outcomes. However, at this stage, these obligations are yet to be determined and will be detailed at secondary legislation, following input from consultations. Without knowing what any potential future modifications to existing

[41] This includes database set up costs of all heat networks registered to the regime, regulatory framework set up costs, including its development and implementation. These costs are incurred via both internal resource and the employment of dedicated consultancies to undertake some of this work, due to their expertise.

[42] Slide 69, Ofgem Annual Report 2020/21 (https://www.ofgem.gov.uk/publications/ofgem-annual-report-and-accounts-2020-21)

[43] Figure is disaggregated as ~£2 for IT development and support, ~£2m for audit and compliance , with remaining costs summing to ~£3m covering legal support (~£0.6m), applications and amendments (~£0.5m), servicing participants and reporting (~£0.7m), enquiries and stakeholder engagement (~£0.3m)and overheads (~£0.8m). https://www.ofgem.gov.uk/sites/default/files/2021-09/RO%20Cost%20Letter%202021-22%20Final.pdf

[44] This could include Smart Meter Communication Licences (gas and electricity), gas and electricity supply licenses as well as transmission and distribution licenses.

codes are, as these will be decided later, it has not been possible to identify a potential scale of these costs.
There may be learning and familiarisation costs to existing licensees who will be required to understand new license conditions and ensure internal resource and processes are in place to ensure compliance. A potential scale of familiarisation costs is provided in paragraph 44iii, although as mentioned, it is unclear how accurately these might represent the costs from these proposals. These are purely illustrative and subject to refinement at secondary stage.
Additionally, engaging in consultation and code modification processes associated with policy intervention may create additional costs to these firms. If a code is needed, licensing load control as an activity is also likely to create additional costs to code administrators to deliver the required code modifications, such as drafting legal text, facilitating workshops and consultations. It is not possible to quantify these costs at this stage, as the requirement for a code medication is not certain, nor are the specific requirements of a code modification Paragraph 44iii provides some illustrative example of potential costs, but it is unclear how accurately these could represent the costs here and do not pre-judge secondary legislation. These costs will be informed by consultation at secondary legislation stage.

**Costs to all end users of electricity**

50. Many of the costs of license arrangements identified above are likely to be passed through to end users of electricity which may have a material impact on the price and bills of end consumers of electricity. These costs are likely to be temporal with a potential price and bill increase during the 2020s before due to the associated transitionary costs of implementing new regulatory occurring before policy intervention is able to increase available DSR flexibility on the system, which is intended to help offset the price and bill impact of this policy intervention. However, these costs could be recovered in large part by licence fees. It is not however possible to comment on the magnitude of these impacts at this stage due to the uncertainty in subsequent policy design. A clearer indication of these impacts will be provided at secondary stage, following additional evidence gathered at consultations.

### 9.2.2. Benefits

51. This policy intends to promote the growth of the UK market for DSR whilst mitigating the risks to both consumers and the energy system that this brings. DSR benefits consumers individually, through providing opportunities to reduce costs of using energy, such as through ‘smart tariffs’. It benefits consumers collectively, through reducing the overall cost of operating a low-carbon energy system. It also benefits the planet, through reducing dependencies on higher-carbon energy generation during periods of high demand.

52. Increased flexibility provided through DSR, electricity storage and interconnection could reduce the decarbonised electricity system costs by c.£10 billion per year by 2050 (2012 prices)[45]. The benefits of DSR, and the opportunity costs of not doing DSR, will increase over the coming decades as uptake of electric heat and transport increases (see below), and our sources of power become more intermittent. Increased uptake of DSR also introduces new risks to consumers and the energy system that require appropriate mitigation.

53. When compared to the counterfactual we intend for policy intervention to result in an increased growth rate in the UK market for DSR products due to both improved consumer confidence and an improved attractiveness of the UK DSR market. In turn, this growth in the

[45] These benefits are undiscounted, and £12bn per year by 2050 in 2020 prices. For further detail, please see annex 1 of the Smart Systems and Flexibility Plan here (https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021)

sales of DSR products is expected to result in higher levels of DSR capacity operating against time of use tariffs or available to the system operator[46].

54. Establishing a regulatory framework to allow interoperability should enable the benefits of DSR. If (i) devices and service provides have appropriate capabilities execute DSR, and (ii) consumers have choice over who they do DSR with and how it is done, consumers and organisations should take advantage of the commercial opportunities DSR can provide. Interoperability also provides a form of consumer protection, through ensuring consumers aren't 'locked in' if their preferences or circumstances change. This should ultimately accelerate the uptake of DSR, benefitting consumers and the energy system

55. Whether or not timely and desirable interoperability standards can be achieved under the counterfactual, will in part, determine the magnitude of benefits discussed below when compared with our counterfactual. If solutions to interoperability between DSR service providers do emerge through market led competition or collaboration, in a timely manner, then the benefits of a government led solution to interoperability may be smaller[47]. However, if markets are unable to deliver interoperability, or deliver lower standards of interoperability compared to government, then the magnitude of benefits discussed below will be considerably higher as DSR markets would be likely to remain relatively nascent.

56. In all states of the world, policy intervention can also be expected to bolster the growth rate of the UK market for DSR services via other channels beyond interoperability. These include the increase in consumer confidence that improved consumer protection, cyber security and data privacy rules are likely to bring. As a result, policy intervention is expected to increase the growth rate of the DSR market under either interoperability counterfactual, alongside mitigating the downside risk that interoperability does not occur or occurs sub-optimally via market led forces.

**System benefits:**

**Reduced electricity system costs**

57. As outlined in analysis underpinning the 2021 Smart Systems and Flexibility Plan, low-carbon flexibility has the potential to reduce the costs of achieving Net Zero by up to c.£10bn per year (2012 prices) by 2050[48]. Policy intervention intends to contribute towards achieving the flexibility required to achieve this cost saving by enabling greater uptake of DSR services. DSR capacity also provides an additional cost saving above other forms of low-carbon flexibility due to the low associated capital cost of DSR capacity[49]. Using BEIS' 2018 published storage cost assumptions[50], a 50MW lithium-ion battery providing frequency management services may be expected to incur a capital expenditure of around £30m. This illustrates the potential capital expenditure saving offered by DSR capacity.

**Reduced costs of electricity system operation**

[46] The achievement of these benefits is interdependent with the enabling powers to ensure minimum technical standards for energy smart appliances being brought forward in this Energy Bill.

[47] Risks below also consider the potential for market led solutions to interoperability result in more favourable interoperability standards. Future policy development intends to mitigate these risks.

[48] These benefits can be expected to accrue via the improved utilisation of intermittent forms of generation such as wind, reduced generation capacity requirement and network build and lower levels of carbon emissions. This is undiscounted, and £12bn per year by 2050 in 2020 prices.. For full details please prefer to annex 1 of the Smart Systems and Flexibility Plan here (https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021)

[49] This low capital cost is associated with many of the capital costs of DSR capable appliances being incurred by the consumer under all scenarios. For example, a consumer is likely to purchase a new washing machine or electric vehicle independent of its DSR capabilities.

[50] Storage costs and technical assumptions for BEIS – summary document (2018), table 5. https://www.gov.uk/government/publications/storage-cost-and-technical-assumptions-for-electricity-storage-technologies

58. This may result due to several mechanisms, due to:

   i. **Reduced procurement requirements for system stability services:** Without adequate cyber security and grid stability requirements in place, it is likely necessary for the system operator to procure additional balancing and system stability services to ensure the safe operation of the electricity system. For example, lower risk of grid instability scenarios may lower short term operating reserve requirements. Greater levels data interoperability as a result of intervention may also increase the visibility of DSR capacity to the system operator allowing for allowing better system stability procurement decisions to be made.
   ii. **Reduced costs of balancing and ensuring grid stability:** Greater levels of DSR capacity on the electricity system can be expected to decrease peak electricity demand reducing the frequency that the system operator will be required to call upon expensive peaking generators. Crowdflex[51], a 2022 flexibility study consisting of 25,000 households estimated that DSR capacity had the potential to reduce peak electricity demand by up to 23%, helping illustrate the potential magnitude of benefits policy intervention can be expected to contribute towards. Research[52] also suggests that DSR capacity may be able to provide frequency response services at lower cost than other alternatives, with savings to the GB energy system estimated at between £100-2000/KW.
   iii. **Increased technology diversity:** Greater levels of DSR capacity available to the system operator across markets allow for greater levels of competition within the energy system and may reduce the costs to the system operator procuring services.

### Reduced risk of electricity system outage events

59. The risk of system outage events is reduced via policy intervention due to the greater requirements put in place to ensure DSR services are cyber secure and avoid issues of grid instability. The extent to which policy intervention will reduce this risk is highly uncertain and dependent on the future demand for DSR services, future policy development and ability for the system operator to mitigate these risks via system stability services or operability requirements. However, the scale of potential costs avoided through policy intervention may be very large, as illustrated by the case study discussed34 when illustrating our counterfactual[53]. These avoided costs may represent a significant benefit to policy intervention and outweigh costs incurred[54].

### Greater innovation

60. Policy intervention to ensure interoperable outcomes in DSR services are achieved reduce barriers to entry for new market participants and result in an effective increase in market size available for firms to compete[55]. This resulting increase in competition and effective market size is likely to increase DSRSP firms' incentive to innovate and invest in research and development. There may also be greater innovation across the DSRSP supply chain, including appliance manufacturers, manufacturers of energy smart appliances are confident

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[51] This study was undertaken by National Grid ESO, Scottish and Southern Electricity Networks Distribution, Octopus Energy and Ohme. The study investigated how 25,000 households responded to price signals by reducing or increasing electricity demand. https://www.nationalgrideso.com/news/domestic-flexibility-could-reduce-peak-electricity-demand-23-new-study-shows?fbclid=IwAR3zGWYnlLrpAqkWJHa6LpbfVivwAuW2rf0bPWuNa5HuZvZNuxjwebrV1IE

[52]Strbac et al. (2015) - Benefits of demand-side response in providing frequency response service in the future GB power systemhttps://www.frontiersin.org/articles/10.3389/fenrg.2015.00036/full#:~:text=The%20key%20benefits%20include%20reduction,in%20systems%20with%20intermittent%20renewables.

[53] This included an assessment of the August 9th 2019 blackout.

[54] The National Cyber Security Strategy (https://www.gov.uk/government/publications/national-cyber-strategy-2022) suggests the growing need for critical national infrastructure to be protected as the smart and flexible energy systems develops. This protection ensures the future energy system needed to achieve Net Zero is secure and resilient to cyber attack which might otherwise be a barrier to achieving this goal.

[55] i.e., because firms are no longer locked into one DSR service providers offer and can be drawn away by other firms through more attractive offers.

their device will be compatible with a wider range of DSRSP firms' products. This greater innovation may result in further cost reductions to the energy system and better offers to consumers[56].

**Consumer benefits:**

**Improved consumer benefit of participating in DSR services**

61. Greater innovation and competition between DSRSP firms enabled by policy intervention is likely to increase the benefit to consumers, either through lower costs, or an increase in the potential saving these products may offer, for example, through new innovative business models or lower profit margins for DSRSP firms. This expected increase in competition or innovation may also increase the accessibility of DSRSP services, through a greater number of business models or products capable of being integrated to a DSRSP device increasing the number of consumers able to participate.

**Reduced Energy Bills for end consumers of electricity**

62. As discussed above, a greater consumer benefit to DSR services, or number of consumers able to access DSR may enable lower energy bills for more consumers participating in DSR services. Moreover however, the reduced system costs described above can be expected to help lower energy bills for all end consumers of electricity. These energy bill savings may contribute towards the achievement of other government objectives, such as protecting consumers who are fuel poor and ensuring the competitiveness of the UK's energy intensive industries.

**Improved consumer confidence**

63. Policy is likely to improve consumer confidence in partaking in DSR services for several reasons. These may include:
    i. **Avoidance of potentially reputationally damaging incidents in DSRSP markets:** incidents where DSRSP firms are found to have mis-sold products, be vulnerable to cyber security attacks[57] or the cause of data leaks are likely to damage consumer confidence in these firms and their products. Policy intervention intends to ensure the frequency of these incidents is minimised, which aims to result in fewer incidents where consumer confidence would be damaged.
    ii. **Greater confidence in security of consumer data:** Government led regulation is likely to improve consumers' confidence that their data is appropriately protected. For example, a 2018 study conducted by the Data and Marketing Association[58] found that 62% of consumers had improved confidence about sharing data with companies after hearing the EU's new GDPR[59] regulations[60].
    iii. **Greater control over contracts:** Policy intervention will ensure consumers are able to switch DSR service provider and avoid incidents where consumers are unfairly locked into contacts. This greater control in supplier of DSR services enabled by

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[56] Note, this benefit is largely dependent on interoperability standards being in place, which may be possible in the absence of policy intervention. However, it is deemed these effects on innovation will be stronger under policy intervention, due to the existence of greater consumer and system protections promoting greater uptake of DSRSP products.

[57] For example, this 2021 BBC article on the cyber vulnerabilities of some home charge point operators https://www.bbc.co.uk/news/technology-58011014

[58] https://dma.org.uk/uploads/misc/5af5497c03984-gdpr-consumer-perspective-2018-v1_5af5497c038ea.pdf

[59] https://gdpr-info.eu/

[60] The importance of consumer confidence in the cyber security of digital products is reiterated by pillar two of the National Cyber Security Strategy.

interoperability is also likely to increase consumers' confidence and willingness to partake in DSR services.

**Improved data protection and reduced potential for the mis-selling of DSRSP products**

64. Data privacy and consumer protection are ends within their own right. When these events occur, large monetary and non-monetary costs may be placed on the consumers. For example, the leaking of personal data may expose consumers to a higher risk of fraud which may cost financial and emotional damage.

### 9.2.3. Risks

65. No substantial risks have been identified with the enabling powers sought in this Energy Bill. Small risks that could be associated with primary powers, such as delayed industry decision making due to increased regulatory uncertainty, are limited in scope and duration due to the release of a 2022 consultation, which will provide more details on policy design and implementation options, alongside offering a window for industry input. This industry input will also be used to help to mitigate the remaining risks associated with secondary legislation, discussed below.

66. Key identified risks of secondary legislation and implementation that policy will intend to mitigate are:

**Risks 1 – Market efficiency:** Requirements set out by policy intervention may risk producing undesirable market outcomes, which would likely reduce the attractiveness of the UK DSRSP market. For example:

- **Risk 1a. Policy intervention restricts innovative product offerings:** The technical and regulatory requirements brought forward for DSRSP products under policy intervention may increase the homogeneity of DSRSP products offered and introduce additional difficulties in bringing forward and testing more innovative business models and products, which may improve the offering of DSRSP firms products to consumers.
- **Risk 1b. Policy intervention reduces the dynamic efficiency of the market:** Digital services are quickly evolving, often resulting in technical standards quickly becoming updated, with new, more innovative approaches likely to emerge[61]. Any time-lag between the emergence of these more innovative approaches and the adjustment of the technical specifications set out by policy intervention will result in a loss of dynamic efficiencies, reducing the potential cost-saving or quality enhancing effects these new approaches could offer.
- **Risk 1c. Policy intervention may increase barriers to entry:** License payments and the costs of compliance with requirements set out in any future license represent an increased cost to DSRSP firms from participating in this market.
- **Risk 1d. Policy intervention may increase regulatory uncertain for investors:** There is a risk that investors and firms may delay or redirect decisions and investments due to the regulatory uncertainty that policy development and implementation creates. For example, to avoid the cost of developing products that do not comply with finalised regulations. These costs

**Risks 2 – Consumer benefits and uptake of DSR services:** The impacts listed under Risks 1 may worsen quality or variety of products offered to consumers, through higher product prices or lower potential savings to consumers, as well as less variety in business models. Were these

[61] A well noted example of this from telecommunications is the move between generations of telecommunication infrastructure, from earlier generations such as 3G up until current 5G.

to materialise, they risk lowering the number of consumers willing to partake in DSR services and lowering the potential benefits from consumers that do partake.

**Risks 3 – Policy development and implementation:** There are risks around the timelines for the development and implementation of secondary legislation. For example, securing sufficient time for parliamentary scrutiny may delay policy development. Similarly, the development of central body functions may overrun, or high learning and familiarisation may impact on the performance of central delivery functions in early years.

**Risks 4 – System benefits to DSR:** The materialisation of risks presented above may reduce the capacity of DSR optimising against time of use tariffs, or available for system services via DSRSP firms. This lower level of DSR available to the electricity system may increase the costs of running the electricity system as additional generation capacity or more capex intensive forms of flexibility are relied on in place of DSR.

### 9.2.4. Summary of impacts

67. A summary of likely impacts and their distribution across key actors identified is included in table 3. below. This will be further developed throughout the policy development process.

*Table 3: Distribution of likely secondary legislation impacts over key groups*

| Group | Transitionary Costs | On-going Costs | Benefits | Risks |
|---|---|---|---|---|
| **DSRSP firms** | Engagement in consultation.<br><br>Retrofit costs.<br><br>Increased regulatory uncertainty.<br><br>Learning and familiarisation | Additional staff costs<br><br>License fees<br><br>Compliance costs | Improved market size<br><br>Increased opportunities for competition<br><br>Reduced risks of cyber attack<br><br>Reduced risk of blackout or grid instability.<br><br>Increased attractiveness to the system operator<br><br>Increased attractiveness to consumers | Reduced market efficiency<br><br>Lack of internationally compatible standards<br><br>Increased barriers to entry.<br><br>Risk of implementation delays results in delayed decisions |
| **Consumers of DSRSP products** | Inconvenience of software updates | Cost pass through from DSRSP firms | Improved consumer confidence<br><br>Greater consumer protection | Reduced product diversity<br><br>Reduced attractiveness of DSRSP products |

| | | | | |
|---|---|---|---|---|
| | | | Improved consumer benefit to DSRSP services, including reduced energy bills<br><br>Greater accessibility | |
| **Central body costs** | Recruitment<br><br>Procurement of services<br><br>Establishment of technical infrastructure<br><br>Learning and familiarisation | Staff and administration costs<br><br>Costs of contracted services<br><br>Costs of IT systems or other technical infrastructure | | Implementation timelines are delayed |
| **Electricity System Operator** | Engagement in consultation | | Reduced risk of system outage.<br><br>Greater visibility of system operation.<br><br>Greater technology options available<br><br>Reduced volume and cost of system services procured | |
| **Ofgem** | Purchase of legal, financial and consulting services.<br><br>Learning and familiarisation | Costs of monitoring, promotion and enforcement of compliance to license | Contribution of policy towards achieving Net Zero at least cost.<br><br>Reduced risk of system outage.<br><br>Improved deal for consumers and UK business. | |
| **Government** | Purchase of professional services | | | |

| | | | | |
|---|---|---|---|---|
| **Cost to other actors in energy system** | Learning and familiarisation<br><br>Engagement in code modification processes | Potential increase in license payments | Reduced risk of system outage. | |
| **End consumers of electricity** (*domestic, industrial, commercial…)* | | Cost-pass through of license payments | Reduced energy bills and cost to achieving Net Zero.<br><br>Reduced risk of system outage.<br><br>Improved competitiveness for UK business | |

## 10. Justification of preferred option and description of implementation plan

68. This impact assessment concludes that there is a clear case for government intervention given the significant risks identified under the counterfactual such as system outage events, undesirable market outcomes and consumer protection concerns. Option 3 was found to best deliver policies objectives. Under this option, government seeks delegated powers in this Energy Bill to allow the Secretary of State for BEIS to create new licensable activities relating to load control, as well as make modifications to existing licence conditions and codes administered by Ofgem.

69. The Government's assessment is that licensing is the most appropriate approach for meeting policy objectives. The use of licensing is well-established in the energy sector, as the primary mechanism for placing regulatory requirements on energy system actors such as energy suppliers, Distribution Network Operators and Transmission System Operators. The legislative framework for licensing in the energy system is set out in the Electricity Act 1989 and the Gas Act 1986, and powers for the Secretary of State and Ofgem within those Acts already provide a legal basis for the administering of licences and the enforcement of conditions and codes attached to licences.

70. Many of the risks posed by load controlling entities such as DSRSP firms, particularly grid stability, interoperability and consumer protection are similar to those for which licence conditions and codes are already in place for other energy system actors. The government believes it is appropriate, therefore, that similar requirements for load controllers are imposed via the same legal mechanism, reducing regulatory complexity for industry and the regulator, and ensuring that a consistent approach is taken to actors across the energy system[62].

71. It is also noted that primary powers being sought in this Energy Bill are enabling only and are therefore not expected to create any substantial impacts. Future economic analysis will ensure sufficient scrutiny of more detailed options for secondary legislation is undertaken.

[62] In the development of the licensing regime for load controlling organisations under the proposed powers, the Government intends to take account of the ongoing efforts of Ofgem and the energy retail market to ensure that the licensing framework remains fit for purpose as we transition to Net Zero.

At this stage, a high-level assessment of secondary impacts and their distribution is provided that will be further developed as part of future consultation stage impact assessments.

## 11. Business Impact Test

72. There are no material impacts to business as a result of the enabling powers set out in primary legislation. As summarised in table 3 above, there may be several direct costs to businesses due to secondary legislation, with the most substantive direct costs to business identified falling upon DSRSP firms. However, BEIS considers intervention to be pro-competition, benefiting DSRSP firms, and therefore to fall out of scope of a more detailed assessment of business impacts. According to the Better Regulation manual[63], a regulatory measure needs to satisfy all of four conditions to be considered to promote competition. In the following section we list the four conditions and provide a comment for each of them to explain how the proposed measures meet them:

a. *The measure is expected to increase, either directly or indirectly, the number or range of sustainable suppliers; to strengthen the ability of suppliers to compete; or to increase suppliers' incentives to compete vigorously.*

**Comment:** Yes. This intervention intends to set out an approach towards interoperability between firms, enabling greater competition through an increased ability for consumers to switch providers. This increase in ability to switch providers of DSR services will likely provide an increased incentive for firms to compete vigorously due to the greater market revenue accessible to all firms. Moreover, policy intervention intends to increase consumer confidence in partaking in DSR services, which in turn can be expected to increase the sale of DSR services. This potential increase in market size can be expected to attract new market participants, further increasing competition between firms.

b. *The net impact of the measure is expected to be an increase in [effective] competition (i.e., if a policy fulfils one of the criteria at (a) but results in a weakened position against another) and the overall result is to improve competition.*

**Comment:** Yes. As summated in bullet a. above, this policy can be expected to increase the scale of competition in DSR markets through reduced barriers to consumers switching between DSRSP firms and an increased DSRSP market growth rate attracting new market entrants. Risks discussed above in section 9.2.3. appreciate policy outcomes that may limit competition in the UK DSRSP market, such as policy intervention decreasing the attractiveness of the UK DSRSP market were low levels of international compatibility to result. Appreciating these risks, the net impact on competition is still found to be positive, given that (i) policy development intends to mitigate the likelihood of these risks from emerging and (ii) the significant risks posed by the counterfactual are expected to result in an overall smaller market for DSR services, suggesting a lower incentive for firms to enter and compete.

c. *Promoting competition is a core purpose of the measure.*

**Comment:** Yes. The primary focus of ensuring interoperability is delivered through policy intervention is to enable greater consumer switching between DSRSPs, allowing for a greater incentive for firms to compete. Either to gain new customers from rival firms or retain current customers.

d. *It is reasonable to expect a net social benefit from the measure (i.e., benefits to outweigh costs), even where all the impacts may not be monetised.*

**Comment:** Yes. Whilst analysis remains unmonetized, the social benefits to intervention, described above in section 9.2.2., can reasonably be expected to outweigh the costs incurred. Appreciating case study 1 above in section 7, policy intervention may be justified against the reduced risk of system outage events due to DSR services being vulnerable to cyber-attacks or

[63] https://www.gov.uk/government/publications/better-regulation-framework

result in grid instability. In addition to this avoidance of undesirable outcomes with high social cost, policy intervention is also expected to increase the capacity of DSR operational within the UK, contributing towards the £10bn by 2050 (2012 prices) saving that flexible asset such as DSR capacity can bring, as set out in analysis supporting the 2021 Smart System and Flexibility Plan[64].

## 12. Small and Micro Business Assessment (SaMBA)

73. Of the roughly 30 DSR firms (excluding chargepoint operators) identified as being within scope of our regulations, internal analysis suggests around 45% of those established, are small or micro in size[65]. It is uncertain how this market may develop over time and therefore how many more small or micro businesses may fall within scope of these measures in the future.

74. For the 47 chargepoint operators identified by DfT, the figure was slightly lower. It was found that around 23% of devices operated by chargepoint operators are operated by small or micro businesses[66]. However, the majority of these small and micro businesses are subsidiaries of large, parent companies or are backed by large investment funds, The impact of this policy on these firms, depends on the extent to which they and the devices they operate, already meet these requirements, and the extent to which any parent companies are able to help meet them. However, this does not include private chargepoint operators, and is uncertain how this will develop to 2050, and therefore is an estimate based on available data.

75. These small and micro firms will be exposed to new costs as a result of policy intervention. For example, defining DSR service provision as a licensable activity will create new license fees to all DSRSP firms and will introduce costs of complying with the license. However, by design, the structure of license fees within the energy sector is designed to limit the burden placed on small and micro firms. Ofgem's 2021 license fee cost recovery principles[67] ensure this by allocating license fees based on the proportion of market customers held by the license holder, which is likely smaller for smaller DSRSP firms. A disproportionate amount of the benefit may be lost were small and micro firms to be exempt from regulation. For example, without policy intervention, small and micro DSR firms may act as entry points to the energy system, maintaining cyber vulnerabilities. Similarly, small and micro firms may continue to risk consumer protection and data privacy concerns, which may reduce consumer confidence in partaking in DSR services, deteriorating intended benefits. Following the Green Book guidance on SaMBAs, this suggests no exemption or mitigation for small and micro DSRSP firms will therefore be required.

76. The benefits of policy intervention also fall upon small and micro DSRSP firms. For example, increased opportunities for consumer switching due to interoperability outcomes being achieved will create greater opportunities to compete for all firms. This benefit may fall disproportionately to smaller firms, who in the presence of very strong network effects, may struggle to convince consumers to switch away from larger firms.

77. For other small and micro businesses, policy intervention is expected to offer new opportunities for these firms to partake in the provision of DSR services, which in turn may offer new revenue streams or lower annual energy bills. These firms, and all of society are

[64] This is £12bn per year by 2050 in 2020 prices.

[65] This is based on data from Companies House. A full definition of firm size also considers the annual revenue earned by firms. Due to data limitations, only number of employees is considered as a partial measure here.

[66] From the Consumer Experience at Public Chargepoints Impact Assessment. Note this considers devices operated, not the proportion of firms, following the approach from the DfT impact assessment.

[67] https://www.ofgem.gov.uk/publications/licence-fee-cost-recovery-principles-2021

also better protected against system outage events, resulting in a small but considerable benefit to all firms.

## 13. Wider Impacts

### 13.1. Equalities impact

78. The Government has reviewed the potential impacts of this policy on individuals with protected characteristics, in line with its Public Sector Equality Duty. Our assessment is that the proposed policy will not – at this stage – have any equalities impacts, given the delegated nature of the powers the Secretary of State is seeking. The powers sought will allow the Secretary of State to introduce a new regulatory framework in future but will not have any practical effect until that time. A further assessment of any equality impacts will be necessary at that point, on the basis of the specific requirements brought forward as part of that framework.

### 13.2. Justice Impact Test

79. As only enabling powers are being taken at this stage, any detailed and enforceable requirements will be set out in secondary legislation. At this point, therefore, the Government does not consider a Justice Impact Test to be necessary.

80. Full consideration of the impact on the justice system will be considered when secondary legislation is developed under these powers.

### 13.3. Trade impact

81. There is no impact on trade expected from primary legislation given that we are seeking enabling powers at primary stage.

82. There is however likely to be an impact on trade at secondary legislation stage. The demand for load controlling services is forecast to increase in both the UK and internationally, as illustrated by graphs 1 and 2 above. Furthermore, around 60% of current firms estimated as operating in the UK DSRSP market are internationally mobile, operating in at least one other country.

83. Internationally compatible standards and regulatory approaches towards DSRSP firms is likely to minimise the costs to these international firms competing in UK markets, alongside helping to maximise the opportunity for UK DSRSP firms to export internationally. The lower barriers to entry that would likely result from increased international alignment of technical standards and regulatory approaches can be expected to increase competition between firms, allow for firms to better exploit economies of scale and greater incentives to innovate. This will likely increase the consumer benefit of participating in DSRSP services via lower costs and greater product choice.

84. The UK is well positioned to be a world leader in setting an approach to the regulation of domestic-scale and small business DSR. For example, three British network companies were placed in the top ten rankings of SP Group's global Smart Grid Index in 2021 (a tally only matched by the USA).[68]

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[68] https://www.spgroup.com.sg/sp-powergrid/overview/smart-grid-index

85. Any potential impact on trade will continue to be considered throughout policy development. Policy development will also seek to understand how any adverse impacts on UK trade can be mitigated.

## 14. Monitoring and Evaluation (M&E)

86. A full monitoring and evaluation plan will be developed at secondary legislation stage. Given these primary powers are enabling only, and the uncertainties in subsequent policy design it is not considered appropriate to develop M&E at this stage.

87. A 'process' evaluation could be used to assess how effective and how efficient the rollout of the regulations has been. Typically, it could be used to analyse what parts of the regulations work, whether the current regulations are appropriate for meeting the objectives and whether the regulations have caused any issues for different stakeholder groups. An 'impact' evaluation could be used to assess the performance of the regulations against the policy objectives listed above in section 3.

88. Data will play an important role in any subsequent evaluation. As such, the M&E plan will need to decide on a range of metrics that could be monitored over time and will provide insight into the extent to which the regulations are meeting the policy objectives. For example, compliance data could be monitored to provide insight into the proportion of the market that are providing services or devices that meet our policy objectives. Market data could be used to track the price of services/devices over time whilst engagement with DSOs could be used to understand the impact our regulations are having on the electricity system.

89. Existing evidence may also be useful, including the rollout of Smart Meters, which may provide insight into the development of central body functions, and ensuring interoperability, data privacy and cyber security outcomes are met. Similarly, the 2021 Smart Charging regulations set requirements upon electric vehicle ChargePoint operators to ensure the market for smart charging is able to develop whilst ensuring the safety of both consumers and the grid. These sources of evidence may provide opportunities for learning for this policy intervention and a range of indicators and evaluation evidence that could feed into this M&E plan.

90. Under a license regime, any evidence gained from M&E would be likely to inform future modifications to licenses and relevant industry codes. Therefore, evidence generated will likely be used by industry participants alongside government and Ofgem. Data requirements and timelines for any potential evaluation are currently uncertain given the early stage of policy development and will be developed alongside policy development.

## 15. Rationale and evidence to justify the level of analysis used in the Impact Assessment (IA)

91. This IA supports enabling powers and will be refined during the 2022 consultation on secondary legislation. At this stage there is significant uncertainty in the detail of the policy options that will be considered at this secondary legislation stage. Therefore, this IA has focused on creating a reasoned case for change by identifying a clear picture of the strategic and economic rationale for intervention to present a clear understanding of the costs and risks associated with our counterfactual, in the absence of intervention. We have then provided justification of how we concluded the need for regulatory measures to mitigate the risks posed under the counterfactual world. Likely impacted entities and organisations have been identified with the potential impacts and risks intervention will have on them listed.

92. To do this we have drawn from both the academic literature, impact assessments on similar policies as well as latest industry and technical reports on the development of the market. We have also split out our assessment of the impact these policy proposals may have into three impact assessments to enable sufficient scrutiny of the enabling powers we are seeking.

## Annex 1: Key policies supporting the UK rollout of DSR

**Half-hourly settlement implementation:** Half-hourly settlement (HHS) is expected to be in place by 2025 and exposes electricity suppliers to the true cost of energy use at different times of day. Market-Wide HHS (MWHHS) will place the right incentives on suppliers to develop and offer new tariffs and innovations that encourage and enable more flexible use of energy, for example, time of use tariffs, automation, vehicle to grid solutions and battery storage. Making the most efficient use of existing infrastructure should reduce the need for extra spending on future generation and network reinforcements. This will help decarbonise the electricity system in a cost-effective way, which will benefit all consumers and wider society.

Ofgem estimate that implemented MWHHS will deliver net benefits to GB energy consumers in the range of £1.55 - £4.5bn.

**Smart meter rollout:** The government is committed to ensuring all households and small businesses can benefit from smart metering[1]. By end September 2021 there were 26.4 million smart and advanced meters across Great Britain, representing 47% smart coverage[2]. Smart meters support the transition to a low-carbon energy system, where the consumption and price data recorded by smart meters enables innovative ‘smart' tariffs when combined with half-hourly settlements[3] for suppliers. These tariffs have variable rates depending on the cost of electricity – rewarding consumers with a cheaper rate if they use electricity at off-peak times or when there is excess clean electricity available. This process will enable incentives for consumers to use energy when renewable generation is available, automatic charging of electric vehicles when prices are low, and allow consumers to take advantage of the flexibility afforded by heat pumps and storage.

**Innovation funding:** One of the priority areas under the UK government's Net Zero Innovation Portfolio (NZIP) is energy storage and flexibility. The funding for the Interoperable Demand-Side Response (IDSR) sub-programme was approved in September 2021 in the Wave 1 Flexibility Innovation Business Case Update. This was for a total of £13.5m of the up to £65m nominal budget for the overarching Flexibility Innovation Programme over ~3.5 years from December 2021 to March 2025.

**Development of standards for Energy Smart Appliances by BSI:** The British Standards Institute has published two standards for energy smart appliances, commissioned by government in 2018 and developed with industry input. These standards are PAS 1878[4] and PAS 1879[5]. They set a technical framework for small scale DSR, guided by the principles of interoperability, data privacy, grid stability and cyber security, and which are compatible with the GB Smart Metering system. The purpose of the Publicly Available Standards (PAS) is to enable

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1 https://www.gov.uk/government/consultations/smart-meter-policy-framework-post-2020-minimum-annual-targets-and-reporting-thresholds-for-energy-suppliers

2 https://www.gov.uk/government/statistics/smart-meters-in-great-britain-quarterly-update-september-2021

3 In April 2021 Ofgem published a decision and full business case for implementing market-wide half-hourly settlement, with the new arrangements taking effect in October 2025.

4 PAS 1878 specifies requirements and criteria that an electrical appliance needs to meet in order to perform and be classified an ESA. It defines the attributes, the functionalities and performance criteria for an ESA, and specifies how compliance with these can be verified. https://www.bsigroup.com/en-GB/about-bsi/uk-national-standards-body/about-standards/Innovation/energy-smart-appliances-programme/pas-1878/

5 PAS 1879 sets out a common definition of demand side response (DSR) services for actors operating within the consumer energy supply chain and provides recommendations to support the operation of energy smart appliances (ESAs). https://www.bsigroup.com/en-GB/about-bsi/uk-national-standards-body/about-standards/Innovation/energy-smart-appliances-programme/pas-1879/

standardised control, subject to consumer consent, of an ESA on an electricity network.

**Smart Charging phase one regulations:** As set out above, the Government has recently laid legislation under the Automated and Electric Vehicle Act 2018 ('AEV Act') to mandate that new private chargepoints sold in Great Britain must be smart, meet device-level requirements, including on cyber security, interoperability and grid stability.

The phase one legislation will apply to private (domestic and workplace) chargepoints for electric cars and vans and will exclude all (both private and public) rapid chargepoints (50 kW or above).

Additional policies are also planned to help ensure the safe use of DSR. These are:

**DCMS Secure by Design[6] (SbD):** The government is committed to ensuring consumer "smart" devices are more secure, with security built in from the start. In April 2021 the Department for Digital, Culture, Media & Sport (DCMS) published the government's response to the call for views on proposals to regulate consumer connected product cyber security. These policies are continuing to be developed.

**Changes to the Networks and Information System[7] (NIS) regulations for ensuring cyber security:** The government is assessing whether changes are required to the NCSC's NIS regulations to ensure cyber security of critical national cyber infrastructure, including its scope and size thresholds for requiring compliance with regulations. In November 2021, the government responded to its call for evidence[8] for amending regulations.

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[6] https://www.gov.uk/government/collections/secure-by-design

[7] https://www.ncsc.gov.uk/collection/caf/nis-introduction

[8] https://www.gov.uk/government/publications/government-response-on-amending-the-nis-regulations/government-response-to-the-call-for-views-on-amending-the-security-of-network-and-information-systems-regulations

## Annex 2: Detailed assessment of longlist options against government policy objectives

### Table 1

| | Option 0 – do nothing | Option 1 – encourage compliance with standards | Option 2 – regulation | Option 3 - licensing |
|---|---|---|---|---|
| **Description** | No action taken by Government. | Government encourages industry actors to follow voluntary standards or codes of conduct – for example, BSI's PAS 1878 or the ADE's FlexAssure Code of Conduct. | Government introduces legislation applying regulatory requirements to any organisations carrying out relevant activities. | Government requires any organisations carrying out relevant activities to obtain a licence from Ofgem and comply with certain conditions attached to that licence. |
| Cybersecurity | No protection | Unlikely to provide any confidence that cybersecurity risks are being mitigated; in absence of any assurance, significant risk that requirements are interpreted and implemented inconsistently. | Likely to provide better cybersecurity protection than Options 0 and 1 but would preclude Government from stopping certain actors from carrying out activities. Risk of unsuitable organisations controlling large amounts of load. Difficulty modifying requirements via parliament could make it challenging to mitigate changing or emerging threats. | Government and Ofgem's ability to modify licence conditions and codes rapidly would allow requirements to keep pace with emerging market and potential cybersecurity threats. |
| Interoperability | No protection | Unlikely to deliver interoperability in practice; in absence of any assurance, significant risk that requirements are interpreted and implemented inconsistently. | Likely to deliver some degree of interoperability, though would require Government to very frequently amend and update its requirements. As above, this may prove challenging if parliamentary process is necessary. | Government and Ofgem's ability to modify licence conditions and codes rapidly would ensure that interoperability endures even as market changes. Alignment with existing regulatory framework for energy actors. |
| Consumer protection | No protection | May provide some protection, particularly where combined with a certification or labelling regime, but as above, absence of assurance is likely to lead to inconsistent application with no recourse for consumers. | Likely to deliver additional protection above Option 1, though as above, frequent modification likely to be necessary to ensure requirements keep pace. | Consistent with approach to consumer protection requirements on other actors with customer relationship in this sector (e.g. energy suppliers). Could be regularly and swiftly updated as market develops. |

| | | | | |
|---|---|---|---|---|
| Grid stability | No protection | | | |
| Data privacy | Some protection offered by cross-cutting legislation, such as General Data Protection | | | |

| | |
|---|---|
| **Title:** Proposed primary regulation of smart heating appliances<br>**IA No:** BEIS003(C)-21-CLH<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business Energy and Industrial Strategy<br>**Other departments or agencies:** **N/A** | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Development/Options<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** EnergyBill2021@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| Cost of Preferred (or more likely) Option | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| Not quantified | Not quantified | Indicative only | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

Reducing greenhouse gas emissions to net zero will require virtually all heat in buildings to be decarbonised. In all future scenarios we expect the electrification of heat, primarily through heat pumps, to play a significant role in decarbonising heating, and we have committed to grow the market for heat pumps to 600,000 installations per year by 2028. This will significantly increase the demand on the electricity network, with the costs to support this borne by bill payers. Deploying electric heating appliances, including heat pumps, in a smart and flexible way can reduce the requirement for large increases in generation capacity and support the balancing of the electricity system, as well as reducing running costs for households. Without clear requirements set for the industry, it is unlikely that smart heating will be taken up at the rate required to achieve the full benefits for consumers and the electricity system during the transition to electrification of heat.

**What are the policy objectives of the action or intervention and the intended effects?**

The government's aim is to maximise electric heating appliances that have energy smart functionality, to benefit both consumers and the electricity system, whilst contributing to decarbonising heating in the UK and the net zero target. Smarter heating will enable the reduction in heating running costs for consumers, while also minimising the need for wider electricity network reinforcement.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

The policy options considered in this impact assessment are:

- Option 0 (counterfactual): do nothing.
- Option 1: support smart heating in government grant schemes - funding for clean heat installations (e.g., BUS, HUG, ECO, SHDF) could mandate or reward smart heat pumps in the scheme criteria.
- Option 2: support smart heating through off-gas grid and new build regulations - the off-gas grid regulations could look to support the uptake of smart heating. Similarly, BEIS could work with the Department for Levelling Up, Housing and Communities (DLUHC) to ensure that the Future Home Standard and Future Building Standard support smart heating.
- Option 3 (preferred option): mandate that in GB all electric heating appliances with the potential to be used flexibly have smart functionality.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:**

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | Yes / No | | | |
| Are any of these organisations in scope? | **Micro** Yes/No | **Small** Yes/No | **Medium** Yes/No | **Large** Yes/No |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** Not quantified | **Non-traded:** Not quantified | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

## Summary: Analysis & Evidence

Policy Option 3

**Description:** Proposed primary regulation of smart heating appliances

**FULL ECONOMIC ASSESSMENT**

| Price Base Year | PV Base Year | Time Period Years | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| Not applicable | Not applicable | Not applicable | **Low:** Optional | **High:** Optional | **Best Estimate:** Not estimated |

| **COSTS (£m)** | **Total Transition** (Constant Price) Years | | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | Indicative costs are presented – not appropriate for aggregated SNPV calculation | |

**Description and scale of key monetised costs by 'main affected groups'**

Impact of secondary legislation is illustrated. Monetised costs incurred by manufacturers include the additional manufacturing cost of hardware and software requirements (£10m per year, 2025, central), transition cost (£4m, one-off, central) and familiarisation costs (£13k, one-off, central). Cost to consumers are treated as transfer. Costs are in 2021 prices.

**Other key non-monetised costs by 'main affected groups'**

- **Consumer:** Potential reduction in consumer choice
- **Business/industry:** Increased customer service requirement for manufacturers
- **Wider society:** enforcement costs, infrastructure costs

| **BENEFITS (£m)** | **Total Transition** (Constant Price) Years | | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | | **Not monetised** |

**Description and scale of key monetised benefits by 'main affected groups'**

- Electricity system benefits of up to £10bn per year by 2050 (2012 prices, discounted) compared to a low flexibility scenario. This represents the overall 'size of the prize' benefits from having a highly flexible electricity system which involves high level of deployment of flexible heat pumps with storage as well as other energy smart appliances and electric vehicles.
- Illustrative bill savings to consumers from using heat pumps with time-of-use tariffs.

**Other key non-monetised benefits by 'main affected groups'**

- **Consumers:** Indirect bill savings from lower energy system costs
- **Business/industry:** Potential export opportunities
- **Wider societ**y: Acceleration of innovation and investment in smart related products and services. Contribution to transition to net zero.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | 3.5 |
|---|---|---|

- Smart heating enables realisation of sizable demand side response benefits but this is dependent on other enablers, such as usage of heat storage, smart tariffs and provision of related smart services.
- The additional cost to business is dependent on the specific requirement in hardware and software. We assume that the technology and cost are similar to the requirements for smart electric vehicle charging points. Sensitivity scenario on cost is presented.

**BUSINESS ASSESSMENT (Option 3)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs: N/A** | **Benefits:** N/A | **Net:** N/A | Indicative estimate provided in IA for illustrating secondary legislation impact. |

## Contents

## Background

The UK was the first major economy in the world to set a legally binding target to achieve net zero greenhouse gas emissions by 2050. To achieve this, we need to transition to low-carbon ways of heating our homes, businesses and public buildings across the board.

Currently, heat in buildings is responsible for 23% of the UK's greenhouse gas emissions[1]. Meeting our legally binding target of a 78% reduction in carbon emissions by 2035, and to reach net zero emissions by 2050, means decarbonising virtually all heat in buildings and most industrial processes. This is a critical decade for action on the decarbonisation of heat and upgrading the energy efficiency of homes and other buildings.

There are several strategic pathways to full decarbonisation of heat by 2050 with a range of low-carbon technologies and systems that may have an important role to play, including a potentially leading role for hydrogen. However, the electrification of heating is the only currently proven option for the decarbonisation of buildings at scale and highly efficient electric heat pumps must form a major part of how we heat our buildings in all future scenarios.

As the government's Heat and Buildings Strategy sets out, this means we need to grow the market for heat pumps to at least 600,000 installations per year by 2028[1]. This level of heat pump deployment is strategically important for any of the potential routes to net zero, and it is essential for ensuring an electrification-led route remains viable. This would require further growth to much higher numbers of annual heat pump installations by the early2030s.

Currently around 55,000 heat pumps are installed in the UK each year, and a rapid scale up of deployment is needed to reach 600,000 installations a year[2]. The Heat and Buildings Strategy sets out the policy action we are taking now to accelerate this transformation and our plans to go further. We will be introducing regulations in 2025 to ensure that all new build homes are installed with low carbon heating. We have also consulted on introducing a new market-based mechanism for low carbon heat and on plans to phase out the installation of fossil fuel heating for those living in homes off the gas grid from 2026. For those wanting to take early action, ahead of the introduction of regulations, we have introduced the Boiler Upgrade Scheme. This scheme provides upfront grant funding of £5,000 for air-source heat pumps and £6,000 for ground-source heat pumps.

There may also be a role for alternative electric heating appliances in decarbonising heating, although evidence to date suggests that this may be limited to specific use cases, such as small flats or hard-to-treat buildings due to the relative inefficiency of alternative electric heating appliances compared to heat pumps. Currently around 8% of homes in GB use direct electric heating as their main heating systems[3].

This scale up of electrification of heat, alongside the electrification of transport, is likely to increase demand on the electricity networks, potentially doubling electricity demand by 2050. 60GW of total flexible capacity may be needed to cost-effectively integrate high levels of renewable generations[4]. Alongside this increase in demand, electricity generation will increasingly be variable, dependent on the time of day, season, and prevalent weather conditions as well as more decentralised, as more renewables are connected to the grid at local level.

Mechanisms are in place to ensure the electricity system is prepared to meet future demand and costs to consumers and businesses are minimised. This includes the Capacity Market, network price controls (such as RIIO) and the Contracts for Difference scheme which drive investment in electricity networks and low carbon generation and ensure there is enough capacity to meet demand. While these mechanisms to ensure sufficient investment are important, it is crucial that the electricity system also has the ability to adjust supply and demand to keep the system balanced.

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1 https://www.gov.uk/government/publications/heat-and-buildings-strategy

2 BSRIA (2022), 'Heat pumps market analysis 2021' (https://www.bsria.com/uk/)

3 Analysis of English Household Survey Ministry of Housing, Communities & Local Government (2018), Scottish house condition survey 2019, Welsh Housing Conditions Survey (energy efficiency of dwellings): April 2017 to March 2018

4 BEIS, Smart Systems and Flexibility Plan 2021: www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021 Technical Appendix I

The government with Ofgem, the energy regulator, jointly published the Smart Systems and Flexibility Plan (2021)[5] which sets out a vision, analysis and work programme for delivering a smart and flexible electricity system that will underpin our energy security and the transition to net zero. The Plan sets out how we will facilitate the transition to a smarter and more flexible energy system, with a series of actions to facilitate flexibility from consumers, for example through smart and flexible appliances, heat pumps or electric vehicle chargers, which is expected to significantly reduce the need for network investment.

### A Smart and Flexible Energy System

BEIS modelling for the Smart Systems and Flexibility Plan demonstrates that flexibility could unlock significant benefits for the electricity network, with a high flexibility scenario reducing system costs by up to £10bn per year by 2050 (2012 prices, discounted) compared to a low flexibility scenario[6].

A smarter electricity system reduces the additional capacity needed and costs from higher electrification of transport and heat, and intermittency of renewables through deploying energy storage technologies at lower cost than additional gas generation, and shifting electric vehicle charging and electric heating demand. Shifting demand to times when overall demand is lower and more low-cost electricity generation is available reduces costs. This more efficient use of resources reduces electricity system costs and this impact is captured in modelling the following:

- helping balance the electricity system which leads to lower-cost system operation;
- lowering peak demand which avoids or defers necessary reinforcements on our transmission and distribution network;
- shifting peak demand to times of lower demand reduces curtailment[7] of low carbon generation; and
- lowering peak demand also reduces the need to build new generating capacity.

Demand Side Response (DSR) refers to actions taken by consumers, in response to a signal, to change the amount of electricity they take off or add to the grid, at a particular time. It can provide cost-effective flexibility to the electricity system – used by the system operator to help balance the system - or by companies to minimise network charges during periods of peak demand. Participation in DSR by domestic and smaller non-domestic consumers remains at an early stage, as there are few smart tariffs on the market, and the smart electric heating market is relatively nascent. Moreover, DSR is happening in the industrial and commercial sectors, where it is provided by a range of companies, on a commercial basis. In future, DSR will be particularly important in the domestic sector for managing the peaks caused by increased electrification of heat and transport as this demand can be smoothed, for example, by exposing consumers to price signals through (voluntary) smart energy tariffs (for example, time-of-use tariffs which charge different unit prices at different times of day to incentivise electricity demand to move away from peak times). To enable flexibility from consumers, they will need to have access to energy smart appliances (ESAs) that make it easier to change their consumption patterns, and tariffs and services that incentivise this change, including stronger price signals.

### The Role of Smart and Flexible Heating

For the purpose of this policy, we have defined a smart heating appliance as a heating appliance for the purpose of space heating and sanitary hot water which is communications-enabled and capable of responding automatically to price and/or other signals by shifting or modulating its electricity consumption. Energy smart functionality can be achieved either through embedded connectivity, or through the use of an add-on module to enable communication and control.

We expect heat pumps to be the principle means of decarbonising heat over the next decade and potentially beyond. As outlined in our Smart Systems and Flexibility Plan, highly flexible use of heat

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[5] BEIS and Ofgem (2021) Transitioning to a net zero energy system: smart systems and flexibility plan https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

[6] BEIS, Smart Systems and Flexibility Plan 2021: www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021 Technical Appendix I

[7] Curtailment refers to reduction of output of a renewable generator from what it could produce given available resources (e.g., wind or sunlight), typically on an involuntary basis due to lack of demand or system inertia.

pumps could enable annual demand to be shifted by up to 50TWh in 2050 and reduce peak demand by nearly 5GW[8]. Smart heating alongside storage – including thermal storage, or the thermal performance of a building's fabric – also has the potential to reduce costs for consumers by shifting demand to cheaper times through tariffs that reward flexibility and reflect generation costs, as well as potentially giving consumers the greater ability to optimise their heating for comfort, cost and carbon, based on their preferences.

In 2018, government consulted on proposals to set regulatory requirements for small scale ESAs. ESAs are devices that are able to provide DSR, including home appliances (fridges, dishwashers etc), as well as heat pumps. Although the consultation did not propose to mandate appliances to be smart, due to the early stage of development of the smart appliances market, the consultation response highlighted that government would retain the option of doing so, should it deem it necessary in the future.

We think there is now the case to take powers to mandate smart for electric heating appliances used for space heating and sanitary hot water. With rapid scale up of electrification of heat expected over the 2020s, and in particular the scale up of heat pump deployment to at least 600,000 installations a year by 2028, the impact on the grid of electric heating will increase significantly, as well as the potential to provide flexibility. Mandating smart functionality is a key enabler in the participation of electric heating appliances in a flexible energy system, and will unlock benefits for both consumers and the electricity system. Without government intervention at this stage, it is unlikely that smart heating will be taken up at the rate required to achieve the full benefits for consumers and the electricity system during the transition to electrification of heat.

Although the primary powers will apply to all electric heating appliances used for space heating and sanitary hot water, subject to consultation, we propose to introduce requirements for energy smart functionality initially for electrical heating appliances with the greatest potential to be used flexibly, namely heat pumps, as well as storage heaters and heat batteries. We propose to keep under review the case for expanding the requirements to other electric heating appliances, including new technologies as they emerge.

## Enablers

There are a number of enablers that need to be realised to maximise the potential of smart electric heating. Considerations include:

### Smart Meter Roll Out

Smart meters are a vital upgrade to our national energy infrastructure and underpin the cost-effective delivery of the government's net zero commitment. They are a critical tool in modernising the way we all use energy and support the transformation of the retail energy market, helping the system to work better for energy consumers. Without the flexibility enabled by smart meters, modelling for the Committee on Climate Change estimates the costs of delivering net zero by 2050 could be up to £16 billion higher each year[9]. As of 30 September 2021, there were 26.4 million smart and advanced meters in homes and small businesses in Great Britain, representing 47% smart coverage[10].

The half-hourly consumption and price data recorded by smart meters unlocks new approaches to managing demand. Innovative products such as smart 'time of use' tariffs reward consumers for using energy away from peak times and enable technologies such as electric vehicles and smart appliances to be cost-effectively integrated with renewable energy sources, as well as allowing energy suppliers to accurately bill their customers.

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[8] BEIS, Smart Systems and Flexibility Plan 2021: www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021 Technical Appendix I

[9] Committee on Climate Change (2019) Net Zero Technical Report https://www.theccc.org.uk/publication/net-zero-technical-report/

[10] BEIS (2021) Smart meters in GB quarterly statistics https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1035290/Q3_2021_Smart_Meters_Statistics_Report.pdf

The government wants to ensure that all households and small businesses in Great Britain can benefit from smart metering. To meet this ambition and drive completion of the rollout, the government confirmed in June 2020 that a new four-year Framework would set energy suppliers annual, individual installation targets on a trajectory to 100% coverage, subject to an annual tolerance level.

**Half Hourly Settlement**

Half-hourly settlement (HHS) uses data from smart meters to expose electricity suppliers to the true cost of energy use at different times of day. Market-Wide HHS (MWHHS) will place the right incentives on suppliers to develop and offer new tariffs and innovations that encourage and enable more flexible use of energy, for example, time of use tariffs, automation, vehicle to grid solutions and battery storage. Making the most efficient use of existing infrastructure should reduce the need for extra spending on future generation and network reinforcements. This will help decarbonise the electricity system in a cost-effective way, which will benefit all consumers and wider society.

Ofgem's final decision[11] to introduce HHS on a market-wide basis is supported by their Full Business Case[12] and Final Impact assessment[13]. Ofgem estimate that implemented MWHHS will deliver net benefits to GB energy consumers in the range of £1.55 - £4.5bn.

Ofgem set out a decision on the transition timetable and expect implementation to full MHHS to take 4 years and 6 months, with completion in October 2025.

**Regulation of Energy Smart Appliances**

Alongside the powers to mandate smart heating, BEIS are taking powers to regulate ESAs, including the following appliances:

- Wet appliances: washing machines; dishwashers; tumble dryers.
- Cold appliances: refrigeration and freezers.
- HVAC: heating, ventilation, air conditioning. This includes electric heating appliances.
- Battery storage: home batteries.

The regulatory requirements will be set through secondary legislation, and will be based on the policy principles of interoperability, cyber security, grid stability and data privacy. This may refer to (and require compliance with) specific technical standards, which indicate compliance with these requirements. Further details of these powers are set out in the Energy Smart Appliance Impact Assessment.

Mandating smart functionality for electric heating appliances will mean that these appliances are subject to the requirements set in secondary legislation for ESAs.

**Regulation of Load Controllers**

As ESAs become more common, and the need for flexibility in the energy system grows, it is expected that DSR services will become increasingly attractive to domestic and small business energy consumers. DSR for domestic and small business premises is expected to be delivered by intermediaries via a range of business models termed 'Demand Side Response Service Providers' (DSRSPs), many of which will be aggregators who combine DSR in relation to a large number of premises.

Some DSR services will involve the remote control of electrical load to provide flexibility services to system operators, while others will allow consumers to optimise their device's usage against price or other signals. DSR can also be delivered through energy management systems which shift demand from charge points or heat pumps to allow the usage of local generation and storage.

BEIS are also taking powers to licence load controllers, with the aim of establishing a regulatory framework by 2025. The proposed powers will allow the detail of cyber security and interoperability

[11] Ofgem (2021) Final Decision HHS

[12] Ofgem (2021) HHS Full business case

[13] Ofgem (2020) HHS Final Impact Assessment

requirements to be specified following public consultation with industry and other interested parties in 2022.

## Problem under consideration and rationale for intervention

### Problem under consideration

The electrification of heat will bring significant new demand for electricity. How electric heating is used could have profound impacts on the electricity system. This is true for both heat pumps and less efficient alternative electric heating technologies, like storage heaters and infrared heating. However, some electric heating technologies, namely heat pumps as well as storage heaters and heat batteries, have greater potential to be used flexibly. Therefore, subject to consultation, we see the strongest case to take action initially to mandate smart for these electric heating technologies.

Work is already underway to ensure the electricity system can best take advantage of new smart technologies that could increase the flexibility of electricity supply and demand, and there is considerable potential for heat pumps to play a key role in this transition. Electric heating that can flex to grid pressures could not only avoid adding to existing peak, but could also provide new valuable options for balancing demand and supply for energy suppliers, network operators and the System Operator. This value could be translated to consumers in the form of lower energy bills and/or additional benefits to having electric heating.

In order for electric heating appliances to partake in the smart grid of the future, appliances must be capable of communicating with, and acting on, information from third parties. There are currently no requirements for this functionality and so weaker motives for the investment and innovation which could benefit consumers.

Furthermore, despite the potential overall running cost savings that smart heating could offer them, prospective heat pump owners may be less inclined to pay the extra upfront cost, albeit this is expected to be a fairly small increase, to install a smart heat pump and opt instead for a cheaper model that does not offer smart. This is reflected in research into consumer attitudes which shows that running cost is a secondary consideration, compared to the upfront cost, when deciding whether to install a heat pump[14].

To ensure that the benefits of smart heating are realised, consumers need to be incentivised to engage with smart heating. There is limited data on current uptake of smart heating offers, such as time of use tariffs, amongst homes with a heat pump but without high level awareness of the benefits, uptake will likely be low.

Without government intervention, it is unlikely that smart heating will be taken up at the rate required to achieve the full benefits for consumers and the electricity system during the transition to electrification of heat.

### Rationale for intervention

The size of the prize of the system benefits associated with deploying energy smart electric heating within appropriate time scales is significant, and without government actions we risk not capturing much of the benefits from flexibility and in de-risking the delivery of the 600k heat pump rollout target.

The uptake of energy smart electric heating appliances increases the amount of flexible electrical demand on the system, allowing the potential for electricity consumption to be shifted away from peak periods. This will result in lower costs to the electricity system of meeting electricity demand through utilising less expensive forms of electricity generation and avoiding network reinforcement/upgrades, benefiting all electricity consumers.

Smart heating has the potential to reduce running cost at the individual level by enabling the consumer to shift their demand and access lower electricity prices. However, there is also a significant positive externality, as at a societal level there will be a reduction in costs due to the avoided infrastructure expenditure that would be required in the absence of flexibility technologies with the ability to shift peak

[14] https://www.nesta.org.uk/report/decarbonising-homes-consumer-attitudes/

demand. Furthermore, the introduction of standards under the ESA will help protect wider society from the emerging risks associated with increased use of smart appliances.

The main aspects of economic rationale for government actions are as follow:

### Positive externalities

These are associated with the deployment and use of smart appliances to manage electricity system demand. The DSR associated with appliances being managed together with other smart flexibility can contribute to £30 – 70 billion cumulative savings between 2020 and 2050 (2012 prices, discounted)[15]. This could enable consumers access to financial incentives from the use of their smart appliances (either through smart tariffs or business services assuming they have an agreement with their supplier or aggregator). Smart functionality will also enable consumers to better manage their bills, potentially lowering these costs. However, there are additional electricity system benefits which may not accrue directly to the smart appliance owner, leading to much lower uptake of smart appliance uptake and usage if left to the market alone.

### Information failure and consumer confidence

Lack of awareness and bounded rationality by consumers in understanding the relative costs and benefits of smart appliances can hinder consumers from wanting to purchase smart heating appliances over conventional ones in the absence of government actions.

### Market power and co-ordination failures

Technological fragmentation is likely to occur in the absence of government actions where firms are unable to co-ordinate effectively in the development of products and associated services. This could result in limited interoperability across products, which would further deter uptake of smart electrical heating. Market conditions in the absence of government actions may incentivise existing firms to actively prevent compatibility across products in order to leverage market power. Together with setting minimum standards for ESAs, the proposed energy smart functionality mandate on electric heating appliances could limit these risks.

## Policy objective

The main objective of mandating energy smart functionality for electrical heating appliances is to maximise the use of electric heating appliances that have smart functionality as the electric heating market – predominantly heat pumps – scales up over the course of this decade, to benefit both consumers and the electricity system, whilst contributing to decarbonising heating in the UK and the net zero target.

The proposed primary powers cover all electric heating appliances providing space heating and sanitary hot water. However, subject to consultation, we propose to introduce requirements for energy smart functionality initially only for electric heating technologies with the greatest potential to be used flexibly, namely heat pumps as well as storage heaters and heat batteries. We propose to keep under review the case for expanding the requirements to other electric heating appliances, including new technologies as they emerge.

Once the mandate is implemented, the smart electric heating appliances will then be subject to the device level requirements around interoperability, cyber security, grid stability and data privacy that are covered in the Energy Smart Appliance Impact Assessment.

## Theory of change

Below is a light-touch logic model, giving a visual representation of our policy and demonstrating the intended relationships between the actions and the objectives stated above. It is included to give an understanding of the logic underpinning the policy and the path we expect the policy to take.

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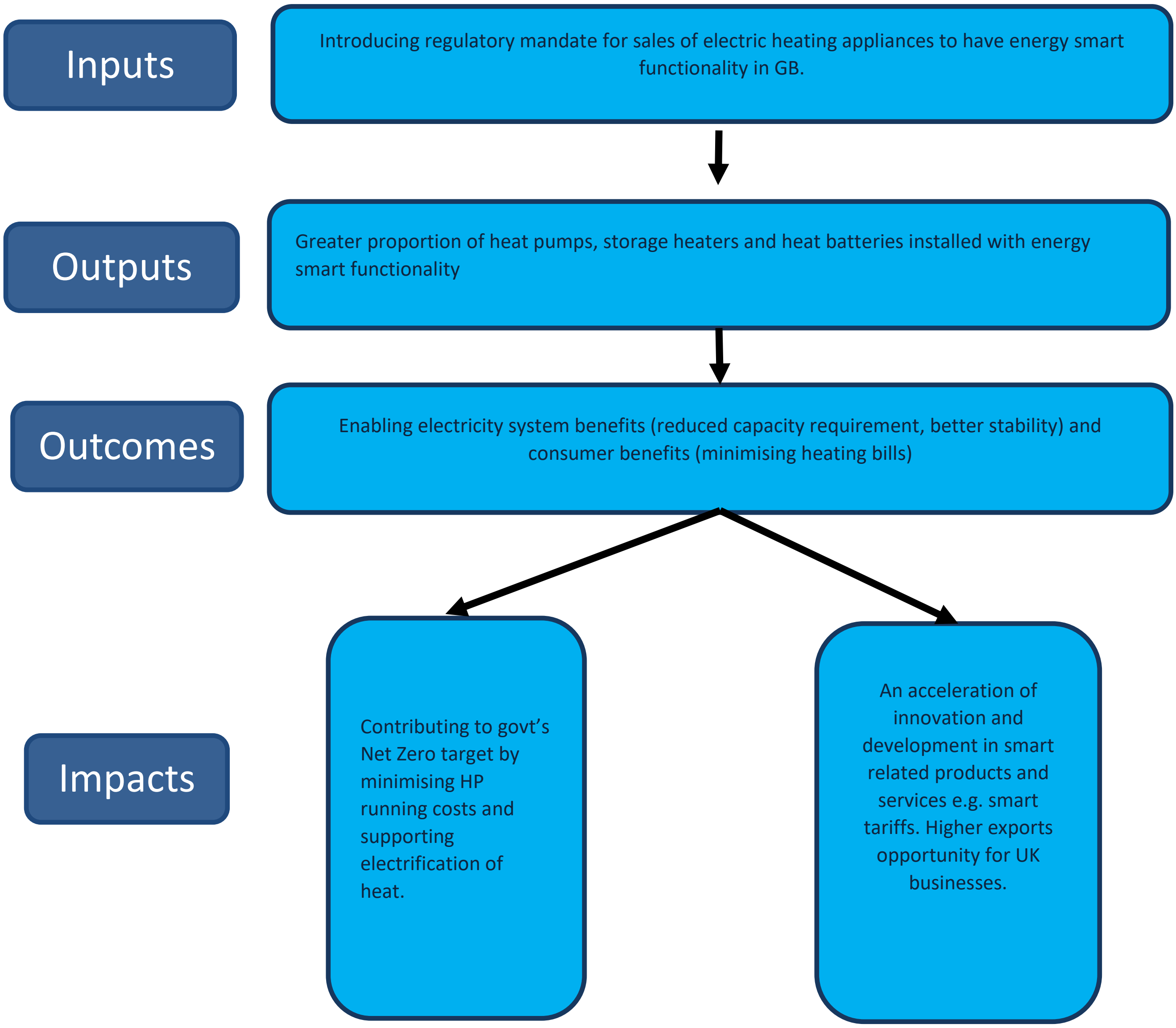
[15] Based on illustrative pathways presented in BEIS, Smart Systems and Flexibility Plan 2021: www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021




## Policy options

### Base case – do nothing

This is the base case scenario, which involves taking no action to mandate or support the uptake of smart electric heating appliances.

If government action is not taken, industry may move towards smartness anyway, bringing forward more smart heat offerings and developing solutions to retrofit 'dumb' heat pumps and potentially other electric heating appliances. BEIS's review of heat pump manufacturers' product sheets and initial engagement with industry suggest that at least 43%-55% of current heat pump sales are already internet connectable (with either embedded connectivity or are currently sold as a bundle with add-on module that enables communication), which is a good indication of energy smart functionality and that 'smartness' is an interest from industry.

However, if left to the market this is likely to lead to slower uptake of smart electric heating, with knock on implications for the electricity impacts and running costs for consumers, as well as potentially impacting on delivery of the 600,000 heat pump target and successful implementation of future regulations to decarbonise heating.

### Option 1 - support smart heating in government grant schemes

There are several existing government grant schemes that provide financial support for heat pump installations, including the Boiler Upgrade Scheme, the Social Housing Decarbonisation Fund, the Home Upgrade Grant and the Energy Company Obligation. In this option, these schemes could mandate or reward smart heat pumps in the scheme criteria.

However, the schemes do not affect uptake of alternative electric heating technologies, and heat pumps supported represent a relatively small portion of the number of heat pumps we expect to see installed annually. Whilst we will continue to pursue this option as a short-term solution to boost the smart heating market, it is unlikely to lead to the long-term mass adoption of smart. Furthermore, the funding and delivery of these schemes is uncertain beyond the end of this Spending Review Period in 2024-25.

### Option 2 - support smart heating through off-gas grid and new build regulations

Under this option, BEIS could incentivise smart heating through the proposed regulations to phase out the installation of high carbon fossil fuel heating systems in homes off the gas grid and work with DLUHC to ensure that the Future Home Standard supports smart heating. However, the number of homes in-scope represent only a relatively small proportion of the total GB housing stock. In a future scenario in which hydrogen does not play a role, or plays only a limited role, we expect to see significant numbers of heat pumps deployed in homes currently on the gas grid. It is important that measures future-proof for this scenario.

### Option 3 (Preferred) - mandate that electric heating appliances sold in GB with the potential to be used flexibly are smart

This power would enable the government to require heat pumps and other electric heating appliances with potential to be used flexibly to have 'smart' functionality to receive, understand and respond to signals sent by energy system participants (e.g., Distribution Network Operators (DNOs), energy suppliers, National Grid or other third parties). This would be for the purposes of balancing energy and demand, and to require any technological functionality in electric heating appliances necessary to ensure ‘smart’ functionality. These appliances will be subject to the proposed powers to set regulatory requirements for ESAs, which proposes that standards and communication protocols used to ensure smart functionality are made openly accessible to enable interoperability so as to prevent consumers from locking into any one particular product type or service provider to access the smart functionality.

Smart functionality could hold benefits to a range of parties, including consumers, energy suppliers and network operators. Many of these functionalities have the potential to hold commercial value that could be transferred to consumers, including through lower energy bills.

It is likely that the requirements would come into effect in the mid-2020s. Although the primary powers will apply to all electric heating appliances providing space heating and sanitary hot water, subject to consultation, we propose to introduce requirements for energy smart functionality initially for electrical heating appliances with the greatest potential to be used flexibly, namely heat pumps, as well as storage heaters and heat batteries. However, the details of any secondary legislation, including the timing of implementation and the cohort of electric heating appliances that the mandate would apply to, would be determined at that stage following further consultation, and so a range of reasonable assumptions have been made about the most likely form of regulation to give an indication of the potential impacts. These impacts will be managed through the secondary legislation stages if required to strike the right balance between costs to business, government and benefits to consumers.

## Monetised and non-monetised costs and benefits (including administrative burden)

The preferred option in mandating electric heating appliances to be smart will incur a range of costs and benefits. We do not expect any direct impacts of enacting *primary* legislation. The costs and benefits presented in the remainder of this section reflect indicative costs and benefits of implementing the regulatory requirements, it is the impact of secondary regulation which has been quantified. At this early stage in policy development only high-level estimates and inferences can be drawn.

In this section we present evidence to draw indicative estimates for the costs and benefits of deploying smart heat pumps and storage heaters against the baseline for the preferred option (option 3). Heat batteries have not been considered. It is more appropriate to present indicative monetised costs and benefits separately instead of an aggregated overall monetised SNPV as the benefits are not fully monetised at this stage. Assessment of the costs and benefits of setting technical requirements for ESAs are presented separately in the Energy Smart Appliance Impact Assessment. Indicative estimates are produced for the preferred option only as the other options are not expected to lead to material impacts on the development or deployment of smart heating appliances.

In estimating the monetised costs for mandating smart heat pumps, we have assumed a heat pump deployment profile consistent with an electrification pathway with up to 1.9m heat pumps installed per year by 2035 in both the baseline and policy scenario[16]. BEIS's review of heat pump manufacturers' product sheets and early engagement with some manufacturers suggest that at least 43%-55% of current heat pump sales are already internet connectable[17]. For modelling purposes we've assumed that 50% of the current market by sales volume are already compliant and will remain so by mid-2020s. The assumption is likely to be conversative as the market share of smart heat pumps are expected to grow.

The uptake rate of storage heaters in the counterfactual and policy scenario is based on current annual UK sales at 100k units per year[18]. For modelling purposes we've made a conservative assumption that 0% of the current market sales have energy smart functionality by default.

A specific date has not been set for when the mandate will take effect in the mid-2020s. 2025 is assumed for the following analysis and it is used purely for illustrative purpose.

**Indicative costs (monetised)**

Regulatory requirements for energy smart functionality will result in an initial cost incurred by businesses. These costs consist of:

- The additional costs of manufacturing appliances with energy smart functionality.
- Transitional costs, such as development costs.
- Familiarisation costs.

Additional manufacturing costs

The additional cost per appliance in making a non-smart heat pump or storage heaters to comply with the proposed regulation will differ between manufacturers depending on the design solution. The exact costs will be driven by the precise details of the standards and functionality requirements set out in secondary legislation, and are expected to be passed on to consumers. At this stage we've used evidence from smart EV charging points to infer about the likely cost per unit, assuming that the hardware and software requirements for smart functionality will be similar[19]. This suggests an additional unit cost of £40. A sensitivity assumption of £100 per unit is assumed based on market review of current retail price of heat pump smart controls. This is considered to be conservative given that add-on modules often come as a bundle with the heat pump unit, which would be cheaper compared to buying the module separately. In addition, these assumptions do not take into account potential future cost reductions for the technology as well as competition effect. Due to limited evidence, we've applied the same cost assumption for heat pumps for storage heaters. Table 1 below summarises the indicative aggregate manufacturing costs for meeting the smart requirement by manufacturers.

Table 1: Indicative monetised additional manufacturing costs per year, undiscounted

[16] The effect of smart mandate on smart heat pump uptake is uncertain. For modelling purposes, we assumed the impact is zero.

[17] This uses estimated market share of UK heat pump manufacturers taken from 'Heat pump manufacturing supply chain research project, Eunomia (2020)' https://www.gov.uk/government/publications/heat-pump-manufacturing-supply-chain-research-project

[18] Evidence gathering for electric heating options in off gas grid homes, Element (2019), Table 8-13 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/831079/Electric_heating_options_in_off-gas_grid_homes.pdf The scope of the policy is for GB. UK sales figure is used as a proxy.

[19] The Electric Vehicles (Smart Charge Points) Regulations 2021 Impact Assessment https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1015290/electric-vehicles-smart-charge-points-regulations-2021-impact-assessment.pdf

| Electric heating appliances | % of volume affected | Units affected, 2025 | Additional manufacturing cost, central | Additional manufacturing cost, high sensitivity |
|---|---|---|---|---|
| Heat pumps | 50% | 150,000[20] | £6m | £15m |
| Storage heaters | 100% | 100,000 | £4m | £10m |
| **Total** | / | **350,000** | **£10m** | **£15m** |

Transition costs

These are one-off costs such as costs of modifying or developing software, completing additional testing and certifications, and updating documentations. These costs are expected to vary by manufacturers and the unit cost would depend on sales volume. We have limited evidence at this stage and we plan to gather further evidence ahead of secondary legislation.

We've used evidence from a Ecodesign preparatory study to give an indication on the likely magnitude of transition costs, which estimates €15-20 (£12.9-17.2) per appliance for this kind of costs[21]. These costs apply only in the first year (assumed to be 2025). Table 2 below presents the indicative estimates on transition costs, using £15 as the mid-point estimate:

Table 2: Indicative monetised transition costs in 2025, undiscounted

| Electric heating appliances | Transition costs, central |
|---|---|
| Heat pumps | £2.3m |
| Storage heaters | £1.5m |
| **Total** | **£3.8m** |

Familiarisation costs

For manufacturing businesses, they will need to spend time familiarising themselves with the new rules and requirements. Reflecting that electric heating manufacturers are typically large multinational companies that would be engaging with EU and other international regulatory bodies irrespective of UK regulation, and dependent on the extent to which the UK aligns with international requirements, the additional familiarisation costs of UK regulation are expected to be low.

Familiarisation costs are driven by the number of staff that are needed to understand the regulations, their wage rates and the complexity of the requirements. To give an indicative sense of scale of these costs, we assumed that in the initial year of the regulatory requirement being introduced (2025), each developer will require additional (legal and managerial) resource to read and understand the legislation of between 3 to 6 hours, with a central estimate of 4.5 hours at a cost of around £59 per hour.[22]

We estimate that there are above 40 Air Source Heat Pump (ASHP) and Ground Source Heat Pump (GSHP) manufacturers with market presence in the UK- the majority of which are foreign

[20] Heat pump deployment unit assumed to reach 300k by 2025, leading to 600k by 2028. Note 300k is used for modelling purposes only. Deployment level will depend on installations in the retrofit and new build market.

[21] Ecodesign for European Commission (2017) Preparatory study on smart appliances. This is based on a non-networked appliance needing a network connectivity module etc. A networked appliance only needing software modifications, testing, documentation etc will cost lower at €5-10 per appliance.

[22] Undiscounted, including non-wage-costs of 16% (ONS (2020Q3) Index of labour costs per hour: Manufacturing). Wage costs based on ONS (2021) Annual Survey of Hours and Earnings: corporate managers and directors at the 90th percentile).

manufacturers[23], plus up to 10 storage heater manufacturers[24]. We use this as a central estimate, with a 50% range for a high sensitivity scenario to reflect the uncertainty on the estimate. The familiarisation costs presented in table 3 below gives the magnitude of the scale and is expected to be an overestimate given that some of the costs will be incurred by foreign businesses.

Table 3: Scale of familiarisation costs, undiscounted:

| | **Central (50 manufacturers)** | **High sensitivity scenario (75 manufacturers)** |
|---|---|---|
| **Familiarisation costs** | £13,000 | £20,000 |

These are the key monetised costs reflected in this appraisal. Over time, we would expect scale and development of competition in the market to lower costs, in particular where aligned with international requirements.

The costs are expected to be passed through to consumers, who may face higher costs for smart appliances (as the manufacturing costs are passed through the supply chain), and who also benefit from the use of smart functionality and lower electricity bills over the lifetime of the appliance.

Impacts to consumers are considered a transfer. This quantified appraisal is partial, based on the limited evidence available to date, and non-quantifiable/non-monetised impacts are considered qualitatively in later sections.

### Illustrative benefits (monetised)

Electricity system benefits

BEIS modelling for the Smart Systems and Flexibility Plan demonstrates that increased flexibility from DSR, storage and interconnection provides significant cost savings in a decarbonised electricity system, with a high flexibility scenario reducing system costs by up to £10bn per year by 2050 (2012 prices, discounted) compared to a low flexibility scenario. Modelled illustrative pathways from 2020-2050 suggest that increased flexibility can lead to cumulative system cost saving of £30bn- £70bn (2012 prices, discounted).[25]

Heat pumps have a significant role to play in unlocking this flexibility, and highly flexible use of heat pumps could enable annual demand to be shifted by up to 50TWh in 2050 and reduce peak demand by nearly 5GW[26].

Energy smart functionality unlocks the potential for heat appliances to shift demand flexibly in conjunction with the use of heat storage, and thereby enabling flexibility benefits in the electricity system.

Indicative bill savings for consumers

Energy smart functionality enables consumers to gain access and make use of time-of-use tariffs. Together with heat storage and demand shifting this allows the potential to reduce heating bills. Since tariffs designed for heat pumps are currently nascent, we have used economy 7 tariffs as a proxy to illustrative the potential bill benefits to consumers from using heat pumps flexibly. The example used suggests that annual heating bill for a low-temperature air source heat pump (LT-ASHP) could be reduced by over £100 for an average home.

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[23] Heat pump manufacturing supply chain research project, Eunomia (2020) https://www.gov.uk/government/publications/heat-pump-manufacturing-supply-chain-research-project

[24] Evidence gathering for electric heating options in off gas grid homes, Element (2019), Table 8-13 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/831079/Electric_heating_options_in_off-gas_grid_homes.pdf The scope of the policy is for GB. UK sales figure is used as a proxy.

[25] These benefits are associated with high level of deployment of flexible heat pumps with storage as well as other energy smart appliances and electric vehicles in a highly flexible electricity system.

[26] BEIS, Smart Systems and Flexibility Plan 2021: www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021 Technical Appendix I

Table 4: Illustrative heating bills for a home with 10,000 kWh of annual heat demand[27]

| | Standard tariff, LT-ASHP@244% in-situ efficiency | Illustrative time-of-use tariff, LT-ASHP@244% in-situ efficiency |
|---|---|---|
| Annual heating bill, 2025 | £960 | £850 |

### Non-monetised costs and benefits, including wider impacts

*Infrastructure cost*

The costs outlined above do not include any infrastructure cost, but this is thought to be minor. Total data used by smart energy services is very small and the infrastructure is being rolled out to meet the requirement for broadband, video etc. There may be an issue with rural communities without reliable internet connection who may not be able to access smart appliance controls, who may potentially be disadvantaged. In England more than 20% of homes using conventional electric appliances as their main heating systems are located in rural areas[28]. However, the government is encouraging the rollout of digital services to remote areas for other reasons, so any increase in cost due to smart appliances would be small. This would also be supported by the infrastructure and connection required by the government commitment to ensuring that every home and small business in the country is offered a smart meter by the end of 2020.

*Increased customer service requirement for manufacturers*

Customer service costs may increase because of these regulations due to the increased consumer interaction associated with the installation of smart technology. This cost would likely fall on the manufacturer; however these costs have not been included in this assessment as they are very difficult to accurately quantify and monetise.

*Reduction in consumer choice*

There are already a broad range of models of heat pumps and storage heaters available on the market which include smart and non-smart versions. These models vary in terms of design, functionality, and price. Removing non-smart models from the market would not significantly reduce the number of models available to the consumer. Similar to smart EV charging points, the additional features required to make electrical heating smart are expected to be mainly software-related, as such we would not expect smart heat pumps or storage heaters to look different in appearance to a non-smart version.

Enforcement costs

This will depend on the form of enforcement of the regulation. Manufacturers of non-compliance could incur enforcement costs such as penalties and associated legal costs, however the costs to non-compliant businesses is not in scope of the Business Impact Target.

An enforcement authority for the legislation has not been appointed yet. The legislation should provide powers to make provision for an enforcement authority, but as these are enabling powers, nothing will materially change on the ground as a result of this legislation passing through parliament.

Ahead of secondary legislation officials will identify the final cost of enforcing the regulatory requirements in collaboration with the enforcing authority on appointment. This will include preparation and set up costs, training, resources, legal costs, active enforcement (including testing, and technical resources), and monitoring and evaluation. These costs will be subject to review by the enforcing authority we wish to designate, BEIS financial officers, other government departments and the Ministry of Justice.

[27] Assumes a 50/50 usage of peak and off-peak tariff for heat, leading to an assumed 12% reduction in overall electricity fuel prices compared to using standard tariffs. The example uses UK averages of E7 and standard tariffs from BEIS's Statistical data set: Annual domestic energy bills, QEP 2.2.4. The use of heat storage is assumed to enable demand shifting.

[28] Analysis of EHS 2018

Export opportunities and innovation of smart energy related products and services

The mandate will expand the market for products and services related to smart functionality, providing stronger incentives for innovation and investment. This could support the growth of UK businesses and potentially lead to export opportunities, given the growing global market for smart energy systems29.

Carbon savings and contribution to net zero objective

Smart functionality has the potential to reduce running cost of heat pumps. This reduces the barrier to mass heat pump adoption which in turn contributes to the government's 10pp target of reaching 600k deployment by 2028. Also, by reducing the overall peak capacity requirement for electricity, smart functionality can support a cost effective transition to net zero, given the importance of electrification to the decarbonisation of many sectors.

## Direct costs and benefits to business calculations

Given that the legislation is for primary powers only, and that decisions on the introduction and detail of any secondary legislation will be taken at a later date in light of the development of the market, the Equivalent Annual Net Cost to Business (EANDCB) of the primary regulation is zero. EANDCB of individual measures will be quantified and scored at the point when any regulations which would then bring about impacts to business within the UK are introduced in secondary legislation.

The costs we have monetised which have direct impact on businesses are additional manufacturing costs of making heat pumps and storage heaters smart, transition costs and familiarisation. A 10-year period from 2025 is used to estimate the ENADCB, as presented in table 5 below. The high sensitivity reflects higher number of companies incurring familiarisation costs and higher manufacturing costs per unit, as discussed in earlier sessions.

Table 5: Indicative ENADCB estimate, 2022 prices, 2020 PV year

| | ENADCB | BIT score |
|---|---|---|
| Central | £18.5m | £92m |
| High sensitivity | £45.6m | £228m |

## Impact on small and micro businesses (SaMBA)

The primary powers sought at this stage are 'enabling powers' only, therefore a full small and micro business assessment will be carried out as part of secondary legislation. At this stage there is not enough detail known about how these proposals may impact small and micro businesses, nor how the exemption process may apply, to enable a full assessment. This section summaries an indicative view about potential impacts on small and micro businesses.

The exact number of small or microbusinesses (defined as having up to 49 FTE and 10 FTE employees respectively, BEIS Better Regulation Framework Manual), that the proposed provisions will affect is uncertain. The businesses directly affected are the appliance manufactures. BEIS's review of manufacturers with market presence in the UK suggests that these are larger and fall outside of the defined employee range[30]. For those indirectly affected we have not been able to quantify the scale of business affected due to lack of evidence. The expected impact is qualitatively discussed below.

The main small and micro businesses that are thought to be affected fall into the category of the supply chain. This may include installers and local retailers who will face labelling and familiarisation costs.

[29] https://www.iea.org/reports/smart-grids

[30] Heat pump manufacturing supply chain research project, Eunomia (2020) https://www.gov.uk/government/publications/heat-pump-manufacturing-supply-chain-research-project

The supply chain will face costs in training their workforce to sell and service appliances that are more complex than non-smart appliances, however, it is likely that this would occur anyway and not as a result of this policy. It is important to also recognise that appliances are continuously changing and evolving, and that supply chain businesses are continually developing their practices.

Of the small and micro business indirectly affected, a number of further methods could be considered when developing secondary legislation to mitigate any costs:

- Partial exception - small and micro businesses could be issued warnings rather than facing sanctions where non-compliance is identified, or by deeming a certain subset of rules not applicable to smaller business.
- Specific information campaigns or user guides, training and dedicated support for smaller businesses - as noted above this would be an essential method of cost minimisation
- Direct financial aid for smaller business - given the expected minimal additional costs, it is our view that this would be disproportionate to initially consider, as other methods would be more appropriate at targeting any additional costs.

### Risks and assumptions

The risks associated with this policy are set out below:

- Non-compliance by industry - If regulatory requirements or technical standards are not clear or strictly enforced, there may be non-compliant products on the market undermining confidence and consumer protection.
- Increased energy consumption – if a heat pump is undersized, installed without sufficient hot water storage, and/or in a building with unsuitable fabric performance, it will not be able to adequately shift demand and be used smartly, or use more energy to do so.
- The additional cost of smart heating appliances jeopardises the transition to electrification of heat, and achieving the aim of 600,000 heat pumps installations a year by 2028 - This is deemed to be low risk, as the additional cost of adding smart functionality is expected to be low relative to the capital costs of appliances.
- Regulation does not drive smart tariffs and services – there is a risk that regulation comes at the wrong time or is insufficient to incentivise smart tariffs and services from suppliers/aggregators meaning that the smart functionality is not used to manage the electricity system.
- Vulnerable consumers are left behind – if they are unable to utilise the smart functionality of their heating appliances or access optimal start tariffs and services, they may be faced with higher energy costs.

We intend to gather more evidence ahead of secondary legislation with the view to refine the assessment of the costs and benefits related to the proposal. The key area of uncertainty and evidence gap are:

- Deployment of electrical heating appliances and the effect of smart in uptake level - Deployment level will depend on consumer choice as well as future government policies in heat.
- Energy smart functionality deployment in the absence of policy – there is inherent uncertainty on the degree to which smart functionality will be sold by default.
- Hardware and software requirement required for flexibility in using heat pumps and storage heaters, and the additional costs associated with enabling the function – this will depend on the specific smart functionality requirement set out in the secondary legislation, and future technology development (including cost reduction).
- The interaction and trade-off between consumer comfort and DSR maximisation for the grid.

## Public Sector Equalities Duty

We assess that the proposed policy will not – at this stage – have any equalities impacts, given the delegated nature of the powers the Secretary of State is seeking. The powers sought will allow the Secretary of State to mandate smart heating in future but will not have any practical effect until that time. A further assessment of any equality impacts will be necessary at that point, on the basis of the specific requirements brought forward.

We have not monetised distributional impacts and aim to explore this further in subsequent impact assessments.

There is currently limited quantifiable evidence on attitudes and behaviours relating to the use of smart electric heating for flexibility, as the market for these devices is still nascent. Therefore, limited evidence exists exploring the differences in consumer group preferences or data on protected characteristics.

Mandating smart functionalities for electric heating appliances will mean that those least able to pay, or those in private rented accommodation are able to access the potential benefits of smart electric heating.

However, whilst the proposed measure will require electric heating appliances to have smart functionality, whether they are used in a smart way in practice - and therefore the household benefits from potential reductions in running costs - depends on whether the household chooses/is able to participate in flexibility.

There is a risk that some consumers may be unable to realise the benefits of smarter heating or that a lack of flexibility potential may manifest in relatively higher bills for certain households. In addition, certain lifestyles or consumer needs may limit the potential to be flexible with heating demand which need to be considered.

## Monitoring and Evaluation

At the stage of implementation, a monitoring and evaluation plan will be implemented to demonstrate the impact and outcomes of the proposed regulations. A thorough evaluation plan will be developed in advance of the implementation of the regulations and will be integral into the delivery of the policy. It is expected that the evaluation will seek to answer questions such as:

- To what extent has the regulation achieved its aims?
- How has the design of the regulation influenced the impacts that were achieved?
- To what extent has the regulation been complied by the sector?
- What is the consumer experience? Does it differ across region/by rurality?

More information on our monitoring and evaluation strategy will be provided in the secondary stage impact assessment. This will include proposed timelines for monitoring activities where appropriate and evaluation.

### Competition impact test

The policy is expected to promote competition in the sales of smart enabled models.
Further consideration of competition impacts will need to be undertaken at the secondary legislation stage, subject to the full details of the proposed legislation.

### Greenhouse gases impact test

This has not been quantified. Contributing to a more flexible electricity network is expected to reduce greenhouse gases emissions enabling variable renewable generation to replace fossil fuel sources.

### Health and wellbeing impact test

There will be indirect air quality benefits associated with reduction in fossil fuel generation at the grid level.

### Human rights impact test

Not applicable.

### Local impacts

Potential local disparities will be analysed at the secondary legislation stage.

### Rural proofing impact test

Average broadband speeds in rural areas tend to be slower than those in urban areas. This is because there is less superfast broadband and rural premises are typically further away from cabinets with longer line connections which can slow performance. Additionally, rural areas have lower coverage from 4G and 5G coverage. The smart functionality in heat requires internet connection via broadband or mobile data. Reduced broadband and network coverage could act as a disincentive for consumers in rural areas to purchase or they might experience diminished performance of their smart heating. The disparity in broadband and network across UK regions is being addressed by policies such as the Shared Rural Network programme and the Gigabit project. The uptake and consumer experience across regions can be included in the monitoring and evaluation framework for the regulations

| | |
|---|---|
| **Title:** Heat Network Zoning Primary-Stage IA<br>**IA No:** BEIS006(F)-22-CH<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy and Industrial Strategy<br>**Other departments or agencies:** None | Impact Assessment (IA)<br>**Date: 06/07/2022**<br>**Stage:** Final - Primary Legislation<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** heatnetworks@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** Qualifying provision |
| £0m | £0m | £0m | |

**What is the problem under consideration? Why is government action or intervention necessary?**

To deliver Net Zero and future carbon budgets, virtually all heat will need to be decarbonised and heat networks are a crucial aspect of the critical path towards achieving heat decarbonisation in the UK. Government intervention is necessary to overcome the key market failures and barriers (higher costs, investor risk aversion and co-ordination failure) that prevent low-carbon heat networks from competing against well-established high carbon heat generation alternatives (e.g. gas boilers and gas combined heat and power). Heat network zoning will overcome these market failures and barriers and put the sector on track to deliver a significant proportion of the UK's heating by 2050. The proposals apply to England only.

In the main body of this impact assessment, we describe the impacts of implementing primary and secondary legislation for the Heat Network Zoning policy. Since this impact assessment accompanies request for powers at the primary legislation stage only, which will have no material impact on their own, the summary pages reflect zero social impact and impact on business.

**What are the policy objectives of the action or intervention and the intended effects?**

The consultation describes the key objectives of heat network zoning, which are to overcome the market failures and barriers which are inhibiting market growth. The policy will deliver heat networks where they are the most cost-effective solution to decarbonise heat. The SMART objectives of the policy are to:

- Deliver the **lowest cost, low carbon heat** to consumers within zones (Measured by p/ kWh heat)
- **Increase in the deployment of low carbon heat networks** (Measured by TWh/ yr)
- **Decrease carbon emissions** from domestic and non-domestic buildings (Measured by MTCO2e abated)
- Utilise a greater amount of **waste heat within heat networks** (Measured by TWh/ yr)

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

The quantified policy options appraised in this impact assessment are defined by the types of buildings that would be required, through regulation, to connect to heat networks within heat network zones. The options are the following:

- **Option 1, low option:** all new builds and large public sector buildings are required to connect to heat networks
- **Option 2, medium option:** all new builds, large non-domestic, and large public sector buildings are required to connect to heat networks
- **Option 3, high (preferred) option:** all new builds, large non-domestic, large public sector and communally heated residential blocks would be required to connect to heat networks.

The 'high' policy option is the preferred option due to it achieving the greatest carbon savings at a lower cost per tonne of $CO_2$, compared to the other options. It also presents the greatest opportunity to maximise non-monetised benefits such as electricity systems benefits, supply chain development and cost reductions, and Jobs and GVA. The 'high' policy option also provides the most buildings with the opportunity to decarbonise heating at the lowest cost, since zones will be defined as areas where heat networks offer the lowest cost solution to decarbonisation of heat.

Further options were explored at long list stage but haven't been considered in the quantitative short list options appraisal.

| | |
|---|---|
| Is this measure likely to impact on international trade and investment? | No |

| Are any of these organisations in scope? | **Micro**<br>No | **Small**<br>No | **Medium**<br>Yes | **Large**<br>Yes |
|---|---|---|---|---|
| What is the $CO_2$ equivalent change in greenhouse gas emissions?<br>(Million tonnes $CO_2$ equivalent over **5th and 6th carbon budget periods**) | | **Traded:**<br>0 | | **Non-traded:**<br>0 |

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:** N/A

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

# Summary: Analysis & Evidence

Policy Option 1

**Description:** Low Policy Option

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 40 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** £0m |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant | Total Cost (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | £0m | **£0m** |

**Description and scale of key monetised costs by 'main affected groups'**

Costs associated with primary legislation alone are assumed to be negligible; however, the monetised costs associated with implementing both primary and secondary legislation are:

- Upfront capital costs of deploying heat networks, relating to the necessary generation and distribution infrastructure. Dependant on type of low carbon technology deployed and the local geography.
- Cost to local and national government in designating heat network zones and implementing policy.
- Cost to business of adhering to policy.

**Other key non-monetised costs by 'main affected groups'**

Certain costs to business have not been quantified at this stage as it hasn't been considered proportionate to do so. These costs are disruption costs associated with significant deployment of heat networks and access costs for the owners of heat sources who will be required to supply a heat network with their waste heat.

| BENEFITS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant | Total Benefit (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | N/A | | £0m | **£0m** |

**Description and scale of key monetised benefits by 'main affected groups'**

Benefits associated with primary legislation alone are assumed to be negligible; however, the monetised benefits associated with implementing both primary and secondary legislation are:

- Net energy savings – low carbon heat networks are more efficient than the counterfactual.
- Carbon savings – reduction in non-traded emissions and small increase in traded sector.
- Air quality savings – improvement in air quality
- Operating cost - reduction in operation and maintenance costs

**Other key non-monetised benefits by 'main affected groups'**

Whole electricity system impact - large scale heat networks could contribute to a smart and flexible electricity system with potential savings of up to £10bn per year by 2050[1].
Supply chain development – provides regulation and strong signal to market.
Jobs and GVA impacts – UK jobs in design, construction, and operation of heat networks. Wider economic benefits e.g. energy savings and developing operations of Energy Service Companies.

| Key assumptions/sensitivities/risks (%) | Discount rate | 3.5% |
|---|---|---|

Details presented in assumptions tables – number of towns/cities, 'infill' of non-target buildings, policy option impacts on existing buildings and new builds, scaling of analysis to national level. Mix of heat network generation technologies, estimates of cost per town/city, cost of feasibility studies, procurement costs, number of zoning coordinators, time require per HN developer/operator for familiarisation with proposals, % of exempt buildings, time required for providing information.

**BUSINESS ASSESSMENT (Option 1)**

| Direct impact on business (Equivalent Annual) £m | | | Score for Business Impact Target (qualifying |
|---|---|---|---|
| **Costs:** £0m | **Benefits:** | **Net:** £0m | £0m |

## Summary: Analysis & Evidence    Policy Option 2

**Description:** Medium Policy Option

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Years** 40 | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** £0m |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | N/A | | £0m | **£0m** |

**Description and scale of key monetised costs by 'main affected groups'**

Costs associated with primary legislation alone are assumed to be negligible; however, the monetised costs associated with implementing both primary and secondary legislation are:

- Upfront capital costs of deploying heat networks, relating to the necessary generation and distribution infrastructure. Dependant on type of low carbon technology deployed and the local geography.
- Cost to local and national government in designating heat network zones and implementing policy.
- Cost to business of adhering to policy.

**Other key non-monetised costs by 'main affected groups'**

Certain costs to business have not been quantified at this stage as it hasn't been considered proportionate to do so. These costs are disruption costs associated with significant deployment of heat networks and access costs for the owners of heat sources who will be required to supply a heat network with their waste heat.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | £0m | **£0m** |

**Description and scale of key monetised benefits by 'main affected groups'**

Benefits associated with primary legislation alone are assumed to be negligible; however, the monetised benefits associated with implementing both primary and secondary legislation are:

- Net energy savings – low carbon heat networks are more efficient than the counterfactual.
- Carbon savings – reduction in non-traded emissions and small increase in traded sector.
- Air quality savings – improvement in air quality
- Operating cost - reduction in operation and maintenance costs

**Other key non-monetised benefits by 'main affected groups'**

Whole electricity system impact - large scale heat networks could contribute to a smart and flexible electricity system with potential savings of up to £10bn per year by 2050[1].
Supply chain development – provides regulation and strong signal to market.
Jobs and GVA impacts – UK jobs in design, construction, and operation of heat networks. Wider economic benefits e.g. energy savings and developing operations of Energy Service Companies.

| **Key assumptions/sensitivities/risks (%)** | **Discount rate** | 3.5% |
|---|---|---|

Details presented in assumptions tables – number of towns/cities, 'infill' of non-target buildings, policy option impacts on existing buildings and new builds, scaling of analysis to national level. Mix of heat network generation technologies, estimates of cost per town/city, cost of feasibility studies, procurement costs, number of zoning coordinators, time require per HN developer/operator for familiarisation with proposals, % of exempt buildings, time required for providing information.

**BUSINESS ASSESSMENT (Option 2)**

| **Direct impact on business (Equivalent Annual) £m** | | | **Score for Business Impact Target (qualifying provisions only)** |
|---|---|---|---|
| **Costs:** £0m | **Benefits:** | **Net:** £0m | £0m |

# Summary: Analysis & Evidence

Policy Option 3

**Description:** High Policy Option

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Years** 40 | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** £0m |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | N/A | | £0m | **£0m** |

**Description and scale of key monetised costs by 'main affected groups'**

Costs associated with primary legislation alone are assumed to be negligible; however, the monetised costs associated with implementing both primary and secondary legislation are:

- Upfront capital costs of deploying heat networks, relating to the necessary generation and distribution infrastructure. Dependant on type of low carbon technology deployed and the local geography.
- Cost to local and national government in designating heat network zones and implementing policy.
- Cost to business of adhering to policy.

**Other key non-monetised costs by 'main affected groups'**

Certain costs to business have not been quantified at this stage as it hasn't been considered proportionate to do so. Examples of these costs are disruption costs associated with deployment of heat networks and access costs for the owners of heat sources who may be required to supply a heat network with their waste heat.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | N/A | | £0m | **£0m** |

**Description and scale of key monetised benefits by 'main affected groups'**

Benefits associated with primary legislation alone are assumed to be negligible; however, the monetised benefits associated with implementing both primary and secondary legislation are:

- Net energy savings – low carbon heat networks are more efficient than the counterfactual.
- Carbon savings – reduction in non-traded emissions and small increase in traded sector.
- Air quality savings – improvement in air quality.
- Operating cost - reduction in operation and maintenance costs.

**Other key non-monetised benefits by 'main affected groups'**

Whole electricity system impact - large scale heat networks could contribute to a smart and flexible electricity system with potential savings of up to £10bn per year by 2050[1].

Supply chain development – provides regulation and strong signal to market.

Jobs and GVA impacts – UK jobs in design, construction, and operation of heat networks. Wider economic benefits e.g. energy savings and developing operations of Energy Service Companies.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | 3.5% |
|---|---|---|

Details presented in assumptions tables – number of towns/cities where heat network zones are designated, the number of buildings which choose to connect to zones but are not required to connect, policy option impacts on existing buildings and new builds, scaling of analysis to national level. Mix of heat network generation technologies, cost of implementing the zoning policy, number of zoning coordinators, time required per HN developer/operator for familiarisation with proposals, % of exempt buildings, time required for providing information.

**BUSINESS ASSESSMENT (Option 3)**

[1] Transitioning to a net zero energy system: smart systems and flexibility plan 2021, link: https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

<table>
<tr><td colspan="3">Direct impact on business (Equivalent Annual) £m</td><td rowspan="2">Score for Business Impact Target (qualifying provisions only)</td></tr>
<tr><td rowspan="2">Costs: £0m</td><td rowspan="2">Benefits:</td><td rowspan="2">Net: £0m</td></tr>
<tr><td>£0m</td></tr>
</table>

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# Evidence Base

## Introduction and Background

1. Meeting our net-zero target will require virtually all heat in buildings to be decarbonised, and heat in industry to be reduced to close to zero carbon emissions. There is demand for low-carbon heating solutions in the marketplace as more local authorities declare climate emergencies and an increasing number of consumers become aware of their carbon impact.

2. Decarbonising heat is a challenging undertaking that has no single solution and will require a combination of leading-edge technologies and increased customer options to make it happen. However, heat networks will be vital to making net zero a reality. They are a proven, cost-effective way of providing reliable, low carbon heat at a fair price to consumers, while supporting local regeneration.

3. Heat networks can benefit from economies of scale and are able to decarbonise a large number of consumers and therefore a large amount of overall heat demand. The carbon saving potential of a heat network is further increased when technologies which enable the use of low-carbon sources such as heat from energy from waste, or heat recovered from industry or environmental sources such as ground and river source heat are used. Furthermore, with thermal storage they can provide demand flexibility to the energy system which is essential in the transition to a net-zero world.

4. This impact assessment supports the passage of primary legislation measures related to heat network zoning. Our proposals for heat network zoning in England will see heat networks deployed in areas where they are the lowest cost, low carbon heating solution[2]. The policy will enable the growth of the heat networks sector, allowing it to play an important role in decarbonising the UK's buildings to achieve net zero carbon emissions by 2050. The CCC estimate that heat networks could provide 18% of UK heat demand by 2050[3]. Similarly, BEIS' recent *Opportunity Areas for District Heating Networks in the UK[4],* study indicates that a significant portion of the UK's heating could be met by heat networks.

## Rationale for Intervention

5. The heat networks market is characterised by a series of interlinked market failures and barriers, which will be addressed by heat network zoning. These market failures and barriers are preventing the sector from growing without government support. Growth is required to put the sector on the pathway to achieving the deployment levels indicated in the CCC's analysis. The policy will directly tackle some of the barriers, whilst it will have an indirect effect on others. The market failures addressed by the policy are listed below.

   a. **Externalities.** There are uncaptured negative externalities associated with the use of conventional, gas-fired, heating technologies. The full societal costs of heating based on fossil fuel combustion should consider the emission of greenhouse gases, leading to climate change and the impacts on health (related to the air

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[2] More information on the proposals for Heat Network Zoning can be found here: https://www.gov.uk/government/consultations/proposals-for-heat-network-zoning

[3] "Research on district heating and local approaches to heat decarbonisation" Element Energy for the CCC, http://www.element-energy.co.uk/2015/12/element-energy-research-on-district-heating-for-the-ccc-published-alongside-5th-carbon-budget-report/

[4] *Opportunity Areas for District Heating Networks in the UK* is a report produced by BEIS in response to the EU Energy Efficiency Directive requirement to conduct a National Comprehensive Assessment for Efficient Heating and Cooling in the UK, https://www.gov.uk/government/publications/opportunity-areas-for-district-heating-networks-in-the-uk-second-national-comprehensive-assessment

quality impacts). Likewise, the relative positive effect of low-carbon heating on air quality and emissions, and thus the lower societal cost, is not captured in its price. This is likely to result in under-investment in low-carbon heating. The benefits of adopting low carbon heating technologies grow as deployment increases, through a positive feedback effect between scale of market, learning, innovation, and cost reduction. This is not factored in individual decision or the private price of low carbon technologies. Zoning will remove the cheaper, higher carbon counterfactual, and direct investment into the heat networks market.

b. **Connection uncertainty** – heat networks currently are characterised by high upfront capital costs and long payback periods, which can deter investors. The risk of heat loads not connecting to networks can create uncertainty which hampers investment. Due to this perceived risk, projects need to require high internal rates of return to attract investors, even if they are economically viable. Zoning provides project sponsors and investors with connection assurance, as key loads will be required to connect to heat networks, as long as it is cost effective (and practical) for them to do so.

c. **Coordination failure -** Developing heat network projects requires coordination between the heat network developer and multiple parties, which can be challenging. As heat networks require a certain amount of heat demand to be viable, difficulties co-ordinating across parties often mean a heat network is scaled back or not deployed even if it would have been the most cost-effective option. Coordination failures can also slow down heat network project development for those that do go ahead. Zoning tackles this market failure by taking a central, strategic approach to heat decarbonisation and giving government the power to designate where zones are, and which buildings must connect.

6. The market failures B and C outlined above are best tackled by a regulatory intervention such as heat network zoning. Indeed, there are several examples of other countries with thriving heat networks markets, who implemented heat network zoning policies, for example Denmark who implemented a zoning policy in the 1970s. The most effective means of tackling negative externalities is through a price of carbon.

7. Throughout the policy development work, regular engagement was carried out with other countries and jurisdictions who have already implemented heat network zoning to assist the growth of the market. More detail is provided on the zoning experiences of other countries in the accompanying consultation document.

## Description of options considered

### Long-list and MCA

8. A long list was developed and agreed with stakeholders. This was split into three categories: Compulsion, Incentivisation and Structural. A ‘Do nothing’ option was not considered as viable for meeting policy objectives but has been used to benchmark long list options. Options have been considered independently using a Multi Criteria Analysis (MCA), noting that some of the options may be developed in conjunction with one another. The long list included non-regulatory means of achieving the policy objectives.

9. Compulsion options (i.e. zoning) describe an area, designated by local government, within which heat networks are the lowest cost, low carbon solution for decarbonising heating. Within these zones some types of building must connect to their local heat network in a given timeframe:

a. **Light touch** – building assessed for connection

   All buildings required to assess whether they should connect to a heat network.

b. **Low** – key anchor loads

   Key anchor loads are encouraged to connect. These are buildings with significant heat demands, which can be one of the first connected demands on a heat network. Other types of buildings may also be required to connect, e.g. new builds and large public sector non-domestic buildings.

c. **High** – all suitable buildings mandated

   All suitable buildings required to connect to HN.

Incentivisation options:

d. **Central government financial support**

   Financial support or incentivisation coming from central government. E.g. targeted grant support or revenue support to heat network projects, or a connection fund to subsidise costs of buildings connecting to heat networks.

e. **Awareness campaigns**

   Raising awareness in local communities about low carbon heating and the benefits of heat networks to generate demand.

Structural options:

f. **Remove distortions between price of gas and electricity**

g. **Business rates exemptions**

   District heating schemes exempt from paying business rates.

Do nothing option (counterfactual):

h. **Do nothing**

   Do not tackle barriers and market failures for heat networks.

10. Workshops were held to identify a number of ‘Critical Success Factors’ covering the following areas:

a. Achieving Policy Objectives (tackle market failures)

b. Novelty of policy proposals

c. Deliverability

d. Value for Money

Each group of success factors was given an overall weighting based on their relative importance, which was agreed by the stakeholder group in a workshop. Achieving Policy Objectives was deemed to be the most important due to the key barriers the policy is trying to overcome sitting in this category, therefore was given the highest weighting of 50%. A detailed description of the MCA methodology can be found in Annex 3 – Multi Criteria Analysis Methodology.

11. The results of the MCA are shown in Table 1 below. Removing distortions between the price of gas and electricity was removed from the process as this issue is being considered in other areas of government.

*Table 1 - MCA results*

| Critical Success Factors | Weighting | Score for each option | | | | | |
|---|---|---|---|---|---|---|---|
| | | Mandatory (compulsion) | | | Incentivisation | | |
| | | Light touch - buildings assess connection | Low - key anchor loads | High - all suitable buildings mandated | Central govt financial support | Generating Consumer Demand | Business rates exemptions |
| | | a | b | c | d | e | g |
| Achieve Policy Objectives | 50 | 1.5 | 2.9 | 4.4 | 2.9 | 2.5 | 2.4 |
| Novelty of policy proposals | 10 | 3.8 | 3.3 | 2.5 | 3.0 | 4.3 | 2.5 |
| Deliverabilit y | 25 | 2.0 | 4.0 | 2.0 | 4.0 | 3.3 | 3.3 |
| Value for money | 15 | 4.3 | 3.8 | 2.5 | 2.5 | 4.0 | 3.0 |
| | | 2.3 | 3.3 | 3.3 | 3.1 | 3.1 | 2.7 |

12. The results of the MCA exercise we carried out show that the mandatory and incentivisation options came out with the highest scores. The mandatory connection options scored slightly higher. An interpretation of the scores being very close together is that all three are necessary in order to overcome the series of interlinked barriers and market failures that exist in the heat networks market. This is also reflected in the theory of change that has been developed for the policy.

13. Mandating connections to heat networks is the only means of overcoming the connection uncertainty and coordination failure barriers set out above. This is reflected in the 'policy objective' scores in the table above. Only a regulatory intervention can tackle these barriers, as has been seen in other countries such as Denmark or Sweden. Zoning overcomes connection risk by ensuring a level of connection to the heat network. The coordination failure is addressed by the policy also requiring coordination beteen the various parties to determine the optimal outcome for the heat network. Through overcoming these market failures, a

zoning policy will de-risk investment in low carbon heat networks. This may reduce the costs of accessing finance to invest in heat networks and encourage private sector investment into the sector.

14. Government capital support alone, without regulation, would be poorly targeted at the underlying coordination failure that exists in the heat network sector, as it would not address it directly. Subsidy support alone could result in deadweight, which would be an inefficient use of government funding.

15. In tandem with a zoning policy, there will likely be be a role for continuing to subsidise the deployment of heat networks, whilst the social impact of the investments on reducing carbon and improving air quality aren't reflected in the prices that the heat network charges for providing low carbon heating. As gas and electricity prices evolve over time, and as the cost of raising capital changes, the role for government subsidy support is expected to reduce over time.

16. As such, a non-regulatory option alone is not anticipated to achieve the intended policy objectives of heat network zoning, and hasn't been included as an option in the short list options appraisal in this IA.

### Short Listed Options

17. The two preferred compulsion options, low and high, were further defined and developed into a short list of policy options, with the addition of a medium option to explore a wider range of buildings required to connect to a heat network. These three options have been taken forward for appraisal.

18. The short list of options are defined by different classes of buildings that would be mandated to connect to heat networks.

The 'high' policy option is the preferred option, as presented in a recent consultation[5], due to it achieving the greatest carbon savings at the lowest cost per tonne of $CO_2$, as well as being expected to have the highest non-monetised benefits including electricity system benefits, supply chain development, and jobs and GVA. In addition, the 'high' policy option presents the opportunity to decarbonise heat, at lowest cost, to the greatest number of buildings; under the 'medium' or 'low' policy options more buildings would need to decarbonise heating through other means, which would be more expensive since heat networks are defined as the least cost low carbon heating solution in zones.

An SNPV will be presented for each of the regulatory policy options. The options are as follows:

a. **Low (option 1)**: all new build and large public sector buildings are required to connect to heat networks, all other buildings encouraged to connect.

b. **Medium (option 2)**: all new build, large public sector and large non-domestic buildings required to connect to heat networks, all other buildings encouraged to connect.

c. **High (option 3, preferred):** all new build, large public sector, large non-domestic and communally heated residential blocks required to connect to heat networks, all other buildings encouraged to connect.

19. At this point it isn't clear whether a very high option, which would mandate a larger group of buildings, would necessarily increase overall deployment of heat networks in zones. This is

[5] Proposals for heat network zoning, https://www.gov.uk/government/consultations/proposals-for-heat-network-zoning

because we assume some buildings would connect voluntarily. However, a very high option may make the deployment more deliverable. A very high option could increase overall costs of the zoning policy, for example through an increased number of exemptions, which needs to be balanced against the wider benefits of the policy. A very high option could also limit consumer choice, which is an important trade off. The policy will continue to develop through engagement with stakeholders and a second consultation before determining the correct buildings to mandate in secondary legislation.

20. The scope of each of the policy options is England only. The measures within the Energy Bill are enabling measures only, which set out the broad powers that government will secure to implement heat network zoning. The detail of the legislation will be defined in secondary legislation. For example, the primary legislation will give government the power to mandate that certain buildings connect to heat networks, without defining the buildings. The specific requirements regarding the types of buildings mandated to connect will be defined in secondary legislation. The policy is expected to come into force between 2023 & 2024.

### Counterfactual

21. The counterfactual represents a 'do nothing' scenario, where the heat network zoning policy is not introduced in any form.

22. For the purposes of the cost benefit analysis two separate counterfactuals have been considered. The quantified analysis has been carried out using a gas counterfactual, and a qualitative assessment carried out against a low carbon 'building level electrification' counterfactual.

23. The gas counterfactual is intended to represent a 'do nothing' scenario where buildings continue to use gas as the main heating fuel, based on existing levels. The low carbon counterfactual also represents a 'do nothing' scenario, in relation to zoning, and presents a discussion on the impact of decarbonising the same stock of buildings with low carbon technologies (i.e. individual heat pumps for buildings).

24. The policy options are compared against a 'do nothing' scenario as the counterfactual in the quantified analysis. The gas counterfactual is used as the default counterfactual in this impact assessment. Discussion on the comparison with a low carbon counterfactual can be found from paragraph 111.

25. Currently 97% of heating is provided by individual heating systems, and the remainder by heat networks. This split of heating is assumed to continue in the counterfactual.

## Policy objective

26. There are multiple policy objectives of heat network zoning. The primary policy objective of heat network zoning is to deliver the lowest cost, low carbon heat to consumers.

27. In achieving the above objective, there are further policy objectives against which the success of the policy can be evaluated. Achieving the below objectives alone wouldn't be sufficient to ensure that heat networks deployed in zones would deliver the lowest cost, low carbon heat:

a. An increase in the deployment of low carbon heat networks
b. Carbon savings relative to a gas counterfactual
c. Increased utilisation of waste heat sources in heat networks
d. Heat networks contribute to lowest power system cost

28. A Theory of Change was developed over a series of workshops to identify key routes to delivering policy objectives and to help identify SMART objectives. A simplified output from the workshops is shown in <u>Annex 4 – Theory of Change.</u>

29. As the policy is at primary legislation-stage, there is a degree of uncertainty behind the target of the SMART objectives. However, it is possible to describe how the policy objectives would be measured and, the timeframe that they would be measured over. Targets will be provided for the policy objectives in the final-stage IA.

| Policy Objective | Metric | Timeframe |
|---|---|---|
| Increase in the deployment of low carbon heat networks | (Low carbon ) TWh/ yr | 2025 - 2050 |
| Reduction in carbon emissions | MTC02e Abated | 2025 - 2050 |
| Increased utilisation of waste heat sources in heat networks | TWh/ yr | 2025 - 2050 |
| Heat networks contribute to lowest system cost | p/kWh | 2025 - 2050 |

## Monetised costs and benefits of each option (including administrative burden)

30. There are multiple monetised costs and benefits in the quantitative analysis, the methodology for calculating them is presented in the following section and the results are presented further down the IA.

31. **Monetised costs:**

- **Upfront capital costs** of deploying heat networks relative to the counterfactual. It is anticipated that there will be a significant deployment of low carbon heat networks due to the policy. This cost relates to the capital cost of the necessary generation and distribution infrastructure for this deployment. This cost is compared to the capital cost of heating buildings in the counterfactual, with building level heating systems. The capital cost of the generation depends on the type of low carbon heat network being deployed, for example whether the heat source is an air source heat pump or energy from waste. Heat networks are variable, and the capital cost depends on the features of the local geography. It has been necessary to generalise the capital costs for the purpose of the present IA.
- **Operating costs** of heat networks deployed in zones relative to the counterfactual. This cost covers the operation and maintenance of both the heat generation source and the distribution infrastructure for the heat network, against the counterfactual. The operating cost doesn’t include fuel costs.
- **Cost to government** of implementing the policy. Implementing a heat network zoning policy will require an increase in resource at different levels of government. It is expected that there will be a role for national and local government in identifying and designating where heat network zones are, and in consulting on proposals with local stakeholders. There will also be a cost to government in enforcing the regulations.
- **Costs to business (heat network developers/ operators/ building owners)** of adhering to the policy. The policy would impose an additional burden on heat network developers and heat network operators in the form of familiarisation costs, plus there will be further policy costs described later in the IA.

32. **Monetised benefits:**

- **Net energy savings** – Low carbon heat networks – which would be largely heat pump led - are more efficient in producing heat than the counterfactual. As a result, less energy demand is created. This is a benefit to society and is valued using the long-run variable cost of energy supply[6].

- **Carbon savings** – The replacement of fossil fuel will lead to a reduction in carbon emissions in the non-traded sector and to a small increase in the traded sector due to an increase in electricity use. These are monetised in accordance with appraisal values in HMT Green Book supplementary guidance.
- **Air quality benefits** –The replacement of fossil fuel will lead to improvement in air quality. These are monetised in accordance with appraisal values in HMT Green Book supplementary guidance.

### Rationale and evidence to justify the level of analysis used in the IA

33. This IA supports primary-legislation powers for heat network zoning, which will have no impact without the details being defined through secondary. Since the details of the secondary legislation for heat network zoning are still uncertain, the costs and benefits set out within this IA should be viewed as illustrative of the impacts of the policy.

34. There will be a subsequent consultation on certain aspects of the policy before the details are defined in secondary legislation. The format of future consultation is currently being scoped. Additionally, a zoning pilot is being carried out in 2022. Through the evidence gained from running the pilot we will be able to refine our analysis for heat network zoning significantly ahead of the secondary legislation.

35. The impacts set out in this IA are uncertain due to the current stage of policy development. To manage the uncertainty, extensive sensitivity analysis has been carried out on key factors which influence the costs and benefits. This will show the impact of some of the uncertainty in the analysis. Throughout the process for developing the subsequent consultation, we will continue to refine the evidence base regarding the impacts of this policy.

## Methodology for Analysis and Key Assumptions

### Overview

36. As mentioned above, the primary-legislation measures being sought in the Energy Bill will have zero impact alone. This IA presents an illustration of the potential impacts of the current policy proposals for heat network zoning, which will be defined in secondary legislation in due course. The details of the secondary is subject to change.

37. The IA presents the impact of the heat network zoning policy proposals on society, business and households. The cost benefit analysis used to calculate the social net present value (SNPV) for each of the policy options has four distinct components:

   a. An estimate of the **deployment of heat networks in zones under the different policy options.**
   b. An estimate of the **type and proportional breakdown of heating generation technologies** serving heat networks, under factual and counterfactual scenarios.
   c. The **cost to government** (central and local) of implementing the policy.

[6] Green Book supplementary guidance: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

d. Cost to heat network developers, operators and building owners. These costs constitute the **cost to business.**

38. We have not quantified the impacts on final consumers on heat networks as part of the SNPV. The policy defines that heat networks are deployed where they offer the most cost-effective means of providing low carbon heat to buildings. Consideration of the impacts to final customers has been discussed in paragraph 135 and the Wider Impacts**Error! Reference source not found.** section.

39. We will describe these sections separately in terms of methodology and assumptions.

40. The cost benefit analysis is carried out over a 40-year appraisal period. This reflects the lifetime of the distribution infrastructure which is the longest-lived asset deployed due to the policy. Given that the appraisal period goes beyond 2050, and the quantified counterfactual is high carbon, we do **not count** carbon savings or air quality benefits beyond 2050, as we assume we meet the 2050 net zero target.

41. Two counterfactuals have been presented in the IA, one of which is quantified and the other discussed qualitatively. The analysis is quantified against a ‘do nothing’ counterfactual where fossil fuel-based heating systems continue to be the dominant heating choice. The other counterfactual is an alternative electrification low-carbon heating scenario which reflects that Net Zero is a legislative commitment, and where heat networks weren’t deployed there would likely be building level electric heating systems (i.e. individual air source heat pumps).

42. For the quantified analysis, the policy impacts are compared against a counterfactual scenario and are then monetised using standard Green Book appraisal values. Social net present values (SNPVs) for the policy options are then derived by comparing the aggregate costs and benefits which are discounted by the social discount rate. Equivalent Annual Net Direct Cost to Business is also calculated for the business sector. Assumptions are varied to produce sensitivity analysis to show the sensitivity of SNPV with respect to changes in the assumptions used.

43. Additionally, there are a series of wider non-monetised impacts of the policy which are discussed qualitatively in relation to the different policy options. It hasn’t been possible to quantify all of the impacts of the policy, either due to the nascency of the policy development or due to evidence gaps, and therefore some of the impacts have been assessed qualitatively.

44. Within our estimates of the impact of the policy options we have assumed a level of optimism bias on the capital costs of developing heat networks. Optimism bias reflects the systematic tendency for policy makers to underestimate the costs of infrastructure projects. The evidence base we have used reflects case study information of planned versus actual costs of environmental infrastructure projects. Following this evidence base, an increase of 21% has been applied to capital costs and operating costs to account for optimism bias[7].

45. The cost benefit analysis for the IA considers the net social impact of **only new heat networks** deployed in zones. We have removed the stock of existing heat networks, and the deployment due to planned policies – the Heat Networks Investment Project and the Green

[7] Select Committee on Environmental Audit, - https://publications.parliament.uk/pa/cm200607/cmselect/cmenvaud/1110/111004.htm

Heat Network Fund – from the scope of the analysis, to avoid double counting. This is described in more detail from paragraph 48.

46. Within our estimates of the impact of the policy options we have assumed that 90% of the benefits of heat network zoning are additional. Given the market failures, low carbon heat networks are unlikely to be deployed without government support. Therefore, we assume that most of the deployment is additional to the policy. As described in the deployment methodology section, the cost benefit analysis only considers new heat networks in zones. Networks deployed through other heat network policies are not in scope of the analysis.

47. To help navigate the four sections of the analytical methodology, the following table has been repeated through this chapter to signal which section of the analytical methodology is being discussed.

| **Analytical Methodology Section Description** |
|---|
| Deployment - Methodology and key assumptions for estimating deployment of heat networks in zones |
| Technology Mix – methodology and key assumptions |
| Cost to Government – methodology and key assumptions |
| Cost to Business - methodology and key assumptions |

## Methodology - Estimating deployment of heat networks in zones under the different policy options

| **Methodology Section Description** |
|---|
| Deployment - Methodology and key assumptions for estimating deployment of heat networks in zones |
| Technology Mix – methodology and key assumptions |
| Cost to Government – methodology and key assumptions |
| Cost to Business - methodology and key assumptions |

### Definition of deployment

48. The deployment of heat networks is the total heat delivered by heat networks under the different policy options. The heat delivered is a function of the following:

a. the number of buildings connected to a heat network in a zone, and
b. the heat demand of those buildings.

49. To reflect the policy options through our analysis we have defined ‘large’ buildings and communally heated residential blocks as being buildings of non-domestic, public sector or residential type with heat demand over 100MWh/yr; however, this threshold is open for feedback as part of the consultation. All key assumptions used in estimating deployment can be found in Table 3.

50. As well as target buildings connecting to heat networks in zones, non-target buildings will also be encouraged to connect to heat networks.

51. The method for estimating deployment looks at both the existing building stock and projections for domestic new builds which could connect to heat networks within zones. Separate approaches have been taken for each and are described below.

**Deployment of heat networks from existing building stock**

52. The approach for estimating deployment of heat networks within zones from existing building stock has been informed by recent experience from BEIS of investigating heat network opportunities as well as analysis from recent the City Decarbonisation Delivery Programme (CDDP)[8] which has tested an initial heat zoning approach across 5 cities and Greater Manchester spanning 15 Local Authority areas in England. The analysis from CDDP provides estimates of the number of buildings and heat demand that could be situated within a heat network zone, and the subset of buildings which could cost-effectively connect to a heat network.

53. We have used outputs from the six cities considered in the CDDP analysis and scaled to national level to estimate deployment. This assumes that zones would be designated in 200 of the largest towns and cities in England (by population, central case). We have used the Economic Potential[9] model, developed for the report *Opportunity Areas for District Heating Networks in the UK[4],* to extrapolate from CDDP metrics.

**Assessing impacts of policy options on heat networks from existing building stock**

54. The methodology used in the CDDP analysis assumes that all buildings that could cost-effectively connect to a heat network do connect to a network. Therefore, the deployment measured in the CDDP analysis includes buildings that are not targeted by the policy, which we have termed as 'infill' buildings. These infill buildings would be encouraged to connect under all policy options.

55. The buildings captured within the CDDP analysis have been segmented into groups of buildings targeted by the policy and non-target or 'infill' buildings based on the definition in paragraphs 14. Since the approach used in the CDDP analysis does not reflect the varying level of deployment through the policy options, we have adapted an approach to estimate deployment under each policy option by:

a. Assuming under the High policy option the full level of deployment from the CDDP analysis can be achieved.
b. Under the Medium policy option, where communally heated residential buildings are not in scope of the policy, we remove a proportion of deployment that is equivalent to the estimated heat demand and number of large residential buildings (from the full level of deployment from the CDDP analysis). We have used the Economic Potential model[7] to estimate reduction that is required from CDDP metrics.
c. Under the Low policy option, similarly to the Medium option, we remove the proportion of deployment equivalent to large residential and large non-domestic buildings (from the full level of deployment from the CDDP analysis).

[8] The Future Market Framework consultation in 2020 recognised the importance of zoning and committed us to trials and research. As part of these trials, we have looked at how the heating systems of six cities across England could be decarbonised and these trials have shown that heat network zoning has the potential to help local authorities meet net-zero commitments. These trials have been titled the 'City Decarbonisation Delivery Programme (CDDP)'.

[9] The Economic Potential model was developed to identify areas in the UK that could present economic viability to develop heat networks. This model was used to inform the report, *Opportunity Areas for District Heating Networks in the UK* (see footnote 4 for more information on the report).

56. For the Medium and Low policy options, we remove the proportions from the total deployment (including infill) to reflect both a reduction in the cohort of target buildings and non-target buildings. The reason for reducing non-target buildings is due to their dependency on larger target buildings to provide cost-effectiveness for connecting to a heat network. Table 2 presents the breakdown of target building by number and heat demand, which is used to approximate deployment under the policy options

*Table 2 - Breakdown of existing target buildings from Economic Potential[9] analysis used to approximate policy options*

| Target Building type | % Target Heat demand | % Target Buildings |
|---|---|---|
| Large non-domestic | 49% | 41% |
| Large public sector | 9% | 8% |
| Communally heated residential | 41% | 51% |

**Deployment of heat networks from domestic new builds**

57. New builds are included within the scope of all of the policy options. We assume that deployment of heat networks amongst new builds does not vary between the policy options.

58. The approach for estimating deployment of heat network in new builds has been to grow the number of existing buildings within zones, identified through the CDDP analysis, in line with ONS projections of national housing stock growth through to 2050, to estimate the number of new builds that would be built within zones in the period. We have then multiplied the estimate of number of new builds within zones by an average assumed heat demand per household of 4,984 kWh/yr[10], to estimate heat demand.

59. Whilst we include the deployment of new builds in our estimates for total deployment due to heat network zoning. We do not include the impact of the new build deployment in the SNPV for the policy. Due to the Future Homes Standard, new build homes would be low carbon in the counterfactual for this analysis.

**Adjusting deployment estimates for existing heat networks and impacts of other policies**

60. We need to take into account the buildings already connected to a district heat network in order to consider the additional deployment resulting from heat network zoning. We define the level of existing district heat networks and potential heat networks from other policies (e.g. the Green Heat Network Fund) as ‘the baseline’. We have estimated this baseline using estimates of heating supply from existing district heat networks in England presented in the *Experimental Statistics on Heat Networks, 2018*[11] and combining this with estimated deployment from the Heat Networks Investment Project (HNIP) and the Green Heat Network Fund (GHNF).

61. The scope for the overlap between the heat network zoning policy and ‘the baseline’ is dependent on the coverage of zones in England. The high policy option will form the largest

[10] This figure represents an average of heat demand for all domestic building types, weighted by projected number of net completions from 2025 to 2029, presented in The Future Homes Standard 2019 Consultation on changes to Part L (https://www.gov.uk/government/publications/the-future-homes-standard-consultation-impact-assessment). These figures are subject to change in-line with changes to the Future Homes Standard regulation.

[11] https://www.gov.uk/government/publications/energy-trends-march-2018-special-feature-article-experimental-statistics-on-heat-networks

zones, in terms of coverage, with the medium and low policy options resulting in smaller zones, and therefore would have a smaller overlap with 'the baseline'. For the high policy option, we assume there is a 100% overlap between heat network zoning deployment and the baseline, since we assume zones would encompass areas of existing heat networks or heat networks delivered through other policies. For the medium and low policy options we assume there would be less of an overlap with the baseline since fewer types of buildings are in scope of the policy options. We have used the breakdown presented in Table 2 to reduce the size of the overlap. For example, for the medium policy option, communally heated residential buildings are no longer in scope, therefore we only deduct 59% of the baseline from our deployment estimates for the medium policy option, to reflect a smaller overlap with existing heat networks and heat networks delivered through other policies.

### Key assumptions - Estimating deployment of heat networks in zones under the different policy options

*Table 3 – Central assumptions for estimating deployment of heat networks in zones*

| Assumption | Description and value | Evidence | Sensitivity analysis |
|---|---|---|---|
| Definition of 'large' target buildings | 'Large' target buildings and communally heated residential blocks to be defined as having more than 100MWh/yr of heat demand. | Judgement | Low impact on result due to 'infill assumption'. Not explored through sensitivity analysis |
| Number of towns and cities | Zones to be implemented in heat-dense areas where deployment will be cost-effective. Using HNDU feasibility studies we have assumed the top 200 towns and cities (by population) could have potential for zones. | HNDU feasibility studies | Explored in the sensitivity analysis in section for 100 and 300 towns and cities. |
| Scalability of CDDP metrics relative to the Economic Potential (EP) model | To estimate national deployment we combine case study insights from CDDP analysis (six cities), with the EP model (national level). The models are independent, and we expect the CDDP analysis is better suited to planning of heat networks.[12] The EP model is likely to overestimate deployment relative to the CDDP analysis, so we assume CDDP metrics scale at a rate of 80% of the areas the suitable for heat networks from the EP model. | Judgement | Explored in the sensitivity analysis in section for scaling at a rate of 60% and 100%. |
| 'Infill' assumption of non-target buildings | The CDDP model requires all buildings (both target and non-target) to connect to a heat network. In our central scenario we assume there will be 'infill' of non-target buildings to the levels seen through the CDDP analysis. The | Estimates from CDDP work[8] | Explored in the sensitivity analysis in section for inclusion and exclusion of infill. |

[12] The analysis carried out for CDDP is based on modelling software which has been developed to plan heat networks in local areas, it is very computationally heavy and considers many local factors when planning networks. The economic potential model is a national level model and therefore can't include the same level of detail in its calculations. The national level model may therefore predict deployment where a more local analysis wouldn't.

| | | | |
|---|---|---|---|
| | level of infill is uncertain and tested within the sensitivity analysis. | | |
| Policy option impacts on existing buildings | The decrease in deployment in the medium and low options is estimated using the decrease in the proportions of buildings no longer in scope of the policy. | Economic Potential model | Explored in the sensitivity analysis in section for detriment to cost-effectiveness of zones. |
| Policy option impacts on new builds | In all policy options we assume there is the same level of deployment from new builds since new builds are required to connect for each of the options. | Judgement | Not explored through sensitivity analysis |
| Average new build heat demand | Average heat demand in domestic new build from 2025 to 2050 is 4,984 kWh/yr[10] | MHCLG | Not explored through sensitivity analysis |
| Building stock growth rate | Building stock in zones increases on average by 14% between 2025 and 2050, in line with national growth. | ONS | Not explored through sensitivity analysis |
| Linear growth of deployment[13] | Deployment as a result of the policy will follow a linear profile, starting from zero and increasing to the maximum level of deployment, between 2025 and 2050. | Judgement | Not explored through sensitivity analysis |

**Methodology – Technology Mix**

| Methodology Section Description |
|---|
| Deployment - Methodology and key assumptions for estimating deployment of heat networks in zones |
| Technology Mix – methodology and key assumptions |
| Cost to Government – methodology and key assumptions |
| Cost to Business - methodology and key assumptions |

62. Carbon emissions are calculated by looking at the net change in fuel use by moving from gas-based heating systems in the counterfactual to low carbon, largely heat pump-led, heat networks deployed within heat network zones. The difference between emissions in both scenarios constitute the carbon savings.

63. Heat pumps are a currently available technology, which we have robust estimates of the costs of deploying. Therefore, our analysis is limited to the impact of deploying heat pump-led heat networks and reflective of an electrification decarbonisation pathway. This doesn't preclude the possibility of there being a hydrogen scenario, with hydrogen playing a role in low carbon heat networks and the counterfactual.

[13] A linear deployment profile has been assumed due to lack of information to predict a more realistic profile. The deployment profile might not be linear in reality, we will work on developing our evidence base on growth rates ahead of the final stage IA.

## Key Assumptions – Technology Mix

64. The mix of heat network generation technologies that deliver heat in heat network zones is another key assumption in the cost benefit analysis. According to the proposals set out in the zoning consultation, there will be a requirement for new heat networks in zones to be low carbon from the outset. This has informed the assumptions we have made regarding the generation technology mix. These assumptions influence the following components of the cost benefit analysis:

a. Carbon and air quality savings relative to the counterfactual
b. Capital and operating costs relative to the counterfactual
c. Net energy savings against the counterfactual

65. Our proposed central generation technology mix is derived in part from the recent *Opportunity Areas for District Heating Networks in the UK*[4] modelling project, which determined the availability of waste heat sources from industry which could be utilised in heat networks. This study proposed that 19% of heat network heat demand could be met with waste heat sources, including Energy from Waste, high temperature waste heat from industry, and waste heat sources that require a water source heat pump to raise the temperature. We assumed that the remainder of the heating was delivered via a mixture of air-, ground- and water-source heat pumps. There is also a role for gas as back-up boilers. The assumed split is described below:

*Table 4 – Central assumption for generation technologies supplying heat networks in zones*

| Technology | % Total Heat Generation |
|---|---|
| EfW | 9% |
| High Temp Waste Heat | 4% |
| Low Temp Waste Heat | 6% |
| ASHP | 14% |
| GSHP | 24% |
| WSHP | 34% |
| Back-up Boilers | 10% |

66. Given the uncertainty surrounding the generation technology mix assumption, we have included a sensitivity analysis where the utilisation of waste heat generation is doubled.

67. In the counterfactual, the buildings are assumed to be heated using the current mixture of heating technologies. This has been derived from the NEED, ND-NEED and ECUK datasets[14]. According to this evidence base, 97% of heating is delivered via individual heating systems, mainly gas boilers, and 3% is delivered via heat networks. This split is assumed to continue in the counterfactual for the analysis. The 3% of heat networks in the counterfactual is assumed to be delivered via gas CHP, energy from waste and water source heat pumps.

[14] Based on internal analysis using the NEED and ECUK datasets. Available at https://www.gov.uk/government/collections/national-energy-efficiency-data-need-framework and https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

*Table 5 – Counterfactual assumption for heating technologies, using current mixture of heating technologies*

| Technology | % Total Heat Generation |
|---|---|
| Gas Boiler Small | 69% |
| Gas Boiler Large | 17% |
| Electric Heater | 11% |
| DH Gas CHP | 1% |
| DH EfW | 1% |
| DH WSHP | 1% |

**Capital and Operating Costs**

68. A key component of the cost benefit analysis is the capital cost of deploying heat networks relative to the counterfactual. The capital costs of heat networks are broken down by the costs of heat generation, and the costs of the distribution infrastructure (the network). A significant proportion of the capital cost of deploying a heat network is due to the distribution infrastructure.

69. The capital and operating cost of generation assets are dependent on the assumed technology mix described above and the deployment. Each of the generation technologies has a unique cost. The same is true for the counterfactual heating technologies, which tend to have lower capital costs. The assumed capital and operating costs are broken down by technology in

70. Annexes

71.

72. Annex 1 – Detailed modelling assumptions, for the factual and counterfactual.

73. As a simplifying assumption, the capital costs of the distribution infrastructure for heat networks are calculated using a single £/ MWh value. The value is £450/ MWh, made up of £300/ MWh for distribution network and £150/ MWh for ancillary costs. The annual operation and maintenance cost of the distribution infrastructure is calculated as a percentage of this value. This assumption is consistent with the value used in the Heat Networks Investment Project analysis and is based on a study of BEIS supported projects. The cost for distribution infrastructure is identical in the factual and in the counterfactual, where there is assumed to be limited heat network deployment.

**Methodology - Cost to Government**

| Methodology Section Description |
|---|
| Deployment - Methodology and key assumptions for estimating deployment of heat networks in zones |
| Technology Mix – methodology and key assumptions |
| Cost to Government – methodology and key assumptions |
| Cost to Business - methodology and key assumptions |

74. The heat network zoning policy proposals, as described in the accompanying consultation, will result in costs to different parts of government. The cost to government can be split into four categories:

a. **The costs of designating zones**. This includes the costs of carrying out the modelling exercise to determine where zones should be and subsequently designating them as such, developing feasibility studies on specific areas and procuring heat network developers in zones
b. **Implementing** the zoning policy. There will be a cost incurred by local authorities who will be tasked with running consultation on zoning proposals, engaging with relevant stakeholders and enforcing the requirements of zoning
c. **Regulating additional heat networks.** The additional heat networks deployed through heat network zoning will impact on the national regulator for the sector. There will be an additional burden due to the regulator having a greater number of heat networks to regulate
d. **Additional staff in BEIS.** To support the rollout of the heat network zoning methodology to designate zones, there will need to be an expansion of resource in BEIS.

*Cost to Government – Zone Designation*

75. The methodology is assumed to be deployed in 200 towns and cities in the central scenario, this is used to inform the costs of designating zones. The consultation describes in more detail the zoning methodology, which has been costed in this IA.

76. The key assumptions (set out in Table 6) that have been used to work out the total cost of carrying out the zoning methodology in 200 towns and cities are described below. The costs have been based on the costs of similar studies carried out by HNDU, and from the recent CDDP work. There is some uncertainty related to how the costs would vary as zoning is rolled out at national scale. We have, therefore, tested increasing and reducing the costs in sensitivity analysis. It is assumed that these costs are incurred over the years 2024 to 2030.

*Table 6 – Central assumptions for the cost to government of designating zones*

| Methodology Stage* | Assumption | Description and value | Evidence | Sensitivity analysis |
|---|---|---|---|---|
| **Stage 1a - National mapping** | Cost per town/ city | £5,000 | Market estimate | Explored in the sensitivity analysis in section |
| **Stage 1a/b** | Proportion of cities going forward to Stage 1b | 85% | HNDU studies | Not explored through sensitivity analysis |
| **Stage 1b - Local Refinement** | Cost per city | £50,000 | Estimates from CDDP work[8] | Explored in the sensitivity analysis in section |
| **Stage 2 - Feasibility** | Average number of zones per city | 3 | Estimates from CDDP work[8] | Not explored through sensitivity analysis |
| | Cost per feasibility study | £40,000 | HNDU Feasibility Studies | Explored in the sensitivity analysis in section |
| **Procurement stage** | Costs of concession | £300,000 per concession | CDDP study | Explored in the sensitivity analysis in section |
| | Cost of DPD procurement[15] | £850,000 per town/ city | HNDU DPD Procurement | Explored in the sensitivity analysis in section |
| | % cities operating a concession style procurement | 75% | Judgement | Not explored through sensitivity analysis |

***** See the accompanying consultation document [add link] for a more detailed description of the proposed methodology for zone identification and designation.

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[15] DPD stands for detailed project development. This is the standard current approach to procuring heat network developers, which requires the organisation in charge of procurement to do a significant amount of project development work for the procurement.

*Cost to Government – Implementation*

77. We anticipate that the zoning proposals, as described in the consultation, will place an additional burden on local authorities as they take on the role of local 'Zoning Coordinators'. Zoning coordinators will be responsible for activities such as:

- Local engagement and consultation on zone designation;
- Formally designating zones;
- Enforcing local zoning requirements (e.g. determining which buildings in zones are required to connect).

78. At this point, the number of local zoning coordinators that will be set up is uncertain, as are the costs of the activities described above. We have made some simplifying assumptions to provide a sense of scale of this cost. In our central scenario, we have assumed that each of the 170 towns and cities that designate zones will have a unique local zoning coordinator. We assume that each local zoning coordinator will require 3 additional FTE over the period 2024 to 2030, to match the period the methodology costs are incurred over. The costs are equivalent to an average G7 salary in government. The cost is calculated using the Civil Service Median Salaries by grade[16] and applying a wage uplift of 19.2%[17].

79. The consultation proposes local zoning coordinators can be constituted at county, district, or metropolitan level, and that several local authorities may work jointly as the zoning coordinator for a wider area. Given the uncertainty regarding where the role of local zoning coordinator will sit, we also present a sensitivity assumption where there are fewer, larger zoning coordinators.

*Table 7 – Central and alternative assumption for the number and role of zoning coordinators*

| Sub-Option | Number of bodies | FTE per ZC | Total FTE |
|---|---|---|---|
| Central | 170 | 3 | 510 |
| Alternative | 35 | 9 | 315 |

*Cost to Government – Regulating Additional Heat Networks*

80. We estimate a significant increase in the deployment of heat networks due to heat network zoning. This will impose an increased burden on the national regulator, who will be in place by 2025. The elements of regulation cost included at detailed in the table below:

*Table 8 – Cost to government of regulating additional heat networks*

| Cost category | Description |
|---|---|
| Authorisation and licensing | Ongoing cost associated with managing and processing all authorisation and licensing applications. |

[16] https://www.gov.uk/government/statistics/civil-service-median-salaries-by-uk-region-and-grade

[17] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/827926/RPC_short_guidance_note_-_Implementation_costs__August_2019.pdf

| | |
|---|---|
| Market monitoring and regulatory development | Ongoing cost associated with monitoring the heat network market, developing market insights and development of current and future regulation. |
| Compliance and enforcement | Ongoing cost associated with managing compliance and enforcement cases with regulated entities. |
| Auditing | Ongoing cost associated with the carrying out audits required with regulated entities. |
| Legal | Ongoing cost associated with legal resource to support compliance and enforcement cases. |
| Overhead and other costs | Ongoing costs associated with the operation of the regulator, the key costs include IT, information security, HR, finance, communications, operations, office costs and insurance. |

81. We do not expect an increase in the monitoring required of heat networks in zones relative to the monitoring that will take place under the market framework. Similarly, we do not anticipate that the national regulator will regulate the zones themselves. As such, the increased costs of regulating mentioned below would be solely attributed to the costs of regulating a greater number of heat networks which are deployed in zones.

82. The additional costs of regulating a greater number of networks have been calculated by extrapolating modelling that has been developed since the consultation stage impact assessment for the Heat Networks Market Framework.[18] The modelling has been developed by BEIS, with input and engagement from Ofgem, Citizens Advice, the Energy Ombudsman, Heat Trust and representatives of the heat network industry.

83. In order to account for how regulator costs may change over time, factors which influence regulatory costs are scaled with the expected growth in the market due to zoning. The regulator costs are dependent on the following metrics: the estimated number of heat suppliers, number of heat networks, number of buildings, number of customers. More detail on how these costs are derived can be found in the Heat Network Market Framework IA which is published alongside this IA.

84. As outlined in Table 6, we assume that there will be on average 3 zones per town and city, and 170 towns and cities. In addition, we have made the simplifying assumption that there will be on average one heat network per zone. Therefore, in total we assume that there will be 510 new heat networks deployed as a result of heat network zoning. To estimate the number of additional suppliers of these heat networks, we have assumed that each supplier has on average 7 individual heat networks.[19] It is therefore assumed that the 510 heat networks are supplied by 75 new heat suppliers.

[18] Future Market Framework Impact Assessment, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/863855/heat-networks-market-framework-consultation-impact-assessment.pdf

[19] Based on BEIS analysis of a sample of the Heat Metering and Billing Regulations Dataset

85. In calculating the cost to Ofgem, the analysis has assumed that the additional heat networks and heat suppliers are deployed linearly from 2025 up to 2035. It is assumed that the increase in overall deployment of heat delivered by heat networks in zones beyond 2035 is due to the expansion of heat networks. This is a simplifying assumption, which will seek to develop ahead of secondary legislation.

*Table 9 - Annual Costs of Regulating Additional Heat Networks*

| **Heat network deployment scenario** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
|---|---|---|---|---|---|---|
| High | £0.5 | £1.8 | £3.1 | £4.3 | £5.4 | £6.5 |
| Medium | £0.2 | £1.1 | £1.9 | £2.7 | £3.5 | £4.2 |
| Low | £0.1 | £0.3 | £0.5 | £0.7 | £0.8 | £1.0 |

86. In practice, elements of regulatory costs may not scale as assumed in our modelling, which could be due to factors such as the level of consolidation in the market and/or levels of compliance with the regulation. However, it isn't possible to estimate the impact of these factors at this point, and therefore this has not been included in the analysis. We will develop our evidence base on this ahead of future IAs.

87. As the policy develops, some of the consumer protections to be introduced by the heat network market framework may be extended to cover non-domestic buildings within zones. This may increase the costs of regulating heat networks in zones. However, it is too uncertain to attempt to quantify this at this point.

*Cost to Government – Additional BEIS Staff*

88. To support the rollout of the zoning methodology, there will need to be an expansion in heat networks technical expertise within BEIS. It is currently uncertain what the extent of this expansion would be. For the purposes of this IA, we have assumed that there would need to be an additional 40 staff members. This has been calculated by comparing the current amount of relevant BEIS resource and the number of heat network projects they support. It is assumed that each of the 40 staff members would be at G7 on average. The cost is calculated using the Civil Service Median Salaries by grade[20] and applying a wage uplift.

*Variation between policy options*

89. We have made the simplifying assumption that most of the costs to government are constant across the policy options. The only cost which varies is the cost of regulating the heat networks, since this is dependent on the heat supplied by heat networks in zones. Most of the costs of determining where zones are, and designating them, described above are fixed and wouldn't vary significantly depending on the different building types in scope of the zone. We don't have the evidence base to determine how these costs would vary between the policy options. We welcome any evidence on this matter through the consultation responses.

[20] https://www.gov.uk/government/statistics/civil-service-median-salaries-by-uk-region-and-grade

### Methodology – Cost to Business

| Methodology Section Description |
|---|
| Deployment - Methodology and key assumptions for estimating deployment of heat networks in zones |
| Technology Mix – methodology and key assumptions |
| Cost to Government – methodology and key assumptions |
| Cost to Business - methodology and key assumptions |

90. The costs to business that have been quantified in the impact assessment cover the costs that will be incurred by:

a. Heat network developers

b. Heat network operators, and

c. Buildings that are required to connect to heat networks

*Heat Network Developers and Operators*

91. Heat network developers and operators will each incur familiarisation costs due to the policy proposals. There would be a one-off cost to reading and understanding the requirements of the regulation, and then disseminating to their respective organisations. For both developers and operators, the central assumptions are as follows:

*Table 10 – Central assumptions for familiarisation costs of policy proposals to heat network developers*

| Assumption | Descriptions and value | Evidence | Sensitivity analysis |
|---|---|---|---|
| **Time per HN developer/ operator** | **7.5 hours per HN developer/ operator**<br>Familiarisation – read and understand the requirements of the regulation, disseminate to staff. Use same assumption as HMBR IA | HMBR IA[21] | Explored in the sensitivity analysis in section |
| **Familiarisation person required** | **75% HNs developers use 'Estate Manager', 25% a consultant**<br>Same as HMBR IA. Average wage £26/ hour | HMBR IA/ ONS Annual Survey of Household Earnings[22] | Not explored through sensitivity analysis |
| **Time Period** | **Years 2 – 6 of policy (2025 – 2030)**<br>Cost incurred in first years of policy. | Judgement | Not explored through sensitivity analysis |

[21] Heat Metering and Billing Regulations Impact Assessment, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/933316/hmbr-final-ia.pdf

[22] https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/datasets/occupation4digitsoc2010ashetable14

92. Heat network operators will also incur additional costs under the market framework of notifying the regulator of their existence and reporting annually on the performance of their network. Following the assumptions set out in the Future Market Framework consultation stage IA[23] we have assumed that it takes each heat network operator on average 1 day a year to collect data on the heat network and report to Ofgem.

93. We have made the simplifying assumption that there will be on average one heat network per zone, in the absence of evidence to suggest otherwise. It is possible that zones could have more than one network. As described above, we estimate there will be 510 zones in total.

*Buildings within Zones*

94. The consultation proposes a requirement for buildings within zones (or potential zones) to provide certain information and data to the local zoning coordinator. This will be used in energy planning, to ensure that the methodology for designating the zone is based on the best possible evidence. We have assumed that it takes each of the buildings required to connect on average 2 person days to collect the data and share it with the zoning coordinator. We welcome any responses to the consultation related to how long it might take to perform this activity.

95. Buildings which are required to connect to heat networks in zones will be able to apply to be exempt from this requirement. The process for doing so is described in the consultation. This process will result in an additional cost being placed on the building. This has been quantified as a cost to business because of the policy. We assume that 20% of buildings which are required to connect apply for exemption. We have not assumed the number of successful applications for exemption as this is highly uncertain.

96. Where a building type is domestic in the preferred policy option, we assume that the cost will be borne by one single actor on behalf of the whole building. The domestic buildings in scope of the policy are communally heated residential blocks. We therefore include this cost in the cost to business.

97. We assume that there will be an online calculator to complete a 'cost effectiveness test', similar to that for the HMBR, as part of the application to be exempt from the heat network zone. The remainder of the assumptions used to calculate this cost are described in the Table 11:

*Table 11 – Costs to buildings which are required to connect*

| Assumption | Approach | Evidence Source | Sensitivity analysis |
|---|---|---|---|
| **% Exemptions** | **20% of buildings apply for exemptions** | Judgement | Explored in the sensitivity analysis in section |

[23] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/863855/heat-networks-market-framework-consultation-impact-assessment.pdf

| | | | |
|---|---|---|---|
| **Exemption cost Effectiveness Test time taken** | **15 hours**<br>Assume two days to collect data and use an online cost effectiveness calculator, similar to the HMBR calculator. | HMBR IA[24] | Not explored through sensitivity analysis |
| **Requirement to provide information** | **15 hours**<br>Assume two days to collect data on heat demand and sharing the information with the local zoning coordinator. | Judgement | Explored in the sensitivity analysis in section |
| **Person required** | **75% HNs developers use 'Estate Manager', 25% a consultant**<br>Same as HMBR IA Average wage £26 / hour | HMBR IA | Not explored through sensitivity analysis |

98. The consultation considers two broad options for who should pay connection costs – leaving it to contractual arrangements between network developers and building owners; or government introducing rules (potentially cost caps) to prevent over-charging. The consultation also sets out various 'trigger points' where buildings would be required to connect to a heat network, which would help avoid scrappage of existing heating systems. Given that the alternative to connection to a heat network would be the capital cost of a new heating system, and that the costs of both the heat network and alternative are very uncertain, we assume that these costs net off in this impact assessment. This is something we will look to address in the final stage impact assessment.

*Variation between policy options*

99. We have made the simplifying assumption that the costs to business would be equal across each of the policy options. Many of the costs to business are dependent on the number of zones, and number of heat networks. It isn't clear how the number of heat networks would vary with the deployment under the policy options. For example, as you move from the high to the low policy option you may have a similar number of heat networks, with each of them delivering less heat. We will update this ahead of the final-stage impact assessment.

### Non-monetised costs and benefits of each option, not included in the Methodology

100. There are several non-monetised costs and benefits that are not captured in the cost-benefit analysis, and therefore that are not included in the calculated SNPVs of the policy options.

- **Whole electricity system impact** – Large scale heat networks with thermal stores and an electric source of heat are strategically important in making a low carbon power supply sector more resilient, by delivering an option to reduce peak demand and/or maximise use of intermittent electricity generation. A smart and flexible electricity system could save up

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[24] Heat Metering and Billing Regulations Impact Assessment, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/933316/hmbr-final-ia.pdf

to £10bn per year by 2050[25]. The flexibility/storage capabilities of heat networks could contribute toward this, although there is limited evidence on the scale of potential benefits.

- **Supply chain development** – by incentivising additional deployment of low-carbon heat networks relative to the counterfactual, heat network zoning will support the development of low-carbon heat supply chains. The policy will provide a strong signal to the market of government ambition and will introduce sustained public investment over a 25-year period, which is expected to have a large and sustained impact on supply chains. This will provide more certainty to the low carbon heat sector, allowing businesses to align strategies, investment plans and training, and drive forward innovation in technologies and business models.

  **Whilst supply chain development is not a monetised cost, it will impact on capital and** operating costs. These costs are based on current values, therefore, do not reflect cost reductions over time, through maturing supply chains. Development of the supply chain is likely to reduce these costs through competition and economies of scale. There may be cost increases in the short-term as supply chains adapt, however, through to 2050 it is anticipated that there will be large scale change to energy supply chains; therefore, there is opportunity for existing supply chains to adapt to benefit heat network supply chains.

- **Jobs and GVA impacts –** A significant increase in investment in the heat networks sector is anticipated to support UK jobs in the design, construction and operation of heat networks. The investment in heat networks is also expected have multiplier effects in the wider economy such as: providing energy savings for users of heat networks; increasing or safeguarding UK jobs and developing the operations of Energy Service Companies (ESCos). The indirect GVA impacts are uncertain and therefore have not been quantified in this analysis.

- **Costs to business** – there are further costs to business which haven't been quantified in the IA as it hasn't been considered proportionate to do so at this stage. These costs are listed below:

  a. **Disruption costs** – there would likely be disruption costs associated with a significant deployment of heat networks. The disruption could take the form of street works where roads need to be dug up, or disruption due to buildings being retrofitted to be suitable for connection to a heat network. The magnitude of disruption costs is expected to be in-line to disruption through the low-carbon counterfactual.

  b. **Compulsion to supply** – the owners of an ambient or non-ambient waste heat source may be required to supply a heat network with their heat. This heat will be low carbon relative to the counterfactual, but supplying it will incur a cost to the business. The magnitude of impact of the compulsion to supply on business is expected to be minimal and could offer opportunities for building owners to generate revenues through sale of heat to the network.

## Results

101. This section presents the results of the deployment analysis, and overall cost benefit analysis, for the three quantified policy options against the counterfactual scenario.

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[25] Transitioning to a net zero energy system: smart systems and flexibility plan 2021, link: https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

102. The results of the deployment analysis for the three different policy options are presented in Table 12. The numbers below are additional to the current stock of heat networks, and networks that will be deployed by HNIP and the GHNF.

103. New builds are included in estimates of deployment to reflect new builds connecting to heat networks in zones, however, news builds are not counted within SNPVs to avoid duplicating benefits presented by new build policies.

104. The total heat demand for England, presented in *Opportunity Areas for District Heating Networks in the UK*[4], is estimated to be 439 TWh in 2050. Table 12 presents the proportion of total heat demand in England that could be delivered by the policy options.

*Table 12 – Deployment under different policy options (not including existing heat networks and deployment through other heat network policies)*

| **Policy option Deployment (TWh)** | | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
|---|---|---|---|---|---|---|---|
| Including new builds | Low | 0.2 | 1.2 | 2.3 | 3.2 | 4.2 | 5.1 |
| | Medium | 0.9 | 5.2 | 9.3 | 13.3 | 17.1 | 20.7 |
| | High (preferred) | 1.4 | 7.8 | 14.1 | 20.0 | 25.7 | 31.2 |
| Excluding new builds (used in SNPV calculations) | Low | 0.1 | 0.7 | 1.3 | 1.8 | 2.4 | 2.9 |
| | Medium | 0.8 | 4.7 | 8.4 | 11.9 | 15.2 | 18.5 |
| | High (preferred) | 1.3 | 7.3 | 13.1 | 18.6 | 23.9 | 28.9 |

105. The SNPVs, and constituent parts, of each of the policy options are presented in Table 13. As shown in the table, there is a significant net capital cost due to the deployment of heat networks against the counterfactual. Table 13 also presents the Benefit-Cost ratio which measures benefits per unit cost. Since costs are larger than benefits, the ratio is below 1, however, the BCR shows that the high policy option, with the lowest SNPV, has the greatest ratio of benefits per cost.

106. The SNPVs for each policy options have changed following the consultation stage impact assessment[26] as a result of removing new builds from the calculation and also amending an error in the model, which has resulted in a higher capital, operational and fuel cost for the factual scenario.

*Table 13*– SNPV and BCR results of different policy options, excluding new builds[27]

| **2020 prices, Present Value base year of 2024** | **High Policy Option (£m)** | **Medium Policy Option (£m)** | **Low Policy Option (£m)** |
|---|---|---|---|
| **Benefit-Cost Ratio** | **96%** | **94%** | **78%** |

[26] Heat network zoning consultation stage impact assessment: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1024221/heat-network-zoning-consultation-stage-impact-assessment.pdf

[27] The numbers in this table are slightly different to the numbers on the front pages of the IA. This table is in 2020 prices, whereas the numbers on the front page are in 2019 prices. Values are also rounded to the nearest £10m.

| **SNPVs** | **-450** | **-380** | **-270** |
|---|---|---|---|
| *Capital costs* | -9,810 | -6,260 | -970 |
| *Operating costs* | 70 | 40 | 10 |
| *Carbon savings* | 9,100 | 5,810 | 900 |
| *Air quality benefits* | 260 | 160 | 30 |
| *Net Energy Savings* | 260 | 160 | 30 |
| *Cost to Government* | -310 | -280 | -250 |
| *Cost to Business* | -20 | -20 | -10 |

Table 14 – *Carbon Emissions Reductions of different policy options*

| **Total (traded and non-traded savings)** | **High Policy Option (MtCO2e)** | **Medium Policy Option (MtCO2e)** | **Low Policy Option (MtCO2e)** |
|---|---|---|---|
| Carbon Budget 4 savings 2023-2027 | 0.8 | 0.5 | 0.1 |
| Carbon Budget 5 savings 2028-2032 | 4.5 | 2.9 | 0.4 |
| Carbon Budget 6 savings 2033-2037 | 9.0 | 5.7 | 0.9 |
| **Carbon Budget 4 to 6 savings 2023-2037** | **14.3** | **9.1** | **1.4** |

**Discussion - General**

107. The quantified SNPVs of the costs and benefits described in this IA show that the impacts of the proposed policy would lead to a net cost for each of the policy options. The primary driver of costs are high upfront capital costs compared to the counterfactual reflecting the significant cost of the heat networks, the distribution infrastructure in particular. The gas boiler counterfactual is relatively low cost in comparison. Capital cost assumptions for heat networks are based on current values and do not consider a price reduction over time, which are to be expected as supply chains develop.

108. The primary benefit of the policy is carbon savings which are achieved by displacing fossil fuel heating systems with low carbon district heating. This is also a key policy objective of heat network zoning. Operating costs are a net benefit against the counterfactual. This is due to the assumptions set out in

109. Annexes

110.

111. Annex 1 – Detailed modelling assumptions, which show a relatively high counterfactual gas boiler operating cost compared to the low carbon heat network scenario.

112. The Benefit-Cost ratio presents the ratio of benefits to costs. It shows that the high policy option receives the most benefit per unit cost. This reflects the primary benefit and key policy objective for the policy, carbon savings, being achieved at the lowest cost rate in the high policy option.

113. The key non-monetised benefits would also be relatively greater for the high policy option. For example, the ability for large scale heat networks to offer the grid flexibility benefits is a significant non-quantified benefit of the policy. This is expected be substantially greater under the preferred option, relative to the other two scenarios, because of higher heat network deployment. Likewise, the development of the heat network supply chain, under the high policy option, would see the greatest opportunity for capital costs to decrease through economies of scale and competition. The high policy option would also result in a greater number of direct and indirect jobs. This adds further weight to the high policy option being the preferred option.

114. Despite each of the zoning policy options having a negative SNPV, the combined SNPV of the wider Heat Network Transformation Programme, comprising of the Green Heat Network Fund, Heat Network Market Framework and Heat Network Zoning, is estimated to have overall positive value to society, under preferred policy options for each policy. Furthermore, there has been no assessment of how efficiencies could arise between the individual policies, which could benefit the overall societal value of the Heat Network Transformation Programme.

## Discussion – Carbon Emissions

115. The estimated carbon savings of each of the policy options are presented in Table 14 above, each of the policy options result in carbon savings against the counterfactual. The preferred (high) policy option abates significant carbon over the 5$^{th}$ and 6$^{th}$ carbon budget periods, substantially more than the other two policy options. Whilst the quantified costs are greater in the preferred option, the cost per $MtCO_2e$ is significantly lower. Given the amount of carbon than needs to be abated to achieve our carbon budget and net zero obligations, and heat network zoning offering the lowest cost pathway to decarbonising heat for zones, this lends greater weight to the high option being the preferred policy option for heat network zoning.

116. The carbon savings in Table 14 include both traded and non-traded savings. The numbers are made up of significant non-traded savings, and a slight increase in emissions in the traded sector. This is due to moving away from the fossil fuel (non-traded) counterfactual, and the factual heat networks consuming electricity which is traded.

## Comparison to Low Carbon Counterfactual

117. As discussed, we have also considered the analysis against a low carbon counterfactual. In the absence of a heat network zoning policy, given the government's Net Zero commitments, it is likely that most buildings would be decarbonised by individual air source heat pumps in an electrification scenario. Given the complexity of the analysis, we haven't quantified the social impact of decarbonising buildings using low carbon heat networks or individual heat pumps. As most whole systems modelling shows, both heat networks and individual heat pumps will be required to decarbonise the UK's building stock.

118. The zoning methodology will define heat network zones as areas where heat networks offer the lowest cost means of decarbonising heat. By definition, heat networks deployed in zones should be lower social cost than individual heat pumps. It is possible that the upfront capital cost of investing in large scale heat networks would be greater than decarbonising an area with individual heat pumps, particularly due to the cost of distribution infrastructure. However, heat network zoning could, at least partially, offset these costs through lower costs of grid infrastructure upgrade as a heat network, with a large thermal store, would put less strain on the power system relative to a mass rollout of individual heat pumps. Heat pumps on heat networks may also have a higher coefficient of performance than an individual system, particularly when utilising waste heat sources.

119. From a carbon emissions perspective, individual air source heat pumps have a slightly lower coefficient of performance relative to ground and water source heat pumps on heat networks. In addition, heat networks utilising waste heat sources, with improved coefficients of performance, can be significantly lower carbon than individual systems. Therefore, it is possible that heat network zoning would offer carbon savings compared to individual air source heat pumps. However, both technologies (heat pumps and heat networks) result in significant carbon savings relative to the current status quo of largely gas-fired heating in domestic and non-domestic buildings.

120. As mentioned above, we have restricted this analysis to an electrification pathway for decarbonisation. The impacts and costs are more certain at this point for electrification, as we build the evidence base for hydrogen.

### Cost to Government

121. The cost to government due to the policy is set out in Table 15 below for each of the policy options. As described in the methodology section, there are four main components of the cost to government.

Table 15 - Cost to Government Breakdown[28]

| Activity | High | Medium | Low |
|---|---|---|---|
| **Methodology Cost (£m)** | 80 | 80 | 80 |
| **Additional Resource in central govt (£m)** | 20 | 20 | 20 |
| **Implementation Cost (£m)** | 160 | 160 | 160 |
| **Ofgem Cost (£m)** | 80 | 50 | 10 |
| **Total (£m)** | 340 | 310 | 270 |

122. Whilst the estimated costs to government of implementing the heat network zoning policy are significant, they result from the assumption regarding the number of towns and cities that the policy will be rolled out in. The most significant costs come from the implementation of the policy within local governments across England. We assume that each local authority will require 3 FTE to implement the policy, which quickly scales to a significant amount. The methodology costs cover each of the stages of the modelling of zones to procuring heat networks across 170 towns and cities. Whilst the total cost is high, this works out at under £500,000 per town and city across England.

[28] The costs in this table are different to the results table for the overall SNPV due to rounding.

123. As mentioned in the methodology section, we have made a simplifying assumption that the majority of the costs to government don't vary with the policy options. This IA therefore implicitly assumes that the modelling to determine where zones should be, and the implementation of those zones doesn't vary with the policy options. One might expect that these costs would be relatively smaller for the medium and low policy options. We will build our evidence base on this ahead of future IAs.

## Sensitivity Analysis

124. Sensitivity analysis has been conducted to explore how results presented could change due to uncertain or biased evidence. To understand the risk associated with our assessment of the policy options, we have explored how the SNPV could be affected by varying our assumptions across the following areas:

a. Deployment, heat generation technologies and policy cost,

b. Carbon values,

c. Optimism bias,

d. Additionality, and

e. Network losses.

125. The results of sensitivity analysis across these areas are discussed in detail in the following sections. In this section, we explore the impact on the SNPV of the preferred (high) option across sensitivity scenarios. Annex 2 - Detailed sensitivity analysis presents the impact on the SNPV for all three of the policy options across sensitivity scenarios.

### Deployment, heat generation technologies and policy cost

126. The process we have used to conduct the sensitivity analysis has been to explore the impacts of the following factors:

a. Deployment being higher or lower than the central case;

b. Generation technologies for heat networks being cheaper than current cost, due to higher levels of waste heat; and

c. The cost of implementing the policy options being higher or lower than the central case.

Table 16 to Table 18 below present scenarios for each of these factors – there are three deployment scenarios, two generation technology scenarios and three policy cost scenarios.

*Table 16 – Deployment sensitivity scenarios and configuration of assumptions*

| Assumption | Description | Central | Lower | Higher |
|---|---|---|---|---|
| **Number of towns/ cities** | The number of towns and cities where the policy could be implemented | 200 | 100 | 300 |
| **Scaling CDDP deployment in relation to the EP model** | How deployment estimates from the from the CDDP analysis could scale in proportion to the EP model results. | 80% | 60% | 100% |

| | | | | |
|---|---|---|---|---|
| **Infill of non-target buildings** | How deployment estimates would be affected if fewer non-target buildings connect to heat networks | Includes infill (all non-target buildings) | No non-target building deployment and 25% reduction in target building deployment | |
| **Policy option 'added' detriment** | Under the low and medium policy options, the reduction in deployment may not be linear relative to the high option, as heat networks become less cost-effective at smaller scale. This sensitivity tests the impact of assuming that relatively smaller heat networks are deployed under the low and medium options. | Deployment is proportional to buildings in scope in option, relative to the high option | Central, with an extra 25% reduction for the Medium and Low policy option | |

*Table 17 – Heat generation sensitivity scenarios and breakdown of heating technologies*

| Technology mix (% Heat Generation) | Central | Alternative |
|---|---|---|
| EfW | 9% | 18% |
| High Temp Waste Heat | 4% | 6% |
| Low Temp Waste Heat | 6% | 12% |
| ASHP | 14% | 11% |
| GSHP | 24% | 18% |
| WSHP | 34% | 25% |
| Back-up Boilers | 10% | 10% |

*Table 18 – Policy cost sensitivity scenarios and configuration of assumptions*

| Section | Assumption | Central | Lower | Higher |
|---|---|---|---|---|
| **Methodology Cost** | Stage 1, cost per city | £5,000 | £2,500 | £7,500 |
| | Stage 2, cost per city | £50,000 | £25,000 | £75,000 |
| | Feasibility per zone | £40,000 | £20,000 | £60,000 |
| | Average zones per city | 3 | 3 | 3 |
| | Procurement cost per city | £300,000 / £850,000 | £150,000 / 425,000 | £450,000 / £1,275,000 |
| **Implementation** | FTE per zone | 3 | 1.5 | 4.5 |
| **Cost to Business** | Familiarisation Cost | 7.5 hours | 4 hours | 15 hours |
| | Notification Cost | 7.5 hours | 4 hours | 15 hours |
| | Number of exemptions | 20% | 10% | 40% |

| | | | | |
|---|---|---|---|---|
| | Exemption time required | 15 hours | 15 hours | 15 hours |

127. We have considered the impacts of these factors in combination as well as independently and presented the key messages arising from the sensitivity analysis in this section of the document. A full account of the results of the sensitivity analysis are presented in Table 28 to Table 30 in Annex 2 - Detailed sensitivity analysis.

128. The central SNPV for the preferred policy option is **£-450m**, which is based on achieving **29 TWh/yr** of additional deployment by 2050, not including new builds. Figure 2 presents the impact of sensitivity scenarios of the central SNPV for the preferred policy option. Figure 1 presents the impact of deployment scenarios relative to the central deployment estimate in 2050, for the preferred policy option.

*Figure 1– Impact of deployment sensitivity scenarios on central deployment in 2050 (TWh/yr)*

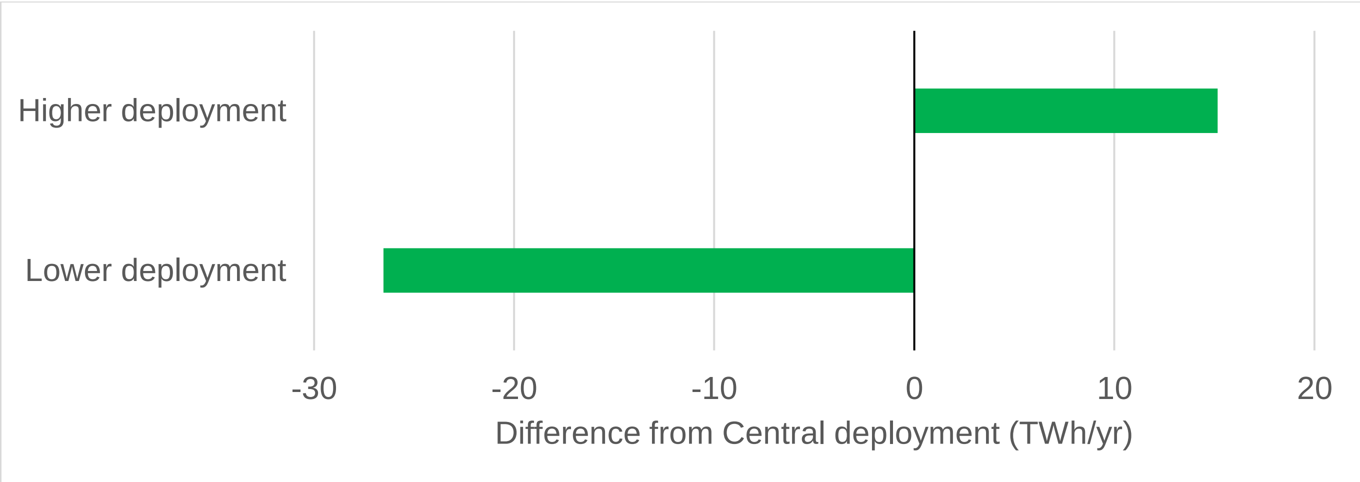
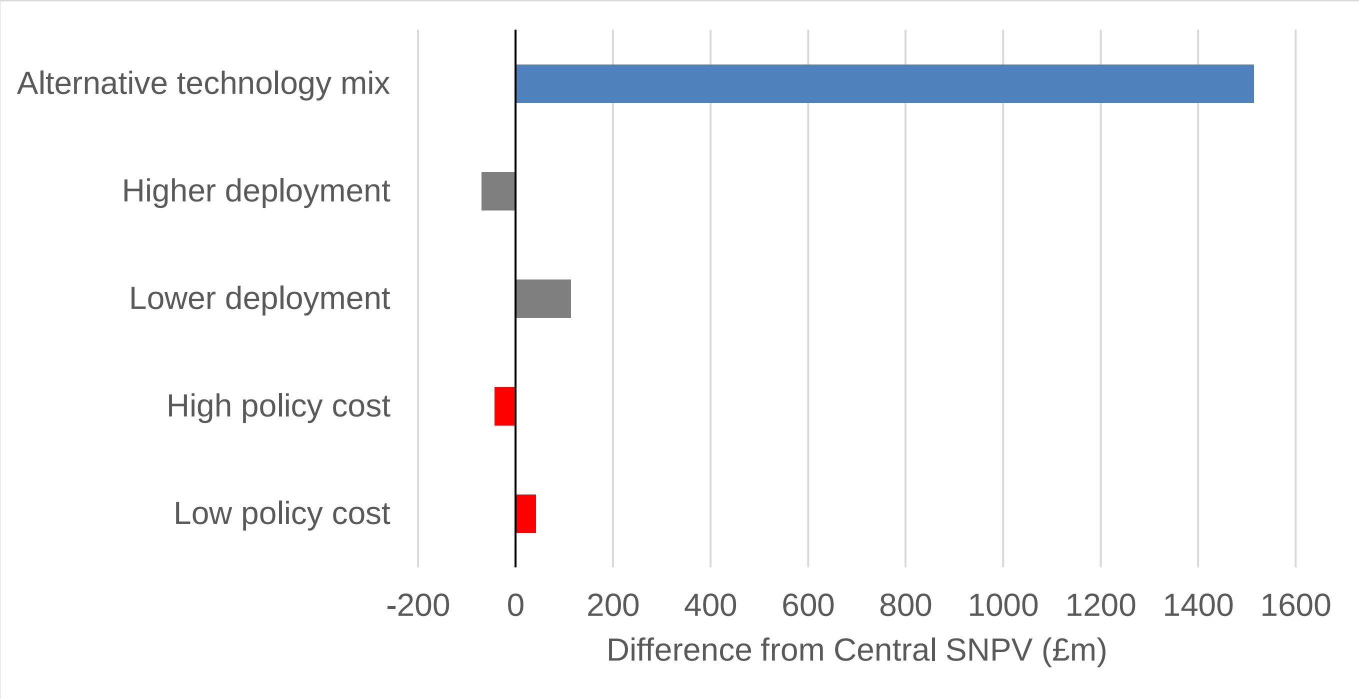



*Figure 2 – Impact of sensitivity scenarios on central SNPV (£m)*




129. Of the three factors explored in the sensitivity analysis, the scenarios exploring different **mixes of heat generation technologies** serving heat networks have the greatest impact on the SNPV. The alternative technology mix draws on a greater proportion of heat generation from sources of waste heat (EfW, High and Low Waste heat sources) and a lower proportion of heat generation from heat pumps, than the central scenario. The greater use of waste heat is expected to result in costs savings due to lower capital costs and lower fuel costs, owing to greater thermal efficiency of heat generation from waste heat sources. Figure 2 shows that by harnessing a greater proportion of waste heat sources, in comparison to the central scenario, there would be significant increases to the SNPV for the preferred policy option, with potential to make the SNPV positive. As well as increasing the SNPV, this sensitivity analysis would increase the size of the non-monetised benefits of heat network zoning that are outlined above.

130. The **level of deployment of heat networks** within zones has the second largest impact on the SNPV. As described in Table 16, in the lower deployment scenario we have assumed that there wouldn't be connections to buildings which haven't been mandated to connect by the policy. Figure 1 illustrates the large decrease in deployment if no buildings connected voluntarily to the network. Figure 2 shows that the lower deployment scenario for the preferred policy option would slightly increase the SNPV, however, since there would be less carbon savings, due to less deployment of low carbon heat networks, the benefit-cost ratio is reduced to 76%, compared to 96% for the central deployment scenario. This sensitivity demonstrates the importance of buildings connecting voluntarily to the heat networks in order to obtain the highest level of benefits per cost of developing the network.

131. We have also explored the impact of **varying estimated policy costs** which include costs of developing a methodology to plan zones, costs of implementing zones, and costs to business of complying with regulation. The impacts of varying costs on the SNPV are smaller than assumptions for technology mix and deployment, however, Figure 2 shows that there could be a difference in SNPV of approximately £50m either side of our central policy cost scenario as result of cost increasing or decreasing across the three areas. As described in the methodology section, there are some unquantified aspects of the policy costs at this

point. The inclusion of these would result in a more significant variation in the SNPV in the sensitivity analysis.

132. As seen in Table 13, the most significant costs in the analysis are capital costs, monetised carbon savings, and fuel costs. As a result, the sensitivity analysis which influences these variables has a significant impact on the SNPV. The policy costs, on the other hand, have a much smaller bearing on the cost benefit analysis. This can also be seen in Figure 2.

**Exploring the impact of carbon values on the central SNPV**

133. The cost of carbon (£2020/tCO2e) has a high impact on the SNPV for the policy options. For the SNPVs presented within this Impact Assessment we have used central Green Book carbon values, which has resulted in the SNPV for the preferred policy option being **£-450m**; however, by using high carbon values the SNPV increases to **£4,100** and using low carbon values the SNPV decreases to a **net loss of £5,000m**.

*Table 19 – Central SNPV using different carbon values, preferred policy option*

| Carbon Value | Central SNPV (£m) |
|---|---|
| High | 4,100 |
| Central | -450 |
| Low | -5,000 |

**Exploring the impact of optimism bias on the central SNPV**

134. The analysis includes optimism bias on the capital costs of developing heat networks to reflect case study information of planned versus actual costs of 'non-heat network specific' environmental infrastructure projects. A buffer of 21% has been applied to capital costs to account for optimism bias[7]. Table 20 presents how the SNPV varies under different levels of optimism bias.

*Table 20 – Central SNPV using different levels of optimism bias*

| Optimism bias value | Central SNPV (£m) |
|---|---|
| 10% | 1360 |
| 21% | -450 |
| 30% | -1930 |

**Exploring the impact of the additionality assumption on the central SNPV**

135. For this analysis we have assumed that 90% of the benefits of heat network zoning are additional. Table 21 presents how the central SNPV would be impacted if different levels of additionality were assumed.

*Table 21 – Central SNPV using different levels of additionality assumptions*

| Additionality value | Central SNPV (£m) |
|---|---|
| 85% | -430 |

| | |
|---|---|
| 90% | -450 |
| 95% | 480 |

**Exploring the impact of network losses assumption on the central SNPV**

136. Network losses refer to heat that is lost through the distribution network. For the factual scenario, heat generated is calculated from heat demand by adjusting for network losses. The counterfactual scenario is negligibly affected by network losses since the majority of heat is generated on-site. Therefore, more generation capacity is required in the factual than the counterfactual. Across BEIS' appraisal of heat network policies, a standard assumption of 20% network losses is assumed, however Table 22 illustrates the impact of reducing the network loss assumption, through better insulated pipes for example. The impact of reducing this assumption significantly decreases capital, operational and fuel costs, and has a high impact on the overall SNPV for each of the policy option, with the high and medium SNPVs becoming positive, assuming 15% network losses.

*Table 22 – SNPVs using different levels of network loss assumptions*

| Network losses | Central SNPV - High policy option (£m) | Medium policy option (£m) | Low policy option (£m) |
|---|---|---|---|
| 20% | -450 | -380 | -270 |
| 15% | 1540 | 890 | -80 |

## Infill Connection

137. As demonstrated in the sensitivity analysis, a significant amount of the total deployment is reliant on non-mandated buildings to connect to heat networks. Achieving the benefits set out within this IA is therefore dependent on non-mandated buildings connecting. In the absence of pilot studies or suitable data from similar policies, there is minimal quantitative data that can be used to estimate the level of infill that we expect to see as a result of mandating connections within zones. We will make sure that the zoning pilot modelling incorporates this into their evaluation, to build our evidence base on infill connection as the policy develops.

138. Whilst the zoning policy development work was taking place over Summer 2021, BEIS commissioned the Centre for Sustainable Energy, ACE Research and SE-2 to carry out social research related to heat network zoning.[29] As part of the research, 337 owner occupiers and 15 members of the private rented sector [30]participated in a survey to understand their views regarding heat network zoning. Below are some of the results, which suggest that switching to a more environmentally friendly heating system is an important consideration in changing current heating systems for private domestic residents :

Q7[31] - 45% of survey respondents said that environmentally friendly heating would be an important consideration if they were to replace heating while it was still working.

[29] The research will be published at a later date in 2022.

[30] The research targeted those in six cities in England: Bristol, Birmingham, Greater Manchester, Leeds, Newcastle and Nottingham.

[31] Q7: If you were to consider replacing your heating system while it is still working, which of these would be the more important consideration in changing your heating system?

Q19[32] - 74% of survey respondents said they were likely to join a heat network assuming they would pay no more than they do currently, and the heat supply would be low or zero carbon.

139. The experience of Denmark's heat network zoning policy also adds some weight to the likelihood of infill connections. Denmark initially had a strong policy in regard to compulsion to connect, which has recently been revoked. The obligation to connect applied to both new and existing buildings. The power to mandate connection has now been revoked as district heating is now seen as very favourable and the power to compel connection was rarely used in recent years. This suggests favourable evidence for voluntary connections, i.e. that compelling some buildings to connect will lead over time to voluntary connections and eventually no longer requiring the powers to compel connections.

### Direct costs and benefits to business calculations

140. The direct costs to business are described in the methodology section above, in the 'Costs to Business' section. The costs to business due to heat network zoning are various:

a. Familiarisation costs of heat network developers and operators
b. Annual reporting of additional heat networks in zones to the national regulator for heat networks
c. The costs to buildings who wish to apply to be exempt from connecting to a heat network in a zone
d. The cost of buildings complying with the requirement to provide building level information to the zoning coordinator to assist with energy planning

141. There are also non-monetised impacts to business as a result of heat network zoning, as described in the methodology section. There would likely be disruption costs for consumers as heat networks get constructed, which may be significant. There will also be benefits to business in terms of fuel savings, some of which may be passed on to final consumers. We need to undertake further work to understand the likelihood, and extent, of this happening.

142. The business NPV and EANDCB values are presented below for the preferred policy option. There will be no impact on business from the primary legislation measures for heat network zoning in the energy bill, the below values relate to the secondary legislation. Given that the policy is at primary legislation stage, and the details of the secondary legislation are yet to be defined, the below numbers are uncertain. They will be updated and validated ahead of the impact assessments supporting secondary legislation for heat network zoning, where the measures will have an impact on business.

| ***Business NPV*** | **2019 Prices (£m)** |
|---|---|
| **Total Business Costs** | 15.5 |
| **Total Business Benefits** | 0.0 |
| **Net Total Business Impact** | -15.5 |

| ***EANDCB*** | **Annualised(£m)** |
|---|---|

32 Q19: How likely do you think you will be to join a heat network like this if you were given the opportunity? When answering, please assume you would pay no more than you do at present and that the heat supply would be from renewable (low or zero carbon) sources.

| | |
|---|---|
| Direct Business Costs | 0.7 |
| Direct Business Benefits | 0.0 |
| Net Direct Cost to Business | -0.7 |

## Wider Impacts

### Small and Micro Business Assessment

143. The primary powers sought at this stage are ‘enabling powers’ only, therefore a full small and micro business assessment will be carried out as part of secondary legislation. While we have proposed the broad categories of buildings in zones which may be required to connect to a heat network, at this stage there is not enough detail known about how these proposals may impact small and micro businesses, nor how the exemption process may apply, to enable a full assessment. Highlighted here is the current view about potential impacts on small and micro businesses.

*Heat Network Developers and Supply Chain*

144. Some heat network developers and organisations in the supply chain may be small or micro businesses. There will be administrative burdens for heat network developers and operators regarding heat network projects in zones. These costs, as a proportion of existing costs, will likely be higher for small and micro businesses. However, an exemption from these requirements isn’t appropriate given that large district heat networks will be deployed in zones, and the heat network developers and operators will be required to familiarise themselves with the legislation to ensure consumers receive the best outcome.

145. Analysis of the current stock of heat networks suggests that many of the current heat network suppliers are small and micro businesses, however this hasn’t been split by communal and district heat networks. Heat network zoning will deploy only district heat networks. Therefore, the current stock of heat network suppliers may be an inappropriate evidence base for the size of heat network suppliers that will operate heat networks in zones.

*Heat customers in existing buildings*

146. Current proposals may require social landlords, housing associations and private landlords of domestic premises with communal heating systems to connect to heat networks. Some of these will be small or micro businesses. Large non-domestic buildings in zones will also be required to connect. Small and micro businesses that own or rent space in large non-domestic buildings may also be impacted. At present it is not possible to gauge the scale of that may be impacted in this way. We will use the outputs of the zoning pilot to develop the evidence base on the size of zones and types of buildings that will be mandated to connect within them.

Heat network consumers in zones will face administrative burdens related to familiarising themselves with the requirements of the policy. There isn’t anticipated to be a significant familiarisation cost for heat consumers, these costs would fall on the heat network developer and operator. Where there are some administrative costs for heat consumers, we don’t anticipate that these would pose disproportionate burdens to small and micro businesses. Additionally, any requirement to connect would happen in an appropriate timescale for all consumers, minimising the burden of connecting to a heat network.

147. The zoning methodology will determine where heat networks offer the lowest cost, low carbon heating solution for decarbonising those buildings. This may actually reduce the

administrative burden for mandated buildings within a zone to work out the most cost-effective way to decarbonise their heating.

148. For buildings in zones that believe they can decarbonise their heating at lower cost following a different solution, there will be an exemption process. This is potentially the most significant administrative burden for heat consumers. A standardised tool will be developed for this process, which will minimise any costs associated with the act of applying for exemptions, meaning that the exemption process will not pose a disproportionate burden on small and micro businesses.

149. Another group of heat customers that may be impacted are micro businesses operating “from home” out of domestic properties in communally heated buildings in zones. These types of buildings are likely to already have the infrastructure in place to allow this type of connection and therefore costs of connecting to a larger district system would be minimal, particularly given that zones will be defined as areas where heat networks offer the lowest cost, low carbon heating solution.

*New Build Developers*

150. There is potential for a small additional burden on new build developers whose buildings are required to connect to heat networks, some of which will be small and micro businesses, as they may need to upskill staff and potentially pay for a connection charge. Under the vision for the Future Homes Standard for new builds however, all new builds will be required to install low carbon heating solutions, and zoning will provide a route to the most cost-effective low carbon heating solution. Therefore, if the Future Homes Standard is legislated first, there aren’t expected to be any additional costs to new build developers due to heat network zoning. For this reason, an automatic exemption for small and micro new build developers is not considered necessary.

*Other Stakeholders*

151. A wider group of stakeholders who may be small or micro businesses have also been considered, for example supply chain organisations and training providers. It has been considered that where any of these groups fall into the category of small or micro businesses, there would not be any detrimental impacts from the zoning policy, as the policy would present opportunities to these groups in terms of more business or investment opportunities, rather than additional costs.

**Trade and Investment Assessment**

152. Heat network zoning will grant local authorities the power to designate zones where heat networks become the default low carbon heating solution. Zones will be defined as areas where heat networks offer the lowest cost solution for decarbonising buildings. Within zones, certain buildings will be mandated to connect to heat networks. The primary objective of the heat network zoning policy is to grow the market for low carbon heat networks.

153. Therefore, the policy may be expected to increase foreign investment into the UK, particularly by European heat network developers. There is already a presence of European companies within the UK heat networks market, with organisations such as Vattenfall (Swedish) or Engie (French) having a significant presence in part due to current heat network policies. With the introduction of heat network zoning this trend may be expected to continue, and indeed there may also be inward investment from non-European companies.

154. There will be no discrimination between domestic and foreign businesses in regard to heat network zoning. The specific policy is still being developed, but it is expected that there

will be a competitive process to procure heat network developers to develop heat networks within zones. The competitive process will be non-discriminatory between foreign and UK heat network developers. Additionally, it is not expected that heat network zoning will constitute a Technical Barrier to Trade (TBT) as it doesn't create any additional requirements for foreign entities to trade with the UK. New heat networks deployed in zones will be required to be low carbon and adhere to the technical standards specified by the Heat Network Market Framework. It isn't expected that either of these requirements will constitute a TBT.

155. As a result of the expertise developed through implementing heat network zoning, the UK may be able to increase exports of heat network services. Indeed, the most recent Energy Innovation Needs Assessment identified heat networks services as one of the UK's greatest export opportunities from low carbon heating in its 'Heating and Cooling' report.33

**Competition Assessment**

156. Heat network zoning will designate areas where certain buildings are mandated to connect to heat networks. These areas will be defined where heat networks offer the lowest cost means of decarbonising heat, determined by a technical methodology.

157. Where an area has been designated a heat network zone, heat network developers will be procured via a competitive process. In some circumstances, one heat network developer will be procured for the whole zone, in others there may be multiple heat network developers within a single zone. In each of these circumstances, there will be a competitive process to procure a heat network developer for the final consumers. This method of procurement is intended to encourage bids from a range of suppliers and thereby deliver a heat network solution which offers the best value for money for consumers.

158. Ahead of a zone being designated, the local authority will run a consultation process with buildings that are mandated to connect to the heat network. Additionally, an exemption process is being developed for buildings that have been mandated to connect to a heat network - within a zone - but believe that they could decarbonise their heating at lowest cost in an alternative way. This ensures that consumers can implement an alternative low carbon heating solution if it would be preferable for them and provides further competitive pressure on the local heat network to offer good value for money to avoid losing otherwise profitable customers.

159. Once consumers are on a heat network, it becomes very difficult for them to switch either their heating technology or heat supplier. At this point, the heat network operator has market power which they may be able to exploit. Given that this is the case, BEIS is ensuring that consumers are provided with consumer protection from the Heat Network Market Framework (HNMF). The HNMF will give Ofgem, as the national regulator, the powers to investigate pricing and to regulate quality of service standards that are provided to consumers on heat networks.

160. An important distinction regarding competition relates to cases where the customers are single owner-occupiers of buildings, or where customers are within buildings of multiple occupancy. In the former case, the customer has more ability to engage with the policy than the latter case. Where customers are within buildings of multiple occupancy, for example businesses renting out office space in large buildings, they may have less control over decisions regarding how to decarbonise the building's heating system. The detail regarding

[33] https://www.gov.uk/government/publications/energy-innovation-needs-assessments

how these situations will be dealt with will be specified in secondary legislation. Through the HNMF, BEIS will also ensure that these consumers are protected to the extent necessary.

### Equalities Assessment

161. An equality impact assessment of the policy option has been carried out. Heat network zoning will directly affect future domestic customers of heat networks in heat network zones. Precise locations will not be known until zones are designated, but the assumption based on evidence from pilot studies and international experience is that heat network zoning is best suited to urban environments. The equality implications will be kept under review to consider further relevant evidence as it becomes available. The evidence for the equality assessment has been based on the current population who are on heat networks. For the purposes of this assessment, we assume that new customers will be similar to existing customers on heat networks.

162. The assessment identified that people who are 65+ years of age and people from Black, Asian and Minority Ethnic (BAME) backgrounds are more likely to be served by heat networks, using most recent evidence[34]. There was no evidence that gender or disability had a disproportionate representation, amongst people served by heat networks.

163. We assume that groups with the protected characteristics of gender reassignment, marriage/civil partnership, pregnancy and maternity, religion or belief, and sexual orientation are unlikely to be disproportionately impacted by connection to heat networks in heat network zones compared to energy customers who do not share those characteristics. However, we have not been able to identify any evidence that would confirm or refute this assumption.

164. A key factor to assessing the impact of the policy on groups is the cost of heating relative to income. It may be considered that people who are 65+ years of age may also have increased heat demand relative to younger occupants and may be more susceptible to fuel poverty. However, it is not anticipated the zoning proposals would negatively impact these groups for the following reasons:

a. The proposal is that zoning would only apply to domestic consumers who already live on communal heat networks, therefore there should not be a change in these consumers' experience before and after heat network zoning. The proposal will also apply to new build developments.
b. The proposal includes an exemption process to be applied on request, which would remove requirement to connect where it would not be cost-effective to do so.
c. The consultation seeks views on whether additional protections are necessary for consumers living in a Heat Network Zone, besides those to be introduced through the Market Framework. Under the Market Framework domestic customers have certain protections, and the Heat Network Zoning consultation seeks views on extending those protections to non-domestic consumers within zones.

165. The Heat Networks Consumer and Operator Survey, and Heat Network Zoning pilot studies will be designed to capture evidence on the potential impacts of the policy on groups, to improve the equalities impact assessment going forward.

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[34] BEIS (2017) Heat Networks Consumer Survey: consumer experiences on heat networks and other heating systems. December. Available online at https://www.gov.uk/government/publications/heat-networks-consumer-survey-consumer-experiences-on-heat-networks-and-other-heating-systems.

## Consumer Bills

166. It isn’t possible to estimate the average impact on consumer bills of switching from gas-based heating to low carbon heat networks. Currently, there is a large disparity between gas and electricity prices, making low carbon heating relatively more expensive compared to higher carbon, gas-based heating systems. However, in the Heat and Buildings Strategy we committed to look at options to shift or rebalance energy levies (such as the Renewables Obligation and Feed-in-Tariffs) and obligations (such as the Energy Company Obligation) away from electricity to gas over this decade. We will launch a Fairness and Affordability Call for Evidence on these options for energy levies and obligations to help rebalance electricity and gas prices and to support green choices, with a view to taking decisions in 2022.

167. The extent that gas and electricity prices will change, and when this will happen, is currently uncertain. Therefore, it isn’t possible to estimate the impact on the average consumer bill of heat network zoning. Further work is being carried out to establish how and against which low carbon alternative (counterfactual) the methodology will test heat networks against – in either an electrification or hydrogen pathway. In the recently published Heat and Buildings Strategy, there is a commitment to aim for cost parity between heat pumps and gas boilers by 2030 with significant cost reductions of at least 25-50% by 2025 and ensuring heat pumps are no more expensive to buy and run than boilers by 2030.

## Fuel Poverty

168. According to analysis of the English Housing Survey, the proportion of consumers in fuel poverty on heat networks is lower than consumers not on heat networks[35]. However, for heat network zoning we would need evidence on the likely make up of future consumers who would connect to heat networks, rather than current consumers. Data of this granularity is not yet available. As described above, this is an area we will build our evidence base on ahead of future consultations and the secondary legislation, through the zoning pilot.

169. Under current gas and electricity prices, consumers would be likely to pay more for their heating on low carbon heat networks relative to gas-fired heating. It isn’t currently possible to estimate the likely impact on bills towards the end of the 2020s, as set out in the preceding section.

170. One of the types of buildings that may be mandated to connect under the preferred policy option is social housing blocks with communal heating. It may be possible that there are a greater number of consumers at risk of fuel poverty within this building type. All consumers that are mandated to connect to heat networks will be provided the consumer protection measures which are offered by the Heat Network Market Framework. Fuel poverty considerations will be an essential feature of the zoning policy as it develops ahead of secondary legislation.

## Regional Impacts

171. There will be strong strategic cases for implementing heat network zones across England. Table 23 presents the regional breakdown of towns and cities that we have assumed to be suitable for implementing heat network zones, within the underlying analysis

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[35] English Housing Survey 2018 to 2019, https://www.gov.uk/government/collections/english-housing-survey’

in this impact assessment. The criteria for determining whether a town or city is suitable for heat network zoning, has been derived from evidence from heat network feasibility studies.

*Table 23 – Representation of how zoning could be deployed across the top 200 towns and cities, using population estimates*

| Region | Number of Towns and Cities |
|---|---|
| East Midlands | 12 |
| East of England | 21 |
| London | 31 |
| North East | 11 |
| North West | 29 |
| South East | 38 |
| South West | 14 |
| West Midlands | 26 |
| Yorkshire and The Humber | 18 |
| **Total England** | **200** |

172. Towns and cities have been identified using the ONS Built Up Area Sub-Divisions (BUASD) boundaries. Whilst many towns and cities are categorised under a single BUASD, larger metropolitan areas such as Greater London and Greater Manchester have multiple BUASDs which correspond to metropolitan boroughs. The top 200 towns and cities have been approximated using the top 200 BUASD ranked by ONS population estimates; the smallest BUASD is estimated to have a population greater than 50,000 people.

## Jobs Impacts

173. Heat network zoning will support direct and in-direct jobs in England. The policy will support jobs in mapping and planning heat networks, the construction of heat networks and their operation and maintenance. As set out above, there is also expected to be an expansion of capacity within local government, central government and the national regulator to support the implementation of the policy. It is anticipated that heat network zoning will support 8,000 direct in-year jobs by 2050, under the preferred policy option.

174. Additionally, the policy will support in-direct jobs. The policy is multifaceted and therefore the jobs can take various forms. For example, there may be in-direct jobs supported to assist businesses in understanding what they are required to do under the policy. By 2050, 7,000 in-direct jobs may be supported by heat network zoning.

## Interactions with other Policies

175. The Heat and Building Strategy[36] sets out how the UK will decarbonise homes, and commercial, industrial and public sector buildings, as part of setting a path to net zero by 2050. Within the Heat and Building Strategy, the Heat Network Zoning policy looks to promote deployment of heat networks in areas where they are the lowest-cost solution for decarbonising heat.

176. The objectives of Heat Network Zoning reinforce a number of policy areas within the Heat and Building Strategy, including transitioning existing buildings to low-carbon heat,

[36] Heat and Buildings Strategy https://www.gov.uk/government/publications/heat-and-buildings-strategy

decarbonisation of buildings and sectors, and development of new low-carbon buildings. In this section we will describe how the Heat Network Zoning policy interacts with wider policies set out in the Heat and Buildings Strategy.

*Interaction with wider heat network policy*

177. To start with wider heat network policy, the Heat Network Market Framework (HNMF) will have important and significant impacts on the success of Heat Network Zoning. The Heat Network Market Framework will appoint a regulator for the heat networks sector with powers to regulate consumer protection (including pricing and quality of service), decarbonisation, provide extra rights and powers to operators and introduce technical standards.

178. The HNMF is an enabling policy for Heat Network Zoning since it will address key market failures for heat networks by establishing a regulatory framework for the sector. One impact of the HNMF is to increase confidence in the development and adoption of heat networks. Heat Network Zoning will look to accelerate the deployment of heat networks by addressing remaining market failures for heat networks, connection uncertainty and coordination failure.

*Interaction between zoning and other technologies*

179. Section 5.3 of the Heat and Buildings Strategy discusses pathways for the transition to low carbon heat, including greening the gas grid, building a market for heat pumps, transforming the heat network market, and unlocking the potential for hydrogen for heating.

180. Heat network zones will be designated in areas where heat networks offer the lowest-cost means for decarbonising heat. However, to achieve the full benefits of implementing a heat network zone, there needs to be high levels of buildings connecting to heat networks, many of which would be voluntary. High uptake of individual heat pumps and hydrogen boilers within zones could limit the benefit of the zone for providing lowest-cost heat. This would limit the size of zones and ability for buildings to connect to a heat network.

181. Therefore, it is important that the implementation of zoning is effectively coordinated with other pathways for the transition to low carbon heat to ensure that the policies work to deliver options for lowest-cost, low-carbon heating solutions, that represent consumer preference.

*Interaction between Zoning and Wider Policies*

182. Section 5.2 of the Heat and Building strategy sets out a portfolio of policies that are designed to decarbonise the building stock, by sector, in the 2020s. Whilst the main focus for these policies is to improve energy performance, through fabric efficiency measures, a number of the policies will also promote the transition to low-carbon heating in the 2020s.

183. Whilst the Heat Network Zoning policy will look to decarbonise heating for buildings over a longer timeframe, from 2025 to 2050, it will target similar groups of buildings to energy performance schemes such as the Public Sector Decarbonisation Scheme, Social Housing Decarbonisation Fund and Home Upgrade Grant. Therefore, it will be important that policies are aligned to achieve long-term strategic outcomes for decarbonisation of buildings.

184. The Future Homes Standard (FHS) and the Future Building Standard (FBS) set out pathways to developing highly efficient new buildings which use low carbon heat. Under each

of the options for the Heat Network Zoning policy, new buildings within zones would be mandated to connect to a low-carbon heat network. It is not expected that Heat Network Zoning would increase costs for developing new builds, since the FHS and FBS both require low-carbon heating, and within zones, heat networks offer the lowest-cost, low-carbon heating. This is discussed further in the Small and Micro Business Assessment section.

## Monitoring and Evaluation

185. We will implement robust monitoring and evaluation during and after program delivery. Given the policy is at primary legislation stage, our M&E plans are restricted until further policy scoping and delivery planning is undertaken; however, additional recruitment has taken place, specifically for M&E posts, to meet the requirements of the policy.

186. The evaluation will be complex due to the novelty of the policy, its geographical coverage, delivery model and range of stakeholders. The evaluation design will draw upon insight from other M&E in this space, including the Heat Networks Investment Project and the Green Heat Network Fund evaluations.

187. The zoning pilot will launch in 2022 which will test elements of the zoning policy ahead of its implementation in 2024. The zoning pilot will have its own evaluation, through which certain aspects of the zoning policy design or process may be refined. The overall zoning evaluation will build upon aspects of this pilot evaluation.

188. The evaluation plan will be derived from the Theory of Change as set out in Annex 4. The evaluation will be predominantly theory-based, and will include components of process, impact and financial (cost-benefit analysis) evaluation. It will seek to answer the questions below, taking account of what works/ doesn't work for whom and in what circumstances.

**Impact evaluation**

- To what extent has the regulation achieved the objectives set out in paragraph 25?
- Has the number and pace of low carbon heat networks delivered increased?
- To what extent have carbon emissions decreased?
- Has there been an increase in the use of waste heat sources in in heat networks deployed in zones?

**Process evaluation**

- How has the design of the regulation influenced the impacts that were achieved?
- How has the policy been delivered, what worked/ didn't work?

**Economic evaluation**

- What have the costs and benefits of the policy been?
- Across different sub-projects, how much has been invested, and what is the anticipated long-term return?
- What is the energy cost for consumers, and how does this compare to other markets, including higher carbon alternatives?

189. The data that would feed into the evaluation would be collected by Ofgem and the zoning data coordinators. The zoning data coordinators will monitor heat network development within zones and monitor and report on the performance of heat networks. Under the market framework, all heat networks will be required to report annually to Ofgem. Ofgem will also monitor how heat networks perform against the consumer protection and technical standards as set out in legislation. At this point it isn't certain where the data would come from for the zoning evaluation, this will be decided as more detailed delivery planning for the policy takes place.

190. More information on our monitoring and evaluation strategy will be provided alongside the final-stage impact assessments supporting the secondary legislation.

# Annexes

## Annex 1 – Detailed modelling assumptions

*Table 24 – Capital and operating cost per generation technology (heat networks)*

| **Generation Technology** | **Capex** Unit | **Capex** Value | **Opex Unit** | **Opex Value** |
|---|---|---|---|---|
| Air Source Heat Pump | £/kWth | 550 | £/ kWh/ yr | 0.003 |
| Ground Source Heat Pump | £/kWth | 600 | £/ kWh/ yr | 0.003 |
| Water Source Heat Pump (WSHP) | £/kWth | 900 | £/ kWh/ yr | 0.003 |
| WSHP - Low grade waste heat | £/kWth | 549 | £/ kWh/ yr | 0.002 |
| WSHP - Medium grade waste heat | £/kWth | 431 | £/ kWh/ yr | 0.001 |
| Energy from Waste | £/kWth | 100 | £/ kWh/ yr | 0.002 |
| Heat Exchanger (high grade waste heat) | £/kWth | 221 | £/ kWh/ yr | 0.004 |
| Gas CHP | £/KWh | 675 | £/ kWh/ yr | 0.01 |
| Back-up Gas Boiler | £/KWh | 23 | £/ kW(th)/yr | 2.250 |

*Table 25 -Capital and operating cost per technology (counterfactual)*

| **Generation Technology** | **Capex** Unit | **Capex** Value | **Opex Unit** | **Opex Value** |
|---|---|---|---|---|
| Commercial | £/kWth | 239 | £/ kW(th)/yr | 5.96 |
| Domestic Gas Boiler | £/KWh | 0.22 | £/ kWh/ yr | 0.01 |
| Electric Heater | £/kWth | 98 | £/ kW(th)/yr | 17.00 |

*Table 26 - Distribution Infrastructure Capex (factual and counterfactual)*

| **Cost** | **Unit** | **Value** |
|---|---|---|
| Network capex | £/MWh | 300 |
| Ancillary capex | £/MWh | 150 |

*Table 27 - Thermal Efficiency (factual and counterfactual)*

| **Heat Network/ Individual** | **Generation Technology** | **Thermal Efficiency (%)** |
|---|---|---|

| | | |
|---|---|---|
| Heat network | Air Source Heat Pump | 321 |
| | Ground Source Heat Pump | 284 |
| | Water Source Heat Pump (WSHP) | 330 |
| | WSHP - Low grade waste heat | 541 |
| | WSHP - Medium grade waste heat | 690 |
| | Energy from Waste | 500 |
| | Heat Exchanger (high grade waste heat) | N/A |
| | Gas CHP | 40 |
| | Back-up Gas Boiler | 85 |
| Individual | Commercial Gas Boiler | 84 |
| | Domestic Gas Boiler | 86 |
| | Electric Heater | 100 |

## Annex 2 - Detailed sensitivity analysis

New builds are not included in deployment and SNPVs in the table below, to minimise duplication with benefits from new build policies.

*Table 28 – Sensitivity analysis for the Low policy option*

| | | Social Net Present Value (£m) | | | | | |
|---|---|---|---|---|---|---|---|
| | | Heat generation technology scenario | | | | | |
| | | Central | | | Alternative | | |
| | | Policy cost scenario | | | Policy cost scenario | | |
| | Deployment in 2050 (TWh/yr) | Low | Central | High | Low | Central | High |
| **Lower** | 0.2 | -220 | -260 | -300 | -210 | -250 | -290 |
| **Central** | 2.9 | -230 | **-270** | -310 | -80 | -120 | -170 |
| **Higher** | 4.2 | -240 | -280 | -320 | -20 | -60 | -100 |

*Table 29 – Sensitivity analysis for the Medium policy option*

| | | Social Net Present Value (£m) | | | | | |
|---|---|---|---|---|---|---|---|
| | | Heat generation technology scenario | | | | | |
| | | Central | | | Alternative | | |
| | | Policy cost scenario | | | Policy cost scenario | | |
| | Deployment in 2050 (TWh/yr) | Low | Central | High | Low | Central | High |
| **Lower** | 1.4 | -260 | -300 | -350 | -180 | -230 | -270 |
| **Central** | 18.5 | -340 | **-380** | -420 | 630 | 590 | 540 |
| **Higher** | 26.8 | -380 | -420 | -460 | 1,030 | 980 | 940 |

*Table 30 – Sensitivity analysis for the High (preferred) policy option*

| | | Social Net Present Value (£m) | | | | | |
|---|---|---|---|---|---|---|---|
| | | Heat generation technology scenario | | | | | |
| | | Central | | | Alternative | | |
| | | Policy cost scenario | | | Policy cost scenario | | |
| Deployment Scenario | Deployment in 2050 (TWh/yr) | Low | Central | High | Low | Central | High |
| **Lower** | 3.3 | -300 | -340 | -380 | -120 | -170 | -210 |
| **Central** | 28.9 | -410 | **-450** | -490 | 1,110 | 1,060 | 1,020 |
| **Higher** | 43.2 | -480 | -520 | -560 | 1,780 | 1,740 | 1,700 |

## Annex 3 – Multi Criteria Analysis Methodology

Workshops were held to identify a long list of options and critical success factors. Each critical success factor grouping was given an overall weighting based on the relative importance.

*Table 31 - Critical Success Factors and weightings*

| Weighting | Success Factor Group |
|---|---|
| 50% | Achieving Policy Objectives |
| 10% | Novelty of Policy Proposals |
| 25% | Deliverability |
| 15% | Value for Money |

Each success factor and policy option was then considered and scored using the definitions in Table 32Table 32. A final score was then calculated for each option accounting for the weights of each group of success factors.

*Table 32 - MCA score definitions*

| Definitions for Scoring Options against Criteria | | |
|---|---|---|
| **Score** | **Definition (first 2 groups)** | **Definition (last 2 groups)** |
| 1 | Very weak alignment | Very high |
| 2 | Weak alignment | High |
| 3 | Moderate alignment | Moderate |
| 4 | Strong alignment | Low |
| 5 | Very strong alignment | Very low |

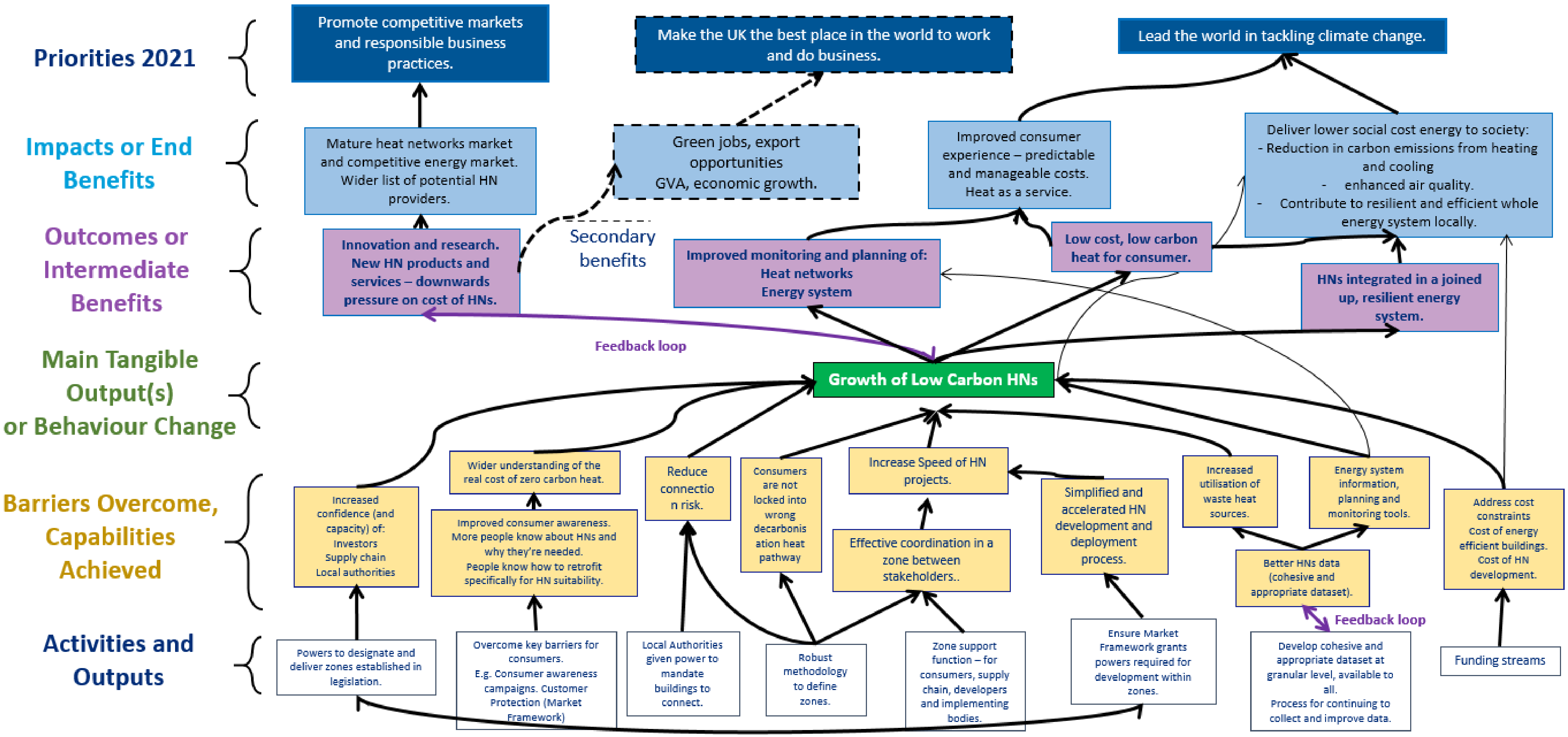
Final scores and a summary of the rationale for each score are shown in Table 33.

*Table 33 – Final scores and rationale for option scoring*

| Critical Success Factors | Weighting | Score and rationale | | | | | |
|---|---|---|---|---|---|---|---|
| | | **Mandatory (compulsion)** | | | **Incentivisation** | | **Structural** |
| | | **Light touch - buildings assess connection** | **Low - key anchor loads** | **High - all suitable buildings mandated** | **Central govt financial support** | **Community engagement campaigns** | **Business rates exemptions** |
| | | **a** | **b** | **c** | **d** | **e** | **g** |
| **Achieve Policy Objectives** | **50** | **1.5** Lowest level of compulsion - minimal impact as may not increase the number of heat networks to the level needed to achieve policy objectives, or address market failures. | **2.9** Low level of compulsion (but higher than "light touch") should address some of the policy objectives but not as much as higher levels of compulsion. | **4.4** Higher levels of compulsion are likely to have the biggest impact on the policy objectives. | **2.9** Financial support will probably be necessary alongside any compulsion options, but alone would likely not be enough to impact some of the key policy objectives like connection risk and coordination failures. | **2.5** Community engagement campaigns important for increasing knowledge of HNs, but alone would not be enough to drive increases in deployment. Previous campaigns to reduce energy bills have not had a big impact. | **2.4** Could be important alongside other options but alone not likely to have big impact on **policy** objectives. |
| **Novelty of policy proposals** | **10** | **3.8** Minimal mandatory connection seen as less politically challenging. | **3.3** Low level of mandatory connection seen to have some level of political considerations but not as much as high mandatory connection. | **2.5** High mandatory connection seen as fairly challenging in terms of political considerations due to potential increase costs and taking away choice from a wider range of buildings. | **3.0** Financial support options alone would likely be less favourable but could have benefits alongside other options. | **4.3** Generally wide support for community engagement campaigns as low cost and potential to facilitate wider knowledge and acceptability of HNs. | **2.5** Financial support options alone would likely be less favourable but could have benefits alongside other options. |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Deliverability** | **25** | **2.0** More complex role for the implementing body in the light touch option as they would have to ensure assessments carried out properly, broker relationships between owners/developers and aligns with other area plans (due to the lower confidence about which buildings will need to connect). | **4.0** Lower mandatory connection would likely require less resource/capability. Will depend on who is the implementing body. | **2.0** Higher mandatory connection would likely require more resource/capability. Will depend on who is the implementing body. | **4.0** Low resource required as there are already some financial support mechanisms in place. | **3.3** Reasonably low resource and capability implications - may already be done in some areas. Adding HNs to existing campaigns would be fairly low additional resource. | **3.3** Medium resource required to implement. Would be a centrally implemented policy but have implications on local authorities |
| **Value for money** | **15** | **4.3** Light touch option would have fairly low cost implications | **3.8** Lower mandatory connection would be lower cost to both government and business than a high mandatory connection option. | **2.5** Reasonably high cost to business if required to connect to HNs and a cost to government in implementing. | **2.5** High cost for government as that is where funding will come from but minimal cost to business. | **4.0** Minimal cost implications. | **3.0** Government may need to compensate Local Authorities for loss of revenue. However, would reduce cost for business. |
| Overall Score | | **2.3** | **3.3** | **3.3** | **3.1** | **3.1** | **2.7** |

## Annex 4 – Theory of Change



## Annex 5 – Groups impacted by the policy[37]

| Group type | Groups | Impact on group | Reference to discussion on impacts in the document |
|---|---|---|---|
| **Government** | Central Government | Cost to designate and implement zones, and support the roll-out of the policy | Methodology – cost to government |
| | Local Government | Cost to designate and implement zones. | |
| | Regulator | Cost to regulate additional heat networks delivered through zoning. | |
| **Business** | Developers | Familiarisation costs. | Methodology – Cost to business. Small and Micro Business Assessment |
| | Operators | Familiarisation costs. | Methodology – Cost to business. Small and Micro Business Assessment |
| | Buildings required to connect | Required to provide information. Applying for exemptions. Disruption costs. Compulsion to supply. | Methodology – Cost to business. Small and Micro Business Assessment |
| | Supply chain | Development. Job and GVA | Non-monetised costs and benefits of each option, not included in the Methodology |
| **Consumers** | Consumers | Disruption costs | Equalities Assessment |

[37] To improve our identification of groups impacted by the policy, and the type and magnitude of impacts on them, there is ongoing research on the social impacts of the policy.

| | |
|---|---|
| **Title:** Heat Networks Market Framework<br>**IA No**: BEIS023(F)-22-CH<br>**RPC Reference No**: RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy, and Industrial Strategy (BEIS)<br>Other departments or agencies: N/A | Impact Assessment (IA)<br>Date: 06/07/2022<br>Stage: **Final**<br>Source of intervention: **Domestic**<br>Type of measure: **Primary legislation**<br>**Contact for enquiries:** Heatnetworks@beis.gov.uk |
| **Summary: Intervention and Options** | **RPC Opinion: Green** |

| Cost of Preferred (£m, 2019 prices, 2020 present value) | | | |
|---|---|---|---|
| Total Net Present Social Value: 0 | Business Net Present Value 0 | Net cost to business per year 0 | Business Impact Target Status Qualifying provision |

**What is the problem under consideration? Why is government intervention necessary?** Heat Networks will be integral to decarbonising heat, especially in a 'Net Zero' world. This heat network regulation aims to respond to a market study by the Competition & Market Authority (CMA), by strengthening consumer protections, improving service quality and standards, and addressing disparities with other utilities. The heat network market is not currently regulated, and some consumers face consumer detriment (outlined in the Heat Network Consumer Survey (HNCS) and CMA market study). This is especially important as Heat Networks have the characteristics of a monopoly, meaning they have market power which can allow them to provide poor services with little consumer recourse. Heat Networks also do not have equivalent statutory powers as other utilities do, which may act as a barrier to growth. This regulation therefore sets out to give Heat Networks these statutory powers.

**What are the policy objectives and the intended effects?** There are three components of this regulation. A) Specifying a heat network regulator and their powers, including powers to take enforcement action. B) Define consumer protection measures to be given to heat network consumers and enforced by the new regulator. C) Define the statutory powers to be given to regulated Heat Networks (rights and powers), to bring them in line with other utilities. The intended effect of A) and B) is to reduce or eliminate the consumer detriment currently faced by some heat network consumers, whilst the intended effect of C) is to provide parity between Heat Networks and other utilities, thus reducing the potential investment risk of Heat Networks. The expected result of these three components together, is to allow for the efficient provision of Heat Networks to customers while maintaining a fair level of consumer welfare.

**What policy options have been considered, including any alternatives to regulation?** There are two overarching options assessed in this IA, a continuation of existing market arrangements (Counterfactual) and establishing a Heat network Regulator. The preferred option is to establish a Heat Networks Regulator and define the required rights and powers, in order to operate in the market a heat supplier must be authorised by the Regulator with optional licensing to gain extra rights and powers. This option has been selected to reflect the structure of the heat network market, reduce unnecessary administrative burdens, and enable the benefits of licensing where required. The consumer protection requirements across both authorised and licensed organisations are expected to be the same.

Will the policy be reviewed? It **will** be reviewed. If applicable, set review date: Secondary legislation

| | | | | | |
|---|---|---|---|---|---|
| Does implementation go beyond minimum EU requirements? | | No | | | |
| Is this measure likely to impact on trade and investment? | | Yes | | | |
| Are any of these organisations in scope? | **Micro**<br>Yes | **Small**<br>Yes | **Medium**<br>Yes | **Large**<br>Yes | |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | Traded:<br>**N/A** | Non-traded:<br>**N/A** | | |

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits, and impact of the leading options.

Signed by the responsible Minister: Date: 24/06/2022

**Summary: Analysis & Evidence Policy Option 1**: **Establishing a Heat network Regulator**

**FULL ECONOMIC ASSESSMENT**

| Price Base | PV Base | Time Period | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| 2020 | 2022 | 10 | **Low:** 0 | **High:** 0 | **Best Estimate:** 0 |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | 0.0 | | 0 | **0** |
| **High** | 0.0 | | 0 | **0** |
| **Best Estimate** | 0.0 | | 0 | **0** |

**Description and scale of key monetised costs by 'main affected groups':**

Costs associated with primary legislation alone are assumed to be negligible. The monetised costs discussed in the main body of the IA reflect the impact of implementing both primary and secondary legislation.

Those monetised pertain exclusively to the costs to establish and run the Regulatory body and the associated costs to business to be compliant with regulatory requirements. Over the 10-year appraisal period, the central additional discounted regulatory costs from the secondary stage are estimated to be £51.0m for developing the regulatory regime, managing the regime, monitoring reporting and monitoring prices respectively. The additional costs to Heat network owners/operators to be compliant is estimated to be £18.4m: this accounts for the cost of applications, familiarisation with the regulation, general compliance costs and complaints handling.

**Other key non-monetised costs by 'main affected groups':** There may be additional costs incurred by heat suppliers due to the need to address any compliance and enforcement issues raised by the Regulator. These costs have not been included as they are highly uncertain and would be avoidable through compliance with the requirements. Furthermore, there may be further regulatory requirements placed on Heat Networks which will be set out by the Regulator such as technical standard and decarbonisation requirements. These impacts will be considered in secondary legislation.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | N/A | | N/A | **N/A** |
| **High** | N/A | | N/A | **N/A** |
| **Best Estimate** | N/A | | N/A | **N/A** |

**Description and scale of key monetised benefits by 'main affected groups':** Benefits associated with primary legislation alone are assumed to be negligible. The associated benefits with implementing both primary and secondary regulation have not been monetised due to the stage of policy development; however, a quantified scale of potential benefits has been provided where evidence allows i.e., consumer protection, pricing, technical standards and extra rights and powers.

**Other key non-monetised benefits by 'main affected groups':** Evidence from the heat network consumer survey suggests that heat network consumers face higher detriment relative to gas and electricity customers. Analysis of heat network tariff data suggest that between 7 – 17% of domestic consumers pay more than a gas boiler comparator. Evidence from the Heat Trust suggests technical standards are the leading cause of complaints and analysis of operational data from 14,000 networks suggests 17 – 28% of networks experience high distribution losses. Heat Networks currently have fewer rights and powers relative to other utilities, which can limit deployment and maintenance. Step-in rights will ensure consumers are protected in the event of a supplier exiting the market. Future decarbonisation requirements will ensure the sector can make the required contribution to net-zero.

| **Key assumptions/sensitivities/risks** | Discount rate (%) | 3.5 |
|---|---|---|

There is uncertainty associated with the final scope and approach to regulation, due to the policy being at primary legislation phase and the inherent uncertainty in regulating a new market, namely the scale of required regulatory activity which is reflected in the estimated costs. In addition, there is uncertainty over the current size of the heat network market. For simplicity, the composition of the market is assumed to remain constant. The assessment of impact of the proposed power provides an indicative sense of scale of the potential impact, however how effective the Regulation will be is dependent on future policy design and the response of the industry.

**BUSINESS ASSESSMENT (Option 1)**

| Direct impact on business (Equivalent Annual) £m: 0 | | | Score for Business Impact Target |
|---|---|---|---|
| **Costs: 0** | **Benefits: N/A** | **Net: 0** | 0 |

# Contents

# Executive Summary

1. A Heat network is a distribution system of insulated pipes that takes heat from a central source and delivers it to a number of domestic or non-domestic buildings. Heat Networks are a crucial aspect of the path towards the cost-effective decarbonisation of heat and achieving net zero by 2050. In the right circumstances, they can reduce bills, support local regeneration and can be a cost-effective way of reducing carbon emissions from heating. Heat Networks have the potential to provide around 20% of the UK's heat demand in a least-cost pathway to net-zero, up from 2/3% today[1].

2. The Competition & Market Authority (CMA)[2] released a market study on Heat Networks in 2018. The CMA set out a number of recommendations for the regulation of Heat Networks. This is a recommendation BEIS agrees with. This IA supports the primary legislation proposal to regulate the heat network market. This includes quantified estimates of the cost of establishing the regulator and the costs to business of being compliant with the requirements. In addition, a quantitative assessment of the potential impact of the proposed powers has also been included.

3. The evidence and analysis carried out in this impact assessment suggests that relative to non-heat network consumers, Heat Networks customers can face lower levels of transparency and quality of service, instances of disproportionately high pricing, instances of poor technical performance and lack of protections in the event of a supplier exiting the market. In addition, unlike other utilities, heat network developers/owners lack the same rights and powers, which can make developing and operating network more burdensome.

4. The Heat network market framework will aim to alleviate/ reduce these issues by introducing greater consumer protections, improve performance through promoting technical standards, and drive forward the growth in the market by ensuring heat network developers can gain access to extra rights and powers. Furthermore, the regulator will have powers to impose future decarbonisation requirements, which will help ensure the sector can make its vital contribution to net-zero.

5. The proposed heat network regulatory arrangement is a tripartite structure consisting of Ofgem as the core regulator, Citizens Advice as the consumer advocacy body and the Energy Ombudsman as the independent dispute resolution body. Across the 10-year appraisal period, additional primary and secondary total costs of funding these organisations are estimated to be £51.0m (discounted), this accounts for the implementation of different aspects of the Regulation and anticipated market growth. The additional estimated costs to business to be compliant with the core requirements of the Regulation is £18.4m (discounted), this includes costs associated with familiarisation, applications, reporting and additional administrative costs.

6. There are expected to be significant benefits which could be unlocked/enabled through the HNMF, ensuring consumers are protected as the market grows. Although, this will depend on how the proposed regulatory powers will be used, which will be subject to further policy development and consultation at secondary legislation stage.

# Problem under consideration

7. The Heat Network market is currently unregulated[3] unlike other utilities such as gas and electricity. This means that currently heat network consumers do not benefit from the same levels of protection as gas and electricity consumers. Further to this, organisations

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[1] Based on analysis using the Heat Networks experimental statistics, 2018 < https://www.gov.uk/government/publications/energy-trends-march-2018-special-feature-article-experimental-statistics-on-heat-networks >

[2] CMA Market Study on Heat Networks <l https://www.gov.uk/cma-cases/heat-networks-market-study >

[3] With the exception Heat Network (Metering and Billing) Regulations 2020 < https://www.gov.uk/guidance/heat-networks >

involved in the development and operation of Heat Networks do not have the same rights and powers as their gas and electricity counterparts, despite both delivering vital services.

8. A market study[4] by the Competition and Markets Authority (CMA) found that, though many heat network consumers are supplied heat at comparable consumer standards to the wider energy sector, a significant proportion experience poor service, including high pricing. The report recommended that the sector should be regulated by a public-sector body which has statutory powers to set regulation, monitor compliance, and enforce against heat network operators that do not comply with the regulation.

9. BEIS agrees with the findings of the CMA to regulate Heat Networks to ensure adequate protections for all heat network consumers, support market growth and decarbonise at the rate needed for it to make its contribution to Net Zero. The government is proposing to establish a regulatory framework for Heat Networks which protects consumers, promotes technical standards, and drives forward the growth and decarbonisation of the Heat Networks market.

## Rationale for intervention

10. A number of market failures and barriers have been identified in the Heat network market which contribute to inefficiencies, drive poorer consumer outcomes, and limit the deployment of Heat Networks below what would be socially optimal.

- **Monopolistic characteristics –** In the right circumstances Heat Networks can offer the most cost-effective provision of heating and/or cooling. Thus, it is the case that it is most efficient for one supplier to supply the market, or in this case supplying the heat to a pool of consumers. However, once connected it is often not possible or feasible for a customer to dis-connect or be excluded. This could lead to instances where consumers face detriment and have little recourse, as the network has market power. This may mean Heat Networks are able to provide poorer services and extract rents from consumers, above what is efficient and equitable.
- **Incentives –** In conjunction with the monopolistic characteristics, Heat Networks are often developed by for-profit organisations without full representation of the future customers. The CMA's market study suggested that developers could have an incentive to be myopic and try to minimise the up-front costs to the detriment of consumers, either through lower standards or recovering additional costs through future consumer bills.
- **Information Failures -** Heat network customers can often face incomplete information and a lack of transparency. When a customer joins a heat network, they often are unfamiliar with its heat network characteristics, which can prevent them from making informed decisions. Once a customer has joined, they may also face a lack of transparency in billing; customers may not be aware of how their bills are broken down and why they are paying what they are.
- **Development/maintenance barriers -** Organisations involved with the development and maintenance of Heat Networks currently have fewer rights and powers, relative to other energy utilities. This can make building, maintaining, and expanding networks more challenging and burdensome. In-part, this could contribute to poorer service standards and a lower level of heat network deployment than would be socially optimal.
- **Equity issues –** In comparison to other utility providers, heat network consumers are not given the same level of protection. This is compounded by the fact that networks tend to serve more vulnerable and elderly consumers. This may mean heat network consumers are disproportionally impacted by instances of consumer detriment, with little recourse or protection.

## Policy objective

11. This regulation has three objectives which relate to the problems in the market specified:

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[4]CMA Market Study on Heat Networks <l https://www.gov.uk/cma-cases/heat-networks-market-study >

- **Consumer protection:** Ensure heat network consumers receive adequate levels of protection by implementing consumer protections and minimum technical standards that ensure consumers are protected from disproportionate prices, receive a reliable supply of heat, transparent information, and a continued supply of heat if their supplier exits the market.
- **Support growth:** Accelerate heat network deployment by providing statutory rights and powers which make it cheaper and quicker to build and expand Heat Networks.
- **Support decarbonisation:** Support the future decarbonisation of Heat Networks by setting maximum carbon emission limits in regulation and achieving emission reductions through minimum technical standards.

## Description of options

12. There are two overarching options assessed in this IA: a continuation of existing market arrangements (Option 0: Counterfactual) and establishing a Heat network Regulator (Option 1).

- **Option 0:** (Counterfactual): Continuation of existing market arrangements.
- **Option 1:** (Preferred) Establish a Heat Networks Regulator and define the required rights and powers. In order to operate in the market a heat supplier, must be authorised by the Regulator with optional licensing to gain extra rights and powers.

13. Several other approaches to Regulation were considered in the consultation stage IA, with the equivalent of option 1 being retained as the preferred option. For simplicity only the two options listed above are discussed in the main body of the IA, however for completeness Annex C - Consultation stage options provides an update to the analysis which underpins this decision in the consultation stage IA.

## Non-Regulatory options

14. There are a few non-regulatory initiatives which partially address issues created by the Heat Networks market being unregulated. For example, the Heat Trust[5], which launched in November 2015, established a voluntary, industry-led consumer protection scheme for Heat Networks that guarantees quality of service standards for approximately 11% of heat network consumers. Separately, the Heat Networks Code of Practice[6](CP1), launched in 2015, defines minimum technical standards for the design and build of Heat Networks. Although these are welcome initiatives, heat suppliers are under no obligation to join and/or comply.

15. The international comparison of Heat Networks Regulatory frameworks[7] commissioned by BEIS identified both regulated and unregulated regimes. The report highlights Germany and Finland as examples of largely unregulated regimes but notes that in both countries the competition authorities can step in on competition issues. The report suggested that an unregulated sector may not meet the needs and expectations of UK consumers.

16. When evaluating non-regulatory approaches, they were deemed not viable to achieve the policy objectives. As the requirements would not be enforceable, this approach would be unable to provide the required level of consumer protections and support to the industry. The limited number of heat network suppliers signed up to Heat Trust suggests that rules on consumer standards may need to be mandated to ensure those standards are

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[5]Heat Trust < https://www.heattrust.org/ >

[6]Developed by the Chartered Institution of Building Services Engineers (CIBSE) and the Association for Decentralised Energy (ADE) < https://www.cibse.org/knowledge/knowledge-items/detail?id=a0q3Y00000IMrmGQAT >

[7] The International Review of Heat Network Market Frameworks by BEIS < https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/863937/international-review-of-heat-network-market-frameworks.pdf >

achieved across the market. This view is supported by engagement with heat suppliers not registered with the Heat Trust.

17. Furthermore, the CMA's market study recommended that government should install a statutory regime whereby there is a sector regulator. This recommendation is supported by the government and is further reinforced by responses to both the CMA's market study, and BEIS's Heat Networks Market Framework consultation[8]. Therefore, non-regulatory options have not been considered further in this IA.

## Counterfactual

18. The counterfactual scenario is a continuation of existing arrangements where the heat network market remains unregulated. The Heat Networks market currently has limited self-regulation and industry standards, such as voluntary membership of Heat Trust and the industry led CP1 technical standards. In the absence of future government action, it is likely these initiatives would continue and possibly grow. An indicative scenario of growth in voluntary Heat Trust membership forms the counterfactual for this IA, more details can be found in Annex B.

19. A continuation and possible expansion of voluntary initiatives is likely to be insufficient to remedy consumer detriment issues or satisfy the CMA's recommendations. As a result, the CMA could still choose to launch a market investigation and use its order making powers to remedy some of the concerns directly. Whilst this would result in some issues being addressed, it is not expected to be the most efficient approach and would not address the more systemic issues faced in the market.
20. Given the anticipated growth in the heat network market, if left unaddressed, there is a risk that consumer detriment could grow. In addition, heat network developers would continue to face the same issues when developing and maintaining Heat Networks if they continue to lack certain rights and powers introduced with the HNMF. In the longer term, this could also act as a bottle neck to growth in the market, potentially limiting deployment.

## Option 1: Establishing a Market Framework (Preferred option)

21. Under this option a Heat Networks regulator would be established and would be given the powers necessary to regulate the market, as set out below. The preferred regulatory model for the Heat Networks market is general authorisation with an optional licence for rights and powers. Under this option, every heat supplier and heat network operator must notify to the regulator to be authorised to operate in the market. An authorised entity will need to comply with consumer protection rules for domestic and microbusiness consumers under the HNMF.[9] In addition, heat suppliers that want additional statutory undertaker rights and powers to build or extend Heat Networks must apply for a licence granted by the regulator.

**22.** This option has been selected to reflect the structure of the heat network market and reduce unnecessary administrative burdens, whilst enabling the benefits of licensing where required. Table 1 provides an overview of the key regulatory powers associated with the HNMF.

**Table 1 – Summary of key regulatory powers**

| Regulatory powers | Scope | Description |
|---|---|---|

[8] The Heat Networks Market Framework Consultation <https://www.gov.uk/government/consultations/heat-networks-building-a-market-framework>

[9] All domestic and microbusiness consumers will be protected by consumer protection rules. We are considering whether certain small and medium sized enterprises should also have the option to be protected and are leaving that option open in primary legislation. This IA is based on our current policy position of consumer protections applying to all domestic and microbusiness consumers.

| | | |
|---|---|---|
| **Authorisation** | All heat suppliers and operators | All heat suppliers and heat network operators will be required to be authorised by the regulator to operate in the market. |
| **Licensing** | Optional for developers and operators | Heat network developers and heat network operators will have the option of applying for a licence to be granted statutory rights and powers. |
| **Transparency & Quality of service** | Heat Networks supplying domestic or microbusiness consumers | Introducing minimum requirements on transparency of information pre and post transaction and quality of service standards to ensure a reliable supply of heat to consumers. |
| **Pricing** | Heat Networks serving domestic or microbusiness consumers | The regulator will have powers to collect pricing data, conduct investigations into instances of disproportionately high prices, and intervene when there is evidence of systemic issues on pricing or cases of significant consumer detriment. |
| **Technical standards** | All Heat Networks | Introducing minimum technical standards on the design and build of Heat Networks to reduce heat loss and consumer complaints, with benefits across pricing and reliability of heat. |
| **Step-in rights** | All Heat Networks | Step-in arrangements will ensure continuity of heating for consumers in the event that their supplier exits the market |
| **Extra rights and powers** | All Heat Networks | Provision of extra rights and powers to licensed networks will lead to cost and time savings in the development, extension, and maintenance of networks. |
| **Decarbonisation** | All Heat Networks | Powers for the regulator to monitor and set future maximum carbon emissions limits for Heat Networks. |

## Summary and preferred option and implementation plan

23. The preferred option is to establish a Heat Networks Market Framework in legislation, with a Heat Networks regulator being given powers to enforce regulatory requirements. The proposed heat network regulatory organisation is a tripartite structure consisting of Ofgem as the core regulator, Citizens Advice as the consumer advocacy body and the Energy Ombudsman as the independent dispute resolution body. We expect the three organisations to work collaboratively, to share expertise and market intelligence and to regulate the Heat Networks market efficiently. The proposed roles and responsibilities are detailed in Table 2 below:

**Table 2 - Proposed governance structure of the HNMF**

| | Responsibility in the HNMF |
|---|---|
| **Ofgem** | Administering the authorisation and licensing regimes. Market monitoring, compliance, and enforcement work to enforce consumer protection rules, including audits. Technical standards, market exit arrangements and decarbonisation[10] . Policy development. |
| **Citizens Advice** | Advocacy and advice for heat network consumers. Administer an Extra Help Unit to support consumers in vulnerable circumstances. National awareness campaigns. Reporting systemic issues to the tripartite group. |
| **Energy Ombudsman** | Provide heat network consumers with access to its independent dispute resolution service. Work with regulated entities to advise on how to reduce volumes of complaints. Reporting systemic issues to the tripartite group. |

24. We will introduce primary and secondary legislation to implement the Heat Networks Market Framework. Primary legislation will establish the roles of the Heat Networks regulator, consumer advocacy body, and independent dispute resolution body. It will set out these entities' objectives, the entities' functions and duties, and the powers they will need to perform them. No impacts are incurred from the primary legislation, as reflected in the summary tables on the first page of this assessment. Any cost estimates outlined in the body of the IA reflect the impacts expected from the regulation at secondary stage.

[10] This is an expected area of remit for Ofgem, however, the costs associated with these have not been included in the cost estimate presented in this annex due to stage of policy development.

25. We intend for secondary legislation to set out in detail the rules and conditions which must be met to be compliant with regulation. This will include setting standards, requirements, and rules which the Heat Networks market will need to comply with and which the regulator will have powers to enforce. This will form the basis of conditions for authorisation to supply or operate a heat network. Conditions for obtaining a licence for statutory rights and powers will also be set out in regulations. We will work with the members of the tripartite regulatory structure to develop policy which will feed into public consultations on the policy approaches for secondary legislation before laying Statutory Instruments before Parliament to ensure stakeholders can provide views on policy design.

26. Secondary legislation will introduce transitionary arrangements, which will mean different elements of regulation will come into force at different times. Regulation needs to account for the importance of ensuring consumers receive adequate levels of protection as soon as possible, the level of preparedness of the Heat Networks market for complying with different aspects of regulation, and set-up and preparatory phases which the regulator and regulatory bodies need to undergo to enforce the rules. Table 3 provides an illustrative timeframe of this phased approach to the Heat Networks Market Framework.

**Table 3 – Indicative implementation timeframe**

| Year | Activity |
|---|---|
| **Year 0** | Secondary legislation introduced and passed. Ofgem set-up phase: developing the data solution for the authorisation and licensing regimes and to support compliance work; policy development; market monitoring; market engagement. |
| **Year 1** | Regulation enters into force - Ofgem becomes operational as regulator. A transition period of 12 months commences, within which all existing heat suppliers and heat network operators need to notify to the regulator to have authorisation. |
| **Year 2** | The transition period ends, with heat suppliers and heat network operators subject to regulatory requirements on certain aspects of consumer protection (e.g., transparency of information) and Ofgem conducting market monitoring and compliance work for these requirements. The Energy Ombudsman and Citizens Advice begin to perform their functions under the HNMF. Heat network developers and operators will have the option to apply for additional licensing for rights and powers. |
| **Year 3** | All heat suppliers in scope of the HNMF will be expected to comply with the framework requirements. Continued phasing in of regulatory requirements such as pricing, technical standards, and step-in rights. The regulator is expected to face additional costs related to compliance and enforcement activities, including auditing, as well as the recurring costs highlighted above. |
| **Longer-term** | Regulator will have powers to amend conditions of authorisation so changes to regulatory requirements may happen to reflect the growth and decarbonisation of the market and Ofgem's learning from regulating the market. Carbon emissions limits come into force, likely in the early 2030s. |

27. We are taking a flexible approach to regulation; this is particularly important given the nascent state of the Heat Networks market and the growth and decarbonisation we expect to see out to 2050. The Regulator will have powers to amend conditions for authorisation. This means that as the market grows and evolves and Ofgem develops more experience of regulating the market, rules on consumer protection can be amended and supplemented to reflect market changes and increased regulatory knowledge.

28. The phasing in of aspects of the HNMF will also allow for the exploration of different approaches to regulation, in consultation with key stakeholders such as industry and consumer groups. Minimum technical standards and consumer protection rules will be developed and expanded in scope over time to allow for flexibility and ensure regulation can take into consideration the development of the market and key learnings.

## Approach to analysis

*29.* To assess the impact of establishing a heat network Regulator, a cost-benefit analysis has been undertaken. This consists of two main elements:

- A quantified assessment of the estimated cost of establishing a Regulator, the Regulatory running costs and the cost to business of complying with the core elements of the Regulation. These costs have been estimated using a Standard Cost Model (SCM)[11].
- An assessment has been made of possible impacts of the proposed regulatory powers. This includes an indication of the scale of the issues the powers intend to address and discussion over where the likely cost and benefits could fall.

30. These costs and benefits are compared against the counterfactual scenario (Option 0). This provides an indication of the expected costs and benefits that arise from the preferred option. The impacts are considered over a 10-year appraisal period. All monetised impacts are presented in 2020 prices and where specified are discounted in accordance with the HM Treasury Green Book[12].

31. This approach has been adopted to reflect the stage of policy development, data availability and difficulty monetising the benefits of Regulation. The qualitative assessment of the impact of proposed powers has been included to provide a sense of the benefits these are envisioned to bring. However, the impact will be dependent on how these powers are used by a future Regulator, which will be subject to future policy development in secondary legislation.

## Evidence sources

32. Key sources of evidence used for the impact assessment:

- **Heat metering and billing regulation (HMBR) notifications**– data on around 14,000 Heat Networks in the UK. The assumptions derived from this source include the current structure of the UK heat network market, estimated number of Heat supplier and the current number of final customers which have been used to assess the likely future burden on the Regulator and industry.
- **CMA market study –** Evidence and data from the CMA market study has been used to strengthen the evidence base, alongside setting out the CMA recommendations.
- **The responses from the 2020 consultation**[13]– The response from the consultation have been used to future develop the policy and analysis of the expect impact of the HNMF.
- **Heat network consumer survey 2017 [14]–** The survey has been used to provide a range of consumer detriment indicators as well inform a number of the assumptions used in the cost estimates.
- **Heat Trust membership data –** Has been used to inform the counterfactual scenario assumptions as well as inform some of the assumptions which fed into both the Regulator and business costs estimates.
- **Ofgem, Citizen's advice and energy ombudsman –** The estimated cost of Regulation has been informed by evidence and insights from these three-organisation based on their expertise in the gas and electricity market.

33. A review of these data/evidence sources has confirmed they are the most appropriate sources for the analysis undertaken. Where evidence gaps have persisted, we have relied on appropriate proxy assumptions and/or evidence from the consultation. Although, there are several key uncertainties and evidence gaps which have been more challenging to manage. A wide range of sensitivities have been tested for the quantified analysis

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[11] Activity cost = price x quantity = (tariff x time) x (population x frequency)

[12] Green book guidance on how to assess and evaluate policy <https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent>

[13] The Heat Networks Market Framework Consultation <https://www.gov.uk/government/consultations/heat-networks-building-a-market-framework>

[14] Heat Network Consumer Survey (HNCS) <https://www.gov.uk/government/publications/heat-networks-consumer-survey-consumer-experiences-on-heat-networks-and-other-heating-systems>

supporting this IA and the remaining evidence gaps have been flagged throughout the IA. Recognising the importance of improving our understanding of the heat network market in order to develop the most appropriate regulatory policies, we are currently undertaking a number of work packages to update/fill remaining evidence gaps which will be used to inform policy development at secondary legislation phase.

# Estimated costs

34. Indicative costs for the impact of the regulation at primary and secondary stage has been estimated for both the counterfactual and Regulatory. These costs pertain exclusively to the cost of establishing a Regulator and the cost to business of being compliant with the requirements. An overview of the costs included is below. Full details on the assumptions used can be found in Annex B – Estimated Cost assumptions.

35. The regulator incurs set-up costs as well as business-as-usual operating costs. These are set out below:

- **Set-up costs:** This will involve the creation of the regulatory framework as well as the systems to manage it, such as setting up a database. It is assumed that these costs take place in the first year of the appraisal period.
- **Operational costs:** This will involve the running of the regulatory regime. The costs to the regulator will relate primarily to compliance, auditing, monitoring the market and enforcement.

36. Heat suppliers and operators are expected to incur costs associated with the requirements of the regulation. Given the stage of policy development only the expected core requirements of the Regulation have been included. These are set out below:

- **Familiarisation and dissemination** - Reading and understanding new regulatory requirements and guidance. This is assumed to happen at a Heat supplier level with dissemination at a heat network level.
- **Authorisation/Licensing application –** All Heat suppliers in the scope of the Regulation will be required to submit an authorisation application to the Regulator and they may also choose to apply for an optional license which is expected to be more time consuming.
- **Reporting –** Annual reporting is expected to be a minimum requirement of the Regulation to gather the information necessary to monitor and regulate the market, this is expected to take place at the Heat network level and is assumed to not require new or specialist IT to complete.
- **Additional administrative costs –** There is expected to be some additional administrative requirements related to dealing with complaints from consumers and preparing the required documentation for audits. The aggregated cost across the market has been estimated, in practise these costs will only be borne by organisation subject to complaints and/or audits.

37. The Regulator and costs to business estimates account for the implementation timeframe and anticipated growth in the market. This has been done by phasing in the costs associated with regulatory activities and therefore the associated resource. To account for the anticipated growth in the market aspects of these costs have been scaled in line with the anticipated growth across the appraisal period. The details on this analysis can be found in Annex B – Estimated Cost assumptions.

38. There may be additional costs incurred by heat suppliers due to the need to address any compliance and enforcement issues raised by the Regulator. These costs have not been included as they are highly uncertain and would be avoidable through compliance with the requirements. Furthermore, there may be further regulatory requirements placed on Heat Networks which will be set out by the Regulator. The impacts of any additional requirements will be considered during the policy development and future secondary legislation impact assessments.

**Counterfactual**

39. The estimated counterfactual costs assume the continuation and growth of voluntary market arrangements. To estimate this, we have forecasted Heat Trust membership over the appraisal period based on the growth in membership over the last 6 years[15], in the central case this leads to around 139,000 customers covered by the Heat Trust by the end of the appraisal period. The current Heat Trust membership fee of £4.61 per customer (Household connection) and £100 per heat network have been used to estimate the total running costs of the scheme. There are no set up costs included as these are sunk costs.

40. There are also expected to be costs to business in the counterfactual. All of the costs to business have been adjusted to reflect the current requirements of Heat Trust membership and only apply to the networks which are members of the Heat Trust. In addition, we have included the costs associated with the 4-year reporting that all networks are required to submit as part of the heat metering and billing notifications. Please see Annex B – Estimated Cost assumptions for more details.

**Table 4 - Overview of total option costs over the 10-year appraisal period (Discounted, £m, 2020 prices)**

| | | Option 0: Counterfactual | Option 1: Establish a Regulator | Additional |
|---|---|---|---|---|
| **Regulator** | Set up | 0.0 | 3.2 | 3.2 |
| | Operating | 4.5 | 52.3 | 47.8 |
| **Heat network operator** | Familiarisation and dissemination | 0.0 | 0.9 | 0.9 |
| | Authorisation/ Licensing application | 0.0 | 0.4 | 0.4 |
| | Reporting | 13.7 | 29.5 | 15.8 |
| | Admin (Audits, complaints) | 0.3 | 1.6 | 1.4 |
| **Total** | | **18** | **88** | **69** |

Note: these costs have been rounded and discounted so may differ from elsewhere in the IA.

## EANDCB

41. This IA has considered the costs and benefits arising to business as a result of setting up a regulator, defining consumer protections and granting rights and powers. Costs and benefits to business can be considered direct or indirect. An impact is considered ‘direct’ if it arises directly from the implementation of the measure. BEIS assesses these direct impacts using the standard methodology to calculate the annual net direct costs for business (Equivalent Annual Net Direct Costs to Business, or EANDCB).

42. All costs presented in this IA are considered to be direct, all costs are expected to directly impact businesses, with the exception of Regulatory set up costs. The EANDCB of the preferred option in the central case are valued at £8.1m per year over the 10-year total appraisal period.

43. To avoid double counting with the heat network zoning final stage IA, we have also calculated the EANDCB to exclude the additional costs associated with market growth due to heat network zoning. When this impact is excluded, the EANDCB of the preferred option in the central case reduces to £7.1m per year over the 10-year total appraisal period. This reflects that if the market growth is attributable to heat network zoning, the

[15] Based on the annual reports from the Heat Trust < https://heattrust.org/annual-reports-v2 >

additional costs of regulating a larger market should be captured under the heat network zoning policy.

## Cost recovery

44. Responses to the consultation stage IA highlighted concerns over the estimated Regulatory costs and their financial impact if they were recovered from heat network consumers alone. Given the relatively small size of the current heat network consumer base, even relatively low costs of Regulation would lead to a large consumer burden. We have worked with industry and the tripartite group to review the cost estimates and investigate other cost recovery options.

45. This resulted in the development of a range of alternative cost recovery options, which are currently out for consultation[16]. For this IA, we have presented the results of the preferred cost recovery option, to recover the costs of Heat network market regulation across gas and electricity consumers, as well as heat network customers. Though, this option may change subject to the results of the consultation. This proposal reduces the average estimated annual impact per heat network consumer from £10.30 to £1.39, whilst increasing the average charge for gas and electricity consumers by around 10 pence annually. This would mean all energy consumers pay comparable amounts for Regulation.  Please seen Annex B – Estimated Cost assumptions for more detail on this analysis.

46. In addition to recovering the cost of funding the Regulator, there could be additional costs passed through to consumers due to the costs to businesses. However, as these estimates do not account for any costs saving to business through the provisions such as extra right and powers or technical standards, this is expected to be an overestimate. The additional costs as expected to be borne by heat network suppliers, who are assumed to passed through 100% to heat network customers. If the costs are recovered in this way, the estimated average impact would be £4.14 per customer per year.

47. Furthermore, the proportion of these costs that are passed on to consumers is expected to vary, for example consultation with local authorities and housing associations suggest the amount passed to consumers may be limited. Although, this would not change the overall cost, just where they are recovered. In addition, many of the organisations which own or operate Heat Networks will have a wider consumer base, over which costs could be recovered. For example, an energy company which operates a heat network may have a wider pool of energy consumers they may choose to recover these costs from, or an organisation like an office, which owns or operates a heat network as part of the business, may be able to recover these additional costs over their wider business consumer base. Therefore, this is likely to be an upper bound estimate of the impact costs to business could have on consumers.

# Assessment of Regulatory benefits

48. The Regulator will have the powers set out above, the impact of these powers will depend on how they are used, which will be detailed in future legislation. For this IA, we have set out an overview of the potential impacts and provided a sense of scale where data has allowed.

**Table 5 – Summary of Regulatory powers impact**

[16] Cost Recovery Consultation on Heat Networks Regulation <https://www.gov.uk/government/consultations/recovering-the-costs-of-heat-networks-regulation >

| Powers | | Consumer | Business |
|---|---|---|---|
| **Transparency & quality of service** | Setting minimum requirements on transparency as quality of service, aims to overcome information failures and inefficiencies. This is expected to bring significant consumer benefits to those consumers who currently have limited protections. It is envisioned heat supplier may have to make changes to their business operation, such as billing procedures and complaints handling | | |
| **Pricing** | There is evidence of disproportionally high price face by a significant minority of consumers. The Regulation will enable investigation to be carried out and intervene if deemed appropriate. Overtime this is expected to improve the understanding of these instances and reduce their prevalence across the industry. This is expected to require suppliers to report on pricing and they may be required to adjust their pricing if deemed disproportionate. In instance where pricing is altered, this would represent a transfer of these cost from consumer to supplier, therefore would need to be manged carefully. | | |
| **Technical standards** | Minimum technical standards are expected to lead efficiency and performance improvements to underperforming networks, to the benefit of both the supplier/operator and the consumers, through potentially lower running costs and improved service standards respectively. While compliance with any future technical standard is expected to come at some costs, the standards are envisioned to follow industry best practise and cost-effective principles. | | |
| **Step-in rights** | Step-in rights will help ensure the continuity of heating in instances where a supplier exits the market and there is no arrangement is place. This is expected to avoid the adverse impact of consumers being left with no heating provision. The Regulator is expected to carry monitoring of the market and provide support to pre-emptively avoid failure where appropriate. | | |
| **Rights and Powers** | The access to rights and power is expected to reduce the reduce the burden associated with deploying and maintaining heat networks. This is expected to reduce the time and cost associated with these activities, for example there is estimated to be a net saving of around £450 per street works application. Consumes are also expected to benefit from improved maintenance and overall benefits associated with heat networks. These powers will be a key enabler of growth in the sector. | | |
| **Decarbonisati on** | A future regulated decarbonisation target would help ensure the network sector make's its contribution to net-zero. This would also provide clear signals and more certainty to the industry. However, Low carbon heat networks typically come at a cost premium to higher carbon alternatives. Although, future policy development is required to ascertain the impact. | | |

Note: Green = expected positive impact, Amber = small impact or uncertain, Red = Expected negative impact

## Transparency & Quality of service

49. The future Regulator will introduce minimum requirements on transparency pre and post transaction (before and after moving into a property on a heat network) and minimum service quality standards to safeguard consumers. This aims to ensure that Heat Networks provide heat reliably and appropriately, as well as ensuring better arrangements for complaints handling, billing processing and information transparency at all stages.

50. These standards are expected to lead to a range of consumer benefit such as access to redress; and a reduction in hassle cost from making complaints or getting information about the heat network. This is also expected to enable heat network operators to be able to evaluate and benchmark their provisions against others in the sector, which could encourage industry to improve standards. There could be some costs associated with any requirements placed on Heat Networks, however these are envisioned to be relatively inexpensive and would bring standards to a comparable footing to the gas and electricity sector. However, these requirements will be subject to future development by BEIS and the future Regulator.

51. The BEIS 2017 heat network consumer survey[17] (HNCS) suggested that heat network consumers were as satisfied with their heating systems as non-heat network consumers. However, the survey found there were a number of areas where Heat Networks customers could face greater detriment. This goes some way to providing a sense of scale of the issues in the market and therefore the possible benefits the regulation could unlock, summarised in Table 6.

**Table 6 - Heat network consumer survey, Indicators of consumer detriment**

| Indicator | | Heat network | Non-Heat network |
|---|---|---|---|
| **Transparency** | Billed based on actual usage | 27% | 53% |
| | Receive any form of billing | 62% | 81% |
| | Bill includes Heat usage | 30% | 61% |
| | Bill includes Unit costs | 28% | 57% |
| | Bill includes Standing charges | 26% | 47% |
| | Reported receiving too little information | 20% | 14% |
| **Quality of service standards** | Control: Heat programmer | 26% | 46% |
| | Experienced overheating in last 12 months | 39% | 22% |
| | Reason for overheating: Lack of control | 23% | 19% |
| | Reason for overheating: Can't turn heating off | 11% | 7% |
| | Loss of heating in the last 12 months | 37% | 24% |
| | Multiple Loss of heating in the last 12 months | 21% | 11% |
| | Complained or had reason too | 32% | 26% |
| | Satisfied with complaint resolution | 45% | 55% |

**Note: This is not an extensive list of consumer detriment indicators**

52. In addition, research carried out by the CMA and Which?[18] found that consumers generally have low awareness of the heating technology prior to moving into to a property. This suggests that consumers are not sufficiently informed about the characteristics of Heat Networks when moving into a property and this could therefore restrict their ability to make informed decisions. In the absence of comparable standards to other regulated utilities, this also limits their ability to challenge Heat Networks on their practises.

53. This provides an indication of a number of the issues faced by heat network consumers and while Regulations alone are not expected to completely removes these issues, the comparison with non-Heat Networks consumers who operate in a Regulated market suggest that there are achievable improvements which could be made.

54. The recently amended Heat Network (Metering and Billing) Regulations 2020 also include a number of requirements on metering and billing based on consumption, the outcomes of which will not be reflected in the 2017 HNCS. The additional impact of any future

[17]Heat Network Consumer Survey (HNCS) <https://www.gov.uk/government/publications/heat-networks-consumer-survey-consumer-experiences-on-heat-networks-and-other-heating-systems>

[18] Study carried out by Which? <https://www.which.co.uk/policy/housing-utilities/363/turning-up-the-heat-getting-a-fair-deal-for-district-heating-users-which-report>

transparency and service standards will depend on where these requirements go further than the amended regulations.

## Pricing

55. The HNCS and the CMA market study both concluded that Heat Networks typically offer a lower or similar consumer cost in comparison to other forms of heating. The HNCS found that Heat Networks were around £100 cheaper per year on median average than non-Heat Networks. However, both studies also found evidence of high pricing for a significant minority of the market.

56. To ensure heat network consumers pay a fair price for heating, the Regulator will have powers to:
    - Require Heat Networks to disclose information relevant to the price paid by consumers
    - Conduct investigations into Heat Networks where prices appear to be disproportionate compared to a range of benchmarks and analysis
    - Intervene when there is evidence of systemic issues on pricing or in cases of significant consumer detriment.

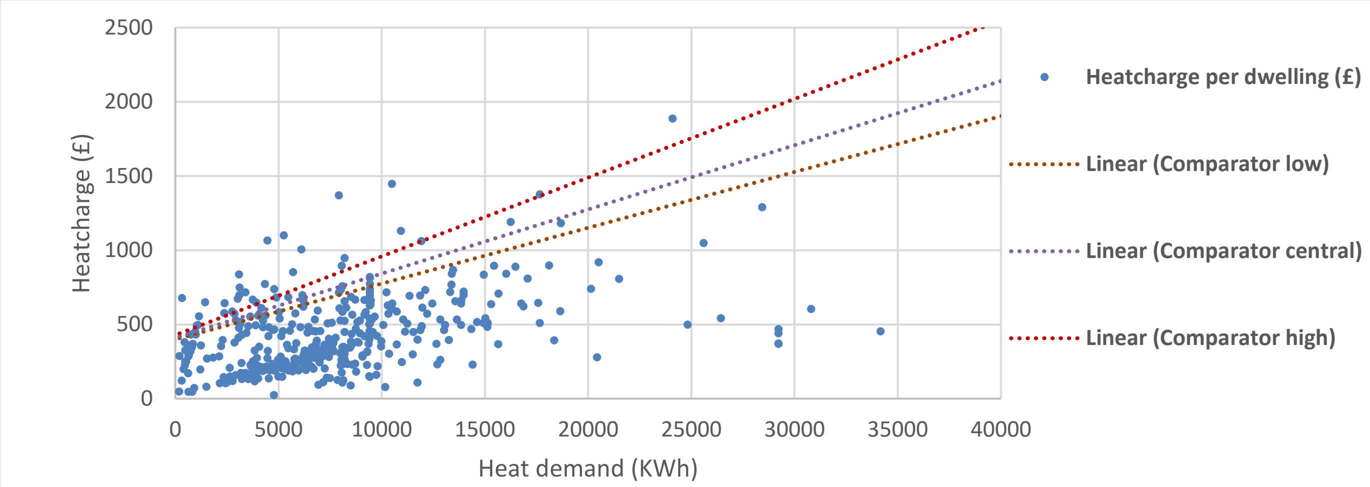
57. The information to be disclosed, the definition of what constitutes disproportionate pricing, and the process for conducting investigations and interventions, will be the responsibility of the Regulator to develop. However, this is anticipated to include reporting basic pricing information to allow for comparisons with networks sharing similar characteristics in order to identify instances of suspected disproportionate pricing. It is expected that the presence of a regulator with these powers alone could have an impact on the pricing behaviour of heat network operators, given the ability to be compared to others in the market and the potential to be investigated by the Regulator. Furthermore, greater transparency on the price charged by networks could allow operators to evaluate their prices relative to other networks, potentially leading to network operators reviewing their prices.

58. An unintended consequence of increased transparency and/or a bench marking approach to identifying disproportionate pricing could potentially lead to current and future Heat Networks anchoring their prices on or within these implied ranges. This could lead organisations to both decrease and increase prices charged. Although this effect could be mitigated through policy design, it would still lead to a situation where prices are assessed to be fair. In addition, respondents to consultation suggested they were aware of instances of disproportionately low pricing where the revenues do not cover the costs of operating the networks.

59. To provide an indicative sense of scale of the potential impact such a comparison approach could have, we carried out **illustrative** analysis on how the estimated costs of individual gas boilers compared to the estimated heat use and heat charge of around 22,000 domestic customers on 445[19] gas powered Heat Networks, collected by Kantar as part of the CMA's market study. The results of this analysis are presented in Figure 1 and discussed below. Please see Annex D - Pricing analysis for details on the methodology and assumptions used.

**Figure 1 - Heat network annual heat charge comparison**

[19] The data from 20 Heat Networks was excluded for data quality reasons




60. The results of this analysis suggest that between 7 – 17% of networks or 1,500 - 3,600 domestic customers in the sample pay more than the gas boiler comparator. If the prices on these networks was set to be equal to the gas comparator, then the cumulative consumer saving would have been of £0.25 – £0.5m annually across the sample. If this was representative of the whole market, scaling this up would indicate a total potential customer saving of between £5 – £10m annually. However, this doesn't account for changes in energy prices or the network generation technology.

61. How effective the future regulator will be at reducing these instances of disproportionate pricing is uncertain. In addition, it's important to note that a saving to consumers will represent forgone revenue to heat network operators. Therefore, it will be vital for the Regulator to build an understanding of what is driving these disproportionate prices and consider the operating model, before ascertaining the appropriate measures/ intervention.

62. There are a range of factors which could influence the price charged by heat network such as the generational heat source, the operational efficiency, and the contractual arrangements with the network operator. For example, in cases where the poor operational performance is leading to higher pricing, this may be better resolved though measures such as the technical standards, discussed in the section below.

63. The operational model of the network will also impact on the ability to adjust pricing. For example, it is common practise in certain segments of the market to run a cost-recovery model, in which only the costs of running the networks are recovered through consumer bills. In this circumstance, a heat network operator may have little practical ability to reduce prices without simply transferring this burden to the operator/owner, at least in the short term. In these circumstances, alternative forms of customer detriment alleviation and support for Heat Networks may be more appropriate.

## Technical standards

64. The quality of the design, build and maintenance of a heat network can significantly impact the network's performance, reliability, and pricing. Over the past three years, technical issues have been a leading cause of complaints to heat network suppliers with Heat Trust membership.[20] These issues are of particular concern due to the shared nature of Heat Networks, technical issues on Heat Networks can impact multiple customers, who have limited ability to address these issues.

65. The Regulator will have powers to introduce minimum technical standards that represent good practice and aim to reduce complaints with benefits across price, quality, and reliability of heat. A technical standards assurance scheme is also expected to be

[20] Based on the annual reports from the Heat Trust < https://heattrust.org/annual-reports-v2 >

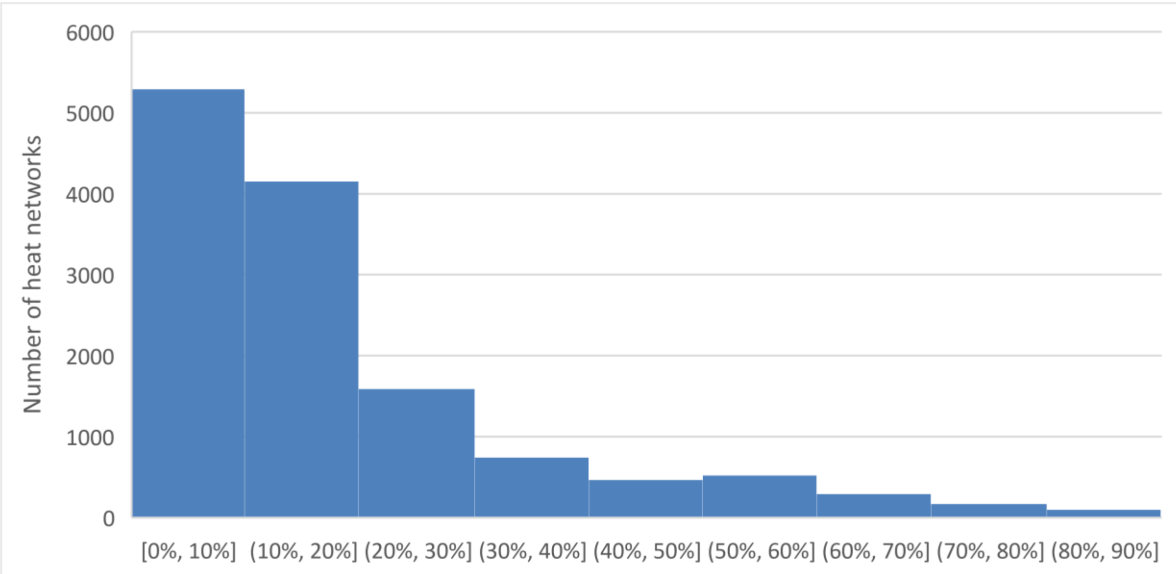
required to monitor standards in the market. Improved technical standards are expected to bring a wide range of benefits such as improved efficiency of Heat Networks, potentially lower capital and operating costs, and increased standardisation of Heat Networks across the market.

66. While the approach will be subject to future development, it is expected that prior to formal standards are introduced, more widespread data gathering would be required to inform the most appropriate approach. For example, requiring networks to report on key performance indicators such as fuel use and heat losses. In addition, requirements may differ for existing and future Heat Networks. This is due to the practical ability of existing networks in the short term to make substantial changes to existing physical infrastructure, relative to networks in development.

67. There has been significant work by industry to develop the voluntary CIBSE Heat Networks Code of Practice for the UK or 'CP1' [21], which is well established within the heat network market and compliance as part of the eligibility criteria for the government's Heat Network Investment Project (HNIP) and Green Heat Network Fund (GHNF). We consider CP1 (2020), or a document that builds on CP1, which describes how design, build, operation, and maintenance works should be done should form part of the technical standards framework. But we consider there may be a case to introduce and require compliance with standards that relate to the activities and competencies of organisations and their staff that carry out heat network works.

68. There is currently limited detailed evidence on the technical specification and performance of the 14,000 Heat Networks known to be operating in the UK and uncertainty over the future standards, meaning a robust quantified assessments of impact are not possible at this stage. However, as a proxy to technical standards we have carried out indicative analysis of the implied network distribution losses[22] from the HMBR data, a distribution of the results is show in Figure 2.

**Figure 2 – Distribution losses of Heat Networks**




69. The majority of networks have distributional losses below 30% with an average of 20%. However, there is a significant minority of networks who were found to have much greater losses. An acceptable level of distributional losses will differ depending on many factors including the density of the network, age, pipe diameter, operating cycles, etc. However,

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[21] CIBSE code of practice for Heat Networks (CP1) < https://www.cibse.org/knowledge/knowledge-items/detail?id=a0q3Y00000IMrmGQAT >

[22] Distributional losses for these purposes are defined as all heat lost from generation to suppling the final customer.

several sources suggest networks should aim for these losses to be up to 20 – 30%[23]. Based on this analysis between 17 – 28% of networks, with 113,000 – 164,000 customers, breach these illustrative losses thresholds, reducing these losses down to the proposed levels would be the equivalent of foregoing 5.7 – 7.5% of total network generation or 1 – 1.3 TWh of heat generation. This would represent a fuel cost saving to the heat network operator, which could be passed on to consumers.

70. In addition, reduced fuel consumption would also be associated with a reduction in carbon emissions and air quality impacts, which will benefit wider society. However, given the uncertainty over how much of this benefit could be unlock and how heat generation may change over time, this has not been quantified. This analysis suggests there could be significant benefits to unlocking these efficiency improvements. However, this analysis does not account for the costs associated with unlocking these improvements. There is expected to be costs associated with adhering to the technical standard requirements. These standards are expected to be informed by industry best practise and follow cost-effectiveness principles. As a result, the impact on networks will vary depending on the characteristics of the network.

71. Evidence from the recent heat network opportunity and optimisation (HNOO) project[24] and the Heat network efficiency scheme (HNES) demonstrator[25], indicate that cost effective operational efficiency improvements can be made to existing networks, where the cost of the interventions will yield a positive saving or at least break even over its lifetime. However, market engagement suggest that network operators are unaware of the possible improvements or lack access to capital to fund them. The outputs from these schemes and the future HNES main scheme will seek to help form the evidence base on future minimum technical standards.

72. In addition, to the potential benefits technical standards could bring to existing Heat Networks, it is expected that the standards can also be utilised by new heat network developments to ensure these networks are built and operated optimally. New build Heat Networks are expected to have more opportunity to incorporate technical standards in the design and development phase. Given the anticipated growth in the market these benefits are expected to be substantial. However, the portion of benefits attributable to any future required standards will depend on how much they improve on the planned standards of new networks.

## Step-in arrangements

73. Step-in arrangements will ensure continuity of heating for consumers in the event that their supplier or operator exits the market. There is an established precedent for step-in regulation for other utilities that individuals are dependent on, with social housing, electricity, water, and gas companies all providing market exit scenarios.

74. The primary legislation will provide powers for the regulator to implement step-in protections. Examples include the strengthening of responsibilities relating to contractual accountabilities for step-in, and to be able to appoint a supplier or operator of last resort. In addition, the regulator will consider if the provisions of a special administration regime for Heat Networks are required. However, these will be introduced on the basis of market monitoring and further stakeholder engagement.

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[23] The Heat Networks Code of Practice for the UK suggest primary losses on a heat network should ideally not exceed 10% and clear justification would need to be given, however no network should exceed 20%. Consultation with BEIS heat network specialist suggested that total network losses of 30% may be reasonable depending on how the network was operated

[24] Optimisation of Heat Networks: < https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/736958/Optimisation_of_Heat_Networks_final_-_GOV.UK.pdf >

[25] Heat Network Efficiency Scheme < https://www.gov.uk/government/publications/heat-network-efficiency-scheme-demonstrator >

75. The impact of these arrangements will in-part depend on how frequently they are required. The historic risk of a supplier or operator failing is assessed to be relatively low for Heat Networks. This is based on:
    - Responses to the market framework consultation
    - Analysis of Companies House data which showed only one case of a heat network exiting the market
    - Engagement with the Heat Trust and Covid Response Group stakeholders, with both confirming that they have no indication of suppliers failing.

76. The design of this step-in arrangements will need to balance the competing priorities of safeguarding consumers' heat supply, whilst ensuring that measures are not unduly burdensome upon regulated entities. Step-in arrangements will be regarded as a last resort. It is expected that other aspects of the market framework such as market monitoring and minimum technical standards will reduce the likelihood of supplier failure.

77. While the risk of market exit is low for all types of heat network, if a heat network operator did leave the market, the likelihood of its customers becoming stranded varies by the type of network. In the event of a communal heat network failing, there is relatively clear accountability. This is mainly due to the impact of the 1985 Landlord and Tenant Act[26] which requires that landlords maintain essential aspects of the building, including communal heating (in most cases). This means that, in the event of a heat network operator/property manager's failure, the landlord/freeholder would be responsible for finding a solution/appointing a new property manager in most cases[27].

78. District Heat Networks typically have different contractual set ups. Many operators will have market exit arrangements in place. Other district Heat Networks are delivered via concessional agreements and are run by a government agency, local authority, or other legal entities. It is often in their interest to insert contractual clauses which cover early termination into the negotiated contract so they can recover their assets.

79. However, there is a higher risk to certain customers when a district heat network has expanded off-site. In the event of an outage, the master developer is less likely to have the same commercial or legislative interest to ensuring customers off-site have adequate heating. This means that district heat network customers using an expanded heating network may face a higher risk of being stranded without heat in the event of a failure.

80. Despite this, existing protections including legislation related to property management and contractual provisions should mean there are few instances where regulatory intervention is required. However, as the market develops and regulations are introduced, it is possible there may be an increase in the risk of market exit for regulated entities. The Regulator will be closely monitoring the rate of exit in the market and engage with suppliers to mitigate this.

## Extra rights and powers:

81. Heat Networks, unlike other utilities (such as electricity, gas, and water), do not have statutory powers to carry out roadworks and other activities which are essential to the construction and maintenance of their networks. For example, utilities companies can excavate the roadway via a permit system, rather than applying for individual licenses for each individual excavation as Heat Networks must.

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[26] Landlord and Tenant Act < https://www.legislation.gov.uk/ukpga/1985/70 >

[27] There are some exemptions in the Landlord and Tenant Act for long leases, though this is rare.

82. This means that Heat Networks often experience longer delays for construction, maintenance, and repair than comparable services. This has a dual effect:

- This leads to uncertainty in the market as it increases the risk of delays, which could increase the amount of idle capital and labour and thus increases costs. This uncertainty could lead to reduced investment in Heat Networks.
- Delays in maintenance and repair may increase consumer detriment as a result of longer outages for consumers and a poorer-quality service.

83. Given that Heat Networks provide an essential service, there is a clear justification for giving them equivalent powers to other utilities to improve consumer outcomes. There is likely to be the additional benefit of increasing certainty for suppliers in the heat network market which may ensure greater investment. While the extra rights and powers are anticipated to be benefits for both existing and new Heat Networks, it's expected that these will be of the most use for the development of new networks.

84. The responses to the consultation where supportive of the provision of extra rights and powers to licensed networks and confirmed this would likely lead to cost and time saving in the development and maintenance of networks. The consultation stage IA provided indicative monetised impact of the rights and powers; however insufficient evidence was ascertained from the consultations to fully verify the assumptions made in the consultation stage IA. Therefore, we have opted for a qualitative assessment of impact summarised in Table 7. The currently live Heat Networks consumers and operator survey will seek to gather greater insight into the use of extra rights and powers.

**Table 7 – Overview of Extra rights and powers**

| | Assessment of impact |
|---|---|
| **Access Rights** | Industry engagement indicated that negotiations required to access land can often lead to delays, the landowner to charge excessive prices or even refusing access. This power would enable the owner/developer to purchase access to the land at market value, if necessary, through the land tribunal. This is expected to reduce the time taken and ensure a fair price is paid. Respondents to the consultation agreed this would mainly be used to install/maintain pipes. |
| **Street Works** | Heat Networks can make use of standardised permits from local authorities rather than licenses which are currently applied for. The average costs saving for applying for a permit as opposed to a license is estimated to be £454[28],the process is also less administratively burdensome for applicants and local authorities. Many respondents to the consultation reported difficulties or delays, some suggested currently approval takes between 8 – 12 weeks. |
| **Rights to lay pipes under roadway** | The legal rights to lay and keep assets under the roadway can be complicated and can represent significant cost and/or delays. While this power will not remove the need for scrutiny of plans or the need to liaise with local authorities. They are expected to place the organisation in a better position to reduce the uncertainty and costs of developing the networks. |
| **Permitted development rights** | Permitted development (PD) rights are a national grant of planning permission enabling certain developments, to be carried out without a specific planning permission. PD is subject to limits and conditions in order to minimise the impact of the development. Licensed heat network organisations would benefit from being able to facilitate the installation and maintenance of Heat Networks, |

[28] The cost saving of applying for a permit in comparison to a section 50 license, was calculated through sampling the costs charged by local authorities for permits and/or licenses across GB

| | |
|---|---|
| | without the need to seek planning permission which is expected to increase the speed of maintenance and developments. However, significant developments would still require planning permission. |
| **Linear obstacle rights** | Developing a heat network frequently involves crossing infrastructure such as railway lines, tramways, or canals. Occasionally these 'linear obstacles' prevent expansion because networks find that engaging with the relevant companies is too time-consuming or simply because routing a network through the infrastructure is too difficult or dangerous. This power would give developers greater certainty and the right to cross these obstacles, subject to there being no safety or practical reason for denying a crossing. Respondents stated that rights to cross linear obstacles would be beneficial to shortening the process of constructing and maintaining Heat Networks |

85. As these extra rights and powers are expected to make developing and maintaining Heat Networks easier, this in turn could lead to additional costs associated with development/maintenance of networks, for example more frequent road disruptions. However, any additional costs would need to be balance against the benefits of works being more efficient, less delayed and the overarching benefits Heat Networks can bring. This has not been quantified as there is a lack of information on the amount of street work delays, the length of delays in street works and the costs that are involved in this disruption.[29]

86. The number of organisations who will apply for licenses is uncertain, however we have estimated that around 100 licenses are applied for based on the number of heat suppliers who own over 10 Heat Networks with at-least one district heat network, local authorities have been excluded as they already have access to these rights and powers. This is a simplifying assumption based on the rationale that a district heat network operators are more likely to seek these extra rights and power, given the size of the networks the operate. This has been tested in the consultation. In practise, organizations are only expected to apply for a license if they gain sufficient benefits to overcome the associated administrative costs.

87. We have estimated the cost to business of applying for a license and to the Regulator for processing the request. The cost of a license will be defined by the future Regulator, but at a minimum is expected to cover the Regulators administrative costs. The cost of a license in the gas & electricity market is currently set to a level which cover the administrative costs of the regulator's operations.[30]

**88.** All organizations who apply for licensing will be subject to additional checks and clearance to ensure they can appropriately manage the extra rights and powers, for example increased financial checks. This will mitigate the risk that these organization miss using these rights and powers. In addition, many of the organisation will already have experience in dealing with these types of developments. Furthermore, the Regulator will have the right to remove licensing and authorisation if deemed appropriate.

## Future Decarbonisation target

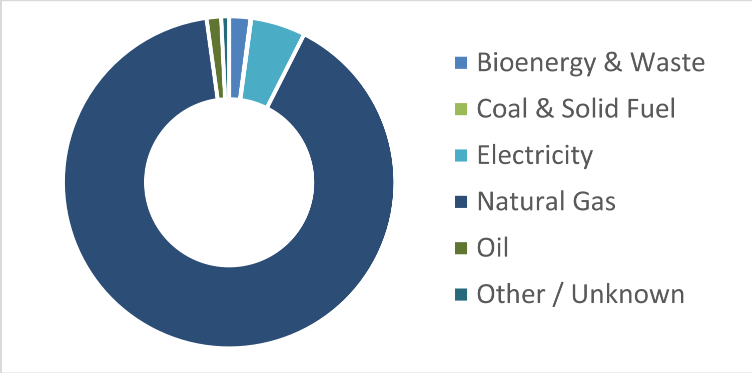
89. The Regulator will have powers to set maximum carbon emissions limits. However, as these powers are at primary legislation any the proposed limits and time frames will be

[29] The Evaluation of Street Works Permit Schemes found that the average societal cost of a day of roadworks to be £221, for those impacting carriageways this figure is £261. However, this is only an average figure non-specific to Heat Networks. Evaluation of Street Works Permits scheme (page 41) < https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/700502/permit-schemes-evaluation-report.pdf >

[30] Based on Ofgem's Licence Fee Cost Recovery Principles < https://www.ofgem.gov.uk/publications/licence-fee-cost-recovery-principles-2021 >

subject to further consideration and consultation at secondary legislation stage. Therefore, we have included a brief discussion on the possible impact of this power for the purpose of the IA.

**Figure 3 - Heat Networks by fuel type**




90. Over 90% of Heat Networks are currently powered by natural gas, with the largest district Heat Networks using combined heat and power (CHP) technology. A future decarbonisation target is anticipated to be required to help support the decarbonisation of Heat Networks, in order to help achieve the UK's net-zero goal. This will likely require Heat Networks to achieve a specified carbon intensity over time which is expected to be achieved by replacing the heat generation with low carbon sources such as heat pumps. However, the most appropriate low-carbon alterative will differently depending on the location and characteristics of the network.

91. Low carbon heat generation technology typically come at an up-front and operational cost premium, relative to higher carbon alternatives. However, on a social basis (accounting for fuel, carbon, and air quality impacts) the net present value of deploying low-carbon heat network is expected to be positive, as demonstrated in the green heat network fund and Heat network Zoning IA's[31]. The heat network investment project (HNIP)[32] and the green heat network fund (GHNF), both offer capital support to fund the development of low carbon Heat Networks. BEIS will consider what additional support may be required in conjunction with any future decarbonisation requirements.

92. The proportion of Heat Networks which will need to decarbonise as a direct result of any future decarbonisation target, will depend on the level of decarbonisation action achieved in the sector via other policies or industry lead action. For example, all high carbon Heat Networks supported by HNIP are required to have decarbonisation plans and all projects supported by the GHNF will be require be low carbon from the outset. Further to this, future policies such as heat network zoning could come with specific low carbon requirement place on the networks.

93. Responses to the consultation suggest that industry were supportive of some form of regulation to reduce the carbon emissions over time so that they can contribute towards net-zero. However, we also agree with feedback that these targets for Heat Networks must be set so that they do not undermine investment in the sector. Although, it's expected that these costs can be minimised to some extent by aligning requirements of the natural replacement cycles.

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[31]GHNF IA: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/942359/GHNF_Consultation_IA.pdf
HNZ IA: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1024221/heat-network-zoning-consultation-stage-impact-assessment.pdf

[32] HNIP < https://www.gov.uk/government/collections/heat-networks-investment-project-hnip-overview-and-how-to-apply >

94. In addition, it's expected that all buildings will need to take the necessary decarbonisation to meet the 2050 net-zero target which is expected to entail adopting lower carbon heating sources, this will see a shift in the appropriate counterfactual. For example, an existing heat network may face the choice between decarbonising the networks heat source or installing individual heat pumps, given the nature of Heat Networks they could still offer the most cost-effective decarbonisation solution. However, this will depend on the characteristics of the network and the timing of other requirements.

95. We believe that regulation should start to impact the technology choices of Heat Networks in the early 2030s, though we are proposing in heat network zoning that in some cases, low carbon requirements will come in earlier[33]. The evidence bases to support a decarbonisation target will come from a variety of sources, including insights from the heat network investment project (HNIP), the recently launch green heat network fund (GHNF) and responses to BEIS's call for evidence on the decarbonisation of CHP plants[34], which is a key technology amongst large district Heat Networks. BEIS has also recently commissioned a research project on decarbonising existing Heat Networks. Alongside further policy development, engagement with stakeholders and consultation.

# Wider impacts

## Interactions with other policy

- **Heat network Zoning (HNZ) -** Aims to establish zones where some types of buildings will be required to connect to a heat network, thereby increasing the growth rate of the heat network sector. This policy is currently under development. A future heat network zoning policy is predicated on market wide regulations provided under the HNMF, social research carried out during policy development indicated that the lack of regulation is one of the key concerns from social housing providers and consumers.[35] As HNZ is expected to lead to significant growth in the market, all new/expanding Heat Networks will be subject to the requirements of the HNMF thus increasing scale of regulatory activity. This has been reflected in our analysis by the inclusion of market growth in our estimated costs. Further to this, they may be extension and or additional regulation required for networks in zones, however this will be subject to future development.
- **Heat network efficiency scheme (HNES)** – HNES is currently at demonstrator stage with the ambition to launch a full scheme in the future. As discussed in the technical standards section, it is anticipated that the learnings and insights from this scheme will be used to help inform any future minimum technical standards for Heat Networks.
- **Heat metering and billing Regulations (HMBR)** – Places requirements on Heat Networks to notify of their existence, install metering devices and bill based on consumption were cost-effective. There is significant overlap with the HNMF, specifically on billing and transparency standards. The future Regulator is anticipated to assume responsibility for the HMBR; however, the practicalities will be subject to future development.
- **Other regulators and bodies** – The Regulator established under the HNMF will be expected to work alongside side other sector regulators and bodies. This includes the members of the tripartite regulatory structure and the Environment Agency, the Competition and Markets Authority, and the Regulator of Social Housing. Interactions between regulators will be considered future during policy development.

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[33] The heat network zoning consultation also considers the rationale for requiring Heat Networks in zones to meet a low carbon requirement. It is proposed that the low carbon requirement shall apply for new networks in zones once the zone is implemented, which we envisage in some cases would be prior to 2030. See < https://www.gov.uk/government/consultations/proposals-for-heat-network-zoning >

[34] BEIS's Call for evidence on the decarbonisation of CHP plants < https://www.gov.uk/government/consultations/combined-heat-and-power-pathway-to-decarbonisation-call-for-evidence >

[35] Heat network zoning social research – to be published at a later date to this impact assessment.

## Equalities assessment

96. An equality impact assessment of the policy has been carried out. The heat network market framework will in-directly affect all customers on Heat Networks. The equality implications will be kept under review to consider further relevant evidence as it becomes available. The evidence for the equality assessment has been based on the current population who are on Heat Networks. This assessment found:

- Due to the nature of HN; being mainly an urban technology and appropriate for multi-tenancy buildings, Heat Networks tend to serve more vulnerable, urban, and elderly consumers[36].
- The HNCS found that 44% of HN consumers are retired, compared to 14% of non-HN customers, suggesting a greater number of elderly people use HN's.
- Black, Asian and Minority Groups (BAME) are more likely to live in urban areas where HN are more likely to be found.[37]

97. This regulation is sets out to alleviate consumer detriment issues, which have been outlined throughout this IA. All heat network consumers will benefit from the improved protections including those with protected characteristics. This support will be delivered through the regulatory structure will be made up of citizens advice, Ofgem and energy ombudsman. The differing bodies will allow for a point of contact for those who are vulnerable and experiencing issues with Heat Networks. The regulatory structure will be required to record the issues of those who are vulnerable and addressing it through bodies such as the Ombudsman.

98. The impact of the regulation on fuel poverty has also been assessed. Analysis of the English housing survey suggest that there is currently a lower portion of consumers connected to Heat Networks in fuel poverty. These consumers will benefit from the protection put in place by the Regulation and could possibly benefit from reviewed Heat Networks charges due to the elements of the regulation focused on pricing, which would impact their fuel poverty status.

## Jobs impact

99. The HNMF will directly support jobs within the future regulator structure, providing jobs with Ofgem, Citizen's Advice and the Energy Ombudsman. In total, there are estimated to be an average of around 81 full time equivalent (FTE) employed by these organisations annually over the first ten years of the regulation. There will also be jobs supported by any external consultants contracted by the regulator, such as auditing. In addition, there will be jobs supported from heat suppliers to process the requirements of the regulation, with the equivalent of 122 FTE jobs expected in the first year of the regulation and an average of 69 FTE jobs in the follow-on years[38] across the whole market.
100. There is also expected to be in-direct jobs supported by supporting the development of Heat Networks. In addition, future requirements such as billing requirements and minimum technical standards could support more jobs in the future in billing and technical organisations.
101. In terms of where these jobs will be located, for the regulatory role this will be dependent where Ofgem, citizens advise and the energy ombudsman base their operations, which hasn't been specified at this stage. The regional distribution of jobs supported within the

[36] Heat Networks Consumer Survey (2017) < https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/665447/HNCS_Results_Report_-_FINAL.pdf >
[37] Government figures on BAME < https://beisgov.sharepoint.com/:w:/r/sites/CleanHeatAnalysis/_layouts/15/Doc.aspx?sourcedoc=%7B3B467D55-242D-493F-B08F-25291EECE4FE%7D&file=FINAL%20HNMF%20FIA%20.docx&wdLOR=c3CA75FEE-B157-4BEF-907A-7126DDD1A918&action=default&mobileredirect=true >
[38] FTE equivalent has been calculated based on the estimated time required to undertake the Regulatory activities based on the assumption that full time employees work 261 day a year and 7.5 hours a day.

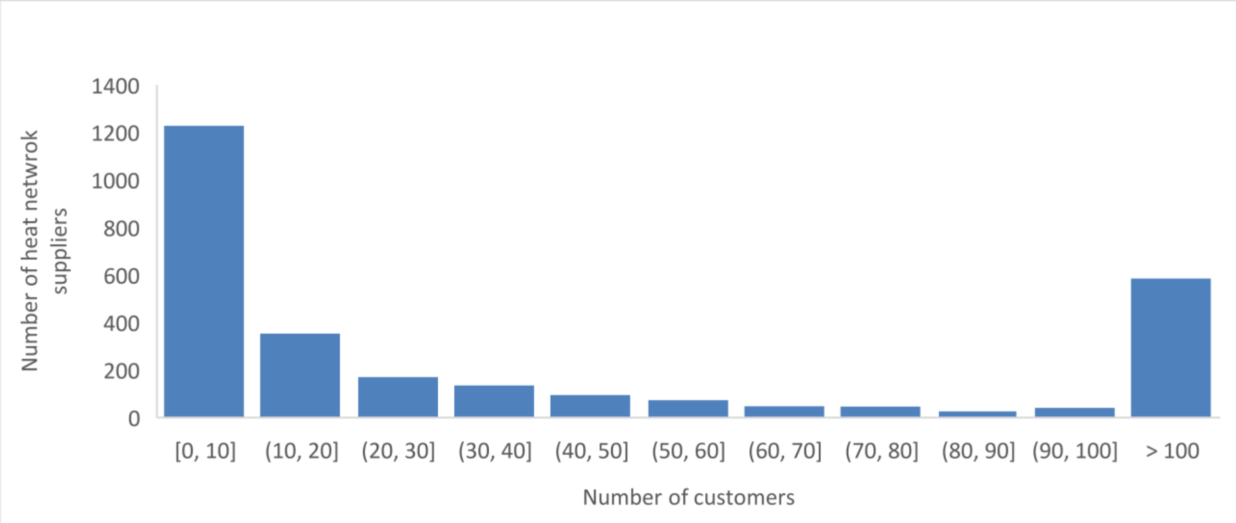
heat network industry are likely to follow a similar distribution to the location of heat networks, which are currently spread across the UK.

## Small and Micro Business Assessment (SaMBA):

102. The HNMF will impact on small and micro businesses (SMBs) in two ways. Firstly, all businesses connected to Heat Networks will benefit from the regulation set out above. Consumer protections will extend to domestic and micro business consumers, with the possibility that they will be extended to other businesses such as SMEs, subject to further policy development. Secondly, any small or micro business involved with the development, operation or management of a heat network, or the supply of heat through a heat network, would be expected to comply with the relevant regulatory requirements. For the sake of brevity, this section will focus on the latter impact on SMBs, as the potential impact on those served by Heat Networks is covered in the sections above.

**103.** The make-up of the Heat Networks market is varied. There are known to be 14,000 Heat Networks that are in scope of regulation, around 12,000 of these are communal network ( serves only one building) and around 2,000 are district heat networks ( serves multiple buildings). In total there are roughly 2,800 suppliers[39]. There is an uneven distribution regarding the amount of Heat Networks that each supplier owns, and how many consumers are served by each heat network. Figure 4 provides the distribution of the number of consumers served by heat suppliers.

**Figure 4 – Heat supplier by total consumer numbers**




**104.** Most Heat Networks in the Heat Network (Metering and Billing) Regulations (HMBR) data have relatively few customers, with 81% of heat network suppliers supplying fewer than 100 consumers and with 86% having fewer than ten Heat Networks. However, this does not necessarily mean these heat suppliers are small and micro businesses[40] as they may manage a heat network alongside other business functions. For example, a large shopping centre may employ many people but have few registered heat customers. The data collected through the HMBR does not cover the size of heat network operators, and therefore it's not possible to be exact in this estimation.

105. In an attempt to overcome this evidence gap, we have carried out analysis on Companies' House data using a sample of around 700 organisations listed as the heat suppliers in the HMBR notification data. The information on the size of the organisation in the Companies House data was found to be incomplete, though of those records where

[39] Based on analysis of: Energy Trends, Experimental Statistics on Heat Networks (2018) < https://www.gov.uk/government/publications/energy-trends-march-2018-special-feature-article-experimental-statistics-on-heat-networks. > Heat suppliers in this context are defined as the organisation who submitted the notification.

[40] Micro business is defined as having up to 10 employees, small business has up to 49 employees. According to Companies House: < https://www.gov.uk/annual-accounts/microentities-small-and-dormant-companies >

the organisation size was identified, the majority were classed as small or micro businesses. While this finding is not conclusive, it reinforces the likelihood that a large proportion of the organisations in the scope of the regulation could be small and micro businesses.

106. Given the nature of the issues the HNMF aims to overcome, it is not appropriate to fully exempt small and micro businesses from these requirements, given customers on these networks make up such a large proportion of the known consumer base. A full exemption would result in a large portion of these consumers not receiving the benefits of the Regulation. A de-minimums threshold was considered during consultation, but we received clear feedback that this would not be preferable. However, this has factored into our current policy design in the following ways:

- An authorisation with option licensing Regulatory model has been selected to reduce the burden on smaller entities in the market. Only organisations who desire rights and powers would be required to get a license.
- We're seeking views on spreading the costs of regulation across heat network, gas, and electricity bills, significantly reducing the financial burden on small and micro businesses.
- While a full exemption from all regulatory requirements is not deemed appropriate, partial exemptions to some regulatory requirements will be considered at secondary legislation stage. For example, our recent consultation on cost recovery seek view on an exemption on cost recovery.

107. In terms of the core requirements outline in this IA, these are not expected to differ between heat suppliers of different sizes, all heat suppliers will face costs of familiarisation, dissemination, annual reporting and additional administrative costs as discussed above. However, as annual reporting takes place at a network level, these costs will scale proportionally with the number of networks managed by a heat network supplier. Illustrative scenarios are provided in Table 8.

**Table 8 – Costs to business on different sizes of heat suppliers**

| Heat supplier | Number of networks owned | Initial costs | Annual costs[41] |
|---|---|---|---|
| **Small** | 1 | 700 | 200 |
| **Medium** | 6 | 1,770 | 1,200 |
| **Large (Licensed)** | 20 | 5,200 | 4,100 |

Note: these costs have been rounded and therefore may differ from elsewhere in the IA.

108. The core requirements of the regulation are not deemed to be disproportional to small and micro business to ensure heat network consumers receive appropriate protection. When assessing if these costs are disproportional, we lack robust data on these companies' finances to conduct detailed analysis. However, as small, and micro businesses are typically smaller in terms of revenues, the initial costs are expected to make up a larger proportion of revenues. Conversely, annual costs are expected to be higher for larger organisations who own/operate multiple networks, however this will vary across organisations.

109. There may be some additional impacts on SMBs by the regulations, such as design consultants or metering and billing companies who often work with or for Heat Networks. For example, the transparency measures introduced by the regulation may provide more trade for metering and billing companies with Heat Networks. These impacts have not been assessed as they are expected to be in-direct and are uncertain at this stage.

[41] Costs associated with audits and complaints have been exclude, as these won't be borne by all heat suppliers

110. In practise, it is expected that as the regulation is developed further, additional exemption or mitigation will be considered and as with all elements of the HNMF, this will be subject to future consultation.

## Trade implications of measure

111. The proposed regulatory powers do not place any direct requirements on trade and investment activities. However, the presence of a Regulator, requirements placed on heat supplier and provision of extra rights and powers, could lead to an indirect impact on trade and investment. These are discussed below:

- All UK heat suppliers will be required to be authorised to comply with the regulation, this requirement will not differ between domestic and foreign businesses. This will require current and future heat suppliers to be aware of this requirement and make the necessary notification/application. However, this is not expected to be overly burdensome and therefore the impact is not expected to be significant. The Regulator will provide greater clarity and insight into the market to help ease this process.
- Heat suppliers are expected to comply with minimum technical standards once set. This could have an impact on the services provided and the associated supply chains of Heat Networks goods. However, this impact will depend on how the future standards are set and how this compares to the current standards across the market. As discussed in the technical standard section. To assess the impacts of the HNMF on Technical Barriers to Trade (TBT), specifically technical standards, we consulted with the Department of International Trade (DIT) and concluded that at this stage the HNMF will not constitute a TBT, nor will it conflict with any World Trade Organisation (WTO) obligations. However, we will continue to work with DIT as the policy develops and re-assess impact accordingly.
- Heat Networks currently provide around 2-3% of UK heat demand; this could increase to around 20% in line with a cost-effective decarbonisation pathway. The regulatory framework is expected to be a key enabler of this growth by providing the necessary consumer protection, greater confidence to the industry as well as extra rights and powers, this is expected to have a positive impact on market growth and therefore investment. Market intelligence suggests, some European firms and investors have expressed interest into the UK market once regulated.

112. When considering the impact on competition and monopolies. The HNMF is not expected to establish a small number of suppliers or hinder competition within the industry. Regulation could have an in-direct impact on future market structure as there may be some consolidation as the market develops and heat suppliers are required to adhere to the regulation. This impact has not been quantified at this stage.

113. Overall, the net impact of the HNMF on Trade and investment is expected to be positive. However, it has not been possible to attribute investment or trade impact directly to the HNMF as it is part of a wider enabling package of policy and market support. In practise the impact will depend on how the proposed regulatory powers are used and the response from the industry, BEIS's understanding of this impact is expected to improve as the policy develops and through monitoring and evaluation once a Regulator is established.

# Key Limitations, Risks and Uncertainties

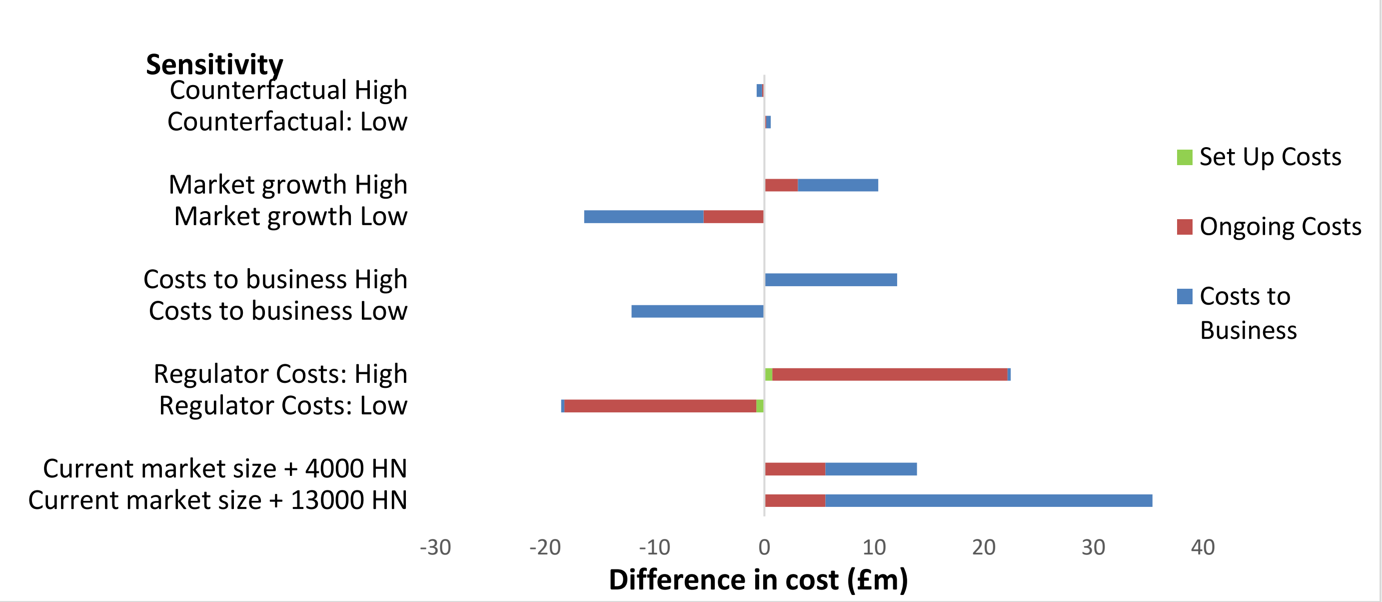
114. The analysis presented in the IA provides an indicative cost estimate of regulating the heat network market, cost to business and a sense of scale of the potential impact of the regulatory powers. However, there are a number of key uncertainties which should be considered alongside this:

- **Impact of Regulatory powers:** The IA provides an overview of the potential impact of the regulatory power; this included a quantification of the scale of the issues these powers are intended to address. However, given the stage of policy develop and data availability it has not been possible estimate the proportion of these benefits which will be unlocked by the regulations. These impacts will be considered in more detail in the secondary legislation stage once more details on the regulatory requirement/approach is known.
- **Stage of policy development:** As flagged throughout the IA, there is considerable uncertainty associated with the final scope and approach to regulation, due to the policy being at primary legislation stage. There is inherent uncertainty in regulating a new market, for which it is difficult to find appropriate comparisons. Secondly, most of the details of the regulation will be defined at the secondary legislation stage.
- **Size of the heat network market -** These cost estimates use inputs from the Heat Metering and Billing Regulations dataset, which contains data from network level notifications. Since this data was not collected for these purposes, a number of assumptions have been made to derive the number of heat suppliers, networks, and customers in scope. In addition, this data is self-reported and was collected in 2017, and hence may not reflect the number of Heat Networks operating now.
- **Estimated compliance and enforcement cases –** Linked to the points above, there is currently insufficient information to robustly estimate the future regulatory case load for the regulated heat network market. Therefore, we have used the gas and electricity market as a proxy. In practice the case load could vary significantly depending on how regulation is implemented and the response from the market. This is mitigated partially through the development of scenarios; however significant uncertainty remains.
- **Market composition –** In addition to the size of the market, it is uncertain how the structure of the market may change over time. As the heat network market grows it is possible that there could be consolidation as the market matures. This could mean that although the heat network market may grow in terms of customers, the number of entities in the market may contract, which could lead to regulatory efficiencies. However larger heat suppliers can also add to the size and complexity of cases, therefore the net impact is uncertain.
- **Cost recovery –** A number of simplifying assumptions have been made to provide indicative customer level cost impacts. The estimate represents the average annual cost per consumer over the appraisal period. This is sufficient to provide an indication of the impact of different cost recovery options considered in the consultation. In practice costs may not be recovered evenly across all consumers, however the difference between options is still expected to be at a similar order of magnitude, given the size of the gas & electricity consumer base.

## Sensitivity analysis

115. Given the uncertainties identified above sensitivity analysis has been carried out on the estimated Regulatory costs to investigate the impact of variation in a number of key variables, the result of this analysis is present is Figure 5 and discussed below. Given the approach taken to assessing the benefits of regulation, it’s not possible to carry out bespoke sensitivity analysis. However, generally these benefits will scale with the size of the market.

**Figure 5 - Sensitivity analysis results**




- **Counterfactual** – to investigate the impact of the counterfactual costs, the growth in membership of the Heat Trust has been varied by +/- 50% to construct a low and higher scenario. Overall, this has a relatively small impact to the overall results. These sensitivities impact the counterfactual regulation and business costs but make very little net difference to the overall costs which are significantly lower than the factual costs.
- **Market growth** – The anticipated growth in the market has been tested firstly by assume a no growth scenario for the low case and higher scenario where the annual growth rate is increased from 4% to 6% based on achieving a higher penetration of heat supplied by Heat Networks[42]. Similarly, to the current size of the market sensitivity, the low and high scenarios lead to a substantial fall and rise respectively in overall costs to business over the appraisal period. However, this is driven by year-on-year growth as opposed to base costs.
- **Cost to business** – To construct a high and low range the time taken to complete the regulatory requirements have been scale +/- 50%, to reflect the uncertainty. As expected, these low and high sensitivities cause a proportionate fall and rise in the overall costs to business but have no impact on the costs to the regulator.
- **Regulator costs** – A high and low scenario for Regulatory costs have been constructed from inputs from the tripartite group, see Annex B for details. As a result, these scenarios represent lower/higher base regulatory cost which significantly impact the estimated on-going regulatory cost there is also a small impact on the required start-up costs. There is a small impact on cost to businesses due to the increase/decrease in the number of audits carried out by the regulator and the admirative burden placed on audited entities.
- **Current size of the heat network market** – Two sensitivities on the size of the market have been tested; the first increases the number of Heat Networks by around 4,000 based on the number of notifications received prior to quality assurance, the second is a more extreme scenario which assumes the current market is twice as large representing a 50% compliance rate with notifications. All markets characteristics are scaled linearly. As expected, an increase in the number of Heat Networks contributes to a substantial rise in overall costs to business estimates and rises expected regulator costs.

## Monitoring and Evaluation

116. The monitoring and evaluation will demonstrate the impact and outcomes of the Heat network market framework, providing a measure of success against the intended benefits,

[42] This is based on achieve a 18% or 81Twh of heat deliver by Heat Networks by 2050, based on the CCC's 6th carbon budget pathways. <https://www.theccc.org.uk/publication/sixth-carbon-budget/ >

as well as providing evidence for future policy development. The monitoring will also be required to provide sufficient evidence to support enforcement and compliance.

117. The evaluation will be predominantly theory-based, and will include components of process, impact and financial (cost-benefit analysis) evaluation. It will seek to answer the questions below, taking account of what works/ doesn't work for whom and in what circumstances.

- To what extent have the Regulations achieved the aims?
- To what extent are the impacts additional to what would have happened without them?
- How effective were the delivery of the amendments?
- To what extent is this offering value for money?
- Are there any lessons going forward for how Heat Networks are regulated?
- How has the design of the regulation influenced the impacts that were achieved?
- How has the policy been delivered, what worked/ didn't work?
- What have the costs and benefits of the regulation been?
- How has the regulation impacted consumers and the heat networks industry?

118. If this approach is adopted then the evaluation would include further analysis of monitoring data, bespoke data collection from heat suppliers and users through surveys and interviews and wider evidence gathering to inform broader impacts. A thorough evaluation scoping exercise will be undertaken to determine the appropriate methodology to answer the main evaluation questions.

# Annexes

## A – Key changes since the consultation stage IA

| | |
|---|---|
| **Number of existing Heat Networks** | The consultation stage IA scaled up the number of networks to around 18,000 in line with the total number of notifications received before quality assurance was carried out. Following a review of the dataset, it was deemed more appropriate to focus on the total number of known networks in our central scenario and carry out sensitivities on the impact of more networks in the market. |
| **Revised costs and methodology** | BEIS has worked extensively with Ofgem, Citizen's advice, energy ombudsman and representatives from the heat network industry to refine the cost estimates used in this IA. This updates to the costs to business assumptions. In addition, the methodology used to estimate costs has been updated to account for the implementation of regulations and growth in the market over time. |
| **Counterfactual** | The same counterfactual has been retained as in the consultation stage IA, however the assumptions used to estimate the costs have been updated in-line with consultation with the heat trust. Specifically, the cost to business associated with the counterfactual have been include based on Heat trust membership requirements and existing notification requirements under the heat metering and billing regulations. |
| **Assessment of proposed powers** | A more detailed assessment of the potential impact of the regulatory powers has been added, alongside a quantified sense of scale where data allowed. In addition, the consultation stage IA included a quantification of the impact of extra rights and powers, a qualitative assessment has been made in this IA owing to insufficient data to inform a robust assessment. |
| **Policy development** | The content of the final IA reflects the latest policy developments which has led to updating the analysis to better reflect the geographical scope of the policy and the proposed powers. For example, this has led to changes in the assumed number of organisations in scope of the Regulation. |

## B – Estimated Cost assumptions

This annex outlines the assumptions behind the estimated Regulator costs, cost to business, the counterfactual and how costs are assumed to be recovered.

### Regulation Cost Estimate

Below is an overview of the approach taken to estimate Regulatory costs, this approach is consistent with the approach taken in the recent consultation on cost recovery[43], full details can be found in the technical annex of the consultation.

A standard cost model approach has been used to estimate the regulatory costs of the preferred option. An overview of the methodology used is as follows:

A) **Current market** - The current size of the Heat Networks market in scope of regulation was estimated using the HMBR notification data.
B) **Identify regulatory activities and estimate the resource** - The members of the tripartite group used the outputs on market size from step A to estimate a range of required resource, which have been used as the key inputs to this cost modelling. This includes the number of full-time equivalent (FTE) staff by seniority, consultancy, and overhead costs. These estimates were then further refined following scrutiny from BEIS and key stakeholders including industry and other regulatory bodies. The ONS statistics on average Civil Service

[43] Recovering the cost of heat networks. < https://www.gov.uk/government/consultations/recovering-the-costs-of-heat-networks-regulation >

pay have been used to calculate the cost of the required FTE.[44] These costs were then inflated by 21.8% to account for non-wage costs, in line with guidance from the RPC.[45]

C) **Profile and scale resource requirements** – To account for the anticipated growth, illustrative annual growth rates have been constructed based on the available evidence, detailed in Table 9.

**Table 9 - Estimated heat network deployment under different growth scenarios**

| Heat network deployment | 2050 (TWh) | Annual growth rate % | Source |
|---|---|---|---|
| **Low** | 14 | 0% | Heat Networks experimental statistics |
| **Central** | 46 | 4% | Heat network Zoning IA[46] |
| **High** | 81 | 6% | CCC's Sixth carbon budget[47] |

### Results

The results from these scenarios can be seen in Table 10, with the analysis suggesting that the set-up costs are estimated to be between £2.6 - £4m in the first year and annual operating costs of heat network regulation would be between £4.5 - £9m, with a central estimate of £6.5m. Please note this result will differ to those presented in the cost recovery constitution annex and main body of the IA due to discounting.

**Table 10 - Annual recurring costs to regulator over the 10-year appraisal period (undiscounted, £m))**

| Year | Set up costs | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 10-year average[48] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low scenario** | 2.6 | 0.7 | 3.0 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | **4.5** |
| **Central scenario** | 3.3 | 0.9 | 3.6 | 7.0 | 7.2 | 7.3 | 7.4 | 7.6 | 7.7 | 7.9 | 8.1 | **6.5** |
| **High scenario** | 4.0 | 1.1 | 4.4 | 9.5 | 9.8 | 10.1 | 10.4 | 10.7 | 11.0 | 11.4 | 11.8 | **9.0** |

Note: these costs have been rounded and therefore may differ from elsewhere in the IA.

### 1. Costs to business estimates

The costs to business with the following methodology calculating the following:

A) **Identify requirement:** The expected requirements to be placed of heat network organisation was based on consultation with Ofgem, response to the consultation and the current policy ambition.

B) **Estimate the frequency and resource** – The number of hours required by businesses to comply with various areas of the regulation was estimated through consultation with Ofgem and a comparison with the heat trust requirements. The frequency of requirements is based on current policy ambition.

C) **Costing -** To estimate the implied costs of undertaking these activities, these tasks are assumed to be carried out by an estimate manager and an internal business

[44] Civil Service median salaries by grade, 2019 < https://www.gov.uk/government/statistics/civil-service-median-salaries-by-uk-region-and-grade >

[45] RPC guidance on implementation costs, 2019 < https://www.gov.uk/government/publications/rpc-short-guidance-note-implementation-costs-august-2019 >

For simplicity, wage costs have been set constant across the appraisal period.

[46] Heat Network Zoning consultation-stage IA, 2021. Please note that we have used the expected growth rate from the preferred option. There is considerable uncertainty around the expected growth in heat network deployment as heat network zoning policy is still at consultation stage. Therefore, this growth rate should be viewed as illustrative.

[47] CCC's 6th Carbon Budget report, 2020 <https://www.theccc.org.uk/wp-content/uploads/2020/12/Sector-summary-Buildings.pdf >

[48] 10-year average excludes set up costs.

consultant split 75:25 respectively. Hourly wage costs have been informed by ONS statistics.[49]

D) **Aggregate costs -** The costs to business were summed across all activities to provide an aggregated costs for the whole market per year.

**Table 11 – Cost to business assumption overview (central case)**

| Assumption | Level | Duration (hour) | Rate (£/hour) | Cost (£) | Frequency |
|---|---|---|---|---|---|
| **Familiarisation & dissemination** | Heat supplier | 9.5 | 27 | 257 | One-off |
| **Authorisation application** | Heat supplier | 3 | 27 | 81 | One-off |
| **License application** | Heat supplier | 24 | 27 | 648 | One-off |
| **Annual reporting set up** | Heat network | 7.5 | 27 | 203 | One-off |
| **Annual reporting** | Heat network | 7.5 | 27 | 203 | Annual |
| **Audits** | Heat supplier/networks | 4 | 27 | 108 | Annual (500 per year) |
| **Complaints** | Heat supplier | 0.5 | 27 | 14 | Annual |

## 2. Counterfactual Cost Estimates

We have assumed that the counterfactual scenario the only form of regulation in the heat network market is the Voluntary Heat Trust. The implied cost of Heat Trust membership over the appraisal period using the following methodology:

A. **Estimate future growth** – The reported growth in heat trust membership was used to derive the observed trend in growth between 2016 to 2020[50]. This trend was then applied to the current heat trust membership to produce an illustrative growth scenario over the appraisal period. Under the low sensitivity, the growth rate was reduced by 50% and under the high sensitivity this growth rate was increased by 50%.

B. **Estimated regulatory costs –** The current heat trust membership costs and energy ombudsman costs were then used to estimate the counterfactual regulatory costs, as summarised in Table 12.

**Table 12 - Additional costs under the Counterfactual**

| Area | Level | Cost | Frequency |
|---|---|---|---|
| **Connection cost** | Per Heat Trust customer | 4.6 | Annually |
| **Joining fee** | Per Heat Trust network | 100 | One-off |
| **Audits** | 20% of Heat Trust networks | 108 | Annually |

[49] Earnings and hours worked, region by occupation by two-digit SOC: ASHE Table 3 <https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/datasets/regionbyoccupation2digitsocashetable3 >

[50] Heat Trust Annual Reports < https://heattrust.org/annual-reports-v2 >

| | | | |
|---|---|---|---|
| **Energy Ombudsman FCR Fee** | 75% of EO complaints | 170 | Annually |
| **Energy Ombudsman Upheld Fee** | 25% of EO complaints | 400 | Annually |

C. **Costs to business** were then calculated in a similar way to the factual case. Though – apart from HMBR annual reporting – costs for a given area of regulation were multiplied by the projected number of Heat Networks/suppliers that will join the Heat Trust (as opposed to all Heat Networks). The differences are summarised in Table 13 below: Heat Networks

**Table 13 - Additional costs to business under the Counterfactual**

| Area | Level | Cost (£) | Frequency |
|---|---|---|---|
| **Annual Reporting** | Per Heat Trust heat network | 203 | 6 Months |
| **HMBR Annual Reporting** | Heat Network (all) | 406 | Every four years |
| **Annual Reporting Set-Up** | Per Heat Trust heat network | 203 | One-off |
| **Complaints** | 2% of all heat network customers | 14 | Annually |
| **Authorisation** | Per Heat Trust supplier | 81 | One-off |
| **Familiarisation & dissemination** | Per Heat Trust supplier | 257 | One-off |

**Table 14 – estimated counterfactual costs (£m, undiscounted, 2020 prices)**

| Year (£m) | Set up costs | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 10-year average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low scenario** | 0.0 | 1.7 | 1.8 | 1.8 | 1.9 | 2.0 | 2.1 | 2.2 | 2.3 | 2.4 | 2.4 | **2.1** |
| **Central scenario** | 0.0 | 1.8 | 1.9 | 2.0 | 2.1 | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 | 2.8 | **2.3** |
| **High scenario** | 0.0 | 1.9 | 2.0 | 2.1 | 2.3 | 2.4 | 2.6 | 2.7 | 2.9 | 3.1 | 3.2 | **2.5** |

Note: these costs have been rounded and therefore may differ from elsewhere in the IA.

## 3. Cost Recovery Estimates

### Regulator ongoing costs

To estimate the average potential bill impact under different cost recovery options, Ofgem and Citizens Advice's annual regulatory costs are divided by the number of consumers captured under a given option. For the purpose of this analysis, it is assumed that heat network, gas, and electricity suppliers pass 100% of the cost of regulation through to their entire consumer base. Energy Ombudsman costs are expected to be recovered directly through fees from heat suppliers and therefore have not been included in the cost socialisation analysis below.

These estimates reflect the preferred option in the current consolation on cost recovery, therefore should be viewed as indicative. In the preferred option the on-going running costs of the Heat Networks regulator are spread across all gas, electricity, and heat network consumers. This has been estimated using assumption on the current size of the energy market and the costs of running Ofgem's current regulatory activities, summarised in table X.

**Table 15 - Estimated annual cost of regulation and size of markets**

| | Heat Networks[51] | Gas | Electricity | Total |
|---|---|---|---|---|
| **Regulatory costs (£m)** | 5.9 (Excluding EO) | 72[52] | | **78** |
| **Customers (million)** | 0.6[53] | 24[54] | 31[55] | **56** |
| | | | | **£1.39** |

Note: these costs have been rounded and therefore may differ from elsewhere in the IA.

The consumer level impact was calculated by dividing the total cost of Regulating all heat network, gas, and electricity consumer by the total number of consumers. This results in an estimated impact of £1.39 per heat network customer, this would also raise the annual cost for gas and electricity customers from around £1.30 to £1.39, to account for the additional costs of regulating the heat network market.

### Costs to business recovery

The cost recovering the implied costs to business have also been estimated, assuming 100% cost recovery. This has been calculated by dividing the total additional estimated cost due to requirements of the regulation by the total number of heat network customers. For simplicity am average has been calculated across the 10-year appraisal period, the inputs to this calculation are summarised in Table 16.

**Table 16 - Costs to business recovery overview**

| | Total |
|---|---|
| **Average Additional cost to business (£m)** | £2.18 |
| **Average Heat network customers (million)** | 0.6 |
| **Cost per customer** | £4.14 |

Note: these costs have been rounded and therefore may differ from elsewhere in the IA.

This results in an average annual cost per customer of £4.14 in the central case. However, this is expected to be an upper bound estimate for two reasons, firstly, not all heat suppliers are expected to pass 100% of these costs onto their customers. Secondly, the number heat network customers are based on the number of dwellings or units which they supply heat too, however, this doesn’t account for the wider potential consumer based of the non-domestic units.

## C - Consultation stage options

The consultation stage IA assessed four regulatory options against the counterfactual[56]. A brief description of these option can be found below:

- ***Option 0: Counterfactual (Do Nothing)*** A continuation of existing market arrangements.
- ***Option 1: Authorisation Plus (preferred)*** Every heat network supplier is authorised, this covers protection measures but does not allow heat network suppliers to apply for additional rights and powers. However, this option gives suppliers the option to apply for a license in order to attain extra rights and powers. A licenced heat network supplier has more stringent requirements on reporting related to consumer protection measures. This option therefore goes beyond the CMA’s recommendation that consumer detriment be

[51] This estimate represents the 10-year average of ongoing costs to Ofgem and Citizens Advice under the central scenario and the number of Heat Networks customers scales with market growth and will therefore differ from table 2. This cost estimate excludes Energy Ombudsman costs which is estimated to be around £0.5m per annum under the central scenario (10-year average)

[52] Ofgem’s Licence fee income, 2019-20, < https://www.ofgem.gov.uk/publications/ofgem-annual-report-and-accounts-2019-20 >

[53] The number of heat network customers have been estimated based on OPSS data and the central growth scenario. It is presented as an average across the 10-year appraisal period.

[54] Regional and local authority gas consumption statistics,2020, <https://www.gov.uk/government/statistical-data-sets/gas-sales-and-numbers-of-customers-by-region-and-local-authority>

[55] Regional and local authority electricity consumption statistics, 2020, <https://www.gov.uk/government/statistical-data-sets/regional-and-local-authority-electricity-consumption-statistics>

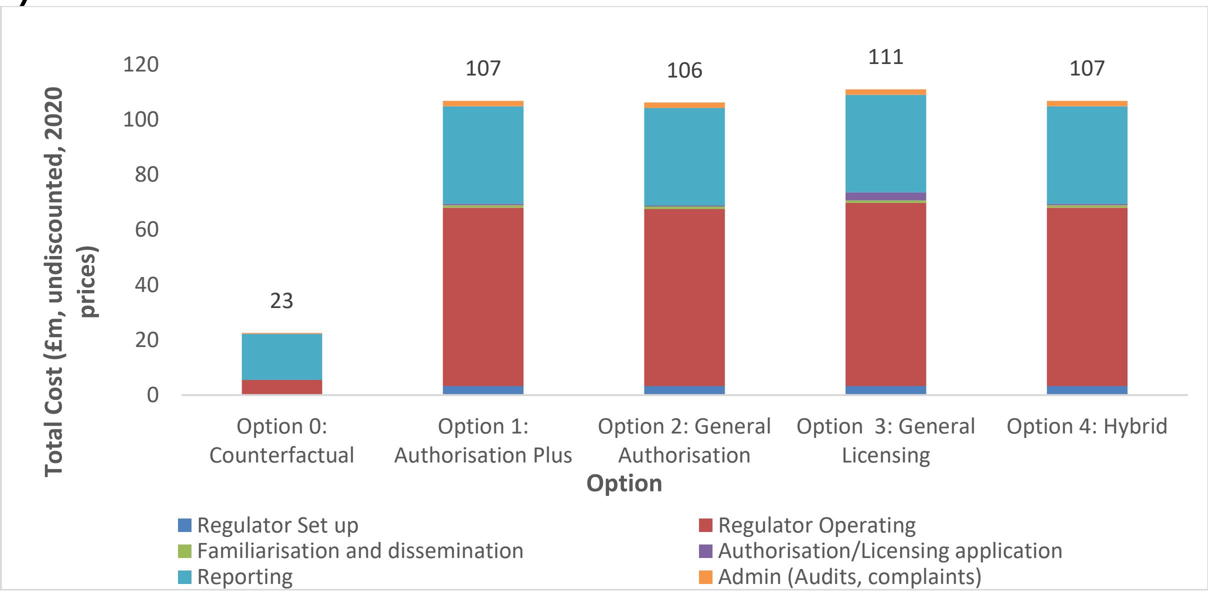
[56] Note that these options are identical to those discussed in the consultation stage IA, but have been reordered for the purposes of this IA.

addressed as it offers Heat Networks the ability to apply for rights and powers should they want them

- ***Option 2: General Authorisation*** Every heat network supplier is required to be authorised. The authorisation regime covers consumer protection measures but, unlike with a licensing regime, does not allow heat network suppliers for apply for additional rights and powers. This option also meets the CMA's recommendations on addressing consumer detriment but is the 'do minimum option'.
- ***Option 3: General Licensing*** Every heat network supplier must be licensed to operate in the market. The decision whether to grant a supplier this licence will depend upon the supplier's ability to undertake the consumer protection measures as well as their financial holdings. The licence covers consumer protection measures with more stringent requirements on reporting than in authorisation and allows the supplier to apply for rights and powers. This option therefore goes beyond minimum implementation of the CMA's recommendations as it goes further to address the market failures in the Heat Networks market.
- ***Option 4: Hybrid*** Every heat network is authorised at the heat network level as in option 2. Heat network suppliers above a certain size threshold are required to be licensed in order to operate. The licence in this option is equivalent to the one in option 3, which has more stringent requirements on reporting related to consumer protection measures. This option also goes beyond the CMA's recommendations as it offers Heat Networks the ability to apply for rights and powers should they desire them.

Authorisation Plus (option 1) is preferred as it meets the CMA's recommendations, addresses all the market failures and is less burdensome than the hybrid model or general licensing, that make licensing mandatory to certain suppliers. The overall costs of the Authorisation Plus option is also expected to be lower than General Licensing and a similar level to the Hybrid option. These differences are driven by lower licensing costs to business, and in the case of General Authorisation, lower ongoing regulation costs, as shown in Figure 6 below:

**Figure 6 - Central costs of each option, split by area (£m, undiscounted, constant 2020 prices)**




Note: cost estimates are not relative to the counterfactual and are undiscounted so may differ from elsewhere in the IA.

## D - Pricing analysis

To estimate the proportion of heat network consumers paying less than the gas comparator, we used a similar methodology to that used in the Heat Trust and the CMA market study. To calculate the gas comparator, we used the methodology outlined in the CMA Heat Networks

Market Study Appendices[57] and was informed by the Heat Trust Cost Calculator[58]. We used three comparators, a low, central, and high price.

The data on Heat Networks heat tariff comes from CMA's market study collected by Kantar. To enable comparability, all the analysis has been carried out in the same base year and the appropriate fuel costs have been used.

The assumptions used were the same as the CMA except slightly different assumptions were made for boiler efficiency and lifetimes. The variable unit prices also differ and were taken from the 2016 Quarterly Energy Projections[59] and low and high sensitivities were applied in line with the Green Book supplementary guidance. These assumptions can be found below in

Table **17**.

The proportion of consumers paying less than a given comparator was then calculated by comparing the average unit price of the comparator with the unit price of a given heat network. The number of heat network consumers paying less than a given gas comparator was summed across the sample. To provide an illustrative sense of scale across the market, this was than scaled by the know size of the current market.

**Table 17 – assumptions used in the BEIS pricing analysis**

| Assumption | Unit | low | central | High | Source |
|---|---|---|---|---|---|
| **Boiler cost (£)** | | | | | |
| **A** | £ | 894 | 894 | 894 | Heat Trust |
| **B** | £ | 1077 | 1077 | 1077 | Heat Trust |
| **C** | £ | 1162 | 1162 | 1162 | Heat Trust |
| **D** | £ | 1595 | 1595 | 1595 | Heat Trust |
| **Installation Costs** | £ | 600 | 600 | 600 | Heat Trust |
| **Annual Q&M** | £ | 200 | 200 | 200 | Heat Trust |
| **Boiler Efficiency*** | % | 85% | 85% | 85% | BEIS assumption |
| **Boiler Lifetime*** | years | 15 | 15 | 15 | BEIS assumption |
| **discount rate** | % | 3.5% | 3.5% | 3.5% | HMT Green book |
| **Variable unit price (£/KWh)** | £/Kwh | 0.031 | 0.036 | 0.044 | 2016 QEP |
| **Fixed costs (£)** | £ | 68.77 | 79.36 | 97.71 | 2016 QEP (scaled with GB) |

## E - Technical standards analysis

To provide a sense of scale of the potential impact greater technical standards could have on the operation of Heat Networks, analysis has been carried out on the implied distribution losses of around 14,000 Heat Networks contained in the Heat metering and billing notifications data. In practise the impact of minimum technical standard is expected to be broader than distributional losses alone, although we currently lack sufficient data one other aspects to robustly quantify.

The data from these notifications has undergone a previous quality assurance process as part of the work which underpins with experimental statistics for heat network, however as this data is self-reported some uncertainty remains, please see as discussed in the published report. The notifications do not contain estimated distributional losses however the implied distribution losses have been derived from the heat generated and heat supplied values provided by Heat Networks as part of the notification for the heat network. The following formula have been used.

[57]P21, Technical Annex to Appendix A: Derivation of the CMA gas comparators. Found in: CMA Heat Networks Market Study Appendices: < https://www.gov.uk/cma-cases/heat-networks-market-study >

[58] Heat Trust Cost Calculator Background assumptions < https://www.heattrust.org/assumptions-data >

[59] 2016 Quarterly Energy Report, Table 2.3.4 < https://www.gov.uk/government/statistics/quarterly-energy-prices-december-2016 >

$$Implided\ distributional\ lossess\ (\%) = 1 - \frac{\text{Heat suplied (TWh)}}{\text{Heat Gernertaed (TWh)}} * 100$$

The distributional losses of all networks were then compared to the indicative ranges of 20 -30% informed by the CP1 Technical standards and consultation with BEIS heat network experts. These ranges were then compared to the estimate losses for each heat network to identify those which exceeded the threshold. Once identified the following equation was used to calculate how much heat generation could be saved if the losses of the network were reduced to the specified threshold.

$$Implided\ generation\ saving\ (Twh) = \left(\frac{\text{Heat suplied (TWh)}}{(1-\text{Current losses})}\right) - \left(\frac{\text{Heat suplied (TWh)}}{(1-\text{threshold losses})}\right)$$

The outputs of the above network level calculations where then summed across all networks above the threshold to provide an aggregated view of the total generation saving across all networks in the sample.

**Title:** ECO4 threshold removal and buy out
**IA No:** BEIS041(F)-22-EEL

**RPC Reference No:** RPC-BEIS-5173(1)

**Lead department or agency:** Department for Business, Energy and Industrial Strategy.

**Other departments or agencies:** None

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage:** Primary

**Source of intervention:** Domestic

**Type of measure:** Primary legislation

**Contact for enquiries:**
beisECOteam@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

**Cost of Preferred (or more likely) Option** (in 2020 prices)

| Total Net Present Social Value | Business Net Present Value | Net cost to business per year | Business Impact Target Status |
|---|---|---|---|
| | | | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

ECO obligation thresholds, which exempt smaller suppliers may lead to an uneven playing field for suppliers, disrupt important price signals and incentivise some suppliers to set their prices in a way that means they recover these policy costs disproportionately from default tariff customers, exacerbating the loyalty penalty. Obligating all suppliers may however mean disproportionately high costs for small suppliers, compared to the size of their obligation.

**What are the policy objectives of the action or intervention and the intended effects?**

The policy objectives are to remove size-based supplier thresholds to rectify market distortions and avoid an uneven playing field for suppliers – contributing to the problem of excess prices for unengaged customers (loyalty penalty). To ensure that removing the ECO thresholds does not put too great a burden on small energy suppliers, a buy-out mechanism which effectively caps spending for some suppliers, is being explored to ensure smaller suppliers can meet their ECO obligations without facing disproportionately high costs.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Option 0: Do nothing and leave ECO4 supplier thresholds as they are currently. Suppliers are obligated under the scheme if they have over 150,000 customer accounts and a supply volume above 300GWh of electricity and 700GWh of gas per year

Option 1: Remove existing thresholds and obligate all suppliers with over 1,000 customer accounts.

Option 2: The preferred option is to remove thresholds for all suppliers with over 1,000 customer accounts but allow suppliers with under 150,000 customer accounts an option to meet their obligation through meeting a spend requirement as opposed to a bill saving requirement. The primary powers for changes to ECO4 within the Energy bill are not self-enacting so will have zero impact without secondary legislation (therefore this IA cover sheet shows no headline impacts). This IA however considers the potential high-level impacts of both primary and secondary legislation for illustrative purposes only.

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:**

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | No | | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** | **Non-traded:** | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

## Summary: Analysis & Evidence

Policy option 1

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Years** 46 | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | | |

**Description and scale of key monetised costs by 'main affected groups'**

Newly obligated suppliers will face new costs in delivering their ECO4 obligation.

**Other key non-monetised costs by 'main affected groups'**

Small suppliers may be faced with very small obligations – which are difficult to deliver. The small suppliers would not benefit from economies of scale that would enable them to spread their delivery risks amongst several delivery partners, or to contract with third parties for the installation of measures on advantageous terms, and their obligation may also be too small to justify the creation of in-house installation arms. This may mean they face set-up costs disproportionate to their very small obligation, increasing the delivery risk.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

Existing obligated suppliers are expected to benefit as the total obligation is split across more suppliers, this is expected to result in a lower obligation on average for existing ECO4 suppliers and reduced delivery costs.

**Other key non-monetised benefits by 'main affected groups'**

Ensuring that almost all suppliers are obligated is expected to ensure a more level playing field for suppliers and help reduce incentives for obligated suppliers to price acquisition tariffs below cost to be competitive with unobligated suppliers. This is therefore intended to avoid ECO contributing to the issue of loyalty penalties for unengaged consumers and improve competition in the market

**Key assumptions/sensitivities/risks** — **Discount rate (%)** 3.5

Analysis at this stage should only be seen as providing a potential scale of impact the policy may have (based on a set of illustrative assumptions), given the uncertainty around final policy design. There is significant uncertainty around the composition of the energy market in future and delivery costs under ECO4.

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** | **Benefits:** | **Net:** | |

## Summary: Analysis & Evidence

Policy option 2

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2020 | **PV Base Year** 2022 | **Time Period Years** 46 | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | | |

**Description and scale of key monetised costs by 'main affected groups'**

Newly obligated suppliers will face new costs in meeting their obligation – although buy-out would guarantee they do not need to spend above a set amount when meeting their obligation. Buy-out is expected to reduce delivery costs for smaller suppliers compared to option 1. However, by providing a lower cost alternative to delivery, buy-out may result in reduced benefits if less bill savings are achieved.

**Other key non-monetised costs by 'main affected groups'**

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | Optional | | Optional | **Optional** |
| **High** | Optional | | Optional | **Optional** |
| **Best Estimate** | | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

Existing obligated suppliers are expected to benefit overall as the total obligation is split across more suppliers, this is expected to result in a lower obligation on average for existing ECO4 suppliers and thus reduced delivery costs.

**Other key non-monetised benefits by 'main affected groups'**

Ensuring that almost all suppliers are obligated is expected to ensure a more level playing field for suppliers, is expected to avoid ECO contributing to the issue of loyalty penalties for unengaged consumers and improve competition in the market. Buy-out is intended to provide a lower cost way for suppliers to meet their obligation without facing disproportionately high costs – this will help reduce the delivery risk associated with small obligations.

| **Key assumptions/sensitivities/risks** | **Discount rate** | 3.5 |
|---|---|---|

Analysis at this stage should only be seen as providing a potential scale of impact the policy may have (based on a set of illustrative assumptions), given the uncertainty around final policy design. There is significant uncertainty around the costs and benefits associated with buy-out delivery, as well as the composition of the energy market in future and delivery costs under ECO4.

**BUSINESS ASSESSMENT (Option 2)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** | **Benefits:** | **Net:** | |

# Evidence Base

## 1. Overview and problem under consideration

1. This Impact Assessment (IA) accompanies primary powers sought within the Energy Bill to create an alternative delivery clause within Energy Company Obligation (ECO) which would allow suppliers a low cost, more flexible way to meet their ECO4 obligation[1].

2. ECO requires energy suppliers to deliver a target of notional annual bill savings by installing energy efficiency and heating measures to homes in Great Britain. These measures help households to keep their homes warmer, reduce their energy bills and carbon emissions.

3. ECO4 is a four-year scheme from April 2022 to March 2026, suppliers will be obligated under the scheme initially if they have over 150,000 customer accounts and a supply volume above 300GWh of electricity and 700GWh of gas per year.

4. ECO supplier obligation thresholds have been identified as a factor that has caused excessive charging in the domestic energy retail market on an enduring basis[2]. The Energy White Paper published on 14 December 2020[3] committed to removing these thresholds. To ensure that removing the ECO thresholds does not put too great a burden on small energy suppliers a buy-out mechanism is being explored. Buy-out would give small suppliers the option to either deliver their full bill saving target or if meeting this target would mean spending disproportionately more (i.e., above the supplier's fair share to £1b per year), they could instead provide evidence that they have met their spend target instead. This effectively caps the level of spend needed in meeting their obligation.

5. The primary powers for changes to ECO4 within the Energy bill are not self-enacting so will have zero impact without secondary legislation (therefore this IA cover sheet shows no headline impacts). The Government will consult in the future on changes to ECO thresholds and the exact design of buy-out. Once the final Government position is clear, changes to ECO4 will be set out in secondary legislation, with an accompanying IA. This IA provides a high-level illustrative assessment of the potential scale and nature of impact of both the primary and potential secondary legislation. However, given the uncertainty around the final policy details, this analysis only provides a sense of scale estimate of the potential impacts. A more detailed assessment will be produced, once the government's final policy position is clear.

6. The current energy price spike and subsequent exits in the market have meant a reduction in the number of energy suppliers. This consolidation in the market has had immediate knock-on impacts on competition, however the long-term implications are yet unknown. Final decisions on thresholds and the need for and design of mitigating options (such as buy-out) will need to be made in the context of the market environment closer to the time. However, it is important for Government to secure primary legislation now to facilitate any future changes. The current market conditions only add to the uncertainty in analysis of secondary legislation. Analysis presented here is intended to provide the current best estimate of costs and discussion of potential benefits. It should be seen as purely illustrative at this stage.

[1] ECO4 is the ECO during the period 2022-2026

[2] Thresholds were first identified as a possible area for reform within the future retail market review – more detail is provided below. https://www.gov.uk/government/consultations/flexible-and-responsive-energy-retail-markets

[3] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

## 1.1 Problem under consideration

7. Since the privatisation of the energy retail market two decades ago, the level of competition has improved significantly. However, this increase in competition has not brought benefits to all consumers, including many of the most vulnerable. Customers who do not engage with the market, for example through switching, remain or are rolled onto their supplier's 'default tariff'. Since these consumers are defined by lower levels of engagement, suppliers are given a position of unilateral market power over them, which weakens competition for their custom and means they are consistently charged higher prices. An assessment of this was formalised by the CMA in their 2016 Energy Market Investigation[4]. This has since become referred to as the 'loyalty penalty' and is a feature common to many similarly structured markets.

8. As part of the joint Future Retail Market Review[5], the Government and Ofgem considered (among other retail policy areas) what further enduring measures would be needed to facilitate competition and tackle the factors that have caused a loyalty penalty. This identified ECO supplier thresholds as a possible area for reform. In 2019 the government consulted, asking for stakeholders' views, on how we should prevent excessive charges for loyal consumers[6].

9. Within that consultation concerns were raised about the current size-based ECO obligation thresholds. It was highlighted that thresholds which exempt smaller suppliers may lead to an uneven playing field for suppliers, disrupt important price signals and incentivise some suppliers to set their prices in a way that means they recover these policy costs disproportionately from default tariff customers, exacerbating the loyalty penalty.

10. There are significant differences in obligation costs between suppliers under ECO. According to the ECO3 Impact Assessment[7]: suppliers below the scheme threshold face no cost; the smallest twelve obligated suppliers are expected to face around £6-7 per dual fuel customer, while the largest six suppliers face £25-27. This sends a price signal that does not represent the underlying efficiency of the supplier. It also means that only customers with obligated suppliers contribute to the recovery of the costs of the scheme. Since current market conditions mean these suppliers are competing for engaged customers with other suppliers facing no obligation costs, competitive forces may incentivise the concentration of these costs in the prices paid by consumers who do not engage. This would lead to an unfair distribution of costs and contribute to the problem of excess prices for unengaged customers (loyalty penalty).

11. The majority of the 2019 consultation respondents agreed that removing the ECO thresholds would help remove imbalances in the retail market and help reduce incentives for suppliers to adopt pricing strategies that lead to excessive charges for loyal consumers[8]. Some respondents also argued that the threshold removal would reduce the pressure on larger suppliers to price tariffs for new customers (usually fixed term) below cost to be competitive with unobligated suppliers, and so reduce their need to set excessively higher charges for their default tariffs to recoup these losses.

[4] https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf
[5] https://www.gov.uk/government/consultations/flexible-and-responsive-energy-retail-markets
[6] https://www.gov.uk/government/consultations/flexible-and-responsive-energy-retail-markets
[7] BEIS (2018) ECO3: 2018-22 - final stage impact assessment https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/749638/ECO_3_Final_Stage_IA__Final.pdf
[8] A summary of consultation responses can be found here: https://www.gov.uk/government/consultations/flexible-and-responsive-energy-retail-markets
Individual responses were published here: https://www.ofgem.gov.uk/publications-and-updates/flexible-and-responsive-energy-retail-markets

12. A small number of respondents disagreed, arguing that small suppliers face substantially higher upfront costs for participating in ECO, and exemptions are necessary to avoid them. The Government agrees that removing the ECO thresholds with the current design would put too great a burden on small energy suppliers. The Government therefore consulted on how to reform these thresholds as part of broader scheme reforms, aimed at reducing the costs of participation in the scheme as part of the ECO4 design consultation[9].

## 2. Rationale for intervention

13. Government intervention to reduce ECO supplier obligation thresholds is needed to correct market distortions created by ECO. This is justified on equity grounds, as it is inequitable that distortion created by ECO thresholds contributes to the problem of excess prices for unengaged customers (loyalty penalty).

14. This is of particular concern to Government in the context of essential goods and services such as energy, which is an unavoidable household cost. Energy can form a large part of the household budgets for those on lower incomes compared with those on higher incomes. The Competition and Market Authority (CMA) found evidence to suggest that households with low incomes, low qualifications, those in the rented sector and those over 65 are more likely to be unengaged and therefore paying more[10]. They found that only 20% of households with incomes below £18,000 switched suppliers in the period 2013 to 2015, compared with a switching rate of 35% for households with incomes above £36,000[11].

15. Removing thresholds will remove imbalances in the retail market, removing market distortions and results in a more efficient market – the intervention is therefore justified on efficiency grounds also.

16. Though exact impacts will depend on market conditions at the time, the removal of thresholds could place new burdens on the smallest suppliers not initially obligated under ECO4. It may also slightly increase the obligations for the smallest obligated suppliers whilst reducing the size of obligations placed on the larger suppliers. Placing new burdens on the smallest suppliers may mean these businesses face disproportionately high upfront and running costs in meeting their obligation, which could reduce competition within the market by deterring new businesses from entering the market. An alternative delivery option is therefore needed to ensure small suppliers are not paying disproportionately high costs when meeting their obligation.

## 3. Policy options

[9] https://www.gov.uk/government/consultations/design-of-the-energy-company-obligation-eco4-2022-2026

[10] Source: CMA energy market investigation Final Report (2016). Available online at: https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf, p. 461

[11] Source: CMA energy market investigation Final Report (2016). Available online at: https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf, p. 33

## 3.1 Policy objectives

The policy objectives are:

- Remove supplier thresholds to rectify market distortions and avoid an uneven playing field for suppliers, which contributes to the problem of excess prices for unengaged customers (loyalty penalty).
- Ensure delivery of measures under ECO, without disproportionate cost impacts to smaller suppliers.

## 3.2 Summary of options

**Policy Option 0 – the 'Do Nothing' Option**

17. Under this option, the current ECO suppliers' thresholds remain unchanged, and no alternative delivery clause is implemented. This option represents the counterfactual against which the costs and benefits of the consultation options are assessed

**Policy Option 1 – remove ECO supplier thresholds no alternative delivery mechanism**

18. All suppliers would be obligated under ECO from April 2024 (ECO4 Phase 3), subject to exemptions for the very smallest suppliers where cost of delivery may be disproportionate, because we deem their customer numbers and supply volumes to be too low. BEIS will determine the size of the exempted suppliers during secondary legislation. However, based on the ECO4 consultation responses[12] the consensus was to exempt suppliers with customers up to 1,000 customer accounts.

**Policy Option 2 – remove ECO supplier thresholds + buy out mechanism (preferred option)**

19. Under this option thresholds would also be removed from April 2024 (Phase 3) for all those with over 1,000 customer accounts, but a buy-out mechanism would be introduced. This is the Government's preferred option and was generally supported by ECO4 consultation respondents. The consultation asked if respondents agreed with the proposal to introduce a buy-out mechanism to enable smaller suppliers to participate under ECO without disproportionate costs to them. Of those with a view, many agreed with this approach (of 110 responses 45% said yes, 10% no and 45% had no view).

20. Government will consult further on which suppliers will be exempt from Obligation. However, the ECO4 consultation found that many respondents agreed with a threshold of 1,000 customer accounts regardless of supply volumes (of 108 responses 38% said yes, 12% said no and 50% had no view). Many highlighted this is consistent with the approach taken under the Warm Home Discount scheme. This compared to the alternative proposal of suppliers with less than 5,000 customer accounts, and a supply volume of 66GWh gas and 18 GWh electricity not being obligated. For this option, of those who had a view, many disagreed (of 101 responses 12% said yes, 27% saying no and 61% having no view.

21. The exact design of buy-out will be consulted on, however it is intended to give small suppliers the option to meet their obligation through either their bill saving target or a spend target.

[12] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1010366/eco4-consultation.pdf

Ofgem will determine each supplier's share of total obligation based on their supply of electricity and gas. This proportion can either be applied to the total bill saving target (£224.3 million in notional annual bill savings) or spend target (£1bn per year). Buy-out will allow small suppliers to delivery against the spend target if they think delivering bill savings will result in disproportionate high costs. For example, a supplier with less than 150,000 customers and 0.5% of the overall obligation of £224.3 million, would either need to deliver £1.12 million of notional annual bill savings (over 4 years) or provide evidence of spending £20 million on ECO4 measures (0.5% multiplied by £4bn).

22. BEIS will consult on how the small suppliers are determined prior to secondary legislation. However, it is expected those with less than 150,000 domestic customers will be able to make use of buy-out, as these suppliers are currently not obligated under ECO.

23. Suppliers would need to declare their intention for using buy-out, whether full or partial, before the start of the next obligation phase (the phases within the obligation, which are set during secondary legislation). They would not be able to change their minds for the phase, during the phase, or after the phase. Suppliers can choose a different approach for each new phase.

24. The rationale for requiring suppliers to decide prior to the obligation phase on whether to use buy-out or deliver ECO measures is to minimise risk of market disruption and administrative burden for Ofgem. This approach was generally supported by ECO4 consultation respondents. The consultation asked if respondents agreed that suppliers should decide whether to buy-out or not during a 'decision window' which is prior to the start of the next obligation phase. Of 99 respondents 26% said yes, 12% said no and 62% had no view.

# 4. Analytical approach

## 4.1 Counterfactual and appraisal period

25. The impacts of primary and potential secondary legislation within this IA have been appraised according to Green Book and supplementary guidance and are presented in discounted real 2020 prices, against a counterfactual of no change to ECO4 (i.e. Option 0). The counterfactual position is based on the ECO4 Final IA[13], this sets out the final position in terms of size of ECO4 obligation, average estimated supplier delivery costs and the wider cost and benefits of the policy.

26. Impacts of changes to ECO4 thresholds will impact suppliers for two years from the expected change in thresholds to the end of ECO4 (April 2024 to March 2026). However, the full policy is appraised over April 2022 to March 2068. April 2022 is chosen as the start year to ensure consistency with other Energy Bill IAs. March 2026 is used to reflect the lifetime of the energy efficiency measures that are expected to be installed during the last two years of ECO4, the longest-lived of which (cavity wall and loft insulation) are estimated to last for 42 years. Given measures are deployed until March 2026, the appraisal period runs to March 2068 (42 years after the last year of ECO4) to ensure that all the energy saving-related benefits from these long-lived measures are captured. The approach of ensuring that the benefits are captured over the full lifetime of the measure is in line with HMT Green Book Guidance.

[13] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003740/eco4-consultation-stage-impact-assessment.pdf

27. We might expect some households to maintain the energy efficiency measures installed to ensure that they last longer than expected. However, as this is a voluntary decision by households, neither the costs nor benefits of doing so are captured within this IA.

## 4.2 Supplier obligation shares

28. To understand the potential impact of changes to ECO4 thresholds an estimate is needed of the distribution of obligation under the counterfactual. For the final phase of ECO3, Ofgem collected data on customer accounts and supply volumes for each supplier at 31st Dec 2020, these data are collected annually to enable Ofgem to set obligations for the next phase of ECO. The data has been used in this IA to give an indication of the potential share of ECO4 obligation faced by different suppliers under the counterfactual as well as new thresholds being applied to estimate the change in supplier shares under Option 1 and 2. However, this data is out of date and will not reflect the latest position of the energy market, especially given the recent exits due to the spike in energy prices.

29. The data has been updated to remove recent exits from the market at 20th Dec 2021, however no other updates have been made. This assumes no new entrants to the market in the last year and assumed the distribution of customer accounts and supply for remaining suppliers has remained consistent. This will not factor in mergers or if some suppliers have taken on a disproportionately large share of customer accounts from existing firms.

30. Ofgem will collect data soon on the supply and customer accounts for remaining suppliers in order to apportion the ECO obligation for ECO4 Phase 1. Future analysis will use the latest data available to consider the impact of removing ECO4 thresholds, however updated data still may not reflect the composition of the market under Phase 3 of ECO4 when thresholds are likely to be removed.

## 4.3 Delivery costs

31. The ECO4 Final IA provides an estimate of the potential delivery and admin costs faced by suppliers under ECO4 of 17.8p per £ of notional annual bill saving achieved (in 2021 prices). However, to understand the potential impacts of changes to ECO4 thresholds an estimate of the delivery costs per supplier is needed. BEIS collects data on suppliers reported delivery and admin costs over ECO3 – these data have been used to show the average costs for suppliers by size of obligation delivered relative to the average cost.

32. Table 1 shows that based on the last four quarters of available data (July 2020 to June 2021) suppliers who delivered 10% or more of the obligation in each quarter reported costs 1.5% below average. This compares to those with less than 1% of the obligation reporting costs 2.3% higher than average. Using these data an estimated total delivery price for ECO4 can be produced for suppliers of different sizes by applying proportions in the second column of the table below to the ECO4 final IA average price of 17.8p. For example, those assumed to have less than 1% of the obligation (based on analysis set out in Section 4.2) are assumed to pay 18.2p per notional annual bill saving achieved compared to the average of 17.8p estimated within the ECO4 IA.

**Table 1: ECO3 delivery and admin cost data split by share of obligation applied to ECO4 average delivery costs[14]**

| Share of total obligation delivered | ECO3 costs relative to scheme average - year ending June 2021 | ECO4 assumed price in pence |
|---|---|---|
| 10% or more | -1.5% | 17.6 |

[14] Data taken from supplier reported quarterly ECO3 costs July-20 to Jun-21

| | | |
|---|---|---|
| 5% or more but less than 10% | 3.0% | 18.4 |
| 1% or more but less than 5% | 3.8% | 18.5 |
| Less than 1% | 2.3% | 18.2 |

33. These estimated ECO4 delivery costs are highly uncertain and are intended to give a sense of scale estimate only. There is a lot of variability in costs reported by suppliers and not always a clear trend showing smaller suppliers face larger costs – for example those delivering between 1% and 5% of the obligation each quarter saw slightly higher costs than those delivering less than 1% when averaged across the last year. Data also suggested suppliers with smaller obligations tended to face lower admin costs than larger suppliers.

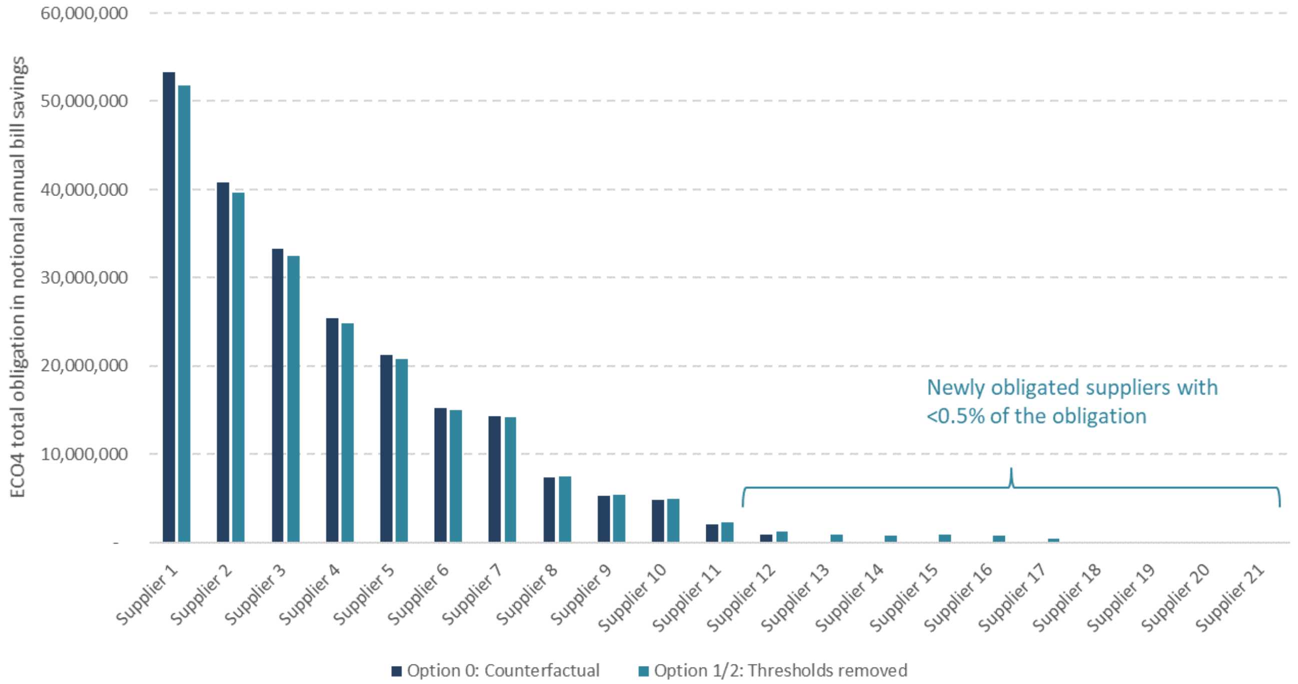
34. Using these data to estimate ECO4 delivery costs assumes that suppliers with similar obligation shares could face similar costs (relative to average) under ECO3 and ECO4. This assumption may not hold in practice given the increase in size of obligation for ECO4 as well as other changes to the scheme and energy market. Once ECO4 commences actual cost data will be collected from suppliers – this will provide a better understanding of actual delivery costs faced by existing suppliers under ECO4, however estimating the costs faced by new suppliers will always be highly uncertain.

## 5. Categories of Costs and Benefits

35. The analysis described in Section 4.2 has been used to create the estimates provided in Figure 1, which shows the share of obligation for different suppliers (ordered largest to smallest) under counterfactual (Option 0) and, under Option 1 and 2 where all suppliers with over 1,000 customer accounts are obligated.

36. Figure 1 illustrates that the largest suppliers would be expected to see a reduction in obligation – given the total obligation is now being distributed across more suppliers. The smallest obligated suppliers may however see a small increase in share. The newly obligated suppliers are expected to have very small obligation, in this example using December 2020 data all newly obligated suppliers have an obligation share below <0.5%.

**Figure 1: Suppliers share of total obligation with thresholds removed and under the counterfactual**



37. Costs and benefits for suppliers can be split into existing suppliers and newly obligated suppliers. Existing suppliers are expected to benefit on average due to having a lower obligation and therefore facing lower delivery costs (although some smaller ones may see a slightly larger obligation), whilst all newly obligated suppliers will see additional costs.

38. Option 2 would allow the obligations faced by newly obligated suppliers to be capped at a specific level of spend – this benefits small suppliers compared to Option 1. However, Option 2 may result in a reduction in ECO4 benefits as some of the ECO4 obligation may no longer be delivered if suppliers choose buy-out and the spend cap is hit before their bill saving target is met.

39. The costs and benefits of buy-out are highly uncertain at this stage – the sections below discuss these potential impacts in more detail. If small suppliers are able to achieve the required level of bill saving target for less than or equal to the spent target (i.e. their share of £4bn over four years), the benefits of buy-out may be equivalent to those of ECO4 main delivery. However, if delivery is much more expensive than modelled and newly obligated small suppliers are only able to deliver a fraction of their bill saving target, ECO4 benefits are likely to scale down proportionately.

# 6. Monetised and non-monetised costs and benefits of each option (including administrative burden)

## 6.1 Costs

***Delivery costs for newly obligated suppliers***

40. Based on the analysis presented in Figure 2 roughly 1.8% of the total obligation would be assigned to newly obligated suppliers – this equates to a target of around £1 million in notional annual bill saving per year. All newly obligated suppliers are expected to have an obligation share less than 0.5% of the total obligation each.

41. Newly obligated suppliers under Option 1 will be required to deliver their ECO4 bill saving obligation fully, however the delivery costs they will face are unknown. Table 1 suggests, under ECO3, suppliers with an obligation share less than or equal to 1% of total, saw delivery costs 2.3% higher than the average across all suppliers. If this pattern was to remain for ECO4 and the average price for ECO4 was assumed to be 17.8p per notional bill saving as set out in the ECO4 Final IA[15] – this could result in suppliers with less than 1% of the obligation facing a delivery cost of 18.2p. These costs are provided in 2021 prices. **Based on this price newly obligated suppliers may face a cost of £34 million (PV, 2020 prices) in delivery costs from March 2024 onwards, under Option 1.**

42. Under Option 2, buy-out is intended to cap the level of spend for newly obligated suppliers to ensure they do not need to pay more than their fair share of the £1 billion per year. Newly

[15] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003740/eco4-consultation-stage-impact-assessment.pdf

obligated suppliers would have the option to meet a spend cap instead of their full bill saving obligation. Assuming all new suppliers choose this buy-out option, total delivery costs would be capped at 1.8% of the £1 billion annual spend therefore £18 million per year. **This means under option 2 delivery costs could be slightly reduced for newly obligated suppliers at £33.2 million (PV, 2020 prices).**

43. These estimated ECO4 costs are highly uncertain and are intended to give a sense of scale estimate only, based on the limited available data. Once ECO4 commences actual cost data will be collected from suppliers – this will provide a better understanding of actual delivery costs faced by existing suppliers under ECO4, however estimating the costs faced by new suppliers will always be highly uncertain. If newly obligated suppliers are able to deliver their obligation for less than 17.8p per bill saving achieved, delivery costs under both Option 1 and Option 2 will be lower.

44. Delivery costs included here cover installation and PAS[16] costs associated with measures installed as well as search costs and admin costs faced by suppliers. As well as higher delivery costs, newly obligated suppliers may also face set-up and familiarisation costs associated with ECO4 – these have not been quantified in isolation at this stage but will be considered once policy detail is clearer.

45. ECO4 delivery is assumed to be split evenly across years, therefore the additional costs start from 2024/25 – with no change against the baseline of ECO4 in 2022/23 and 2023/24.

**Table 2: ECO4 delivery costs for newly obligated suppliers- (£m PV 2020 prices)**

| Year | **Option 1: thresholds removed** | **Option 2: buy-out + thresholds removed** |
|---|---|---|
| 2022/23 | | |
| 2023/24 | | |
| 2024/25 | 18.5 | 18.0 |
| 2025/26 | 18.5 | 18.0 |
| **Total** | 36.9 | 36.1 |
| **Present Value (PV)** | **33.9** | **33.1** |

### *Reduction in ECO4 benefits*

46. Under Option 2, if smaller suppliers suspect they may face higher costs for ECO4 than estimated within the Final IA, they are likely to choose to buy-out. This would mean meeting a spend target and not fully delivering their bill saving target, resulting in lower delivery and some loss of ECO4 benefits. A loss of ECO4 benefits would mean a reduction in societal benefits such as improved air quality and carbon savings, as well as potentially lower bill savings and comfort savings for some ECO4 households.

47. Given the uncertainty around design of the policy, ECO4 costs faced by suppliers and future composition of the market, it has not been possible to provide a central estimate for the potential reduction in ECO4 benefits under Option 2. Any reduction in delivery is likely to mean

[16] PAS provides a framework of standards on how to conduct effective energy retrofits of existing buildings. PAS 2035 covers how to assess dwellings for retrofit, identify improvement options, design and specify Energy Efficiency Measures (EEM) and monitor retrofit projects. PAS2035:2019 is designed to work alongside the updated PAS 2030:2019 (previously PAS2030:2017) standards which sets out how the installation of specific EEMs should be carried out in existing domestic buildings. PAS2035 and updated PAS2030 was introduced under ECO3 with all measures delivered after 31st December 2020 required to comply with PAS2035:2019 and delivered by an installer certified to PAS 2030:2019.

all benefits related to ECO4, including energy saving, air quality benefits, carbon savings and comfort taking benefits for households scale down proportionately.

***Delivery risk (non-monetised)***

48. Under option 1, the removal of thresholds may increase the risk that ECO4 is not fully delivered, as the obligation would be split between nearly all suppliers with no support for newly obligated suppliers. The small suppliers would not benefit from economies of scale that would enable them to spread their delivery risks amongst several delivery partners, or to contract with third parties for the installation of measures on advantageous terms, and their obligation would likely be too small to justify the creation of in-house installation arms. This may mean they face set-up costs disproportionate to their very small obligation, increasing the delivery risk for these suppliers.

49. Buy-out is intended to mitigate some of this risk, therefore delivery risks are expected to be greater under Option 1, where there will be no buy-out option for newly obligated suppliers. This IA has not been able to monetise delivery risks given the uncertainty around the exact design of preferred options and uncertainty around the future compositions of the market.

## 6.2 Benefits

***Reduction in delivery costs for existing obligated suppliers***

50. Under both option 1 and 2 existing ECO4 suppliers on average could see a reduction in their obligations and therefore a reduction in delivery costs. Like newly obligated suppliers, delivery costs for ECO4 existing suppliers have been estimated based on ECO3 cost data, looking at the delivery costs relative to the average faced by suppliers of different sizes (shown in Section 4.3).

51. **Using these highly uncertain delivery cost assumptions, the reduction in obligation for existing ECO4 suppliers is estimated to result in a saving of £32.3 million under both Option 1 and 2 (PV, 2020 prices).**

***Competition benefits (non-monetised)***

52. Ensuring that almost all suppliers are obligated is expected to ensure a more level playing field for suppliers and help reduce incentives for obligated suppliers to price acquisition tariffs (usually fixed term) below cost to be competitive with unobligated suppliers. This is therefore intended to reduce their need to set excessively high charges for their default tariffs to recoup these losses.

53. This could mean some consumers see lower bills whereas others see an increase – this impact is expected to balance out overall, but may mask distributional impacts depending on who the winners and losers are. Customers most likely to benefit are those who are less engaged and currently face loyalty penalties. There is evidence to suggest that these households are more likely to have low incomes, low qualifications, those in the rented sector and those over 65.

54. It is not possible to quantify the impacts of this as it is not known to what extent ECO contributes to the issue of loyalty payments. There is also limited evidence available on how suppliers pass their ECO costs onto their customers, given this is a private commercial decision on which Government has control.

55. The energy market has consolidated in recent months due to the gas price spike and subsequent exit of numerous small energy suppliers. Although the gas price spike is expected to subside – there could be longer term implications for competition in the market. Final decisions on ECO4 thresholds and buy-out will be taken in the context of market conditions closer to April 2024.

## 6.3 Net Present Value (NPV)

56. This IA has not provided a full NPV for this policy due to uncertainty around the potential reduction in ECO4 delivery because of buy-out. The table below provides estimates based on two extreme scenarios intended to show the full range of potential impacts.

57. The first scenario assumes buy-out results in no change in ECO4 benefits, the second assumes all ECO4 benefits are lost for suppliers using buy-out. Both these scenarios are unlikely but are intended to show the full range of potential impacts. Under option 2 the biggest cost is the reduction in ECO4 benefits – this would be borne by society by the loss of potential air quality benefits and carbon savings and by some ECO4 households who may lose out on energy savings (resulting in lower energy bills) and comfort taking benefits.

58. Competition impacts are non-monetised, although are not expected to impact the NPV, as some consumers will see higher bills while others see lower. However, they could potentially have distribution impacts where lower income households benefit from lower bills. An equity-weighted NPV has not been provided at this stage.

**Table 3: ECO4 NPV – (£m PV 2020 prices)**

| | Option 1: thresholds removed | Option 2: buy-out + thresholds removed (Scenario 1) | Option 2: buy-out + thresholds removed (Scenario 2) |
|---|---|---|---|
| Delivery costs for ECO4 newly obligated suppliers | 33.9 | - | - |
| Delivery cost of buy-out for newly obligated suppliers | - | 33.1 | 33.1 |
| Reduction in ECO4 benefits | - | - | 93.3 |
| **Total Costs** | **33.9** | **33.1** | **126.4** |
| Reduction in delivery costs for main scheme existing obligated suppliers | 32.3 | 32.3 | 32.3 |
| **Total Benefits** | **32.3** | **32.3** | **32.3** |
| **NPV** | **-1.5** | **-0.8** | **-94.1** |

59. At this stage it is not possible to identify potential regional impacts of buy-out, however, this will be considered further down the line.

# 7. Direct costs and benefits to business calculations

60. Table 4 shows the potential direct costs and benefits to business. Option 2 results in a smaller cost to business, as the new burdens placed on smallest suppliers is reduced due to buy-out (£33.1 million compared to £33.9 million in option 1). Under both options existing obligated

suppliers see an overall benefit of £32.3 million. This saving for existing ECO4 suppliers is smaller than the costs imposed on newly obligated suppliers observed in Option 1 despite the overall size of obligation remaining the same. This is because smaller suppliers are assumed to face higher costs when delivering their ECO4 obligation.

61. Based on the illustrative assumptions used for this IA, the net impact on business of the preferred option is a cost of £0.8 million, however this is highly uncertain at this stage and will depend on the final policy decisions as well as the state of the energy market in from early 2024. Despite the uncertainty, the net impact on business is expected to be small but with the smallest suppliers seeing the highest costs compared to savings of larger businesses.

**Table 4: ECO4 Business NPV – (£m PV 2020 prices)**

| | Option 1: Thresholds removed | Option 2: Buy-out + thresholds removed |
|---|---|---|
| Delivery costs for main obligation newly obligated suppliers | 33.9 | - |
| Cost of alternative delivery for newly obligated suppliers | - | 33.1 |
| **Total Costs** | **33.9** | **33.1** |
| Reduction in delivery costs for existing obligated suppliers | 32.3 | 32.3 |
| **Total Benefits** | **32.3** | **32.3** |
| **Business NPV** | **-1.5** | **-0.8** |

| **£m 2019 prices – 2020 present values (negative value is a benefit)** | | |
|---|---|---|
| Equivalent annual net direct cost to business over two years | 0.7 | 0.4 |
| BIT Score | 1.4 | 0.7 |

## 8. Risks and assumptions

62. Analysis presented above presents the best proportionally available evidence at this stage but should only be seen as providing a potential scale of impacts the policy (based on a set of illustrative assumptions) given the uncertainty around final policy design.

63. There are three other key areas of uncertainty:

- At this stage it is unknown what prices might be faced by suppliers under ECO4 and if newly obligated suppliers will want to make use of buy-out and the impact buy-out may have on ECO4 delivery. As the policy develops, modelling will aim to provide estimates, but at this stage IA only illustrative scenarios are possible.
- There is considerable uncertainty around what the energy market may look like at the start of 2024, which means it is very difficult to know how many additional suppliers could become obligated under policy changes and the impact for those already obligated. Policy design will need to consider the state of competition in the market before making final decisions on removing thresholds and mitigating options such as buy-out.
- There is also significant uncertainty around the ECO4 delivery costs faced by existing obligated suppliers and newly obligated suppliers once thresholds are removed. More data will become available throughout ECO4, but estimating the potential costs for newly obligated suppliers will still carry significant uncertainty.

## 8.1 Sensitivity tests

64. Further sensitivity testing will be completed as the policy details become clearer and modelling develops.

# 9. Impact on small and micro businesses

65. Small energy suppliers, not already obligated by ECO, are most likely to face costs because of changes to ECO thresholds. However, buy-out is intended to mitigate some of the impacts on these suppliers to avoid disproportionately high costs from removal of thresholds.

66. The analysis conducted for this IA based on December 2020 data with recent exits removed, suggests around 10 new suppliers would be obligated under the proposed lower thresholds. However, there may have been further exists from the market in the near future which may reduce this figure; prior to 2024 there may be also be more new entrants to the market.

67. It has not been possible to source data that distinguishes energy suppliers by their number of employees. Given the absence of data on the number of employees by energy supplier, it has not been possible to undertake an assessment of the effect of this policy on small and micro businesses using the most typical definition of small and micro businesses (which are those with between 11-50 employees and 10 or fewer employees, respectively). Indeed, given the complexity of energy suppliers' operations and business structures, an employment-based definition may not have given an accurate representation of whether an energy supplier is a small or micro business – it is common practice in the energy supply industry to have a third-party business manage a large proportion of the business operations (including back-office functions and installations), which would likely skew the findings of any such assessment.

68. Instead, this IA has used an annual turnover-based approach where a small business is defined as one with an annual turnover less than £6.5 million and a micro business is defined as one with an annual turnover less than £632,000. This is in line with the approach used for the Smart meter policy framework post 2020 IA[17]. Annual turnover has been estimated by combining supplier data (held by BEIS) on the number of meters they operate (as of 31 December 2020) with the average bill value per fuel type. These results have then been compared with information from Companies House to determine which energy suppliers are small and micro businesses, as measured by annual turnover.

69. Based on this approach only two of the newly obligated suppliers are small or micro businesses – it has not been possible to split these into small and micro. Further analysis will be conducted in future (once market conditions have stabilised) to better understand the numbers of small and micro businesses that could be affected by policy changes.

# 10. Equalities Impacts

70. As the design of buy-out has not yet been agreed, it is not possible to consider which households may benefit and the potential equalities impacts. Equalities impacts will be considered as options for delivery develop, further analysis will be published in later IAs.

[17] https://www.gov.uk/government/consultations/smart-meter-policy-framework-post-2020-minimum-annual-targets-and-reporting-thresholds-for-energy-suppliers

71. The final ECO4 IA[18] provides an assessment of how different groups of people may be affected by ECO4, in line with the government's guidance on the Equality Duty. At this stage there is no evidence to suggest the potential reduction in ECO4 delivery would affect some social groups with protected characteristics more than others.

## 11. Monitoring and Evaluation

72. A monitoring and evaluation plan is being developed for ECO4 – with full details provided within the ECO4 Final IA. Government will consider where it may be appropriate to evaluate this policy as part of that. Monitoring data will be collected on which suppliers choose to make use of buy-out. Data will also be collected by Ofgem on each supplier's progress towards their obligation target and their self-reported level of spend.

## 12. Justice Impacts

73. There will not be a significant impact on the legal system or the volume of cases going through the courts, as BEIS is not making significant changes to the enforcement regime. The justice system would become involved were someone to seek to challenge an Ofgem enforcement action for a breach of the obligation or potentially where Ofgem sought a court order

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[18] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003740/eco4-consultation-stage-impact-assessment.pdf

**Title:** Proposed primary regulation of Energy Smart Appliances
**IA No:** BEIS044(F)-22-ESNM

**RPC Reference No:** RPC-4195(1)-BEIS

(RPC-BEIS-5173(1))

**Lead department or agency:**
Department for Business Energy and Industrial Strategy

**Other departments or agencies:** **N/A**

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage: Final**

**Source of intervention: Domestic**

**Type of measure: Primary legislation**

**Contact for enquiries:**
smartenergy@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| Cost of Preferred (or more likely) Option | | | | |
|---|---|---|---|---|
| **Total Net Present Value** | **Business Net Present Value** | **Net cost to business per year** (EANDCB, 2014 prices) | **One-In, Three-Out** | **Business Impact Target Status** |
| Not Applicable - Primary legislation | Not Applicable - Primary legislation | Not Applicable - Primary legislation | Not Applicable | Qualifying Provision |

**What is the problem under consideration? Why is government intervention necessary?**

Energy Smart Appliances (ESAs) could enable significant demand-side response and, in turn, significant benefits to consumers and the electricity system, if taken up at scale. But current uptake of ESAs is unlikely to achieve the scale needed to realise these benefits. To ensure a more socially optimal level of deployment, Government can act to address the following market imperfections: a) coordination failures which could lead to a 'first mover disadvantage' for manufacturers and suppliers; b) risks to the system and to consumer trust if cyber security, data privacy and interoperability risks are not managed appropriately; and c) incomplete information e.g. lack of awareness by consumers of the benefits of ESAs**.**

**What are the policy objectives and the intended effects?**

The government is proposing to set regulatory requirements for ESAs in the 2020s. The main objectives behind this are:

1. Provide certainty in the sector to help rectify the coordination failure between the availability of ESAs and smart tariffs, enabling electricity system benefits and consumer rewards.
2. Ensure minimum levels of functionality and of ESAs to protect consumers and the system and limit cyber- security and grid- stability risks.
3. Enable the UK marketplace to be at the forefront of an emerging sector. This should help drive faster and higher levels of product development and uptake in the sector.

**What policy options have been considered including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Alternative policy options were explored at consultation stage. This included a non-regulatory approach of setting voluntary standards only, which was deemed not robust enough to provide adequate protection against the risks of ESAs. The other considered option was to mandate all appliances to be smart, but this was deemed premature and too costly at this point. This Impact Assessment therefore assesses an option that was considered and consulted on: setting regulatory requirements in the mid-2020s. This would raise awareness and trust among consumers, and thereby encourage smart appliance uptake, whilst minimising familiarisation and transition costs.

**Will the policy be reviewed?** Primary legislation **will not** be reviewed.

| | | | | |
|---|---|---|---|---|
| Does implementation go beyond minimum EU requirements? | **N/A** | | | |
| Are any of these organisations in scope? | **Micro** **Yes** | **Small** **Yes** | **Medium** **Yes** | **Large** **Yes** |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** indicative assessment | **Non-traded:** **0** | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ________ Date: 24/06/2022

## Summary: Analysis & Evidence Policy Option 1 (RECOMMENDED OPTION)

Description: **Setting regulatory requirements for Energy Smart Appliances in 2025.**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 22 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | Low: 0 | High: 0 | Best Estimate: 0 |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Cost (Present Value) |
|---|---|---|---|---|
| Low | 0 (primary legislation) | - | 0 (primary legislation) | **0 (primary legislation)** |
| High | 0 (primary legislation) | | 0 (primary legislation) | **0 (primary legislation)** |
| Best Estimate | 0 (primary legislation) | | 0 (primary legislation) | **0 (primary legislation)** |

**Description and scale of key monetised costs by 'main affected groups'**

This impact assessment considers the introduction of primary legislation to allow the Government to take powers to set regulatory requirements for Energy Smart Appliances. These are enabling powers only, and so we do not expect any associated costs. We illustrate the impact of secondary legislation. Setting regulatory requirements leads to higher uptake of Energy Smart Appliances (ESAs) over the counterfactual over the 2020s, with higher manufacturing costs passed onto consumers.

**Other key non-monetised costs by 'main affected groups'**

As this is primary legislation for enabling powers only, there are no associated non-monetised costs. We provide an assessment of the non-monetised costs associated with secondary legislation.

| BENEFITS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Benefit (Present Value) |
|---|---|---|---|---|
| Low | 0 (primary legislation) | - | 0 (primary legislation) | **0 (primary legislation)** |
| High | 0 (primary legislation) | | 0 (primary legislation) | **0 (primary legislation)** |
| Best Estimate | 0 (primary legislation) | | 0 (primary legislation) | **0 (primary legislation)** |

**Description and scale of key monetised benefits by 'main affected groups'**

We do not expect any associated benefits with the primary legislation. We provide indicative benefits to society from secondary legislation. There will be electricity system benefits passed on as lower energy bills to consumers and carbon emissions savings to society, due to a significant increase in ESA uptake above the counterfactual.

**Other key non-monetised benefits by 'main affected groups'**

As this is primary legislation for enabling powers only, there are no associated non-monetised costs. We provide an assessment of the non-monetised benefits associated with secondary legislation.

**Key assumptions/sensitivities/risks** 3.5%

We present three different scenarios for the impact of secondary legislation. These vary assumptions around the uptake of smart appliances, number of businesses affected, and costs faced by businesses.

**BUSINESS ASSESSMENT (Option D)** Indicative assessment of secondary legislation, see section 14

| Direct impact on business (Equivalent Annual) £m: | | | Score for Business Impact Target (qualifying provisions only) £m: |
|---|---|---|---|
| **Costs: 0** [Because primary legislation] | **Benefits:** 0 [Because primary legislation] | **Net: 0** [Because primary legislation] | N/A |

## Contents

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# 1 Introduction

This impact assessment sets out the existing evidence regarding the setting of regulatory requirements for Energy Smart Appliances. The Government consulted on its proposed approach to smart appliance policy and on the case for introducing primary legislation to allow the Government to take powers to set regulatory requirements for Energy Smart Appliances.

An Energy Smart Appliance (ESA) is an appliance which is able to be remotely configured and respond automatically to information, such as price and other signals, by modulating its energy consumption and / or changing the time at which electricity flows through the appliance. These changes to the consumption pattern are, what we call, the 'flexibility' of the smart appliance. This IA explores the development of the ESA market and regulatory requirements in Great Britain (GB), where consumers purchase ESAs and either themselves (incentivised by Time of Use tariffs) or through a business service[1], change their pattern of demand to consume energy when it is cheaper (i.e. generally off-peak). For the electricity system, this reduces electricity system costs by helping to balance electricity supply and demand and by making more efficient use of low-carbon energy sources. Changing the pattern of energy demand in this way is known as demand-side response, or DSR.[2]

The Government with Ofgem, the energy regulator, jointly published the Smart Systems and Flexibility Plan (2021)[3] which sets out a vision, analysis and work programme for delivering a smart and flexible electricity system that will underpin our energy security and the transition to net zero. The latest Plan sets out how we will facilitate the transition to a smarter and more flexible energy system, and is the first major publication on this area since the government passed legislation requiring the UK to meet net zero carbon emissions by 2050. The most recent plan restated the Government's commitment to take powers to regulate Energy Smart Appliances.

We originally consulted on proposals regarding setting standards for ESAs in March 2018 (hereafter referred to as 'the consultation'). The consultation[4] proposed to enact enabling powers (when Parliamentary time allows) to set regulatory requirements for certain Energy Smart Appliances (ESAs). The consultation sought stakeholder views on this proposal and on the principles and functionalities on which these regulatory requirements should be based. We also asked for evidence and views on how to put this policy into practice. Feedback in consultation responses demonstrated some confusion about our use of the phrase "setting standards", as our proposals were to mandate that smart appliances satisfied certain principles. To reflect this feedback, we now refer to "regulatory requirements" to avoid any confusion with technical standards. This wording is used throughout the remainder of this document and refers to the principles, and associated functionalities, that we intend to set through legislation. This is different to voluntary "technical standards", usually developed by industry, by which compliance with those principles and functionalities could be demonstrated.

Following the consultation, the Government published its response[5] and outlined the responses that had been received, and the key decisions that had been made in response to the consultation. The response stated that the Government intends to take powers to set regulatory requirements for ESAs, and that it intended to base any regulatory requirements on the principles of interoperability, data privacy, grid

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[1] This service can be carried out by businesses such as the consumer's energy supplier or through a contract with an independent aggregator. In return for this, it is expected that the business will reward consumers with a payment that reduces the cost of their electricity compared to other consumers who do not purchase smart appliances and take part in this service. A DSR aggregator is a demand service provider that combines multiple short-duration consumer loads for sale or auction in organised energy markets.

[2] Demand-Side Response (DSR) is defined by Ofgem as 'actions taken by consumers to change the amount of electricity they take off the grid at particular times in response to a signal'. In practice DSR means the active reduction in the electricity a user is taking from the grid at a given moment in time. This term is typically used to describe two activities – a) reducing demand for a short period, for example by shifting a process to a different time of the day or turning fridges/air conditioners off for a brief period, or (more commonly) b) using on-site 'backup' generators to temporarily meet on-site requirements and/or export energy to the grid (the vast majority of DSR active in the UK currently). This impact assessment is concerned with type a) in the domestic sector.

[3] BEIS and Ofgem (2021) Transitioning to a net zero energy system: smart systems and flexibility plan https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

[4] BEIS (2018) Proposals regarding setting standards for smart appliances https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/690805/Consultation_on_Proposals_regarding_Smart_Appliances-.pdf

[5] BEIS (2018) Consultation Outcome: proposals regarding setting standards for smart appliances https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/748115/smart-appliances-consultation-government-response.pdf

stability, cyber security and consumer protection, and would align internationally, whenever that is in the UK's interest.

The Energy White Paper[6] restated the Government's commitment to take powers to regulate ESAs in December 2020. The White Paper notes that the market for ESAs is just emerging, and regulation is required to support its development and to ensure that appropriate consumer protection is in place ahead of time. Furthermore, that "devices should be able to link with any service provider's systems so that consumers cannot be locked into a single provider".

The next section sets out the background information on ESAs including the analytical evidence base of electricity system benefits of smart flexibility (DSR and energy storage). Sections 3 and 4 outline the problem with the status quo and the rationale for government intervention. Section 5 includes flow diagrams to explain the theory of change for government intervention and strength of evidence. Sections 6 and 7 explain the objectives of the described counterfactual and the policy option. Sections 8, 9 and 10 set out the costs and benefits of the policy option and indicative cost-benefit analysis. The following sections 11 – 14 justify the level of analysis as proportionate and detail impacts to small and micro businesses, as well as wider impacts. The final section (Section 15) summarises rationale for the intervention.

# 2 Background

The Government has a challenging and critical set of objectives in the energy sector: ensuring security of energy supply, keeping bills as low as possible for households and businesses, and decarbonising both cost-effectively and in a way that enables us to reap the economic benefits of this transition, as well as protecting the interests of existing and future consumers. There are important challenges ahead in delivering these objectives:

- Electricity demand will increase as heat and transport are electrified – potentially doubling by 2050[7] ; and significant quantities of additional generation will need to be added to our electricity system over the next few decades.
- Electricity generation will increasingly be variable, dependent on the time of day, season, and prevalent weather conditions. Generation and storage are becoming increasingly decentralised, with solar and batteries being deployed on the distribution network, and in individual buildings and by local communities.

At the same time, new data and communication technologies are creating opportunities to manage the electricity system in different ways e.g. in aggregating load from smart appliances or electric vehicles (EVs) to use in frequency response or load shifting.[8] We are also seeing dramatically falling costs of batteries and other technologies. Understanding and influencing consumer behaviour, in this changing landscape, will be a challenge.[9]

## 2.1 The role for smart flexible technologies

**The transition to a smarter and more flexible UK energy system can reduce the costs of our system by up to £10bn a year by 2050** (2012 prices, undiscounted).[10] A smarter electricity system reduces the additional capacity needed and costs from higher electrification of transport and heat, and intermittency of renewables through deploying energy storage technologies at lower cost than additional gas generation and shifting electric vehicle charging and heat pump demand. Shifting demand to times when overall demand is lower and more low-cost electricity generation is available reduces costs. This more efficient use of resources reduces electricity system costs and this impact is captured in modelling the following:

[6] BEIS (2020), Energy White Paper p.36 https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[7] BEIS (2020), Energy White Paper (page 42), https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[8] Frequency response refers to actions taken by National Grid to ensure that system frequency is kept within specified limits. Load shifting involves moving energy demand so it can be more easily met – usually from peak times to times of lower system demand.
[9] EA Technology for Defra (2011) Delivering the benefits of smart appliances
[10] BEIS and Ofgem (2021) Transitioning to a net zero energy system: Smart Systems and Flexibility Plan

- smart flexibility (DSR and energy storage) can be used to help balance the electricity system which leads to lower-cost system operation;
- lowering peak demand which avoids or defers necessary reinforcements on our transmission and distribution network;
- shifting peak demand to times of lower demand reduces curtailment[11] of low carbon generation; and
- lowering peak demand also reduces the need to build new generating capacity.

### 2.1.1 What is Demand-Side Response (DSR)?

DSR refers to actions taken by consumers, in response to a signal, to change the amount of electricity they take off or add to the grid, at a particular time. It can provide cost-effective flexibility to the electricity system – used by the system operator to help balance the system - or by companies to minimise network charges during periods of peak demand. Participation in DSR by domestic and smaller non-domestic consumers remains at an early stage, as there are few smart tariffs on the market, and the ESA market is relatively nascent. Moreover, DSR is happening in the industrial and commercial sectors, where it is provided by a range of companies, on a commercial basis. In future, DSR will be particularly important in the domestic sector for managing the peaks caused by increased electrification of heat and transport as this demand can be smoothed, for example, by exposing consumers to price signals through (voluntary) smart energy tariffs (for example, time-of-use tariffs which charge different unit prices at different times of day to incentivise electricity demand to move away from peak times). To enable flexibility from consumers, they will need to have access to energy smart appliances that make it easier to change their consumption patterns, and tariffs and services that incentivise this change, including stronger price signals.

### 2.1.2 When do we need to see significant DSR?

Electricity demand – in the absence of smart flexibility – is expected to increase, becoming peakier and more unpredictable through greater electrification of heat and vehicles. This creates both challenges in terms of meeting or shifting peak demand, and new opportunities in using demand-side response to manage the electricity system e.g., from vehicle-to-grid (a system in which plug-in electric vehicles communicate with the power grid to sell DSR services by either returning electricity to the grid or by throttling their charging rate).

The 2021 Smart Systems and Flexibility Plan[12] found that up to 60 GW of low carbon of flexible assets may be needed by 2050, saving the system up to £10bn per year by 2050 (2012 prices, undiscounted). This significant need from flexibility is increasingly needed over the 2020s and is necessary to ensure optimal use of governments commitment to deliver 40GW of offshore wind capacity by 2030.

### 2.1.3 Policy timeline

As outlined above, in order to unlock a maximum technical potential of DSR from the residential sector in the mid-2030s, there are a number of enablers which need to be realised before we could expect significant development of the ESA market. We also need to keep abreast of what is happening internationally. Considerations include:

- **The smart meter roll-out -** the Government confirmed in June 2020 that a new four-year Framework would set energy suppliers annual, individual installation targets on a trajectory to 100% coverage, subject to an annual tolerance level[13].

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[11] Curtailment refers to reduction of output of a renewable generator from what it could produce given available resources (e.g., wind or sunlight), typically on an involuntary basis due to lack of demand or system inertia.
[12] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[13] As of 30 September 2021, there were 26.4 million smart and advanced meters in homes and small businesses in Great Britain, representing 47% smart coverage. BEIS (2021) Smart meters in GB quarterly statistics https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1035290/Q3_2021_Smart_Meters_Statistics_Report.pdf

- **Half hourly settlement -** Ofgem's final decision[14] to introduce HHS on a market-wide basis is supported by their Full Business Case[15] and Final Impact assessment[16].

- **BSI Standards -** The British Standards Institute published two standards for energy smart appliances in May 2021, commissioned by Government and developed with industry input. These standards are PAS 1878[17] and PAS 1879[18]. These standards or documents derived from them, either in part or in full may be designated in secondary legislation using the powers enabled by this legislative intervention. This will be subject to further consultation.

- **Regulation of load controllers -** Alongside the powers taken to regulate ESAs, we are taking powers to licence load controllers. Our assessment is that alongside consultation, enabling powers are required as soon as possible, to ensure that a regulatory framework can be put in place from 2025.

- **Secure by Design -** DCMS have introduced the Product Security and Telecommunications Infrastructure Bill, which will place obligations on economic actors such as manufacturers and distributors to ensure that 'consumer connected products' and their 'associated services' meet minimum cyber security requirements[19].

- **EV roll out and smart chargepoint regulations** - The Government has recently made legislation under the Automated and Electric Vehicles Act (AEVA) 2018, with the Electric Vehicles (Smart Charge Points) Regulations 2021[20], to mandate that private chargepoints sold in Great Britain must be smart, meet device-level requirements, including cyber security, data privacy, and grid stability. These regulations come into force on 30 June 2022, expect for cyber requirements which will come into force on 30 December 2022.

- **Future regulation of smart chargepoints –** the powers being sought to set requirements on ESAs will apply to smart chargepoints so that all ESAs are regulated under one coherent regime. This includes the requirement for devices to be smart which covers electric heating appliances. Secondary legislation made under these powers will replace the existing smart chargepoint regulations mentioned above. These changes are assessed in a separate impact assessment titled "Proposed primary regulation of Energy Smart Appliances – Smart Charge Points".

- **Electric Heating Appliances** - The Government is also seeking enabling powers to require that all electric heating appliances meet requirements around smart functionality.

- **Innovation -** Funding for the Interoperable Demand-Side Response (IDSR) sub-programme was approved in September in the Wave 1 Flexibility Innovation Business Case Update. The programme is expected to run from February 2022 to March 2025.

### 2.1.4 EU context

Prior to the UK's exit from the EU, there were two main pieces of European legislation on energy-related products: the Ecodesign for Energy-Related Products Directive (2009/125/EC) establishing a framework

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14 Ofgem (2021) Final Decision HHS

15 Ofgem (2021) HHS Full business case

16 Ofgem (2020) HHS Final Impact Assessment

17 PAS 1878 specifies requirements and criteria that an electrical appliance needs to meet in order to perform and be classified an ESA. It defines the attributes, the functionalities and performance criteria for an ESA, and specifies how compliance with these can be verified. https://www.bsigroup.com/en-GB/about-bsi/uk-national-standards-body/about-standards/Innovation/energy-smart-appliances-programme/pas-1878/

18 PAS 1879 sets out a common definition of demand side response (DSR) services for actors operating within the consumer energy supply chain and provides recommendations to support the operation of energy smart appliances (ESAs). https://www.bsigroup.com/en-GB/about-bsi/uk-national-standards-body/about-standards/Innovation/energy-smart-appliances-programme/pas-1879/

19 It is intended that this legislative regime proposed for ESAs, therefore, will not duplicate or contradict the DCMS regime, but at least in the area of cybersecurity, will include and go beyond their requirements.

20 UK Government (2021) Draft Statutory Instruments: The Electric Vehicles (Smart Charge Points) Regulations 2021 https://www.legislation.gov.uk/ukdsi/2021/9780348228434.

for the setting of ecodesign requirements for ErPs ("the Ecodesign Directive", though elsewhere it may also be referred to as the ErP Directive 2009), and the Energy Labelling Regulation 2017 ((EU) 2017/1369) setting a framework for energy labelling ("the Energy Labelling Regulation"). In addition, there was various product-specific ecodesign and energy labelling legislation sitting under these frameworks that was retained and still applied in the UK.

The Ecodesign Preparatory Study on Smart Appliances (Lot 33) analysed technical, economic, environmental, market and societal aspects of energy smart appliance. The study started in 2014, and finished phase 2 in 2018, which included a refinement of policy options[21].

We understand that the EU, using technical assistance from the Joint Research Committee, are undertaking further work on the selection of products with high demand response potential over the next two years. This includes development of interoperability requirements for ESAs and setting up a code of conduct.

The intent is to align with international standards whenever that is in our interests.

### 2.1.5 UK Market and Manufacturers

Globally, key manufacturers developing smart appliances include Whirlpool, LG, Samsung, Panasonic, Electrolux and Bosch. There are currently few UK-centred companies with significant positions in the smart appliances market; and these are typically large international firms based in the UK[22]. Although several energy smart appliance manufacturers are shown to have presence in the UK, this is largely for retail and distribution purposes, with the production process occurring outside the UK.

Growth from Knowledge data suggests that sales of smart domestic appliances in GB reached over £120m in 2018, as shown in Figure 2. Smart washing machines and tumble dryers represented most of the market. Table 1 outlines the manufacturers with the largest sales in GB. For washing machines, appliances with app control represented 14.9% of the total market and appliance with smart checks and diagnosis represented 11.9% of the market.[23]

**Figure 1: Sales of GB smart domestic appliances in 2017 and 2018 (£m)**

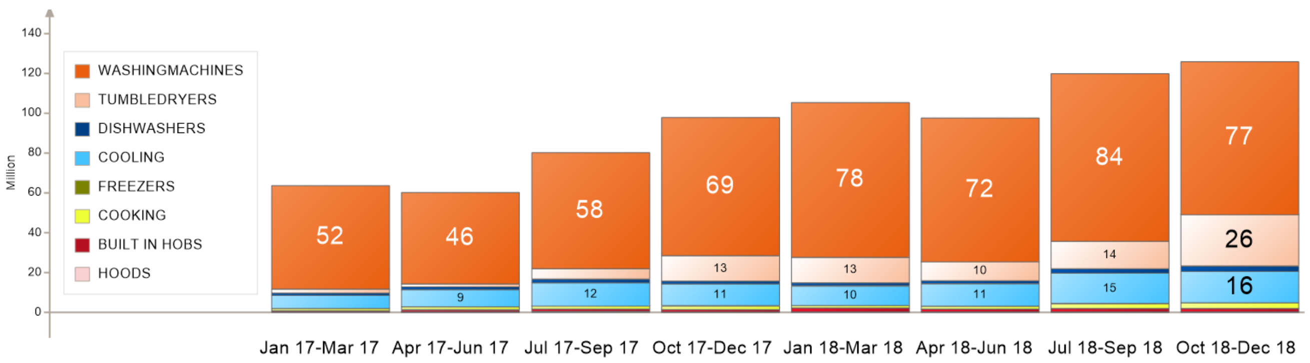



**Table 1: Top 3 selling brands of GB Energy Smart Appliances[24]**

| Appliance | Functionality | Brand | Number of Sales (thousand) |
|---|---|---|---|

[21] European Commission (2018) Ecodesign Preparatory Study on Smart Appliances

[22] Ofgem (2013) Smart Cities: Opportunities for the UK

[23] Growth from Knowledge (2019) Major Domestic Appliances: Trends and Insights

[24] Growth from Knowledge (2019) Major Domestic Appliances: Trends and Insights – where blanks are shown, data was not available or there was no other market presence

| | | | |
|---|---|---|---|
| **Washing Machine** | App Control | Hoover | 280 |
| | | Candy | 87 |
| | | LG | 41 |
| | Smart Check/Diagnosis | Samsung | 332 |
| | | LG | 19 |
| | | - | - |
| **Tumble dryers** | App Control | Hoover | 1,108 |
| | | Miele | 109 |
| | | Candy | 92 |
| | Smart Check/Diagnosis | Samsung | 16 |
| | | - | - |
| **Dishwashers** | App Control | Siemens | 0.2 |
| | | Bosch | 0.2 |
| | | Miele | 0.1 |
| | Smart Check/Diagnosis | - | - |
| **Cooling** | App Control | Samsung | 1.8 |
| | | Bosch | 1.4 |
| | | Hoover | 0.08 |
| | Smart Check/Diagnosis | Samsung | 1.2 |
| | | - | - |

# 3 Problem under consideration and rationale for intervention

## 3.1 Problem under consideration

Smart appliances can help consumers manage or reduce their bills by shifting electricity demand automatically to times of day when energy is cheaper or to provide grid services such as frequency response to Electricity System and Network Operators. The market availability and consumer uptake of these appliances is currently very limited but as outlined in the previous section, energy smart appliances could offer significant DSR potential and, in turn, significant benefits to consumers and the electricity system, if taken up at scale.

### 3.1.1 Market development

The world is becoming increasingly connected; the number of devices connected to the internet was estimated at 26 billion as of 2015 and projected to grow to 50 billion or more by 2020.[25] In the UK alone, it is estimated that there were 13.3 million Internet of Things (IoT) [26] connections in 2016. This is expected to rise to over 150 million by 2024. [27]

[25] Deloitte (2015) Inside the Internet of Things
[26] Internet of Things refers to consumer products which are connected to the internet and/or home network and provide associated services. Such products range from toys, to smart TVs, watches and fridges.
[27] Deloitte (2015) Inside the Internet of Things

Studies suggest that the uptake of ESAs in scope of this legislation is still relatively small. In 2019/2020, the average rate of smart take-up was 3% for large appliances and is predicted to increase to 4% by the end of 2021.[28] A survey by Ipsos Mori at the end of 2020 found that only 2% of households participating had a smart kitchen appliance, compared to 17% having a smartphone and 9% having a smart TV. Overall, 48% of households had purchased some type of smart device.[29] Research by Smart Energy GB found that 68% of adults would like to receive cheaper energy for using appliances outside peak energy times – rising to 80% among smart users, and 87% of adults found at least one smart technology appealing.[30] Research suggests one of the biggest drivers for adoption of smart appliances will be the replacement cycle – as consumers replace their existing appliances at end of life, they will consider new options available to them.[31]

To illustrate the value that smart appliances can have to the system, we conducted an initial, indicative assessment of the value of a hypothetical scenario in which 100% of fridges, freezers, dishwashers and washing machines are smart. The estimated benefits to the electricity system of all these appliances would be a cumulative benefit of £405m from 2025-2034 (if other relevant smart appliances had been considered the benefits would likely be significantly higher). Some of this will be realised without Government intervention, but despite early positive signs in market development, there are a number of barriers to the development and uptake of smart appliances, outlined below, including lack of demand, issues with supply and coordination failures.

**Lack of demand:**

- **Bounded rationality and cost of products:** people only consider a finite number of factors when purchasing an item and have a short-term focus – they are unlikely to undertake a lifetime value for money assessment, and smart functionalities add another element to the equation. Consumers most commonly spend only 1-2 hours researching smart devices before making a purchase.[32] Considerations may be complicated further if an appliance is expensive or bought as a 'distress purchase' as often happens in the case of boilers for example.[33] 48% of respondents to a recent survey by Deloitte found connected products too expensive,[34] however according to the Ecodesign study, payback periods would be short. A trial of appliance labels in John Lewis stores found that consumers changed their purchasing behaviour when presented with cost-of-use information.[35]

- **Consumer mistrust of smart products:** there have been several high-profile media articles recently, questioning the cyber-security safety and use of connected "Internet of things" (IoT) products. The Deloitte study found 26% of respondents are deterred from purchasing connected devices because they think the technology still needs to evolve. 13% of respondents were holding back from buying connected devices because they are concerned about their device getting hacked, while 11% do not want their usage data accessed by companies.[36] This suggests that mistrust of devices is limited but needs addressing. The impact of setting minimum requirements was seen with heat pumps in Germany where an initial collapse of the market was eventually reversed through the introduction of technical standards, quality assurance and information campaigns which addressed consumer confidence problems.[37]

**Issues with supply:**

- **Lack of interoperability requirements**: currently there are no set regulatory requirements for smart appliances internationally or at EU level. Interoperability (the ability of a product or system

[28] Statista Digital Market Outlook (2021) Smart Homes
[29] Cambridge Consultants for Ofcom (2017) Review of the latest developments in the Internet of Things
[30] Smart Energy GB (2017) Smarter living: What consumers want from new smart energy products and services
[31] Deloitte (2016) Switch on to the connected home
[32] Ipsos Mori (2020) Attitudes Towards IoT Security: Summary Report
[33] Competition is likely to drive down prices for consumers, and encourage competition and growth in the market. Technavio (2016) Smart Home M2M Market in Western Europe
https://www.technavio.com/report/europe-machine-machine-m2m-and-connected-devices-smart-home-m2m-market
[34] Deloitte (2016) Switch on to the connect home
[35] DECC (2014) Evaluation of the DECC/John Lewis energy labelling trial
[36] Deloitte (2016) Switch on to the connect home
https://www2.deloitte.com/content/dam/Deloitte/uk/Documents/consumer-business/deloitte-uk-consumer-review-16.pdf
[37] Vivid Economics prepared for BEIS (2017) International Comparisons of Heating, Cooling and Heat Decarbonisation Policies.
https://www.gov.uk/government/publications/international-comparisons-of-heating-cooling-and-heat-decarbonisation-policies

to work with other products or systems) is vital to enable consumer choice and ensure consumers can benefit fully from a connected home; ensuring consumers are not locked in to using certain service providers, or devices from a particular manufacturer. Interoperability also refers to the ability of an ESA to work seamlessly across any appropriate DSR service operated by any authorised energy system actor, so that owners of ESAs can freely switch the DSR service provider controlling or configuring their device. Open standards[38] would enable interoperability, promoting competition and innovation.[39] Creating these standards can help build trust in the nascent industry.

- **Cyber risks:** there are risks that products are being produced without appropriate attention given to cyber or data privacy – this risks problems in future which could further undermine consumer trust in the emerging market.

**Timing, scale and coordination failures:**

- **Limited financial incentives for consumers:** For consumers to benefit financially from owning and using ESAs, depends on the capability to measure time of use and the emergence of Time of Use tariffs and/or businesses that provide a service to reward demand side response is required. As of 30 September 2021, there were 26.4 million smart and advanced meters in homes and small businesses in Great Britain**Error! Bookmark not defined.**. Smart meters, which record half hourly consumption, allow the consumer to make use of a smart tariff. There are limited smart tariffs or agregation services available on the domestic market at present which would allow the consumer to realise energy bill savings from smart appliances,

- **Lack of consumer demand to stimulate market development:** without demand for their products, manufacturers are unlikely to significantly invest in the development of ESAs given high capital costs of innovation.

- **Lack of scale to realise timely system benefits**: as outlined in the section above, from 2030 onwards given forecasted increases in electricity demand from the greater electrification of heat and transport, DSR can reduce costs to the electricity system. ESAs offer significant cost-effective DSR potential but given the lifetime of products, for this potential to be available at scale requires earlier action to stimulate market development and consumer uptake (rather than relying on a demand-led/market led approach).

## 3.2 Rationale for intervention

### 3.2.1 Addressing timing and coordination issue to stimulate demand and supply

Building on the previous section, the following market failures exist which imply uptake would be sub-optimal in the absence of Government intervention. If we wait for the energy tariff and aggregation market to develop first to fully incentivise uptake, then given the 10-15 year lifetime of products[40], the potential benefits from DSR in the 2030s might not be fully realised in time for when they may be required. This suggests that some form of intervention will be key to establishing greater use of DSR from smart appliances, compared to the business-as-usual case, in order to maximise electricity system benefits within appropriate time scales.[41]

1) **Positive externalities** are associated with the deployment and use of smart appliances to manage electricity system demand. By 2050, illustrative scenarios for the Smart Systems and Flexibility Plan indicate that we will need 60GW of total flexible capacity, consisting of around 30GW of combined short-term storage and demand side response. Increased flexibility could reduce system costs cumulatively

[38] Technical standards made available to the general public and are developed (or approved) and maintained via a collaborative and consensus driven process. They are intended for widespread adoption. International Telecommunication Union: : http://www.itu.int/en/ITU-T/ipr/Pages/open.aspx
[39] This is supported by: BEIS and Ofgem (2016) responses to the BEIS Smart Systems Call for Evidence.
[40] Based on the report "Study of Life Expectancy of Home Components" provided by the National Association of Home Builders, https://www.atdhomeinspection.com/advice/average-product-life/
[41] BEIS (2017) Realising the potential of demand-side response to 2025

by £30-70bn between 2020 and 2050. (2012 prices, undiscounted)[42] Consumers of Energy Smart Appliances should receive a financial incentive from the use of their appliances with DSR services (either through smart tariffs or business services assuming they have an agreement with their supplier or aggregator). Smart functionality will also enable consumers to better manage their electricity bills, potentially lowering these costs. However, there are additional electricity system benefits which will not accrue directly to the smart appliance owner (instead being spread across all electricity consumers), leading to less than optimal smart appliance uptake and usage if left to the market alone.

2) **Coordination failures** in the nascent market for smart appliances could lead to a 'first mover disadvantage'. Creating minimum requirements, which deliver clear parameters for technical development and build consumer trust in cyber-security and data privacy, should signal a time for businesses to begin developing their products and services to help boost demand for smart appliances.[43]
3) Creating the right **conditions for competitive behaviour** can limit technological fragmentation, which would deter consumers from purchasing smart appliances. By creating requirements, the Government can ensure open communication channels are used and so smart appliances are interoperable, thus leading to improved consumer experience and expected higher uptake.
4) **Imperfect information**, particularly lack of awareness and bounded rationality by consumers in understanding the relative costs and benefits of smart appliances, as well as mistrust of the smart functionality, can hinder consumers from wanting to purchase and use smart appliances. Setting regulatory requirements will provide certainty to consumers on what an appliance is offering and increase consumer trust. This can be supported by labelling, providing information to consumers to help overcome this barrier.

### 3.2.2 Addressing consumer protection and cyber threat

Consumer protection

To protect consumers against potential risks associated with smart appliances the following points should be considered:

a. **Data Privacy**: Data will be created by, and potentially stored in, smart appliances. Data privacy is important to protect consumers and for consumers to have confidence in choosing to participate in a smart energy system. Existing regulation on data privacy will continue to apply, in particular the Data Protection Act 2018. The Government is considering whether and how functionalities (as part of regulatory requirements) should give additional protection, on top of existing data protection regulations. ESAs and DSR will generate large amounts of data relating to consumers' energy consumption and usage patterns. The improper storage, use or sharing of this data will lead to data privacy issues.

b. **Cyber security for individuals**: there are potential risks to individuals from third parties controlling smart appliances without permission,[44] or to have access to data regarding consumption and access to insight into a consumer's home life through appliances. There are also risks posed to the electricity system itself (explained in more detail below), but we are also mindful that cyber-security issues can adversely affect consumer confidence in, and acceptance of, smart energy applications.[45] Therefore, there is a role for Government, Ofgem and industry to ensure the risks are addressed proportionately.

Cyber security for the electricity system

[42] Ofgem and BEIS (2021) Smart Systems and Flexibility Plan

[43] For example, smart tariffs are limited on the market thus far: Tide from Green Energy is one of the first of its kind.

[44] e.g. Nest hackers in 2014 in the USA on smart thermostats: https://motherboard.vice.com/en_us/article/internet-of-things-ransomware-smart-thermostat

[45] https://www.theregister.co.uk/2016/12/02/broadband_mirai_takedown_analysis/

A primary driver for regulatory intervention is cybersecurity. Government-commissioned risk assessments indicate that without Government intervention, there is a significant risk that cyber-attackers could exploit ESAs, in aggregate, to destabilise the electricity system and attack Critical National Infrastructure. For example, cyber-attackers could seek to compromise large numbers of devices in order to simultaneously and repeatedly turn them on and off, which would cause significant challenges for the system operator in managing and balancing the grid. Risk assessments indicate that there will be enough smart devices on the system by 2025 that an attack of this type could feasibly cause local or national power outages (i.e. blackouts) in certain circumstances.

There are also current real-world case studies which show the vulnerability of an energy system increasingly reliant on connected devices, such as the security flaws recently revealed within electric vehicle chargepoint company, PodPoint[46], or the Colonial Pipeline cyber-attacks in the US[47]. Risk assessments suggest that the risk and impact of such incidents will grow quickly as the number of smart devices increases over the course of the 2020s.

The proliferation of Internet of Things (IoT) devices is increasing in all aspects of our everyday life and throughout the home environment. There is already a well-established market for products including IoT thermostats and smart chargers for electric vehicles, which are covered by separate regulation, and manufacturers are exploring new markets with products including smart appliances. In the move to a smart energy system, that is more complex and more driven by data and communication technologies, it is essential that cyber-security risks are effectively understood and acted upon. System stability will continue to be a key requirement of a future system and will be a priority focus in this changing environment.

The Government has undertaken significant stakeholder engagement across industry to assess the magnitude of the smart cyber-security risk up to 2030, including consideration of the increasing levels of smart electric vehicle charging and electrical heating. We believe that this risk, although comparatively small now due to the low penetration and the types of DSR on the network, could increase with time as the amount of DSR grows to balance an increased amount of renewables and as the role of automated DSR becomes more prevalent in the domestic sector. The Government takes its duty seriously to ensure sufficient protections are in place to mitigate potential risk to grid stability, such as the threat from cyber which smart appliances could be associated with.

### 3.2.3 The interdependence of regulatory actions proposed in this Energy Bill

The overarching objective of policy intervention can be summated as aiming to enable increased growth in the market for DSR products and services, whilst ensuring sufficient levels of protection are in place for consumers and the energy system. The achievement of this objective requires consideration of both the energy smart appliances capable of providing DSR alongside the current and future organisations that may operate these appliances on the consumers behalf. For example, the achievement of cyber security at the device level may still result in cyber risks at the system level, due to the risk of inadequate cyber security procedures in place within the form, such as relying on default passwords for internal information systems.

Without due consideration of risks and opportunities across each component of the DSR supply chain, any regulatory framework would be likely to not fully realise the overarching policy objective, and the benefits attached to its achievement.

## 3.3 Theory of change

Creating a standardised marketplace through Government intervention should address the market failures and barriers set out in the previous section to enable faster market development, ensuring consumer

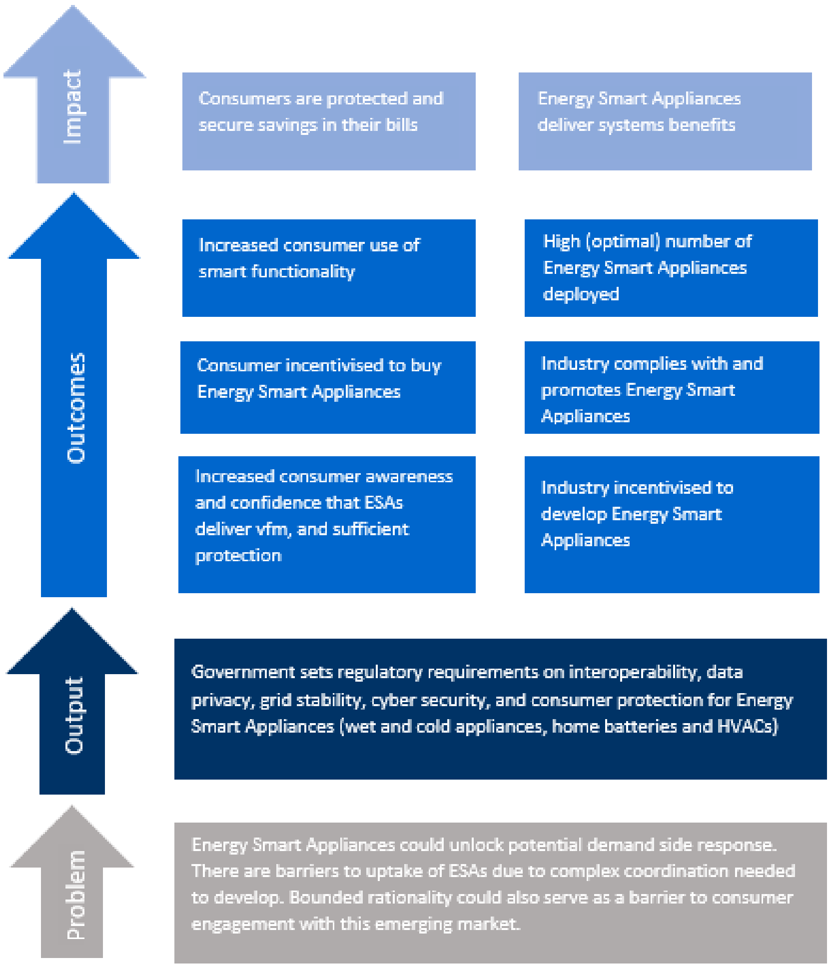
[46] 'Pod Point electric car chargers: security flaw may have put 140,000 app users' data at risk' https://www.which.co.uk/news/2021/11/pod-point-electric-car-chargers-security-flaw-may-have-put-140000-app-users-data-at-risk/

[47] 'How a major oil pipeline got held for ransom' https://www.vox.com/recode/22428774/ransomeware-pipeline-colonial-darkside-gas-prices

protection and providing electricity system benefits. Below we set out in a diagram the thinking behind the intended impacts of the policy (Figure 3). The diagram shows how creating regulatory requirements influence both industry and consumers to manufacture/purchase smart appliances and how this leads through to consumer protections and seeing bills savings.

There are a number of preconditions which are required to achieve optimal deployment namely the smart meter roll out; half hourly settlement; innovation and understanding the direction with international standards (see previous section for more detail).

**Figure 2: Theory of Change - Secondary Legislation for Smart Energy Appliances**[48]




## 4 Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

Based on the impact assessment guidance criteria, we have followed a proportionate approach to approximate costs and benefits. This is based on both the fact that there is limited data available and that the details of the requirements will only be known at secondary legislation stage. We are at early stages of policy development and given the complex, wide ranging and innovative nature of the benefits of this policy, we are currently unable to fully quantify benefits. We have tested assumptions with stakeholders in the consultation and did not receive any contradictory evidence, but we will continue this dialogue and

[48] This Theory of Change follows the framework outlined in the Government's Magenta Book on designing evaluation.

- Problem = the problem the intervention aims to address
- Output = What is delivered or produced
- Outcome = the early or medium-term results
- Impact = the long-term results

build our evidence base to develop the policy accordingly. We note the high levels of uncertainty with benefits and distributional impacts throughout this document.

# 5 Descriptions of options considered

This section sets out the assessed policy option and the counterfactual.

## 5.1 Base case – do nothing (the counterfactual)

Government takes no action to implement regulatory requirements for energy smart appliances. Consumers will benefit from the cyber security requirements placed on these devices via the Product Security measures introduced by DCMS[49]. With regard to ESA's 'energy smart functionality' for DSR, industry will continue to rely on PAS 1878 and PAS 1879 to guide the technical requirements for ESAs. Although we expect the standards to provide a definition and guide for manufacturers of smart appliances, they remain voluntary and as of yet no appliances have been manufactured to comply with PAS 1878.[50] Additionally, we do not expect they will have a significant impact on the uptake of smart appliances. We use the uptake in smart appliances used in the Ecodesign Preparatory Study's Business as Usual scenario, which assumes that by 2030 up to 20% of relevant appliances will be smart (see Table 5). [51]

## 5.2 Option 1 - Regulatory requirements for smart appliances

Under this option, the Government will implement regulatory requirements for all relevant smart appliances in GB. (See Box 1 for explanation of appliance types). We intend to take powers to set these regulatory requirements for certain energy smart appliances. We will provide the specific technical requirements for secondary legislation. We are considering the following:

- An open communications protocol (or several) that would allow interoperable communications to and from the device
- A specific DSR protocol
- A minimum common data model, specifying the messages that must be exchanged between devices and service providers
- Minimum requirements relating to the secure storage of personal data on the device
- Minimum requirements relating to the secure transmission of personal data
- Minimum requirements relating to protections against misuse, and preventing access by unauthorised entities
- Capability to apply a randomised offset to responses in load control signals, to avoid large simultaneous switches in load on the electricity network following changes in price on a time of use tariff
- Minimum requirements that relate to authentication and encryption of communications between devices and organisations with whom they communicate
- Minimum requirements relating to secure connections to service providers or connected systems
- The requirement to use a specified cryptographic solution (such as a particular public key infrastructure[52]) in order to support the authentication, encryption and secure connections

49 https://www.gov.uk/government/collections/the-product-security-and-telecommunications-infrastructure-psti-bill-factsheets

50 https://www.bsigroup.com/en-GB/about-bsi/uk-national-standards-body/about-standards/Innovation/energy-smart-appliances-programme/pas-1878/

51 Depending on the appliance: 20% for fridges and freezers, 16% for tumble dryers, 8% for dishwashers, 4% for washing machines. European Commission (2018) Ecodesign Preparatory Study on Smart Appliances: Task 7 report https://eco-smartappliances.eu/sites/ecosmartappliances/files/downloads/Task_7_draft_20170914.pdf

52 A public key infrastructure is a system for managing cryptographic keys that can be used to authenticate, encrypt and de-crypt communications. Several public key infrastructures are used to support the GB smart metering arrangements.

- Minimum requirements relating to secure update of firmware
- A labelling scheme alongside the technical requirements that could assist consumer awareness and informed consumer choice

This regulation will require that all relevant energy smart appliances will meet requirements around the areas listed above. We also expect the regulation to provide a signal to industry for the need and value of smart appliances in the electricity system and to increase trust and confidence of consumers in smart functionality. Therefore, we expect the regulation to increase the percentage of appliances which are smart. Details of this assumption are provided in the section on monetised benefits.

In the consultation IA, we considered an option to mandate that *all* relevant appliances must be smart (rather than just setting requirements for the smart versions of relevant appliances) if it was deemed to be necessary in future. The Government believes it is currently too early to mandate appliances to be smart, but it will retain the option of doing so should it deem it necessary in the future. These impacts would be assessed separately if Government wishes to pursue this option. As a result, the NPV of the option presented here is significantly smaller than in the consultation IA.

**Box 1: Explanation of appliance categories**

The following categories of appliance are referred to throughout this document as 'relevant appliances', which include the following appliances:

- Wet appliances: washing machines; dishwashers; tumble dryers.
- Cold appliances: refrigeration and freezers.
- HVAC: heating, ventilation, air conditioning.[53]
- Battery storage: home batteries.

Note:
The enabling powers in the legislation allow the Secretary of State to amend the list of specific purposes to which the energy smart regulations can apply. This means that if an appliance can be used in the future for small-scale DSR, we have the power to bring it in to scope of the regulations. This would be subject to affirmative procedure and consultation with parliament.

## 5.3 Definition of smart and relevant appliances

For the purpose of this policy we have defined an ESA as an electrical device which is communications-enabled and capable of responding automatically to price and/or other signals by shifting or modulating its electricity consumption and/or production.

In line with the Government's Cutting Red Tape programme, our initial focus is on those appliances which can contribute in a significant way to DSR objectives, so no undue burden is placed upon businesses. In the case of ESAs, significance can be determined in terms of potential to shift electricity demand from peak periods i.e. appliances which consume a high level of electricity and can be used flexibly by consumers. While the majority of the evening peak electricity demand is made up of cooking, audio-visual and lighting, these are not particularly flexible services, thus TVs, lighting and cookers are not in scope of these regulations. Other appliances such as cold and wet appliances offer greater potential to shift consumption away from peaks, e.g. fridges can be turned off for 15-30 minutes at a time, maintaining a safe temperature, if consumption needs to be reduced.[54] This does not affect the consumer's enjoyment of the product's service, so it is deemed appropriate for DSR.

The Ecodesign study identified three groups of appliances where potential is greatest, based on those that a) consume a relatively high level of electricity[55] and b) they can be used flexibly by consumers. Appliances which fit these criteria are known as 'relevant appliances' which are summarised in Box 1 in the previous section.

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53 A separate Impact Assessment assesses the impact of mandating that all electrical heating appliances must have smart functionality (Smart Heating Impact Assessment).
54 Frontier Economics/LCP (2015) Future potential for DSR in GB
55 Note that Ecodesign did not define 'high' electricity use or flexibility – they did a detailed qualitative assessment where they decided on the case for inclusion of each group.

- Group 1: flexibility which can be shifted for 3 hours (wet appliances – dishwashers, washing machines and tumble dryers).
- Group 2: flexibility which can be shifted for 1 hour or less (battery storage and cold appliances).
- Group 3: residential and tertiary cooling and heating which can be shifted for 1 hour, but with an additional constraint to avoid loss of comfort.

This is backed up by analysis by Frontier and LCP for the Government, which suggests that wet appliances in domestic premises have a maximum technical potential of 3.8 GW, and cold appliances 1.1 GW at 5:30pm during a winter energy consumption peak in 2030.[56] The combination of smart tariffs with automation and/or direct control could deliver peak energy demand reductions of 60-200% greater than smart tariffs alone.[57] Smart heating, ventilation and air conditioning (HVAC) offer similar benefits, and battery storage could use electricity during the day and overnight when it is more plentiful and generate electricity during peaks when it is needed by consumers, alleviating pressure from the grid.

Electric vehicle chargepoints also fit the criteria and can provide significant benefits to the energy system through managing the additional demand electric vehicles will place on the grid. In December 2021, Government mandated that private (domestic and workplace) chargepoints should have smart functionality and meet minimum device-level requirements, delivering many of the benefits discussed in this impact assessment for other ESAs. There are however some shortcomings in the primary powers used to make these regulations (Sections 15 and 16 of the Automated and Electric Vehicles Act 2018), primarily concerning enforcement, and as the uptake of all ESAs, including smart chargepoints, increases, it is imperative Government has one cohesive regime for all smart devices. Therefore, the measures proposed for ESAs in the Energy Bill will also apply to smart chargepoints. As mentioned above, given the existing regulations for these devices, a separate impact assessment has been published.

**Therefore, this impact assessment considers the scope of Government intervention to be focused on cold and wet appliances, HVAC and battery storage only, defined hereafter as ‘relevant appliances’.**

## 5.4 Policy outcomes

Table 2 outlines the outcomes, electricity system, market and consumer impacts and risks:

**Table 2: Electricity system, market and consumer impacts and risks from each of the policy options**

| | COUNTERFACTUAL (DO NOTHING) | OPTION 1 |
|---|---|---|
| EXPLANATION | Government takes no action for smart appliance policy. Industry relies on voluntary standards (e.g. PAS 1878 and 1879) to guide the technical requirements for ESAs. | Government set regulatory requirements. Transition from voluntary standards to regulatory requirements for smart appliances in 2020s. |
| ELECTRICITY SYSTEM IMPACTS | **Smart appliance uptake is low,** potential for DSR from smart appliances and associated electricity system benefits are minimal particularly over the 2030s when flexibility is required for electricity system benefits. | **Increased smart appliance uptake**: over the 2020s, regulatory requirements encourage market development. Critical mass of smart appliance uptake leads to greater consumer confidence, combined with wider availability of smart tariffs and aggregation contribute to electricity system benefits and bill savings.<br><br>Electricity network operators have trust and confidence that ESAs are **cyber secure**, and that there is no risk to critical national infrastructure resulting from a cyber-attack. |

[56] Frontier Economics/LCP (2015) Future potential for DSR in GB. While these figures are estimates for winter peak in 2030 we consider that current peak load from these appliances is likely to be a similar order of magnitude. See also Drysdale and Jenkins (2014), Flexible demand in the GB domestic electricity sector in 2030.
[57] Frontier Economics/LCP (2015) Future potential for DSR in GB.

| | | |
|---|---|---|
| MARKET AND CONSUMER IMPACTS | Cost reduction likely to be driven by a larger international larger market for circuitry which allows an appliance to have smart functionality. **UK market development is limited** and could stall.<br><br>**Consumer protection is limited, as standards in place are voluntary.**<br><br>**Consumers have full choice** of appliances, but range of smart appliances may be limited and they might not be interoperable across manufacturers. | **Cost reduction likely to be driven by an international market for circuitry.** Significant market development and competition driving reduction in mark-up: creates clear signal for GB market to move towards smart appliances. Specific technical requirements for the GB market could create additional costs and reduce the learning to the GB market.<br><br>**Consumer protection**: Regulatory requirements will ensure consumer protection and increase trust.<br><br>Consumers have confidence that their devices are **cyber secure**, and their personal data is protected.<br><br>Although choice of non-smart appliances is not taken away., we expect regulations to encourage the development of the ESA market and drive an increase in uptake of ESAs over non-smart appliances. |
| DISTRIBUTIONAL IMPACT | Some consumers will choose to purchase and pay more for smart appliances if they consider them to be beneficial. | Allows time for behaviour change and smart tariffs/aggregation offers to develop, as well as standardisation helping to reduce cost.<br><br>More consumers will choose to purchase a smart appliance, but we expect cost savings once uptake increases. Consumers will still have the choice to buy a non-smart appliance, so will only buy a smart appliance if they consider them beneficial. |

# 6 Policy objective

The main objective behind potential minimum requirements is to:

1. Provide certainty in the sector to help rectify the coordination failure between the availability of smart appliances and smart tariffs, enabling electricity system benefits and consumer rewards.
2. Ensure minimum requirements of functionality of smart appliances to protect consumers and the electricity system.
3. Enable the UK marketplace to be at the forefront of an emerging sector (including software development and smart components).

# 7 Summary and preferred option with description of implementation plan

This impact assessment concludes that there is a clear case for government intervention given the significant DSR potential energy smart appliances could offer. If taken up at scale, these would provide benefits to consumers and the electricity system. Without intervention, a large uptake of energy smart appliances might not be incentivised until the energy tariff and aggregation market is mature. The potential benefits of DSR in the 2030s might not be realised in time for when they are required. Intervention will be key to establishing greater use of DSR from smart appliances, compared to the business-as-usual case, in order to maximise electricity system benefits within appropriate time scales. Regulation is also required to ensure that appropriate cyber security mitigations and consumer protections are in place ahead of time. Under the preferred option, the government seeks delegated powers in the Energy Security Bill to allow the Secretary of State to set regulatory requirements for all relevant smart appliances in GB.

It is also noted that primary powers being sought in the Energy Security Bill are enabling only and will therefore not have any impacts on the market at this stage. Future economic analysis will ensure sufficient scrutiny of more detailed implementation options for secondary legislation is undertaken. At this stage, a high-level assessment of secondary impacts and their distribution is provided that will be further developed as part of future impact assessments

# 8 Monetised and non-monetised costs and benefits (including administrative burden)

Government intervention into the ESA market by setting regulatory requirements will incur a range of costs and benefits (Table 3 and 4). We do not expect any direct impacts of enacting *primary* legislation. The costs and benefits presented in the remainder of this section reflect indicative costs and benefits of implementing the regulatory requirements. It is **the impact of *secondary* regulation which has been quantified**. At this stage, many details of secondary have not been finalised therefore not all impacts can be quantified and monetised. At this early stage in policy development only high-level estimates and inferences can be drawn. All monetised impacts should therefore be understood as indicative, giving a sense of scale of the possible impacts rather than a robust estimate.

In the remainder of this section, we present evidence to draw indicative estimates for the costs and benefits of additional uptake due to policy options compared against the counterfactual. The presented impacts are likely underestimating the benefits of this policy:

- Due to limited data availability, we were not able to monetise impacts on all relevant appliances and have only considered costs and benefits from wet and cold appliances (fridges, freezers, washing machines and dishwashers), excluding the impacts on HVAC and batteries.
- Additionally, benefits are likely to be underestimated here, as there may be some scope for small and medium enterprises to purchase smart appliances intended for the domestic sector.
- Monetised benefits include benefits from the additional uptake of ESAs. We have not monetised all benefits associated with the regulatory requirements, like increased consumer protection or cyber security benefits. Monetising these benefits would also likely increase the overall NPV.

**Table 3: Monetised and non-monetised costs by impacted group**

| Monetised | Non-monetised |
|---|---|
| **Business/Industry**<br>• Manufacturing costs of making an ESA meet the requirements<br>• Familiarisation Costs<br>• Transition costs of complying with the requirements<br><br>**Consumers**<br>• Manufacturing costs of making an ESA meet the requirements<br>• Familiarisation Costs<br>• Transition costs of complying with the requirements | **Business/Industry**<br>• Familiarisation and transitioning costs of the supply-chain<br>• Labelling costs<br><br>**Consumers**<br>• Distributional impacts<br>• Familiarisation costs<br><br>**Wider Society**<br>• Transitional costs of implementing policy<br>• Enforcement costs |

**Table 4: Monetised and non-monetised benefits by impacted group**

| Monetised | Non-monetised |
|---|---|
| **Wider Society**<br>• Lower electricity system costs<br>• Reduced carbon emissions | **Business/Industry**<br>• Greater demand for smart appliances and potential for more profit |

| | |
|---|---|
| | • Opportunity for UK to lead in software and smart components development for an emerging sector<br>• Coordination benefits – smart appliances taken up at scale allow suppliers and aggregators to develop smart tariffs and services<br><br>**Consumers**<br>• Lower energy bills when combined with a smart tariff or other DSR offering<br>• Increased consumers choice and experience due to interoperability<br>• Consumer protection – increased data protection and cyber security<br><br>**Wider Society**<br>• Cyber protection for the electricity system<br>• Air quality improvements<br>• Wider economic benefits for example supporting the smart supply chain |

## 8.1 Monetised costs and benefits per appliance

Regulatory requirements for ESAs will result in a cost incurred by business: without knowing the form and content of these, it is difficult to provide a precise estimate, but these costs will consist of:

a) The on-going costs of manufacturing ESAs which are compliant

b) Initial costs of complying with the technical standards (transition costs)

c) Familiarisation costs

These are the key monetised costs reflected in this appraisal. Over time, we would expect significant scale and development of competition in the market to lower costs, in particular where aligned with international requirements.

The key monetised benefits of smart appliances are to the electricity system, from lower peak demand lowering costs of generation capacity, network and balancing costs and enabling greater use of low carbon technologies.

Both costs and benefits are expected to be passed through to consumers, who may face higher costs for ESAs (as the manufacturing costs are passed through the supply chain), and who also benefit from the use of smart functionality and lower electricity bills over the lifetime of the appliance.

Impacts to consumers are considered a transfer and explored in later sections. As such this quantified appraisal is partial, based on the limited evidence available to date, and non-quantifiable/non-monetised impacts are considered qualitatively in later sections.

*Illustration of costs and benefits*

For illustration of the costs and benefits, we draw on the example of a dishwasher bought in 2025. The additional manufacturing cost to the appliance in order to meet the smart requirements is between £2-£8 in 2025. Due to learning this falls to £1.20-£5 in 2030 (details in next section). The electricity system benefits per appliance are estimated over the lifetime of the appliance, i.e. at £3.10 in 2025 and £2.50 in 2030 (as per Ecodesign business-as-usual scenario, details in the next section).[58][59] We have interpolated between these years to estimate appliance benefits for each year for a lifetime of 13 years (2025 – 2034 for this appliance).

In the remainder of this section we set out the detail behind these cost and benefits estimates and explain assumptions behind uptake under the different policy options.

## 8.2 Policy option uptake assumptions and sensitivity analysis

In this impact assessment, we take a projected ESA uptake in the UK and multiply by the estimated costs and benefits per appliance (detailed later in the section). This allows an initial estimation of the order of magnitude of costs to manufacturers and electricity system benefits from ESAs.

Although only GB is within the territorial scope of this primary legislation, the analysis looks at the impact on the entire UK market. This is due to the lack of available data at GB level. As GB represents 97% of the UK domestic electrical appliance market, we can assume that a similar percentage of the benefits and costs would be captured by GB actors.[60]

To estimate the stock of ESAs in the counterfactual, we take proportions of the share of appliance stocks projected to be smart under the "business-as-usual" (BAU) scenario in the Ecodesign Preparatory study on smart appliances (Table 5) and apply it to the total UK appliance stock estimated using the BEIS Products Policy model.[61] We currently only have data for wet and cold appliances in the Products Policy model, and so at this stage, we have not modelled the impacts on HVAC and batteries.

The counterfactual assumes an uptake of smart appliances which is based on an uptake from an EU-wide industry assessment. The main implication this has for costs is that the counterfactual does not specifically take into full account of the impact of the timeline of wider UK policies set out in Section 2.1.3 (for example, on voluntary standards, smart meters, half hourly settlement and innovation). These are considered preconditions to encourage and unlock the benefits of smart appliances but reflecting the market barriers and failures outlined in section 3, these wider policy developments alone are not expected to significantly determine the level of ESA uptake in the counterfactual. However, it is important to note that the counterfactual forecast is subject to uncertainty due to limited evidence in the nascent industry and for the GB market.

We expect that regulatory requirements will increase the uptake of ESAs, as they will boost innovation and increase consumer trust and confidence in smart functionality. The Porter Hypothesis argues that whilst environmental policy may create compliance costs in the short-run, well-designed policies can help overcome market failures triggering an increase in innovation which raises productivity and more than offsets the compliance costs.[62] The 'weak' form of the hypotheses where regulation may increase the competitiveness of firms has found overall support from empirical literature. The 'strong' form which requires that innovation will more than off-set the cost of compliance has mixed support. Studies like Managi (2004) show that the strong hypothesis can be applied to the impact of environmental policy on the green productivity of US agriculture.[63] Regulations which set technical and performance requirements can work as a market-pull instrument, encouraging industry to find more efficient and effective ways of designing and manufacturing products. Giraud-Héraud (2018) introduced an additional rationale for regulatory intervention, on top of market imperfections and inefficiencies. They suggest that the role of government led food policies (information campaigns, nutritional regulation) can not only drive increased

58 European Commission (2017) Ecodesign Preparatory Study on Smart Appliances

59 2020 prices, discounted

60 ONS (2021) Number of VAT and/or PAYE based enterprises by Standard Industrial Classification

61 The BEIS products policy model has two main applications a) to provide cost benefit analyses to inform impact assessments of Ecodesign product legislation; and b) to provide estimates of energy savings that can be fed into BEIS Energy and Emissions Projections, to assess UK performance against its carbon targets. The modelling approach calculates stock or sales depending on the quality of the data. Where there is good confidence in stock data, then sales figures can be automatically generated by the models or alternatively the stock of individual products can be calculated based on sales data and replacement (lifespan) of products.

62 Porter and van der Linde (1995) Toward a New Conception of the Environment Competitiveness Relationship

63 Managi (2004) Competitiveness and environmental policies for agriculture: Testing the Porter hypothesis

firm performance but can reduce consumer concerns towards more innovative and nutritional food products.[64]

The regulatory requirements for ESAs are designed to provide consumer protection by setting requirements around cyber and data security. This should reduce consumers' concerns around the security of these connected devices. We would expect that consumers using energy smart appliances have a more positive experience using their smart functionalities because the risks of security incidences are reduced. Through word of mouth, positive media, and industry efforts, this should then encourage more consumers to purchase ESAs and engage with their smart functionalities.

Labelling would also act as a pull instrument as it would enable consumers to recognise the energy smart capabilities of the appliance. This would pull the market towards ESAs. The impact of labelling on consumer choices can depend on the type of label used and the information it contains.[65] For example, a survey on safety and security labels of smart devices found that icons with text underneath were the labels most likely to convince participants from switching from their usual brand.[66] Further research is required to understand the parameters of a label for ESAs for the secondary legislation stage.

Studies on food labelling show that consumers use the information to make healthier food choices. For example, one study found that food labelling would increase the amount of people selecting healthier food products by about 18%.[67] Evidence suggests that energy labelling can have a similar impact on consumers behaviour. A study of a mandatory Australian Energy label found that 10 years following its introduction, the label had 45% of consumers surveyed had made more sustainable decisions when purchasing household appliances. [68]

For the purpose of the impact assessment, we assume that the regulations become effective through secondary legislation by 2025. We have modelled an illustrative scenario that the regulations drive an increase in uptake of energy smart appliances by 20% from 2026 onwards. These assumptions should not be interpreted as projections of what BEIS expects under the policy option, more as sensitivity analysis to understand patterns between the different options. We present a sensitivity analysis of a four-year delay on the impact of the policy, to reflect a scenario where industry and consumers are slower to respond.

Uptake assumptions are as follows:
(Note this should not be interpreted as a prediction of a timeline.)

- **Counterfactual** – As set out above, we take proportions of the share of appliance stocks projected to be smart under the BAU scenario in the Ecodesign study (Table 5) and apply it to the total UK appliance stock estimated using the BEIS Products Policy model.[69]
- **Option 1:** a 20% increase in uptake levels above the counterfactual from 2026.
- **Option 1 (sensitivity):** a 20% increase in uptake levels above the counterfactual from 2029. This represents a four-year delay.

**Table 5: Percentage of smart enabled appliances per benchmark year under counterfactual and policy option uptake**

| | 2014 | 2020 | | 2030 | |
|---|---|---|---|---|---|
| | **BAU** | **BAU** | **Policy option** | **BAU** | **Policy option** |
| **DISHWASHERS** | 0% | 2% | 2% | 8% | 10% |
| **WASHING MACHINES** | 0% | 1% | 1% | 4% | 5% |
| **TUMBLE DRYERS, NO HEAT PUMP** | 0% | 2% | 2% | 16% | 19% |
| **REFRIGERATORS AND FREEZERS (RESIDENTIAL)** | 0% | 5% | 5% | 20% | 24% |

Source: Adapted from European Commission (2017) Preparatory study on smart appliances, and BEIS analysis

[64] Giraud-Héraud et al. (2016) The agro-food industry, public health, and environmental protection: investigating the Porter hypothesis in food regulation
[65] Wachter, Sutterlin and Siegrist (2015) Desired and Undesired Effects of Energy Labels – An Eye-Tracking Study
[66] Harris Interactive (2019) Consumer Internet of Things Security Labelling Research Findings
[67] Cecchini and Warin (2016) Impacts of food labelling on food choices and eating behaviours: a systematic review and meta-analysis of randomized studies.
[68] Harrington & Wilkenfeld (1997) Appliance Efficiency Programs in Australia: Labelling and Standards, Energy & Buildings
[69] BEIS internal products policy modelling calculations.

There is significant uncertainty both in how the policy options will affect uptake, and in how they will influence usage of the smart functionality, due to the complexity of the issue: it depends on consumer behaviour, business models and the access to smart tariffs and services that consumers have. The potential for uptake may be greater than estimated here, as there may be some scope for small and medium enterprises to purchase smart appliances intended for the domestic sector.

The costs and benefits are calculated over an appraisal period from 2025 to 2046. This appraisal period has been chosen to account for the benefits and costs over the lifetime of ESAs sold in the first 10 years of the regulations. We assumed that an ESA has an expected lifetime of 13 years which has been informed by the report "Study of Life Expectancy of Home Components" provided by the National Association of Home Builders.[70]

Since the cost of a smart appliance occurs in the first year that it is bought, but the benefits of that appliance occur in every year of its use, we have deviated from the standard appraisal period of ten years. However, we consider a policy impact on the first 10 years of sales of ESAs following the regulations becoming effective. In reality, costs and benefits of the regulations will continue further than this as the uptake of ESAs continues to rise. However, to be compliant with the Green Book[71], we consider the costs for appliances purchased from 2025 up to the end of 2034.

The accumulated stock of ESAs will begin to decrease in 2036 when appliances bought in 2025 are being retired. As more ESAs are retired, and no new sales are assumed, the stock eventually reaches zero in 2045. The benefits in this impact assessment hence reflect benefits over the life-cycle of appliances bought between 2025-2034. Benefits will continue to accrue until the last appliance purchased in 2034 has been retired and the stock of smart appliances purchased due to this policy is zero in 2047.

## 8.3 Indicative costs

The primary or direct costs of these measures, if implemented through secondary legislation, would come about from the additional costs that smart appliance manufacturers will incur from manufacturing additional products. To assess the wider or indirect impact on GB businesses requires a consideration of the different businesses types:

- **Smart appliance manufacturing businesses**: these will have to implement any proposed regulatory requirements and will face costs of manufacturing ESAs to these requirements as outlined in the following section. Manufacturers are not obligated to make all relevant appliances smart,[72] and our assumption is that manufacturers who choose to produce ESAs will face additional manufacturing costs but will only rationally choose to do so should this be net beneficial for them (i.e., they will pass on costs, or for future market share).

  Considering that there are currently few GB-centred companies with significant positions in the ESA market, and these are typically large international firms based in GB, these costs are largely incurred by foreign businesses, and it is our assessment that manufacturers who will seek to become ESA manufacturers will fully pass on through the supply chain as costs to consumers.

- **Non-smart appliance manufacturing businesses**: There will still be a market for non-smart appliances so we assume that non-smart appliance manufacturers will not be affected.

- **Smart appliance service providers (new entrants):** these can either be physical businesses e.g. aggregators or software solution developers (i.e. smart appliance ‘Apps’). Both business types require standardised smart appliances to justify the large development costs of these services and the regulatory requirements can achieve the required market reach for these businesses. Note that

[70] https://www.atdhomeinspection.com/advice/average-product-life/

[71] HM Treasury (2020) The Green Book: Appraisal and Evaluation in Central Government https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

[72] With the exception of electrical heating appliances, BEIS is seeking primary legislation to mandate that all electrical heating appliances will need to meet the smart requirements. The impact of this is addressed in a separate Impact Assessment.

the UK leads Europe in the development of these kinds of businesses (for example: Open Utility, Open Energi, Green Running, Kiwipower,). Cost incurred by these types of business are largely unknown, dependant on the scale and nature of the service provided, but it is assumed that new entrants will only enter the market if activity is likely to be net beneficial.

- **Appliance supply chain**: these are the businesses that sell appliances, install and maintain them. Most of the costs relate to training to understand ESAs, however appliances are continuously changing and evolving. It is our initial assessment that the additional costs related to the smart element of new product ranges will be small.

- **Consumer businesses:** those businesses that purchase the smart ESAs as end consumers. Since ESA users are rewarded by lower energy bills, or through taking part in DSR via an aggregator for a monetary payment, and since a business can choose whether to buy a ESA or not, the expectation is that through active and voluntary choice this will be a net benefit to consumer businesses. The rate of usage is uncertain, particularly among different consumer types as some may engage and benefit more than others.

- **Electricity industry:** this includes National Grid, Distribution Network Operators, energy suppliers, electricity generators who can save investment through using DSR over conventional ways to balance electricity supply and demand. The National Infrastructure Commission has projected the demand for DSR services will grow in the 2020s as we progressively decarbonise the grid and so there would be greatest benefit from the maximum amount of DSR being available.[73] In this analysis, we have captured the electricity system benefits and we would expect that these savings would be passed on to consumers by competitive pressures and market regulation by Ofgem, in the form of lower energy prices

### 8.3.1 Unit costs for manufacturers

We are at the early stages of policy development and given the wide ranging and innovative nature of the costs of this policy, we are unable to fully quantify costs at this stage. The costs captured in this impact assessment are estimates of the additional costs of making an energy smart appliance meet the expected regulatory requirements, multiplied by the increase in sales above the counterfactual as a result of policy intervention (as outlined in section 8.2). We expect and assume that the additional cost incurred to manufacturers will be passed on to consumers, reflected in the final sale price of energy smart appliances.

Today, most new appliances already feature electronic controllers which in principle would be capable of managing a smart operation of the appliance. However, each smart appliance has to be equipped with a communication module, which will typically be either a powerline communication or a wireless module (such as WLAN or ZigBee). At this stage it has not been possible to differentiate how these costs may vary between manufacture types. Although thought to be relatively low, this may differ between a manufacturer that produces a range of electronic products or more ‘traditional’ appliance-specific manufacturers.

The smartphone industry is currently driving the cost reductions in communications modules or “circuity”, which is benefitting energy smart appliances, as the circuitry is fairly homogenous across these technologies. As the market for energy smart appliances increases, we could start to see this drive further cost reductions. To create cost-reduction scenarios in this impact assessment, we use a ‘learning rate’ of 15% meaning that cost falls by 15% for every doubling of market size[74]. For the central scenario, we assume that businesses manufacturing smart appliances for the UK and EU market do not face additional manufacturing costs for meeting GB requirements, beyond purchasing the necessary circuitry.

Industry engagement suggested that the unit cost for circuitry was around £3.20 when 10 million units were achieved in the market. We use a range of £2-£8 for the unit cost in 2025, when the total UK and EU market is expected to be larger than 10 million units. This range reflects the uncertainty of the manufacturing costs and is a conservative assumption given the central estimate assumes a unit cost of £5.00 for a market larger than 10 million units.

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[73] National Infrastructure Commission (2016) Smart Power

[74] Based on 2001 research on cost reductions in Korea’s semiconductor sector https://www.tandfonline.com/doi/abs/10.1080/00036840122474

For the central and high scenarios, the 15% learning curve is applied to the total UK and EU smart appliance market to represent a scenario where the circuitry required to meet the ESA regulations is homogenous with other circuitry used for smart appliances. Although, GB seeks to set these ESA requirements ahead of EU policy for ESAs, we expect these policies to align. The wider ESA market (or even overall smart appliance market e.g. smartphones) will drive cost reductions.

In the low scenario ‘Additional GB Requirements’, we assume that manufacturers face additional costs to meet GB specific requirements. Specific technical requirements are uncertain and will be developed for secondary legislation. Therefore, it is not yet clear whether manufacturers will have to incorporate additional software and hardware in order to meet these, or whether the additional circuitry incorporated to ‘smarten’ an appliance (under the ‘EU BAU’ scenario) is sufficient. For this ‘Additional GB Requirements’ scenario, we assume that manufacturers selling ESAs in GB will face small additional costs to meet specific requirements which do not align with general requirements for manufacturing a smart appliance in Europe. For this we assume a range of £3.20 -£12.90 for the per unit manufacturing costs in 2025 to meet ESA requirements and apply the learning curve to the smaller UK market.[75]

We only monetise the costs for wet and cold appliances. Home batteries and HVACs are excluded. Home batteries are smart by default and so the additional cost of smartening a battery is considered zero.[76] However, manufacturers may be faced with small costs for ensuring batteries meet other requirements around cyber security, data security and safety. There will be costs faced by manufacturers of smart HVACs to meet these requirements. However, we have insufficient evidence to estimate this. We estimate that currently between 43%-55% of heat pumps are internet connected (with either embedded connectivity or are currently sold as a bundle with an add-on module that enables communication).[77] Although internet connection does not indicate that an appliance already meets the ESA requirements, it is a good indication that the appliance has a level of ‘smartness’. This suggests that a much larger percentage of heat pumps are smart compared to wet and cold appliances. Other heating and cooling appliances are also in scope of the regulations. However, heat pumps will present a large share of the smart HVAC market and will provide the largest flexibility benefits for the grid from household appliances alongside EVs. Highly flexible use of heat pumps could enable annual demand to be shifted by up to 50 TWh in 2050 and reduce peak demand by up to 5GW in 2050.[78]

As previously noted, there are currently few GB-centred companies with significant positions in the market, and these are typically large international firms based in the GB, so these costs are largely incurred by foreign businesses and it is our assessment that manufacturers will seek to fully pass this on through the supply chain to higher consumer costs. At this point it is not possible to estimate whether the additional costs would make any of these manufacturers exit the GB market (should the GB set its own regulatory requirements), but the consultation responses did not suggest this would be a likely outcome. We also recognise that there is uncertainty around how costs would be passed through to consumers and also to what extent prices are likely to come down with time particularly if we see high volumes and good competition between suppliers. In each of the options, this impact is expected to be small since the price increase is small and we expect ESA appliances, when used, would be net-beneficial for the consumer over the lifetime of the product. Additionally, consumers will still have the choice between an energy smart appliance or a non-smart appliance, with the exception of electrical heating appliances.

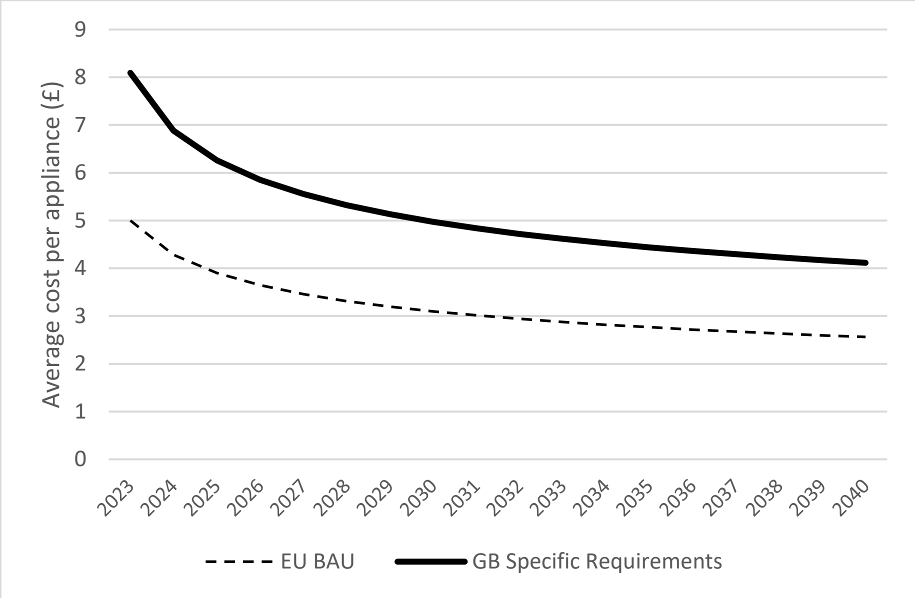
**Figure 3: Implied cost reduction curves from different levels of market penetration**

[75] We assume that the UK smart appliance market represents 13% of the EU+UK market, based on the UK and EU-28 housing stock data in 2016. European Commission (2016) EU Buildings Database

[76] European Commission (2017) Ecodesign Preparatory Study on Smart Appliances

[77] This uses estimated market share of UK heat pump manufacturers taken from ‘Eunomia (2020) Heat pump manufacturing supply chain research project’.

[78] Ofgem and BEIS (2021) Smart Systems and Flexibility Plan: Transitioning to a Net Zero Energy System




Source: BEIS calculations. Assumptions developed through in industry engagement. Based on log2 learning rate of 15%, from an initial cost of £2-8 under EU BAU in 2025.

### 8.3.2 Potential retail mark up

Evidence on the current impact of retail mark-up is limited, and limited in relevance, given the small niche and nascent market to date and expectation that policy intervention would lead to reductions in cost over time:

- UK market research was undertaken for this impact assessment, comparing prices of internet connected appliances against non-connected alternatives (including fridges, washing machines, dishwashers, and heating controls from the leading manufacturers). Findings implied manufacturers are currently using this feature as a way of differentiating their high-end products e.g., including an interface on the appliance – the assessment could not find comparable non-smart and smart technologies and so could not isolate the price impact of smart functionality. A wide price variation was found between non-smart and smart energy appliances (40% to 400% cost increase) with the average cost increase over 200%. Given the low additional component cost (under £5) this does not appear to relate to the cost of 'smartness', rather a way of differentiating high-end products.
- As part of the Ecodesign study, one manufacturer estimates that the mark-up on price was around €100-200 (£80-161 in 2014 prices) for enabling demand side response to a heating device.[79] [80]This cost accounts for research and development, installation and updates, and is for a device which had no smart functionality beforehand. For example, most air conditioners and heat pumps already have integrated technologies capable of responding to third party signals. The study notes that cost does not appear to be a huge barrier to consumers taking up smart appliances if the additional value is understood (i.e. not just monetary savings but higher comfort and additional functionality).[81]

As outlined in the previous section, in future, we expect to see significant cost reduction for manufacturers, particularly if we align with the EU. Over time, we would also expect significant development of competition in the market – policy intervention will enhance competition by leading to increased volumes and allowing manufacturers to compete on a level playing field.[82] Given the further work required to finalise requirements and complexity of additional components, there still remains considerable uncertainty around the extent to which development of the market would lower costs to manufacturing and pass through to retail prices.

[79] European Commission (2017) Ecodesign Preparatory Study on Smart Appliances : Task 4 Report

[80] ONS (2021) GBP: Euro exchange rate 2014: 1:1.2411

[81] European Commission (2016) Ecodesign Preparatory Study on Smart Appliances: Task 7 Report

[82] Evidence of standards driving competition can be seen where following introduction of energy efficiency standards, prices have decreased while quality and consumer welfare increased. See LSE (2017) Do energy efficiency standards hurt consumers? Evidence from household appliance sales

In this IA we estimate that manufacturers will face a unit manufacturing cost of £2-8 in 2025 to ensure that an ESA meets the requirements. We expect this unit cost to fall over time as cost reductions are driven by economies of scale and innovation, with access to a growing market and more investment from manufacturers. It is our initial assessment that manufacturing costs will be passed through to consumers but there will be no significant retail mark up as energy smart appliances would not be a niche market were regulatory requirements to be set. We also do not expect to see a reduction in appliance sales due to the level of appliance price increase. The consultation has not revealed any additional or contradicting evidence to these assumptions, and we will continue to stay in dialogue with stakeholders and seek to develop our evidence base to inform subsequent impact assessments.

### 8.3.4. Transition and familiarisation costs

The impact of transition and familiarisation will depend on the business type shown in Table 6. At this stage in policy development, the exact detail of the technical requirements for ESAs has not been developed and will be set out in secondary legislation. This is alongside uncertainty in how international regulation may develop. As such the impact on transition and familiarisation costs cannot be assessed with certainty, and the costs that we present are only indicative. As the detailed policy develops subject to the outcomes of public consultation in 2022, we will have a clearer understanding of the magnitude of these impacts and will look to assess this in future IAs.

Secondary legislation will impose obligations on economic actors in the supply chain in respect of the manufacture and distribution of ESAs, to ensure that the devices meet the minimum device level standards before they are placed on the market. This includes: manufacturers, authorised representatives and importers, distributors, wholesalers and retailers. The economic actors will be subject to the duty to ensure devices are compliant with the regulations and take action where a device is not compliant. We expect that most costs will fall on the manufacturers as these businesses will design their products to meet the requirements. However, other actors will incur costs as they will need to familiarise themselves with the regulations and implement processes that ensure that the ESAs placed on the market are compliant. For this reason, we monetise only the costs to manufacturers, but we do qualitatively assess the impact on other actors which we expect to be small.

**Table 6: Transition costs by affected group**

| | | Type of cost | Qualitative Assessment | Valuation |
|---|---|---|---|---|
| **Business** | Smart Appliance Manufacturing Businesses | Development costs of security and protocol changes<br>Security certificates and certificate management | We assume that the costs of modifying software and testing and documenting it etc. will occur at the beginning of the new regulatory alignments being introduced. This ‘first of a kind’ (FOAK) cost is a common concept in engineering economics, as it allows to write off all costs related to development to the first product. This is because, the first products are typically sold to users who have a preference for new technologies and are not price sensitive.<br>The Ecodesign preparatory study estimates €5-10 per appliance for this kind of costs.[83] These costs apply only in the first year, during which we assume that just over 1 million appliances will be sold. Assuming £7.50 as the central | £8.2m |

[83] European Commission (2016) Ecodesign Preparatory Study for Smart Appliances: Task 4

| | | | | |
|---|---|---|---|---|
| | | | transition cost per appliance, we estimate that the cost will be £8.2m (central).[84]<br>Considering that there are currently few GB-centred companies with significant positions in the smart appliances market, and these are typically large international firms based in the GB, these costs could largely be incurred by foreign business. | |
| | | Assurance and demonstrating compliance | Due to assurance schemes in this area not being sufficiently developed, we cannot measure the impact of mandating specific conformity assessment procedures.<br><br>As this area develops however, we may wish to mandate assurance schemes in respect of certain ESA types before they are placed on the market, and potentially extend to assurance of any firmware upgrades before the upgrades are applied to devices that have already been deployed. This would create transition costs for manufacturers to ensure that the appliance has undergone the appropriate assurance process before placing it on the market, from a statement of compliance, third party certification, device registration and labelling.<br><br>Furthermore, manufacturers may need to adapt to potentially new cyber security requirements or designated standards, to developments in the area of assurance schemes | To be developed |
| | Appliance Supply Chain (ASC) | Training costs to understand smart appliances and be able to sell them | The ASCs will have costs in training their workforce to sell and service appliances that have significantly more complexity than non-energy smart appliances. However, appliances change anyhow, and the additional costs related to the energy smart element of new product ranges will be small. In addition, most ASC will sell energy smart appliances regardless of whether regulatory requirements exist, and it is unlikely that training costs will increase with a higher uptake of | Negligible |

[84] 2020 prices, undiscounted

| | | | | |
|---|---|---|---|---|
| | | | energy smart appliances. Hence these costs would occur anyway independent of regulation. We therefore estimate the additional costs of this policy to be close zero. | |
| | Electricity Industry | DSR transition costs of moving to a new regulatory system | These costs are considered within the Energy Bill as part of a separate Impact Assessment which considers the regulatory framework governing the organisations | Addresses in a separate Impact Assessment |
| **Consumers** | | Installation and commissioning costs | Energy Smart appliances might require additional expertise to install and to connect to another appliance / a Smart Meter / a DSR service provider. Some consumers might want to commission a service provider to do this. However, consumers will have the choice between a smart or non-smart appliance and if these costs are too high, the consumer is unlikely to choose an energy smart appliance. Setting regulatory requirements is unlikely to cause any additional installation costs, rather, ensuring interoperability and shared protocols might reduce installation time and effort. | Negligible or even a benefit |
| | | Training costs to learn how to use a smart appliance | The main difference will be operating the appliance.  They will need to select an objective in the appliance rather than a method – for example 'I want my clothes washed by 07:00 tomorrow' or 'I want to minimise my heating bill but keep my house warmer than 18C' and the appliance interface will need to allow this to be done easily. Consumers will also need to understand how they may need to register the device with a DSR service provider, and how their appliance may be controlled by a third party. However, consumer interfaces will not be mandated by this policy, so there will be no additional costs due to this policy. | No additional costs |

**Familiarisation costs**

For manufacturing businesses, they will need to spend time familiarising themselves with the new rules and requirements. We will publish secondary legislation in advance of it becoming effective in order to give industry appropriate time to familiarise with the requirements and build changes into supply-chain lead times.

Manufacturers are typically large multinational companies that would be engaging with EU and other international regulatory bodies irrespective of GB regulation. We therefore expect the additional familiarisation costs of GB regulation are expected to be low, however this is dependent on the extent to which the UK aligns with international requirements,

These costs are driven by the number of staff that are needed to understand the regulations, their wage rates and the complexity of the requirements. To give an indicative sense of scale of these costs, we assumed that in the initial year of the regulatory requirement being introduced (2025), each developer will require additional (legal and managerial) resource to read and understand the legislation of between 3 to 6 hours, with a central estimate of 4.5 hours at a cost of around £60 per hour.[85] We expect there are a small number of ESA manufacturers with market presence operating in the UK. Even if more manufacturers enter the smart appliance market, we do not expect this to exceed 180 manufacturers.[86] We use this as a central estimate, with a +/- 50% range for the high and low scenarios. Table 7 shows that even with the high estimate, familiarisation costs won't exceed £73,000, we therefore do not expect them to be a burden to businesses. Again, it is likely that some of these costs will incurred by foreign business.

**Table 7: Scale of familiarisation costs**

| | Number of affected developers | Familiarisation costs |
|---|---|---|
| **LOW** | 90 | £24,000 |
| **CENTRAL** | 180 | £47,000 |
| **HIGH** | 270 | £71,000 |

## Indicative present value costs for policy options

Table 8 sets out the indicative present value costs for the policy option under different cost reduction scenarios. Estimated costs are partial and only cover the additional costs to (detailed below) the manufacturer (as outlined in the section above and detailed below) and the indicative transition and familiarisation costs. We expect cost to Government to be negligible as set out in the next section.

Policy options cover 'relevant' domestic appliances, i.e. wet appliances, cold appliances, HVAC and battery storage. However, in this impact assessment we only assess costs and benefits for wet and cold appliances.

**Table 8: Indicative Present value additional annual cost of smart appliances under policy options (£m)**

| Scenario | PV Costs (£m) |
|---|---|
| **Do nothing** | **29.1** |
| **Option 1 – Central** | **41.6** |
| **Option 1 – Low (Delayed and Additional GB Requirements))** | **93.0** |

Note: 2020 prices; discounted to base year 2022 at 3.5% Government discount rate; appraisal period for appliances purchased 2025 – 2046.

Under the Central scenario, we assume that there will be manufacturing costs to incorporate new circuitry into appliances in order to enhance smart functionality requirements. If we assume the circuitry market benefits from learning across a European market and the EU or a different international body aligns its approach with GB requirements, the manufacturing costs will be lower and the cost reductions for circuitry will be larger. If the EU or a different international body decides to regulate ESAs and GB chooses to align its approach, GB can benefit from cost savings (as evidenced in the central scenario compared to the

[85] Undiscounted, including non-wage-costs of 16% (ONS (2020Q3) Index of labour costs per hour: Manufacturing). Wage costs based on ONS (2021) Annual Survey of Hours and Earnings: corporate managers and directors at the 90th percentile).

[86] There are around 175 manufacturers of electrical domestic appliances in GB, ONS (2021) Number of VAT and/or PAYE enterprises by Standard Industrial Classification. As we expect only a small proportion of these are ESA manufacturers, we use 180 as a conservative upper bound demonstrate the maximum scale of transition costs in case all manufacturers would decide to produce smart appliances.

'Additional GB Requirements' sensitivity, see Figure 4). If GB were to set regulatory requirements without any action by the EU or other international standards and GB manufacturers were required to make specific changes to their energy smart appliances for the GB market beyond the circuitry assumed under the EU BAU scenario, the overall smart appliance market would be smaller and therefore cost reductions could be slower. That would increase overall costs over the appraisal period. However, as the technical regulations will not be specified until secondary legislation it is uncertain whether their manufacturers would face additional costs.

The British Standard Institution (BSI)'s Energy Smart Appliances Programmes addressed current standardisation gaps, following the nascent international efforts to standardise DSR internationally. However, work is ongoing within European and international level standards development organisations. GB will seek to align with international standards when it is in our interest to do so.

## 8.4 Costs to different groups

### 8.4.1 Enforcement costs

We would expect these powers to have low associated level of administrative burden both on the smart appliance industry and on the Government. However, this will depend on the requirements introduced under secondary regulation and the provisions required to manage these.

An enforcement authority for the legislation has not been appointed yet. The legislation should provide powers to make provision for an enforcement authority, but as these are enabling powers, nothing will materially change on the ground as a result of this legislation passing through parliament. We expect to formally appoint an enforcement authority between Winter 2022 and preparation of the secondary legislation (estimated in 2025). The regulations should allow for the BEIS Secretary of State to designate an enforcement body that will perform certain functions.

The exact mechanism and amount required to fund enforcement costs arising from this legislation is subject to further policy development, and discussions with whoever takes on the enforcement role. Officials will identify the final cost of enforcing the regulatory requirements in collaboration with the enforcing authority on appointment. This will include preparation and set up costs, training, resources, legal costs, active enforcement (including testing, and technical resources), and monitoring and evaluation. These costs will be subject to review by the enforcing authority we wish to designate, BEIS financial officers, other government departments and the Ministry of Justice.

The Office for Product Safety and Standards (OPSS) would be a potential but leading candidate, given that they have experience in enforcing product safety legislation, and currently enforce the Ecodesign Regulations[87]. If OPSS is chosen as the enforcing authority, we expect that a power will not be needed for the Secretary of State to fund them as they are part of BEIS. However, we expect that a funding power may be needed if a different enforcing authority is appointed, either initially or in the future. For example, if an independent regulator was to be appointed, we may need a power to fund them in order for them to carry out their activities as the enforcing authority.

### 8.4.2 Additional electricity consumption of consumers

ESAs responding to signals from the electricity network may require some small additional electricity consumption compared to non-smart appliances, and evidence varies on this. Additional electricity may be required either because appliances are required to be in standby mode or by deviating from the most energy efficient operation point e.g. by cooling deeper or heating higher. Ecodesign finds the operating costs related to in-house communication infrastructure is mostly shared with other devices and applications, so the cost that can be attributed to the energy smart appliance is assumed to be very low or negligible. One study of the impact of smart functionality found that electricity consumption of the appliance increases between 0.1% and 2%, ranging between €0.02 and €1.10 per appliance per year.[88]

[87] Ecodesign Regulations https://www.legislation.gov.uk/uksi/2010/2617/contents

[88] R. Stamminger et al (2009), Strategies and Recommendations for Smart Appliances; a report from the Smart-A project.

### 8.4.3 Infrastructure costs

The costs outlined above do not include any infrastructure cost, but this is thought to be minor. Total data used by smart energy services is very small and the infrastructure is being rolled out to meet the requirement for broadband, video etc. There may be an issue with rural communities without reliable internet connection who may not be able to access smart appliance controls, who may potentially be disadvantaged. However, Government is encouraging the rollout of digital services to remote areas for other reasons, so any increase in cost due to energy smart appliances would be small. This is alongside the roll-out of smart meters. In September 2021, there were 26.4 million smart and advanced meters in homes and small businesses. [89]

### 8.4.4 Cost of label

When deciding on the details of regulatory requirements for secondary legislation, it could be decided to introduce a label or icon to indicate the compliance of smart appliances. This will be scoped further in later stages of policy development. The cost of redesigning or introducing labelling depends on the type of labelling used e.g sticky labelling, e-labelling or laser etching. Studies suggest that additional labelling would not pose considerable costs to manufacturers. The Ecodesign study estimates energy labels cost €0.3 per label. There could also be additional costs for staff time associated with labelling, unless labelling requirements were easily built into current labelling practices. An online survey with companies on the introduction of e-labelling for electronic appliances in the EU suggests that the labelling costs would be small relative to existing costs and e-labelling could even reduce the total cost of compliance for manufacturers.[90]

Our internal engagement with stakeholders suggests the cost of additional labelling information would be negligible in the context of broader Ecodesign requirements and labelling requirements (labelling requirements for smart appliances are not thought to be any more complex or require further verification of requirements than the existing labelling processes). Specific policy requirements for labelling will also seek to minimise any additional labelling costs. For example, long lead times could be provided so that manufacturers do need to recall models and re-label but simply schedule labelling into the production model cycle. Other businesses in the supply chain such as distributors, should also not face any additional labelling costs, assuming that original appliance manufacturers are compliant.

In addition to costs outlined in this section, we acknowledge there are a number of intangible and uncertain costs which are not monetised here due to lack of data, namely the possibility of stifling innovation, by setting unclear or too prescriptive minimum requirements. The Government is aware of this risk and will work with industry to minimise it.

## 8.5 Indicative benefits

As noted previously for cost, the policy is still in development and given the complex, wide ranging and innovative nature of the benefits this of policy, we are unable to fully quantify the benefits at this stage. The Ecodesign study has undertaken detailed quantitative analysis on the benefits of smart energy appliances to the electricity system in the EU and this IA draws heavily on that assessment.

### 8.5.1 Ecodesign analysis

The Ecodesign study investigates how future flexibility provided by smart energy appliances can unlock potential domestic DSR and support the electricity system. The study estimates the value of the economic and environmental benefits potentially provided by the flexibility of ESAs to the electricity system. The focus is on the impacts for where DSR is used in the day-ahead market,[91] however the study notes that additional use cases exist where the flexibility of ESAs would have significant value (such as using DSR to manage imbalances or use by Distribution System Operators to solve local grid congestion constraints).

[89] BEIS, 2021, Smart Meter Statistics Report: September

[90] Valdani Vicari & Associat Economics & Policyi (2018), Study for the introduction of an e-labelling scheme in Europe Cost Benefit Analysis

[91] The day-ahead market is the main arena for trading power. Here, contracts are made between seller and buyer for the delivery of power the following day, the price is set and the trade is agreed.

The study calculates two indicators which are relevant to this impact assessment: economic savings and emission savings:

1) **Economic value in terms of total electricity system costs.** This indicator quantifies the avoided costs related to the more efficient use of the electricity system following the introduction of the flexibility from smart energy appliances. The model captures benefits in terms of avoided or deferred transmission network reinforcements; avoided generation build; avoided curtailment of low carbon generation; and better operation of the electricity system, but does not model savings to the distribution network from smart. This economic benefit is also estimated on an annual, per-appliance basis for the EU average but is not necessarily in line with what we would expect in the UK for reasons outlined below.
2) **Total amount of $CO_2$ emissions avoided to 2030**. This indicator quantifies part of the environmental benefits of decreased utilisation of the less efficient and more CO2-emitting peaking power plants in the electricity system. This benefit is also incorporated into the annual per appliance benefit for the EU average.

The Ecodesign study assesses two scenarios against the base case: 1) business as usual (BAU) where they use industry views of expected uptake with no policy intervention and 2) 100% uptake: a theoretical scenario where all relevant appliances are smart. The base is a theoretical case where no flexibility from smart energy appliances is allowed. Total electricity system benefits increase over time as more smart energy appliances are used and flexibility becomes more valuable to the system. Over time, increasingly volatile wholesale prices are predicted due to both increased penetration of renewables and higher fossil fuel prices/$CO_2$ price.

The Ecodesign study calculates the marginal benefits per individual appliance by comparing marginal electricity prices in scenarios with smart energy appliance flexibility against no smart appliance flexibility. The overall electricity system savings and CO2 emissions savings are then apportioned to individual appliances based on the share of smart energy appliances and their flexibility profiles. There is a finite potential value to the electricity system so as the system becomes 'saturated' with smart energy appliances, marginal benefits decrease. However, with greater scale across the options/level of uptake, overall benefits still increase, just at a decreasing rate. It is for this reason that benefits per appliance in the Ecodesign study generally decrease between 2020 and 2030, and benefits are lower in the 100% uptake case (Table 9). These results are very dependent on assumptions and the approach to modelling the electricity system – more detailed modelling for a GB specific electricity system could lead to different results.[92] We will explore this further for secondary legislation.

**Table 9: Estimated monetary benefits from providing flexibility per smart appliance per year (EU28 average)**

| | | 2020 | | 2030 | |
|---|---|---|---|---|---|
| **Group** | **DSR capable appliance** | **BAU** | **100%** | **BAU** | **100%** |
| Periodical appliances | Dishwashers | 4.2 | 1.0 | 2.9 | 0.8 |
| | Washing machines | 2.3 | 0.6 | 1.6 | 0.4 |
| | Tumble dryers, no heat pump | 4.5 | 1.1 | 3.0 | 0.7 |
| Energy storing appliances | Refrigerators and freezers (residential) | 0.5 | 0.2 | 0.3 | 0.2 |

Source: European Commission (2017) Preparatory study on smart appliances
Note: converted into GBP based on assumed exchange rate of 1.24 EUR/GDP (2014 prices*)*

To estimate total benefits, we take marginal benefits per appliance under Ecodesign's BAU scenario and multiply by the projected stock of smart energy appliances from 2025 as outlined previously.

[92] Comparison of Ecodesign study's levels of electrification of heat and transport c.f. our GCS modelling.

### 8.5.2 Indicative present value benefits for policy options

Present value benefits estimated using the methodology above are presented in Table 10. These are partial as reflect only electricity system benefits and CO2 emissions reductions.

The total benefits estimates are based on combining smart energy appliance uptake scenarios (as outlined in section 8.2) together with marginal benefit assumptions (based on scenarios outlined in section 8.2.1). A scenario approach is used to explore sensitivity behind our central estimate, reflecting limitations in the evidence base and inherent uncertainty in the assumptions.

If the impact of the uptake is delayed by four years due to e.g. lack of consumer recognition, it would impact results but still create a significant benefit.

**Table 10: Indicative present value of electricity system and CO2 emissions savings benefits for uptake under policy options (£m)**

| Scenario | PV system benefits |
|---|---|
| **Do nothing** | **117.9** |
| **Option 1 - Central** | **138.6** |
| **Option 1 – Low (Delayed)** | **130.9** |

Source: BEIS calculations based on uptake projections from Ecodesign using Products Policy model data and benefits per appliance from Ecodesign.
Note: 2020 prices; discounted to base year 2022 at 3.5% Government discount rate; appraisal period for appliances purchased 2025 – 2046 (13 year lifetime per appliance).

### 8.5.3 Non-monetised benefits

**Cyber security benefits**

Cyber security is a primary driver behind this regulatory intervention. There is a significant risk that cyber-attackers could exploit energy smart appliances, with number of attacks increasing with the uptake of appliances. There are a wide range of costs from cyber-attacks which can affect individuals and wider society; destabilising the electricity network or Critical National Infrastructure, power outages, loss of personal data, loss of internet access and operation of internet connected devices.

A report by the Home Office in 2019 estimated that the average cost of cyber-crime in England and Wales, relating to computer viruses and access to personal information was £550 per incident (2015/616 prices). In 2015/2016, there were over 2 million cases with a total cost of £1.1bn. The costs include:

- ‘anticipation’ expenditure to detect and prevent cyber-crime, insurance ad
- ‘consequence’ expenditure resulting from damage, physical and emotional harm, loss of output (e.g. productivity). However, this does not include service costs to the victim support service or police services.

One type of cyber-attack is when malware is used to cause a loss of service to user by occupying the bandwidth of their network and overloading the computational resources of the system. A study by the University of California seeks to quantify the costs occurred by consumers from this type of attack, known as a distributed denial of service attacks.[93][94] It estimates the cost to consumers of increased energy and bandwith consumption. However, it does not include the costs to consumers such as degraded performance of consumer devices, and time and money spent disinfecting devices. It considers three different scenarios outlined in the table below.

[93] University of California (2018) Quantifying Consumer Costs of Insecure Internet of Things Devices

[94] A distributed denial of service attack is where a number of devices (which have previously been infected, for example by malware) communicate with each other at the same time to create a host which causes a network resource (such as a web resource) or targeted device to be significantly slower to respond or cease to function

**Table 11: Electricity and bandwith consumption costs from cyber attacks**

| Scenario | Details | Total electricity and bandwidth consumption costs |
|---|---|---|
| KrebsOnSecurity | A 77-hour long attack against the KrebsOnSecurity website in 2016, which compromised 24,000 devices. | $324,000 |
| Dyn, Inc. | An attack against the company's domain name system infrastructure in 2016, which compromised over 100,000 devices. | $115,000 |
| Worst-Case | This is a hypothetical 50-hour long attack which assumes over 600,000 devices were compromised by a powerful malware | $68,147,000 |

The increasing awareness of data protection and cyber security can create a lack of trust in smart appliances. Sovacool et al. (2020) conducted a study amongst stakeholders in smart technology and found that "privacy, security and hacking" was the primary risk or barrier for 81% of respondents.[95] Similarly, a consumer study by Traverse (2018) for Citizens Advice found that the majority of respondents were concerned about what data would be collected from them, how this data would be used and how this affected their risk of cyber-attacks.[96] Therefore, implementing cyber security requirements for all Energy Smart Appliances should provide consumers with confidence and encourage their uptake and the use of their flexibility services.

**Safety benefits**

There were over 24,000 accidental fires in dwellings in 2020/2021 in the UK. Fires caused by tumble dryers, washing machines, fridge/freezers and dishwashers accounted for 6%. The majority of these are caused by faulty appliances or leads. [97] Although fridge/freezers account for a smaller number of fires, the damage can often be serious when they do occur and since they are usually left on at all times it can mean a fire can be left undiscovered for longer. Every fire avoided has the potential to save lives, prevent injuries and damage, and reduce costs to the emergency services.

Smart appliances can use condition monitoring and predictive maintenance to detect failures and faults before they develop into safety hazards. Sensors can be used to detect patterns in vibrations, temperature, pressure, moisture etc. outside of normal operation. The appliance can then alert the manufacturer or consumer via an app.

Smart and connected appliances can also improve the effectiveness of product recalls. BEIS research found that only 53% of consumers had registered their recently purchased white goods.[98] Smart appliances can incentivise registration or eliminate the need for it. Manufacturers could also communicate a recall notice directly to uses through their smart device. Other benefits from smart appliances are provided by collecting data on performance and usage for future design and communication with consumers to encourage appropriate usage.

**Interoperability benefits**

Benefits from interoperability have not been monetised. Interoperability will avoid costs for consumers and energy systems actors. It aims to allow consumers to switch between flexibility service providers without

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[95] Sovacool, B. & Furszyfer Del Rio, D. (2020) Smart home technologies in Europe: A critical review of concepts, benefits, risks and policies. Renewable and Sustainable Energy Reviews, Volume 120

[96] Traverse (2018) The future of the smart home: Current consumer attitudes towards Smart Home technology

[97] Home Office (2021) Fire Statistics Data Tables

[98] BEIS (2020) Consumer attitudes to product safety.

becoming locked into specific service providers, preventing them from switching to new providers and taking advantage of new offers. Putting in place minimum standards to deliver interoperability will ensure that – like in the retail energy market - consumers are able to switch freely between service providers in search of a better deal or innovative services. This will drive competition and choice in the emerging smart energy sector, incentivising organisations to develop novel products and services, and ensuring a positive consumer experience. Interoperability will be essential to allow any authorised energy system actor to control the DSR response of ESAs to provide grid services such as frequency response.

However, because the ESA market is nascent, there is not sufficient data available to estimate the current cost to actors and the expected cost reduction delivered by interoperability requirements.

**Business opportunities**

Wider economic benefits, for example supporting the energy smart appliance supply chain and creating green jobs, have not been quantified due to lack of evidence in the nascent industry. This regulatory proposal is therefore the start of a new industry in GB and should be viewed differently to regulating existing industries. Our quantitative analysis expects the annual sales of ESAs in the GB to reach over 1.5m by 2032. With a growing market and leading regulation set by the UK Government, we would expect this to drive growth in the GB ESA supply-chain. A large share of hardware manufacturing is likely to remain abroad especially if the EU and international standards align with GB regulation, but opportunities for GB businesses in the development of enabling software could be large.

An analogy to the regulatory requirements outlined in this IA would be the roll out of smartphones in the telecommunications industry, where the Government (in conjunction with the EU) released radio spectrum and regulated that this must be used for services to the 3GPP standard. By timely regulation of the smartphones, the UK Government has ensured the development of businesses that is estimated to be worth £31bn per annum to the UK economy by 2025. [99] Note that this is in an industry where the UK no longer produces the smartphone hardware but excels in the production of services ('Apps'). It is this success in the telecommunications industry, that this proposal for regulation in the upcoming energy smart appliance industry is designed to emulate.

# 9 Social cost-benefit analysis

The overall quantified additional costs and benefits are based on the above outlined annual benefits and annual manufacturing costs and one-off transition and familiarisation costs to manufacturers.

Table 12 shows for the example of 2030 how we have calculated the undiscounted annual costs and benefits.

- Additional costs of producing a smart appliance occur every year and are based on additional sales (above counterfactual). In 2030, additional sales are the same across the central scenario and the sensitivities (20% more sales than in the counterfactual). Annual costs are calculated by multiplying the costs per appliance in 2030 (£3.10 in central scenario, £5.00 in 'Additional GB Requirements' sensitivity) with the assumed number of appliances sold in that year. These costs are higher in the "Additional GB Requirements" sensitivity, as we assume lower cost reduction (see Figure 4).
- There are no familiarisation or transition costs in 2030 as these only occur in the first year, 2025, when the regulations are assumed to become effective.
- The annual benefits depend on the additional stock of energy smart appliances (above counterfactual), not on the sales in each year. As an energy smart appliance generates system benefits every year it is in use, and we assume a lifetime of 13 years, additional sales of appliances from years 2025-2034 will generate benefits in 2030. Annual benefits are calculated by multiplying the stock in 2030 with the assumed per appliance benefits in 2030 (see Table 12). The benefits are not impacted by the "Additional GB Requirements" sensitivity, however the stock of appliances in 2030 will be smaller in a delayed policy scenario and hence benefits are lower in that scenario.

**Table 12: Calculating annual costs and benefits in 2030 (2020 prices, undiscounted)**

[99] https://www.theguardian.com/technology/2014/jun/26/uk-apps-economy-worth-four-billion-pounds

| Scenario | Do nothing (counterfactual) | Central | Low (Delayed and Additional GB Requirements) |
|---|---|---|---|
| **ESA sales (million)** | 1.1 | 1.3 | 1.3 |
| **Costs (£m)** | 3.4 | 4.1 | 10.5 |
| **ESA Stock (million)** | 6.3 | 7.4 | 6.7 |
| **Benefits (£m)** | 9.5 | 11.2 | 10.2 |

The NPV is calculated through the additional costs and benefits of the regulation (e.g., taking the counterfactual costs and benefits from the Option 1 costs and benefits). The resulting net value is discounted (NPV base year 2022). This is done for all years from 2025-2046 and gives, together with the transition and familiarisation costs in year 2025, the Net Present Value (NPV) of each of the scenarios (Table 13).

Given the partial estimates of costs and benefits, the NPV is only a partial representation. We have also only assessed costs and benefits for domestic wet and cold appliances due to data limitations If HVACs and batteries were included, we would expect the scale of the costs and benefits to increase.

**Table 13: Indicative net present value (NPV) benefits (£m, 2020 prices, discounted to base year 2022 at 3.5% Government discount rate)**

| Scenario | Low | Central | High |
|---|---|---|---|
| **Costs** | 46.5 | 12.5 | 7.0 |
| **Benefits** | 13.1 | 20.7 | 20.7 |
| **NPV** | **-33.4** | **8.2** | **13.8** |

Source: BEIS analysis (2021)
Note: The scope of this analysis covers wet and cold appliances only, it does not estimate costs/benefits for batteries and HVAC. Ranges in benefits reflect uptake, ranges in costs reflect market size: the high end of the cost range reflects the UK setting a different technical standard to the EU, and the low end reflects the EU regulating for all relevant appliances to be smart.

The central and high scenarios present a positive NPV. There is some uncertainty in achieving a positive net result in case that the GB does not align with international regulation in the future and GB requirements create additional costs for manufacturers selling products to the UK. This would mean GB following different requirements and therefore not achieving the same levels of cost reduction anticipated in a larger market. The Government considers it very unlikely that there will not be international standards for smart appliances, but if that were the case, there would still likely be advantages in setting minimum requirements for the GB market (for example addressing cyber security and interoperability concerns, which we currently have not quantified). The Government would take this into account (including through consultation) when determining the timing and nature of the regulatory requirements. When technical requirements are specified at secondary legislation, we will explore whether these will create additional manufacturing costs beyond those that we have assumed in the central scenario.

It is important to emphasise that the quantified net benefits for wet and cold appliances, from reduced electricity system costs and CO2 emissions, may be greater than estimated here. We have only modelled uptake of energy smart appliances in UK households but some small and medium enterprises may purchase ESAs intended for the domestic sector.

The net societal impacts of the policies shown in Table 13 are not expected to be distributed equally across society, with manufacturers in particular expected to incur the direct costs presented, however these are likely to be passed on to the consumer. There are significant electricity system benefits that will be passed through to consumers in lower bills, however it is unknown how these benefits will be apportioned between the customer, aggregator/supplier, and society as a whole. Benefits will also accrue to the ESA owner, if they have contracted with some type of smart tariff e.g. a time of use tariff or direct load control through an aggregator.

The NPV is indicative as due to multiple limitations summarised below:

- The details of secondary legislation are not yet known.
- The evidence base to estimate electricity system benefits and carbon emissions savings is limited
- There is uncertainty and insufficient evidence to be able to allocate the share of benefits across society, through lower domestic and non-domestic energy prices and bills.
- There is uncertainty around the uptake of energy smart appliances by domestic and non-domestic consumers.

Finally, the NPV only captures a proportion of the costs and benefits of secondary legislation. It does include the benefits of all heat pumps being smart, which have the largest flexibility value for flexibility of all appliances in scope. It also does not capture other benefits like cyber security which is expected to be large.

# 10 Risks and assumptions

### 10.1.1 Limitations, evidence gaps and risks with this approach

The approach does not capture all benefits and costs associated with the policy option. Current limitations are as follows:

Costs

- At this stage in policy development, the exact detail of the technical requirements for ESAs has not been developed and will be set out in secondary legislation. This is alongside uncertainty in how international regulation may develop. As such the costs to business cannot be assessed with certainty, and the costs that we present are only indicative. However, we draw upon research with industry and previous studies on similar policies to illustrate different cost scenarios, using a low, central and high range to reflect uncertainty.
- Similarly projecting the impact of secondary legislation on uptake is subject to inherent uncertainty. Again, scenarios are used to reflect this with changes in uptake based on the impact of previous policies which are expected to have similar effects.

Benefits

- The Ecodesign Preparatory Study on Smart Appliances[100] forms our main evidence. It models a simplified EU-28 system rather than GB specific. There are cultural and seasonal differences between the countries which lead to appliances being used differently and a different electricity generation mix leading to different marginal energy costs and emissions intensity. The evidence base is likely to underestimate benefits to the GB because the GB has more renewables (estimated around 69% of total electricity supplied in the UK in 2030 will come from renewables) [101] and less interconnection than average EU which makes flexibility more valuable.
- The Ecodesign analysis assumes limited other sources of flexibility, which may over attribute flexibility benefits to smart energy appliances, where in practice flexibility may come from other flexible technologies such as energy storage.
- The EU market is a lot larger than the UK market and so smart energy appliances could become more saturated and their ability to provide value by flexibility is less. This would suggest the benefits per appliance are underestimated for a GB system.
- The approach considers the technical potential of appliances – we have not assessed in detail the impact of consumer behaviour on usage of functionality.

[100] European Commission (2018) Ecodesign Preparatory Study on Smart Appliances

[101] BEIS (2021) Energy and Emissions Projections: Net Zero Strategy Baseline

### 10.1.2 Policy risks

The risks associated with this policy are set out below:

- Non-compliance by industry – the nature of this risk varies between the policy options. If regulatory requirements or technical standards are not clear or strictly enforced, there may be non-compliant products on the market undermining confidence and consumer protection.
- Increased energy consumption – smart appliances may use more energy on standby or by deviating from the most energy efficient operation point e.g. by cooling deeper or heating higher.
- Regulation does not drive uptake and/or use of functionality is low - this could be driven by multiple factors such as: additional cost of smart appliances, media push back and general consumer disengagement with energy issues.
- Regulation does not drive smart tariffs and services – there is a risk that regulation comes at the wrong time or is insufficient to incentivise smart tariffs and services from suppliers/aggregators meaning that the smart functionality is not used to manage the electricity system.
- Vulnerable consumers are left behind – if they are unable to afford smart appliances or have inflexible load, they may be faced with higher energy costs.

Given the risks outlined, it is important that we monitor these risks when the regulations become effective so that we can take appropriate policy actions such as adjust the regulations or provide support to incentivise compliance and engagement if needed.

## 11 Direct costs and benefits to business calculations

Given that the legislation is for primary powers only, and that decisions on the introduction and detail of any secondary legislation will be taken at a later date in light of the development of the market, the Equivalent Annual Net Direct Cost to Business (EANDCB) of the primary regulation is zero. EANDCB of individual measures will be quantified and scored at the point when any regulations, which would then bring about impacts to business within the UK, which are introduced in secondary legislation.

Nevertheless, we have produced an initial indicative estimate for EANDCB for secondary regulation. Based on the available evidence this reflects the direct costs incurred by product manufacturers from the proposed policy, but at this stage we are not able to quantify any direct benefits. Non-monetised benefits include, for example, additional profit generated from energy smart appliances. As a result, these indicative estimates are considered partial, and subject to uncertainty. Particularly there is uncertainty around what extent costs are likely to come down with time given assumptions on competition, learning rates and volume of sales/ uptake under different policy options. All these costs are also assumed to be transferred to consumers, as discussed previously.

The costs we have monetised which have direct impact on businesses are additional costs of manufacturing energy smart appliances which meet the regulatory requirements, transition costs and familiarisation costs. We consider these costs for the stock of appliances affected by the regulation in the first 10 years from when the regulations become effective. This gives a present value net cost to business of £12.5m (2020 prices, 2022 base year). To calculate the EANDCB, we use this 10-year period. This gives an EANDCB of £1.5m (2020 prices, 2022 base year, Government 3.5% real discount rate).[102].

Unlike, the manufacturing costs which occur in the first year of the appliance's lifetime, benefits occur across the whole of its lifetime, which is assumed to be 13 years. Therefore the total appraisal period to calculate the overall NPV is 22 years per appliance. This accounts for the first 10 years stock which is affected and their entire lifetime. The last year of stock we appraise is in 2034 and these appliances retire in 2046. We do not use the total appraisal period of 22 years to calculate the EANDCB as this would underrepresent the costs to businesses. Likewise, we do not use 10 years for the total appraisal period as this would underrepresent societal benefits.

[102] This figure is calculated using the Government online Impact Assessment calculator, and uses the central scenario.

# 12 Impact on small and micro businesses

The exact number of small or micro businesses[103] (that the proposed provisions will affect, is uncertain. There are around 175 manufacturers of electric domestic appliances in Great Britain and we expect that a small proportion of these produce energy smart appliances, most of which are foreign businesses with locations in the GB.[104] 66% and 27% of electrical equipment manufacturers, the sector under which electrical appliance manufacturers fall, in GB are micro and medium sized businesses.[105] However, we expect that the large majority of ESA manufacturers in GB are large businesses (for example, Whirlpool and Bosch).

The main small and micro businesses, that are thought to be affected, fall into the category of the supply chain and service provider categories set out in Section 8.3.4. Of these, the service providers are strongly growing and would benefit from an increasing business opportunity. These are new business types which will benefit from the growing ESA market and proposed regulatory requirements due to an increased need for enabling software, and distribution, installation and maintenance services.

The costs on these types of businesses should be small as manufacturers should incur most of the costs of compliance. Smaller businesses like local retailers may face some small costs in regards to familiarisation and adding labelling if not already integrated by the manufacturer.

The supply chain will face costs in training their workforce to sell and service appliances that are more complex than non-smart appliances, however, it is likely that this would occur anyway and not as a result of this policy, as described in Table 4. It is important to also recognise that appliances are continuously changing and evolving, and that supply chain businesses are continually developing their practices. Our initial assessment is that the additional costs related to the smart element of new product ranges are likely to be small, and not dependent on the additional uptake of energy smart appliances.

We have considered how these businesses could be supported and costs could be mitigated.

- Transition period - requirements can be introduced gradually, in order to provide a sufficient timeframe for manufacturers, including small businesses, to redesign their products and services in accordance with the requirements.
- Awareness campaigns - the UK Market Surveillance Authority is required to raise awareness of the Ecodesign and Energy Labelling Requirements, so industry and small businesses will be made aware of the consequences of placing non-compliant products on the market. Specific information campaigns provided through this channel could be used to mitigate any disproportionate demands in respect of understanding what compliance looks like and what is required.
- Partial exception - small and micro businesses could be issued warnings rather than facing sanctions where non-compliance is identified, or by deeming a certain subset of rules not applicable to smaller business.
- Extended transition period – there could be a later transition to regulatory requirements for small and micro businesses
- Temporary exemptions – this could be provided for a sub-set of service providers, to continue existing business for older non-smart products. This could be extended to exempt any small and micro business that have to conduct redesign in order to be compliant. Valid reasons (such as capacity or financial) would have to be provided to justify a longer time period than larger businesses.
- Varying requirements by type and/or size of business - given the expected minimal additional costs it is our view that this would be disproportionate to initially consider, as other methods would be more appropriate at targeting any additional costs.

[103] defined as having up to 49 FTE and 10 FTE employees respectively, BEIS Better Regulation Framework Manual

[104] ONS (2021) Number of VAT and/or PAYE enterprises by Standard Industrial Classification – SIC 2751

[105] ONS (2021) Number of VAT and/or PAYE enterprises by Standard Industrial Classification and employment sizebands – SIC 27

- Specific information campaigns or user guides, training and dedicated support for smaller businesses - as noted above this would be an essential method of cost minimisation
- Direct financial aid for smaller business - given the expected minimal additional costs, it is our view that this would be disproportionate to initially consider, as other methods would be more appropriate at targeting any additional costs.

# 13 Wider impacts

### 13.1.1 Public Sector Equalities Duty

We have also not monetised distributional impacts due to lack of data and aim to explore this further in subsequent impact assessments.

The rate that consumers will begin to take up ESAs is uncertain. There is currently limited quantifiable evidence on attitudes and behaviours relating to the use of ESAs for domestic/small-scale DSR, as the market for these devices is still nascent, with the exception of smart EV chargepoints, which are growing steadily. Therefore, limited evidence exists which have explored the differences in consumer group preferences or data on protected characteristics.

BEIS commissioned the Energy Systems Catapult to undertake a research project to provide technical and social research to review the domestic and international evidence base, including current innovation activities to identify:

- the barriers to Low Income and Vulnerable (LIV) consumers participating in a smart energy system
- where innovation can help enable low income and vulnerable consumers to participate in a smart energy system.

The findings reveal a limited amount of evidence about how LIV consumers could participate in smart energy products and services of the future. The evidence reviewed showed the majority of existing innovation projects on LIV consumers have focused on accessing and using products and less on how these consumers could purchase or pay for them.[106]

Take up of ESAs will also encourage consumers to adopt associated smart energy services such as Time of Use (ToU) tariffs. Yunusov & Torriti (2021) published relevant research on the distributional effects of ToU tariffs.[107] Their modelling showed that ToU tariffs led to bill increases for high income consumers in both households with and without children. Bill increases are milder for middle income households without children and middle-income retired couples, and that ToU tariffs would provide financial benefits to single parents in low-income households.

Ofgem's decision to implement Market-wide Half Hourly Settlement (MHHS) will facilitate changes to the energy system which may affect different consumers based on their individual circumstances. Ofgem's Impact Assessment also notes that there is very limited usable evidence available to quantify the potential distributional impacts across specific consumer groups of implementing MHHS, and to assess whether consumers will respond to the flexibility options it may facilitate.[108]

Some consumers with protected characteristics will feel better equipped to engage in a smart energy market. It is possible that some consumers may struggle with digital tools such as smartphone apps, and could need additional support to help them engage and make informed choices. For example, depending on their circumstances, elderly consumers and people with disabilities may need more specific support from their energy provider than other consumers. Furthermore, consumers who search online for information to compare different smart products and services, are more likely to be able to find and compare different offers. Whereas, some elderly consumers who may not be familiar accessing this

[106] Energy Systems Catapult for BEIS (2021) Project Involve: How can innovation deliver a smart energy system that works for low income and vulnerable consumers?
[107] Yunusov and Torriti (2021) Distributional effects of Time of Use tariffs based on smart meter electricity demand time use activities https://www.sciencedirect.com/science/article/abs/pii/S0301421521002822?via%3Dihub
[108] Ofgem (2021) Market-wide Half-hourly Settlement: Final Impact Assessment https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/mhss_final_impact_assessment_final_version_for_publication_20.04.21_1_0.pdf

information online, may struggle to find adequate information and support. This means providing appropriate advice, help and usable tools that assist these consumers' understanding.

Accessing ESAs will be a major barrier for some consumers, in particular due to potential upfront cost in purchasing energy smart appliances. Furthermore, certain consumers in social housing, on low incomes or those living in private rented accommodation where landlords must agree to install flexibility options such as smart appliances or storage batteries.

Research is already extensive in the area of disability; showing that disabled households more likely to worry about energy bills, have higher costs of energy, and are more likely to live in fuel poverty[109]. The use and installation of new technologies may be both challenging for disabled people and come at a cost. Furthermore, extra thinking will need to go into the design of how these new technologies can be used for disabled people, with various disabilities needing to be considered as they will be impacted differently.

ESAs will be able to be remotely controlled by the consumer or other third parties, including DSR service providers. This could potentially improve user experience and optimisation of these devices, by giving control to others, if consumers are impaired by physical disabilities. However, there are risks that consumers with specific disabilities, or associated health conditions, which prevents those households from having the flexible consumption patterns to use these devices for DSR.

Recognising the above, it is important to note, with the exception of electric heating appliances, the equivalent dumb (i.e. not connected) appliances will still be available on the market. Consumers will have a choice about which are the most appropriate appliances to purchase, and will not be forced to buy smart appliances, nor will they be forced to utilise their smart capabilities.

### 13.1.2 Impact on rural areas

Average broadband speeds in rural areas tend to be slower than those in urban areas. This is because there is less superfast broadband and rural premises are typically further away from cabinets with longer line connections which can slow performance.[110] Additionally, rural areas have lower coverage from 4G and 5G coverage.[111] The smart functionality of ESAs requires internet connection via broadband or mobile data. Therefore, reduced broadband and network coverage could act as a disincentive for consumers in rural areas to purchase an ESA or they might experience diminished performance of their ESAs. The disparity in broadband and network across UK regions is being addressed by policies such as the Shared Rural Network programme and the Gigabit project.[112] [113]The uptake and consumer experience of ESAs across regions can be included in the monitoring and evaluation framework for the regulations.

### 13.1.3 Impact on Greenhouse gases

Smart appliances will improve the utilisation of low carbon generation, thus avoiding existing peaks of demand - which is largely met through fossil-fuelled generation. This could make significant savings in the traded sector. Section 8.5 gave an indication of these benefits. We have not been able to split out the specific monetised benefits from CO2 emissions reductions due to the nature of the modelling. The modelling also reflects an electricity system for the EU-28. The environmental benefits per appliance could be larger in the GB due to the relatively high expected share of generation coming from renewable energies in GB.

[109] https://www.scope.org.uk/campaigns/extra-costs/out-in-the-cold/

[110] Defra (2020) Rural broadband statistics

[111] Ofcom (2020) Connected Nations: England Report

[112] https://www.gov.uk/government/news/better-broadband-for-500000-rural-homes-in-uk-gigabit-revolution

[113] https://www.gov.uk/government/news/shared-rural-network

### 13.1.4 Competition and innovation

This policy is intended to promote competition. For example, the interoperability principle would aid competition between manufacturers and service providers, as it allows customers to choose different appliances and services, avoiding the risk of consumers being locked in to using devices from a particular manufacturer and services from a certain provider. Further consideration of competition impacts will need to be undertaken at the secondary legislation stage, subject to the full details of the proposed legislation. These regulations, together with Government funded innovation programmes for energy storage and flexibility, will spur innovation, encouraging industry to evolve and bring interoperable and user-friendly energy smart appliances to the market.[114]

## 14 A summary of the potential trade implications of measure

Primary legislation will not have any implications for the UK's trade as it is enabling powers only. Secondary legislation would set requirements for all relevant ESAs sold in Great Britain. This will have implications for businesses selling to Great Britain and those exporting ESAs abroad.

The UK Government is setting primary legislation for ESAs ahead of international trade partners. However, we understand that the EU are considering the selection of products with high demand response potential over the next two years. This includes development of interoperability requirements for ESAs and setting up a code of conduct. We will continue to monitor international standards and will aim to align with these when it is in our interests.

The GB specific requirements will be specified at secondary legislation, so it is not currently possible to understand whether businesses will face additional requirements for selling into or out of the UK. If requirements for the GB market are different to those of other markets, businesses selling to GB and other markets could face additional costs. Businesses will have to familiarise themselves with the different requirements and may have to provide separate assurance processes (e.g., conformity assessment) to demonstrate their products are compliant for each market. We expect the manufacturing costs to be limited because the technologies which could be needed for energy smart appliances to be compliant are fairly homogenous across different appliances and across countries. When developing the specific GB requirements, we aim to consult with industry to understand whether these will create additional costs for businesses manufacturing products for multiple markets.

## 15 Monitoring and Evaluation

An initial theory of change is presented in Section 5. It illustrates how the intervention intends to achieve the objectives, in order to drive outcomes: energy smart appliances provide DSR to reduced electricity system costs whilst ensuring consumers are protected and rewarded for their participation through reduced electricity bills.

To assess the performance of this intervention against its objectives it is likely that a mix of quantitative and qualitative indicators will be required, some of which may require additional data collection. A more detailed monitoring and evaluation (M&E) plan will be provided when the regulations are implemented through secondary legislation. For the purposes of this primary legislation Impact Assessment, we provide an initial outline for the M&E below.

To monitor how businesses have initially responded to the requirements, quantitative indicators of compliance can be used. For example, % of the market which are compliant with each requirement, % of business improvements required, number of market participants. To monitor how businesses and consumers have initially responded to the regulations, qualitative research can be used to seek consumer experiences and attitudes towards smart appliances, and to seek businesses attitudes towards the requirements. Monitoring (indicators and method of collection) should be considered alongside regulation implementation, as appropriate. Any monitoring data collected will also contribute to evaluation activities.

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[114] Ofgem and BEIS (2021) Transitioning to a Net Zero System: Smart Systems and Flexibility Plan – Energy storage and flexibility is one of the priority areas under the £1bn Net Zero Innovation portfolio, with at least £100 million of innovation funding.

To evaluate the impact of the requirement, a theory-based, mixed-methods impact evaluation design will likely be required[115][116]. This is because using quasi-experimental methods would require the identification of a suitable counterfactual, which may not be possible), and a theory-based evaluation design is also most suited to answering *why* and *how* observed results occur. In particular, we will be interested in understanding how and why businesses and consumers have responded to the regulations, and how and whether this has led to the desired outcomes. As part of this, it will be important to identify any unintended consequences of the regulations.

Within the framework of the chosen theory-based impact evaluation approach (e.g. contribution analysis), specific methods of data collection are likely to include:

For the 1st policy objective[117], it is likely that quantitative measurements on the number of smart appliances, % of appliances which are smart, and number of flexible/time-of-use tariffs will be required. This could be supported by quantitative and qualitative research with consumers and manufacturers. It would be valuable to understand if and how consumers are engaging with the smart functionalities and what is driving this behaviour, for example ease of use, lower electricity tariffs, environmental benefits. It would also be valuable to understand how suppliers influence consumer behaviour and encourage the purchase and use of smart appliances alongside time-of-use tariffs. This data would likely be collected through focus groups with consumers.

For the 2nd policy objective[118], indicators of compliance can be used to assess whether manufacturers are meeting requirements around smart functionality, consumer safety, interoperability, cyber security and data security. It would also be important to assess if the regulations are contributing to the protection of the electricity grid. Data from smart appliance suppliers and distribution network officers could show if and how the electrical load from smart appliances had shifted use away from hours of peak demand or to times where there is more renewable electricity capacity. This data would likely be collected through a quantitative survey, if existing administrative data is not available. This could be complemented by research with consumers on their use of appliances, through further surveys, qualitative interviews or focus groups.

For the 3rd policy objective[119], qualitative research with smart appliance manufacturers would be valuable to understand to what extent the regulations have driven the smart appliances market and provided UK businesses opportunities. This could be supported by a market review of the smart appliance supply-chain and how this has changed since the regulations were implemented.

It is difficult to assess the timelines over which the performance of the policy should be measured. Market compliance and the initial impact on consumer use could be measured shortly after implementation. However, as evidence suggests, flexibility through DSR will be important from the mid-2030s onwards. Therefore, it will be important to monitor the smart appliances market and ensure the technologies available and consumer behaviour will continue to generate these benefits in the medium to long-term.

# 16 Summary

The Government is committed to ensuring there is appropriate regulation of ESAs in GB. The Government therefore intends to take powers to set regulatory requirements for certain ESAs. There was wide support from respondents to our consultation for the proposal to take powers on setting regulatory requirements

[115] Having said this, the chosen evaluation approach will ultimately depend on the key evaluation questions, as identified by policy colleagues.
[116] A theory-based evaluation approach uses an explicit Theory of Change (ToC) to understand whether and how an intervention contributed to the observed results. The ToC is used as a 'map' through which to test the assumed causal chain of events, with evidence of what happened. For further detail, see: https://www.canada.ca/en/treasury-board-secretariat/services/audit-evaluation/evaluation-government-canada/theory-based-approaches-evaluation-concepts-practices.html#toc2. A quasi-experimental evaluation approach creates a counterfactual group that as is as similar as possible to the intervention group through statistical methods. It then observes the difference in outcomes between the counterfactual group and intervention group. See: https://www.betterevaluation.org/en/resources/guide/quasi-experimental_design_and_methods
[117] Objective 1: Provide certainty in the sector to help rectify the coordination failure between the availability of smart appliances and smart tariffs, enabling electricity system benefits and consumer rewards.
[118]Objective 2: Ensure minimum requirements of functionality of smart appliances to protect consumers and the electricity system.
[119] Objective 3: Enable the UK marketplace to be at the forefront of an emerging sector (including software development and smart components).

for ESAs. This Impact Assessment assesses the impact from making the proposed regulatory requirements effective from 2025.

Based on the assessment made in this impact assessment, this policy option will provide benefits to society and allow Government flexibility to adapt its strategy in light of new information and as the market develops – it is therefore a “low regret” option. As this is a new and rapidly developing sector, we recognise that the smart system may evolve in a number of foreseen or unforeseen ways. Therefore, Government must take a flexible approach. This is expected to result in lower transition and familiarisation costs, whilst achieving a significant scale of benefits to the electricity system.

We note that the quantitative analysis presented in this impact assessment is only partial, for example, it does not take full account of all relevant appliances (for example, smart heating and batteries) and does not capture all of the costs, risks and benefits (for example environmental benefits). Improvements to both our quantitative and qualitative evidence base is already ongoing and the results will inform future impact assessments.

**Title:** Extending competitive tendering in the GB electricity network
**IA No:** BEIS007(F)-22-ESNM

**RPC Reference No:** RPC-4464(1)-BEIS (RPC-BEIS-5173(1))

**Lead department or agency:** BEIS

**Other departments or agencies:** Ofgem

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage:** Final

**Source of intervention:** Domestic

**Type of measure:** Primary legislation

**Contact for enquiries:** EnergyBill2021@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices, 2020 Present Value terms) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** Non-qualifying regulatory provision (pro-competition) |
| N/A | N/A | £8.4m[1] | |

**What is the problem under consideration? Why is government intervention necessary?**

In the coming years, significant investment will be needed in the electricity network to support the increased electricity demand and renewable generation needed to meet our Carbon Budget targets and achieve Net Zero, in a way that is secure, sustainable, affordable and value for money for consumers. In 2021, approximately a fifth to a quarter of a typical household electricity bill was made up of the cost of transporting electricity from the place that it was generated to the customer.[2] It is imperative that Government looks for opportunities to bear down on these costs and reduce those being passed through to consumers.

In 2009, Government introduced legislation that enables the Office of the Gas and Electricity Market Authority (Ofgem) to run a competitive process to identify the party that owns and operates electricity transmission infrastructure that connects offshore generators like windfarms to the mainland. The regime has proved a success and has brought estimated savings for consumers in excess of £800 million since 2009.[3,4]

The Government is planning to extend this competitive regime to the onshore electricity network. Introducing a competitive tender process would enable new parties to enter the market, address the information asymmetry that exists between Ofgem and the network companies it regulates and introduce for the first time direct, in-the-market competitive pressure on capital and operational expenditure on large onshore electricity network infrastructure. Government intervention is necessary because the establishment of this regime requires primary legislation.

This IA assumes that competed assets are connected at the transmission level and operated by Transmission Operators (TOs), however, the primary legislation will cover the onshore network as a whole, and will therefore also allow for assets that are connected at the distribution level to be completed and operated by Distribution Network Operators (DNOs). However, due to a lack of data on the number and value of distribution network connected assets that meet the criteria for competition, this IA does not attempt to assess the costs and benefits of extending competition to distribution network connected assets. Similarly, the legislation will allow for competition to be between network assets and solutions which require a contract for implementation (as opposed to a licence granted by Ofgem). Only Transmission-connected licensable assets are considered in this Impact Assessment due to available data and the policy position being that competition will likely be introduced for transmission-connected large assets to begin with, as alternative solutions become market-ready to be competitive with traditional solutions.

[1] The EANDCB figure differs slightly from that reported in the 2020 version of the IA and associated RPC opinion (RPC-BEIS-4464(1) 16 July 2020). This reflects the addressing of comments in the RPC opinion, including exclusion of Ofgem cost recovery through fees and the appraisal period over which the EANDCB figure has been calculated. Estimates of net direct cost to business will be revisited at the secondary legislation stage and a further IA will be submitted to the RPC for EANDCB validation. This IA might include additional costs (potentially at the distribution network level).

[2] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill. Estimate based on an average electricity bill for a typical domestic customer of the six large suppliers.

[3] https://www.ofgem.gov.uk/publications-and-updates/consultation-cepabdo-evaluation-offshore-transmission-tender-round-1-benefits

[4] 2020 prices. Original figure of £770 million (2014/15 prices) consists of the lower range (conservative) estimate of total savings for TR1, TR2 & TR3 for counterfactual #3 and can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

**What are the policy objectives of the action or intervention and the intended effects?**

The primary policy objective is to extend competitive tendering to areas of the onshore electricity network where it is efficient and cost-effective to do so, thereby bearing down on the cost of network investment to limit the costs being passed through to consumers.

Based on the experience of the offshore competition regime and taking into account tender costs incurred by Ofgem, Government estimates that the introduction of this system could, in a medium scenario, provide overall net estimated savings in the range of **£300m - £500m** (2020 prices, PV over 32 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset, allowing for scheme setup and asset construction). This is a conservative estimate of the possible benefits – in reality, the net benefits from introducing competition could be significantly higher than this, especially if many large-scale electricity transmission projects are brought forward earlier in the wake of Government's recently announced commitment to reducing carbon emissions to 78% of 1990 levels by 2035[5].

In addition, competition will help bring on new technological solutions, financial innovation and more investment in research and development. It should also encourage new players into the market and drive-up performance. It could also help identify innovative, significantly cheaper, alternatives to current network solutions put forward by regional monopoly operators, for example non-build 'market' solutions instead of traditional 'asset-build' solutions.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Four options were considered in this IA:

**Do Nothing**: The status quo remains in place: all onshore network assets continue to be built by the 'incumbent' or 'monopoly' owners of the networks in their respective regions.

**Alternative 'Do Nothing Option'**: The status quo remains in place: all onshore network assets continue to be built by the 'incumbent' or 'monopoly' owners of the networks in their respective regions. However, using existing powers, Ofgem could award licences for the construction and operation of onshore network assets without corresponding primary legislation. In order to achieve benefits associated with competition, Ofgem has already considered alternative ways in which it could introduce competition (and/or replicate its effects) under its current powers i.e. the Competition Proxy model (CPM) and Special Purpose Vehicle (SPV) model. In the case of the CPM, it was considered that this would not bring the benefits of true competition, as monopolies remain, and so costs are estimated by benchmarking against other network companies alone. In the case of the SPV model, the full benefits of competition are more difficult to achieve due to the need for the monopoly provider to run the competition and contract with the winning bidder. This risks sub-optimal outcomes as a result of inefficient running of the competition and/or allocation of risk. In addition, hurdles remain for third parties entering the market without legislation, so the benefits associated with new markets and businesses developing will not arise and subsequently Green Recovery aims are not contributed to by this option. Without a clear legal framework in place, investors may be less willing to come forward, weakening the level of competition and reducing the potential savings for consumers.

**Policy Option:** Government introduces changes to primary legislation that enable a body appointed by the Secretary of State to tender competitively licences and/or contracts for onshore electricity network assets or services where there would be a demonstrable consumer benefit from doing so, as judged by applying certain criteria to an indicative solution to solve the constraint in question, and for Ofgem to grant a relevant licence to the successful bidder. The initial expectation is to extend competition to new, high value and separable onshore electricity transmission network solutions. The changes to primary legislation will also allow for competition of licences and/or contracts relating to the onshore electricity **distribution** network. Government will ensure sufficient flexibility within the legislation to extend competition to distribution level in the future if this is in the interest of consumers. This is the preferred option.

**Alternative 'Policy Option'**: Government could introduce legislation that enables a body appointed by the Secretary of State to run tenders and award licences for the construction and operation of certain onshore network assets on a competitive basis, but mandate competition for all assets, regardless of size, newness or other criteria. Government expects this would be disproportionate and that, competitive tendering of onshore network assets will only lead to benefits for consumers in certain circumstances.

| | |
|---|---|
| Is this measure likely to impact on international trade and investment? | TBC |

5 https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035

| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
|---|---|---|---|---|
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** N/A | | **Non-traded:** N/A |
| **Will the policy be reviewed?** No. **If applicable, set review date:** | | | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

# Summary: Analysis & Evidence

Policy Option 1

**Description:**

**FULL ECONOMIC ASSESSMENT**

| Price Base | PV Base | Time Period | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| 2020 | 2022 | 32 years | **Low:** N/A | **High:** N/A | **Best Estimate:** N/A |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Cost (Present Value) |
|---|---|---|---|---|
| **Low** | N/A | | N/A | **N/A** |
| **High** | N/A | | N/A | **N/A** |
| **Best Estimate** | N/A | | N/A | **N/A** |

**Description and scale of key monetised costs by 'main affected groups'**

The expected changes to primary legislation would enable secondary legislation that would, in turn, enable a body appointed by the Secretary of State to run tenders that determine competitively the party that would be granted a licence by Ofgem to own and operate certain onshore electricity network assets or the party that would be given a contract to undertake a network solution. The primary legislation in itself would therefore not create any immediate costs: these will only take effect once the subsequent secondary legislation is in place. It is estimated that there will be costs associated with setting up the scheme and running additional tenders. While these costs are likely to be higher than the cost of regulation under 'Do Nothing', they are estimated to be outweighed by the benefits realised through competitive tendering. Under the preferred option, the body appointed by the Secretary of State to run the tenders incurs **setup costs** which we expect it will pass through to the National Grid Electricity System Operator (ESO) these are estimated to be £3m. In future some of these costs might be recouped through tender costs. The **cost of running tenders** is incurred by a body appointed by Secretary of State and passed through to the successful bidder. In the first instance, this cost is estimated to be between £0-£70m (PV of costs over 32 years). Successful incumbent transmission operators (TOs) or new entrants incur **bid costs**, which Government estimates to be between £0-£165m (PV of costs over 32 years). Based on the offshore experience, set-up, tender and bid costs (of successful bidders) are assumed to be passed through to generators / suppliers and ultimately end-consumers. The bid costs of unsuccessful bidders are assumed to remain with them; although these can be proxied using anecdotal data on total investment, this data is of insufficient quality to be used in an official assessment. Therefore, the bid costs of unsuccessful bidders have not been quantified. Additionally, the Electricity System Operator - that calculates Transmission Network Use of System (TNUoS) charges - will have to deal with more parties in the market. However, as the system operator (SO) already deals with a number of parties involved in transmission networks (three onshore TOs and a number of other operators), additional interface costs are assumed to be £0.

This IA uses Ofgem's Special Purpose Vehicle (SPV) model to quantify the range of possible benefits from opening the construction of eligible network assets or other solutions to competition. The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can **increase** by up to 10% due to inefficient implementation by the incumbent. This IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model. In the worst-case, analysis shows that a poorly designed competition can **increase the total construction costs** of tendered assets by up to **£200m** (PV of costs over 32 years, with an assumed 10-year investment period) in the scenario with the largest pipeline of eligible assets (Scenario 5). This cost is assumed to pass through to end-consumers – however, it is important to note that a poorly designed competition only serves to reduce the total net benefit to society and will not manifest as an additional cost to businesses in any scenario. This is because increased asset costs imply increased regulated revenue streams, which keeps the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. The additional construction costs end up being passed down to end-consumers as part of increased network charges via the allowed revenue system.

**Other key non-monetised costs by 'main affected groups'**

Competitive tendering would enable any successful bidder to deliver the construction or operation of selected assets or other network solutions, which may lead to new parties entering the market should they be the successful bidder. In this scenario, the incumbent TO would no longer deliver that asset and would forego return on this investment; instead, the new entrant would incur the asset/network solution costs, which would ultimately be a gain as they will earn a return on this investment. These effects have not been separately quantified for the incumbent TOs and new entrants as they depend on the success rates of either group during a competitive tender (potential upper bounds are set out in the supporting evidence).

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | N/A | | N/A | **N/A** |
| **High** | N/A | | N/A | **N/A** |
| **Best Estimate** | N/A | | N/A | **N/A** |

**Description and scale of key monetised benefits by 'main affected groups'**

The expected changes to primary legislation would enable secondary legislation that would in turn enable the competitive tendering of onshore transmission licences. The primary legislation in itself would, therefore, not create any immediate benefits; these can only be realised once the relevant secondary legislation is in place. The overall monetised benefit to society associated with extending competitive tendering is the cost saving associated with increased competition, which is likely to be more effective in a range of circumstances in revealing the true and more efficient costs of TOs than through the price control process. In terms of any benefits to the group of incumbent TOs and new entrants, this IA assumes, for simplicity, that returns on investment are unchanged between 'Do Nothing' and the 'Policy Option'. Caveats around this assumption are set out in the supporting evidence. The ultimate quantified benefits of cost savings are felt by consumers.

Extending competition to the onshore electricity network is expected to deliver savings to consumers, which analysis shows will range between **£0-£1.2bn** depending on the scenario. According to Government's central scenario (pipeline scenario 3), this intervention will deliver a net benefit to consumers of between **£300m - £500m** (PV over 32 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset, allowing for scheme setup and asset construction).

This will be achieved via a reduction in the **operating** and **construction** costs of eligible assets. Based on the operating cost savings from the offshore experience, this IA estimates that **operating** cost savings alone will range between **£0-£1bn** (PV over 32 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset, allowing for scheme setup and asset construction) across scenarios. Extending competition to the onshore electricity network is also likely to lead to non-negligible financing cost savings – however, estimating this element is difficult as a result of the very different risk profiles that bidders will face by taking on additional construction risks. Given these uncertainties, there is a large margin for error for calculating the potential financing cost savings; therefore, this IA does not attempt to quantify this benefit.

**Construction** cost savings have been estimated using Ofgem's SPV model, which assumes that construction costs of tendered assets can decrease by up to 10% in an efficiently run competition – though the model also stipulates that a poorly run competition can **increase** construction cost by up to 10% in the worst-case scenario. The analysis shows that construction costs savings are estimated to amount **up to £200m** (PV of costs over 32 years, with an assumed 10-year investment period) in the scenario with the largest pipeline of eligible network assets (Scenario 5) with an efficiently run competition.

**Other key non-monetised benefits by 'main affected groups'**

Introducing competition can bring many wider non-monetised long-term innovation benefits to society beyond the monetised reduced cost of investment in assets over time. These include new technological solutions being brought forward and more investment in research and development. These will in turn drive costs down in the long run for the industry overall. Reduced barriers to entry will mean that new parties may enter the market, while incumbent TOs will incur lower transmission asset costs (either due to not being appointed as the successful bidder or due to experiencing more efficient costs through competitive pressures). These effects have not been separately quantified for incumbents and new entrants as they depend on the success rates of either group during competitive tendering. Furthermore, there are also benefits due to reduced costs of price control regulation for Ofgem and incumbent TOs. However, Ofgem has advised that it is not possible to estimate these costs in isolation.

| Key assumptions/sensitivities/risks | Discount rate (%) | 3.5% |
|---|---|---|

A full list and detailed explanation of assumptions underpinning the monetised costs and benefits, risks and sensitivity analysis is included in the main body of this IA in the 'Assumptions and Risks' section.

Key assumptions for quantifications include:

- 3.5% discount rate, discounted to 2022.
- **2020 price base**: unless stated otherwise, all prices in this IA are quoted using the 2020 price base. To avoid any confusion resulting from the large number of different sources using varying price bases, all prices quoted in this IA have been converted to a 2020 price base, where possible. The original figures have been included in the footnotes for ease of sourcing.
- There is no end date to the proposed 'Policy Option'. Therefore, the IA assumes that assets are tendered over the next 10 years, with benefits considered over 20 years for each asset.
- This IA assumes that setting up the scheme will take at least 2 years, tendering will take at least 1 year, and construction will take up to 3 years per asset. Asset operation is therefore assumed to start in the 7th year.
- Pipeline scenarios of eligible projects in the future are approximated by considering historic information on Transmission Investment for Renewable Generation (TIRG) and the Transmission Investment Incentives (TII) framework over the Transmission Price Control Review 4 (TPCR4) from 2007/08 to 2012/13. The pipeline scenarios also reflect the levels of investment that has occurred over the RIIO-T1 (via the Strategic Wider Works (SWW) investment mechanism) and ED1 price control regimes.
- The pipeline scenarios assume that a set of criteria will be adopted that will identify the assets suitable for tendering. The best available information at the time of writing this IA, in line with Ofgem's Integrated Transmission Planning and Regulation (ITPR) final conclusions[1], is that these assets will be new, high-value (i.e. over £100m expected capital value), and separable.
- Tender costs are based on a 1% of asset value, which is an Ofgem estimate based on the offshore experience.
- Bid costs of successful bidders (which include preparing bids for evaluation, reaching the licence grant and acquiring the asset) are assumed to be 2.4% of asset value and are based on the 'Evaluation of OFTO Tender Round 2 and 3 Benefits' report by Cambridge Economic Policy Associates (CEPA) and on internal discussions with Ofgem. Bid costs of unsuccessful bidders (which only refer to the preparing of bids for evaluation) have not been quantified.
- The operating cost percentage savings experienced in the offshore regime and the price control counterfactual, as set out in the CEPA report, have been applied to asset values in this IA.
- Two different versions of the operating cost pathways are used: a "central" set and a "pessimistic" set. The lower starting premium of the "pessimistic" is supposed to reflect the (extremely unlikely) scenario where all assets in the pipeline are of the smallest possible size that is expected to be eligible for competition (valued at £100m), which could limit the range of possible operating cost savings. **Government believes that the inclusion of the 'pessimistic' pathways for Opex in the range of results risks significantly understating the benefit to society** that can be gained from increased competition. Therefore, only the "central" set of pathways are used to derive the final cost saving figures in this IA; the "pessimistic" set is only used as a sensitivity to test the robustness of the results.
- Finance cost percentage savings have not been quantified as part of this IA.
- The CEPA report points out that there are limits to the extent to which lessons for the onshore network can be drawn from results in the offshore network whilst also asserting the OFTO approach offers lessons for structuring other contestable infrastructure opportunities. Results in the offshore network, for example, are context and time-specific, and there are real-world, technological differences between on- and offshore transmission assets. However, while savings in the onshore network are likely to be driven by different factors, Government believes that it is reasonable to assume that the overall levels of saving in operational expenditure under competition will be comparable across the onshore and offshore regimes.

This IA assumes that competed assets are connected at the **transmission level** and operated by Transmission Operators (TOs). However, primary legislation is expected to cover the onshore network as a whole and will therefore also allow for competition for network assets that are connected at the **distribution level** (and thus operated by Distribution Network Operators, DNOs). However, due to a lack of data on the number and value of distribution network connected assets that meet the criteria for competition, this IA does not attempt to assess the costs and benefits of extending competition to distribution network connected assets.

**BUSINESS ASSESSMENT (Option 1)**

| Direct impact on business (Equivalent Annual) £m: | | | Score for Business Impact Target (qualifying provisions only) £m: |
|---|---|---|---|
| **Costs: £9.5m** | **Benefits: £0** | **Net: -£9.5** | TBC |

[1] Ofgem, 'RIIO-2 Sector Specific Methodology – Core Document', published May 2019, https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodology_decision_-_core_30.5.19.pdf, pp. 89 & 91.

# Contents

## Results of the Cost Benefit Analysis of the proposed intervention

### Net Cost / Benefit Estimates: 'Policy Option' vs 'Do Nothing' option

1. This section presents the key findings of the full cost benefit analysis of the proposed policy intervention (the 'Policy Option' versus the 'Do Nothing' option). A brief summary of the methodology used to derive these estimates is provided below. For a more detailed overview of the underlying assumptions and their associated risks, please refer to the '*Monetised and non-monetised costs and benefits of each option*' section of this IA (pp. 26-51).
2. These costs and benefits are classified as **direct impacts at the secondary legislation stage** as they are expected to result directly from the implementation of secondary legislation.
3. The GB onshore network consists of both high voltage electricity transmission and lower voltage distribution systems. The proposed changes to primary legislation will cover the entire onshore network, both transmission and distribution. However, this IA **only captures assets are connected at the transmission level** and operated by Transmission Operators (TOs) and does not include assets that are connected at the distribution level and operated by Distribution Network Operators (DNOs). This is for two reasons:
    a) Distribution connected assets tend to be smaller in size/value and therefore there is some uncertainty as to how the "high value" would be defined if this were used as a criterion – at the transmission level the expectation is that this would be defined as being over £100m in expected capital value and it is anticipated that indicative solutions to constraints at hand would need to meet this and two other requirements to be eligible for tendering – the other two being that assets need to be "new" and "separable"; and
    b) There is a general lack of readily available data that could be used to accurately estimate the number and total value of distribution network connected assets that meet the expected criteria for competition.
4. Therefore, this IA quantifies the expected net benefit from extending competition to the GB **transmission network only**. In doing so, <u>this IA is very likely underestimating the overall net benefit to society from this intervention</u>. Distribution network impacts will be quantified if the Secretary of State considers it appropriate to include distribution assets in regulations setting criteria for assets to be subject to competition.
5. The focus of this IA is to quantify the benefits of competing out licensed transmission-level assets. In doing so, it omits the potential benefits of introducing contracted out services and flexible network solutions on both the transmission and distribution level. This reflects the policy position that competition will most likely be introduced for transmission-connected large assets to begin with, as alternative solutions become market-ready to be competitive with traditional solutions. In effect, this means that this IA potentially underestimates the overall benefits that could materialise from the introduction of competition in the electricity networks sector.
6. The quantifications presented here **are approximations and ranges of potential costs and benefits**. They are intended to provide a sense of scale rather than precise costs and benefits which Government expects from competition. It is inherently difficult to predict with any accuracy the potential efficiency benefits that introducing a competitive process might bring, given the many uncertainties around the project pipeline, and the fact that examples of the use of competition in transmission delivery are context specific. It is also difficult to quantify meaningfully the dynamic benefits of competition, such as the scope for increased innovation and the introduction of new products, services and technologies.
7. The creation of a new competition regime for GB's onshore electricity network is expected to lead to a significant net benefit to society, through cost savings that will eventually be passed

down to consumers. This IA quantifies **two types of benefits** that are expected to materialise under increased competition:

a) Lower operating costs (or 'operating/Opex cost savings'); and

b) Lower construction costs (or 'construction/capital/Capex cost savings'). These lower costs are assumed to materialise if the competition regime is set up and managed well. However, this IA explicitly factors in the risk that **a poorly managed competition may in fact lead to increased construction costs** versus the price control counterfactual.

8. As well as quantifying two distinct types of benefit, the new competition regime will entail some administrative costs that will also be passed down to consumers. For the purposes of this IA, **four types of costs** were quantified:

a) Set-up costs – the one-off costs associated with creating the competitive regime;

b) Tender costs – the costs associated with running a particular competitive tender;

c) Bid costs – the costs of bidding into a particular competitive tender; and

d) Increased construction costs – this is a special cost that materialises only in the (very unlikely) event of a **poorly managed competition** regime. If the regime is managed well, it is expected that overall construction/capital costs will decrease. If it is managed moderately well, there is no change to the overall construction costs of tendered assets.

9. Much of this IA relies on the findings from the offshore transmission asset experience, assessed in the CEPA report on Tender Rounds 2 and 3 of Ofgem's offshore transmission owners ('OFTO') licensing regime[1]. The expected benefits to society from increased competition in the GB onshore network are estimated against **a price control counterfactual** from the CEPA report where the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime. In the CEPA report, this is outlined as "Counterfactual 3", and is the most comparable counterfactual to the 'Do Nothing' option, as well as being the conservative counterfactual.

## Methodology: estimating operating (Opex) cost savings

10. The IA's approach to quantifying operating cost savings is based around applying a set of possible operating cost savings pathways to a pipeline of network assets. These pipelines are supposed to represent the total value of future onshore network assets/investments that would meet the expected eligibility criteria for competition – a total of 5 pipeline scenarios are considered, reflecting uncertainty around both the size of future investment in the GB onshore network and the nature of the assets in that pipeline – i.e. whether they will meet the expected eligibility criteria for competition. More detail on the pipeline scenarios and how they were derived can be found in the '*Monetised and non-monetised costs and benefits of each option*' section of this IA (pp. 26-49).

11. The IA uses a set of operating cost 'pathways' (derived from the CEPA report on Tender Rounds 2 and 3) to estimate the range of possible operating cost savings that would be expected to materialise under increased competition.

12. The basic premise behind these 'pathways' is that **there is uncertainty regarding the effectiveness of future price discovery by the regulator** (Ofgem, via its periodic regulated price controls) and its ability to drive down incumbent costs towards the 'true' market value under the 'Do Nothing' counterfactual:

a) Pathway 5 represents the most 'optimistic' version of the counterfactual, where Ofgem is relatively efficient at discovering the 'true' market price of operating the new asset

[1] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

via its regulatory toolkit, and thus manages to force the incumbent operator to decrease their overall operating costs through successive price control reviews. The regulator eventually succeeds in eliminating all operating costs in excess of the 'true' market value by the end of the lifetime of the asset – i.e. after four successive price control periods (which are assumed to last 5 years for simplicity).

b) Pathway 4 represents a slightly more pessimistic version of the counterfactual, where Ofgem is able to gradually decrease the excess operating cost of the asset, but there still remains a small difference ('premium') versus the true market value by the end of the lifetime of the asset due to less efficient price discovery.

c) Pathway 6 represents the most pessimistic version of the counterfactual, where Ofgem is inefficient at price discovery and is unable to force the incumbent operator into reducing excess operating costs at all.

13. **Two different versions of the above three operating cost pathways are used** (see tables 9 and 10): a "central" set and a "pessimistic" set. The "central" set (**pathways 4 – 6**, shown in Chart 1 below, **orange lines**) have been derived from the CEPA report on OFTO Tender Rounds 2 and 3. The "pessimistic" set (also shown in Chart 1 below, **blue lines**) are constructed in the same way as pathways 4 – 6, but have a lower starting premium. This lower starting premium is supposed to reflect the (extremely unlikely) scenario where all assets in the pipeline are of the smallest possible size that is expected to be eligible for competition (valued at **£100m**), which could limit the range of possible operating cost savings. This is based on the finding by Frontier Economics that operating cost savings are dependent on asset size and can be as low as **1%** of the value of the asset.[2] It is important to note however that such a scenario is extremely unlikely – large-scale transmission projects are often worth many hundreds of millions of pounds.

14. For each set of pathways, the mean 'premium' is taken from all three pathways in each year. This mean value is then applied to the relevant asset pipeline scenario to calculate the mean expected operating cost saving for that year. This is repeated for every year of operation (this IA assumes a 20-year operating lifetime per project).

15. Chart 1 below shows the expected operating cost **premia** vs the price control counterfactual for each pathway group. If a pathway reaches 0%, this means that its operating costs are identical to those under the price control counterfactual (which is equivalent to 'Do Nothing'). Therefore, the higher the premium, the higher the positive difference (i.e. benefit) vs the price control counterfactual scenario.

16. Due to the extreme nature of their underlying assumptions, the "pessimistic" pathways are not used to derive the estimates of operating cost savings presented in this IA. **Only the "central" set of pathways are used.** The "pessimistic" pathways are only applied as a sensitivity to test the robustness of the Opex savings estimates.

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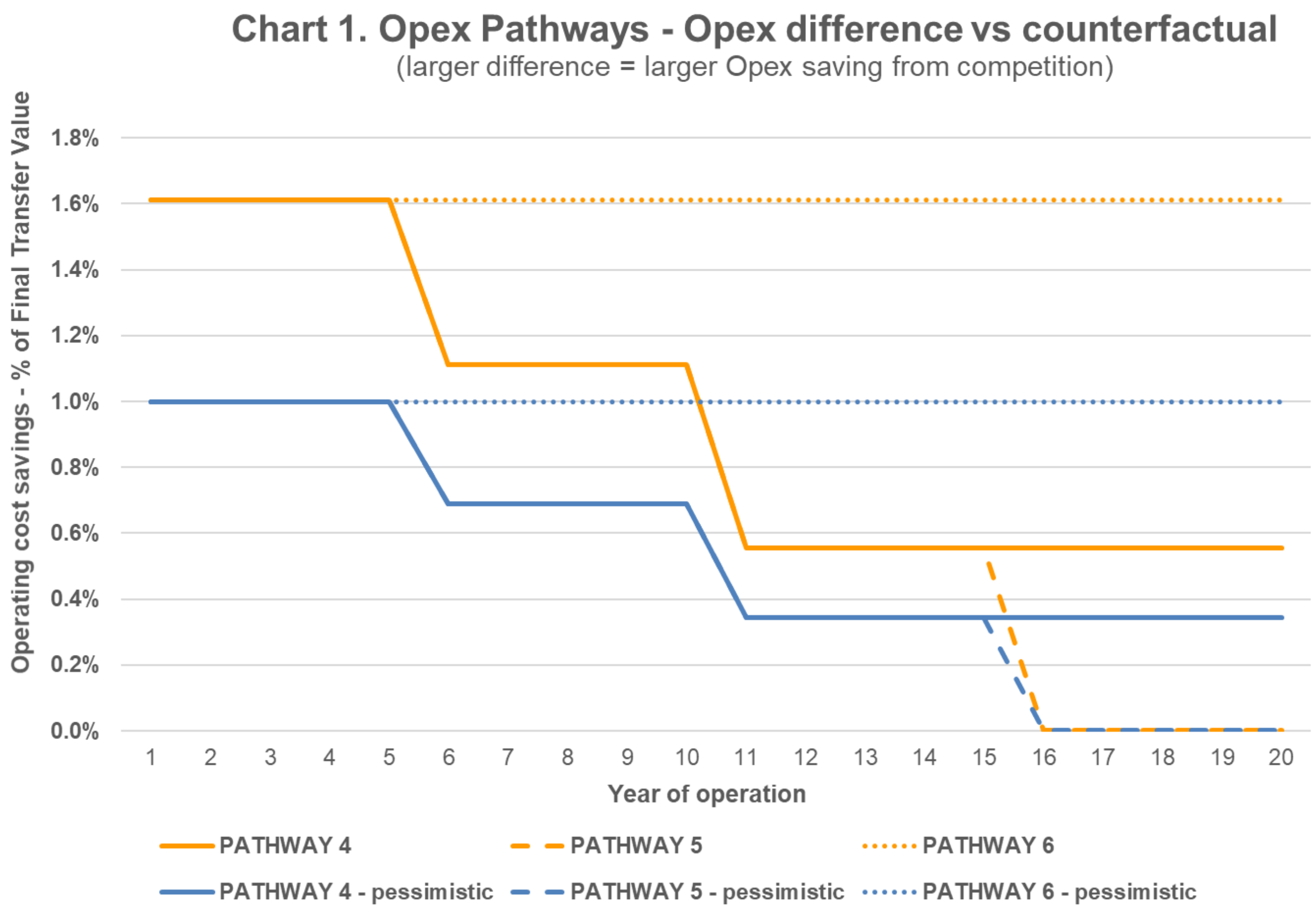
[2] Frontier Economics, 'A cost benefit analysis of the potential introduction of competitively appointed transmission operators', published January 2016, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf, p. 53




## Methodology: estimating construction (Capex) cost savings

17. To estimate capital savings, we use evidence from Ofgem's SPV model. Analysis conducted by Ofgem assumes construction cost savings can amount to **10%** of the value of the asset for an efficiently run competition.[3] The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can increase by up to 10% due to inefficient implementation by the incumbent. This IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model.

18. As a sensitivity, we have included two further Capex savings scenarios where the capital saving from competition is **0%** (i.e. no net benefit) and **-10%** for a poorly managed competition. This sensitivity aims to account for the increased construction risks that could be borne by new entrants versus an incumbent TO – though it must be stressed that the latter scenario (of a 10% increase in construction costs) is highly unlikely, as the tenders would be run by an independent party that is incentivised to ensure a successful and efficient tender.

[3] Ofgem, 'Hinkley-Seabank project: minded-to consultation on delivery mode', published January 2018, table 3.3, https://www.ofgem.gov.uk/ofgem-publications/127841, p. 28

**Results of cost benefit analysis**

19. Table 1 below summarises the estimated direct net monetised benefit to business in NPV terms across five scenarios. The scenarios demonstrate the likely scale of potential costs and benefits. Note that not all costs and benefits could be quantified (as set out in detail in the section ‘Monetised and non-monetised costs and benefits of each option’).

20. The quantified direct net cost to business is in the range of £3m to £235m (PV) over the appraisal period of 32 years, with a central estimate of £120m (PV). Note that while some businesses, namely TOs and new entrants, incur the direct expenditure, they will pass these costs onto other businesses, namely generators and suppliers (indirect cost), which ultimately pass them on to end-consumers, which includes business consumers (indirect cost).

21. Table 2 below presents the quantified direct net benefit to society of the proposed intervention versus a price control counterfactual (‘Do Nothing’ scenario). The overall net benefit to society across all 5 pipeline scenarios is in the range of **-£3m to £1.0bn** (NPV over 32 years, see Table 2).

22. The net benefit to society under the central scenario (pipeline scenario #3) is estimated to range between **£300m – £500m** (NPV over 32 years). Chart 2 below illustrates the magnitude of the various costs and benefits that could materialise depending on what scenario on construction costs (a ‘well managed’ vs a ‘poorly managed’ competition) is realised.

23. Scenario 3 represents a conservative estimate of the possible benefits – in reality, the net benefits from competition could be significantly higher, especially if many large-scale electricity transmission projects are brought forward earlier. The latter is made more likely by the Government’s recently announced commitment to reducing emissions to 78% of 1990 levels by 2035[4], in line with the Committee on Climate Change’s (CCC) recommendation in Carbon Budget 6.[5]

24. In order to meet these targets, significant investment in networks will be necessary. We recognise that network companies have already been taking steps towards increasing efficiencies and driving innovation when making this type of investment. However, given the scale of change that is required for Net Zero and the level of investment that is required, we see competition as providing a clear opportunity to further drive efficiencies and ensuring the best price for consumers.

25. All of these costs and benefits will be incurred as a consequence of secondary legislation. None of these costs or benefits relate directly to the primary legislation associated with this IA.

[4] UK Government, https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035

[5] The CCC, https://www.theccc.org.uk/publication/sixth-carbon-budget/

**Table 1: Quantified Net Direct Cost/Benefit to Business, NPV over 32 years, £m, 2020 prices (discounted to 2022)**

| NPV (£2020m, discounted to 2022) | | Scenario 1 | Scenario 2 | Scenario 3 | Scenario 4 | Scenario 5 |
|---|---|---|---|---|---|---|
| **Benefits** | **Total quantified benefits** | **-*** | **-*** | **-*** | **-*** | **-*** |
| **Costs*** ** | Bid costs of appointed incumbent TOs or new entrants | £0m | £50m | £80m | £95m | £165m |
| | Set-up and tender costs (Ofgem/appointed body pass through) | £3m** | £20m | £40m | £45m | £70m |
| | Additional interface costs for the SO | £0m | £0m | £0m | £0m | £0m |
| | Costs due to delay risk | £0m | £0m | £0m | £0m | £0m |
| | **Total quantified costs** | **£3m** | **£70m** | **£120m** | **£140m** | **£235m** |
| **Total cost/benefit to business** | | **-£3m** | **-£70m** | **-£120m** | **-£140m** | **-£235m** |

* Benefits for businesses are zero as the analysis assumes that reduced asset costs imply reduced revenue streams, therefore keeping the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. Should the competitive tender regime provide better or more stable returns, or should businesses outperform anticipated cost structures as set at the time of the tender by more than under 'Do Nothing', businesses would experience a benefit. In addition, businesses experience a benefit through lower cost of regulation under the RIIO price control (their own and the appointed body's costs decrease); however, these could not be quantified in this IA.

** In Scenario 1, the appointed body's set-up costs are fully recovered through the licence fee (paid by the ESO) (direct cost). In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost).

*** In the event that a poorly managed competition leads to increased construction costs, the additional cost will of course reduce net social welfare. However, **the additional costs for businesses as a result of a poorly designed competition will be nil**, as increased asset costs imply increased (regulated) revenue streams, which keeps the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. The additional construction costs simply end up being passed down to end-consumers as part of increased network charges via the allowed revenue system.

Note: All estimates are rounded.

**Table 2: Quantified Net Direct Cost/Benefit to Society, NPV over 32 years, £m, 2020 prices (discounted to 2022)**

| NPV (£2020m, discounted to 2022) | | Scenario 1 | Scenario 2 | Scenario 3 | Scenario 4 | Scenario 5 |
|---|---|---|---|---|---|---|
| Benefits * | Consumer cost savings | £0m | £240-360m | £420-630m | £480-730m | £835-1,265m |
| | **Total quantified benefits** | **£0m** | **£240-360m** | **£420-630m** | **£480-730m** | **£835-1,265m** |
| Costs | Bid costs of appointed incumbent TOs or new entrants | £0m | £50m | £80m | £95m | £165m |
| | Set-up and tender costs | £3m | £20m | £40m | £45m | £70m |
| | Costs due to delay risk | £0m | £0m | £0m | £0m | £0m |
| | Additional interface costs for the SO | £0m | £0m | £0m | £0m | £0m |
| | **Total quantified costs** | **£3m** | **£70m** | **£120m** | **£140m** | **£235m** |
| **Total cost/benefit to society*** | | **-£3m** | **£170-290m** | **£300-510m** | **£340-590m** | **£600-1,030m** |

Note: All estimates are rounded.
*The uncertainty around construction cost savings means that the consumer cost savings and thus benefits to society need to be shown as a range of possible values. The range of benefits is based on the estimated operating cost savings (based on pathways 4-6) and the three modelled construction cost (capex) savings scenarios assumed under the SPV. The lower value of a range shows the net benefit to society assuming a poorly managed competition that leads to increased capital costs (-10% capex saving), while the upper range assumes an efficiently run competition that leads to significant reductions in capital costs (10% capex saving).

26. Government believes that the inclusion of the 'pessimistic' pathways in the range of results risks significantly understating the benefit to society that can be gained from increased competition. The estimates presented in this IA include several other sensitivities that already factor in optimism bias – i.e. the use of CEPA's pathways 4-6 instead of the more optimistic pathways 1-3 and the inclusion of a scenario where asset construction costs increase by 10% as a result of a poorly designed competition. The latter scenario is very unlikely to materialise, but it is necessary to include due to the lack of concrete data on construction cost savings. The data on operating cost savings on the other hand is much more robust as it is based on extensive data and analysis of the OFTO experience.

27. As an illustration, the use of the 'pessimistic' pathways reduces the lower bound of the net benefit to society under the central scenario (pipeline scenario #3) by ~£200m – from a range of **£300m – £500m** down to **£100m – £500m**. In the very unlikely event that all tendered assets are no larger than ~**£100m** in value, the associated operating cost savings – though much reduced compared to the central case – still result in a large net benefit to consumers, to the tune of hundreds of millions of pounds (see chart 4).

28. Charts 3 and 4 illustrate the range of benefits to society across all 5 pipeline scenarios. Chart 3 shows the size of the total savings using the central operating cost assumptions (pathways 4-6, central case), while chart 4 uses the 'pessimistic' versions of pathways 4-6. It is clear that the overall benefit to society from increased competition in onshore networks will be very substantial in all but one pipeline scenario even in the event of pessimistic scenarios materialising.

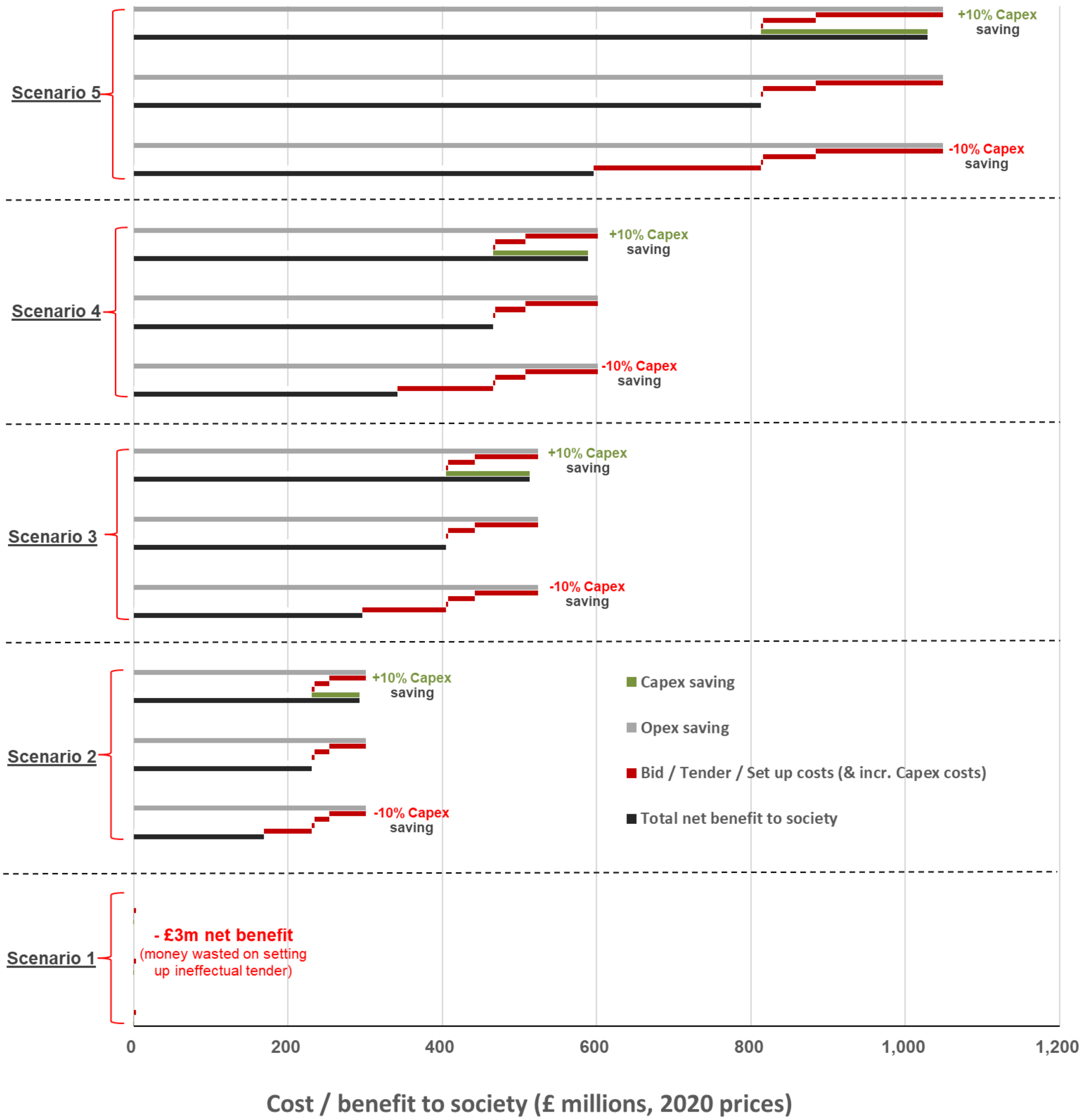
29. Table 3 below presents the range of possible savings per project that are likely to materialise under the 'Policy Option.' Our analysis shows that the introduction of competition in the onshore network is expected to yield savings to the tune of **9% – 16%** per project over a 20-year period. This range includes operating cost savings only. With the addition of construction costs, we expect to see **7% – 19%** savings on a per project basis. The lower bound of the latter range represents the unlikely scenario where construction costs are 10% higher than under 'Do Nothing' due to a poorly managed competition.

**Table 3: Range of expected savings from increased competition depending on pathway and scenario, on a per project basis**

| | Capex savings scenario | | |
|---|---|---|---|
| | Poorly managed competition (-10%) | No net Benefit (0%) | Efficiently run competition (10%) |
| Pathway 4 | 8% | 11% | 13% |
| Pathway 5 | 7% | 9% | 12% |
| Pathway 6 | 14% | 16% | 19% |
| Pathway 4 - pessimistic | 4% | 7% | 9% |
| Pathway 5 - pessimistic | 3% | 6% | 8% |
| Pathway 6 - pessimistic | 8% | 10% | 13% |

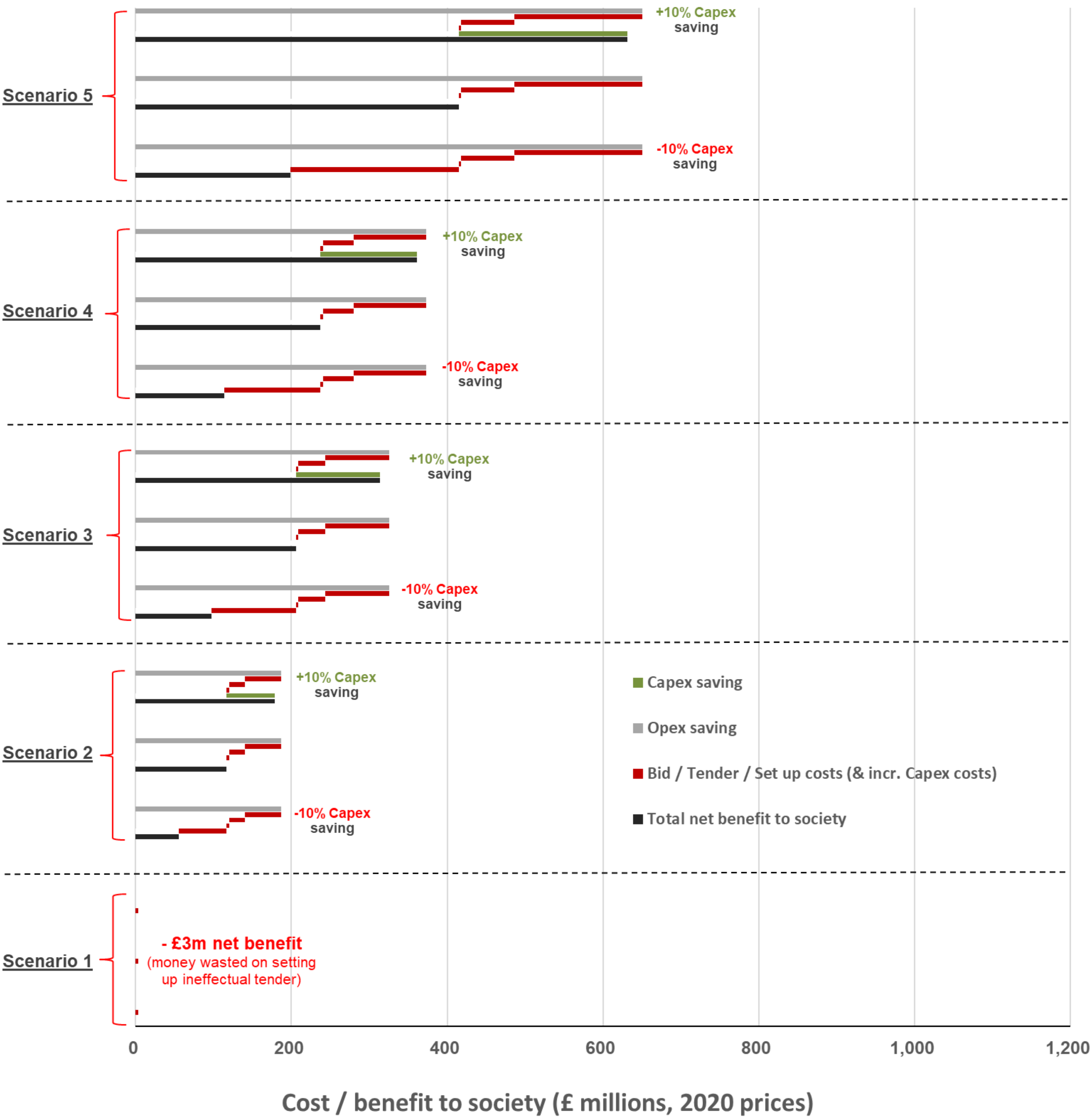
Notes: 1. These use NPV savings figures over a **20-year** period of operation per project. This IA assumes a project lifetime of 20 years.
2. These don't include any costs associated with the tendering or bidding process (which aren't very meaningful in a per project basis on account of their small relative size – about 0.5-2.4% of asset Capex per project).

Chart 3. Pipeline scenarios 1-5: Opex CENTRAL CASE
range of estimated benefits (NPV over 32 years)



## Chart 4. Pipeline scenarios 1-5: Opex PESSIMISTIC (sensitivity)

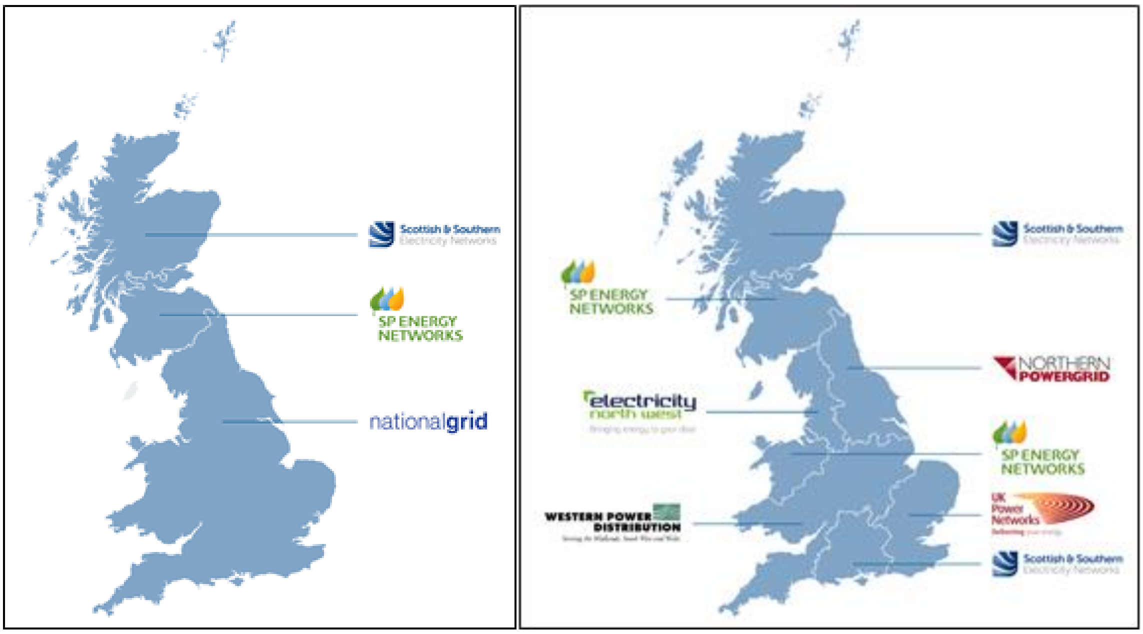
range of estimated benefits (NPV over 32 years)



## Background and problem under consideration

30. Great Britain's electricity network is a mixture of high and low voltage infrastructure that conveys electricity through Great Britain, her territorial seas and the wider Renewable Energy Zone. It consists of three integrated transmissions networks (each owned by one of three transmission operators - TOs) and fourteen integrated distribution networks (owned by six distribution operators – DNOs). The TOs and DNOs are responsible for maintaining, reinforcing, and extending their network which is geographically limited in scope (see figure 1). Licences granted to the network operators by Ofgem set out their responsibilities, obligations and, ultimately, their allowed revenues. The System Operator (SO) is responsible for directing and coordinating the flow of electricity across the National Electricity Transmission System (NETS) and works with the three TOs to ensure this happens.

**Figure 1: Electricity transmission (left) and distribution (right) network owners in the GB mainland**




## Onshore electricity transmission and distribution – regional monopoly regime

31. There are nine electricity network operators in mainland GB. At the transmission level: National Grid Electricity Transmission (NGET) in England and Wales, Scottish Power Transmission (SPT) in the south of Scotland, and Scottish Hydro Electric Transmission (SHE-T) in the north of Scotland. At the distribution level: Scottish Hydro Electric in the north of Scotland and the south coast of England, Scottish Power Energy Networks (SPEN) in the south of Scotland, Merseyside and north Wales, Northern Power Grid (NPG) in Northumbria and to Hull, Electricity North West (ENW) for Cumbria, Western Power Distribution (WPD) for the midlands, South Wales, Devon and Cornwall, and UK Power Networks (UKPN) for the South East, London, Kent and the east Midlands.

32. The Electricity System Operator, a legally separate entity within the National Grid Group, provides the role of SO across the NETS. The network owners operate as monopolies in their geographically-defined network regions. Because they are monopolies, Ofgem[1], as the network regulator, seeks to ensure value for money for consumers through price control regulation, which

[1] https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

serves to limit the amount of allowed revenue that a network company can take over the length of a price control period. The network companies recover their allowed revenues through charges to generators and suppliers who in turn pass them through to customers. Allowed revenues are set at a level which covers the companies' costs and allows them to earn a reasonable return, subject to them delivering value for consumers, behaving efficiently and achieving their targets.

33. Ofgem agrees the price control for a particular network company by setting a revenue cap for the business, based on the size of its asset base and its projected investment over the period of the price control. The revenue cap will take account of the operating cost of the asset base, depreciation, tax, the development work and investment the company intends to take forward, and the cost of capital of maintaining and developing the network. Once the revenue cap has been set, the network company is responsible for running its business and meeting its licence and statutory obligations (which include maintaining an efficient, coordinated and economic system)[2] within the limits of that cap. They can also benefit (or suffer) from over-performing (or underperforming) against Ofgem's cost estimates.

34. The previous price control for onshore electricity transmission networks, 'RIIO-T1'[3], ran from 2013-2021 and for electricity distribution, 'RIIO-ED1', is currently running for 2015-2023. In some cases, investment in the system need only be taken forward if certain projects are undertaken. Because there was uncertainty when finalising the RIIO-T1 price control regimes about the timing of and need for such projects, network companies were able to bring forward certain high-value[4] projects for regulatory approval through the so-called 'Strategic Wider Works' process. This helps to ensure that transmission assets are in place to connect new, large generation projects (for example), while also ensuring that investments are in the interest of existing and future consumers. Ofgem set out that projects brought forward under the SWW regime could be subject to competition.[5]

35. The SWW regime was a mechanism that allows Transmission Owners (TOs) to bring forward large investment projects that were not part of the RIIO-T1 price control settlement. It has been used by Ofgem to regulate the delivery of several such projects, ensuring that they are implemented efficiently.[6] However, the SWW did not introduce competition to project delivery, as the incumbent TO is expected to deliver the project under the mechanism. For RIIO-T2, SWW has been replaced by Large Onshore Transmission Investments (LOTI), which also does not introduce competition to project delivery.

36. Ofgem started the 'Extending Competition in Transmission' project in 2015 to consider the most appropriate ways to introduce competition into onshore electricity transmission networks. The project initially focussed on the CATO (Competitively Appointed Transmission Owner) model[7], which involves the award of a licence to a party following a competition run by an independent party. The CATO model considered both 'late' (post planning consent) and 'early' (pre planning consent) competitions. Development of the CATO model was paused in 2017 following delays to the introduction of enabling legislation. In mid-2017 Ofgem developed the Special Purpose Vehicle (SPV) model as an alternative mechanism that allows Ofgem to introduce competition to the delivery of large onshore electricity transmission projects. Under the SPV model, the

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[2] Section 9(2) (a) of the Electricity Act 1989 states that transmission licensees have a duty to "develop and maintain an efficient, co-ordinated and economical system of electricity transmission".

[3] The RIIO T1 price control (Revenues = Incentives + Innovation + Outputs) ran from 1 April 2013 to 31 March 2021.

[4] The onshore TOs each have a different threshold value level for Strategic Wider Works: NGET=£500m; SPT=£100m; SHE-T=£50m. See: Ofgem, 'SWW Guidance (Version 2)', published October 2013, https://www.ofgem.gov.uk/publications-and-updates/guidance-strategic-wider-works-arrangements-electricity-transmission-price-control-riio-t1-0, p. 23

[5] See 'Competition Assessment' in Ofgem, 'Strategic Wider Works FAQ', published December 2013, https://www.ofgem.gov.uk/publications-and-updates/strategic-wider-works-faq

[6] Ofgem, 'Strategic Wider Works – Delivery of large onshore electricity transmission projects', https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works

[7] Ofgem, 'Quick Guide to the CATO Regime', published November 2016, https://www.ofgem.gov.uk/publications-and-updates/quick-guide-cato-regime-november-2016

incumbent TO would run a tender to appoint an SPV to finance and deliver a project on its behalf through a contract in effect for a specified revenue period – usually covering the period of its construction and 25 years of operation.[8]

37. Ofgem have regularly reviewed the arrangements for planning and delivery of onshore electricity transmission networks in GB.[9] In September 2018, Ofgem published an Impact Assessment on applying the SPV model to future new, separable and high value projects, which concluded that the application of the SPV model could lead to potentially significant savings for consumers, although those savings were not likely to be as large as under the proposed CATO model.[10] In mid-2019 Ofgem published its decision to seek to apply competition (whether under the CATO, SPV or Competition Proxy Models) to new, separable and high value electricity transmission projects coming forward under the RIIO2 price control period. In December 2020 Ofgem published its Sector Specific Methodology Decision outlining its decision to use the same criteria to identify projects that may be suitable for late model competition across all sectors, including electricity distribution over the RIIO-ED2 price control period.[11]

### Offshore transmission – competitive delivery

38. Offshore transmission concerns the transmission of electricity from an offshore generating station such as a wind farm to the mainland grid[12]. Increasing levels of offshore wind generation in the past decade created a need for a process to identify the party that would be responsible for owning and operating these connections. The Energy Acts of 2004 and 2008 amended the Electricity Act 1989 to enable Ofgem to run a competitive process to identify the party to be awarded a licence for this purpose. Such licensees – offshore transmission owners – are known as 'OFTOs'.

39. The first competitive tender for an offshore connection was launched in July 2009. Interested parties submit bids to purchase, maintain, operate, and receive a regulated return from an offshore transmission asset for 20 to 25 years[13]. To date, the competitive tender regime has granted 21 licences to transmission assets worth approximately £6 billion[14]. A further 25 projects, worth approximately £22 billion, are also in the pipeline[15].

40. In May 2014, an independent report commissioned by Ofgem[16] found that in the first tender round, which consisted of nine projects and £1.1 billion[17] worth of investment, the competitive offshore transmission regime generated savings of £280-£540 million[18] against any other plausible counterfactual regime. In March 2016, a subsequent independent report commissioned

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[8] Ofgem, 'Impact Assessment on applying the Special Purpose Vehicle model and Competition Proxy model to future new, separable and high value projects', published September 2018, https://www.ofgem.gov.uk/publications-and-updates/update-extending-competition-transmission-and-impact-assessment, p. 2

[9] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission

[10] Ofgem, 'Update on Extending Competition in Transmission and Impact Assessment', published September 2018, https://www.ofgem.gov.uk/publications-and-updates/update-extending-competition-transmission-and-impact-assessment

[11] OfGem, 'RIIO-ED2 Sector Specific Methodology Decision', published December 2020, https://www.ofgem.gov.uk/publications-and-updates/riio-ed2-sector-specific-methodology-decision

[12] Note that offshore transmission is distinct from cross-border transmission. The latter relates to the high-voltage lines that link the National Electricity Transmission System (NETS) with transmission systems in other countries.

[13] The most recent tender round, TR6, has extended the operational period to 25 years to reflect technological developments in the sector.

[14] Unclear price base. Sourced from: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders

[15] Unclear price base. Sourced from a combination of OfGem's OFTO website: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders and NGESO's TEC register: https://data.nationalgrideso.com/connection-registers/transmission-entry-capacity-tec-register

[16] CEPA/BDO, 'Evaluation of OFTO Tender Round 1 Benefits', published May 2014, https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf

[17] Unclear price base. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', Figure 4.1, published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, p. 12

[18] 2020 prices. Original figures (2014/15 prices) were in the range of £245-470 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', Table C.1, p. 68

by Ofgem[19] found that in the second and third tender rounds, with six projects and around £1.7 billion worth of investment, the generated savings were in the £490-£860 million range[20].

41. The 2016 report considers five counterfactual cases, and identifies, for example, £600 million of NPV savings (excluding tax) against a counterfactual where capital costs were low, and the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime (Counterfactual 3).[21] These savings were split broadly equally between the financing and operation of the assets. The report notes that competitive tendering led to savings through innovation and different contracting approaches. The report concludes that the offshore tendering approach offers lessons for structuring other contestable infrastructure opportunities.

[19] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits'

[20] 2020 prices. Original figures (2014/15 prices) were in the range of £425-750 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', tables 6.1 & 6.2, pp. 36-38

[21] 2020 prices. Original figure (2014/15 prices) amounted to £526 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', tables 6.1 & 6.2, pp. 36-38

### The problem under consideration

42. Government believes that there would be benefit in introducing a competitive process for the allocation of licences and or/ contracts for onshore electricity networks. However, because the current legislative framework only allows for the competitive allocation of licences for offshore transmission, primary legislative change is needed.

## Rationale for intervention

43. In the coming years, significant investment will be needed in the electricity network to support the increased electricity demand and renewable generation needed to meet our Carbon Budget targets and achieve Net Zero, in a way that is secure, sustainable and affordable and value for money for consumers. Approximately a fifth to a quarter of the typical household electricity bill in 2019 was made up of the cost of transporting electricity from the place that it was generated to the customer[22]. Government is committed to looking for opportunities to bear down on these costs and reduce those being passed through to consumers. The experience of competitive delivery of offshore licences shows that significant savings can be made through a competitive approach to network solution delivery.

44. Competition can drive companies to rationalise costs, increase efficiency and improve productivity. Competition can also encourage access to a wider and more diverse pool of labour across different organisations, as well as promoting innovation. Access to more sources of capital can provide timely investment, and natural competitive drivers can lead to lower pricing for goods and services.

45. Government has sought to promote competition in other parts of the energy market. The outcomes of the third round of the Contracts for Difference auctions, in which renewable energy projects compete for a fixed-term contract to provide electricity, were announced in late 2019, and resulted in a clearing price for Offshore Wind which was almost 70% lower than negotiated contracts from 2013 (a clearing price of around £40/MWh[23] in 2012 prices, which is close to the wholesale price). Further, and as outlined above, competitive tendering for offshore transmission connections has provided savings of £780m-£1,250m across the first fifteen projects[24].

46. Whilst elements of the RIIO framework serve as a proxy for natural competition, such as Ofgem's process of comparing and benchmarking network company costs against each other, a number of market failures persist:

    a. **Market power and barriers to entry**: The incumbent network operators currently have monopoly rights over the planning, construction and operation of all network assets in their respective regions. While network operators already competitively tender certain aspects of their projects, they retain overall control and cost information. This prohibits the ability of other parties to participate fully in the market, regardless of the fact that they may be able to deliver assets more efficiently. Limiting the size of the market also limits innovation, approaches to procurement, price-reflectivity, financing and construction.

    b. **Imperfect information**: Ofgem does not currently have access to the same level of information as the companies it regulates. While incumbent network operators engage with the supply chain by, for example, running tenders for construction of network assets, Ofgem is only presented with a single source of information and no choice over which party owns and operates a particular asset. This information asymmetry reduces the size of the Authority's evidence base and in turn weakens its ability to bear down on costs. Competition can bring increased diversity in the industry, which will increase the sources of information that Ofgem can use to assess cost submissions. This should provide a more effective means of revealing the true costs incurred by network operators and reveal efficient prices more quickly than negotiations and the benchmarking[25] process alone. This will strengthen Ofgem's ability to bear down on costs for those assets that continue to be regulated through the price control process.

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[22] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill. Estimate based on an average electricity bill for a typical domestic customer of the six large suppliers

[23] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-3-results

[24] 2020 prices. Original figures of £680-1,090m (2014/15 prices) can be found in CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', p.54, published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[25] 'Benchmarking', is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

c. **Foregone positive externalities**: Restricting competitive tendering to offshore transmission restricts in turn the positive externalities associated with increased competition. This is because increased competition brings long term innovation benefits beyond the reduced costs of those firms that take part in a tender. Firms, in their drive to gain market share, are more likely to draw on innovative technologies and to increase their investment in research and development. This will in turn drive costs down in the long run for the industry overall.

## Policy objectives

47. The principal policy objective of this measure is to push the costs of developing and operating certain onshore network solutions to the efficiency frontier by putting in place a legislative framework that is expected to allow a body(ies) appointed by Secretary of State to run competitive processes for identifying the licence and/or contractholder(s) that can build and operate such solutions. Government recognises that it is unlikely to be cost-effective for Ofgem, business, or the consumer to run a competitive tender for all onshore network assets. The societal costs of running a tender for a small project, for instance, would likely be higher than any savings achieved by running it. As such, only those assets which meet a certain set of technical criteria will be eligible for competitive tender. These criteria may be changed over time to ensure that increasing efficiency and future technological developments can be reflected in the decision as to whether or not to run a tender. Government will ensure sufficient flexibility within the legislation to extend competition to distribution level in the future if this is in the interest of consumers. The impact of doing so would be considered in future impact assessments at the appropriate time.

48. Ofgem and Government are considering the type of network assets suitable for competitive tender, and significant work has already been conducted considering how to define such assets at the transmission level. In January 2018, Ofgem confirmed three criteria for onshore transmission competition, as set out below, remain appropriate[26]:

    a. The asset must be **new**. This is a readily-comprehensible criterion which has the benefit of making it easy for industry to identify which assets may be tendered.

    b. The asset should be '**high value**'. The cost savings from competitive tendering are at least partly proportional to the value of the asset being tendered; the greater the value of the asset, the greater the cost savings. There is a certain level of cost associated with running a tender that cannot be escaped (although may be reduced over time and with process familiarity), and additional costs may be incurred depending on the value and complexity of the asset that is being tendered. In order to realise benefits from competition, the value of the asset needs to be significant enough that the cost savings outweigh the costs.

    c. The asset should be '**separable**' from the rest of the network. This means that projects should be easily identifiable as discrete projects and that ownership and operational boundaries and responsibilities are clear. Separable projects are more easily scoped and defined, giving greater clarity on the opportunity presented by the tender.

49. We expect these to be applicable under the legislative framework for transmission solutions, and are asking whether the high value threshold of £100m remains appropriate in our associated consultation document. **For the purposes of this IA, we will consider all projects are installed at the onshore transmission network level and satisfy the criteria above.**

50. For the purposes of this IA, it has been assumed that incumbent network operators will be able bid for licences or contracts that will enable them to operate onshore network assets.

[26] https://www.ofgem.gov.uk/publications-and-updates/update-competition-onshore-electricity-transmission

Government and Ofgem will undertake further work to understand how best to manage and prevent any conflicts of interest that may arise because of the fact that market incumbents necessarily possess more information about the nature of the network in their region than new market entrants.

## Policy options considered, including alternatives to regulation

51. Four options have been considered in this IA (two main and two alternative options). While costs and benefits are only expected once secondary legislation has come into force and relevant policies have been implemented, for transparency only the two main options have been appraised qualitatively in detail and, where possible, quantitatively (based on the competitive tendering experience in offshore transmission, and Ofgem's Special purpose Vehicle model). Two alternative options were considered, but have not been appraised quantitatively due to their inherent limitations:

    - **Do Nothing:** The status quo continues. Offshore transmission assets can be competitively tendered, but all onshore network assets continue to be built, owned and operated by the incumbent, monopoly owners of the networks in their respective areas.
    - **Policy Option:** Government will introduce changes to primary legislation that enable a body appointed by the Secretary of State to tender competitively those onshore electricity network solutions where indicative solutions to the constraint at hand meet criteria set by the Secretary of State. The expectation is initially to extend competition to new, high value and separable onshore transmission network assets. The benefits of extending competition to onshore distribution network assets was not quantified at this stage. This is the preferred option.

52. There are two alternative options to legislative change of the kind described here, neither of which Government believes are desirable.

    - **Alternative 'Do Nothing' Option**: Using existing powers, Ofgem could award licences for the construction and operation of onshore network assets without corresponding primary legislation. In order to achieve benefits associated with competition, Ofgem has already considered alternative ways in which it could introduce competition (and/or replicate its effects) under its current powers i.e. the Competition Proxy model (CPM) and Special Purpose Vehicle (SPV) model.[27] In the case of the CPM, it was considered that this would not bring the benefits of true competition, as monopolies remain, and so costs are estimated by benchmarking against other network companies alone. In the case of the SPV model the full benefits of competition are more difficult to achieve due to the need for the monopoly provider to run the competition and contract with the winning bidder. This risks sub-optimal outcomes because of inefficient running of the competition and/or allocation of risk. In addition, hurdles remain for third parties entering the market without legislation, so the benefits associated with new markets and businesses developing will not arise and subsequently Industrial Strategy aims are not contributed to by this option. Without a clear legal framework in place, investors may be less willing to come forward, weakening the level of competition and reducing the potential savings for consumers.
    - **Alternative 'Policy Option'**: Government could introduce legislation that enables a body appointed by the Secretary of State to run the tenders to award licences for the construction and operation of certain onshore network licences on a competitive basis, but mandate competition for *all* assets, regardless of size, newness or other criteria.

[27] The CPM & SPV are both 'late competition' models as defined in Ofgem's 'RIIO-2 Sector Methodology' (published December 2018), https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-consultation. These differ from 'early competition' models, in that the latter are designed to deliver creative and novel ideas that solve network problems, whereas 'late competitions' are used for the delivery of projects that have already been designed and obtained the necessary consents.

Government expects this would be disproportionate and that, competitive tendering of onshore network assets will only lead to benefits for consumers in certain circumstances.

53. These alternative options will not be considered further in this IA.

## Monetised and non-monetised costs and benefits of each option

54. As set out above, costs and benefits are only expected once secondary legislation has been implemented and the two main options have been appraised qualitatively and quantitatively, where possible, for transparency.

### 1. Do Nothing

55. There is no change to primary or secondary legislation in 'Do Nothing' and, therefore, there is no cost. The sections below set out the costs of the status quo for baseline purposes only to be able to enable a comparison with the costs associated with the 'Policy Option' where the costs are non-zero.

**1.1 Cost of network assets assumed eligible**

56. In order to estimate the savings under the 'Policy Option' resulting from improved cost discovery and more efficient prices, it is necessary to set out which onshore network assets would be eligible for competition and what their costs are under 'Do Nothing'.

57. There is a high degree of uncertainty around the scale and timing of the pipeline of projects that would be potentially eligible. There is also a high degree of commercial sensitivity around using information from the actual project pipeline. To account for this uncertainty, five stylised pipeline scenarios of investment over the next 10 years that abstract data from specific projects are considered (see Table 4). There is no end date to the proposed Policy Option, so the 10-year cut-off for new assets coming forward has been assumed for the purposes of this IA.

58. These scenarios use historic capital expenditure information over the Transmission Price Control Review 4 (TPCR4) period from 2007/08 to 2012/13 (as estimated by Ofgem) under schemes such as Transmission Investment for Renewable Generation (TIRG)[28] and the Transmission Investment Incentives (TII)[29] framework. These pipeline scenarios also use data from RIIO-T1 (via the Strategic Wider Works (SWW) investment mechanism[30]) and ED1 price control regime.[31]

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[28] www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview
www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-sp-transmission-ltd-and-scottish-hydro-electric-transmission-ltd

[29] Ibid.

[30] www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal.pdf; www.ofgem.gov.uk/ofgem-publications/84439/finaldecisionletter-kintyrehunterston.pdf; www.ofgem.gov.uk/ofgem-publications/87262/decisionontheproposedbeaulymossfordreinforcementunderriio-t1strategicwiderworksarrangements.pdf; www.ofgem.gov.uk/ofgem-publications/91977/decisiononourassessmentofthecaithnessmoraytransmissionproject.pdf

[31] See Ofgem, 'ET1 PCFM November 2018', published November 2018, in 'RIIO-ET1 Financial Model following the Annual Iteration Process 2018', https://www.ofgem.gov.uk/publications-and-updates/riio-et1-financial-model-following-annual-iteration-process-2018

**Table 4: 'Do Nothing' Assumed Asset Costs across Pipeline Scenarios (2020 prices)**

| | Annual | Total investment over next 10 years (undiscounted) |
|---|---|---|
| Scenario 1 | £0 per year | £0 |
| Scenario 2 | £600m every other year | £2.4bn |
| Scenario 3 | £600m per year | £4.2bn |
| Scenario 4 | £1.2bn every other year | £4.8bn |
| Scenario 5 | £1.2bn per year | £8.4bn |

59. Scenario 1 represents an extreme lower bound where no project is deemed eligible under the chosen criteria over the next 10 years, hence there being no investment. Scenario 5 represents an extreme upper bound with £1.2bn worth of assets per year being deemed eligible and therefore £1.2bn per year of investment (an undiscounted total of £8.4bn investment over the next 10 years given that the first three years are used for a competition set up and the first tender round). These extremes are based on high value transmission assets being brought forward in particular years over the TPCR4 period but are unlikely to be a permanent phenomenon. Scenario 3 represents the central case as it is roughly equivalent to investments made on new assets over the course of the TPCR4 by TOs – approximately £3.9bn worth of capital investment was spent on new assets to connect new electricity generation capacity to the network between 2007 and 2014.[32] Though it is worth noting that even this scenario is quite conservative – in reality, TOs are expected to substantially increase their investments going forward due to increased demand from the electrification of heat and transport – so using past investment trends is likely to underestimate the benefits of this intervention. However, this IA has opted to use more conservative estimates due to uncertainty around how many of these future assets would meet the eligibility criteria for competition.

60. Overall, the pipeline scenarios encompass the levels of investment that has occurred over the RIIO-T1 and ED1 price control regimes.[33] Discussions with Ofgem have confirmed that the above set of pipeline scenarios are also broadly in line with the potential pipeline of projects under RIIO-T2 that might meet the criteria for competition (based on current draft RIIO-T2 business plans).

61. Scenario 3 includes an annual investment of £600m (an undiscounted total of £4.2bn investment over the next 10 years) roughly represents the average annual investment over TPCR4. It is possible that projects eligible for competition are brought forward on a less frequent basis, rather than, for instance, every year. To account for this intermittency, Government has included two further scenarios, i.e. £600m every other year (Scenario 2) (an undiscounted total of £2.4bn investment over the next 10 years) and £1.2bn (Scenario 4) every other year (an undiscounted total of £4.8bn investment over the next 10 years). Scenario 5 represents an extreme upper bound, with an annual investment profile of £1.2bn per year (an undiscounted total of £8.4bn

[32] 2012/13 prices. Ofgem, 'Transmission networks: Report on the performance of Transmission Owners during the regulatory periods TPCR4 and TPCR4RO 2007-08 to 2012-13', published March 2014, https://www.ofgem.gov.uk/publications-and-updates/transmission-networks-report-performance-transmission-owners-during-regulatory-periods-tpcr4-and-tpcr4ro-2007-08-2012-13, p. 7.
This figure is calculated by taking the difference in opening and closing Regulatory Asset Value (RAV) of electricity TOs (plus some additions to account for 'shadow RAV') under the period covered by TCPR4.

[33] See Ofgem, 'ET1 PCFM November 2018', published November 2018, in 'RIIO-ET1 Financial Model following the Annual Iteration Process 2018', https://www.ofgem.gov.uk/publications-and-updates/riio-et1-financial-model-following-annual-iteration-process-2018

investment over the next 10 years). Annex A summarises the investment and operation assumptions.

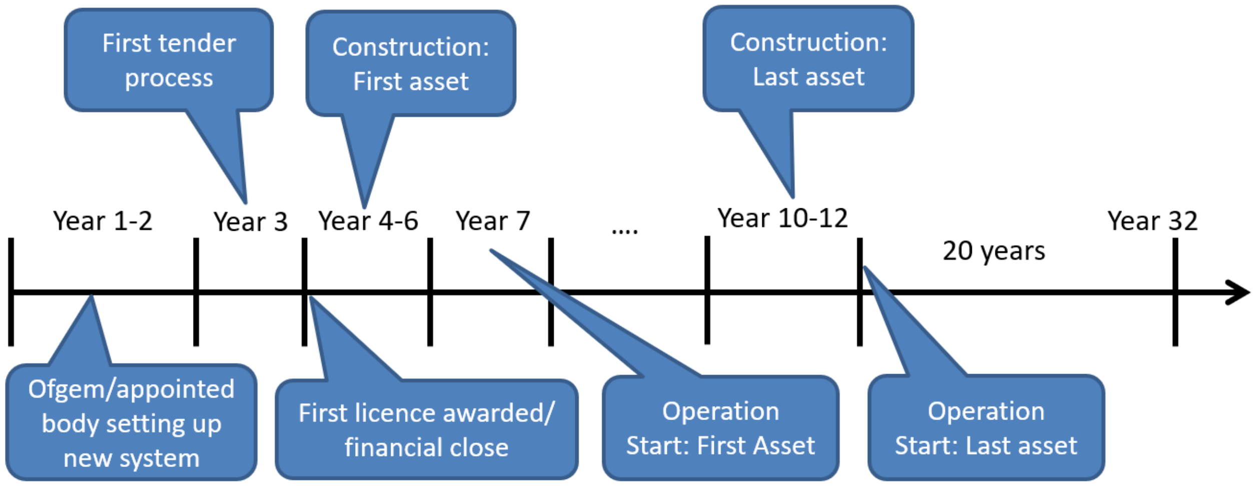
62. Discussions with Ofgem suggest that Scenario 5 is closer to what the TOs are expecting to take forward under the RIIO-ET2 price control period in terms of network investment – up to £1.1bn of investment per year that might meet the criteria for competition.[34] However, there is a risk that this pipeline of planned investment could suffer from delays and attrition, and it is unknown how many of these assets will fully satisfy the criteria for competition. Therefore, this IA purposefully uses a more conservative investment pipeline (Scenario 3) as its central case assumption. Scenario 3 represents a conservative estimate based on the investment profile observed over the last few years – and using it will result in a net benefit to society that is more on the conservative side. However, it is worth noting that the benefits from increased competition could be substantially higher than that suggested by this conservative central scenario.

63. These investment averages can cover one or several projects. Cost implications related to the number of projects are set out under the costs and benefits of the 'Policy Option'.

64. This IA considers the impact of the measure under the 'Do Nothing' and 'Policy Option' scenarios over the same timescale. Ofgem, and therefore this IA, assumes a two-year period to set up the scheme and, for the purpose of this IA, each tender process is assumed to take one year. Most OFTO tenders so far have taken ~18 months,[35] but we have assumed a tender length of 12 months in this IA for the sake of simplicity (the additional 6-month delay implied by an 18-month tender would have a negligible impact on results). The proposed policy does not have an end date. Therefore, this IA assumes assets being built over the next 12 years – i.e. from Year 4 up to Year 12 with 3 years of construction per asset – with savings occurring over a 20-year time period for each of these assets (based on the offshore experience). This is set out in further detail in Annex A. Furthermore, it is assumed that construction costs are incurred in the year following the tender, with construction taking three years per asset. Therefore, this IA assumes that asset operation will start three years following the tender. It is assumed that under 'Do Nothing', the timing of the financial close of assets is the same as under the 'Policy Option'. Figure 2 sets out the assumed timings.

65. This IA assumes 2023 as a start year for scheme set-up (Year 1), with the first potential financial close in 2026. Note that a later start date for the stylised scenario analysis in this IA would only alter the degree of discounting assumed in the NPV of the proposed 'Policy Option'. Undiscounted costs and benefits would remain unchanged.

**Figure 2: Assumed Timings in this IA**




## 1.2 Cost of regulation for transmission assets assumed eligible

66. Under the 'Do nothing' option there are costs associated with regulating large transmission such as those falling under TIRG, TII or SWW. These include costs associated with eligibility, needs case and project assessment stages, as well as a consultation phase. Costs are incurred by both Ofgem and the TOs. Ofgem estimates that this process takes approximately 12-15 months from the start of the assessment process to a funding decision for well-evidenced proposals[36] (but it can take upwards of 2 years for many projects) but is unable to provide an estimate for these costs in isolation. The costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial. Increased competition is likely to reduce overall regulatory costs for Ofgem – these counterfactual costs and potential regulatory savings (in excess of scheme management and set-up costs) are not quantified however, as Ofgem does not have a separate estimate for these costs.

67. Costs of regulation faced by Ofgem are passed on to the network businesses that hold licences for gas transportation, electricity transmission with system operator conditions (National Grid Electricity System Operator), and electricity distribution. Costs are currently passed through to licensees proportionate to the number of customers they serve. These costs are treated as 'pass-through costs', which means that licence holders, in turn, recover the costs from generators and suppliers, which ultimately pass costs onto consumers. In addition, licensees also face costs of regulation. Costs of regulation faced by licensees directly, in addition to those passed through to them by Ofgem, are also assumed to be ultimately passed through to consumers in this IA. This principle is integral for assessment of these costs (and their reduction) in the IA, which shall be demonstrated through the costs and benefits under the 'Policy Option' below.

## 1.3 Interface costs of the System Operator (SO)

68. Currently, the System Operator (National Grid Electricity System Operator) already interacts with a range of industry actors, including three onshore TOs, a number of OFTOs, 14 different DNO regions and interconnector operators. For the purposes of this IA, these interface costs have not been quantified for use as a counterfactual under 'Do Nothing', because additional new entrants under the 'Policy Option' are expected to cause only marginal changes for the SO (costs are assumed to be zero). Therefore, there is no change in costs between 'Do Nothing' and the 'Policy Option'.

[36] https://www.ofgem.gov.uk/ofgem-publications/85263/strategicwiderworksfactsheet.pdf

## 2. Policy Option (compared to 'Do Nothing')

69. This section provides a qualitative and, where possible, quantitative assessment of these costs and benefits of the Policy Option. These costs and benefits are classified as direct impacts from the time that secondary legislation is implemented as they are expected to result directly from the implementation of secondary legislation.

70. The quantifications represent approximations and ranges of potential costs and benefits. They are intended to provide a sense of scale rather than precise costs and benefits which Government expects from competition. It is inherently difficult to predict with any accuracy the potential efficiency benefits that introducing a competitive process might bring, given the many uncertainties around the project pipeline, and the fact that examples of the use of competition in transmission delivery are context specific. It is also difficult to quantify meaningfully the dynamic benefits of competition, such as the scope for increased innovation and the introduction of new products, services and technologies.

### 2.1 Additional costs (monetised / non-monetised) as compared to 'Do Nothing'

71. Table 5 below sets out the additional categories of costs and benefits identified with regards to the 'Policy Option' as compared to 'Do Nothing'.

**Table 5: Costs and Benefits**

| | Costs | Benefits |
|---|---|---|
| **Generators/ Suppliers and ultimately end-consumers ("Consumers")** | • Set-up/Tender/Bid costs (of successful bidders) (TO pass through) [3] – *monetised*<br>• Costs due to delay risk – *not monetised*<br>• Costs due to delay risk (TO pass through) – *not monetised* | • Cost savings through more competition<br>  ○ Better information for Ofgem benchmarking – *not monetised*<br>  ○ Innovation (technical, commercial, financial) – *not monetised*<br>  ○ More efficient and innovative procurement practices – *not monetised*<br>  ○ New sources of labour and capital – *not monetised*<br>  ○ Increased diversity in the industry – *not monetised*<br>  ○ Improved timescales – *not monetised*<br>  ○ Widening of expertise in different areas of the network and potential widening of investment activity in other areas of the industry – *not monetised*<br>• Lower cost of regulation under the price control (TO pass-through) [3] – *not monetised* |
| **Incumbent Transmission Operators ("Producers")** | • Bid costs – *monetised*<br>• Potentially foregone returns on assets (transfer within the producer group) – *not monetised*<br>• Costs due to delay risk – *not monetised*<br>• Tender costs (Ofgem/appointed body pass through) – *monetised* | • Lower cost of regulation under the price control – *not monetised*<br>• Lower cost of regulation under the price control (Ofgem/appointed body pass-through) – *not monetised*<br>• Reduced expenditure on transmission assets due to not being appointed successful bidder (transfer within the producer group) or due to revealing a more efficient cost – *not monetised* |
| **ESO** | • Set up costs (Ofgem/appointed body pass through) – *monetised*<br>• Additional interface costs – *not monetised* | |
| **New entrants ("Producers")** | • Bid costs – *monetised*<br>• Potentially higher expenditure on transmission assets (transfer within the producer group) – *not monetised*<br>• Costs due to delay risk – *not monetised*<br>• Tender costs (Ofgem/appointed body pass through) – *monetised* | • Potential for market entry – *not monetised*<br>• Potential gain of returns on assets (transfer within the producer group) – *not monetised* |
| **Ofgem (or body appointed by the Secretary of State to run the tenders)** | • Tender costs (directly passed through) [1] – *monetised*<br>• Set-up costs (directly passed through) [1] – *monetised* | • Lower cost of regulation under the price control (directly passed through) [2] – *not monetised*<br>• Reputation and confidence – *not monetised* |

*Note:*
*1 The set-up costs that Ofgem or the appointed body incurs are directly passed through to the ESO and Ofgem's or the appointed body's tender costs are directly passed through to incumbent TOs or new entrants. These are considered to be direct costs to the ESO, incumbent TOs and new entrants. Note that in future some set-up costs may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender rather than from the ESO (this would also be a direct cost to business).*
*2 The lower cost of regulation under the price control for Ofgem is directly passed on to incumbent TOs. This is considered to be a direct benefit to incumbent TOs.*
*3 Based on the offshore experience, set-up, tender and bid costs (of successful bidders) passed through to generators/suppliers and ultimately end-consumers. The same holds for lower cost of regulation under the price control (benefit). These costs/benefits are considered indirect impacts of the 'Policy Option' through incumbent TO or new entrant recovery/pass through.*

72. For the purposes of this IA:
    a) 'Set-up costs' are the one-off costs associated with creating the competitive regime;
    b) 'Tender costs' are the costs associated with running a particular competitive tender; and
    c) 'Bid costs' are the costs of bidding into a particular competitive tender.
73. In order to estimate the additional costs associated with extending competitive tendering to some transmission assets, this IA relies on the findings from the offshore transmission asset experience, assessed in the CEPA report on OFTO Tender Rounds 2 and 3[37]. For the purposes of the quantifications in this IA, cost savings are estimated against a price control counterfactual from the CEPA report where the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime. In the CEPA report, this is outlined as "Counterfactual 3", and is the most comparable counterfactual to the 'Do Nothing' option, as well as being the conservative counterfactual.
74. The CEPA report sets out that, against the price control counterfactual (Counterfactual 3) as set out above, the cost to society of the first three OFTO tender rounds of bid costs were between £7m and £45m in each round, for a grand total of £70m across all three tender rounds (NPV).[38] Expressed as a percentage of the total Final Transfer Value (FTV) of OFTOs in those rounds (£2.9bn), bid costs total approximately 2.4% of the asset value on average.
75. Costs incurred by a body appointed by Secretary of State from running the tender process are assumed to be 1% of the asset value. In reality this will vary by project and tender round. For example, in place of one large project, several smaller projects could be tendered in a given year, which may either increase the Secretary of State-appointed body's administration costs (because they are running several projects) or decrease them (because they are running several projects at once). Consequently, 1% represents an appropriate long-run average and is based on Ofgem's, as the body which runs OFTO tenders, experience to date.
76. The 'Assumptions and Risks' section gives the full list of appropriate caveats associated with using the CEPA report for this IA. The list below, however, summarises the key points:
    a) While new entrants are likely to incur a lower capital expenditure than incumbent TOs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. However, as is the case with large investments in other sectors, refinancing is likely to take place post-construction which would almost certainly lower the cost of capital substantially (from its pre-construction level).
    b) Savings in the offshore regime, in particular for TR1, were at least in part realised by offshore generators quoting very low prices for maintenance costs in an attempt to maintain control over their own assets (appointed OFTOs can subcontract operational and maintenance work)[39]. It is arguable that because there is less likely to be a

[37] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits
[38] 2020 prices. Original figure of £7m - £42m (2014/15 prices) can be found here: CEPA, 'Evaluation of OFTO Tender Round 2 & 3 Benefits", published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, pp. 36, 38 & 68
[39] https://www.ofgem.gov.uk/publications-and-updates/consultation-cepabdo-evaluation-offshore-transmission-tender-round-1-benefits, p52

corresponding generation asset to attempt to control in an onshore competition, onshore bidders will not be incentivised to bid in this way, and that overall savings may be lower. However, savings could be seen in construction delivery, and there have been genuinely innovative approaches to asset maintenance in the offshore regime by OFTOs which have not subcontracted maintenance to offshore generators, which have brought about savings.

c) Government recognises, as indicated in the CEPA report, that there are limits to the extent to which lessons can be drawn from the CEPA report conclusions for the onshore electricity transmission network, given that the outcomes demonstrated in the report are context - and time - specific. However, Government believes that the onshore projects expected to be captured by competitive tendering share similarities with offshore projects – being new, high-value, and separable – and, therefore, comparisons are reasonable. It is also the case that this report, which estimates the savings realised by introducing competition into the offshore electricity transmission network, is the best indication of the operating savings likely to be realised by introducing competition into the onshore electricity transmission network.

*2.1.1 Additional costs to generators, suppliers and ultimately end-consumers under the Policy Option*

77. **Set-up/Tender/Bid costs (of successful bidders) (TO pass through):** In the offshore competitive regime:

a) Set-up costs are incurred by the body appointed by the Secretary of State to run the tenders. They are directly passed onto the ESO as part of the ESO's licence condition (direct cost for the ESO, see 'the ESO' section below). The terms of this licence also allow the ESO to consider this cost a 'pass-through' cost for the purposes of the price control: in other words, the costs are recovered from generators and suppliers, who in turn are assumed to pass these costs on to end-consumers.

b) Tender costs are incurred by the body appointed by the Secretary of State to run the tenders. These costs are directly passed onto the successful bidder in a tender round (direct cost for successful bidder). Bidders will build that cost into their proposed revenue stream, which means that the tender costs are ultimately passed on to generators, suppliers, and ultimately end-consumers.

c) Bid costs are in the first instance incurred by incumbent TOs and new entrants (direct cost) (see relevant sections below). If a bidder is successful, this cost will be passed through to generators, suppliers and ultimately end-consumers through the revenue stream. If the bidder is unsuccessful, the costs will formally remain with them, though some informal pass-through to end-consumers may occur if the bidder is already operational in the transmission market.

For this IA Government has assumed that the same will hold for onshore assets. The bid costs of unsuccessful bidders will remain with the bidder. Generators recoup the passed-through set-up, tender and bid costs from end-consumers in the form of higher wholesale prices (if price setting plants are affected) and through higher clearing prices in the Capacity Market (a cost to consumers). In the case of some low carbon plant, costs are passed through in the form of higher clearing prices in Contract for Difference allocation rounds therefore leading to potentially less low-carbon generation uptake within the Control for Low Carbon Levies, which would lead to higher emissions (a cost to society). Suppliers pass the set-up, tender and bid costs to end-consumers through higher network charges on customer bills. Therefore, end-consumers ultimately bear these costs. This IA assumes that all set-up, tender and bid costs are fully passed through to consumers, either informally or formally through the licence. This is based on the offshore experience.

78. In order to estimate the likely scale of the set-up, tender and bid costs borne by end-consumers, this IA applies cost assumptions as supplied by Ofgem and experienced in the offshore competitive tendering process. The set-up cost is assumed to be £3m. The costs for the body appointed by the Secretary of State of running the tender process are assumed to be 1% of the asset value, while bid costs for incumbent TOs and new entrants are assumed to be 2.4% of the asset value. These assumptions, combined with the pipeline scenarios, results in set-up, tender and bid costs of £3m-£235m across scenarios as set out in Table 6 below.

**Table 6: Estimated Set-up/Tender/Bid Costs (2020 prices)**

| | Annual* | 32 Year Period (PV) |
|---|---|---|
| Scenario 1 | £0m per year | £3m** |
| Scenario 2 | £20m every other year | £70m |
| Scenario 3 | £20m per year | £120m |
| Scenario 4 | £40m every other year | £140m |
| Scenario 5 | £40m per year | £235m |

* The annual figures exclude the appointed body's set-up costs of £3m as these are transitional, one-off costs.
** In Scenario 1, the appointed body's set-up costs are fully recovered through the licence fee (paid by the ESO, direct cost). The ESO passes these costs through to generators/suppliers, which ultimately pass them through to end-consumers. In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost), who will also pass these costs on to generators/ suppliers and ultimately to end-consumers.
Note: All estimates are rounded.

79. **Costs due to delay risk**: There is a risk that generation new build could be delayed due to the time taken to run a tender. It is worth noting that under the 'do nothing' option, the incumbent is still required to tender for much of the delivery for certain appointed projects, so the risk of delay here represents the risk of a longer tender process than under the counterfactual. Added delay in network asset delivery implies direct costs for developers of new generation assets (if they depend on the tendered network asset) as it implies a delay to their timetables. Generators are assumed to pass these costs on to end-consumers. As explained in the paragraph below, the quantifications in this IA assume that the appointed body's framework will prevent any delays from occurring. However, if the generation new build is for wider system purposes – such as a reinforcement of an existing part of the network – then the cost of delay will be in the form of additional constraint costs paid by consumers.

80. **Costs due to delay risk (TO pass through):** In addition to the direct cost on generation new build, a delay also implies a direct cost to incumbent TOs and new entrants (set out in the relevant sections below). Incumbent TOs and new entrants are assumed to pass on their higher costs to generators and suppliers, in the form of higher charges, which will ultimately be borne by end-consumers. To address the delay risk, Ofgem is expected to develop a tender process that fits with project timings and does not cause additional delays for projects where some early development work has already been completed. Ofgem's general framework is likely to include incentives on the competitively appointed party to encourage timely delivery. Additionally, the robustness of the bidders' delivery plans is likely to be a key aspect of the appointed body's tender evaluation process. These measures are likely to help ensure competitively tendered projects are delivered within the appropriate time frame. The quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

### *2.1.2 Additional costs to incumbent TOs under the Policy Option*

81. **Bid costs**: If incumbent TOs bid in the tender process they incur costs in preparing bids for evaluation, reaching the licence grant and acquiring the asset. Based on the offshore experience, bid costs of successful bidders are estimated to be 2.4% of the asset value. It is not possible to isolate the bid costs falling onto incumbent TOs, should they decide to bid, as it is dependent on the TO success rate in the tender process. For illustration, as an extreme upper bound, it can be assumed that incumbent TOs are the successful bidder in all tenders and therefore face the 2.4% bid costs on all tenders (see Table 7). As set out in the 'Set-up/Tender/Bid costs (of successful bidder) (TO pass through)' section above, this IA assumes that all set-up, tender and bid costs are fully passed through to consumers.

82. The bid costs of unsuccessful bidders are not taken into account due to lack of evidence and commercial sensitivity of this information. They do however present a cost to society. There is no formal mechanism under Ofgem's OFTO regime or price control regime (RIIO) for unsuccessful bidders to recover their bid costs directly from consumers. We assume that the bid costs of unsuccessful bidders remain with them. It is important to note that bid costs for incumbent TOs are partially offset by cost savings under the price control process. Ofgem does not have a separate estimate of these cost savings and they are, therefore, not quantified in this IA.

83. In theory it is possible to roughly proxy total bid costs of all parties – both of successful and of unsuccessful bidders – using anecdotal evidence from TR1, TR2 and TR3. Based on internal discussions with Ofgem, unsuccessful bidders faced costs in the range of 0.1-0.5% of the total capital value of a project being competed, per bidder, over the course of all three tender rounds, with an average of 2-3 unsuccessful bidders per project.[40] As an extreme upper bound, it can be assumed that each project has 3 unsuccessful bidders that all face the same bid cost of 0.5% on the total value of capital investment, and that all these unsuccessful bidders are able to recover these costs from consumers – e.g. in the unlikely scenario that they are all active in the GB electricity market. This approach significantly impacts total bid cost estimates, which can amount to over **£270m** (PV, over a 32-year period) with the inclusion of losing bidder costs, **almost double** the maximum of £165m under pipeline Scenario 5. However, given the uncertainties involved in this extreme assumption, this IA does not include this proxy of total bid costs in the final assessment. Due to the commercial sensitivity of this information, there is little indication as to what proportion unsuccessful bidders are overseas companies with little involvement in the GB electricity market. Companies that fall into the latter category would not be able to pass on the cost of their unsuccessful bids to GB consumers, thus removing it as a 'cost to society.'

**Table 7: Estimated Bid Costs (2020 prices)**

| | Annual | 32 Year Period (PV) |
|---|---|---|
| **Scenario 1** | £0m per year | £0m |
| **Scenario 2** | £15m every other year | £50m |
| **Scenario 3** | £15m per year | £80m |
| **Scenario 4** | £30m every other year | £95m |
| **Scenario 5** | £30m per year | £165m |

Note: All estimates are rounded and these costs and those in Table 9 are mutually exclusive.

[40] Based on internal discussions with Ofgem (September 2019).

84. **Tender costs (Secretary of State's appointed body pass through)**: Under the 'Policy Option', the proposed cost recovery mechanism, would allow the body appointed by the Secretary of State to recover the costs of any tender it conducts (also captured under the 'Ofgem/appointed body' section below). This is a direct cost to the successful bidder. Ofgem estimates that its tender costs are 1% of the asset value. In reality this will vary by project and tender round, but 1% represents an appropriate long run average and is based on Ofgem's experience to date. It is not possible to indicate what proportion of tender costs the body appointed by the Secretary of State will recover from incumbent TOs, as it is dependent on the TO submitting a bid and, if they bid, their success rate in the tender process (the successful bidder of any given tender bears those costs alone). For illustration, as an extreme upper bound, it can be assumed that incumbent TOs are successful bidders in all tender rounds and therefore the appointed body's 1% tender cost is fully passed on to incumbent TOs (Table 8). Incumbent TOs then recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above. If they are not the successful bidder in any tenders, the appointed body would not recover any costs from them and they would only face their own bid costs, which have not been quantified due to lack of evidence.

**Table 8: Estimated Tender Costs (Ofgem/appointed body recovery) (2020 prices)**

| | Annual | 32 Year Period (PV) |
|---|---|---|
| **Scenario 1** | £0m per year | £0m |
| **Scenario 2** | £6m every other year | £20m |
| **Scenario 3** | £6m per year | £34m |
| **Scenario 4** | £12m every other year | £39m |
| **Scenario 5** | £12m per year | £69m |

Note: All estimates are rounded and these costs and those in Table 10 are mutually exclusive.

85. **Potentially foregone return on assets (transfer)**: In the scenario that an incumbent TO does not bid or fails to be appointed as successful bidder for a specific project that previously would have fallen under their regional monopoly, they will lose the right to deliver and operate a project which they otherwise would have retained. The incumbent TO would forego the revenue stream for the investment, but would also not incur the asset costs (set out in the benefits section below). The unsuccessful incumbent TO therefore foregoes the return on the investment.

86. The potential reduction in return for incumbent TOs represents a **transfer within the 'producer' group** (incumbent TOs and new entrants) as a new entrant would instead earn the return (given they would receive the revenue stream and incur the asset cost). For simplicity, for the purpose of this IA it has been assumed that the gain in return for new entrants offsets the loss in return for incumbent TOs. Therefore, the return to the 'producer' group is assumed to be unchanged. While new entrants incur a lower capital expenditure than incumbent TOs, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption on returns being unchanged is a fair one.

87. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how exactly revenue streams will be set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able

to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

88. There might also be transfers *amongst* incumbent TOs, where a TO is the successful bidder for an asset in another incumbent TO's previous regional monopoly area. This IA does not estimate impacts for each individual incumbent TO. Both these types of transfers have not been quantified as they depend on the incumbent TOs (or an individual incumbent TO) submitting a bid and, if they bid, their success rate in the tender process.

89. In addition, incumbent TOs may lose economies of scale, which could push up overall costs in other areas of non-competed business. However, given the size of the incumbent TOs current transmission portfolios and the relative scale of the assets likely to be selected for tendering, this is highly unlikely. Further, by applying suitable criteria in regulation as discussed above, Government will work to ensure that competitive tendering of select projects provides additional cost efficiencies and wider benefits. This IA does not quantify the value of the potential loss of assets or return on these investments as this depends on the incumbent TOs submitting a bid and, if they bid, their success rates.

90. **Costs due to delay risk**: There is a risk that projects could be delayed due to the time taken to run a tender. This would have implications for asset costs. As set out in the 'generators/suppliers and ultimately end-consumers' section above, the quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

*2.1.3 Additional costs to the ESO under the Policy Option*

91. **Set-up costs (Body appointed by Secretary of State pass through):** The body appointed by Secretary of State incurs set-up costs in creating the competitive regime. In general, Ofgem costs are funded by payments made to the Authority by parties who are licenced by it. With regards the creation of a competitive regime for electricity transmission assets, set-up costs will be recovered from the Electricity System Operator (ESO). These costs therefore constitute a direct cost to business. In future, some costs associated with the setting up of the scheme may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender. This has not been separately quantified as it depends on who would be successful during a competitive tender.

92. **Interface costs**: Under the Policy Option, the ESO could bear an additional administrative burden arising from the requirement to interact with a broader group of industry parties. However, these costs are likely to be negligible (and have here been assumed to be zero) as, under 'Do Nothing', the ESO is already interacting with three onshore TOs and a number of OFTOs, DNOs and interconnector operators. This means that the addition of new parties to the market would have only a marginal effect. The incremental interface cost associated with adding new parties to the network cannot be determined.

93. The 'Assumptions and Risks' section discusses the treatment of preliminary works in the analysis.

*2.1.4 Additional costs to new entrants under the Policy Option*

94. **Bid costs:** New parties, as bidders in the tender process, incur costs in preparing bids for evaluation. Based on the offshore experience, the bid costs of successful bidders are estimated to be 2.4% of the asset value. It is not possible to isolate the bid costs falling onto new parties as it is dependent on the new entrants' success rate in the tender process. For illustration, as an extreme upper bound, it can be assumed that new parties are the successful bidder in all tenders and therefore face the 2.4% bid costs on all tenders (see Table 9). As set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above, this IA assumes that all tender and

bid costs are fully passed through to consumers, either informally or formally through the licence. This is based on the offshore experience.

95. Note that bid costs of unsuccessful bidders are not taken into account due to lack of evidence and commercial sensitivity of this information. They do however present a cost to society. Usually, the bid costs of unsuccessful bidders remain with them and cannot be passed on directly to consumers. However, unsuccessful bidders that are not regulated and are already active in the energy market can, in theory, pass on the costs of unsuccessful bids to their customers. All bidders can also pass on the costs of unsuccessful bids indirectly, via things like decreased dividends for investors, being forced to find savings in other parts of the business etc. This will represent a cost to society – though quantifying this cost is difficult due to a lack of sufficient evidence. Unlike for incumbent TOs, bid costs relating to preparing the bid are not partially offset by cost savings under the price control process.

96. In theory it is possible to roughly proxy total bid costs of all parties – both of successful and of unsuccessful bidders – using anecdotal evidence and data from TR1, TR2 and TR3. Data from comparable projects suggests that unsuccessful bidders can face costs in the range of 0.1-0.5% of the total capital value of a project being competed, per bidder, with an average of 2-3 unsuccessful bidders per project.[41] As an extreme upper bound, it can be assumed that each project has 3 unsuccessful bidders that all face the same bid cost of 0.5% on the total value of capital investment, and that all these unsuccessful bidders are able to recover these costs from consumers – e.g. in the unlikely scenario that they are all active in the GB electricity market. This approach significantly impacts total bid cost estimates, which can amount to over **£270m** (PV, over a 32-year period) with the inclusion of losing bidder costs, **almost double** the maximum of £165m under pipeline Scenario 5. However, given the uncertainties involved in this extreme assumption, this IA does not include this proxy of total bid costs in the final assessment. Due to the commercial sensitivity of this information, there is little indication as to what proportion unsuccessful bidders are overseas companies with little involvement in the GB electricity market. Companies that fall into the latter category would not be able to pass on the cost of their unsuccessful bids to GB consumers, thus removing it as a 'cost to society.'

**Table 9: Estimated Bid Costs (2020 prices)**

| | Annual | 32 Year Period (PV) |
|---|---|---|
| **Scenario 1** | £0m per year | £0m |
| **Scenario 2** | £15m every other year | £50m |
| **Scenario 3** | £15m per year | £80m |
| **Scenario 4** | £30m every other year | £95m |
| **Scenario 5** | £30m per year | £165m |

Note: All estimates are rounded and these costs and those in Table 7 are mutually exclusive.

97. **Tender costs (Secretary of State-appointed body pass through)**: The intention is that Ofgem will recover the costs to it of conducting a tender (also captured under the 'Ofgem/appointed body' section). This is a direct cost to the successful bidder. Ofgem, as the body which deals with OFTO tenders, estimates that their tender costs are 1% of the asset value. It is not possible to indicate how much of their tender costs the body appointed by the Secretary of State will recover from new parties as it depends on the success rate of the latter in the tender process (bearing in mind that it is the successful bidder only of a given tender which bears the costs

[41] Internal BEIS assumption.

associated with running it). For illustration, as an extreme upper bound, it can be assumed that new entrants are successful bidders in all tender rounds and, therefore, Ofgem's estimated 1% tender cost is fully passed on to new entrants (Table 10). Based on the offshore experience, new entrants are then assumed to recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above. Any bidder that is not successful would not be subject to the recovery of tender costs from the body appointed by Secretary of State: only individual party bid costs would be incurred, which have not been quantified due to lack of evidence.

**Table 10: Estimated Tender Costs (Ofgem/appointed body pass through) (2020 prices)**

| | Annual | 32 Year Period (PV) |
|---|---|---|
| **Scenario 1** | £0m per year | £0m |
| **Scenario 2** | £6m every other year | £20m |
| **Scenario 3** | £6m per year | £34m |
| **Scenario 4** | £12m every other year | £39m |
| **Scenario 5** | £12m per year | £69m |

Note: All estimates are rounded and these costs and those in Table 8 are mutually exclusive.

98. **Potential increased expenditure on transmission assets (transfer)**: If a new entrant is appointed as successful bidder, that new entrant will incur the costs of that asset (although those costs will be more efficient as a result of the new competitive pressures on them). At the same time, the new entrant would receive the revenue stream on the asset and therefore would gain overall by earning the return on the asset.

99. The increased expenditure on assets represents a **transfer within the 'producer' group** (incumbent TOs and new entrants), because any increased expenditure by new entrants under the 'Policy Option' (with more efficient costs) is more than offset by a reduction in status-quo expenditure from incumbent TOs (set out in the benefits section). At the same time that incumbent TOs benefit from less expenditure on assets, they would not receive the revenue stream on the asset and therefore will overall be worse off by losing the return on the asset (set out in the 'generators/suppliers and ultimately end-consumers' section above). This transfer of asset costs (and returns) has not been quantified as it depends on the success rate of new entrants in the tender process.

100. **Costs due to delay risk**: There is a risk that projects could be delayed due to the time taken to run a tender. For new entrants this is a delay compared to the timings of an asset built by incumbent TOs under 'Do Nothing'. This would have implications for asset costs. As set out in the 'generators/suppliers and ultimately end-consumers' section above, the quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

*2.1.5 Additional costs to the body running the tenders under the Policy Option*

101. **Set-up costs**: The body running the tenders incurs costs setting up the competitive process, including on the development of policy, legal and operational frameworks (including the modification of codes and standards) and structures needed to run tenders. Ofgem estimates these costs to be between £2m-£3m (2013/14 prices). For the purpose of this IA, a high / conservative estimate of £3m 2013/14 prices – equivalent to £3.3m in 2020 prices – has been chosen. As set out above, these costs are assumed to be directly recovered from the ESO. It therefore constitutes a direct cost to business. In future some costs associated with the setting up

of the scheme may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender.

102. **Tender costs**: Ofgem incurs costs when running an individual tender, on items such as the staff and resources required to design the tender process, to evaluate bids, and to ensure that appointed licensees meet their obligations. The costs to this body of running a tender are assumed to be 1% of the asset value, as explained by the assumption above. In reality, this will vary by project and tender round, but 1% represents an appropriate long run average and is based on Ofgem's experience to date. There may be some efficiency savings gained by grouping projects together, but in this IA an upper bound cost estimate has been assumed. Table 11 sets out the tender costs across scenarios. These costs are partially offset by a reduction in regulatory costs for the body appointed by the Secretary of State to run tenders. However, as set out above, Ofgem does not have a separate estimate for these costs. Therefore, the estimates of net cost to this body are high/ conservative.

103. It is important to note that a 'high value' criterion minimises the relative costs of tendering. A 'new' and a 'separable' criterion minimises interfaces and therefore the ongoing tender costs associated with more parties.

104. The appointed body recovers its tender costs from successful TOs, which in turn are assumed (based on the offshore experience) to recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above.

**Table 11: Estimated Set-up/Tender Costs (2020 prices)**

| | Annual* | 32 Year Period (PV) |
|---|---|---|
| Scenario 1 | £0m per year | £3m** |
| Scenario 2 | £6m every other year | £20m |
| Scenario 3 | £6m per year | £40m |
| Scenario 4 | £12m every other year | £45m |
| Scenario 5 | £12m per year | £70m |

* The annual figures exclude the appointed body's set-up costs of £3.3m as these are transitional, one-off costs.
** In Scenario 1, the appointed body's set-up costs are fully recovered through the licence fee (paid by the ESO) (direct cost). The ESO passes these costs through to generators/suppliers, which ultimately pass them through to end-consumers. In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost), who will also pass these costs on to generators/ suppliers and ultimately to end-consumers.
Note: All estimates are rounded.

## 2.2 Additional benefits (monetised / non-monetised) as compared to the 'Do Nothing' option

### *2.2.1 Additional benefits to generators, suppliers and ultimately end-consumers under the Policy Option*

105. **Cost savings through competition**: Extending competitive tendering to some onshore transmission assets significantly benefits generators and suppliers (and ultimately end-consumers) by addressing various market failures present under 'Do Nothing'.

106. Firstly, generators, suppliers and consumers benefit because new parties are able to enter the market (barriers to entry that exist under 'Do Nothing' are removed) and there is increased competitive pressure on all operators. This drives:

- **Innovation**. New parties could be invited to present designs, manage the supply chain and operate the transmission assets. Current incumbents are encouraged to seek savings and produce innovative approaches to delivering and maintaining assets. Innovation may also occur in the technical, commercial and financial space.
- **More efficient and innovative procurement practices** and, therefore, more efficient pricing.
- **Access to new and more diversified sources of labour and capital** as competition widens the pool of transmission owners and investors. This has the benefit of increasing the exposure of financing costs to competitive pressure, and in driving innovation.
- **Increased diversity in the industry** which increases the sources of information that Ofgem can use to benchmark[42] cost submissions. This helps to improve the regulation of all transmission projects, not only those that are subject to competition.
- **More timely delivery** of transmission assets through the deepened incentives on construction.
- **Widening of expertise** in different areas of the network and **potential widening of investment activity** in other areas of the industry.

107. Secondly, generators, suppliers and consumers benefit because competitive pressures in the market allow better cost discovery and therefore a reduction in imperfect information. Under 'Do Nothing', Ofgem does not have access to the same level of information as the companies it regulates, an information asymmetry which can impede Ofgem's evidence base and ability to act in the interest of consumers. Although price controls represent an effective method of controlling costs, competitive pressures under the 'Policy Option' are likely to be more effective in some circumstances through revealing the true and more efficient costs of TOs which will, therefore, address the information asymmetry between the regulated company and Ofgem, should Ofgem be the appointed body by the Secretary of State to run the tenders. This is likely to improve Ofgem's assessment of the efficiency of companies' total costs.

108. It is very likely that competitive tendering will bring about efficient prices more quickly than negotiations and price reviews as part of a price control. While incumbent TOs do engage with the supply chain by running tenders for construction of transmission assets, Ofgem is only presented with a single source of information and no choice over which party owns and operates a particular asset. Competitive pressure will bring increased diversity in the industry, which will increase the sources of information that Ofgem (should it be the body appointed by the Secretary of State to run the tenders) can use to benchmark cost submissions, thus helping to improve the regulation of all transmission projects, not only those that are subject to competitive tendering.

109. There are three ways in which cost savings filter through to consumers. First, savings in the form of lower TNUoS charges are passed through to generators (23%) and suppliers (77%)[43]. Second, the cost savings felt by generators can be passed to end-consumers in the form of lower wholesale prices (if it affects price setting plants) or through lower clearing prices in the Capacity Market. Third, in the case of some low carbon generators, cost savings can be passed to consumers through lower clearing prices in Contract for Difference allocation rounds and therefore potentially more low carbon generation uptake within the Control for Low Carbon Levies, which would lead to lower emissions (a benefit to society). The cost savings that fall to suppliers are assumed to be passed to end-consumers through lower network charges on customer bills. In the first instance any cost savings are experienced by the incumbent TOs and new parties (set out in the relevant sections below).

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[42] 'Benchmarking', is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.
[43] National Grid ESO, 'Final TNUoS Tariffs for 2021-22 – Report (updated 04022021)', published January 2021, p. 29, https://www.nationalgrideso.com/document/186176/download

*2.2.2 Level of savings to generators, suppliers and ultimately end-consumers under the Policy Option*

110. In order to estimate approximate additional cost savings from extending competitive tendering to some onshore transmission assets, this IA relies on the approach adopted in Ofgem's SPV model[44] and on the offshore transmission asset experience, as assessed in the CEPA report on OFTO Tender Rounds 2 and 3[45]. For the purposes of this IA, cost savings are estimated against a price control counterfactual where construction and operation of the transmission asset is onshore TO-led (Counterfactual 3). This counterfactual is the most comparable to the 'Do Nothing' option, as well as being the conservative counterfactual.

111. The analysis in the CEPA report focuses on cost savings in NPV terms, i.e. savings over the economic life of the asset. The report argues that due to competitive pressures the costs borne by consumers will be driven down as the true cost of the asset is revealed and pricing becomes more efficient. The report assumes that this happens faster than might have taken place under the price control review process.

112. Note that for the purpose of this IA, potential tax savings have not been considered due to lack of a suitable counterfactual – in the CEPA report they were derived using a simplified approach devised for OFTOs which is unlikely to be applicable for onshore assets.

113. The CEPA report sets out that against Counterfactual 3 the benefits to society for the first three tender rounds of the OFTO regime are estimated to be £880-£1,130m (NPV excluding tax),[46] broken down into operating (£600-£850m, NPV)[47] and financing (£360m, NPV)[48] cost savings. The report also sets out the financing and operating cost assumptions, from which these figures are derived.

114. This IA uses a set of operating cost 'pathways' to estimate the range of possible operating cost savings that would be expected to materialise under increased competition. These have been derived from the CEPA report on OFTO Tender Rounds 2 and 3 (shown in Chart 1 below) and show the possible operating cost 'premia' versus an incumbent bidder. The first set (Table 12 below, central pathways 4-6, also see orange lines in chart 1) represents the potential operating cost savings versus a price control counterfactual (which is equivalent to 'Do Nothing' in our analysis) under Tender Rounds 2 and 3.[49] These are more conservative than pathways 1-3, the latter of which were derived from OFTO assets that were tendered as part of Tender Round 1.[50] The CEPA report provides several reasons for this – such differences in project size between tender rounds – and suggests that the lower Opex savings achieved under Tender Rounds 2 and 3 is evidence of the beneficial impact of the contestable OFTO programme, in which successive bidding rounds support increasingly refined price discovery.[51]

115. Thus, pathways 1-3 represent the (larger) Opex savings that could be achieved in a sector that has not previously been subjected to competitive pressures, whereas the more modest Opex savings range of pathways 4-6 represents a sector that has already been subjected to some

[44] Ofgem, 'Update on Extending Competition in Transmission and Impact Assessment', published September 2018, https://www.ofgem.gov.uk/publications-and-updates/update-extending-competition-transmission-and-impact-assessment

[45] https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[46] 2020 prices. Original figure of £770m – £990m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[47] 2020 prices. Original figure of £520m – £745m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[48] 2020 prices. Original figure of £315m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[49] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, pp. 33-34

[50] Pathways 1-3 can be derived using the average of the 'low' and 'high' pathways and the preferred bidder levels presented in CEPA/BDO analysis of TR1 – see chart for counterfactuals 3 & 4, p.98 of CEPA/BDO, 'Evaluation of OFTO Tender Round 1 Benefits', published May 2014, https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf

[51] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, p. 21

form of competitive pressure and price discovery. One could argue that it would be more appropriate to use pathways 1-3 for our analysis, as the onshore assets we are trying to capture in have not yet been subjected to such competitive pressures. However, our analysis uses the more conservative pathways from the CEPA report (pathways 4-6) in order to control for several important factors that could partly limit the benefits of increased competition in the onshore network:

a) **Differences in savings potential**: there is some uncertainty around whether the range operating cost savings represented by the premia in pathways 1-3 are fully applicable to onshore assets, as there are some differences between the OFTOs and the onshore network generally. This is especially the case in terms of scale and the underlying risk profiles – OFTOs have to date been point to point connection wires rather than a complex network and thus have relatively simple Operation and Maintenance contracts. The onshore transmission network on the other hand tends to be more complex – the increased complexity in the onshore network could mean a materially different risk profile that could dampen appetite for investment, competitive pressures and thus the overall savings potential.

b) **Fixed costs**: there is some evidence that the operating costs as a percentage of FTV in Tender Rounds 2 and 3 decreased compared to Tender Round 1 as a result of relative project size (assets under TR2/TR3 tended to be larger than in TR1). Therefore, it looks as if some of the underlying Opex consisted of fixed costs. Evidence from a 2016 Frontier Economics study also supports the view that Opex savings from competition could be dependent on the size of tendered assets.[52]

c) **Economies of scale**: the incumbent TOs could benefit from existing economies of scale, since some of the fixed operating costs can be divided across their relatively large portfolio of assets. They may therefore have a natural advantage that may partially offset the benefits of competition.[53]

116. This IA uses the more conservative pathways 4-6 to estimate the range of potential operating cost savings from competition in order to reduce the risk of overstating the benefits that could be realised from increased competition in the onshore network. These results of using these pathways are presented in Table 14.

117. We have also decided to include an additional set of sensitivities around operating cost savings in order to control for the possible impact of asset size on operation cost savings – these new 'pessimistic' versions of pathways 4-6 are based on evidence from Frontier Economics' study on the benefits of Ofgem's proposed 'late' CATO model.[54] The paper presents a range of possible operating cost savings that could be realised in a competitive context versus a 'National Grid project specific' counterfactual, where infrastructure is delivered by National Grid alone (which is broadly comparable to this IA's 'Do Nothing' scenario). The paper shows that operating cost savings could be dependent on asset size – ranging from 1% to 1.6% of the value of the asset – **with the lower range (1%) being applicable to assets valued at £100m**.[55]

118. However, it is not clear from the report to what extent these savings materialise over the lifetime of the asset. It is unlikely that the 1% saving is a premium that materialises over the entire lifetime of the asset – this IA assumes that Ofgem could drive down operational costs under the 'Do Nothing' scenario, though likely at a slower rate than under increased competition. Therefore, we have constructed a new set of 'pessimistic' pathways based on CEPA's pathways 4-6 – the

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[52] Frontier Economics, 'A cost benefit analysis of the potential introduction of competitively appointed transmission operators', published January 2016, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf, p. 53

[53] *Ibid*., p. 41

[54] Ofgem, 'Quick Guide to the CATO Regime', published November 2016, https://www.ofgem.gov.uk/publications-and-updates/quick-guide-cato-regime-november-2016

[55] Frontier Economics, 'A cost benefit analysis of the potential introduction of competitively appointed transmission operators', published January 2016, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf, p. 53

difference being that the starting premium is at **1%** rather than **1.6%** (see table 13 below, also see blue lines in chart 1). The relative trajectory of these 'pessimistic' pathways is identical to that of CEPA's pathways 4-6 – i.e. in years 6-10, the premia of pathways 4 and 5 are at ~70% of their value in year 1-5, in years 11-15 they are at ~35% etc. 100. These pathways thus represent a pessimistic scenario where operating cost savings from the introduction of competition in onshore networks are more limited than envisaged. The results of using these pessimistic pathways are presented in Table 15.

119. Table 12 below sets out the three pathways for operating cost assumptions used in the CEPA report, expressed as the difference between operating costs for Counterfactual 3 and the assumed preferred bidder under the OFTO regime. Operating costs are expressed as percentage of the final transfer value. This IA assumes that the final transfer value is equivalent to the capex of the project.

**Table 12: Opex CENTRAL case – Operating cost savings assumptions (% of final transfer value)**

| Difference between Counterfactual 3 and the preferred bidder | **'Pathway 4'** – Central | **'Pathway 5'** – Low | **'Pathway 6'** – High |
|---|---|---|---|
| | 1.6% (Years 1-5)<br>1.1% (Years 6-10)<br>0.6% (Years 11-15)<br>0.6% (Years 16-20) | 1.6% (Years 1-5)<br>1.1% (Years 6-10)<br>0.6% (Years 11-15)<br>0.0% (Years 16-20) | 1.6% (Years 1-5)<br>1.6% (Years 6-10)<br>1.6% (Years 11-15)<br>1.6% (Years 16-20) |

120. Using these operating cost assumptions, central, low and high cost saving scenarios can be established. The average of these represents the average savings from each asset over an assumed 20-year period of operation.

**Table 13: Opex PESSIMISTIC (sensitivity) – Operating cost savings assumptions (% of final transfer value)**

| Difference between Counterfactual 3 and the preferred bidder | **'Pathway 4'** – Pessimistic Central | **'Pathway 5'** – Pessimistic Low | **'Pathway 6'** – Pessimistic High |
|---|---|---|---|
| | 1.0% (Years 1-5)<br>0.7% (Years 6-10)<br>0.3% (Years 11-15)<br>0.3% (Years 16-20) | 1.0% (Years 1-5)<br>0.7% (Years 6-10)<br>0.3% (Years 11-15)<br>0.0% (Years 16-20) | 1.0% (Years 1-5)<br>1.0% (Years 6-10)<br>1.0% (Years 11-15)<br>1.0% (Years 16-20) |

121. It must be stressed that the 'pessimistic' pathways (table 13) represent an extreme scenario where all tendered eligible assets in the pipeline are valued ~**£100m** – thus leading to lower than expected operating cost savings. Such a scenario is extremely unlikely, as large-scale transmission projects are often worth many hundreds of millions of pounds.

122. Therefore, the estimates derived from the 'pessimistic' versions of pathways 4-6 have been used for sensitivity purposes only and have **not** been included in the main table of results (Table 2). Government believes that the inclusion of the 'pessimistic' pathways in the range of results risks significantly understating the benefit to society that can be gained from increased competition. The estimates presented in this IA include several other sensitivities that already factor in optimism bias – i.e. the use of CEPA's pathways 4-6 instead of the more optimistic pathways 1-3 and the inclusion of a scenario where asset construction costs increase by 10% as a result of a poorly designed competition. The latter scenario is very unlikely to materialise, but it is necessary to include due to the lack of concrete data on construction cost savings. The

data on operating cost savings on the other hand is much more robust as it is based on extensive data and analysis of the OFTO experience.

123. Therefore, the central range of estimated benefits will only use the results from table 14 – the results of the 'pessimistic' pathways (table 15) are only presented for illustrative purposes. The impact of this sensitivity is also shown in chart 4. As an illustration, the use of the 'pessimistic' pathways reduces the lower bound of the net benefit to society under the central scenario (pipeline scenario #3) by ~£200m – from a range of **£300m – £500m** down to **£100m – £500m**. In the very unlikely event that all tendered assets are no larger than ~**£100m** in value, the associated operating cost savings – though much reduced compared to the central case – still result in a large net benefit to consumers, to the tune of hundreds of millions of pounds (see chart 4).

124. Thus, the savings calculated using pathways 4-6 (non-pessimistic) represent the central case of operating cost savings across all pipeline scenarios. The range of operating cost savings under the 'central case' pathways 4-6 is shown in Table 14.

125. This IA assumes that all operating cost savings are passed on to consumers (Tables 14 & 15).

**Table 14: Estimated Operating Savings through Competition over 32 years (2020 prices) – using pathways 4-6 (Opex CENTRAL case)**

| | Annual* | 32 Year Period (PV) |
|---|---|---|
| **Scenario 1** | £0m per year | £0m |
| **Scenario 2** | £20m per year | £300m |
| **Scenario 3** | £35m per year | £525m |
| **Scenario 4** | £45m per year | £600m |
| **Scenario 5** | £75m per year | £1,050m |

Note: All estimates are rounded;
*Average annual estimate over the capacity lifetime (25 years)

**Table 15: Estimated Operating Savings through Competition over 32 years (2020 prices) – using pathways 4-6 (Opex PESSIMISTIC sensitivity)**

| | Annual* | 32 Year Period (PV) |
|---|---|---|
| **Scenario 1** | £0m per year | £0m |
| **Scenario 2** | £15m per year | £190m |
| **Scenario 3** | £25m per year | £325m |
| **Scenario 4** | £30m per year | £370m |
| **Scenario 5** | £45m per year | £650m |

Note: All estimates are rounded;
*Average annual estimate over the capacity lifetime (25 years)

126. In addition to operational savings, the OFTO regime saw important financing cost savings (£360m, NPV).[56] It is difficult to estimate potential financing cost savings for onshore competition, given that the fact that bidders will be taking on construction risk of the asset means that the risk profile is very different. It is also hard to predict a likely cost of capital for onshore projects for new entrants because financiers have never funded them to engage in these types of projects before. However, as is the case with large investments in other sectors, refinancing is likely to take place post-construction which would almost certainly lower the cost of capital substantially (from its pre-construction level). Given these uncertainties, the margin for error for calculating the potential financing cost savings is large; therefore this IA does not attempt to quantify it.

127. Tenders in offshore networks have so far only been run for the right to operate an asset. Tenders for onshore network assets would however almost certainly be run for the right to operate *and* construct an asset. In principle, it is most likely that competition for construction would bear down on costs, which could represent a further saving for consumers. Given the lack of evidence from the offshore experience, this IA draws on different evidence to quantify the impact of the 'Policy Option' on construction costs.

128. To estimate capital savings, we use evidence from Ofgem's SPV model. Analysis conducted by Ofgem assumes construction cost savings can amount to **10%** of the value of the asset for an efficiently run competition.[57] The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can increase by up to 10% due to inefficient implementation by the incumbent. This IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model.

129. As a sensitivity, we have included two further Capex savings scenarios where the capital saving from competition is **0%** (i.e. no net benefit) and **-10%** for a poorly managed competition. This sensitivity aims to account for the increased construction risks that could be borne by new entrants versus an incumbent TO – though it must be stressed that the latter scenario (of a 10% increase in construction costs) is highly unlikely, as the tenders would be run by an independent party that is incentivised to ensure a successful and efficient tender. We apply these assumptions to our scenarios as described in Table 16. It is important to note that the savings (costs) won't all materialise in the year of construction. Instead, these are spread gradually over a longer time period and are passed on to consumers via reduced (increased) network charges using Ofgem's Allowed Revenue approach, in which the capital costs of assets are depreciated over a 45-year period.

[56] 2020 prices. Original figure of £315m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[57] Ofgem, 'Hinkley-Seabank project: minded-to consultation on delivery mode', published January 2018, table 3.3, https://www.ofgem.gov.uk/ofgem-publications/127841, p. 28

**Table 16: Capital cost savings assumptions (% of capex of the project)**

| | Capex savings scenario | | |
|---|---|---|---|
| | Poorly managed competition | No net benefit | Efficiently run competition |
| Scenario 1 | -10% | 0% | 10% |
| Scenario 2 | -10% | 0% | 10% |
| Scenario 3 | -10% | 0% | 10% |
| Scenario 4 | -10% | 0% | 10% |
| Scenario 5 | -10% | 0% | 10% |

130. The evidence for construction cost savings from the SPV model is not as robust as the evidence from the OFTO experience considered for operating costs as it has not arisen from the revealed information of a competitive process. Nonetheless, as the evidence used in the evaluation of the delivery model for a new, high-value and separable onshore transmission asset it constitutes the most relevant and best evidence available at the time of writing. Feedback from Ofgem has clearly indicated that the approach used in the SPV model is the most appropriate one for this analysis.[58] In not including it, this IA would risk being too conservative in the size of the savings that the policy option may realise.

131. The construction cost savings assumed by the SPV model are supported by anecdotal evidence from outside the UK. Examples include the application of competitive tendering to transmission in the “Fourth Line” project in Buenos Aires, Argentina, which led to 44% reduction in total costs.[59] In February 2017, the Energy Networks Association published a report detailing examples where early model competition in high value transmission projects had led to significant cost savings in the rage of 10%-60%.[60] These figures should be treated with caution, given the uncertainty around the counterfactuals used and thus their limited applicability to the GB electricity market. However, these studies do suggest that cost savings and thus benefits to consumers from increased competition in otherwise monopolised markets can be substantial.

132. This IA assumes that all capital cost savings are passed on to consumers (Table 17).

[58] Based on internal discussions with Ofgem (September 2019).

[59] Littlechild and Skerk, (2004) ‘Regulation of transmission expansion in Argentina Part I: State ownership, reform and the Fourth Line’, p. 60.

[60] Ofgem, ‘Developing early models for introducing competition in onshore electricity transmission networks,’ published February 2017, https://www.ofgem.gov.uk/system/files/docs/2017/04/ena_working_group_report_16_feb_2017.pdf, pp. 65-73.

**Table 17: Estimated Capital Cost Savings through Competition over 32 years (2020 prices)**

| | Poorly managed competition (-10%) | | No net Benefit (0%) | | Efficiently run competition (10%) | |
|---|---|---|---|---|---|---|
| | *Per project (undiscounted) over lifetime* | *32 Yr Period (PV)** | *Per project (undiscounted) over lifetime* | *32 Yr Period (PV)** | *Per project (undiscounted) over lifetime* | *32 Yr Period (PV)** |
| **Scenario 1** | £0m | £0m | £0m | £0m | £0m | £0m |
| **Scenario 2** | -£30m | -£60m | £0m | £0m | £30m | £60m |
| **Scenario 3** | -£30m | -£110m | £0m | £0m | £30m | £110m |
| **Scenario 4** | -£60m | -£125m | £0m | £0m | £60m | £125m |
| **Scenario 5** | -£60m | -£215m | £0m | £0m | £60m | £215m |

Note: All estimates are rounded; these costs are included in Table 2 indirectly – by reducing the benefits (for a poorly managed comp.).
*Capital cost savings (costs) do not all materialise on the year of construction. Instead, these are spread gradually over a longer time period and are passed on to consumers via reduced (increased) network charges using Ofgem's Allowed Revenue approach, in which the capital costs of assets are depreciated over a 45-year period.

133. This IA assumes that all savings are passed on to consumers (Table 18). These represent stylised ranges of cost savings, which are mainly aimed at providing a sense of scale rather than a precise assessment of what benefits from competition would be.

**Table 18: Estimated Cost Savings through Competition over 32 years (PV, 2020 prices)**

| | Poorly managed competition (-10%) | No net Benefit (0%) | Efficiently run competition (10%) |
|---|---|---|---|
| **Scenario 1** | £0 | £0 | £0 |
| **Scenario 2** | £0.2bn | £0.3bn | £0.4bn |
| **Scenario 3** | £0.4bn | £0.5bn | £0.6bn |
| **Scenario 4** | £0.5bn | £0.6bn | £0.7bn |
| **Scenario 5** | £0.8bn | £1.0bn | £1.3bn |

Note: All estimates are rounded.

134. **Lower cost of regulation under the price control (TO pass-through):** Set-up, tender and bid costs will be partially offset by lower costs of price control regulation. These lower costs arise from the fact that there would no longer be a need for the TO to conduct a project assessment under the terms of the price control[61]. This will ultimately benefit consumers (indirect benefit). The benefit is initially felt by the incumbent TOs (captured in the sections below). The appointed body passes any reduced cost of regulation under the price control mechanism on to the ESO, which is considered a direct benefit. The ESO will pass these savings on to generators (14%) and suppliers (86%) through lower TNUoS charges (indirect benefit). Generators pass these savings through to end-consumers either in the form of lower wholesale prices (if price setting plants are affected) or in the case of low carbon plant in the form of lower clearing prices in Contract for Difference allocation rounds and therefore potentially more low carbon generation uptake within the Control for Low Carbon Levies, which if it materialised would lead to lower emissions (a benefit for society). This IA assumes that suppliers pass these savings through to end-consumers through lower network charges on customer bills.

[61] Under 'Policy Option', Ofgem determine the needs case.

135. As set out under 'Do Nothing', Ofgem does not have a separate estimate of these reduced costs under the price control mechanism. The costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial. Therefore, because these costs cannot be quantified, the net costs estimated in this IA under the 'Policy Option' might represent a conservative estimate.

*2.2.3 Additional benefits to incumbent TOs under the Policy Option*

136. **Lower cost of regulation under the price control**: Incumbent TOs benefit from lower costs of price control regulation, as they will not have to submit a project assessment submission under the price control for a project which will be competitively tendered. As set out under 'Do Nothing', Ofgem does not have a separate estimate for the reduced costs of regulation under the price control mechanism. Therefore, the net costs estimated in this IA represent high estimates. Incumbent TOs pass any cost reductions through to end-consumers as set out in the 'Lower cost of regulation (TO pass-through)' section above.

137. **Lower cost of regulation under the price control (Ofgem/appointed body pass-through):** Ofgem benefits from a reduced cost of regulation under the price control, because it no longer needs to undertake a project assessment under the price control. It passes these savings on to the respective incumbent TO. As set out under 'Do Nothing', Ofgem does not have a separate estimate for the reduced costs of regulation under the price control mechanism. Therefore, the net costs estimated in this IA represent high estimates. Incumbent TOs pass any cost reductions through to end-consumers as set out in the 'Lower cost of regulation (TO pass-through)' section above.

138. **Lower expenditure on transmission assets**: Reduced barriers to entry in the transmission market, and an increased number of parties in the market, will create competitive pressure and better cost discovery. Incumbent TOs will consequently spend less on assets due to either:

a) not being appointed as the successful bidder in situations where the asset would otherwise have fallen into their region (case 1, transfer); or

b) being appointed as successful bidder but at a more efficient asset cost (case 2).

139. The lower expenditure under case 1 represents a **transfer within the 'producer' group** (incumbent TOs and new entrants) as any reduced expenditure by incumbent TOs is partially offset by an increase in expenditure from new entrants (who would anyway have more efficient costs due to competitive pressures, as set out in the cost section). In this case, the incumbent TO would not receive the revenue stream and, therefore, the return for the asset (as set out in the cost section). In turn, the potential increase in expenditure for new entrants is offset by their receipt of a revenue stream. These transfers have not been quantified as they depend on the incumbent TOs submitting a bid and, if they bid, their success rate in the tender process.

140. Expenditure under case 2 is reduced because the incumbent TO has been appointed as successful bidder, but competitive pressures mean that their costs are more efficient.

141. The 'Assumptions and Risks' section below discusses the treatment of preliminary works in the analysis.

*2.2.4 Additional benefits to the ESO under the Policy Option*

142. There are no additional benefits for the ESO under the 'Policy Option'.

*2.2.5 Additional benefits to new entrants under the Policy Option*

143. **Market entry**: New players will benefit from the policy option because it creates a route to market.

144. **Potential gain of returns on assets (transfer)**: An increased market share for new entrants means that they should benefit from a return on any assets they own in the form of a revenue stream, provided that actual asset delivery costs are not eroding the returns.

145. The potential return for new entrants represents a **transfer within the 'producer' group** (incumbent TOs and new entrants), because it can only occur when an incumbent TO loses the return (given they would not receive the revenue stream, though not incur the asset cost). For simplicity, this IA assumes that the loss in return for incumbent TOs is offset by the gain in return for new entrants. Therefore, the return to the 'producer' group is assumed to be unchanged. While new entrants incur a lower capital expenditure, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption on returns being unchanged is a fair one.

146. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how revenue streams are set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

147. Note that these transfers have not been quantified as they depend on the new entrants' success rate in the tender process.

*2.2.6 Additional benefits to Ofgem/the appointed body under the Policy Option*

148. **Lower cost of regulation under the price control (directly passed through)**: Tender costs will be offset by reduced costs of regulation under the price control. The reduced cost of regulation relates to the reduced costs of undertaking a project assessment for projects covered by the price control mechanism under 'Do Nothing', but deemed eligible for competitive tendering in the 'Policy Option'. Ofgem or the appointed body will pass any reduced cost of regulation directly on to the ESO (direct benefit), which will then pass these savings on to generators/ suppliers, and ultimately end-consumers, as set out in the 'Lower cost of regulation (TO pass-through)' section above. Ofgem does not have a separate estimate for these reduced costs. However, as the costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial, it is likely to offset the additional tender costs to a certain degree. Therefore, the net costs estimated in this IA represent high/conservative estimates.

149. **Reputation and confidence benefit**: Ofgem is likely to experience a reputational benefit from being better able to protect existing and future consumers. Furthermore, introducing competition would mitigate the current information asymmetry that exists between Ofgem and the TOs, the existence of which suggests that Ofgem is currently inhibited from ensuring consumers are provided the best value for money. Confidence in the regulator is, therefore, increased when competition is applied, if Ofgem is appointed by Secretary of State to run tenders.

## Note on Net Cost / Benefit Estimates

150. Table 1 (found in the 'Results of the Cost Benefit Analysis of the proposed intervention' section of this IA) summarises the estimated direct net monetised benefit to business in NPV terms across the five scenarios. The scenarios demonstrate the likely scale of potential costs and benefits. Note that not all costs and benefits could be quantified (as set out in the detailed sections above).

151. The quantified direct net cost to business is in the range of £3m to £235m (PV) over the appraisal period of 32 years, with a central estimate of £120m (PV). Note that while some businesses, namely TOs and new entrants, incur the direct expenditure, they will pass these costs onto other businesses, namely generators and suppliers (indirect cost), which ultimately pass them on to end-consumers, which includes business consumers (indirect cost).

152. The net benefit to society is in the range of **-£3m to £1.0bn** (NPV over 32 years) (Table 2). All of these costs and benefits will be incurred as a consequence of secondary legislation. None of these costs or benefits relate directly to the primary legislation associated with this IA. The net benefit to society under the central scenario (pipeline scenario #3) is estimated to range between **£300m – £500m** (NPV over 32 years).

## Assumptions and Risks

153. For the quantifications in this IA, various assumptions have been made. These are set out below. Most importantly, the monetised impacts estimated in this IA aim to provide a sense of scale of benefits and costs, rather than to provide definite predictions of likely costs and benefits.

154. **Cost savings due to competition:** The benefits section above sets out how Government has derived cost savings in this IA. Much of this analysis relies on a comparison with an independent evaluation of the results of the first three rounds of offshore tenders carried out for Ofgem by CEPA. Several caveats need to be borne in mind:

a) While new entrants are likely to incur a lower capital expenditure than incumbent TOs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. However, as is the case with big investments in other sectors, refinancing is likely to take place post-construction, which would almost certainly lower the cost of capital substantially (from its pre-construction level).

b) Savings in the offshore regime were realised in part by offshore generators bidding for very low maintenance costs in an attempt to maintain control over their own assets. Arguably, because there is no corresponding generation asset to attempt to control in an onshore competition, onshore bidders will not be incentivised to bid for such low maintenance costs, and overall savings may be lower. However, savings could be seen in construction delivery, and there have been genuinely innovative approaches to asset maintenance in the offshore regime which has brought about savings.

c) Two reports by CEPA analysed the level of savings realised in delivering the first 15 offshore licences. A further 6 licences have been awarded since the CEPA reports were published, and an additional 25 projects are on the pipeline. Given that these have not yet been analysed in a report similar to the CEPA reports, the analysis in this IA does not factor in any changes that these additional licences would make to achievable operating cost savings.

d) Government recognises, as indicated in the CEPA report, that there are limits to the extent to which lessons can be drawn from the CEPA report conclusions for the onshore electricity transmission network, given that the outcomes demonstrated in the report are context - and time - specific. However, Government believes that the onshore projects expected to be captured by competitive tendering share similarities with offshore projects – being new, high-value, and separable – and, therefore, comparisons are reasonable. It is also the case that this report, which estimates the savings realised by introducing competition into the offshore electricity transmission network, is the best indication of the operating savings likely to be realised by introducing competition into the onshore electricity transmission network.

155. **Pipeline scenarios:** The IA proposes a future pipeline of eligible projects by analysing historic information on TIRG[1] and TII[2] investments over TPCR4 from 2007/08 to 2012/13. The IA has also considered the levels of investment that have occurred over the RIIO-T1 (under and SWW[3]) and ED1 price control regimes. The IA emphasises the uncertainty surrounding this pipeline and the likelihood that assets will eventually be constructed through competitive

[1] www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview
www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-sp-transmission-ltd-and-scottish-hydro-electric-transmission-ltd

[2] Ibid.

[3] www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal.pdf; www.ofgem.gov.uk/ofgem-publications/84439/finaldecisionletter-kintyrehunterston.pdf; www.ofgem.gov.uk/ofgem-publications/87262/decisiononthe proposedbeaulymossfordreinforcementunderriio-t1strategicwiderworksarrangements.pdf; www.ofgem.gov.uk/ofgem-publications/91977/decisiononourassessmentofthecaithnessmoraytransmissionproject.pdf

tendering in the future. Whilst Ofgem does possess a forecast of projects to be constructed, this forecast is commercially sensitive, and there is no certainty over which of the projects in it would be competitively tendered. To mitigate this uncertainty, this IA considers five investment scenarios over the next 10 years of £0per year, £0.55bn every other year (an undiscounted total of £2.2bn investment over the next 10 years), £0.55bn per year (an undiscounted total of £3.85bn investment over the next 10 years), £1.1bn every other year (an undiscounted total of £4.4bn investment over the next 10 years) and £1.1bn per year (an undiscounted total of £7.7bn investment over the next 10 years). Note that all undiscounted totals account for the first three years being used for scheme set up and the first tender round. £0 per year is considered an extreme lower bound, while £1.1bn per year represents an extreme upper bound. However, if more than £1.1bn per year were to be realised, the additional benefits from competition would outweigh the associated costs. Therefore, in this respect, the IA risks being too conservative in terms of benefits from competition. Discussions with Ofgem have confirmed that the above set of pipeline scenarios are also broadly in line with the potential pipeline of projects under RIIO-T2 that might meet the expected criteria for competition (based on current draft RIIO-T2 business plans).

156. The IA assumes that a set of criteria (new, high-value, separable) will be applied to the pipeline scenarios to select the assets that will be tendered. This represents the best available information at the time of writing this IA. However, the final criteria will be set by the Secretary of State in regulations. Therefore, there is a risk in the level of precision of the final criteria, which reflects the possibility that the investments captured by competitive tendering will change. The fact that the scenarios encompass a wide range of possible outcomes mitigates against this risk.

157. If a tender fails, no bidder is appointed, and a third party who agrees to manage the asset cannot be found, Ofgem intends to enable a ‘last resort’ mechanism. Under this mechanism, a transmission owner will be required to manage the relevant assets for a period of time. This mechanism exists in the offshore regime, but has never been used, because competitions have never failed in this way. This IA assumes that assets would be built by a competitively appointed TO, or eventually transferred to a competitively appointed TO through commercial negotiations, a reasonable assumption given that the offshore scheme has to date always been successful in appointing an owner.

158. **Size of projects:** The investment averages are assumed to cover one or several projects (depending on the ‘high value’ criterion). Because tender and bid costs are expressed in percentage terms, this IA assumes that costs increase in tandem with higher asset values or more projects. The impacts of size or number of projects on tender costs are set out in the tender cost section under the ‘Policy Option’.

159. **Preliminary works**: The incumbent regional transmission licensee or the SO may complete early development work and some preliminary works prior to a tender. The current expected position is that the incumbent regional transmission licensee would undertake these works; however, it is possible that Ofgem would request that the SO carries out these works in future. The nature and extent of these works would depend on the tender model used. If the SO takes on these works, while this may involve a small amount of additional cost for the SO, these costs will be offset by the work no longer undertaken by TOs (transfer within the “Producer” group). These arrangements will be further considered as part of secondary legislation when a detailed framework is developed. This has not been quantified in this IA.

160. **Cost of regulation of projects assumed eligible**: In order to estimate the cost of regulation for potentially eligible projects, it is worthwhile considering the costs faced by other large projects, such as those falling under TIRG, TII or SWW. These include costs associated with eligibility, needs case and project assessment stages. Ofgem estimates that this process takes approximately 12-15 months from the start of the assessment process to a funding decision for

well-evidenced proposals, but it can take upwards of 2 years for many projects.[4] Costs are incurred by both Ofgem and the TOs. As advised by Ofgem, it is not possible to provide an estimate for these costs in isolation. However, the costs of conducting price controls and assessing the needs cases and project assessments for specific projects within the price controls are non-trivial.

161. **Chosen assessment timeframe:** Extending competitive tendering to transmission assets is considered to be a permanent policy change i.e. there is no end-date. Therefore, for the purpose of the quantifications in this IA, pipeline scenarios of network assets coming forward over the next 10 years and their respective savings over a 20-year period have been used. This is in line with the evidence provided by the offshore regime. The appraisal timeframe in this IA in full is therefore 32 years. Choosing a longer time frame magnifies the scale of the costs and benefits; however, the overall conclusion that more competition is beneficial for society is unchanged.

162. **Return on Investment for incumbent TOs and new entrants**: For simplicity, it is assumed that the group of incumbent TOs and new entrants as a whole has unchanged returns between 'Do Nothing' and the 'Policy Option'. While, under the Policy Option, new entrants incur a lower capital expenditure, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption that returns are the same across 'Do Nothing' and the 'Policy Option' is a fair one.

163. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how revenue streams are set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

164. **Bid costs for incumbent TOs and new entrants:** Bid costs include the costs incurred in preparing bids for evaluation, reaching the licence grant and acquiring the asset. Actual bid costs from the offshore regime are commercially sensitive and cannot be used for the purposes of this IA. Instead, this IA uses the findings from the CEPA report, which sets out that successful bidder costs are £80m,[5] or approximately 2.4% of the Final Transfer Value (FTV), over fifteen projects. 2.4% of asset value is likely to be a conservative estimate. Offshore, because generators build the assets that are eventually transferred to the winning bidder, time and resources are spent on due diligence on those built assets, which can substantially add to bid costs. We do not expect this to be the case for onshore (because the competitively appointed party will build their own asset), which means that bid costs may be lower. Further, there will be other avoided onshore costs (such as not having to prepare SWW project assessment submissions), which may reduce the overall size of the bid costs. There is no separate estimate of these avoided costs and they are therefore not quantified in this IA.

165. The cost to each unsuccessful bidder of preparing bids for evaluation has not been quantified because this information is commercially confidential. The total costs of unsuccessful bids in each tender round would also rely on the total number of bidders, which varies across tenders.

166. **Additional interface costs for the SO:** This IA assumes that there are no additional interface costs for the SO. There may be an incremental interface cost associated with adding

[4] https://www.ofgem.gov.uk/ofgem-publications/85263/strategicwiderworksfactsheet.pdf

[5] 2020 prices. Original figure of £70m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

new parties to the network; however, because the SO already interacts with a broad group of industry parties, additional parties would only lead to a marginal increase in cost, which Government estimates to be zero. Industry codes and standards are already in place to manage the relationships between parties and, where necessary, they can be amended to accommodate competitively appointed TOs and to ensure that industry relationships are managed in a constructive and efficient manner.

167. **Tender costs for the body appointed by the Secretary of State to run the tenders:** Ofgem estimates that scheme set-up costs are between £2m-£3m (2013/14 prices). For the purpose of this IA, a conservative estimate of £3.3m (2020 price base) spread over two years has been assumed. These costs will occur prior to launching the first tender, regardless of the subsequent volume or frequency of tenders. Costs of running an individual tender, associated broadly with staffing, technology and external advice on legal technical and financial matters, are assumed to be 1% of the asset value. This is based on the offshore experience. In reality, these costs will vary by project and tender round, given that there are some fixed costs associated with running tenders. However, it is expected that these costs will balance out over time and 1%, therefore, represents an appropriate long run average.

168. In place of one large project, several smaller projects could be tendered in a given year, which may either increase the appointed body's administration costs (because they are running several projects) or decrease them (because they are running several projects at once). Consequently, 1% represents an appropriate long-run average and is based on Ofgem's experience to date. For the purpose of this IA, an upper-bound cost estimate has been assumed. It is important to note that these costs would be partially offset by other avoided costs (e.g. Ofgem assessment and processing of SWW project assessment submissions). However, these costs have not been quantified.

## Innovation impacts

169. Innovation impacts from increasing competition in the GB onshore network have only been quantified indirectly in this IA. The expected benefits from reduced operating and construction costs would partly be driven by an expanded market which in turn should incentivise market participants to adopt cost saving innovations through the introduction of new services and technologies.

170. The incumbent network operators currently have **monopoly rights** over the planning, construction and operation of all network assets in their respective regions. While network operators already competitively tender certain aspects of their projects, they retain overall control and cost information. This presents a **significant barrier to entry** as it limits the ability of other parties to participate fully in the market, regardless of whether they may be able to deliver assets more efficiently. Limiting the size of the market also limits approaches to procurement, price-reflectivity, financing and construction. The proposed intervention will help to address some of these barriers to innovation via increasing competitive pressures in the market.

171. Depending on the nature of the tenders, new market participants will be invited to present designs, manage the supply chain and operate the transmission assets. Current incumbents will be further encouraged to seek savings and produce innovative approaches to delivering and maintaining assets.

172. Particular attention should be given to the ways in which the policy will diversify the sources of labour and capital, both of which would incentivise innovation. Opening up investment opportunities to new parties allows different sources of labour and capital to enter the industry. Competitive pressure and the involvement of new parties in the market will likely lead to preferential financing costs and drive innovation. On an individual project basis, innovation can result in lower costs and better value for consumers.

173. For example, in financing, Greater Gabbard OFTO was the first UK and second EU project to use the innovative EIB Project Bond Credit Enhancement (PBCE) product[6], reducing the cost of capital and giving value to consumers. In technology development, TC Ormonde OFTO Ltd was awarded funding through the 2014 Network Innovation Competition to develop an offshore cable repair vessel and universal cable joint.[7] This has reduced the cost of offshore maintenance and produced benefits for consumers.

174. Innovation may also occur in the technical, commercial and financial space – these are, however, very difficult to quantify, and have therefore not been monetised in this IA.

## Household bill impacts

175. We expect that the savings derived from the introduction of competition in GB's onshore networks will be passed down to consumers. Government estimates find that, on average over the next 30 years, onshore competition in transmission networks can be expected to save around £1 per year on the average annual household dual fuel bill.

176. This estimate is based on our conservative estimate of the possible benefits of introducing competition – in reality, the net benefits from introducing competition could be significantly higher than presented in this IA. This means that the actually realised future average household bill savings could be higher than suggested by our estimate.

177. This estimate does not account for changes to household consumption as a result of achieving Net Zero. The average household consumption of electricity is expected to increase with electrification of heat and transport, so if a household were to increase their electricity consumption by installing a heat pump or getting an electric vehicle, the saving on their electricity bill would increase.

[6] https://www.ofgem.gov.uk/press-releases/ofgem-grants-offshore-transmission-licence-greater-gabbard-wind-farm

[7] https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition/transmission-capital-partners

## Public Sector Equality Duty (PSED) and Onshore Competition Proposals

178. The PSED is a duty requiring public authorities and others carrying out public functions to have due regard to:

a) eliminate unlawful discrimination, harassment, victimisation and any other conduct prohibited by the Equality Act 2010;

b) advance equality of opportunity between people who share a protected characteristic and people who do not share it; and

c) foster good relations between people who share a protected characteristic and those who do not.

179. We have reviewed how the PSED relates to expanding competition in GB's onshore network. Our assessment is that the proposed intervention does not lead to any discrimination, harassment, victimisation or other prohibited conduct as described under Limb a) of PSED. As set out in this Impact Assessment, we expect competition in onshore electricity networks to lower the costs associated with addressing network constraints. As more electricity network reinforcement will be necessary in order to meet Net Zero by 2050, lowering the network costs associated with those reinforcements should have the effect of lowering consumer bills, as network investment is funded via consumer bills across GB. We do not expect this to impact negatively on any group with a protected characteristic under the Equality Act 2010 and it should benefit all consumers, regardless of their characteristics and backgrounds.

184. Under limb (b) we consider that the policy may remove or minimise disadvantages connected with particular protected characteristics. Those with protected characteristics may be exposed to higher electricity consumption costs if their consumption is higher. Competition would lower the additional costs necessary for network reinforcement to meet Net Zero, and so the anticipated increase on bills of those with protected characteristics may be less, assuming their consumption is higher than those without that protected characteristic. So the policy could to advance equality of opportunity between people who share a protected characteristic and people who do not share it in some circumstances. Given the nature of this policy is to lower bills, we consider the policy is neutral in regard to limb (c) of the PSED –the decision to proceed will have no effect on relations between individuals who share a protected characteristic and people who do not share it.

185. We have also considered how the policy will be implemented in the table below (Table 19) and consider that the steps in implementing onshore competition policy will take PSED considerations, across the three limbs, into account.

**Table 19: Does PSED relate to Onshore Competition?**

| Onshore Competition Policy Point | PSED |
|---|---|
| **SoS appointing a body to run tenders** | SoS is bound by PSED when exercising his/her power to appoint a body.. |
| **Body running tenders** | SoS would select a body able to undertake this role with due regard to PSED. A body exercising public functions must have regard to PSED in the exercise of those functions, so PSED would be applicable to any decision made by an Appointed Body exercising a public function. |
| **Ofgem awarding a licence** | Ofgem already undertakes this duty (granting licences), in line with all its duties as a public authority. |
| **Criteria for competitions (in secondary regs)** | Criteria are set based on physical infrastructure data and analysis that follows. This does not involve individuals and their associated characteristics. |
| **Ofgem deciding when competitions are triggered** | Ofgem already undertake this duty for offshore competitions. They make this assessment based on objective criteria related to the criteria set out in associated Regulations. |

186. Given our consideration of PSED in the context of policy of competition in onshore networks, we intend to ***Proceed as planned with the policy***. As with competitive tenders offshore, we will undertake analysis for competitions on the electricity onshore network as competitions take place. As part of this, we will consider PSED and whether the conclusions reached at this stage of the policy still hold, or whether updates should be made and amendments to policy considered.

## Wider impacts

### Economic and financial impacts

187. The estimated quantified and non-quantified impacts on consumers and businesses of extending the use of competitive tendering in the GB transmission network are covered in the monetised costs and benefits assessment above. This also addresses the expected impacts on Ofgem. Impacts on small and start-up businesses are captured in the Small and Microbusiness Assessment below.

188. Particular attention should be given to the ways in which the policy will diversify the sources of labour and capital and incentivise innovation. Opening up investment opportunities to new parties allows different sources of labour and capital to enter the industry. Competitive pressure and the involvement of new parties in the market will likely lead to preferential financing costs and drive innovation. On an individual project basis, innovation can result in lower costs and better value for consumers.[8]

189. Increased diversity in the industry also increases the sources of information Ofgem can use to benchmark[9] cost submissions, thus helping to improve the regulation of all transmission projects, and not only those that are subject to competition.

190. More investment in electricity networks may also prompt stronger investment appetite from newer investors.

### Social impacts

191. There are no social impacts expected to arise under the ‘Policy Option’.

192. Government does not expect any additional impacts of the ‘Policy Option’ on vulnerable consumers as a subset of GB consumers. However, consumers who have lower incomes will generally see greater relative improvements in the affordability of their electricity compared to ‘Do Nothing’. This is because the majority of benefits achieved under the ‘Policy Option’ will be passed by suppliers to consumers through lower network charges which are a fixed proportion of consumer bills. Consumers in lower incomes tend to have lower energy consumption which means they benefit more from lower fixed charges.

### Environmental impacts

193. The proposed ‘Policy Option’ is unlikely to have any significant environmental impacts. Innovative approaches to delivering and maintaining transmission assets may lead to lower embedded carbon levels. In addition, lower network costs may serve to encourage investment in the energy sector more generally, and this may focus on low carbon generation.

### Trade impacts

194. Following this consultation stage IA, we will assess the potential impacts on international trade and investment and demonstrate these impacts in our Final Stage Impact Assessment (if applicable), in consultation with the Department for International Trade (DIT).

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[8] For example, in financing, Greater Gabbard OFTO was the first UK and second EU project to use the innovative EIB Project Bond Credit Enhancement (PBCE) product (https://www.ofgem.gov.uk/press-releases/ofgem-grants-offshore-transmission-licence-greater-gabbard-wind-farm), reducing the cost of capital and giving value to consumers. In technology development, TC Ormonde OFTO Ltd has been awarded funding through the 2014 Network Innovation Competition to develop an offshore cable repair vessel and universal cable joint (https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition/transmission-capital-partners). This is intended to reduce the cost of offshore maintenance and produce benefits for consumers.

[9] ‘Benchmarking’ is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

## Monitoring and evaluation

195. For any subsequent secondary legislation following on from this measure, we will ensure appropriate and proportionate monitoring, evaluation and review processes are put in place.

## Rationale and evidence that justify the level of analysis used in the IA

196. Where possible, impacts of the proposed measure have been quantified and monetised, mainly to provide a sense of scale of the likely impacts. The quantification of pipeline scenarios is stylised due to the uncertainty and market sensitivity around potentially eligible projects in the pipeline. Monetisation draws heavily on the competitive tendering experience for offshore transmission assets (because it is the best available source of data). Sensitivity analysis has been used to demonstrate the uncertainties associated with the assumptions made in this IA.

## Small and Microbusiness Assessment (SMBA)

197. There are no small or microbusinesses currently operating in the transmission sector. The current incumbent TOs – National Grid Electricity Transmission, SP Transmission and SHE-Transmission– are large businesses. Operators of offshore transmission assets who secured their licences through the competitive process introduced in 2009 are all Special Purpose Vehicles consisting of consortia of large businesses, such as construction companies or financial institution investors.

198. The policy option proposed here does not introduce any additional burdens on small or micro-businesses. Instead, the policy option lifts a barrier to small- and microbusiness-involvement in the transmission market by opening up the market to new entrants.

199. Small and micro-businesses may see greater relative improvements in the affordability of their electricity compared to ‘Do Nothing’ than other businesses.

## Government consultation on competition in onshore electricity networks

200. This analysis was published in the form of a Consultation Stage Impact Assessment in August 2021 alongside a consultation on this policy.[10] We received some helpful comments and feedback from respondents which we have summarised below.

201. Several respondents stated that the Impact Assessment does not include costs associated with delays or failures of projects, delays to Net Zero or security of supply. One respondent indicated the Farmer report which sets out that there is a clear benefit from certain, long-term sustainable pipeline of projects, as these lead to innovation, productivity and efficiency savings, as an example of the risks associated with uncertainty in the forward look of network projects.

- ***Government response***: The Government consultation stated that we see competition policy as a key enabler of Net Zero and that we will work to build the policy to ensure that as much certainty as possible is provided to the market to avoid costs associated with uncertainty. We are continuing to work with Ofgem and stakeholders to provide clarity on the point at which projects are declared eligible for competition and have included more information on this point in the Government’s Response to consultation at question 7. With regards to the specific point on security of supply, we will work with Ofgem and the Appointed Body to ensure that assessment criteria for tenders are robust and the risk to security of supply is mitigated.

202. Several respondents stated that the Impact Assessment only considers competition at the transmission level, and further analysis is required before a decision is taken to extend competition to the distribution network

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[10] Gov UK (2021), ‘Competition in onshore electricity networks’, https://www.gov.uk/government/consultations/competition-in-onshore-electricity-networks.

- ***Government response***: We agree with this assertion and welcome the valuable input from stakeholders through the consultation on the application of competition at distribution level. We will continue to develop this policy for thorough analysis and will rigorously assess costs and benefits ahead of introduction of a competitive regime for distribution network solutions.

203. One respondent stated that the Impact Assessment does not consider weighing up the value of projects which are more short term against those with longer lifetimes

- ***Government response:*** Given that the Consultation stage Impact Assessment focused on the transmission level only, short-term projects were mostly outside the scope of the IA. The focus of the IA was on quantifying the potential benefits that could arise with a new competition regime for assets on the transmission network, which tend to have relatively long asset lifetimes and involve much longer time horizons for planning and construction and which tend to be more expensive. By excluding short term projects, the consultation stage IA potentially arrives at conservative estimates; this conservative approach is necessary partly due to the uncertainty around the precise nature of the future competition regime and how many future assets would meet the eligibility criteria for competition. We will assess the potential costs and benefits of a competitive regime for shorter term projects and distribution network solutions – we plan do this ahead of the introduction of a competitive regime for distribution network solutions.
- It will be for the Appointed Body to assess different solutions which bid into a tender under this competitive framework, and we expect as part of the solution-agnostic framework that this sort of comparison will be undertaken as part of due diligence as a responsible Appointed Body.

204. One respondent asked that the methodology by which the Impact Assessment set the high value threshold for a project being eligible for late-model competition at £100m be made clearer, whilst recognising the value of a threshold.

- ***Government response:*** The IA's 'high value' threshold for a project being eligible for competition was based on Ofgem's proposed threshold for the CATO model.[11] We recognise that there may be value in a lower 'high value' threshold – however, the IA purposely opted to use more conservative estimate of £100m per asset due to uncertainty around the precise nature of the future competition regime.

205. One transmission owner indicated that their building of new assets on the network is subject to competition in the market and seek further information on how CAPEX savings found in the Impact Assessment were reached.

- ***Government response:*** The IA's Capex assumption was derived Ofgem's SPV model.[12] Ofgem's analysis assumes construction cost savings can amount to 10% of the value of the asset for an efficiently run competition. The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can increase by up to 10% due to inefficient implementation by the incumbent. Our IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model. As a sensitivity, we have included two further Capex savings scenarios where the capital saving from competition is 0%

[11] See: Ofgem (2020), 'Draft Impact Assessment on applying late competition to future new, separable and high value projects in electricity distribution networks during the RIIO-2 period', p. 3.

[12] see: Ofgem, 'Hinkley-Seabank project: minded-to consultation on delivery mode', published January 2018, table 3.3, https://www.ofgem.gov.uk/ofgem-publications/127841, p. 28

(i.e. no net benefit) and -10% for a poorly managed competition. This sensitivity aims to account for the increased construction risks that could be borne by new entrants versus an incumbent TO – though it must be stressed that the latter scenario (of a 10% increase in construction costs) is highly unlikely, as the tenders would be run by an independent party that is incentivised to ensure a successful and efficient tender. Our analysis showed that even with a pessimistic Capex savings scenario (10% increase in costs), the introduction of competition would still result in significant net benefit to society.

- By allowing for a range of solutions to come forward from a range of bidders, we expect to find savings through new and innovative savings, in both CAPEX and OPEX.

206. One respondent stated that costs would occur due to fragmentation of the network and this should be included in policy analysis for competition.

- ***Government response:*** We consider that the savings associated with competition will far outweigh any costs associated with fragmentation. The System Operator will administer the balancing of the electricity system, including for successful bidders under this competitive regime in the same way as with incumbent network companies.

207. We will continue to consider these points raised and consider them as we develop analysis on this policy as it continues to progress towards implementation.

## Summary and preferred option with description of implementation plan

208. In 2019, approximately a fifth to a quarter of a typical household electricity bill was made up of the cost of transporting electricity from the place that it was generated to the customer.[13] Bearing down on the costs of developing, improving and maintaining the infrastructure through which electricity is transmitted ensures that customer bills are kept as low as possible.

209. In 2009, Government introduced legislation that enables Ofgem to determine through a competitive process the party that owns and operates offshore transmission infrastructure. It is estimated that between 2009 and 2016, this approach created savings of £490-£860 million.[14]

210. In light of this, Government proposes to enable competitive tendering in other areas of the electricity network, where it and Ofgem judge that a competitive tender could be socially beneficial.

211. Government is proposing primary legislation that would enable implementation of this competitive process through secondary legislation.

212. At the primary legislative stage, there are no immediate monetised costs or benefits. The costs and benefits at the secondary legislation stage have been assessed as far as possible. This assessment is based on stylised assumptions about eligible projects, and estimated costs and savings are based on the offshore experience of competitive tendering and on the assumptions underpinning Ofgem's Special Purpose Vehicle model for onshore transmission competition. This analysis suggests that the proposal should result in a net benefit to society of between **-£3m to £1.0bn** (NPV over 32 years, 2020 prices) with a medium scenario of **£300m to £500m**. The estimated impacts will be further analysed at the secondary legislation stage.

[13] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill. Estimate based on an average electricity bill for a typical domestic customer of the six large suppliers.

[14] 2020 prices. Original figures (2014/15 prices) were in the range of £425-750 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', tables 6.1 & 6.2, pp. 36-38

## Annex A

1. The table below lays out the assumed investment and operational timings for the purposes of this IA. Year 1 and 2 are needed to set up the scheme; the first tender takes place in Year 3; and construction of the first asset begins in Year 4. There are 5 investment scenarios assumed in this IA:

    a) No investment
    b) £0.6bn every other year (an undiscounted total of £2.4bn investment over the next 10 years)
    c) £0.6bn per year (an undiscounted total of £4.2bn investment over the next 10 years)
    d) £1.2bn every other year (an undiscounted total of £4.8bn investment over the next 10 years)
    e) £1.2bn per year (an undiscounted total of £8.4bn investment over the next 10 years)

2. The savings generated by the policy option from each asset are considered over a 20-year time period from start of operation. This is based on the time period used in the offshore regime. This results in an overall assessment period of 32 years.

| | **Year 6** | **Year 7** | **Year 8** | **Year 9** | **Year 10** | **Year 11** | **Year 12** |
|---|---|---|---|---|---|---|---|
| Construction ► Operation ▼ | Asset 1 built | (Asset 2 built) | Asset 3 built | (Asset 4 built) | Asset 5 built | (Asset 6 built) | Asset 7 built |
| **Year 7** | x | | | | | | |
| **Year 8** | x | x | | | | | |
| **Year 9** | x | x | x | | | | |
| **Year 10** | x | x | x | x | | | |
| **Year 11** | x | x | x | x | x | | |
| **Year 12** | x | x | x | x | x | x | |
| **Year 13** | x | x | x | x | x | x | x |
| **Year 14** | x | x | x | x | x | x | x |
| **Year 15** | x | x | x | x | x | x | x |
| **Year 16** | x | x | x | x | x | x | x |
| **Year 17** | x | x | x | x | x | x | x |
| **Year 18** | x | x | x | x | x | x | x |
| **Year 19** | x | x | x | x | x | x | x |
| **Year 20** | x | x | x | x | x | x | x |
| **Year 21** | x | x | x | x | x | x | x |
| **Year 22** | x | x | x | x | x | x | x |
| **Year 23** | x | x | x | x | x | x | x |
| **Year 24** | x | x | x | x | x | x | x |
| **Year 25** | x | x | x | x | x | x | x |
| **Year 26** | x | x | x | x | x | x | x |
| **Year 27** | | x | x | x | x | x | x |
| **Year 28** | | | x | x | x | x | x |
| **Year 29** | | | | x | x | x | x |
| **Year 30** | | | | | x | x | x |
| **Year 31** | | | | | | x | x |
| **Year 32** | | | | | | | x |

## Annex B

***Index of terms***

**BEIS: Department for Business, Energy and Industrial Strategy**

**CATO**: Competitively Appointed Transmission Owner

**CEPA**: Cambridge Economic Policy Associates

**CF**: Counterfactual

**DNO**: Distribution Network Operators

**ITPR**: Integrated Transmission Planning Regulation

**NETS**: National Electricity Transmission System

**NPV**: Net Present Value

**Ofgem**: Office of Gas and Electricity Markets

**OFTO**: Offshore Transmission Owner

**PV**: Present Value

**SO**: System Operator

**SWW**: Strategic Wider Works

**TII**: Transmission Investment Incentives

**TIRG**: Transmission Investment for Renewable Generation

**TO**: Transmission Owner

**Title:** Proposed primary regulation of Energy Smart Appliances – Smart Charge Points

**IA No:** BEIS042(F)22-ESNM

**RPC Reference No:** RPC-BEIS-5173(1)

**Lead department or agency:** Department for Business Energy and Industrial Strategy

**Other departments or agencies:** Office for Zero Emission Vehicles (OZEV)

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage:** Final

**Source of intervention:** Domestic

**Type of measure:** Primary legislation

**Contact for enquiries:**
smartenergy@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| £0m | £0m | £0m | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

In 2021, Government introduced the Smart Charging Regulations which will ensure EV charge points have smart functionality and meet minimum device-level standards relating to cybersecurity and grid stability. Government is seeking to introduce similar requirements for other Energy Smart Appliances via the Energy Bill. There are two broad issues with the current approach:

1. Separate regulatory regimes can lead to misalignment across ESAs, and;
2. There are limitations in the smart charging regulations related to the current enforcement regime and the range of actors in the market Government can regulate.

Intervention is required to ensure regulatory alignment with other ESAs is maintained and to address the limitations associated with the existing Smart Charging regulations.

**What are the policy objectives of the action or intervention and the intended effects?**

- To create one regulatory regime for all energy smart appliances including charge points, so the same requirements can be mandated and enforced in a consistent manner;
- To increase the effectiveness of enforcement measures when regulating smart charge points, compared to the current AEVA powers; and
- To ensure businesses are taking on proportionate responsibility for ensuring compliance with regulations for smart charge points.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

- Option 0: Do nothing
- Option 1: Legislative Action through the Energy Bill (the preferred option)
- Option 2: Amend the existing powers for charge points (Section 15 and 16 of the AEVA)
- Option 3: Government acts without statutory basis (not viable)

The preferred option is the only option that can achieve the policy objectives; ensuring one regulatory regime for all energy smart appliances, increasing the effectiveness of enforcement measures when regulating smart charge points and ensure businesses are taking on proportionate responsibility for ensuring compliance with regulations for smart charge points.

**Will the policy be reviewed?** This will not be reviewed

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** 0 | **Non-traded:** 0 | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister:  Date: 24/06/2022

# Summary: Analysis & Evidence — Policy Option 1

**Description:**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year N/A | PV Base Year N/A | Time Period Years N/A | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** 0 | **High:** 0 | **Best Estimate:** 0 |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | 0 | | 0 | **0** |
| **High** | 0 | | 0 | **0** |
| **Best Estimate** | 0 | | | |

**Description and scale of key monetised costs by 'main affected groups'**

N/A

**Other key non-monetised costs by 'main affected groups'**

- Compliant businesses could incur administrative costs as they familiarise themselves with any changes in the enforcement regime or if they experience any changes to their legal obligations or responsibilities.
- Non-compliant organisation will incur the additional cost associated with heavier sanctions imposed upon them. These organisations will also have to cover the legal costs associated with the enforcement procedure after successful prosecution.
- Enforcement officer (Government) from issuing new/updated industry guidance.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | 0 | | 0 | **0** |
| **High** | 0 | | 0 | **0** |
| **Best Estimate** | 0 | | | |

**Description and scale of key monetised benefits by 'main affected groups'**

N/A

**Other key non-monetised benefits by 'main affected groups'**

- Businesses will benefit from greater clarity on roles and reduced complexity from having a coherent regulatory approach across all ESAs. Certain businesses will also benefit from a more proportionate allocation of responsibilities
- Wider society will benefit from reduced incidence and duration of non-compliance. This could have significant social benefit by reducing the risk of criminal activities (e.g. cyber-attack)
- Enforcement body will benefit from an enhanced enforcement regime which will enable some costs to be recovered and reduced complexity associated with identifying non-compliance

**Key assumptions/sensitivities/risks** — **Discount rate** N/A

- The introduction of our measure does not increase the obligations or roles of compliant businesses. This is because the current definition of charge point "seller" in the 2021 regulations is very broad.
- Some businesses could experience a reduction in their responsibilities. This benefit materialises in the form of a reduced legal burden, however we do not expect the change to influence how the business operates and the costs they incur.
- The only measurable differences between the existing regulations for smart charge points and the ESA powers are with respect to how obligations are differentiated across different actors and the enforcement regime.

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m: 0** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs: 0** | **Benefits:** 0 | **Net:** 0 | 0 |

# Evidence Base

## Introduction

1. This impact assessment sets out an initial assessment for **taking new primary powers to regulate electric vehicle (EV) charge points.** These powers are being taken through the 2022 Energy Bill as part of a package of measures for energy smart appliances (ESAs[1]). Our 'preferred option' would ensure that charge points are included within scope of the following powers:

    a. Enabling powers which allow Government to place requirements on certain ESAs to ensure they are safe for both consumers and the electricity grid.

    b. Enabling powers which allow Government to mandate that certain devices must be smart.

2. The overall objective of these new powers is to deliver one coherent regulatory regime for these appliances and to ensure Government's objectives for a smart and flexible energy system are met.

3. Separate impact assessments have been published which measure the impact of setting requirements for ESAs and mandating smart functionality on electric heating appliances. This impact assessment considers the costs and benefits associated with bringing smart EV charge points in scope of these powers. As existing regulations already mandate for smart functionality and device-level requirements, the impact of this intervention is different relative to other ESAs that are currently unregulated. All obligations for these measures will be set out in secondary regulations later in the 2020's, therefore a detailed impact assessment will be undertaken at this later stage.

## Background

4. ESAs are devices that are to be remotely configured and respond automatically to information, such as price and other signals, by modulating their energy consumption and / or changing the time at which electricity flows through the appliance. These changes to the consumption pattern are, what we call, the 'flexibility' of the smart appliance.

5. This flexibility reduces electricity system costs by helping to balance electricity supply and demand and by making more efficient use of low-carbon energy sources. Changing the pattern of energy demand in this way is known as demand-side response, or DSR.

6. The Government with Ofgem, the energy regulator, jointly published the Smart Systems and Flexibility Plan[2] (2021) which sets out a vision, analysis and work programme for delivering a smart and flexible electricity system that will underpin our energy security

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[1] Home appliances such as dishwashers, washing machines, fridges, heating and cooling.

[2] HMG (2021): *'Transitioning to a net zero energy system: smart systems and flexibility plan'* - https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

and the transition to net zero. This plan, and the Energy White Paper[3] (2020) restated the Government's commitment to take powers to regulate ESAs. These powers are now being sought through the Energy Bill, and they will enable the following to be implemented via secondary legislation later in the 2020s:

a. To allow Government to place requirements on certain energy smart appliances to ensure they are safe for both consumers and the electricity grid, and

b. To allow Government to mandate the electric heating appliances must have smart functionality

7. Smart charge points are an additional ESA which will facilitate the charging of EVs in a smart and flexible way and help manage their impact on the electricity network. Using the powers in the Automated and EV Act 2018 (AEVA)[4], Government has already acted via the Electric Vehicle Smart Charge Points (EVSCP) Regulations 2021[5] ("the EVSCP Regulations") to ensure that charge points for EVs sold in the UK have smart functionality[6] and meet minimum device-level standards relating to cybersecurity and grid stability.

8. The EVSCP regulations will take effect from 30 June 2022[7], after which a person must not sell a relevant charge point that does not comply with the requirements in the regulations[8]. Charge point manufacturers are expected to bear the costs related to the design and performance of charge points where they need to make upgrades to comply with the regulations. These costs have been assessed in 'The EVs (Smart Charge Points) Regulations 2021 – Impact Assessment'.[9]

9. The Office for Product Safety and Standards (OPSS) has been appointed as the enforcement body for the EVSCP regulations and has a variety of enforcement tools available to ensure compliance. Their enforcement actions can range from investigatory action such as issuing information notices and powers of entry, to giving civil penalties (including financial penalties) for non-compliance. OPSS are also able to accept enforcement undertakings whereby a relevant person/business can express in writing actions they will take to address non-compliance in a specified timeframe.

[3] HMG (2020): *'Energy White Paper Powering our net zero future'* - https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

[4] HMG (2018): '*Automated and EVs Act 2018'* https://www.legislation.gov.uk/ukpga/2018/18/contents/enacted

[5] HMG (2018): - *The EVs (Smart Charge Points) Regulations 2021* - https://www.legislation.gov.uk/ukdsi/2021/9780348228434#f00005

[6] Smart charging can be defined as the ability to delay or modulate charging in response to an external signal. It allows charging load to be controlled and shifted to different times of the day

[7] Cybersecurity requirements will enter into force in December 2022, given the relatively significant changes to hardware and software required to come into compliance.

[8] The Regulations place requirements on any person or business selling, offering, or advertising a charge point for sale. Following the definition in the Automated and EVs Act 2018, a sale includes the act of hiring, lending, leasing, or giving a charge point from one party to another.

[9] HMG (2021): *'The EVs (Smart Charge Points) Regulations 2021: Impact Assessment'* - https://www.gov.uk/government/consultations/electric-vehicle-smart-charging

## Problem under consideration and rationale for intervention

10. Government needs to enable the transition to a smart and flexible system by encouraging the uptake of smart technology and ensuring it is safe to both consumers and the electricity grid. At the device-level, this means ensuring ESAs, including charge points, are smart and meet technical requirements for cyber security, data privacy, grid stability and interoperability.

11. As explained above, Government currently has powers that can be used to regulate charge points and will be seeking separate powers through the 2022 Energy Bill to regulate other ESAs. However, there are two broad issues with the current approach:

12. Firstly, as the smart energy market grows, and more consumers have a range of smart appliances in their homes and workplaces, it is imperative that a cohesive legislative approach is taken for all energy smart appliances. All these devices operate very similarly on a technical level (i.e. connected devices that can modulate energy load), meaning they provide similar benefits to DSR but also pose the same risks (e.g. cyber security). As a result, Government intends to set new, similar regulatory requirements in the mid-2020s for all ESAs, including charge points, and the regulation and enforcement of these requirements will be the same. Unless the primary powers are aligned, it will not be possible to set the same regulatory regime for all ESAs and charge points which risks creating an uneven regulatory playing field where companies could face different regulatory approaches for very similar activities.

13. Secondly, when developing the EVSCP regulations, it became apparent that the existing AEVA powers were limited in certain areas, creating unnecessary complexity for both the regulator and industry in terms of ensuring compliance with the regulations. The two limitations are explained below and relate to the range of **economic operators** Government were able to regulate under Section 15 of the AEVA, and the breadth of the generic **enforcement powers** under Section 16.

_Economic operators_

14. Under the AEVA, the obligation for ensuring that charge points meet the requirements set out in the regulations falls on the seller. In practice this is likely to cover a very wide range of organisations that operate across the supply chain and perform different activities.

15. It is estimated[10] that in the UK approximately 30% of charge points installed in homes are purchased directly from manufacturers (e.g. PodPoint), whilst 45% are acquired from vehicle dealerships (e.g. Renault) and 25% are acquired from energy retailers (e.g. EDF), installers and 3rd party vendors[11]. In addition to the sale of charge points direct to the end user, the AEVA definition of charge point "seller" also covers the sale of charge points

[10] Delta-EE (2022): How Do EV Drivers Acquire Their Home CP? – *publication available to service subscribers only*

[11] This is a company reselling home CPs via an online platform or via a brick-and-mortar store.

between businesses[12]. This is likely to significantly increase the number and types of organisations covered by the existing definition.

16. In typical product regulation, a "tiered" approach is adopted whereby differentiated obligations are applied throughout the supply chain in line with the level of responsibility each actor (e.g. manufacturer, importer, retailer) could reasonably have for a product's compliance. The underlying intention of our existing approach and the tiered approach is broadly similar in that they both aim to introduce conditions on the sale of charge point into the UK. The key difference is that the existing approach places the same obligations across the entire supply chain, whilst an enhanced tiered approach would mean that appropriate obligations could be placed on different actors

17. It is uncertain precisely how many organisations operate across the supply chain, however, as demonstrated above, given our broad definition of "seller", it is likely that all actors are likely to fall in scope of the full weight of obligations. This could lead to the following issues;

    a. Charge point sellers having to undertake additional due diligence or bear the costs of non-compliance despite lacking the technical expertise to assess which requirements apply or having little control and oversight of how devices are made. Although the EVSCP regulations won't come into force until 30 June 2022, we expect this to cause some confusion amongst industry, particularly those more involved in distribution of products.

    b. Uncertainty for businesses around what responsibilities sit with the business and what is expected of other actors in the supply chain.

    c. Increased enforcement costs incurred by Government where more work is required to identify where the non-compliant party is in a chain of sales – for example, multiple requests for information.

    d. Applying obligations at the point of sale only also means Government is unable to place post-sale responsibilities on economic actors, such as the obligation to investigate and notify of any non-compliance found after devices have been sold.

*Enforcement powers*

18. The second limitation relates to the generic enforcement powers. While the AEVA provide for regulations enabling the enforcement authority to serve notices, enter premises, inspect, and seize goods and apply civil sanctions to sellers of charge points, these are more limited than typical product legislation. In particular:

    a. Where non-compliance is identified, the AEVA only enable the enforcement authority to impose financial penalties. While these penalties are often sufficient as

[12] For example, a manufacturer or wholesaler may sell a charge point to an installation company who then sells the charge point to the end user.

a deterrent for low-level non-compliance, it is common that the enforcement authority can also rely on criminal sanctions for the most persistent and serious offences, such as intentional non-compliance, obstructing enforcement and purporting to act as an enforcement officer.

b. The current drafting of AEVA currently does not allow Government to recover costs from non-compliant businesses for enforcement action undertaken to investigate and ensure remedy of non-compliance.

19. In the short term, it is unlikely that these limitations would significantly hinder either the enforcement authority's ability to enforce the smart charge point regulations or a business's ability to comply. However, feedback received by BEIS and OPSS from industry in anticipation of the EVSCP Regulations coming into force suggests the lack of differentiation of sellers' responsibilities is leading to some of the above issues already, heightening the perceived risk of operating in the GB charge point market. In addition, the limited enforcement powers will impact the enforcement body's ability to implement an effective enforcement regime. As the market grows, and there is a greater proliferation of charge points, this risk will increase and could lead to increased non-compliance, preventing Government from meeting the policy objectives for smart charge points.

20. There are a number of market failures that exist which explain why the market alone is unlikely to stimulate the uptake of smart charge points and mitigate the risks that they pose to the energy system and consumers. These are explained below:

a. Smart charge points allow EV charging to be shifted to different times of the day. This flexible form of charging helps mitigate the potential impact EVs could have on the energy system by reducing peak electricity demand from EV charging and therefore deferring costly investment in additional electricity generation capacity and network reinforcement. Not only will this help reduce the cost of charging for the EV owner (private benefits), it also provides substantial benefit to wider society (social benefits)**.** By mandating smart functionality, the smart charging regulations encourage uptake to ensure that the **positive externality** is captured, and social returns are maximised[13].

b. Grid stability as a system concept is a **public good**; the benefits of a stable electricity grid benefit all market participants in a non-rivalrous and non-excludable way[14]. As such, grid stability is subject to the **free-rider problem[15]** in which individual market participants may be incentivised to act in a way that does not ensure the stability of the system. In the context of charge point manufacturers, this may be to avoid installing more costly device hardware or software that enables effective stability actions to take place resulting in additional strain on ensuring grid stability is maintained.

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[13] It is estimated that the introduction of the smart charging regulations could provide up to £1.1bn of benefit to the power system (Net Present Value, 2021 prices).

[14] Non-rivalry suggests the benefit one energy market participant receives from having a stable grid does not reduce the amount of benefit another can receive from having a stable grid. Non-excludability suggests that all energy market participants receive the benefit of a stable grid.

[15] The free rider problem is the burden on a shared resource that is created by its use or overuse by people who aren't paying their fair share for it or aren't paying anything at all.

c. Were a cyber-attack to be successful this could result in significant consequences for society. There are current real-world case studies which show the vulnerability of consumers and the energy system increasingly from connected devices, such as the security flaws recently revealed within EV charge point company, PodPoint[16], Investment in cyber security will help avoid this cost, however private firms will not fully capture these benefits which is likely to lead to underinvestment in cyber security **(negative externalities).** Two case studies illustrating the potential societal impacts has been provided in the annex.

21. The limitations in our existing regulatory regime could reduce the effectiveness of the EVSCP regulations and prevent Government from addressing these market failures and achieving its wider objectives. In some cases, a reduction in compliance is driven by additional market failures that have been created by the limitations in the EVSCP regulations. For example; an inability to place obligations on all actors in the supply chain creates a **'principal agent problem'** whereby an actor in the supply chain (e.g. distributor) is responsible for proving compliance on a product despite having little control or influence over a product's design.

## Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

22. The primary powers that are being sought are enabling powers and will not impose any substantial costs or benefits on businesses, consumers of government.

23. The impacts discussed in this impact assessment consider the introduction of secondary legislation which will be required to define the obligations that will be placed on organisations and expand the enforcement regime of the enforcement body. As discussed in the costs and benefits section, quantifying the impacts of this measure is very challenging and not proportionate. Firstly, it would require the development of an appropriate analytical methodology[17]. Secondly, any analysis would be reliant on several assumptions that would need to be established. These components are subject to such a range of uncertainty that combining them would not create a meaningful value. As such it has not been possible to provide a full social cost benefit analysis. Instead, this analysis places focus on identifying the correct potential impacts that could arise from the use of our measure.

## Description of options considered

24. This section describes the three policy options that are being considered. In this section we have identified the differences between the 'preferred option' and a 'do nothing' scenario. An assessment of the extent to which each of the options achieve our policy objectives can be found in the annex (Table A).

[16] 'Pod Point electric car chargers: security flaw may have put 140,000 app users' data at risk' https://www.which.co.uk/news/2021/11/pod-point-electric-car-chargers-security-flaw-may-have-put-140000-app-users-data-at-risk/

[17] For example; 'What if?' or 'Switching value' scenario based analysis

**Option 0 – Do nothing**

25. This scenario maintains the status quo and therefore considers a state of the world in which the powers in the Energy Bill are not introduced. As such, new powers to regulate smart charge points are not taken along with other ESAs.

**Option 1 – Legislative Action through the Energy Bill (the 'Preferred Option')**

26. Under this option, the new primary powers being sought through the Energy Bill to set regulatory requirements for ESAs would be extended to charge points. Tables 1 and 2 illustrate the differences between the regulatory regime adopted by pursuing this option against the current arrangements.

*Economic Operators*

27. Table 1 provides a comparison of how legal obligations are assigned across actors in the supply chain. As mentioned, currently all organisations face the exact same legal obligations and therefore are responsible for ensuring charge points comply with the entirety of the EVSCP regulations. In practice this means that all charge point sellers (likely to include manufacturers, importers, authorised representatives[18] and distributors[19]) will have to have to provide a technical file which outlines how the device meets the regulations, complete statements of compliance and could be subject to enforcement action from the OPSS.

28. Under Option 1, obligations vary across different organisations. This option demonstrates a more appropriate split of responsibility by aligning the legal obligation of each actor with the role they are likely to play in the supply chain. Effectively, it's likely that manufacturers and importers responsibility will remain largely the same, but distributors would no longer be responsible for the charge points' technical requirements. In addition, this option allows post-sale responsibilities to be placed on economic actors via laying further secondary legislation under the new Energy Bill powers, such as the obligation to notify and investigate non-compliance.

Table 1 – Responsibilities

| Economic Actor who places a charge point on the GB market | Legal obligation in Option 0 - (do nothing) | Proposed legal obligation in Option 1 (preferred option) |
|---|---|---|
| **Manufacturer, authorised representatives and importer** | Responsible for ensuring relevant charge points sold in GB meet 2021 regulations, which includes technical | Ensuring devices meet technical requirements<br><br>Writing the assurance documents to prove compliance |

[18] Any natural or legal person established in Great Britain who has received a written mandate from a manufacturer to act on their behalf in relation to a specified task.
[19] Proposed definitions are drawn from our legal instructions for the Energy Bill and is consistent with most product safety legislation.

| | | |
|---|---|---|
| | device-level requirements, assurance and enforcement obligations | Post-sale responsibilities such as investigating and notifying non-compliance<br><br>Cooperation with the enforcement authority |
| **Distributors, wholesalers and retailers** | | Checking assurance documents and cooperation with the enforcement authority |

*Enforcement*

29. Table 2 compares the enforcement regime. Under our ‘preferred option’, the enforcement body will have to power to apply a proportionate response to the most severe cases of non-compliance and impose criminal sanctions on actors when necessary. In addition to this a power will be granted to enable costs incurred by the enforcement body to be recovered.

**Table 2 – Enforcement regime**

| | **Option 0 (do nothing)** | **Option 1 (preferred option)** |
|---|---|---|
| Criminal Sanctions | The enforcement authority has the ability to issue civil penalties, such as compliance notices, to bring businesses into compliance, and the ability to issue financial penalties if deemed appropriate.<br><br>No criminal sanctions can be applied. | In addition to the existing civil penalties already available to the enforcement authority, criminal sanctions can be applied to more severe cases of non-compliance, or to those who disrupt the enforcement process. |
| Cost recovery | There will be no power to recover costs from non-compliant businesses from enforcement action undertaken to investigate and remedy breaches.<br><br>This means costs incurred for investigating and remedying non-compliance will be to Government and therefore the taxpayer. This means any costs incurred by the enforcement authority will be to Government and therefore the taxpayer. | The regulations allow for costs to be recovered from by the enforcement authority from non-compliant businesses for their costs occurred when investigating and remedying the breach. |

**Option 2 – Amend the existing powers for charge points (Section 15 and 16 of the AEVA)**

30. Instead of taking a new power to regulate charge points, Government could take a new primary power which amends the existing powers under the AEVA to bring them in line with the approach being taken to regulate other energy smart appliances.

31. This option would address the known limitations associated with the AEVA by allowing future secondary legislation to split the obligations across different economic actors and make use of the wider enforcement powers. However, under this option maintaining full alignment with ESAs will be challenging over time. This is because of the following reasons;

    a. The powers will likely be progressed at a similar time, and Parliament may suggest amendments to the powers during their passage. Keeping the two sets of powers aligned throughout the parliamentary and drafting process will therefore be challenging.

    b. Any future amendments needed to the primary powers would require both the ESA Energy Bill and charge point AEVA powers to be edited, to ensure they both remained aligned.

32. In order to maintain alignment across the regulatory regimes, Government may need to draft and lay multiple sets of secondary legislation. Given the challenges mentioned previously, this will become increasingly burdensome for Government and presents a risk of temporary or permanent misalignment.

33. Furthermore, it would add complexity for industry. Companies who manufacture or sell EV charge points as well as other ESAs would need to familiarise themselves with two parallel sets of regulations designed to deliver very similar outcomes.

**Option 3 – Government acts without statutory basis (not viable)**

34. Under this option, no new powers for smart charge points are taken meaning Government works within its existing powers in the AEVA. Smart charge points would continue to be regulated separately to other energy smart appliances, meaning the objective to have one consistent regulatory regime would not be met.

35. Government could try to informally divide obligations across actors in the supply chain for smart charge points (within the scope of "point of sale"), but without any amendments to legislation, instead publishing the expected responsibility of each party in non-statutory guidance. This would not be in line with what is drafted in legislation and therefore this enforcement approach would not have a legal basis.

36. This option would also mean that Government would not have the ability via secondary legislation to require businesses to notify and investigate non-compliance, meaning the enforcement authority will have to undertake greater efforts to monitor for non-compliance and then issue compliance notices. This option would not solve the wider

enforcement issues relating to the lack of criminal sanctions and the inability to recover costs which Government is also seeking to address under these changes to the AEVA.

## Policy objectives

37. The objectives for taking new powers to regulate EV charge points in the 2022 Energy Bill are:

    a. To create one regulatory regime for all energy smart appliances including charge points, so the same requirements can be mandated and enforced in a consistent manner;

    b. To increase the effectiveness of enforcement measures when regulating smart charge points, compared to the current AEVA powers; and

    c. To ensure businesses are taking on proportionate responsibility for ensuring compliance with regulations for smart charge points.

38. Meeting these policy objectives are essential to ensure smart charge points are regulated effectively enabling wider Government objectives are achieved which include maximising the use of smart charging whilst providing protections for consumers and the wider energy system[20].

## Summary and preferred option with description of implementation plan

39. The powers being sought through the 2022 Energy Bill for ESAs are enabling powers, therefore implementation will be through secondary legislation. Some transitional arrangements will be required when new regulations under the new powers come into effect, such as revoking the existing 2021 EVSCP regulations to avoid duplication.

40. Timelines for secondary legislation is not confirmed as further consultation is required before legislation can be drafted, finalised and made. The body who will take on the role of the enforcement authority is to be determined once secondary legislation is drafted.

## Monetised and non-monetised costs and benefits of each option (including administrative burden)

41. The primary powers that are being sought are enabling powers and therefore will not impose any substantial costs or benefits on businesses, consumers or government. The impacts discussed below are derived from the introduction of secondary legislation, where the material changes for regulating smart charge points will arise from enabling different obligations to be placed on different actors and the expansion of the enforcement regime. These impacts have been discussed at a high level with a focus on identifying the correct potential impacts that could arise from the use of our measure.

[20] Wider government objectives are explained in more detail in the consultation document that supports the EVSCP regulations – HMG (2019): "Electric Vehicle Smart Charging" - https://www.gov.uk/government/consultations/electric-vehicle-smart-charging

42. The aims of this intervention are to increase the effectiveness of the existing smart charging regulations, ensure businesses are taking on proportionate responsibility for ensuring compliance and to ensure regulatory alignment across all ESAs. The main benefits associated with meeting these aims are the positive impacts our intervention will have on reducing the risk of non-compliance and regulatory misalignment. Any non-compliant smart charge point could leave individuals exposed to the risk of third parties controlling charge points without their permission, or to have access to data regarding consumption. In the most severe cases, non-compliance could pose a serious threat to society in the form of a cyber-attack which could have significant costs on the consumer and/or energy system. It is likely that our measure will reduce the incidence (i.e. frequency of non-compliance) and duration (i.e. time it takes for non-compliance to be identified and then addressed) of non-compliance and therefore the risk of these criminal activities occurring.

43. In order to quantify the full benefit from our measure, several assumptions would need to be established such as the number of non-compliance incidences occurring and the probability of non-compliance leading to criminal activity in the baseline. If it is considered that criminal activity would occur, further assumptions would be required on the expected level of impact it could have on individuals and/or the energy system. Lastly, an assumption would be required on the probability that our measure would be sufficient to deter the event from occurring. This methodology could be used to estimate the costs that could be avoided in the baseline, however, these components are subject to such a range of uncertainty that combining them would not create a meaningful value.

44. The assessment below concludes that that the expected impact from this primary legislation and the exercise of the secondary powers arising from it, fall below the de-minimis threshold (+/-£5m EANDCB).

## Direct costs and benefits to business calculations

### Illustration of potential costs and desired benefits of secondary legislation

### Option 0 – Do nothing

45. As explained in the Problem Under Consideration, there are several limitations with the existing regulatory approach for smart charge points which could lead to regulatory divergence and increase the frequency or duration of non-compliance. A summary of how these risks manifest is provided in Table 3 below.

**<u>Table 3 – Risks</u>**

| Limitation | Risks |
|---|---|
| Regulatory misalignment across ESAs | Two separate regimes for charge points and other ESAs could lead to an increased risk of **regulatory divergence** caused by the following issue: |

| | |
|---|---|
| | • Any changes made to how ESAs are regulated would need to be replicated for charge points in order to maintain a consistent approach. This is not possible without additional primary legislation, therefore it can be assumed that regulatory misalignment will arise in the 'do nothing' scenario. This could increase complexity for companies who manufacture, distribute or sell multiple types of ESA. |
| Economic Operators | Inability to place differentiated obligations on different actors in the supply chain could lead to an increase in the **frequency and/or duration of non-compliance** caused by the following issues:<br><br>• Charge point sellers are required to demonstrate compliance despite lacking the technical expertise to assess which requirements apply or having little control and oversight of how devices are made. This could lead to sellers being penalised where they bear the costs of non-compliance<br><br>• The lack of clarity in legislation for business regarding their responsibilities could lead to leading to agreements being made between businesses to clarify roles themselves.<br><br>• Increased complexity identifying the non-compliant party in a chain of sales. This could lead to Government carrying out additional investigatory work.<br><br>• Businesses may only investigate and take action to remedy compliance failures following a compliance notice issued by the enforcement authority rather than proactively. |
| Enforcement | Limited enforcement powers could increase the risk of the **most severe cases of non-compliance** and increase **costs to Government.** This is caused by the following issues:<br><br>• Enforcement powers currently only extend to financial penalties and do not extend to criminal sanctions.<br><br>• Inability of Government to recover costs from non-compliant businesses for enforcement action undertaken to investigate and ensure remedy of non-compliance. |

### Option 1 - Legislative Action through the Energy Bill (the 'Preferred Option')

46. Our preferred option will bring charge points in scope of the ESA primary powers. Policy analysis has been conducted to compare the regulatory requirements contained in our measure against the requirements set out in our existing regulations for charge points (AEVA). This analysis is presented in the Annex (Table B) and shows the only

measurable differences between the requirements in the regulations are with respect to how obligations are differentiated across different actors and the enforcement regime. As such, we can conclude that bringing charge points in scope of the ESA primary powers will enable regulatory alignment and in doing so, will address the limitations in the smart charge point regulations. There are no other measurable differences between the existing smart charge points regulations and the ESA primary powers.

47. This section explores the impacts associated with addressing the limitations in the smart charge point regulations and in turn mitigating against the risks presented in Table 3.

## Monetised costs and benefits

48. The impacts from subsequent secondary legislation Impacts have been quantified and monetised where possible. However, it has not been possible to aggregate any impacts due to limited data on the number of organisations operating in the market. It is estimated that there are between 90 – 100 charge point manufacturers[9] in the market, however there is limited data on the number of retailers, wholesalers, importers etc.

49. Given the broad definition of charge point “seller” within the 2021 EVSCP regulations all organisations that sell charge points face the exact same legal obligations regardless of their role in the supply chain. The introduction of this measure will result in variation in responsibilities across the different actors in the supply chain. Below is an assessment of how the costs and benefits could vary across different actors.

## Indicative costs

### All compliant businesses

50. Administrative costs associated with familiarisation of the changes in the regulation. The magnitude of this impact will depend on how much material is added/updated to the existing guidance. If it is assumed the entire guidance is reviewed[21], it could take each business approximately 20mins – 2 hours 20 mins[22] to read and understand the legislation at a cost of around £60 per hour.[23]

### Charge point sellers

51. Currently, charge point sellers are legally responsible for ensuring charge points they sell fully comply with the technical requirements set out in the EVSCP regulations. In practice this involves providing a technical file and statement of compliance. Under Option 1, it is likely that sellers will have a reduced legal obligation, however, will still have a duty of

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[21] This is conservative assumption given that some parts of the existing guidance would remain.

[22] HMG (2019): RPC Short Guidance Note – Implementation Costs - https://www.gov.uk/government/publications/rpc-short-guidance-note-implementation-costs-august-2019

[23] Undiscounted, including non-wage-costs of 16% (ONS (2020Q3) Index of labour costs per hour: Manufacturing). Wage costs based on ONS (2021) Annual Survey of Hours and Earnings: corporate managers and directors at the 90th percentile).

care[24] and will need to take reasonable steps to check the product they are selling complies with the regulation. In practice, the impact this change will have will depend on the extent to which the seller is currently checking the charge points they sell are compliant. It is understood that many such sellers already seek written assurance. As such, we do not expect this requirement to change the activities that many businesses already perform, nor lead to a change in cost. However, for sellers that currently only undertake a very light touch assurance approach (e.g. via email exchange), this could represent an increased burden and therefore could increase costs.

**Manufacturers**

52. Under the current EVSCP regulations manufacturers are in effect responsible for building and designing products that comply with the technical requirements. The implementation of these new powers will not change that obligation, manufacturers will still be responsible for ensuring products are designed in line with the regulations. We therefore don't expect them to see any change in cost.

**Non-compliant businesses**[25]

53. A non-compliant organisation will incur the additional cost associated with heavier sanctions imposed upon them. These organisations will also have to cover the legal costs associated with the enforcement procedure after successful prosecution. The scale of the additional cost will vary case to case according to the nature of the breach.

54. Post-sale responsibilities will be placed on business to (i) investigate any potential compliance failure and (ii) take action in relation to the compliance failure. In the baseline it is assumed the non-compliant business would incur the cost associated with investigating and remedying the non-compliance once a compliance notice has been issued by the enforcement body. This measure would require the non-compliant business to take a proactive approach and therefore bring this cost forward in time.

**Enforcement body**

55. One-off cost associated with resource required to update the industry guidance. Based on current costs of enforcement it is expected costs will be low (<£20,000). However, this is highly uncertain, and the scale of the costs will vary depending on the extent of the changes required to the existing guidance. Feedback from the OPSS has indicated that we do not expect the introduction of our measure to have any further administrative costs. For example, it is not expected that changes to the enforcement regime will have an impact on resource burden or monitoring activities of the enforcement body

**Consumers**

[24] Detail to be subject of consultation and further secondary legislation.

[25] Impacts on non-compliant organisations have been included for completeness and to inform policy development. However, as per normal impact assessment practice these impacts are not included in the Business Impact Target (BIT)

56. The introduction of these powers will not increase the costs to any compliant businesses regarding the manufacture or sale of a charge point. As such, it is unlikely to impact the price of a charge point.

## Indicative benefits

### All compliant businesses

57. This intervention will provide greater legal clarity of roles and responsibilities which will benefit all businesses and could reduce any additional costs that might have been incurred from business differentiating obligations themselves.

58. Regulatory alignment could reduce complexity and potentially costs for companies who manufacture, distribute, or sell multiple types of ESA.

### Charge point sellers

59. As discussed in paragraph 51, it is expected that all charge point sellers will have a reduced legal obligation. In practice, some sellers will see a reduction in cost, for example if they are currently providing a technical file, statement of compliance and undertaking their own detailed assessment of charge points.

### Manufacturers

60. As discussed, we do not expect the intervention to change obligations for manufacturers. As such they will continue to be responsible for designing and manufacturing compliant products and providing supporting assurance documents (e.g. technical file). This intervention will therefore not impose any additional costs or benefits.

### Enforcement body

61. Differentiating obligations across actors in the supply chain will make it easier to target enforcement to relevant business, reducing the level of investigatory work required by the enforcement body.

62. Changes to the enforcement regime will enable the OPSS to recover certain legal costs associated with the enforcement procedure after successful prosecution. Benefits will depend on the extent of the powers being considered, but these could include powers to recover costs for any or all of the activities incurred in the process of investigation, intervention and sanction. It has not been possible to provide an average cost of enforcement activity as the resources needed for each activity varies widely and the level/severity of the penalty applied in an enforcement activity will vary substantially as well.

### Wider society

63. A reduction in the incidence and duration of non-compliance is likely to reduce the risk of criminal acts such as a cyber-attack. The potential benefit of avoiding this cost could be signficant, however as discussed, providing an accurate quantification of this benefit is very challenging as it is dependent on several uncertain assumptions. Avoiding the potential cost incurred from a case of non-compliance and ensuring the electricity system and consumers are protected.

64. A reduction in non-compliance should reduce the potential cost to the criminal justice system. The scale of the cost burden is highly uncertain and likelihood of these costs occurring are to be largely determined by the details set out in secondary legislation. At this point, therefore, the Government does not consider a Justice Impact Test to be necessary.

## Summary

65. The introduction of these powers will improve the effectiveness of the regulation of smart charge points by reducing the frequency and duration of non-compliance. Ultimately these powers will help ensure the policy objectives are met and the benefits of the smart charging regulations (up to £1.1bn[526]) are realised.

66. It is very challenging to accurately quantify the benefit to business of introducing this measure. The impact assessment has concluded that the costs associated with this measure at the secondary legislation stage are expected to be very small whilst the two case studies in the annex provide an illustration of the potential scale of the costs that could be avoided (benefits) from mitigating against events that could cause disruption to the energy system. This comparison of the costs and benefits indicates that it is very likely that the society benefit of this measure will far outweigh the costs imposed on business.

## Risks and assumptions

67. Given the broad definition of charge point “seller”, it has been assumed that all organisations currently must adhere to the regulations in full. For some organisations, the introduction of this measure will reduce the number of obligations they are responsible for. For all other organisations, they will see no change in their obligations and will not acquire new obligations as they already adhere to the regulations in full. The exception to this rule would be an organisation that is not considered a “seller”, however given the broad definition, we do not expect these organisations to exist.

68. Some businesses could experience a reduction in their responsibilities. This benefit materialises in the form of a reduced legal burden, however change may not influence how the business operates and the costs they incur.

69. The only measurable differences between the existing regulations for smart charge points and the ESA powers are with respect to how obligations are differentiated across different actors and the enforcement regime.

[26] NPV, 2021 prices

## Impact on small and micro businesses

70. As highlighted in the ‘costs’ section, we do not expect the introduction of this measure to impose any significant costs to businesses at the primary or secondary stage.

71. Introducing the power to place varying obligations on different economic actors across the supply chain will lead to a more proportionate allocation of responsibilities. All businesses (including small and micro businesses - SaMBs) are likely to benefit from a greater clarification of roles. It is estimated that between 15 – 20% of charge point manufacturers active in the UK market are classified as SaMBs (less than 50 full time employees)[5]. As described in Table 1, it is expected that the responsibilities of manufacturers and importers will stay the same, however some actors such as distributors will benefit further from a reduction in the level of obligations, they are legally responsible for. It is not expected that any business will experience an increase in responsibilities relative to the baseline. Greater detail on the number of market participants is required to understand the number of SaMBs that will benefit from this measure.

72. Applying exemptions for SaMBs is not appropriate in this situation as it would reduce our ability to redistribute responsibilities and for businesses to realise the benefits from this measure. Similarly, it would not be appropriate to make exemptions for SaMBs regarding changes to the enforcement regime.

73. In addition to this, expanding the enforcement regime will not impose any signficant cost to compliant businesses.

## Wider impacts (consider the impacts of your proposals)

74. As set out in the previous section, there are several benefits that could arise to businesses from the introduction of our measure. In theory, greater clarity on roles and responsibilities could reduce barriers to entry.

75. The smart charging market is nascent and at an early stage of development. The rate of innovation within the market is high, with new smart charging offers and services being marketed by energy suppliers and other organisations. The existing Smart Charging Regulations specify the minimum requirements needed to deliver appropriate protections, whilst avoiding being overly prescriptive about how charge point sellers must deliver the approach. The legislation will also be kept under review, and we expect to make updates in the mid-2020’s to keep pace with future innovations in the market. Any future changes would be implemented via these new powers.

76. An internal assessment, undertaken by BEIS, has also concluded that this measure will not have any disproportionate impacts on those with protected characteristics as per guidance as part of the Public Sector Equality Duty (PSED) Act because these changes pertain specifically to implementing an improved enforcement approach and cost

recovery system, as opposed to making any changes that will impact consumers. The Impact Assessment published for the 2021 Smart Charge Point Regulations also confirmed that a similar PSED assessment had found no such disproportionate impacts on those with protected characteristics.

## Justice Impact Test

77. As only enabling powers are being taken at this stage, any detailed and enforceable requirements will be set out in secondary legislation. At this point, therefore, the Government does not consider a Justice Impact Test to be necessary.

78. Full consideration of the impact on the justice system will be considered when secondary legislation is developed under these powers.

## A summary of the potential trade implications of measure

79. The introduction of this measure is not expected to impact international trade and investment. As set out in the costs/benefits section, the ability to place differential obligations on actors could ensure that importers have more proportionate responsibilities. Using these new powers, future legislation will be able to set specific requirements for importers, making their expected role in ensuring charge points meet regulatory requirements clearer.

## Monitoring and Evaluation

80. A programme of evaluation work is being developed which will assess the EVSCP regulations. This includes a ‘process evaluation’ which considers whether the regulations are being delivered as intended and an impact evaluation (2024/25) which will assess whether the programme has achieved its intended objectives. Further details of this work can be found in the ‘The EVs (Smart Charge Points) Regulations 2021 – Impact Assessment[5]’

81. It is not proportionate at this stage to develop a full evaluation plan due to uncertainty over details to be provided through secondary legislation. It is possible that the evaluation of Legislative Action (i.e. amend the AEVA) (the ‘Preferred Option’) could be integrated into the existing evaluation programme discussed above. However, this will be dependent on when the secondary legislation is laid.

82. Table 4 below provides information on the type of information that would be included in the evaluation.

**<u>Table 4 – Monitoring and Evaluation</u>**

| Objective | Measure | What does success look like? | Measuring impact |
|---|---|---|---|

| | | | |
|---|---|---|---|
| To create one regime for all energy smart appliances, including charge points to ensure devices are smart and secure | Regulating charge points alongside all other ESAs in the Energy Bill | Regulatory alignment across all ESAs | By regulating charge points in the Energy Bill this ensures that charge points and all other ESAs are regulated under the same regime. As such, we can be confident that any regulatory changes are reflected across all technologies and therefore the policy objectives have been achieved. |
| To ensure business are taking on proportionate responsibility | Ability to place varying obligations on the different economic operators | Greater clarification on roles and responsibilities across the supply chain<br><br>Businesses face enforcement action that is proportionate to their role in the supply of smart charge points.<br><br>No additional obligations for businesses | <u>Industry feedback</u><br><br>- Feedback from organisations can be used to gather information on the benefit of the clarification of roles and responsibilities. It could also be used to gather insight on the additional costs imposed or other unintended consequences. |
| To increase the effectiveness of enforcement measures when regulating smart charge points, | Ability to apply a proportionate response to the most severe cases of non-compliance and impose criminal sanctions on actors when necessary. In addition to this a power will be granted to enable costs incurred by the enforcement body to be recovered | Reduced levels of non-compliance<br><br>Costs can be recovered by the OPSS in the event of non-compliance.<br><br>Minimal increase in cost burden to the OPSS | <u>Compliance data</u><br><br>- The OPSS publish details of their enforcement actions online. This could be used to monitor compliance.<br><br>- Feedback from the OPSS could be used to verify any cost implications that have been imposed from this measure |

## Annex

### Table A - Options Assessment

| Options | Policy Objectives | | |
|---|---|---|---|
| | *1 - To regulate all ESAs, including smart charge points, under one regime* | *2 - To increase the effectiveness of enforcement measures for measure made under this part, such as the smart charge point regulations* | *3 - To ensure businesses are taking on proportionate responsibility for ensuring compliance with the regulations made under Section 15* |
| Do nothing | **Objective not met**<br>Government continues to regulate smart charge points separately to ESAs, meaning there is misalignment between the two regimes.<br><br>Differences are mainly in the enforcement approach and the way obligations are placed on businesses, meaning reduced efficiency for the enforcement authority who may enforce both the ESA and smart charge point regulations, and confusion across businesses in the smart energy market. | **Objective not met**<br>The enforcement authority will continue with deficient enforcement powers, meaning:<br><br>- Criminal sanctions cannot be applied meaning the EA does not have the range of enforcement tools needed to deal with more severe non-compliance or those who are not cooperative;<br>- Costs are not recoverable by Government from non-compliant businesses. | **Objective not met**<br>Businesses remain unclear on their obligations under the smart charge point regulations, especially where those selling charge points are not directly involved in their manufacture.<br><br>Government is unable to place varying obligations on specific economic actors (via secondary legislation). |
| Legislative Action (the 'Preferred Option') | **Objective met**<br>Government includes smart charge points in its new powers for ESAs.<br><br>All regulations for ESAs and smart charge points are the same | **Objective met**<br>The enforcement authority will have sufficient enforcement powers, meaning:<br><br>- Criminal sanctions can be applied meaning the EA has the range of | **Objective met**<br>Businesses have clarity over their obligations under the smart charge point regulations, and suitable responsibilities are split across different economic actors in the supply chain. |

| | | | |
|---|---|---|---|
| | allowing one consistent regulatory regime to be in place for smart devices. | enforcement tools needed to deal with more severe non-compliance and;<br>- Costs are recoverable by Government from non-compliant businesses. | |
| Legislative Action (amending the AEVA) | **Objective partially met**<br>Existing powers for smart charge points are amended to try and align them with the new ESA powers.<br><br>Complete alignment is unlikely to be achieved, where powers are split across two primary legislative vehicles. | **Objective met**<br>The enforcement authority will have sufficient powers.<br><br>The consequences are the same as the option above. | **Objective met**<br>Businesses have clarity over their obligations under the smart charge point regulations, and suitable responsibilities are split across different economic actors in the supply chain.<br><br>The consequences are the same as the option above. |
| Government acts without statutory basis | **Objective not met**<br>Government continues to regulate smart charge points separately to ESAs, meaning there is misalignment between the two regimes.<br><br>Therefore, the consequences are the same as the “do nothing” option above. | **Objective not met**<br>Without legislative changes, the EA cannot apply criminal sanctions or have the power to recover costs.<br><br>Therefore, the consequences are the same as the “do nothing” option above. | **Objective partially met**<br>Government could chose to make a distinction in obligations across the supply chain without it being set in legislation, however there would be no legal basis for this enforcement approach, leaving Government open to legal challenge. |

**Table B - Primary Powers comparison**

| New powers under the Energy Bill 2022 | Current powers under the AEVA 2018 | Difference for smart charge points only |
|---|---|---|

| | | |
|---|---|---|
| Obligations are placed on different businesses (economic actors) across the supply chain | Obligations apply to sellers only | Obligations will move from being solely on a seller to being split across the manufacturer/importer and distributor. |
| Private charge points and electric heating appliances (which include heat pumps) must have smart functionality | Private charge points must have smart functionality | No difference |
| Energy Smart Appliances must meet device-level requirements (cyber security, data privacy, grid stability and interoperability) | Private charge points must meet device-level requirements (cyber security, data privacy, grid stability and interoperability) | No difference |
| Allows for an assurance scheme to be set up to help prove compliance | Allows for an assurance scheme to be set up to help prove compliance | No difference |
| Range of enforcement powers allow for an Enforcement Body to investigate, remedy and penalise non-compliance | Range of enforcement powers allow for an Enforcement Body to investigate, remedy and penalise non-compliance but they are limited in some areas | AEVA does not allow the following enforcement powers: (i) criminal sanctions and (ii) cost recovery from non-compliant businesses. |

**Case study 1 : Integrated Infrastructure: Cyber Resiliency in Society by Cambridge Centre for Risk Studies, 2016[1]**

1. The Cambridge Centre for Risk Studies researched the UK's resilience to a cyber-attack to determine the possible costs to national infrastructure of a more interconnected society. The UK Critical Infrastructure Catastrophe Scenario models a cyber-attack on the substations within the electricity distribution network in the south and east of the UK and its impacts on Critical National Infrastructure, the economy and wider society. This regional power supply disaster affects 9-13 million electricity customers, and 8-13 million people reliant on transportation, digital communications and water services, depending on the scenario considered.

2. Across these same scenario attacks, the economic costs to sectors range from £11.6 billion-£85.5 billion and it suggests an overall GDP loss of between £49-£442 billion across the UK in the subsequent 5 years. The scenario begins with "Trojan Horse" hardware being placed in substations across the region and using mobile phone technology to start rolling blackouts across the region during the winter months. Until the pieces of hardware are identified and removed, the prolonged electricity outages will have knock on effects to the transportation, digital communications and public health sectors in particular. 40-45% of UK port freight was also disrupted in this example, primarily at Felixstowe and Dover, which is key for supply chain distribution with Europe.

3. The style of cyber-attacks faced by demand side response service providers could be to information technology rather than operational technology, as in this example, but the threat of wider impacts from prolonged lack of power still exists.

4. This report concluded that cooperation and communication across sectors, and between government regulatory agencies and industry is vital to recognise the true costs of a cyber-attack and creating a safeguarding strategy to protect both the physical infrastructure and the wider economy from this threat. The paper states the process of assessing ROI of cyber security measures requires change, to reflect the true costs of an extreme cyber-attack on society. Reducing this risk via some additional cost to business and government could be hugely beneficial.

**Case study 2: The August 9th 2019 power outage[2]**

5. On 9th August 2019, a power outage caused interruptions to over 1 million consumers' electricity supply and 892 MW of net demand was disconnected from distribution networks as a result of low frequency demand disconnection, representing around 4% of national demand. A lightning strike caused a fault on the transmission network, disconnecting a number of small generators and two large generators. This led to a fall in system frequency and further generation disconnects beyond the back-up power arrangements, and therefore demand disconnection was required. Ofgem report that the

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[1] Cambridge Centre for Risk Studies (2016): Integrated Infrastructure: Cyber Resilience in Society, https://www.jbs.cam.ac.uk/wp-content/uploads/2020/08/crs-integrated-infrastructure-cyber-resiliency-in-society.pdf

[2] https://www.nationalgrideso.com/information-about-great-britains-energy-system-and-electricity-system-operator-eso

major impacts of the event were faced by other sectors, resulting from the lack of resilience to the disturbance of the affected service providers. This included predominantly transport with over 500 rails services disrupted and Newcastle airport being disconnected. Other essential services such as hospitals and water pumping stations were also disconnected as a result of the outage, and several thousands of customers experienced disruption to their water supply. Ofgem concluded that whilst the actions of the ESO were effective to restore the system within 45 minutes, this outage highlighted the risks of managing system security and stability in a developing electricity system. They further concluded that the cost to increase the ESO's frequency response would not be value for money considering the knock on impact to consumer bills, which might limit the extent to which the additional investment occurs.

**Replacement power to amend Energy Performance of Buildings Regulations.**

The power to revoke, amend and create new Energy Performance of Buildings Regulations previously derived from the European Communities Act 1972 (ECA), section 2(2). This power was lost following the repeal of the European Communities Act 1972 when the EU Transition Period ended on 31 December 2020. Under the European Union (Withdrawal Act) 2018, Government has limited power to revise the Energy Performance of Buildings Regulations in respect of fees and charges and under section 74 of the Energy Act 2011 has the power to make regulations in connection with the disclosure of data entered on the Energy Performance of Buildings Register.

Therefore, save in the respects identified above, the Government no longer has the power to make substantive amendments to the energy performance of buildings regime. The energy performance of buildings regime includes provisions regarding the production of energy certificates such as Energy Performance Certificates (EPCs) the details of which are set in secondary legislation. The new primary power sought will apply to England and Wales as this is a devolved issue for Scotland and Northern Ireland (who have a comparative system). The current set of Regulations transposed respective EU Energy Performance Directives and pre-dates Government's ambition to bring all greenhouse gas emissions to net zero by 2050.

The proposed new primary power in the Energy Bill seeks to replace the former 2(2) power and will not itself impact on business activity. Replacement of the power will reinstate the situation which existed prior to EU exit and will enable England and Wales to have the ability to amend, revoke and create new regulations to meet the UK's own net zero ambitions. Where Government proposes to make changes to the Energy Performance of Building Regulations, these proposed changes will be subject to the outcome of consultation, requirements for Regulatory Impact Assessment and parliamentary approval of secondary legislation, as appropriate.

The repeal of the European Communities Act 1972 did not affect powers relating to other Building Regulations in England and the devolved administrations. It did not impact on the UK Government and Devolved Administration's powers to change future housing and buildings standards which include energy efficiency standards. In December 2021, following consultation, the UK Government announced uplifts to energy efficiency standards in the Building Regulations for domestic and non-domestic buildings in England and the relevant Regulatory Impact Assessments[1] were verified by the Regulatory Policy Committee.

[1] https://www.gov.uk/government/publications/2021-uplift-to-energy-efficiency-standards-improved-ventilation-and-new-overheating-requirement

| | |
|---|---|
| **Title:** Extension of the Domestic Gas and Electricity (Tariff Cap) Bill<br>**IA No:** BEIS047(F)-22-ESNM<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy and Industrial Strategy<br>**Other departments or agencies:** N/A | Impact Assessment (IA)<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** retailenergy@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| N/A | N/A | **N/A** | Qualifying Provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

In the absence of intervention, and before other measures can take effect, an estimated £1.5bn per annum "loyalty penalty" is expected to return to the domestic retail energy market from 2023, which will disproportionately affect low-income and vulnerable households. Ofgem put in place a package of remedies designed to improve competition, but many of these measures will take time to take effect. Since the current price cap was introduced in 2019, there have been some potential improvements to the effectiveness of competition. However, while recent market conditions have seen fixed tariffs rise above default tariffs, even prior to this, over half of the market (51% of domestic customers) still remained on default tariffs and around two-fifths of the market had remained on default tariffs for more than three years. A lack of consumer engagement has significant implications for competition between suppliers and resulting consumer outcomes and the loyalty penalty is a symptom of a range of market failures, which mean that a large portion of the market is not characterised by effective competition.

**What are the policy objectives of the action or intervention and the intended effects?**

The Government's objective is for the policy to protect domestic energy customers from unjustifiably high prices until the conditions for effective competition are in place and to minimise any disproportionate impacts (that currently exist in the retail energy market) for low income and vulnerable customers.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Various options were considered before the final two options. Many of these will require time to have an impact, such as Ofgem's Faster and More Reliable Switching Programme, which is expected to be introduced in Summer 2022, subject to continued successful testing. In July 2021, the Government also published the Energy Retail Strategy as well which includes a range of HMG and Ofgem policies to improve competition in the market by removing barriers to market information and increasing consumer engagement. Two final options are presented: (1) do nothing; and (2) enable the Government to allow Ofgem the powers to extend the temporary price cap on default energy tariffs beyond the end of 2023, if conditions for effective competition are not in place. These are considered in the context of measures already taken to drive competitive outcomes for household energy customers, as well as those for which outcomes have yet to fully take

**Will the policy be reviewed?** N/A. **If applicable, set review date:** N/A.

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | No | | | |
| Are any of these organisations in scope? | **Micro**<br>Yes | **Small**<br>Yes | **Medium**<br>Yes | **Large**<br>Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions?<br>(Million tonnes $CO_2$ equivalent) | **Traded:**<br>N/A | **Non-traded:**<br>N/A | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

# Summary: Analysis & Evidence — Policy Option 2

**Description: Option 2:** Enable the Government to allow Ofgem the powers to extend the temporary price cap on default energy tariffs beyond the end of 2023, if conditions for effective competition are not in place (costs and benefits expressed relative to do nothing Option 1).

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2019 | PV Base Year 2020 | Time Period: Indefinite with 2 yearly extensions | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Cost (Present Value) |
|---|---|---|---|---|
| Low | N/A[1] | | N/A | N/A |
| High | N/A | | N/A | N/A |
| Best Estimate | N/A | | | |

**Description and scale of key monetised costs by 'main affected groups'**

Ofgem's Impact Assessment for the current formulation of the price cap estimated an aggregate direct impact on supplier revenues of £1,174m per year. Ofgem will develop and consult on the detail of the methodology for extending the tariff cap including evidence of the impact different cap designs would have.

**Other key non-monetised costs by 'main affected groups'**

The primary cost would be a reduction of energy suppliers' revenues from customers on SVTs and other default tariffs which may lead to lower profitability if it is not fully offset by efficiency improvements. Potential other costs include those to customers not on SVTs and default tariffs if suppliers raise these tariffs to counteract the impact of the cap although the operation of competition between a range of suppliers in the non-default tariff market minimise this. Customers may also decide not to switch as they believe they are protected. However, in designing the cap, Ofgem is required to minimise this potential risk.

| BENEFITS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Benefit (Present Value) |
|---|---|---|---|---|
| Low | N/A | | N/A | N/A |
| High | N/A | | N/A | N/A |
| Best Estimate | N/A | | N/A | N/A |

**Description and scale of key monetised benefits by 'main affected groups'**

The main benefit of this option is reduction in household expenditure on energy. Before the initial introduction of the price cap in 2019, Ofgem's Impact Assessment found that a typical household on a default tariff would save between £76-£120 following introduction of the cap based on their methodology, with an estimated £1,233m per year aggregate savings across households . Beyond 2023, Ofgem will continue to be responsible for setting the price cap level and maintaining the methodology for doing so. They will be required to do so in a way that protects future and existing domestic customers, while meeting wider market objectives.

**Other key non-monetised benefits by 'main affected groups'**

The key benefit of this option would be the protection of SVT and default tariff customers from unjustifiably high tariffs and a reduction of the annual consumer detriment until conditions for effective competition are in place. There may also be an increase in trust in the market if customers feel that they are unlikely to be on poor value deals. Lower revenues could drive further efficiency improvements among suppliers and more money for households to spend on good and services and/or reduce the prevalence of underheating with associated health benefits. Unless they reduce their costs (e.g., through efficiencies), it may also reduce the ability of larger suppliers to sustain low or no profits in the competitive part of the market, leading to market share growth and greater profitability for more efficient challenger companies.

| Key assumptions/sensitivities/risks | Discount rate (%) | 3.5% |
|---|---|---|

Costs and benefits will depend on the detailed methodology Ofgem adopts to extend the level of a tariff cap. This will become clear as Ofgem develop and consult on their methodology for setting the cap level.

[1] OFGEM will produce analysis to determine costs/benefits when they design the methodology for extending the cap

**BUSINESS ASSESSMENT (Option B)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** | **Benefits:** | **Net:** | |
| N/A | N/A | N/A | N/A |

# A fairer deal for energy customers - Evidence Base

## Section 1: Strategic Overview

***Historical Context***

1. The Government is committed to ensuring a well-functioning market economy as the best way to deliver prosperity and security for everyone. For markets to operate effectively, it is crucial that customers understand them and have confidence they are working in their interest.

2. However, the Government recognises that sometimes markets develop in ways that mean large numbers of customers do not benefit. Historically, the retail energy market has offered one such example. Following privatisation of the energy retail market two decades ago, the level of competition improved – some customers began moving between tariffs and suppliers, new suppliers entered, more competitive product offerings emerged, and customer choice increased. However, this increase in competition did not bring benefits to all customers, including many of the most vulnerable.

3. In this market, like that for many utilities, customers who do not engage with the market, for example through switching, remain or are rolled onto their supplier's 'default tariff'. Since these consumers are defined by lower levels of engagement, suppliers are given a position of unilateral market power over them, which weakens competition for their custom and means they can be consistently charged higher prices.

4. An assessment of the effects of this was formalised by the CMA in their 2016 Energy Market Investigation. They found a long-standing problem and that domestic customers were paying £1.4bn a year on average more for their energy than they would do in a hypothetical competitive market. Further to this, a similar assessment was conducted by Ofgem in 2018 which found that total detriment to domestic customers from excessive prices was £1.5bn a year.[1,2] This phenomenon has become referred to as the 'loyalty penalty' and is a feature common to many similarly structured markets. Energy suppliers, for a long time, operated a two-tier market, in which people who frequently switch tariffs benefit from lower prices, but loyal customers pay higher prices. This matters because energy is an unavoidable necessity which makes up a significant portion of household budgets, and demand for which is relatively unresponsive to price changes in the short-term.

***Introduction of current energy tariff price cap***

5. To overcome this persistent problem, in 2017 Ofgem introduced a cap on prices paid by prepayment meter and some other vulnerable customers (the safeguard tariff). Following this, in 2018 the Government introduced a duty on Ofgem to implement a market-wide Default Tariff Cap (the price cap) if conditions for effective competition are not in place, to ensure all vulnerable customers received protection from the loyalty penalty. A price cap has been in place since January 2019.

6. Under the current Default Tariff Cap Act (2018), the cap can be extended one year at a time if the conditions for effective competition in the market are not in place, up until the end of 2023 at the latest.

7. Since 2020, every year Ofgem have produced a report with their assessment of whether conditions are in place for effective competition.[3] Ofgem's 2021 report [4] includes updated analysis to account for progress since their 2020 review and explains that currently conditions for effective competition are not present in the retail energy market. Ofgem recommended that the

[1] https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf
[2] Reference to Ofgem IA 2018
[3] https://www.ofgem.gov.uk/sites/default/files/docs/2018/11/appendix_11_-_final_impact_assessment.pdf
[4] https://www.ofgem.gov.uk/publications/outcome-2021-review-whether-conditions-are-place-effective-competition-domestic-supply-contracts

default tariff cap on default tariffs and standard variable tariffs be extended until the end of 2022. The report notes, and the Government agrees, that following the introduction of the price cap, there were some improvements in the effectiveness of competition, such as increased engagement among some consumers leading to rising switching levels, particularly in 2019, and progress with the smart meter rollout. However, progress has been limited and there are clear reasons to expect that conditions allowing the removal of the price cap may not be in place before the end of 2023. As a result, in July 2021 the Government announced its intention to seek powers that would enable extension of the cap beyond this point, if needed.

8. Subsequent to Ofgem's report and the Government's July announcement, the unprecedented sudden and substantial rise in wholesale gas and electricity prices in the autumn of 2021 left many suppliers, particularly those who had limited forward hedged positions and weak balance sheets, unable to maintain solvency. This led to a substantial decrease in the number of active suppliers. At the same time, switching levels fell sharply due to the reversal of the usual differential between standard variable and fixed tariffs across the market. The longer-term impacts on the effectiveness of competition are highly uncertain, but the increase in market concentration and the potential for greater risk aversion among some consumers may further slow progress towards conditions for effective competition.

9. In all, it is clear that there is still more to do to ensure consumers would pay fair prices in the absence of a price cap. Following the events of late 2021, the Government is reviewing its overarching retail market strategy, and has emphasised the importance of taking account of lessons learned during the period. The impact of any policy reforms as part of this strategy will take time to feed through.  If the price cap expires before the conditions for effective competition are in place, there is a substantial risk that the millions of consumers who remain on default tariffs will be exposed to the excessive charging that existed before the price cap's introduction.

10. As per section 1 of the default tariff cap 2018, Ofgem are responsible for protecting existing and future domestic consumers who pay standard and variable default rates and in doing so must have regard to the following matters:
    a) The need to create incentives for holders of supply licences to improve their efficiency;
    b) The need to set the cap at a level that enables holders of supply licences to compete effectively for domestic supply contracts;
    c) The need to maintain incentives for domestic customers to switch to different domestic supply contracts;
    d) The need to ensure that holders of supply licences who operate efficiently are able to finance activities authorised by the licence.

11. Given Ofgem's independent role in determining the methodology for setting the level of any price cap, this Impact Assessment presents a largely qualitative discussion of the costs and benefits of the various options considered. Indicative illustrations of costs and benefits are also provided based on extensive analysis conducted by Ofgem during their development of detailed price cap policy ahead of implementation in January 2019.

## Section 2: Problem under consideration

12. Since the current price cap was introduced in 2019, there have been some potential improvements to the effectiveness of competition. However, while recent market conditions have seen fixed tariffs rise above default tariffs, even prior to this, over half of the market (51% of domestic customers) still remained on default tariffs and around two-fifths of the market had remained on default tariffs for more than three years.[5] Once the existing price cap legislation ends in 2023, without further intervention, the market is likely to return to circumstances where this group, in which low income and otherwise vulnerable households are disproportionately represented, face excessive prices as a result of the lack of competition in this subsection of the market.

[5] https://www.ofgem.gov.uk/sites/default/files/2021-08/CfEC_review_2021_publication_final.pdf

**Current state of the market - two-tier market**

13. Although competition in the retail energy market increased in the years following privatisation, many customers have not benefitted.

14. The energy market continues to operate with two broad tiers:

    a) A competitive tier, where suppliers compete to attract customers who engage with the market by switching tariffs or supplier. The competition is mainly driven by price, with some secondary features such as environmental credentials of the tariff and customer service.[6][7] Although this segment has grown, it still remains less than half of the market.

    b) A default tariff tier, where customers do not regularly engage with the market. There is some movement into and out of this segment, but it still typically comprises over half the market.

15. In the absence of intervention, this two-tier market enables suppliers to charge disengaged customers significantly more than the cost to serve them, with minimal risk of losing their custom. Reduced consumer engagement has significant implications for competition between suppliers, and resulting consumer outcomes and the loyalty penalty are a symptom of a range of market failures (discussed in further detail in the next section), which mean that a large portion of the market is not characterised by effective competition.

16. As a result, suppliers are able to earn excess profits, or to persistently operate with significant inefficiencies. As mentioned previously, Ofgem found this detriment to be £1.5bn a year. In addition, the majority of households that are impacted disproportionately are low income households and vulnerable people – this is expanded upon, in the next section.

## Section 3: Rationale for intervention

**The loyalty penalty is a symptom of a range of market failures, which mean that a large proportion of the market is not characterised by effective competition.**

17. The majority of households that do not engage/switch suppliers in the market include many low-income households and vulnerable people.[8] Households with low incomes, low qualifications, those in the rented sector and those over 65 are more likely to be losing out. Repeated Ofgem Consumer Surveys find that those in lower social grades and with lower incomes are more likely to be disengaged. Their most recent survey in 2019 found that the proportion of households in the lowest social grades (DE) that report never having switched energy supplier was 43%, compared to 20% of consumers in the highest social grades (AB).

18. Low income and other customers in vulnerable situations are also more likely to face disproportionate impacts from higher energy prices since energy costs often comprise a higher proportion of their income. For the poorest households, 23% of their total expenditure was spent on housing, fuel and power in 2020 compared to 10% of total expenditure for the richest households.[9] As such, poorer households are disproportionately impacted by higher energy costs. They are also more likely to be exposed to the risks of under-consumption of energy, including to health, such as from the rationing of heat among those at risk of fuel poverty.

19. There are a variety of market failures (discussed below) where the impact falls on these disproportionately affected groups likely to be in vulnerable circumstances. As such, there is a clear case for government intervention to limit negative distributional consequences.

[6] Outputs used from Ofgem's 2019 Consumer Survey to allow comparability with previous years, given changes to survey methodology in 2020, and the potential for one-off factors resulting from the effects of COVID 19.

[7] Ofgem Consumer Survey 2019, Consumers Engagement Survey 2019 Data Tables, Table 170

[8] Households who have never switched will remain on their area's old incumbent energy supplier's default SVT, and households who are on fixed tariffs but do not switch at the end of their tariff default to their supplier's SVT.

[9] ONS family spending for financial year ending 2020

20. In their 2018 response to the Loyalty Penalty Super Complaint, the CMA identified the causes of the loyalty penalty in consumer markets.[10] Many are highly relevant to the domestic retail energy market:

- **Automatically renewed and deemed contracts.** Due to the importance of the continuity of supply to customers, the energy market regulatory framework allows 'default arrangements' to be applied. These take the form of automatically-renewed contracts for customers outside of fixed-term contracts and deemed tariffs for those new to a property. As highlighted by the CMA, such arrangements directly contribute to loyalty penalties in a variety of consumer markets, since they enable consumers to remain 'passively loyal' with their existing supplier. This creates a market segment particularly at risk of weak competition, because of the reduced extent of market engagement by consumers on default tariffs, and the ease with which they can be identified by suppliers.

- **Barriers to market information and engagement.** Consumers rely on access to high-quality information and advice on factors such as price and customer service to make informed choices. This is particularly important in a competitive market, with a wide variety of suppliers and variation in the types of tariffs available, depending on consumer usage patterns and preferences. Several information barriers are likely to restrict customers from understanding the market:

    - **Perceptions that shopping around can be very time and cognitively consuming.** Engaging with the market requires consumers to access information on offers available, assess them and act on this information in line with their preferences. Some may have misconceptions, for example, thinking this is more time consuming or difficult to search than it really is.

    - **For those only engaging without using the internet, independent sources of information are limited and not well known.** Ofgem survey results in 2019 found that 30% of customers with no internet use were not confident in choosing the best energy deal for their household, as opposed to 15% of those who regularly use the internet.[11] Those on low incomes or from a lower social grade were also significantly less likely to use price-comparison websites (PCWs) when switching compared to those from higher social grades or higher incomes.[12]

    - **Many customers do not have confidence in the results generated by PCWs.** The Ofgem Consumer Survey results from 2019 found that 30% of customers did not believe PCWs to be unbiased in the way they present energy deals.[13] The CMA Energy Market Investigation found that 43% of those who were not confident in getting the right deal through a PCW said they did not believe the results of the search, and 26% said they found the information was too complex and were unsure of what the right deal was.[14]

    - **Misconceptions of supply risk.** The CMA's qualitative research provided evidence that consumers may be concerned that switching could temporarily stop their energy supply.[15] The Ofgem survey data from 2019 found that 12% of people were concerned that something might go wrong, and they might get cut off following a switch.[16]

[10]CMA, Tackling the loyalty penalty: Response to a super-complaint made by Citizens Advice on 28 September 2018: https://assets.publishing.service.gov.uk/media/5c194665e5274a4685bfbafa/response_to_super_complaint_pdf.pdf
[11] Ofgem, Consumer Survey 2019, Consumer Engagement Survey 2019 Data Tables, Table 341
[12] Ofgem, Consumer Survey 2019, Consumer Engagement Survey 2019 Data Tables, Table 227
[13] Ofgem, Consumer Survey 2019, Consumers Engagement Survey 2019 Data Tables, Table 306
[14] CMA, Energy Market Investigation, Final Report: Appendix 9.1: CMA domestic customer survey, Page A9.1-11
[15] CMA, Tackling the loyalty penalty: Response to a super-complaint made by Citizens Advice on 28 September 2018. Page 24
[16] Ofgem, Consumer Survey 2019, Consumer Engagement Survey 2019 Data Tables, Table 309

## Section 4: Policy Objective

21. The Government's objective is to protect domestic energy customers from unjustifiably high prices until the conditions for effective competition are in place for domestic supply contracts and to minimise any disproportionate impacts (that currently exist in the retail energy market) for low income and vulnerable customers. Various options have been considered below to be able to achieve the Policy objective.

## Section 5: Options considered

22. A variety of other measures are being considered and implemented to improve effective competition in the energy market targeting specific market failures set out above. In recent years, Government and Ofgem, working closely with industry, have made various decisions in order to improve how the market functions and raise consumer confidence and trust. Many of these will require time to have an impact, such as Ofgem's Faster and More Reliable Switching Programme, which is expected to be introduced in Summer 2022, subject to continued successful testing. In July 2021, the Government published an Energy Retail Strategy, which includes a range of HMG and Ofgem policies to improve competition in the market by removing barriers to market information and increasing consumer engagement.

23. Furthermore, the last few months have seen unprecedented increases in the levels and volatility of wholesale gas prices across the globe. This has led to a shift in the size and shape of the energy retail market, with a significantly higher number of suppliers exits and consumer hesitancy to switch. In response, the Government is also reviewing lessons learned and refreshing our current Energy Retail Strategy to promote a more resilient and sustainable market, which continues to protect consumers as we move to a net zero energy system.

24. The Government has also considered 'opt-in' and 'opt-out' switching programmes. The programmes would involve a form of direct communication either prompting customers to consider their choices in the market ('opt-in') or be informed that suppliers have been switched on their behalf and to get in contact if they wish to remain on their current supplier ('opt-out'). However, given recent market developments, the Government has announced it is pausing policy development on these programmes which in any case would require significant further work and engagement to enable a smooth roll-out consistent with a stable and well-functioning market.

**Final Options**

Given the above, two final options are considered:

*Option 1: 'Do-Nothing' Scenario*

25. In the 'do nothing' scenario, the current default tariff cap will expire at the end of 2023 at the latest. In the absence of effective competition, this would have substantial negative consequences for millions of households, including many vulnerable consumers.

26. Given the persistent market failures and limited progress in improving competitive conditions, it is expected that majority of the c.15 million households who are typically on SVTs and default tariffs would return to paying substantially above the competitively efficient level. Many of these households will be low-income or vulnerable, for whom energy represents a greater proportion of total household expenditure, and who are the least likely to have switched to better value tariffs. Doing nothing would therefore not achieve the desired policy objective.

*Option 2: Enable the Government to allow Ofgem the powers to extend the temporary price cap on default energy tariffs beyond the end of 2023, if conditions for effective competition are not in place*

27. This option would give the Secretary of State (SoS) and parliament the power to extend the application of price cap on standard variable and other default tariffs by Ofgem beyond the end of 2023. The application of any price cap would remain dependent on effectiveness of competition in the retail energy market and the methodology for determining the level of any cap would continue to be for Ofgem to determine. For the purpose of this impact assessment, the price cap is assumed to be set based on the same principles as the current cap. Further Statutory Instruments will be required to make further extensions to the application of the price cap for at most two years at a time, if the conditions for effective competition are deemed not to be present.

28. To ensure that the cap considers developments in the market as well as changes in the costs of supplying energy, the legislation will continue to require Ofgem to review the level of the cap at least every six months.

29. As previously mentioned, over half of the market has been protected by the default tariff cap. Whilst measures to improve competition take time to take effect, extension of the default tariff cap will help in continuing to protect many vulnerable and low-income consumers. Therefore, we have concluded that allowing the cap to remain in place beyond the end of 2023, is the best option while the Government continues to address the underlying factors that have caused the loyalty penalty. Ofgem will continue to produce reports for effective competition, but by the end of 2023, if the three conditions for effective competition are still not met, this legislation will allow Ofgem to be able to extend the default tariff price cap beyond 2023. In this context, maintaining the price cap remains essential to ensure that consumers are protected from excessive charging until market conditions can be stabilised and improved.

## Section 6: Costs and Benefits of Preferred Option (Option 2)

**Option 2: Extending the current temporary energy tariff cap**

30. In addition to this Impact Assessment, Ofgem will develop and publish their own proportionate analysis of the direct and indirect impacts of the cap where appropriate in line with their regulatory duties, including an impact assessment where appropriate. Ofgem will continue to monitor the effectiveness of how the price cap is implemented and will continue to publish reviews as to whether the market conditions still require a cap to be in place. These reviews will, alongside the data already regularly collected and reported by Ofgem and BEIS, enable ongoing monitoring of the market and enable analysis of the impact of the price cap. Depending on how close the market is to achieving effective conditions for competition, the cap would be extended via an affirmative SI for at most two years at a time. Ofgem would publish their report on whether market conditions still require a cap to be in place ahead of the SI process, during appropriate years as set out in the new legislation.

***Direct Impacts***

Reduction in household energy expenditure

31. Capping SVTs and default tariffs will lead to a reduction in total energy expenditure across households on these tariffs, as the detriment faced as a result of the loyalty penalty is directly limited. The extent and distribution of these benefits will vary across households. Households whose energy tariffs would have been higher under "do nothing" will experience benefits from a cap associated with lower energy bills, i.e., more disposable income to spend on other goods and services, and/or warmer homes as a result of comfort-taking, which is especially likely to give rise to equity benefits for vulnerable and low-income households.

32. Since 2016, there have been several assessments of the size of the consumer detriment. The CMA's 2016 Energy Market Investigation found an annually increasing detriment, as supported by Ofgem's 2018 Final Impact Assessment for the current Default Tariff Cap which found a similar scale of detriment of around £1.5bn per year in 2017. The same exercise led to the conclusion that a typical household on a default tariff would save £76-120 per year following the introduction of the cap, with an estimated £1,233m per year aggregate savings across households[17][18]. Since a price cap is currently in force and the cap level, and underpinning methodology, will be independently determined by Ofgem it is challenging to provide an updated assessment. However, since there has been limited change to underlying competitive dynamics since Ofgem's assessment, we consider that this remains a useful indicator of the likely scale of benefit.

<u>Reduction in energy suppliers' revenues</u>

33. Energy suppliers overall will experience a reduction in revenues from default tariffs – the direct result of reduced tariff prices for their customers. Those suppliers who would otherwise charge the highest tariff prices and with larger proportions of their customers on default tariffs are likely to be most significantly affected. As with the consumer benefit from lower tariff prices, given the current presence of the price cap, isolating the direct impact of the cap on supplier revenues is challenging. Ofgem's Impact Assessment for the current formulation of the price cap estimated an aggregate direct impact on supplier revenues of £1,174m per year.[19]

34. In addition to these impacts there will be a direct cost to Ofgem of developing, administering, and implementing the price cap and costs to domestic retail energy suppliers to provide Ofgem with certain information as part of the processes to maintain the methodology and from updates to the cap level where they necessitate price changes for their customers. Given that the current price cap has been in force since 2019, these costs are expected to be low in comparison to total impacts as it is likely that Ofgem and suppliers will have gained familiarity with the processes and put in place procedures for features such as regular price updates.

***<u>Indirect Impacts</u>***

Various indirect impacts are likely to continue as a result of the extension of the default energy tariff cap. The potential impacts considered below are:

- impacts on competition,
- impacts on domestic fixed tariffs and non-domestic contracts,
- impacts on small suppliers,
- impacts on the wider market, and
- impacts on energy demand.

*<u>Impacts on competition</u>*

35. To maintain healthy competition in this market segment, the price cap legislation puts a duty on Ofgem to consider factors critical to competition when setting the cap level. There are various ways in which extension of the default tariff cap may affect competition:

- Scope for suppliers to use higher revenues from poor value SVTs to undercut competitors in the non-standard tariff market may reduce;

[17] Ofgem (2018) Press Release, https://www.ofgem.gov.uk/publications-and-updates/energy-price-cap-will-give-11-million-fairer-deal-1-january. This is the range between the average and maximum saving for dual fuel customers.
[18] Ofgem (2018) Final Impact Assessment: Default Tariff Cap, Table A11.12, Page 70.
[19] From Ofgem's 2018 IA

- Suppliers might be incentivised to engage customers so that they reduce the number of their customers on SVT or default tariffs;

- PCWs might be negatively affected if there is a smaller pool of switchers, although the intention of the legislation is to maintain the incentives for customers to switch and suppliers to compete[20];

- There is a risk that a supplier could choose to exit the market as a result of this measure. However, as well as considering the impact on competition and switching, Ofgem will need to consider the need to ensure that an efficient supplier is able to finance activities authorised by their supply licence;

- Competition might decrease as customers may choose not to engage if the gains from switching are decreased, and/or if they perceive that they are being protected by the Government and hence on a fair tariff.

36. In the current market structure, switching choices by consumers are the primary driver of inter-supplier competition. It was expected that the introduction of the default tariff cap could lead to a reduction in the numbers of customers switching. Despite this, switching rates reached record highs after the cap was introduced in 2019 – consumer switching reached record levels in February 2020.[21] The rolling average annual switching rate for electricity increased from 13% in February 2016 to 21% in February 2020. Throughout 2020 and most of 2021, switching rates remained at levels well above typical levels from recent years. While, as discussed above, this was negatively affected by the unprecedented pattern in wholesale prices in autumn 2021 as discussed above, the experience post-2019 provides early indicative evidence that a market with price protection for the most disengaged consumers can be consistent with continued competition in other market segments.

37. Effective competition in the retail market also relies on the ability of efficient suppliers to sustainably operate in the market, and to be able to finance their activities. Ensuring the price cap setting methodology allows this is therefore a key element of minimising any potential negative impacts of a price cap on competition.

38. Following the events precipitated by wholesale market conditions in the autumn and winter of 2021, a large numbers of suppliers became insolvent and exited the market.[22] In general terms, these insolvencies were largely the result of suppliers having sold fixed-price tariffs, without having sufficiently hedged against the risk of significant rises in underlying wholesale costs through forward purchases.[23] Ofgem have announced plans to take actions that ensure that licenced suppliers are required to take greater steps to ensure their resilience to such events in future.

39. At the same time, the wholesale volatility experienced during this period was unprecedented, and this meant that Ofgem's pre-existing methodology for setting the cap level did not capture the full range of costs to which suppliers were exposed. Ofgem have taken steps to adjust the cap methodology in the short-term to correct for this and are conducting a wide-ranging consultation exercise to ensure the price cap continues to be set in line with the principle that efficient suppliers must be able to finance their activities.[24,25] The lessons of this exercise will also be applied to the development of any Ofgem methodology used to determine cap levels post-2023.

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[20] This is likely to be harder to do while the energy crisis is alive and wholesale costs remain high

[21] https://www.ofgem.gov.uk/sites/default/files/2021-08/CfEC_review_2021_publication_final.pdf

[22] Footnote to be completed based on latest market structure before publication

[23] Typically, energy suppliers offer customers contracts that fix prices for an extended period (generally at least 12 months). Given the inherent volatility in underlying wholesale costs, it is typical that supply businesses simultaneously enter into forward price purchases for the energy necessary to fulfil these contracts to protect themselves against price risk that they would be unable to withstand.

[24] Ofgem reference

[25] Ofgem reference

*Impact on the wider market*

40. Depending on the methodology used to determine the cap level and its impact on supplier incentives and behaviours, there could be an impact on how suppliers buy energy in the wholesale market. This could impact liquidity in different parts of the wholesale market. For the parts of the market where liquidity decreases, this could reduce price transparency for independent companies, reducing the scope for developing innovative tariffs.

*Impact on energy demand*

41. If a cap results in lower tariffs, then this could encourage more use of gas and electricity. This would have a direct benefit for those using more energy, including health benefits, but would also have an impact on greenhouse has emissions. Any impact on demand or carbon emissions would be dependent on the price elasticity of demand (which is generally quite inelastic in the domestic energy market), as well as the level of the cap.

## Section 7: Small and Micro Business Assessment (SaMBA)

42. There are now 26 energy suppliers in the domestic retail energy market, up from 13 in 2010, with around 11 suppliers classified as either a small business or microbusiness as of 13th May 2022. Of these, zero suppliers currently have a customer base in excess of 250,000.

43. To ensure equal treatment, the Government's approach is to apply the tariff cap to all domestic energy suppliers. The rationale for this is to protect customers from being charged poor value tariffs until the conditions for effective competition are in place[26]. It would not be fair to have the customers of some suppliers protected and others not.

44. In practice however, this measure should impact smaller suppliers proportionately less as, in general, they are likely to have proportionately fewer default customers given their lack of legacy customer bases, and smaller, newer suppliers are expected to generally have costs (excluding policy costs) below those allowed for in the setting of a cap methodology[27]. These suppliers would, therefore, be able to continue offering competitive tariffs and cheaper contracts which will provide incentives for engaged customers to switch to. The winter of 2021/22 saw many suppliers failing due to rapidly and sharply rising wholesale prices which left suppliers with short-term hedging strategies with a need to purchase energy at far higher prices than they had anticipated when setting consumer tariffs. Given that this effect applied to fixed-term tariff customers, who generally made up the majority of these suppliers' customer bases, as well as those on capped tariffs, and that suppliers would always face competition from those with more advantageous hedging strategies, we anticipate that a similar outcome would have occurred with or without a price cap.

45. If there are smaller suppliers that have built their business model around loyal customers defaulting onto more expensive deals, then this measure will have a more significant impact on them. The administrative cost of complying with the primary legislation is expected to be relatively small in comparison to total operating costs.

## Section 8: Equality Assessment

46. The Department for Business, Energy and Industrial Strategy (BEIS) is required to comply with the public sector duty (PSED) set out in the Equality Act 2010 ("the Act"). The PSED requires the Minister to have due regard to the need to advance equality of opportunity, eliminate discrimination and foster good relations between those with and without certain protected

[26] Which, as discussed previously in this IA is not yet the case

[27] From Ofgem's IA

characteristics. This due regard is taken to eliminate unlawful discrimination and to tackle prejudice and promote understanding. The characteristics that are protected by the Equality Act 2010 are: age, disability, gender reassignment, marriage or civil partnership (in employment only), pregnancy and maternity, race, religion or belief, sex and sexual orientation.

47. There is a significant risk that the conditions for effective competition (CfEC) will not be in place by the end of 2023 (current longstop date). If the price cap expires before the CfEC are in place, there is a substantial risk that the majority of the 15 million households who have typically been on default tariffs will be exposed to the excessive charging that existed before the price cap's introduction.

48. We do not consider that this policy treats some people less favourably than others because of a protected characteristic. The price cap is a relatively simple measure that limits what energy suppliers can charge consumers on default tariffs. Therefore, we do not consider that the price cap (or its extension beyond 2023) will have a discriminatory impact on people with protected characteristics nor have any other impact prohibited by the 2010 Act.

49. The implications of our proposals for the equality duty have been considered in depth in this assessment. Overall, this policy is therefore expected to only impact consumers on default tariffs, many of whom can be defined as "disengaged consumers" as they have not changed or expressly chosen their energy tariff for a long time.

## Section 9: Business Impact Target

50. This regulatory policy change may or may not score against the business impact target as the rules for this Parliament have not yet been agreed.

## Section 10: Rationale and evidence that justify the level of analysis used in the Impact Assessment

51. This This Impact Assessment is based on the legislation introducing requirement on Ofgem to extend the current supply licence condition that caps SVTs and other default tariffs. The rationale for the legislation is underpinned by extensive evidence base originally compiled and tested by the CMA. Ahead of the introduction of the current tariff cap, Ofgem also produced their own IA. Ofgem will be responsible for implementing the cap and setting the methodology for determining its level, in line with the requirements of the legislation. The analysis in this impact assessment does not prejudge the work of Ofgem on this issue but includes a discussion of the expected impacts of a price cap, including using illustrative evidence from the experience of the price cap as implemented so far.

## Family Test

52. We expect this measure to continue to benefit families that are on SVTs or other default tariffs, many of whom are low-income. It will reduce the energy costs of these families and/or help them afford to heat their homes more adequately. In this respect, the policy could have potential benefits for family formation and families going through key transitions.

| | |
|---|---|
| **Title:** Enhancing the UK's nuclear third-party liability regime through accession to the Convention on Supplementary Compensation (CSC)<br>**IA No:** BEIS034(F)-22-NPID<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** Department for International Trade (DIT), Government Actuary's Department (GAD) | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** International<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** parisbrussels@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion:** Green

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value**<br>£0m | **Business Net Present Value**<br>£0m | **Net cost to business per year**<br>£0m | **Business Impact Target Status**<br>Not a regulatory provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

There are concerns amongst private sector developers and participants in the UK's nuclear supply chain about the UK's current nuclear third-party liability arrangements and the potential for unlimited claims from countries outside of the current Paris-Brussels regime. (Section 1 provides descriptions of the various regimes). Failure to address these concerns could significantly impact on the ability to deliver future nuclear projects with private sector investment. This could make it very difficult for new nuclear projects - both gigawatt-scale and Small Modular Reactors (SMRs) - to proceed, threatening the UK's ability to achieve key government objectives as articulated through the Prime Minister's Ten Point Plan and the commitment to Net Zero by 2050. Government intervention is necessary as the policy solution identified is for HMG to extend our liability regime to better protect nuclear investors and participants not covered by the existing regime.

**What are the policy objectives of the action or intervention and the intended effects?**

The policy objectives are to: give private sector developers increased confidence in investing in new nuclear projects; offer participants in the UK's nuclear supply chain protection from additional claims from non-Paris-Brussels countries; and reduce negative impacts on the costs and timings associated with essential projects. Although it will be difficult to measure the success of our intervention in a quantifiable way, we expect to receive qualitative evidence that our actions have: positively impacted developers' decision to invest in the UK; improved the conditions for the supply chain: and reduced negative impacts on the costs and timings of essential projects.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Five options have been considered.

1. "Do nothing" option of continuing with the UK's current liability arrangements. Whilst not allowing us to achieve the policy objectives above, it has been retained as a useful counterfactual against the impacts.
2. The provision of unlimited HMG indemnities to companies upon request.
3. Preferred option: Accede to the Convention on Supplementary Compensation for Nuclear Damage (CSC), an international treaty which offers additional protections to countries not protected under the UK's current nuclear third-party liability regime.
4. Ratify the Joint Protocol between the Paris and Vienna Conventions which would apply the channelling and capping principles to additional countries, which do not play an active role in the UK's nuclear sector.
5. Ratify the Joint Protocol and accede to the CSC simultaneously which would take longer than Option 3.

**Will the policy be reviewed?** There are no plans to review the policy. However, if an incident were to occur it is likely a review of UK nuclear liabilities would occur.

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | Yes | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:**<br>NA | **Non-traded:**<br>NA | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

# Summary: Analysis & Evidence — Policy Option 3

**Description:** Accede to the Convention on Supplementary Compensation (CSC)

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2019 | PV Base Year 2021 | Time Period Years 10 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** 0 | **High:** 0 | **Best Estimate:** 0 |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | | | | |
| **High** | | | | |
| **Best Estimate** | 0 | | 0 | 0 |

**Description and scale of key monetised costs by 'main affected groups'**

Accession to the CSC will create a contingent liability on HMG and therefore the taxpayer. This would only be affected in the event of an incident in a contracting party after exceeding the 300 SDR[1] operator liability limit. Under present conditions, the potential UK liability would be around £7.5m, and we do not expect significant divergence from this in the short to medium term[2]. To date there have been no calls on this fund. Any liability would not sit on the balance sheet as it is a remote risk, but the wider potential impact of such an event would be large. Due to the small likelihood of such an event occurring, monetised costs have been assumed to be zero.

**Other key non-monetised costs by 'main affected groups'**

Accession to the CSC would not provide any additional protection from claims made by countries that are not party to any treaty enforcing the channelling and capping principles. If such a claim were made, this could cost UK businesses as well as HMG. However, accession to the CSC does significantly reduce the potential risk of unlimited claims being made.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | | | | |
| **High** | | | | |
| **Best Estimate** | 0 | | 0 | 0 |

**Description and scale of key monetised benefits by 'main affected groups'**

If, following UK accession, a nuclear accident occurred in the UK which exceeded operator liability, we could draw on the around £120m international fund[3] to make compensation payments to affected CSC countries, including the UK itself. Due to the small likelihood of such an event occurring, monetised benefits have been assumed to be zero.

**Other key non-monetised benefits by 'main affected groups'**

Accession to the CSC would apply the channelling and liability capping principles to those which play or could play a significant role in the UK's nuclear sector. Section 1 provides a full list of CSC contracting parties. Accession would offer greater confidence to private sector investors to invest in new nuclear projects and decommissioning activities, by removing the barrier to investment presented by the lack of protection against unlimited claims from CSC countries.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | N/A |
|---|---|---|

The key assumptions are 1) the CSC would function alongside the Paris and Brussels Conventions; 2) the contingent liability assessment is based on current membership of the CSC, with our contributions being based on installed capacity and current UN contributions. The key risks are 1) joining the CSC would not mitigate against possible claims from countries not party to any treaty enforcing the channelling and capping principles; 2) investors may be reluctant to invest in nuclear projects if there are delays in the Parliamentary process; and 3) the insurance industry may choose to increase operator's insurance premiums due to accession (see paragraph 84).

**BUSINESS ASSESSMENT (Option 3)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** NA |
|---|---|---|---|
| **Costs:** 0 | **Benefits:** 0 | **Net:** 0 | |

1 SDR – special drawing rights. A unit of account operated by the IMF as a weighted average of certain currencies (inc. GBP). 1 SDR = 1.03 GBP 02/02/2022.
2 The UK CSC contribution is dependent on installed capacity, SDR-GBP exchange rate and UN contributions at the time of incident. Calculated Feb 2022.
3 The total fund is dependent of CSC membership at the time of an incident, and contracting parties installed capacity and UN contributions.

# Contents

# Evidence Base

## Section 1: Overview

### 1.1 Background

1. There are three international nuclear third-party liability regimes:

    - The 1960 Paris Convention and 1963 Brussels Supplementary Convention (the Paris-Brussels regime).
    - The 1963 Vienna Convention.
    - The 1997 Convention on Supplementary Compensation for Nuclear Damage (the CSC).

2. These regimes ensure that the victims of a nuclear incident have access to adequate compensation, as well as supporting investor confidence in a global industry where incidents tend to be characterised by very low probability but potentially extremely high impact. All three regimes have similar principles: ensuring adequate compensation for victims (who only need to prove harm, not fault); protecting the supply chain by channelling all liability to the operator with claims being heard in the country in which the incident occurred; and capping the operator's overall financial liability. Further information on the details of the different international nuclear third-party liability regimes can be found in Annex A. Meanwhile, Annex B provides a full list of contracting parties to the various international nuclear third-party liability regimes at present.

3. The UK is currently only party to the Paris-Brussels regime, which it implements domestically through the Nuclear Installations Act 1965. This regime establishes a largely western European framework for compensating victims of nuclear incidents. On 01 January 2022, the 2004 protocols to amend the Paris and Brussels Supplementary Conventions came into force in the UK. This increases the operators' maximum liability from €140m pre ratification to €700m in 2022 rising to maximum of €1.2bn[1] over five years. The Brussels Supplementary Convention provides an additional €300m as part of an international pool which all contracting parties contribute to and can access.

4. The Vienna Convention establishes a similar international framework for compensating victims of nuclear incidents. Its principles are much the same as the Paris Convention and its contracting parties include many eastern European countries, Russia, much of South America and Saudi Arabia[2]. There is a Joint Protocol between the Paris and Vienna Conventions. It extends reciprocal benefits to a party of the other Convention, provided both parties have also ratified the Joint Protocol. The Joint Protocol ensures that only one of the two conventions will apply, and the amount of liability is determined by the convention to which the state of the liable operator is party. The UK is a signatory to the Joint Protocol but is yet to ratify it. There are currently no plans to ratify the Joint Protocol for the reasons outlined in Section 3.4, although this remains an option for the future.

5. The CSC aims at establishing a minimum national compensation amount and an international pooling mechanism for providing additional compensation funds as required. The CSC is open to countries that are party to either the Paris or Vienna Conventions, or have equivalent national

[1] The 1986 Chernobyl nuclear accident demonstrated the need to increase the amounts of liability and to broaden the types of damage that were provided for in the existing liability regime. In response to that need, a major international modernisation effort was undertaken, with the intent of ensuring that victims in all countries affected by a nuclear accident would be accorded equitable compensation for damage suffered. See https://www.oecd-nea.org/jcms/pl_20382/2004-protocol-to-amend-the-paris-convention

[2] Vienna countries: Argentina, Armenia, Belarus, Benin, Bolivia, Bosnia and Herzegovina, Brazil, Bulgaria, Cameroon, Chile, Croatia, Cuba, Czech Republic, Egypt, Estonia, North Macedonia, Hungary, Jordan, Kazakhstan, Latvia, Lebanon, Lithuania, Mauritius, Mexico, Moldova, Montenegro, Niger, Nigeria, Peru, Philippines, Poland, Romania, Russia, Saint Vincent and the Grenadines, Saudi Arabia, Senegal, Serbia, Slovakia, Trinidad and Tobago, Ukraine, Uruguay.

legislation. Key members include the US, Canada and Japan, all countries which play a significant role in the UK's nuclear industry.

6. Table 1 below lists the contacting parties to the CSC at present and information on their nuclear reactors. Information on the UK has also been provided for context. This list is subject to change as countries can accede at any time and as nuclear reactors begin and end generation.

*Table 1: CSC contracting parties and number of nuclear reactors, as of January 2022.*[3]

| Country | No. of existing reactors | No. of reactors under construction |
|---|---|---|
| Argentina | 3 | 1 |
| Benin | 0 | 0 |
| Canada | 19 | 0 |
| Ghana | 0 | 0 |
| India | 23 | 6 |
| Japan | 33 | 2 |
| Montenegro | 0 | 0 |
| Morocco | 0 | 0 |
| Romania | 2 | 0 |
| United Arab Emirates | 2 | 2 |
| United States of America | 93 | 2 |
| **Total** | **175** | **13** |
| | | |
| United Kingdom | 11 | 2 |

## 1.2 Problem under consideration

7. There are concerns amongst private sector developers and participants in the UK's nuclear supply chain about the UK's current liability arrangements and the potential for unlimited claims against them from countries outside the current Paris-Brussels regime. Section 8.4 provides evidence of these concerns. This concern has been heightened since the Fukushima nuclear incident in Japan in 2011. Following that, claims were brought in the USA directly against the operator and the supply chain. As Japan was not party to an international convention at that time (though it acceded to the CSC in 2015), the claimants successfully argued that the channelling and capping principles of the regimes did not apply. A US court agreed to hear the claims and these cases took over 10 years to conclude (all dismissed) and are thought to have cost millions of dollars in legal fees. Since Fukushima, there has been no other large-scale nuclear incident, but investors remain concerned about extra-territorial liabilities.

8. This lack of protection from unlimited claims from non-Paris or Brussels countries is a barrier to potential investment in new nuclear. This was a key reason why investors would not commit to the Wylfa Newydd project during the 2018/2019 negotiations. Failure to address these concerns would therefore have a significant impact on the ability to deliver future nuclear projects with private sector investment and could make it more difficult for a project like Sizewell C to proceed. Investors may choose to A) not invest; B) delay investment; or C) invest, but in doing so, incur significant costs due to the high associated risk. Without this measure, extra risk would be introduced into the capital raising process.

[3] This information is from the IAEA Power Reactor Information System (PRIS) database. Correct as of 18/01/2022. Argentina, Benin, Ghana, Montenegro, Morocco, Romania and the UAE are parties to the 1997 Vienna Convention. Canada, India, Japan and the USA are parties whose legislation complies with the Annex to the CSC.

9. Furthermore, suppliers from outside of the Paris-Brussels regime (particularly the US) have requested unlimited indemnities from HMG as they are not protected by Paris-Brussels should a claim be brought in their countries. HMG has refused as we do not want to set a precedent or take on the additional risk, but this has resulted in considerable delays and financial impacts on decommissioning projects. For example, not providing Government intervention in a Nuclear Decommissioning Authority (NDA) project resulted in significant costs to NDA and a delay to an essential decommissioning project (see paragraph 94).

## 1.3 Rationale for intervention

10. Government intervention is required to secure potential private investment in new nuclear developments, and to offer security to current and future participants in the UK's supply chain and decommissioning activities. Under the existing regime, operators are not protected from claims from non-Paris-Brussels countries. Without government intervention, we expect that private sector investors would be unwilling to participate in the UK's nuclear sector, which would undermine our efforts to decarbonise the GB power sector in line with the government's net zero goals, while retaining essential security of supply and keeping electricity affordable for consumers.

11. With the exception of the 'do nothing' option, the policy options we have identified as potential solutions all require some form of Government intervention, either via the provision of ad hoc HMG indemnities, or via legislative changes to enable us to accede to or ratify additional international liability treaties. These options are set out in more detail in Section 3.

12. Legislative change would be required to enable accession to the CSC. Primary legislation will therefore be needed to make the necessary changes to the Nuclear Installations Act 1965. As well as completing the legislative changes, we would still need to complete the accession process, which we estimate would take at least 12 months,. Note that the policy landscape is exceptional: the UK has not acceded to an international nuclear liability treaty since the 1960s and, as the situation currently stands, the UK would be the first country to be party to both Paris-Brussels and the CSC.

13. Although the Nuclear Installations Act 1965 already provides Ministers with the power to ratify the Joint Protocol between the Paris and Vienna Conventions, we would still need to complete the ratification process, which we estimate would take at least 12 months.

## Section 2: Policy objective

14. As outlined above, there are concerns amongst private sector developers and participants in the UK's nuclear supply chain about the UK's current nuclear third-party liability arrangements. The objective of this intervention is to alleviate those concerns by:

- Expanding the number of countries to which the channelling and liability capping principles would apply, including to the US, Canada and Japan, which play a significant role in the UK's nuclear sector. This would offer protection for operators from claims from more non-Paris-Brussels countries;
- Giving private sector developers maximum confidence in investing in new nuclear projects
- Offering current and future participants in the UK's nuclear supply chain greater protection from claims (by ensuring all claims are channelled to the operator in line with the principles of the international liability regimes); and
- Reducing the risk of increased costs and timings associated with essential nuclear projects by enabling companies to fulfil contracts without requesting unlimited Government indemnities.

15. All of the interventions considered below (with the exception of Do Nothing) attempt to achieve these objectives via a form of Government intervention, providing a solution which requires no action on the part of developers or suppliers.

16. The nature of these objectives are such that it will be difficult to measure the success of our intervention in a quantifiable way. Whilst the first two objectives are natural outcomes of acceding to the CSC, the issue of investor confidence is not something that can be measured in a SMART manner. The success of this objective will be identified through qualitative evidence which we would expect to provide the following indicators of success:

- Qualitative evidence from private sector developers that our intervention directly impacted on their decision to invest in a new nuclear project in the UK;
- Qualitative evidence from participants in the UK's nuclear supply chain that our intervention has enabled them to fulfil contracts/do business without risk of claims against them (as claims are channelled to the operator);
- Qualitative evidence from the UK nuclear industry that our intervention has helped prevent issues with suppliers requesting unlimited indemnities, which could result in increased costs and timings associated with essential projects.

17. It should also be noted that some of the benefits of accession would only crystallise in the event of a major accident in the UK. The likelihood of such an event occurring is shown to be extremely low and decreasing, supporting a view that safety standards at nuclear power plants (which are most likely to cause a major accident) have been improving. See paragraph 33 for further explanation.

18. This policy could help enable future new nuclear projects in the UK, supporting the Government's ambition to decarbonise the GB power sector, consistent with achieving net zero greenhouse gas emissions by 2050, articulated through the Prime Minister's Ten Point Plan, the Energy White Paper (EWP) and the Net Zero Strategy, while retaining essential security of supply and keeping electricity affordable for consumers. It would also support the Government's Levelling Up agenda. Whether large-scale, Small Modular Reactors or nascent advanced technologies, new nuclear can support jobs and growth at both national and regional levels. A new nuclear power station such as Sizewell C would create thousands of new jobs in the local area during construction and operation, thousands more across the UK supply chain, and boost skills and British businesses across every corner of the country.

19. We consulted with the Better Regulation Unit within BEIS who confirmed that the policy measure is out of scope of the better regulation framework. The measure falls within the statutory exclusion of 'grants or other financial assistance on behalf of a public authority' section 22(4)(c) of the SBEE Act, in which the full text notes '...the giving of grants or other financial assistance by or on behalf of a public authority'. RPC opinion is therefore not required.

## Section 3: Descriptions of options considered

## Option 1 - Do nothing

20. We continue with the UK's current liability arrangements. These offer operators protection from unlimited claims from Paris-Brussels countries and also protect the supply chain from any claims (all claims channelled to the operator).

21. However, the current situation does not offer any protection from claims from non-Paris-Brussels countries. Not intervening in any way was a contributing factor to investors being

unwilling to commit to the Wylfa project. It has also resulted in financial increases and delays to essential decommissioning activity.

22. No intervention is likely to result in private sector investors being less willing to participate in the UK's nuclear sector, including in potential gigawatt-scale projects such as Sizewell C. This would undermine the power sector's ability to decarbonise by 2035 (subject to security of supply) as outlined in the Net Zero Strategy.

## Option 2 - Provide unlimited HMG indemnities to companies upon request

23. HMG agrees to provide businesses (operators, supply chain participants) with unlimited protection from claims from non-Paris-Brussels countries. These would be provided upon request from companies which play an essential role in the UK's nuclear sector (e.g. where a company is the only one that produces a certain component required for an essential project).

24. However, this would result in HMG taking on all risk of any claims from non-Paris-Brussels countries, something we would want to avoid. HMG has refused to provide unlimited indemnities in the past, both because of the risks involved, and to avoid setting a precedent elsewhere in the sector or in other areas.

## Option 3 - Accede to the Convention on Supplementary Compensation (CSC)

25. The preferred option is accession to the CSC. This would require primary legislation to amend the Nuclear Installations Act 1965, as well as the UK completing the accession process.

26. In order to join the CSC, it is necessary to be party to the Paris Convention (or the Vienna Convention), or to have equivalent liability regimes in place. Therefore, acceding to the CSC and leaving the Paris-Brussels regime is not a viable option.

27. Accession would increase the number of countries to which the channelling and liability capping principles apply, including to countries which play or could potentially play a significant role in the UK's nuclear sector (e.g. the USA, Canada and Japan). See Table 1 above for the full list of contracting parties. This would offer potential private sector participants much greater confidence in investing in the UK's nuclear projects. In fact, accession to the CSC is very likely to be a requirement for potential private investment in new nuclear developments, as well as for many participants in the UK's supply chain and decommissioning activities. This option would therefore reduce excessive extra risk in the capital raising process.

28. The CSC would operate alongside our current liability regime (Paris-Brussels) and provide an additional international fund to which the UK would contribute in the event of an incident in a contracting party state. Should the incident occur in the UK, we could draw down from the fund.

## Option 4 - Ratify the Joint Protocol between the Paris and Vienna Conventions

29. The UK is already a signatory to the Joint Protocol and HMG have publicly stated that it is considering ratification. We have not specified any timescales, but it would require primary legislation to amend the Nuclear Installations Act 1965, followed by the ratification process.

30. Ratifying the Joint Protocol would increase the number of countries to which the channelling and liability capping principles apply. It would offer reciprocal benefits between Paris countries and Vienna countries. Essentially this means that should an incident occur in the UK (a Paris member state), which affected a Vienna member state, and both states had ratified the Joint Protocol, victims in the Vienna member state could make a claim as if they were a Paris member state. Similarly, if an incident occurred in a Vienna member state that affected the UK (a Paris member state), victims in the UK could make a claim as if they were a Vienna member state.

31. However, the Vienna Convention's contracting parties include many eastern European countries, Russia, much of South America and Saudi Arabia. These countries do not currently as much of a significant role in the UK's nuclear sector as the CSC countries do, and therefore it would not currently be as beneficial to ratify the Joint Protocol over acceding to the CSC.

### Option 5 - Accede to the CSC and ratify the Joint Protocol simultaneously

32. Combine Options 3 and 4 to achieve maximum protection for the UK's nuclear sector. This would take longer to complete and would involve considerable Parliamentary time. This runs the risk of investment decisions on future nuclear projects needing to be taken before both of these actions were complete, thus not actually offering the protection and confidence to investors as they make their investment decisions.

## Section 4: Monetised and non-monetised costs and benefits of each option

33. GAD produced some analysis in June 2020[4], which demonstrates that the probability of a nuclear incident occurring would be low based on historical data. This is supported by the fact that there have been no calls on the CSC international fund to date. This analysis is based on nuclear incidents that would likely exceed the 300m SDR of operator liability and therefore require international contributions to the CSC international fund. The frequency of events reduces as more recent periods are considered, supporting a view that safety standards at nuclear power plants (where a major accident is most likely to occur) have been improving. This therefore demonstrates that the probability of an event is very low, reducing the likelihood of HMG incurring significant costs as a result of accession (although, if a nuclear event did occur, the wider potential impact would be large). This analysis will be used to illustrate the expected loss associated with the contingent liability, under Options 3 and 5, based on a probability of an incident occurring.

34. The impacts of a nuclear incident are, however, very dependent on, among other things, the type of incident, the weather conditions at the location and how quickly it is brought under control. As such, nuclear incidents are highly individual and not easily modelled. Therefore, most of the costs and benefits of acceding to the CSC are unquantifiable and are assumed to be zero for the headline figures produced in this Impact Assessment. The sections below outlines illustrative costs and benefits only.

## 4.1 Option 1 - Do nothing

### Benefits to operators and UK supply chains

[4] Analysis of the frequency of nuclear events has previously been carried out by GAD as part of a separate analysis connected to the Paris and Brussels Conventions. In their original analysis, GAD combined information on historical INES4+ events with an estimate of the number of nuclear reactors that were in operation at that time. To support BEIS with CSC considerations, this analysis was further updated to only consider INES 5+ events which are more relevant to the CSC.

35. If we continue with the UK's current liability arrangements, UK operators and supply chain participants would be protected from unlimited claims from Paris-Brussels countries.

### Cost to operators and UK supply chains

36. If a nuclear incident happened in the UK, operators would be liable up to €1.2bn under the Paris-Brussels regime. As claims are channelled to the operator, the supply chain would be protected.

37. However, UK businesses would continue to have no protection from unlimited claims from non-Paris-Brussels countries. Furthermore, countries such as Japan and the US, that play or could play an active role in UK's nuclear sector, are not protected from unlimited claims from non-Paris-Brussels countries and therefore are unlikely to be willing to invest further. These claims could be costly, as demonstrated by the Fukushima accident, which is thought to have cost Tepco and General Electric (the operators of Fukushima) millions of dollars in legal fees, despite the claims being ultimately dismissed.

38. Under Option 1, there would be no familiarisation costs to UK businesses, as the existing regime would remain in place.

### Benefits to HMG/taxpayer

39. If a nuclear incident occurred in the UK, we would be able to draw on the international fund worth €300m under the Brussels Convention, if the €1.2bn operator liability had been exceeded.

### Costs to HMG/taxpayer

40. HMG would contribute €35m to the international fund (worth €300m) under the Brussels Convention in the event of an incident in a contracting country (or the UK itself) that exceeds the €1.2bn operator liability. This burden would fall on the taxpayer. There is an existing remote contingent liability in place for this.

41. HMG would also be exposed to unlimited claims from non-Paris-Brussels countries under the existing regime. Private sector investors would still lack confidence to invest in UK nuclear due to this lack of protection, potentially impacting our ability to successfully deliver future nuclear projects.

## 4.2 Option 2 – Provide unlimited HMG indemnities to companies upon request

### Benefits to operators and UK supply chains

42. This would be industry's preferred option as it would provide a watertight solution for claims. For this reason, this option would likely leverage the most confidence from private sector investors. Supply chain participants and operators would be protected against unlimited claims; however, the conditions of the indemnities would vary depending on the terms agreed by the government.

### Cost to operators and UK supply chains

43. Operators would still be liable up to €1.2bn under the Paris-Brussels regime, as mentioned above. There would be no familiarisation costs to UK businesses as no additional burden would be placed upon them.

**Benefits to HMG/taxpayer**

44. This option would provide private sector developers and investors with confidence to invest in UK nuclear, addressing their concerns under the existing regime. This would therefore help encourage the development of new nuclear in the UK, supporting the Government's ambition to reach net zero greenhouse gas emissions by 2050.

**Costs to HMG/taxpayer**

45. HMG would take on all risks of any claims from non-Paris-Brussels countries. The scale of this cost could be huge, especially if several claims were made and claims had to be contested. This burden would fall on the taxpayer, for the sake of protecting the sector from unlimited claims. This option would offer no incentive to the market to manage its risks as HMG would simply provide unlimited indemnities to companies upon request, which could cause costs to spiral. This option also raises subsidy control implications[5].

46. If unlimited indemnities are provided in the nuclear sector, this could also set a precedent for the UK Government to provide unlimited indemnities in other sectors, resulting in an even greater burden on the taxpayer.

**Wider benefits**

47. This option would help to support the Government's objectives of decarbonising the power sector, consistent with achieving net zero by 2050, as it would encourage investment in nuclear, a low carbon source of energy.

## 4.3 Option 3 – Accede to the CSC

48. Accession to the CSC is BEIS' preferred policy option.

**Benefits to operators and UK supply chains**

49. UK operators and supply chain participants would be protected from unlimited claims from Paris-Brussels countries as well as CSC contracting parties, such as Canada, US and Japan. These countries play, or could play, an active role in the UK's nuclear sector. Accession to the CSC would enable greater access to the international supply chain, some of which cannot be easily replicated in the UK.

50. This option, although second to Option 2, is preferred by potential investors compared to the remaining options. It is therefore highly likely to also leverage confidence from private sector investors and developers.

**Cost to operators and UK supply chains**

51. Operators would still be liable up to €1.2bn under the Paris-Brussels regime, as mentioned above.

[5] Otherwise known as state aid.

52. Acceding to the CSC would require UK operators to ensure the minimum compensation amount is available (300m SDR) for a nuclear incident in the UK. We already meet this criteria as the Paris-Brussels regime requires us to impose a maximum liability of €1.2bn on the operator (which is greater than the 300m SDR), topped up by public funds depending on the operator's level of liability[6]. Therefore we do not expect any additional burden of liability on operators.

53. We also do not expect there to be any familiarisation costs to UK businesses for acceding to the CSC, we do not expect any additional liability to be placed on operators.

**Benefits to HMG/taxpayer**

54. Accession to the CSC would protect nuclear operators and HMG from needing to provide financial cover for unlimited claims from contracting parties of the CSC, which avoids the extensive cost burden on the taxpayer under Option 2, although we note that accession does not provide protection from non-Paris-Brussels or non-CSC countries.

55. Furthermore, if a nuclear incident happened in the UK, we would be able to draw on the CSC's international fund, which would be worth around £120m, if the operator's liability had been exhausted.[7] The CSC international fund and the Brussels international fund do not come into force sequentially; they can be used at the same time, but they are dealt with separately depending on where the claims come from.

56. As under Option 2, accession to the CSC would provide private sector investors with confidence to invest in UK nuclear, encouraging the development of new nuclear projects, which in turn helps to support the Government's ambition to decarbonise the power sector, consistent with achieving net zero greenhouse gas emissions by 2050.

**Costs to HMG/taxpayer**

57. Based on current installed capacity, exchange rates, UN contributions and assuming no other country leaves or joins the CSC, the UK's contribution to the international fund would be around £7.5m[8] per incident, if the operator's liability had already exceeded 300m SDR. This burden would fall on the taxpayer. However, there have been no calls on the CSC international fund to date. Should the UK accede to the CSC the international fund would amount to around £120m. HMG would also still be exposed to claims from countries that are not party to any treaty enforcing the channelling and capping principles.

**Wider benefits**

58. Accession to the CSC would also support the Government's objective decarbonising the GB power sector, consistent with achieving net zero by 2050, as it would encourage investment in the UK's nuclear sector by CSC contracting parties.

## 4.4 Option 4 – Ratify the Joint Protocol between the Paris and Vienna Conventions

[6] Note that although HMG is liable for the difference, the sites prescribed as intermediate or low have significantly lower liability limits because they pose significantly less risk and are extremely unlikely to have the type of incident that would result in claims in excess of their liability limits. Therefore, the possibility of HMG needing to make up the difference to €1.2bn is extremely low.

[7] As of February 2022, the international fund currently amounts to 102m SDR (£105m). This rises to 113m SDR (£116m) with the UK's participation.

[8] This figure is based on current UN contributions and installed capacity. As we cannot predict when an incident would occur, our calculations must be based on our current contributions. Our actual contributions at the time of an incident could be different as it would be dependent on our installed capacity at that point.

### Benefits to operators and UK supply chains

59. The benefits to UK operators and supply chain participants would be similar to those under Option 1. However, UK businesses would also be protected against claims from member countries of the Vienna Convention.

### Cost to operators and UK supply chains

60. This option would still not provide protection against claims from CSC contracting parties such as the US or claims from non-treaty countries. The Vienna Convention's contracting parties include many countries which play a less significant role in the UK's nuclear sector than the CSC countries do.

61. Operators would still be liable up to €1.2bn under the Paris-Brussels regime, as mentioned above, and similarly, there would be no familiarisation costs to UK businesses.

### Benefits to HMG/taxpayer

62. The benefits to HMG would be the same as under Option 1, that is being able to draw on the international fund worth €300m under the Brussels Convention, if the operator liability had exceeded €1.2bn. The Paris Convention extends the liability regime to other countries with an equivalent and reciprocal regime, so this may offer a route for claims to be channelled from Vienna Convention countries in any case without having to ratify the protocol.

### Costs to HMG/taxpayer

63. The costs to HMG/taxpayer would be the same under Option 1. HMG would contribute approximately €35m to the international fund in the event of an incident in a contracting country (or the UK itself) that exceeds operator liability. This burden would fall on the taxpayer.

64. Many private sector developers and investors would continue to lack confidence to invest in UK nuclear due to the lack of protection from claims from affected parties in CSC contracting parties and other countries not party to any convention. This would impact our ability to successfully deliver future nuclear projects.

### Wider costs

65. This option would do less to support the Government's objectives for nuclear power, as it would protect UK businesses from claims from contracting parties of the Vienna Convention (who have signed the Joint Protocol), but not the countries that are most interested or keen to invest in the UK's nuclear sector. Options 2,3 and 5 do provide this protection. Therefore, investment in this low carbon source of energy is less likely.

## 4.5 Option 5 – Accede to the CSC and ratify the Joint Protocol simultaneously

### Benefits to operators and UK supply chains

66. Option 5 provides the most protection to UK businesses without HMG providing unlimited indemnities, protecting them from claims from Paris-Brussels, Vienna and CSC contracting parties.

### Cost to operators and UK supply chains

67. Operators would still be liable up €1.2bn under the Paris-Brussels regime as mentioned above.

68. However, this option runs the risk of investment decisions on future nuclear projects needing to be taken before one or both of the actions are complete. It may take time for confidence to grow if the domestic legislation and treaty ratification processes take too long and hence protection may not be offered in time. Investment decisions may be postponed.

69. Under Option 5, there would also be no familiarisation costs to UK businesses as no additional burden is placed upon them.

**Benefits to HMG/taxpayer**

70. Option 5 would provide maximum protection for nuclear operators and HMG needing to provide financial cover against claims globally. HMG would be highly unlikely to need to provide unlimited indemnities, as is the case under Option 2.

71. As under Options 2 and 3, acceding to the CSC and ratifying the Joint Protocol simultaneously would provide private sector investors with confidence to invest in UK nuclear, addressing their concerns under the existing regime.

72. Furthermore, if a nuclear incident happened in the UK, we would be able to draw on the CSC international fund which would be worth around £120m, if the operator's liability exceeded 300m SDR. We would also be able to draw on the international fund worth €300m under the Brussels Convention, if operator liability had exceeded €1.2bn.

73. The Paris Convention extends the liability regime to other countries with an equivalent and reciprocal regime, so this may offer a route for claims to be channelled from Vienna Convention countries in any case without having to ratify the protocol.

**Costs to HMG/taxpayer**

74. Acceding to the CSC and ratifying the Joint Protocol would take a long time to complete and would involve considerable parliamentary time (although this could possibly be mitigated if we were to propose a joint set of amendments). As mentioned, investment decisions may be postponed if the process takes too long, impacting the UK's nuclear programme and emissions targets.

75. There may still be concerns raised by investors around claims from non-treaty countries, although investors are highly likely to accept that the UK's liability regime has been strengthened by acceding to the CSC and ratifying the Joint Protocol.

76. As mentioned under Option 3, the UK government's contributions to the CSC fund would be around £7.5m per incident, if the operator's liability had already exceeded 300m SDR. Our contributions to the international fund under the Brussels Convention would also remain the same if the UK ratified the Joint Protocol at the same time.

77. We are prioritising accession to the CSC as those member states are the ones most likely to invest in the UK's nuclear sector at present. However, in the future, should it look likely that investment from Vienna/Joint Protocol countries is being limited by the UK not ratifying the

Joint Protocol, we would look to ratify the Joint Protocol, subject to Ministerial agreement and Parliamentary time.

**Wider benefits**

78. This option would also support the Government's objective of decarbonising power consistent with achieving net zero by 2050, as it would encourage investment in the UK's nuclear sector by contracting parties of both the CSC and the Vienna Convention.

## 4.6 Summary

79. Table 2 below provides a summary of the non-monetised and monetised costs and benefits of each of the policy options outlined above.

*Table 2 – Monetised[1] and non-monetised costs and benefits summary*

| Policy Option | Monetised Costs and Benefits | | | Non-Monetised Costs and Benefits | | |
|---|---|---|---|---|---|---|
| | Cost - Operator Liability | Benefit – International Fund | Cost - HMG/taxpayer | Benefits - Wider | Benefits – Operators and HMG | Cost – HMG/taxpayer and operators |
| **Option 1 - Do nothing** | €1.2bn under Paris-Brussels, if the nuclear accident happened in the UK. | UK nuclear incident: HMG could call on an international fund worth €300m under the Brussels Convention (if the €1.2bn operator liability has been exceeded). | HMG will contribute €35m to the international fund under the Brussels Convention in the event of an incident in a contracting country (or the UK) that exceeds €1.2bn operator liability. | Supports the Government's net zero ambitions. | Protection against unlimited claims from Paris-Brussels countries. | Potential costs from claims from member countries of the CSC, Vienna Convention and non-treaty countries. |
| **Option 2 - Provide unlimited HMG indemnities to companies upon request** | Same as Option 1. | Same as Option 1. | Same as Option 1. However, the non-monetised costs under this option are significant. | Option 2 does the most to support the Government's net zero ambitions as it provides maximum confidence to investors. | Protection against all claims however conditions of the indemnities may vary depending on the terms agreed by HMG/HMT. | Taxpayers could face unlimited costs under this option. |

[1] Note that, for the summary of this Impact Assessment, monetised costs and benefits are assumed to be zero due to the small likelihood of such an event occurring.

| | | | | | | |
|---|---|---|---|---|---|---|
| **Option 3 - Accede to the CSC** | €1.2bn under Paris-Brussels, if the nuclear accident happened in the UK. Operator liability under CSC is 300m SDR, which is lower than €1.2bn under Paris-Brussels (meaning that we do not expect operator liability to be increased by accession to CSC). | Same as Option 1. Additionally, for a UK nuclear incident, HMG could draw on the CSC international fund which would be worth ~£120m, if the operator's liability has been exhausted. | Same as under Option 1. The UK would also contribute around £7.5m under current assumptions per incident to the CSC international fund, if the incident has already exceeded 300m SDR. | Option 3 does more than Option 1 to support the Government's net zero ambitions but less than Option 2. This is because investors will have relatively higher confidence than under Option 1 to invest in UK nuclear, but less than if unlimited indemnities were provided. | Protection against claims from CSC contracting parties on top of Paris-Brussels. | Potential costs from claims from non-treaty countries and member countries of the Vienna Convention, although the risk is significantly reduced. |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Option 4 - Ratify the Joint Protocol between the Paris and Vienna Conventions** | Same as Option 1. | Same as Option 1. | Same as Option 1. | Same as Option 3. | Protection against claims from Paris-Brussels and Vienna countries (assuming both have signed the Joint Protocol). | Potential costs from claims from CSC members and non-treaty countries. |
| **Option 5 - Accede to the CSC and ratify the Joint Protocol simultaneously** | Same as Option 3. | Same as Option 3. | Same as Option 3. | Same as Option 3. | Protection against claims from CSC, Paris-Brussels and Vienna countries. | Adequate protection may not be provided within the required timescales for investment in new nuclear projects, due to considerable parliamentary time to complete both actions.<br>Still no protection from non-treaty countries but risks are significantly minimised. |

## Section 5: Direct costs and benefits to business calculations

80. We do not expect there to be any direct costs to businesses since accession to the CSC will create a contingent liability on HMG and therefore the taxpayer. The liability will not sit on the Government balance sheet as it is a remote risk. Furthermore, accession does not increase the operator's liability. We already meet the minimum compensation amount (300m SDR) under the Paris-Brussels regime by imposing a maximum liability of €1.2bn on the operator. We therefore expect the net cost to businesses per year to be zero.

81. We also do not anticipate there to be any direct benefits to businesses since all benefits to businesses will be indirect and dependent on the level of private sector confidence leveraged.

## Section 6: Risks and assumptions

### 6.1 Assumptions

82. The main policy assumptions are:

- The CSC would sit alongside the Paris and Brussels Conventions, as in order to join the CSC, it is necessary to be party to the Paris Convention (or Vienna Convention), or to have the equivalent liability regimes in place.

83. The main assessment assumptions are:

- A cap on operators' liability limits of €1.2bn under the current Paris-Brussels liability regime and Nuclear Installations Act 1965. This change came into force on 1 January 2022.
- The assessment has been completed based on current membership of CSC and current contributions (calculated using IAEA calculator). As it is impossible to predict when a nuclear incident could occur, we can only use the current figures to make the assessment, although our contribution would be based on our installed capacity and UN contributions at the time of an incident, and the overall size of the fund would be dependent on the membership of the CSC at the time of an incident.
- We assume that announcing the UK's plan to accede to the CSC should boost investor confidence, providing the UK with a greater ability to leverage private sector capital and enabling greater investment in new nuclear.

### 6.2 Risks

84. The main risks are:

- Delays in obtaining Parliamentary time or in the Parliamentary process once the Bill is in train will postpone the point at which the UK is able to accede to the CSC and protection is provided to investors and businesses. In the meantime, investors may be reluctant to invest in new nuclear projects and UK businesses may incur similar costs to those experienced by the NDA. However, we expect that even announcing that the UK intends to accede (which we will be able to do once we have Ministerial agreement) should significantly boost investor confidence, even without formal accession having taken place.
- Joining the CSC would not mitigate against the possibility of claims arising from countries that are not party to any treaty enforcing the channelling and capping principles. It would

however deal with a great majority of concerns and would in effect ensure the channelling and capping principles were applied for the key players in the global nuclear supply chain.

- Although accession to the CSC would not impose additional liability on nuclear operators, there is a risk that the insurance industry may choose to increase operators' annual insurance premiums as a result of accession. It is unknown how much premiums might increase by, if at all, and, as the overall operator liability would not increase, we would not expect insurance premiums to increase significantly. However, it should be noted that if one insurer were to increase their premium pricing, it is very likely the rest of the commercial market would follow suit.

## Section 7: Impact on small and micro businesses

85. We do not anticipate any additional burden on small and micro business. As under the current regime, operators are still liable up to €1.2bn under Paris-Brussels and 300m SDR under CSC and claims will be channelled to the operator only. Accession to the CSC creates a contingent liability on HMG and therefore the taxpayer, not on business. There will therefore be no disproportionate burden on small and micro businesses. We also do not anticipate there to be any future scenarios which could result in a disproportionate burden on UK businesses.

86. This policy will positively impact small and micro supply chain businesses, as it provides them with protection against claims from CSC contracting parties (however all UK businesses are protected under this policy regardless of size). The policy aims to bring business to UK supply chains and encourage capital investment which enables the completion of planned nuclear projects. The net impact of this policy on small and micro businesses will therefore be positive.

87. Note that in practical terms, if an incident was significant enough to trigger claims from CSC countries, it is extremely unlikely to have occurred at one of the intermediate or low-level risk sites, as the activities undertaken at those sites are extremely unlikely to cause an incident of that scale (hence their classification as low/intermediate risk). The operators of these sites tend to be smaller businesses, but they have appropriate financial cover in place to cover their liabilities under the existing Paris-Brussels arrangements anyway and would not require additional cover under CSC. The UK's two biggest operators, EDF and NDA, operate standard risk sites, where an incident that triggered CSC claims would be most likely to take place (although the risk even then remains very low), but again, those businesses have appropriate financial cover in place under Paris-Brussels and would not require additional cover under CSC.

## Section 8: Wider impacts

## 8.1 Assessment of equalities impact

88. The measures in this impact assessment do not raise any issues relevant to the Public Sector Equality Duty under section 149(1) Equality Act 2010 because the decision to accede will have an equal impact on all nine relevant groups. Accession to the CSC would not have adverse impacts on any of the groups with protected characteristics.

89. Operators would continue to be liable for up to €1.2bn, if the nuclear accident happened in the UK, under the Paris-Brussels regime and therefore no additional financial cover would be required under the CSC. As mentioned, accession to the CSC creates a contingent liability on HMG and therefore the taxpayer, irrespective of protected characteristics.

## 8.2 Greenhouse gas assessment

90. We cannot currently quantify the impact that accession to the CSC would have on greenhouse gas emissions. It is not possible to isolate and quantify how accession to the CSC influences investment in UK nuclear and the corresponding impact this has on carbon emissions from the UK's power sector. However, we can predict that accession to the CSC would indirectly help to reduce emissions by encouraging the development of low carbon nuclear in the UK.

91. We do not believe that the proposals will directly lead to a direct change in emissions of greenhouse gases, as the CSC relates to compensation for nuclear damage. However, as mentioned in paragraph 14, the policy aims to enable greater participation in new nuclear, supply chains and decommissioning activities in the UK. As nuclear is a low carbon energy source, greater investment in nuclear would therefore suggest lower emissions.

92. Therefore, there is potential for this policy to indirectly reduce greenhouse gas emissions from the power sector, assuming that accession to the CSC encourages greater investment from its member countries in UK nuclear. This would also support the UK Government's objectives to reach net zero by 2050, as mentioned in paragraph 18.

## 8.3 Environmental assessment

93. Acceding to the CSC would allow us to access an additional international fund on top of the Paris-Brussels fund, in the event of an incident exceeding operator liability, worth around £120m (assuming UK accession). This additional fund could be used for any valid claim, including those related to environmental clean-up following a nuclear accident. However, we cannot quantify the environmental impact of acceding to the CSC since there is no way to predict if there will be any calls on the CSC international fund and what claims this fund might be used to pay.

## 8.4 Assessment of impacts on decommissioning processes and UK organisations

94. Acceding to the CSC would also benefit the UK's decommissioning programme. The Nuclear Decommissioning Authority (NDA) has found that some overseas suppliers of specialist equipment required for decommissioning work have requested unlimited liability indemnities to keep supplying equipment to cover any potential claims that may be brought in a non-Paris-Brussels party country. To date, HMG has not provided such indemnities but devising solutions to this issue has led to considerable additional costs for the NDA. Accession to the CSC would therefore avoid cost increases, such as the one described above, for those involved in nuclear decommissioning activities, by expanding the number of countries to which the channelling and capping principles apply.

95. Over the next decade, all but one of our existing nuclear plants will come offline. This will lead to an increase in nuclear decommissioning activity. The NDA and others involved in decommissioning activities may therefore face further cost increases, without government intervention.

96. We have not quantified the impact that accession to the CSC will have for the UK's nuclear decommissioning programme given the uncertainties around the costs to businesses of changing suppliers.

## 8.5 Innovation impacts

97. Under the current arrangements, the UK is potentially exposed to unlimited claims from countries outside of the Paris-Brussels regime. Accession to the CSC would help raise confidence amongst private sector developers and participants in the UK's nuclear supply chain, by expanding the channelling and capping principles.

98. If the concerns of industry were left unaddressed, this could have serious ramifications for the construction and operation of new nuclear in the UK (gigawatt-scale and SMRs). The advanced nuclear sector has the potential to create high-skilled jobs and export opportunities through the innovation of SMRs and AMRs (Advanced Modular Reactors). SMRs are potentially less expensive to build than traditional nuclear power plants because of their smaller size, factory based modular build and more flexible deployability. Both AMRs and SMRs adopt next-generation technologies and their role in achieving net zero greenhouse gas emissions by 2050 is becoming increasingly recognised. If industry's concerns are left unaddressed, it could make it financially unviable for these innovative projects to proceed.

99. Providing a solution to this issue is seen as essential, not only to potential investors, but also to the supply chain, much of which has its domicile in the USA or Japan, two countries not currently covered by the UK's current liability arrangements.

100. We cannot currently quantify the impact that accession to the CSC will have on innovation, as we cannot isolate and quantify our policy's impact on investor confidence. However, we know that private sector developers have concerns regarding the existing liability arrangements, and therefore predict that it will have a positive impact on innovation and the progression of the UK's nuclear programme.

## Section 9: A summary of the potential trade implications of measure

101. We do not believe the policy will directly impact trade and investment, as the policy measure relates to compensation for third-party nuclear damage. However, we expect there to be impacts indirectly. For this reason, BEIS and DIT concluded that a qualitative assessment of trade implications should be provided.

102. Acceding to the CSC should boost international trade with CSC contracting parties, benefiting both existing and new nuclear, as well as those involved in decommissioning activities. It would enable British companies to obtain essential parts for nuclear activities from CSC contracting parties, such as the US, who have previously agreed not to trade in certain circumstances under the existing regime. We expect businesses across the UK to benefit from the increase in international trade, particularly those located close to new and existing nuclear sites such as Sellafield, Hinkley and Sizewell.

103. As mentioned, private sector investors and developers currently lack the confidence to invest in the UK's nuclear sector under the existing arrangements. This is due to a lack of protection against potentially unlimited claims from non-Paris-Brussels countries. This lack of protection is a significant barrier to potential investment in new nuclear projects. We expect

that acceding to the CSC would overcome this barrier, providing potential investors with greater confidence to invest in UK nuclear.. Annex C presents some data provided by the Department for International Trade (DIT) using FDI Markets[1] which demonstrates the opportunity to increase investment into the UK nuclear sector.

## Section 10: Monitoring and evaluation

104. It will be difficult to measure the impact of our intervention in a quantifiable way. Nevertheless, we would expect to receive qualitative evidence from private sector developers that our intervention directly impacted on their decision to invest in a new nuclear project in the UK; from participants in the UK's nuclear supply chain that our intervention has enabled them to fulfil contracts/do business without risk of claims against them; and from the UK nuclear industry that our intervention has helped prevent issues with suppliers requesting unlimited indemnities, which could result in increased costs and timings associated with essential projects.

105. As the recommended intervention is accession to an international treaty there is no expectation that the intervention would be reviewed or amended in the future, unless it were proven to have had a negative impact on the areas outlined above, which is improbable.

106. It is worth noting that there is no subscription cost associated with our intervention which might have been subject to an annual review of such expenses by the Department. BEIS reviews all of its contingent liabilities on a bi-annual basis. This is primarily a financial process although the supporting narrative is also reviewed. Through this process, monitoring of the exact level of the CSC liability will be undertaken, given the variable nature of it.

107. A review of the impact of our intervention will be part of broader reviews of nuclear policies such as the Nuclear Sector Deal or any Final Investment Decision for the Sizewell C project.

108. It remains an option to ratify the Joint Protocol in the future, thus increasing even further the number of countries to which the channelling and liability capping principles apply, should those countries (e.g. Russia, Saudi Arabia, South/Central American countries) happen to take on a more significant role in the UK's nuclear supply chain. We are prioritising accession to the CSC as those member states are the ones most likely to invest in the UK's nuclear sector at present. However, in the future, should it look likely that investment from Vienna/Joint Protocol countries is being limited by the UK not ratifying the Joint Protocol, we would look to ratify the Joint Protocol, subject to Ministerial agreement and Parliamentary time.

## Section 11: Preferred option and implementation plan

## 11.1 Preferred option

109. The preferred option is to accede to the CSC. Primary legislation is required to make the necessary changes to the Nuclear Installations Act 1965 to implement the requirements of the CSC. Secondary legislation is not required – all changes can be made via primary legislation. There is no requirement for consultation as this is not standard practice in relation to international treaties.

[1] https://www.fdimarkets.com/

110. Acceding to the CSC would allow us to achieve our policy objectives of giving private sector developers greater confidence in investing in new nuclear projects; offering participants in the UK's nuclear supply chain protection from claims; and reducing the risk of increased costs and timings associated with essential projects by enabling companies to fulfil contracts without requesting unlimited Government indemnities. By addressing the concerns amongst private sector developers regarding the lack of protection against unlimited claims, we would remove a barrier to investment as well as a risk in the capital raising process. Accession would furthermore provide protection to UK operators and supply chain participants against legal claims from non-Paris Brussels countries which play, or could play, an active role in the UK's nuclear sector.

111. As mentioned, this policy would help to support the UK Government's ambition to decarbonise the power sector, consistent with achieving net zero emissions by 2050, by encouraging investment in low carbon nuclear, which is a fundamental part of the UK's energy mix.

## 11.2 Implementation plan

112. Alongside making the necessary changes to the Nuclear Installations Act 1965, we will start the formal accession process, working with the International Atomic Energy Agency and the depositary body for the CSC to accede. It is difficult to provide an accurate assessment of how long the process will take but it is very likely to be upwards of 12 months.

113. HMG announcing that the UK is going to accede and the legislative process of amending the Nuclear Installations Act 1965 being underway/complete should significantly boost investor confidence, even without formal accession having actually taken place.

## <u>Annex A – Details of the international nuclear third-party liability regimes</u>

1. There are three international nuclear third-party liability regimes, as set out below. These regimes ensure that the victims of a nuclear incident have access to adequate compensation, as well as supporting investor confidence in a global industry with a considerable risk profile.

2. All the international regimes have similar principles:

i) to ensure adequate compensation for damage caused to persons, property and the environment by a nuclear incident;
ii) to make sure that nuclear operators, who are in the best position to ensure the safety of their nuclear installations and transport activities, assume full responsibility for any breach of duty giving rise to damage (while not being exposed to an excessive liability burden); and
iii) to ensure that those associated with the construction, operation or decommissioning of nuclear installations (such as builders or suppliers) are exempt from liability for any such breach.

3. In addition, these regimes ensure that a claimant only has to prove harm, not fault; all claims are heard in the country in which the incident occurs; and the overall operator obligation is capped. Some of the regimes create international pooling mechanisms among contracting parties which provide additional compensations funds for victims if required.

4. States that are not party to any of the conventions may have liability legislation that provides equivalent compensation arrangements as under the conventions.

**The Paris Convention and Brussels Supplementary Convention[2]**

5. The Paris and Brussels Conventions establish a largely western European framework for compensating victims of nuclear incidents. The UK is party only to this regime. Under Paris-Brussels, operators are currently liable up to £140m in the event of an incident. As a result of lessons learned from the Chernobyl nuclear incident, in 2004, the signatories of Paris Brussels agreed amendments to the regime, which, since ratified on 1 January 2022, has seen operators' liability limits increase to €1200m. The Brussels Supplementary Convention provides an additional €300m as part of an international pool which all contracting parties contribute to and can access.

6. The UK's domestic nuclear third-party liability regime is implemented through the Nuclear Installations Act 1965 and is based on the Paris and Brussels Conventions. In preparation to ratify the 2004 Protocols on 1 January 2022, the UK has completed the necessary legislative changes – the Nuclear Installations Act 1965 was prospectively amended by the Nuclear Installations (Liability for Damage) Order 2016.

**The Vienna Convention[3]**

7. The Vienna Convention establishes a similar international framework for compensating victims of nuclear incidents. Its principles are much the same as the Paris Convention and its contracting parties include many eastern European countries, Russia, much of South America and Saudi Arabia.

8. Note that there is a Joint Protocol which provides a bridge between the Paris Convention and the Vienna Convention. It extends reciprocal benefits to a party of the other Convention, provided both parties are also parties to the Joint Protocol. The Joint Protocol ensures that only one of the two conventions will apply and the amount of liability is determined by the convention to which the state of the liable operator is situated. The UK is a signatory to the Joint Protocol but has not ratified it.

**The Convention on Supplementary Compensation[4]**

9. The Convention on Supplementary Compensation aims at establishing a minimum national compensation amount and an international pooling mechanism for providing additional compensation funds as required. To date there have been no calls on the CSC international fund. The Convention is open to countries that are party to either the Paris or Vienna Conventions, or have equivalent national legislation. Key members include the US, Canada and Japan, all countries which play a significant role in the UK's nuclear industry.

[2] Paris-Brussels countries: Belgium, Denmark, Finland, France, Germany, Greece, Italy, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, Turkey, UK.
[3] Vienna countries: Argentina, Armenia, Belarus, Benin, Bolivia, Bosnia and Herzegovina, Brazil, Bulgaria, Cameroon, Chile, Croatia, Cuba, Czech Republic, Egypt, Estonia, North Macedonia, Hungary, Jordan, Kazakhstan, Latvia, Lebanon, Lithuania, Mauritius, Mexico, Moldova, Montenegro, Niger, Nigeria, Peru, Philippines, Poland, Romania, Russia, Saint Vincent and the Grenadines, Saudi Arabia, Senegal, Serbia, Slovakia, Trinidad and Tobago, Ukraine, Uruguay.
[4] CSC countries: Argentina, Benin, Canada, Ghana, India, Japan, Morocco, Montenegro, Romania, United Arab Emirates, United States.

## Annex B – Current contracting parties of international nuclear third-party liability regimes[5]

| Paris-Brussels | Vienna Convention | Joint Protocol | Convention on Supplementary Compensation |
|---|---|---|---|
| Belgium | Argentina | Benin (VC) | Argentina |
| Denmark | Armenia | Bulgaria (VC) | Benin |
| Finland | Belarus | Cameroon (VC) | Canada |
| France | Benin | Chile (VC) | Ghana |
| Germany | Bolivia | Croatia (VC) | India |
| Greece | Bosnia and Herzegovina | Czech Republic (VC) | Japan |
| Italy | Brazil | Denmark (PC) | Morocco |
| Netherlands | Bulgaria | Egypt (VC) | Montenegro |
| Norway | Cameroon | Estonia (VC) | Romania |
| Portugal | Chile | Finland (PC) | United Arab Emirates |
| Slovenia | Croatia | France (PC) | United States |
| Spain | Cuba | Germany (PC) | |
| Sweden | Czech Republic | Ghana (VC) | |
| Switzerland | Egypt | Greece (PC) | |
| Turkey | Estonia | Hungary (VC) | |
| UK | North Macedonia | Italy (PC) | |
| | Hungary | Latvia (VC) | |
| | Jordan | Lithuania (VC) | |
| | Kazakhstan | Netherlands (PC) | |
| | Latvia | Norway (PC) | |
| | Lebanon | Poland (VC) | |
| | Lithuania | Romania (VC) | |
| | Mauritius | Saint Vincent and the Grenadines (VC) | |
| | Mexico | Slovakia (VC) | |
| | Moldova | Slovenia (PC) | |
| | Montenegro | Sweden (PC) | |
| | Niger | Turkey (PC) | |
| | Nigeria | Ukraine (VC) | |
| | Peru | United Arab Emirates (VC) | |
| | Philippines | Uruguay (VC) | |
| | Poland | | |
| | Romania | | |
| | Russia | | |
| | Saint Vincent and the Grenadines | | |
| | Saudi Arabia | | |
| | Senegal | | |
| | Serbia | | |
| | Slovakia | | |
| | Trinidad and Tobago | | |
| | Ukraine | | |
| | Uruguay | | |

[5] "PC" or "VC" indicates that a state is a party to the Paris Convention or the Vienna Convention respectively. https://www.oecd-nea.org/jcms/pl_29284/joint-protocol-relating-to-the-application-of-the-vienna-convention-and-the-paris-convention-joint-protocol

## Annex C – FDI Markets data

1. Using FDI Markets and searching for the sub-sector 'Nuclear Electric Power Generation', we can observe that the level of inward FDI[1] in the sub-sector has been relatively low over the past decade, between January 2011-December 2020. Only 10 international companies have invested in UK nuclear projects during this period. There is greater capital investment from Paris-Brussels countries than CSC contracting parties over the period. Following accession, we would expect to see higher inward FDI from CSC contracting parties. However, given the low number of projects, it would be very difficult to estimate a clear trend over time with this data.

[1] Note, the database focuses on greenfield FDI (where new physical projects or operations are being established) and that some of the CAPEX figures are estimates by the FDI Markets, rather than from validated courses.

| | |
|---|---|
| **Title:** Amendment of regulation of nuclear sites in the final stages of decommissioning and clean-up<br><br>**IA No.:** BEIS030(F)-22-NPID<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** ONR | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Final<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** energybill2021@beis.gov.uk |

# Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2020 prices, 2022 present value) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| £490m | £11m | £-0.8m | Not a regulatory provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

The Nuclear Installations Act 1965 (NIA65) provides the framework for licensing nuclear sites and for the third-party nuclear liability regime in the UK. Recent international recommendations set out a procedure for excluding sites from the nuclear liability regime when hazards and risks fall below specified levels and we would like to adopt these recommendations. UK nuclear sites in the final stages of decommissioning and clean-up are currently subject to overlapping regulation by the Office for Nuclear Regulation (ONR) and the environment agencies. This overlapping regulation is unnecessary when nuclear hazards have been removed, and results in additional clean-up costs as well as increased regulatory costs to nuclear site licence companies. Currently, licensees can surrender licences when licensable activities have finished, leaving ONR to regulate via “directions” until liability can be ended. ONR has concerns about this approach as directions cannot replace all licence conditions. Finally, recent amendments to the nuclear third-party liability regime have increased costs for operators of disposal facilities for low level radioactive waste of nuclear origin. However, recent international recommendations, if adopted, would allow some of these disposal facilities to exit these requirements and therefore reduce costs.

Amending the regulatory framework requires legislative change. We anticipate that secondary legislation may be required, however, it will be very limited in scope and BEIS legal has advised that the savings will accrue from the primary legislation amendments.

**What are the policy objectives of the action or intervention and the intended effects?**

The policy objectives are:
(1) to align UK legislation with two separate international standards (the OECD NEA Decommissioning Exclusion and the OECD NEA LLW Exclusion) on nuclear third-party liability,
(2) to ensure that nuclear sites are regulated by the most appropriate regulators during the final stages of nuclear decommissioning and clean-up; and
(3) to enable a more sustainable approach to radioactive waste management.

As a result of (1), we anticipate that nuclear sites will be able to be delicensed earlier than they can at present. They will continue to be regulated by the relevant environment agency and the Health and Safety Executive (HSE). These proposals are intended to have the following effects:

a) To allow more proportionate and sustainable clean-up of nuclear sites
b) To reduce the generation of low and very low-level radioactive waste requiring management off site and the costs associated with its disposal, as well as the pressure on existing disposal facilities.
c) To allow ONR to concentrate its specialist nuclear safety and security resource on sites that require this expertise.

Also as a result of 1) operators of eligible disposal facilities for low level radioactive waste of nuclear origin will be excluded from the requirement to have specialist cover for nuclear third-party liability. This will reduce costs and burdens on the operators of these facilities.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

A non-legislative approach was considered in the consultation IA and was dismissed on the grounds that it would not provide sufficient certainty for regulators and the industry. It would require ONR guidance to re-interpret the existing "no danger" criterion in legislation (NIA65), which could be difficult, since the existing interpretation was taken following extensive consultation and legal advice. Moreover, some of the benefits of the selected policy option such as removing the right of site operators to surrender their nuclear licences at any time and consulting the HSE on decisions relating to licence variation and revocation, are only possible via amendment of primary legislation. Finally, proposals to allow qualifying low level waste disposal facilities to exit the nuclear third-party liability regime require legislative change.

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date: 2034**

| | | | | |
|---|---|---|---|---|
| Does implementation go beyond minimum EU requirements? | | N/A | | |
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope?[1] | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** | **Non-traded:** -0.08 | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

[1] There could be monetised indirect impacts to small and micro companies. Further comment in the SAMBA.

## Summary: Analysis & Evidence — Introduce new legislation

FULL ECONOMIC ASSESSMENT

| Price Base Year | PV Base | Time Period | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| 202020 | 2022 | 20 | Low: 340 | High: 640 | Central Estimate 490 |

| COSTS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Cost (Present Value, 2022) |
|---|---|---|---|---|
| Low | 0.0 | | 0.7 | 8.9 |
| High | 0.0 | | 0.7 | 8.9 |
| Central Estimate | 0.0 | | 0.7 | 8.9 |

**Description and scale of key monetised costs by 'main affected groups'**

The estimated monetised costs associated with implementing primary legislation are included below. While impacts are not expected to start until 2024, we use a 2022 present value year for consistency with other measures within the Energy Bill.

The Nuclear Decommissioning Authority (NDA), ONR, environmental regulators and HSE have confirmed that they will incur no additional costs overall. Additional environmental monitoring costs (paid by the NDA and site licence companies) are estimated as £15m (2024 - 2043, undiscounted or £9.09.0m discounted). Familiarisation costs for the Site Licence Companies (SLC) and operators of disposal sites for low level waste are expected to be low at around £0.017m (undiscounted) as they are already required to familiarise themselves with periodic amendments to regulatory guidance.

**Other key non-monetised costs by 'main affected groups'**

Potentially fewer jobs would be needed to excavate sub-surface material and to transport and dispose of low and very low-level (LLW and VLLW) radioactive waste. However, the majority of waste is from surface material and jobs associated with its clean-up will not be affected.

| BENEFITS (£m) | Total Transition (Constant Price) | Years | Average Annual (excl. Transition) (Constant Price) | Total Benefit (Present Value, 2022) |
|---|---|---|---|---|
| Low | 0 | | 24 | 340 |
| High | 0 | | 44 | 640 |
| Best Estimate | 0 | | 34 | 490 |

**Description and scale of key monetised benefits by 'main affected groups'**

The estimated monetised benefits associated with implementing both primary and secondary legislation are included below.

Savings from exiting liability earlier than at present are £19m (discounted). Savings from ending overlapping regulation and ending the licence earlier than at present are £19m (discounted). Reductions in the remediation work required are expected to reduce excavation costs for the NDA and site licence companies by £200m (discounted) and to reduce the costs of transport and disposal of LLW and VLLW by £250m (discounted). There is a wide range between high and low estimates due to uncertainty over how much remediation work is required. The best estimate is the mid-point between the high and low estimates. We estimate greenhouse gas savings of £16m (discounted) from the reduction in transport and waste disposal activities.

| | |
|---|---|
| **Other key non-monetised benefits by 'main affected groups'** Non-monetised benefits are difficult to quantify and/or small, including: i) reduced pressure on disposal facilities for radioactive waste, due to a reduction in LLW and VLLW generated; ii) reduced risk to workers undertaking excavation; iii) reduced traffic (fewer lorries required to transport the waste to disposal facilities); iv) reduced risk of associated traffic accidents; v) subject to planning permission, potential earlier re-use of former nuclear sites and vi) greater certainty in the provision of disposal capacity for low level waste from nuclear decommissioning. | |
| **Key assumptions/sensitivities/risks** | 3.5 |
| Savings under these proposals are sensitive to the estimated amount of sub-surface structures that could be left in-situ, rather than excavated. Between 5% and 20% of the structures to be demolished are estimated to be sub-surface from architectural drawings. Total cost savings have been estimated by the NDA and its site licence companies who have also provided an annual profile of savings. The appraisal period (2024 -2043) has been selected to cover the sites for which we have best information. However, analysis of costs and benefits over other periods has also been included.<br><br>Sellafield, the largest and most complex site, has not been included because the site characterisation is not sufficiently detailed to provide reliable estimates or to confirm when work might start. We know that these benefits will be large and anticipate that they will continue for around 100 years. Estimated savings are therefore conservative. The consultation did not produce further evidence on Sellafield. All estimates presented are rounded to 2 significant figures. | |

**BUSINESS ASSESSMENT (Introducing legislation)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs** 0 | **Benefits: 0.8** | **Net:** -0.8 | -£3.5 |

Contents

# Evidence Base

# Section 1: Overview

## *1.1 Background*

1. This impact assessment supports the passage of primary legislation measures related to measures that affect nuclear sites in the final stages of decommissioning and some that affect certain disposal facilities for waste of nuclear origin. We consider these separately. The analysis presented in this impact assessment is illustrative of the costs and benefits that could be expected following the implementation of both primary and secondary legislation.

### *1.1.1 Nuclear sites in the final stages of decommissioning*

2. All nuclear sites require a licence under the Nuclear Installations Act 1965 (NIA65) and are regulated by the Office for Nuclear Regulation (ONR). The NIA65 also provides the framework for nuclear third-party liability, as required under international and UK law[1]. Ending the nuclear licence and ending the period of nuclear third-party liability are two separate steps in NIA65.

3. **Nuclear decommissioning takes place over a long period**. To date, few nuclear power stations anywhere in the world have reached the final stages of decommissioning and clean-up. Under the revised decommissioning schedule plan announced by the Nuclear Decommissioning Authority (NDA), the ten former Magnox power stations will be decommissioned over a period up to 2080. The most contaminated site is Sellafield and clean-up at this site is scheduled to last over 100 years.

4. In the early stages of decommissioning, the spent fuel and higher activity radioactive waste are removed and securely stored elsewhere. This removes nuclear risks and reduces radiological hazards on a reactor site by over 99%[2]. In the final stages of decommissioning and clean-up, the nature of the hazard associated with nuclear sites is broadly similar to that at non-nuclear industrial sites undergoing clean-up for radioactive contamination[3]. Such non-nuclear sites are regulated by the relevant environment agency and the Health and Safety Executive (HSE).

5. The NIA65 was drafted in 1965, when little consideration had been given to decommissioning. It requires that a nuclear site is returned to a state suitable for **unrestricted** use before it can be released from nuclear regulation. This requirement is referred to as the "no danger" criterion.

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[1] The Paris Convention 2004 Protocols: See summary https://www.oecd-nea.org/law/paris-convention.html "Protocol to amend the Convention on third-party liability in the field of nuclear energy of 29 July 1960 as amended by the additional protocol of 28 January 1964 and by the protocol of 16 November 1982" 12/02/2004 https://www.oecd-nea.org/law/paris_convention_protocol.pdf

[2] http://ukinventory.nda.gov.uk/wp-content/uploads/sites/2/2014/01/Fact-sheet-decommissioning-of-nuclear-power-facilities.pdf

[3] For example, certain pharmaceutical or medical facilities.

6. The “no danger” requirement was interpreted by the regulator[4] in 2005 following legal advice and extensive public consultation. Details of the reasoning are set out in Annex A.

7. Meeting this interpretation of the “no danger” criterion generally means removing virtually all the foundations and sub-structures from a site and transporting them to disposal facilities elsewhere. For a typical Magnox nuclear site, this can represent thousands of cubic metres of lightly radioactive waste, generally classed as low and very low-level waste (LLW and VLLW)[5].

#### *1.1.2 Disposal facilities for low level radioactive waste of nuclear origin*

8. Nuclear decommissioning produces large volumes of low and very low level radioactive waste, largely from demolition of lightly contaminated structures. Some of this waste is suitable to send to permitted disposal facilities. These facilities do not require a nuclear licence, but since 1st January 2022, when the 2016 Nuclear Installations (Liability for Damage Order[6]) came into effect, they have been required to have nuclear third party liability cover. This has had the effect of increasing costs for operators.

### *1.2 Problem under Consideration*

#### *1.2.2 Nuclear sites in the final stages of decommissioning*

9. In 2014, the Steering Committee of the OECD Nuclear Energy Agency decided that nuclear sites in the final stages of decommissioning can be excluded from the nuclear third-party liability regime if they meet certain conditions (referred to as the “Paris Convention Decommissioning Exclusion Criteria”)[7]. The UK is a member of the OECD Nuclear Energy Agency and has a member on the Steering Committee. Exiting the EU has had no impact on this membership. While there is no obligation on the UK to adopt decisions made by the Steering Committee, and thus doing so would be a domestic policy choice, aligning the NIA65 with these decisions would bring the UK into line with international best practice in this area and reduce liability cover costs.

10. In addition, the major problem with the current regulatory framework is that **nuclear sites remain subject to nuclear regulation by the ONR even when nuclear safety issues are no longer present**. In addition, these sites are regulated by the relevant environment agency. Although the nuclear and environmental regulation regimes are generally separate, they differ in their approach to site clean-up and re-use. We consider that remaining in the nuclear regulatory regime after nuclear-specific safety

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[4] HSE was the regulator at the time and the interpretation has been adopted by ONR.

[5] Low-Level Waste (LLW) contains relatively low levels of radioactivity, not exceeding 4 gigabecquerel (GBq) per tonne of alpha activity, or 12 GBq per tonne of beta/gamma activity. The waste includes items such as scrap metal, paper and plastics. Very Low-Level Waste (VLLW) is a sub-category of LLW with specific activity limits. Sites that produce VLLW can dispose of the waste with regular household or industrial waste at permitted landfill facilities. The major components of VLLW from nuclear sites are building rubble, soil and steel items. Low and very low-level waste constitutes around 0.002% of the radioactivity of the UK radioactive waste inventory, but around 90% of the volume of waste (“Radioactive Wastes in the UK: A Summary of the 2016 Inventory”).

[6] The Nuclear Installations (Liability for Damage) Order 2016 implements the Paris Protocols 2004. These protocols amend the Paris Convention and the Brussels Supplementary Convention on nuclear third-party liability in various ways, one of which is to extend the requirement for nuclear third party liability to all disposal facilities for radioactive waste of nuclear origin.

[7] A.2.12 “Decision and Recommendation of the Steering Committee Concerning the Application of the Paris Convention to Nuclear Installations in the Process of Being Decommissioned”, OECD Nuclear Energy Agency, 30 November 2014. https://www.oecd-nea.org/law/decommissioning-exclusion.html

and security issues have been resolved results in unnecessarily high regulatory costs of compliance and unnecessary complexity for site operators.

11. In particular, as discussed in paragraph 77, the current nuclear regime generally requires removing virtually all the foundations and sub-structures from a site and transporting them to permitted waste disposal facilities elsewhere. In practice, the NDA estimates that around 2% of the concrete bioshield is radioactive, mostly LLW. But since it is not possible (for safety reasons[8]) to separate out the contaminated 2%, all the material would currently be required to be disposed of at a dedicated LLW facility.

12. The excavation and transport of this waste for disposal elsewhere result in several impacts on people and the environment. In particular: risks to construction and demolition workers; traffic risks due to movement of heavy lorries taking waste away and bringing fresh material in for filling voids; and the filling up of the limited capacity in specialised radioactive waste disposal facilities.

13. In some cases, it may be optimal to leave structures in situ. In many cases, the risks of leaving lightly contaminated substructures and soils in place, or using them to fill voids on-site, where it is safe to do so are than the impacts of excavating, transporting and disposing or storing them elsewhere[9]. The current requirement to meet the “no danger” criterion is inflexible. It does not allow the site operator to weigh up the impacts of moving the lightly contaminated material against the environmental, social and economic impacts of leaving it in place.

14. Finally, under the current regime, existing regulatory nuclear site licensees can surrender their licence at any time (although it would be an offence to carry out any prescribed activities on the site without a licence). If a licensee surrenders its licence, ONR will continue to regulate via “directions” until the period of responsibility for nuclear third-party liability can be ended (which is currently at the “no danger” point but see paragraph 9 above). The scope of regulation by directions is significantly reduced and is limited to preventing injury and damage to property by ionising radiations. This means that it might not be possible to replicate some of the powers ONR uses under licence conditions under directions (for example powers relating to staffing, property transactions, finance or retaining appropriate records). To date, there is very limited experience of regulation via directions with only one historic case available[10] which does not provide experience that will be useful when considering the delicensing of major power stations or other nuclear reactors. Given this reduced scope and lack of experience, ONR has concerns about using directions for the extended regulation of nuclear sites during decommissioning and its current guidance notes that “The absence of any detail concerning directions in NIA 1965 suggests that no specific directions are intended by the Act”. The same guidance states that “ONR does not encourage the surrender of nuclear site licences”[11].

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[8] Scraping concrete results in dust formation which has health risks; if the concrete is radioactively contaminated, the health risks are higher. For this reason, it is not possible to separate the contaminated concrete from non-contaminated concrete.

[9] Under the “Radioactive Substances Regulations”, applied by the environment agencies, provide a robust framework for determining the overall impacts of in-situ disposal on a particular site. Under these regulations, the site operator is obliged to submit a peer-reviewed site-wide environmental safety case and waste management plan to the environment agency, which will determine whether an in-situ disposal can be permitted.

[10] Queen Mary College research reactor, delicensed 1983, regulation by direction for 15 days only

[11] Section 10, “The Delicensing Process for Existing Licensed Nuclear Sites”, ONR publication, NS-PER-IN-005 Revision 3, December 2019 for review in December 2022.

*1.2.3 Disposal facilities for waste of nuclear origin*

15. Nuclear decommissioning produces large volumes of low and very low level radioactive waste, largely from demolition of lightly contaminated structures. Some of this waste is suitable to send to permitted disposal facilities. These facilities do not require a nuclear licence, but from 1st January 2022, when the 2016 Nuclear Installations (Liability for Damage Order[12]) came into effect, they are required to have nuclear third party liability cover. This has had the effect of increasing costs for operators.

16. In 2016, the Steering Committee of the OECD Nuclear Energy Agency decided that certain disposal facilities for low level radioactive waste of nuclear origin can be excluded from the nuclear third-party liability regime if they meet certain conditions (referred to as the "Paris Convention Low Level Waste Exclusion Criteria")[13]. The UK is a member of the OECD Nuclear Energy Agency and has a member on the Steering Committee. Exiting the EU has had no impact on this membership. While there is no obligation on the UK to adopt decisions made by the Steering Committee, and thus doing so would be a domestic policy choice, aligning the NIA65 with these decisions would bring the UK into line with international best practice in this area and reduce liability cover costs for operators of qualifying low level waste disposal facilities (not all such facilities will qualify).

17. A separate issue is that some such disposal facilities are located on nuclear sites. As set out in the 2012 Government Response to a consultation on implementation of the Paris Brussels Conventions on nuclear third party liability[14], these facilities require nuclear third party liability but do not require a nuclear licence. However, owing to the "no danger" criterion in NIA65, they cannot currently be excluded from the licensed site. This fact acts as an incentive to nuclear site operators to construct disposal facilities on greenfield land adjacent to the site, rather than on the site itself. Unnecessary use of greenfield land is discouraged under planning guidance.

## *1.3 Rationale for Intervention*

18. At the core of the problem under consideration, current legislation provides inefficient, costly conditions for both nuclear site licensed companies and disposal facilities. This is a factor stemming from historical legislation, enacted prior to full understanding of the complexities with decommissioning and is a form of government failure. Government intervention in the form of both primary and secondary legislation is required to correct this failure to avoid negative externalities and improve efficiency.

*1.3.1 Nuclear sites in the final stages of decommissioning*

[12] The Nuclear Installations (Liability for Damage) Order 2016 implements the Paris Protocols 2004. These protocols amend the the Paris Convention and the Brussels Supplementary Convention on nuclear third party liability in various ways, one of which is to extend the requirement for nuclear third party liability to all disposal facilities for radioactive waste of nuclear origin.

[13] "Decision and Recommendation of the Steering Committee Concerning the Application of the Paris Convention to Nuclear Installations in the Process of Being Decommissioned", OECD Nuclear Energy Agency, 30 November 2014. https://www.oecd-nea.org/law/decommissioning-exclusion.html

[14] The 2012 response to the 2011 consultation on implementation of changes to the Paris and Brussels Conventions on nuclear third party liability, https://www.gov.uk/government/consultations/compensating-victims-of-nuclear-accidents

19. The Nuclear Installations Act 1965 (NIA65) provides the framework for licensing nuclear sites and for the third-party nuclear liability regime in the UK. The legislation was written long before decommissioning had been seriously considered.

20. Recent international recommendations (the “Decommissioning Exclusion”, described in paragraph 9, above) set out a procedure for excluding nuclear sites in the process of being decommissioned from the nuclear liability regime when hazards and risks fall below specified levels. The UK is not under obligation to adopt these standards, but doing so would align with international best practice and would reduce liability costs for operators.

21. Currently, NIA65 would allow an operator to surrender their licence at any time[15], leaving ONR to regulate via “directions” until the period of responsibility for nuclear third party liability can be ended. Thus, in principle, an operator could surrender its licence before the Decommissioning Exclusion criteria are reached. Regulation via directions has shortcomings; although it might be possible to replicate powers under licensing conditions that relate to risk or injury or damage to property by ionising radiations, it might not be possible to replicate powers in other licence conditions relating to, for example, staffing, property transactions, finance or retaining appropriate records in a way that satisfies the international requirements. There is therefore a strong case for removing the licensee’s right to surrender the licence unconditionally.

22. UK nuclear sites in the final stages of decommissioning and clean-up are currently subject to dual regulation by the Office for Nuclear Regulation (ONR) and the environment agencies. In the final stages of decommissioning and clean-up, these two regulatory regimes differ in their approach to land remediation. Currently, nuclear sites remain under nuclear regulation until the “no danger” point is reached, resulting in the adverse effects described in paragraphs 11 to 13. **Once nuclear matters have been resolved**, we consider that continued nuclear regulation is unnecessary. Radiological protection would be more appropriately regulated by HSE, while land remediation is most appropriately regulated by the environment agencies under the Radioactive Substances Regulations (and other environmental protection legislation). The Radioactive Substances Regulations provide a robust mechanism for assessing the wider impacts of different clean-up proposals and identifying the best overall solution for the site.

23. Moreover, while a nuclear site licence is in place, the security arrangements mean that it can be difficult to redevelop the site for non-nuclear purposes. A secondary benefit of the proposals is that they may facilitate earlier re-use of former nuclear sites.

24. In summary, this overlapping regulation results in additional cost burdens due to requirements to clean-up to the “no danger” point. Therefore, Government intervention is required in order to improve the efficiency of the process, simultaneously reducing costs and increasing clarity (through removal of conflicting regulation).

#### *1.3.2 Disposal sites for low level waste of nuclear origin*

25. The “Nuclear Installations (Liability for Damage) Order 2016 came into effect on 01/01/2022 and requires disposal facilities for radioactive waste of nuclear origin to have cover for nuclear third party liability. This imposes additional costs on the disposal companies.

[15] Although it would be an offence to carry out any prescribed activities without a nuclear licence.

26. Recent international recommendations (the “Low Level Waste Exclusion”, described in paragraph 16, above) set out a procedure for excluding qualifying disposal facilities for low level waste from the nuclear liability regime if hazards and risks fall below specified levels. The UK is not under obligation to do adopt these standards but to do so would align with international best practice and would reduce liability costs for operators. It should be noted that not all disposal facilities for low level waste will qualify but we expect four disposal facilities to be eligible to apply.

27. Some disposal facilities for low level waste are located on nuclear sites, although they do not require a nuclear licence. Under the current regulatory framework, they cannot be excluded from the nuclear licence until they reach the “no danger” point described in paragraphs 5 to 7, which will not occur for many decades after the rest of the site has been delicensed. This fact acts as an incentive to nuclear site operators to construct disposal facilities on greenfield land adjacent to the site, rather than on the site itself. Unnecessary use of greenfield land is discouraged under planning guidance. Allowing ONR to remove these sites from the nuclear licence would help to discourage the unnecessary construction of such sites on greenfield land. Therefore, inefficient legislation is producing negative externalities.

### *1.4* ***Consultation***

28. In November 2016, BEIS published a discussion paper on the principles of amending the regulatory framework for nuclear sites in the final stages of decommissioning and clean-up. A more detailed consultation on our proposals was published in May 2018, alongside an impact assessment[16].

29. The Government response[17] showed a high level of support for proposals to adopt the Decommissioning Exclusion, to remove the licensee’s right to surrender the licence unconditionally and to allow ONR to exclude disposal facilities that do not require a nuclear licence from the nuclear licensed site.

30. The 2018 consultation reiterated the UK Government’s intention to adopt the Low Level Waste Exclusion[18].

31. This final stage IA updates and replaces the 2018 consultation IA. **The key difference between the 2018 version and this version is that Magnox has amended its decommissioning schedule significantly[19]. Further, this IA presents savings from the whole programme and savings from individual components, which will be the subject of separate regulations (see section 7).**

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[16] https://www.gov.uk/government/consultations/the-regulation-of-nuclear-sites-in-the-final-stages-of-decommissioning-and-clean-up

[17] https://www.gov.uk/government/consultations/the-regulation-of-nuclear-sites-in-the-final-stages-of-decommissioning-and-clean-up

[18] The 2012 response to the 2011 consultation on implementation of changes to the Paris and Brussels Conventions on nuclear third party liability, https://www.gov.uk/government/consultations/compensating-victims-of-nuclear-accidents, states “However Government believes that low level and very low level (V/LLW) nuclear waste disposal facilities do not present a sufficient level of risk to warrant inclusion in the Paris liability regime. Therefore the UK is proceeding with its application for the exclusion of these facilities to the Steering Committee of the OECD Nuclear Energy Agency (NEA) under which the Conventions are managed”. In 2016, the OECD NEA Steering Committee published the Low Level Waste Exclusion.

[19] In 2018, the assumed decommissioning plan for the Magnox sites was that each site would enter a period of care and maintenance and that all sites would undergo final stage decommissioning in the 2080-2100 period. In 2021, the NDA announced that the Magnox sites would be decommissioned on a rolling basis, with the Trawsfynydd site being the first to be fully decommissioned. https://www.gov.uk/government/case-studies/timing-of-the-magnox-reactor-decommissioning-strategy. This new version of the IA is based on the rolling decommissioning schedule.

## Section 2: Policy objective

32. The objectives of these proposals are five-fold:
    - to ensure that the site is regulated by the most appropriate regulator in each phase of decommissioning;
    - to enable a more sustainable approach to waste management and site clean-up;
    - to reduce liability costs once the decommissioned nuclear site meets criteria set out in internationally agreed standards;
    - to allow ONR to exclude disposal facilities that do not require a nuclear licence from the nuclear site boundary; and
    - to reduce liability costs for qualifying low level waste disposal facilities that meet criteria set out in internationally agreed standards.

33. The UK Government formed a Working Group, comprised of representatives from ONR, Nuclear Decommissioning Authority (NDA), the environment agencies and HSE. This group explored several options for improving the regulatory regime. The principles adopted in formulating the proposals presented in the consultation were:
    - there must be no relaxation of regulation for public protection; the proposals align with international standards and the UK Health Security Agency[20] guidance; and
    - regulation should align with the statutory principles of good regulation, namely: proportionality, accountability, consistency, transparency and targeting.

## Section 3: Description of options considered

### *3.1 Do nothing*

*Nuclear sites in the final stages of decommissioning*

34. Under the “do nothing” option, nuclear sites will remain subject to nuclear regulation by the ONR, even when nuclear safety issues are no longer present. In addition, these sites will continue to be regulated by the relevant environment agency. Although the nuclear and environmental regulation regimes are generally separate, they differ in their approach to site clean-up and re-use. We consider that remaining in the nuclear regulatory regime after nuclear-specific safety and security issues have been resolved results in unnecessarily high regulatory costs of compliance and unnecessary complexity for site operators.

35. If legislation is not amended, then nuclear sites will remain subject to nuclear third party liability and nuclear regulation until the “no danger” point described in paragraphs 5 to 7 is met. Since meeting this criterion requires the removal of even lightly contaminated substructures and demolition waste, then large volumes of such waste, that could, potentially, be disposed of on-site, subject to environmental permitting, will be excavated and transported for disposal elsewhere.

36. This has several negative impacts. Removing material that could safely be disposed of on site will result in unnecessary risks to excavation workers and additional transport impacts for local communities, such as traffic, noise and dust. In some cases, lightly contaminated waste could have been used to fill voids, but, under the “do nothing” option, such waste would have to be removed and fresh material transported onto the

[20] Formerly, Public Health England had the responsibility for radiological protection standards in GB

site – again with transport implications. Using existing disposal facility capacity for this material may not be the best use of a limited resource. Finally, the “do nothing” option will result in additional costs; the costs of nuclear third party liability beyond the point at which it is required by international standards, the costs of the nuclear site licence and the costs of excavating and transporting the material that could have been safely left in-situ to disposal facilities elsewhere.

#### *3.1.2 Disposal facilities for low level waste of nuclear origin*

37. Under the “do nothing” option, the incentive to construct facilities on greenfield land (described in paragraph 17, will remain. Existing disposal facilities, located on a nuclear site, will continue to have no route for delicensing, even though they do not require a licence. This could result in unnecessary costs for operators.

38. Under the “do nothing” option, disposal facilities for low level waste that would meet the internationally agreed standards in the “Low Level Waste” Exclusion would still require nuclear third party liability, leading to unnecessary costs for operators. Alternatively, to avoid such costs, some operators of these sites may refuse to take waste of nuclear origin (and therefore fall out of the nuclear third party liability regime). This would reduce the disposal capacity available, which could have important negative impacts on the decommissioning programme as a whole.

### *3.2 Consideration of a non-legislative approach*

39. BEIS convened a lawyers’ group comprising members from the NDA, ONR, HSE, Natural Resources Wales, Scottish Environmental Protection Agency, the Environment Agency, Defra, DCLG[21] and the Scottish and Welsh Governments to examine the viability of a non-legislative approach under which ONR would amend its guidance to reinterpret the “no danger” criterion in NIA65 to align with the Paris Decommissioning Exclusion criteria. This group concluded that a non-legislative approach would not be viable for the following reasons:

- the 2005 interpretation of the “no danger” criterion in NIA65 was taken following legal advice and extensive consultation, as described in Annex A;
- the “Paris Decommissioning Exclusion” document (footnote 7) does not use the term “no danger”. Instead, it refers to risks being sufficiently low that the application of the nuclear third-party liability regime is no longer necessary;
- this option would not deliver all the benefits of the proposals. For example, the licensee would retain the right to surrender the licence unconditionally, leaving ONR to regulate via “directions” – something we propose to change;
- under this option, HSE would not become a statutory consultee when a nuclear site licence is varied or revoked (see paragraph 43)42;
- BEIS published a discussion paper in November 2016[22], in which one of the questions asked for views on whether legislative change was necessary. Most responses were in favour of legislative change and none suggested alternative approaches.

40. **This option was therefore rejected in the consultation stage impact assessment and is not considered here. The proposals require legislative change.**

[21] Now the Department for Levelling up, Housing and Communities.

[22] https://www.gov.uk/government/publications/discussion-paper-on-the-regulation-of-nuclear-sites-in-the-final-stages-of-decommissioning-and-clean-up

### *3.3 The Proposals: Amendments to NIA65*

*3.3.1 Proposals for nuclear sites in the final stages of decommissioning*

41. We propose that ONR will be able to allow a nuclear installation[23] to exit the requirement for nuclear third-party liability once content that the site has met the conditions established by the OECD Steering Committee on Nuclear Energy (the "Paris Convention Decommissioning Exclusion" Criteria)[24]. This will be an alternative to the "no danger" criterion described in paragraphs 5 to 7 and Annex A. Under the proposals, once the nuclear liability regime ceases to apply, third party liability (under ordinary law) would then apply to the site, providing an alternative but nevertheless still robust legal regime for third party damage or injury.

42. We propose to make use of the optional criterion 4 in the Decommissioning Exclusion, which allows the competent authority to require evaluation of any aspect relating to the magnitude and severity of potential nuclear damage into account**. This will ensure that meeting the Decommissioning Exclusion will also mean that all nuclear safety issues have been resolved to ONR's satisfaction and the nuclear site licence can be ended.**[25] Further details are given in Annex A. **Savings from costs to cover liability insurance would start from this point.**

43. We propose to remove the licensee's right to surrender the licence at any time. ONR will retain its power to revoke or vary a licence. To end the licence, we propose that: a) installations in the process of being decommissioned must meet the Decommissioning Exclusion, including criterion 4, as described above b) HSE[26] and the relevant environment agency are consulted and c) nuclear security issues have been resolved[27]. To vary the licence to exclude any part of the site that does not include a nuclear installation, we propose that there are no conditions, although we would expect ONR to instigate an informal handover process to HSE and the relevant environment agency. **Savings on regulatory costs would start from the end of the licence[28].**

44. Following the revocation of the site nuclear licence, the site will be regulated by the relevant environment agency and HSE. This would not result in any additional costs (see paragraphs 114 and 115 for further information). Any remaining final site clean-up will be in accordance with the existing environmental regulatory framework.

45. Figure 1 (paragraph 47474747, below) shows a comparison of the current regulatory framework with the proposed one.

46. **Based on data from the NDA and site licence companies, the largest savings from these proposals would come from reduced costs for land remediation, transport**

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[23] In the UK, all parts of a nuclear site, whether they contain nuclear installations or non-nuclear buildings such as offices are required to be covered by nuclear third party liability under NIA65. For parts of the site that do not contain nuclear installations, we are proposing simpler criteria to exit the requirement for nuclear third party liability, so that these parts of the site can be delicensed earlier and re-used more easily for non-nuclear purposes.

[24] Note that we do not propose to re-interpret the "No danger" criterion, which would remain in place as an alternative option for determining the end of the period of responsibility. See Annex A for further discussion.

[25] This reflects the current position, as included in the legal instructions sent to OPC.

[26] The relevant environment agency is already a statutory consultee on issues of licence variation and revocation, if radioactive waste is concerned.

[27] Nuclear security issues would be expected to have been resolved well before licence surrender/revocation or variation. These are covered by other legislation, but ONR proposes an administrative check at the point of licence revocation.

[28] These regulatory savings include savings associated with the licence fee, security (e.g. fences and patrols) and work associated with compliance with nuclear regulation.

**and disposal of waste. These savings are expected start shortly after the introduction of a new regulatory framework[29] and continue for decades**.

47. While the nuclear site licence is in place, it is extremely difficult to use the site for any other purpose. Once the nuclear licence is revoked/surrendered, the site operator may apply for planning permission to allow the site to be used for recreational, commercial or other purposes. Thus, a secondary benefit from this step is that it will allow former nuclear sites to be re-used earlier.

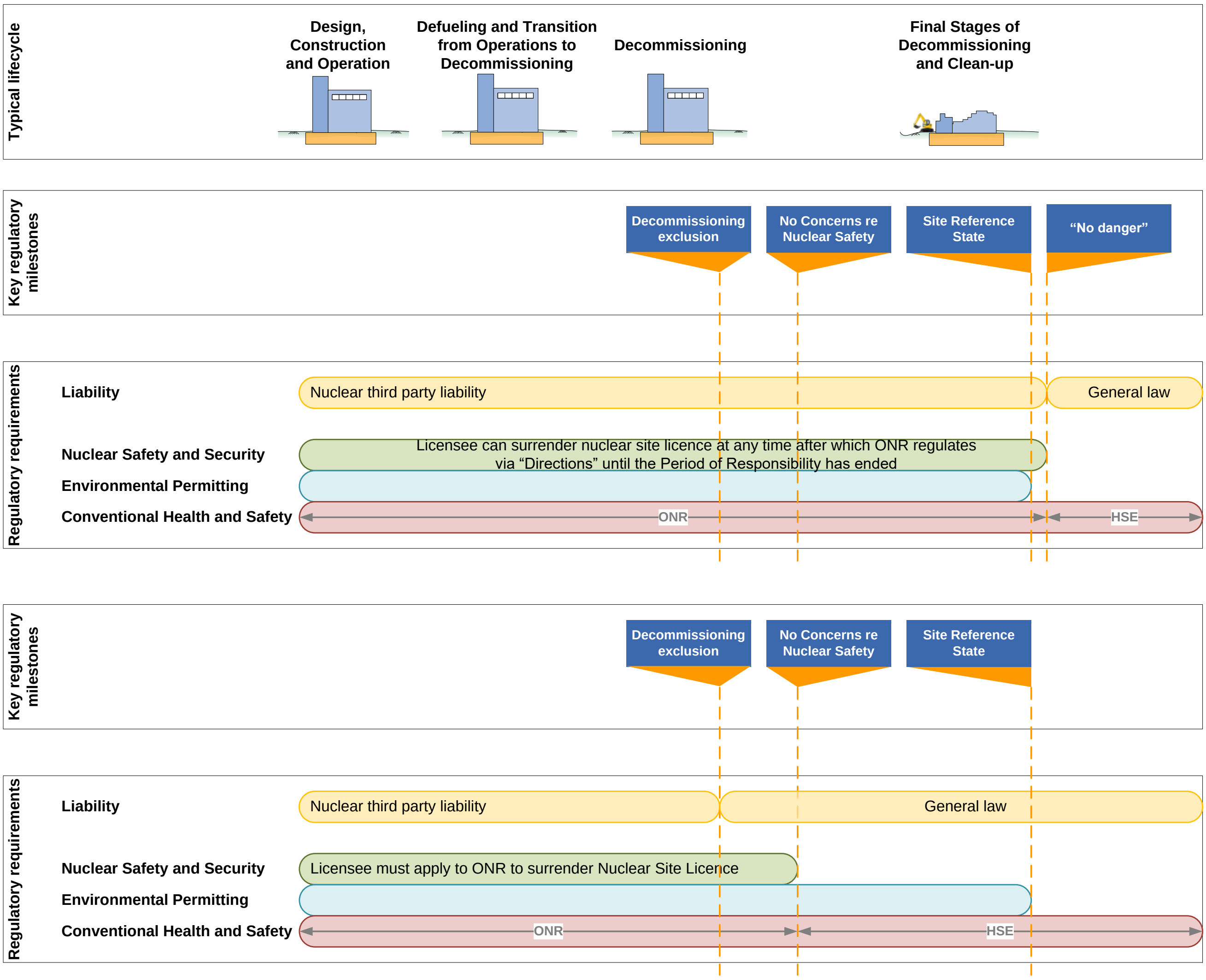


**Figure 1: The current and proposed regulatory regimes for nuclear sites in the final stages of decommissioning (current top, proposed lower)**

The blue flags ("Decommissioning Exclusion", "No concerns re nuclear safety", "Site Reference State" and "No Danger") represent key points on the timeline of site clean-up. The yellow bar represents the third-party liability regime. Once the site exits the nuclear third-party liability regime, third-party liability is covered by general UK law. The green bar represents the nuclear licence[30]. The blue bar represents the environmental regulation, which continues until the site

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[29] The savings for the Magnox sites, Dounreay and Winfrith would be expected to start shortly after the introduction of a new regulatory framework. We do not have clarity on when savings from Sellafield would start. Savings from the application of the proposals to the decommissioning of the EdF-E fleet would be expected to start sometime in the 2040s.

[30] Currently, under NIA65, the licensee can surrender the licence at any time, leaving ONR to regulate via "directions" until the end of the period of nuclear third-party liability, but we propose to remove this option by requiring the licensee to apply to ONR as described in paragraph **Error! Reference source not found.**.

meets the “Site Reference State”[31] in both the current and proposed frameworks. The red bar represents conventional health and safety regulation.

*3.3.2 Proposals for disposal facilities for waste of nuclear origin*

48. We propose to amend NIA65 to allow ONR to exclude disposal facilities for waste of nuclear origin that do not require a nuclear licence from the nuclear licensed site. This proposal will encourage site operators to build disposal facilities on nuclear sites, rather than on other land, for example greenfield land adjacent to the nuclear site. The benefits of this specific measure are environmental, and the proposal is in alignment with principles set out in planning guidance[32,33]. It has not been possible to monetise this benefit in this assessment.

49. Disposal facilities that meet the criteria specified by in the LLW Exclusion will be eligible to apply for exclusion from the nuclear third-party liability regime. Under the proposals, once the nuclear liability regime ceases to apply, third party liability (under ordinary law) would then apply to the site, providing an alternative but nevertheless still robust legal regime for third party damage or injury.

50. At present, there are only four LLW facilities in the UK that would be expected to meet these criteria and we would expect the operators to apply for the exclusion as soon as any new legislation comes into effect. **Savings from this measure would start at the point of a successful application**. Estimated savings are relatively small compared to those from the nuclear licensed sites but the measure is important, since it will help ensure that there are sufficient disposal facilities for low level waste as the UK’s decommissioning programme accelerates.

*3.3.3 Appropriateness and proportionality of proposals*

51. The proposals to simplify the regulatory framework are anticipated to result in a range of benefits, including:

- allowing ONR to concentrate its specialist nuclear safety and security resource on sites that require its expertise;
- allowing site operators to work to a single set of land remediation standards, rather than two sets, as at present;
- facilitating more sustainable and cost-effective clean-up and potentially, allow for the earlier re-use of sites; and
- removing barriers to constructing disposal facilities for radioactive waste on existing nuclear sites.

52. These **proposals will not result in any increase in the risk to public health over the current baseline.** The Paris Convention Decommissioning Exclusion and Low Level Waste Exclusion Criteria include a condition requiring that “under all reasonably conceivable conditions, including accidental occurrences and security events, and assuming that protective actions have not been taken”, the annual effective radiological

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[31] The Site Reference State is defined in the “Guidance on Requirements for the release of nuclear sites from the Radioactive Substances Regulations”, consultation document February 2016, the Scottish Environment Protection Agency, the Environment Agency and Natural Resources Wales. Note that this state is similar to the “no danger” criterion in the NIA65.

[32] England: “National Planning Policy Framework”, paragraphs 117-121; Scotland: “Building Standards technical handbook 2017: non-domestic buildings”, section 3.0, Environment; Wales: “Planning Policy Wales, edition 10, 2018”, paragraph 3.39.

[33] Economic benefits would be calculated only on the basis of land price (for a small amount of land, e.g. 6 hectares at Dounreay). These amounts are negligible, the real benefits are environmental.

exposure for an off-site member of the public should not exceed 1 millisievert – the same as the international annual radiation dose limit for members of the public[34].

53. Under the proposals, once the nuclear liability regime ceases to apply, third party liability (under ordinary law) would then apply to the site, providing an alternative but nevertheless still robust legal regime for third party damage or injury.

54. We consider that the proposals are:

- Proportionate (because they will remove slightly overlapping regulation, and ensure that environmental regulators, rather than nuclear regulators, take decisions on land remediation).
- Accountable (because nuclear site operator will have to apply to ONR to exit the nuclear third-party liability regime and operators of disposal facilities for low level radioactive waste of nuclear origin will have to apply to the Secretary of State). In both cases, the procedures will be set out in legislation.
- Consistent (because the proposed regulation by HSE and the relevant environment agency after the end of the licence is consistent with the regulation of non-nuclear industrial sites with comparable hazards and risks).
- Transparent (because we propose to adopt internationally accepted conditions for exiting nuclear third-party liability).
- Targeted (because they apply to nuclear site operators and operators of qualifying low level waste disposal facilities only).

55. We consider that the proposals should be adopted as a package. The three proposals relating to nuclear sites in the process of being decommissioned (adopting the Decommissioning Exclusion, amending the licence revocation procedures and ending the licensee’s right to surrender unilaterally) will only work as a package. In principle, the proposals to allow disposal facilities to be excluded from the licensed site and to adopt the Low Level Waste Exclusion are separate but in practice, these measures are vital to ensuring that the UK has sufficient capacity for the disposal of low and very low level waste that will result from decommissioning activities. All of these measures require amendments to NIA65 and we therefore propose that these amendments are adopted as a package. Some measures may require secondary legislation as well.

## Section 4: Monetised and non-monetised costs and benefits

### *4.1 Analytical Methodology*

56. Our analytical approach combines a quantitative and qualitative assessment of the proposals (resulting from both primary and secondary legislation) relative to a “do nothing” (no change) baseline.

57. We assess the relative costs and benefits of each option against a range of impact categories:

a) Costs associated with familiarisation with new legislation.
b) Costs associated with excavation of sub-surface material.
c) Costs associated with transport and processing of subsurface waste requiring disposal.
d) Costs associated with greenhouse gas emissions from transport and disposal of waste.
e) Costs associated with environmental monitoring.

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[34] ICRP 103 2007 "The 2007 Recommendations of the International Commission on Radiological Protection", Ann ICRP 37 1-332.

f) Costs associated with exiting the nuclear third-party liability regime and ending the nuclear licence.
g) Costs associated with liability costs for low level waste facilities that meet the Low-Level Waste Exclusion criteria.
h) Impacts on the volume of low-level waste (LLW) and very low-level waste (VLLW) requiring disposal at a permitted radioactive disposal facility and the associated preservation of capacity.
i) Impacts on traffic associated with transport of waste and material to fill voids.
j) Impacts on risks of accidents to workers excavating and removing waste and in risk of traffic accidents relating to transport of the material.
k) Impacts on time required to remediate and redevelop sites.
l) Impacts on employment.

58. The first seven of these categories (a to g) fall under our quantitative assessment. The remaining impacts are relatively small, uncertain and/or inherently difficult to monetise and are therefore included in the non-monetised analysis.

59. In the consultation, which ran from 08/05/2018-03/07/2018, we asked for further evidence to inform the impact assessment. While we did not receive any numerical data, we did receive some qualitative information, which has been included below. **It should be noted that Magnox has since revised its decommissioning schedule and this IA has been updated to take account of this change.**

### *4.2 Sites examined, assumptions and appraisal period*

60. As shown in **Table 1** below, ONR currently regulates 35 nuclear sites in the UK. Of these:
- 17 sites are the responsibility of the NDA (of which 14 are in the process of decommissioning[35] and 3 are operational nuclear sites[36]);
- 1 EdF plant is being defuelled;
- 7 are operational nuclear power plants;
- 6 are defence-related;
- 1 is a healthcare site operated by GE Healthcare[37];
- 1 is a small university research reactor;
- 1 an operational waste processor; and
- 1 is a nuclear power plant in the process of construction.

61. This analysis focuses on the 14 NDA nuclear estates which are currently in the process of decommissioning: Harwell, Winfrith, Sellafield, Dounreay and the 10 Magnox nuclear power plants (see footnote 35).

62. This grouping has been chosen because all Magnox sites are of similar design and age, having been constructed between 1959 and 1970. Harwell and Winfrith were primarily research reactor sites, although of different sizes and so have been considered separately. Sellafield is a particularly complex site, including reactors, a reprocessing plant, and facilities for producing and storing plutonium for military and civil purposes. Dounreay was the UK fast reactor research site and included a reprocessing plant.

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[35] Magnox nuclear power plant sites including; Berkeley, Bradwell, Chapelcross, Dungeness A, Hinkley Point A, Hunterston A, Oldbury, Sizewell A, Trawsfynydd, Wylfa. Also Harwell, Winfrith, Sellafield and Dounreay.

[36] These are: Capenhurst (fuel processing), Springfields (fuel processing) and the Low-Level Waste Repository at Drigg (waste management).

[37] A second GE Healthcare site, GE Healthcare Cardiff was delicensed in December 2019.

63. **The analysis in the IA has been performed based on the NDA's new schedule for the decommissioning of the 10 Magnox nuclear power plant sites. Under this new schedule, the first Magnox site to be fully delicensed will be Trawsfynydd in about 2035 and the others will be delicensed on a rolling basis from 2040 – 2080. This is the main difference between the current IA and the one published with the consultation in 2018.**

64. The proposals will require amendments to primary legislation and the development of new secondary legislation. This is likely to take time and so we have assumed that no savings are possible before 2024. While our 20-year appraisal period then starts in 2024, we use a 2022 present value year for consistency with other measures within the Energy Bill.

65. For Winfrith, we expect the benefits from not needing to excavate, transport and dispose of waste to accrue in the years up to 2032. For Dounreay, these benefits will accrue in years up to 2040. For the Magnox sites, we expect savings between 2024 and 2080, see Annex C.

66. Savings from Harwell are expected to be small and to cover the period 2050s to 2060s.

67. Sellafield is the largest and most complex site and the process of decommissioning and clean-up is expected to take over 100 years from 2024 to 2123 or thereabouts. We have only been able to source high level estimates for the potential savings from these proposals over a 100-year timescale and the uncertainties on these estimates are much higher than those sources for other sites (for example, at Sellafield, the undiscounted estimates of savings from transport and disposal vary by more than 50% and the time profile for the potential savings is not well understood, which clearly has a significant impact on discounted figures). Further work is required to characterise the sub-surface structures before reliable estimates of the savings and the yearly profile of these savings can be calculated. **For this reason, we have elected to omit the savings from Sellafield in this impact assessment. As a result, our estimates of savings provided by the programme will be an under-estimate.**

68. Springfield and Capenhurst are part of the NDA estate but are operational fuel processing sites. Although some old facilities on these sites are being decommissioned, we do not expect these sites to be affected by the proposals in the consultation for the foreseeable future.

69. EdF Energy operates eight nuclear sites in the UK[38]. Current proposals are to start decommissioning in the 2020s and 2030s and to finish in the 2080s, but it is possible that further lifetime extensions may be granted. **Since the proposals in this consultation refer to the later stages of decommissioning, we would not expect significant savings from these sites before the mid-2040s. These savings have not been included in the analysis.**

70. GE Healthcare operates two small nuclear licensed sites, one of which (Cardiff) was delicensed in 2019 and therefore will not be affected by these proposals. The Amersham site will be affected by the proposals. Since the next use of this site is likely to be for housing or commercial buildings, GE Healthcare intends to remediate to the existing "no danger" criterion, which means that no excavation savings or waste transport savings will be made. However, under the proposals, part of this site will make

[38] The Edf Energy sites are entirely separate from the NDA estate.

liability cover savings from around 2026 to around 2035 and GE Healthcare has provided estimates of these savings, which we have included in the analysis.

71. We are not aware of any plans to decommission the Cyclife metal recycling site and therefore do not think that it would be affected by the proposals[39].

72. We do not expect that the proposals will result in any savings from the decommissioning of the small research reactor at Imperial College. It is in an advanced phase of decommissioning, with delicensing, under the current arrangements, due in 2021[40].

73. **In order to limit our analysis to the sites for which we have the most reliable information, we have selected an appraisal period of 20 years between 2024 and 2043. Thus, this analysis presents estimated savings from Winfrith, Dounreay, the first two of the 10 Magnox sites and the GE Amersham site only for this period.** Savings from Harwell and the EdF-Energy sites fall outside this period as do additional savings from the remaining 8 Magnox sites (which will occur between 2043 and 2080). However, we include analysis examining the sensitivity to different choices of appraisal period. Savings from Sellafield have not been included (see paragraph 6767676767 and Annex G for further discussion).

**Table 1: UK nuclear sites**

| Category | Number of sites | Description | Dates of decommissioning | Included in this IA |
|---|---|---|---|---|
| NDA - Magnox | 12 | 10 former nuclear power stations and 2 research reactors (Winfrith and Harwell) | Up until around 2080 under current plans[41]. | Yes, except Harwell, see paragraph 6666 |
| NDA – other | 5 | 2 large, complex sites (Sellafield & Dounreay),<br>2 fuel processing sites (Capenhurst, Springfields), and one Low-Level Waste Repository | Dounreay – up to 2040<br>Sellafield – for the next 100 years<br>Capenhurst no plans to decommission<br>Springfields – no plans to decommission<br>LLWR – not applicable, this is a disposal facility. | Dounreay – Yes<br>Sellafield – No (see paragraph 67 67)<br>Capenhurst – No (see paragraph 6868)<br>Springfields – No (see paragraph 6868)<br>LLWR – Not applicable |
| EdF | 1 | Dungeness B in the process of being defueled | Decommissioning expected to start in the 2020s-2030s and currently expected to finish in the 2080s | No – see paragraph 6969 |
| EdF | 7 | 7 operational power plants | Decommissioning expected to start in the 2020s-2030s and | No – see paragraph 6969 |

[39] This site is far smaller and less complex than the former nuclear power stations and research reactors, so even if it were decommissioned, we would expect the savings to be minimal in comparison with the main sites identified in point 61.

[40] Email from Trevor Chambers, Head of Reactor Centre, Imperial College London 23/03/2020.

[41] The analysis in the IA has been performed based on an assumption that there will be a rolling programme of decommissioning of the 10 Magnox former nuclear power stations, with the first site (Trawsfynydd) being fully delicensed in 2035 (parts may be delicensed earlier) and the final site being fully delicensed in 2080. Winfrith is expected to be delicensed in 2032 and Dounreay in 2041.

| Category | Number of sites | Description | Dates of decommissioning | Included in this IA |
|---|---|---|---|---|
| | | | currently expected to finish in the 2080s | |
| Hinkley C | 1 | In construction | Not known, expected in the 2100s | No |
| Defence | 6 | Operational | Late 2030's Rosyth, other dates not known but after 2040. | No |
| GE Healthcare | 1 | 1 small healthcare site | Part of the site will complete decommissioning in 2020/2021 and the final part to expected to be delicensed in the mid 2020s [42]. | Yes – see paragraph 7070 |
| Cyclife | 1 | Metal recycling plant | No decommissioning plans | No – see paragraph 7171 |
| Imperial College | 1 | Small research reactor | Decommissioning until 2021 | No – see paragraph 7272 |

74. Annex B, Table 20 shows key dates for each site. These dates are important for determining when different savings occur.

### *4.3 Quantitative Assessment*

75. This section presents a quantitative analysis of the proposals against the baseline scenario (current regulatory framework) **for the period 2024 to 2043 where a 2022 present value year has used for consistency with the rest of the Energy Bill. It outlines the illustrative costs and benefits that could be expected following the implementation of both primary and secondary legislation. Since secondary legislation is required for the impacts to be realised, the primary legislation in itself has zero impact.**

76. The key monetised impacts have been identified as:

[42] Note that GE Healthcare Cardiff was delicensed in December 2019.

a) Costs associated with familiarisation with new legislation.
b) Costs associated with excavation of sub-surface material.
c) Costs associated with transport and processing of subsurface waste requiring disposal.
d) Costs associated with greenhouse gas emissions associated with transport and disposal of waste.
e) Costs associated with environmental monitoring.
f) Costs associated with exiting the nuclear third-party liability regime and ending the nuclear licence for nuclear sites[43].
g) Costs associated with liability costs for low level waste facilities.

Each are considered in the sections below. All estimates presented are rounded to 2 significant figures.[44]

#### *4.3.1 Costs associated with familiarisation with new legislation*

***Background***

77. The proposals will require site operators to spend time familiarising themselves with the new regulations. Guidance documents have not yet been prepared, however, ONR anticipates that there might be two documents relating to the new proposed amendments for nuclear licensed sites mentioned in paragraphs 42 to 43, each around 40 pages long[45]. For LLW operators, BEIS will publish one document, also around 40 pages long.

78. The regulation relating to nuclear sites covers licensed nuclear site operators, which are large companies. Site Licence Companies (SLCs) are already required to respond to periodic updates to ONR's inspection and assessment guidance and safety assessment principles, and therefore have the necessary expertise to interpret regulatory updates in-house. Further familiarisation costs are expected to be negligible, as we expect managers to interpret the key elements of the guidance when instructing staff.

79. The regulation relating to LLW disposal facilities covers medium to large sized companies, which are similarly required to respond to periodic updates on regulatory matters and therefore have the necessary expertise in house.

***Assumptions***

80. As above in paragraph 7777, we estimate each of the three documents would be around 40 pages in length. We assume that the two documents that concern nuclear sites would be read by around 27 middle-ranking managers and 27 lawyers[46]. Using the Regulatory Appraisal Subgroup Methodology[47], we assume that each individual would read each document three times to understand the intricacies correctly and also a reading speed of 200 words per minute and 500 words per page. Lastly, to estimate

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[43] The GE Healthcare nuclear licensed site pays for its own liability cover. Up until 01/01/2022, the NDA had insurance cover for this liability. However, from 01/01/2022, the UK Government has taken on this liability for nuclear sites in the NDA estate. This means that the liability savings from the Decommissioning Exclusion presented in this IA are an over-estimate. The liability savings for the LLW disposal facilities are not affected by this; these companies will take out private insurance.

[44] Note that due to figures being presented to 2 significant figures, estimates may not appear to sum to the totals.

[45] Email from ONR 19-12-2017. Note that ONR has participated in the Steering Group and therefore is familiar with proposals. ONR writes large numbers of guidance documents for their inspectors and licence holders and therefore, we consider that their estimate of the number of pages is likely to be reliable.

[46] ONR estimates 4 middle managers will be affected at Dounreay, 1 at Winfrith, 1 at each of the 10 Magnox sites and 4 at Magnox Ltd HQ, plus 8 people in the supply chain, making a total of 27 people for the 12 sites considered in this IA. [Source: e-mail from ONR, 19-12-2017]. We anticipate that the number of lawyers would be similar.

[47] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/609201/business-impact-target-guidance-appraisal.pdf, Case Study 4.
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/609201/business-impact-target-guidance-appraisal.pdf, Case Study 4.

wage costs, we take wage estimates from ONS's annual survey of hours and earnings (£822.6 gross per week for managers and £748.4 for lawyers, ASHE 2019)[48] and uplift for 20.2% non-wage costs.

81. We anticipate that the LLW Exclusion guidance would need to be read by around eight middle ranking managers and eight lawyers for the four existing sites concerned and use the same salary assumptions as above.

***Quantified Estimates[49]***

82. Based on these assumptions, we estimate familiarisation costs for ONR guidance relating to nuclear sites of around £14,000. Using the same assumptions80, we calculate familiarisation costs for the LLW Exclusion guidance of around £2,000. **This suggests a total familiarisation cost in 2020 prices of around £717,000** (which does not appear to be the sum of the previous figures due to rounding)**.**

#### *4.3.2 Costs associated with excavation of sub-surface material.*

***Background***

83. As a result of the proposals, we anticipate that nuclear site operators will dispose of some material on-site (subject to environmental permitting). This includes some sub-structures, for example, reactor bioshields[50], ponds and foundations, which may lie up to 12m underground.

84. Leaving this material underground (subject to environmental permit) will mean that less excavation work is required. Excavation work is a complex engineering task requiring specialist equipment and skilled workers.

***Assumptions***

85. **Clearly, disposing of material on-site will reduce the requirement for excavation.** The NDA has provided approximate estimates of savings from sub-structure excavation. These are based on the avoidance of excavation activity resulting in wage cost savings. **The NDA's estimates exclude non-wage cost and capital equipment rental savings and are therefore conservative**. The NDA intends to update these assumptions, but, at present, they are the best available.

86. **Table 2** shows the estimated number of person-years required to complete the excavation process at each site (based on current technology). We estimate the excavation savings by multiplying the assumed number of full-time equivalent employees engaged in this activity by an assumed average salary of £45,984[51] and by the duration of the excavation in years. Note that the figure for the Magnox sites is the total for all 10 sites together; the estimated excavation costs at each Magnox site are a little higher than those at Winfrith.[52]

[48] 2019 Provisional data set Table 16.1a – Weekly Pay Gross 2019 https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/datasets/industry4digitsic2007ashetable16

[49] Familiarisation costs = Cost of employees time [estimated as wage x non-wage uplift] x time to review documents, in weeks

[50] Specialised concrete shield around a nuclear reactor.

[51] The median gross annual pay for employees in the treatment and disposal of hazardous waste is £45,984 (2019, ASHE Table 16).

[52] Note that there are no anticipated "on site disposals at the GE Healthcare site and therefore no excavation savings for this site.

**Table 2: Estimated person years per site for the final stages of decommissioning (information supplied by the NDA)**

| | Assumed Person Years | Assumed period over which excavation savings can be made[53] |
|---|---:|---:|
| Total for 10 Magnox sites | 10,000 | 2024-2080 |
| Dounreay | 1,500 | 2024-2040 |
| Winfrith | 800 | 2024-2032 |

87. The NDA has also provided time profiles of savings associated with excavation, (see graphs in Annex C). The time profiles of avoided waste generation allow us to estimate the proportion of excavation savings that would be expected to occur during the appraisal period. For the 10 Magnox sites, only part of the total potential savings from the proposals would be realised in the appraisal period of 2024-2043 and only two of the Magnox sites will be fully delicensed during this period. The remainder of the savings would be realised in the period up to 2080.

***Quantified Estimates[54]***

88. **Table 3** shows the estimated savings from reductions in excavation operation due to the proposals. The analysis suggests that undiscounted savings over the appraisal period could sum to around £8280million (£200million when discounted to 22022 present value).

**Table 3: Estimated savings from reductions in waste excavation (rounded to 2 significant figures)**

| Site | Excavation savings estimated by NDA (2024 - 2123)[55] (2020 £m, undiscounted) | Duration | Proportion of savings occurring in the period 2024-2043[56] | Estimated excavation savings for 2024-2043 (2020 £m, undiscounted) | Estimated excavation savings for 2024-2043 (2020 £m, 2022 present value) |
|---|---:|---|---:|---:|---:|
| Winfrith | 39 | Until 2032 | 100% | 39 | 32 |
| Magnox (Total for all 10 sites) | 490 | Until 2080 | 34% | 170 | 110 |
| Dounreay | 73 | Until 2040 | 100% | 73 | 54 |
| **Total** | **570** | | | **280** | **200** |

### *4.3.3 Costs associated with transport and processing of subsurface waste requiring disposal.*

***Background***

[53] See “Key Dates” table in Annex B.

[54] Cost savings from reduced excavation = excavation savings i.e. worker time savings [estimated as average wage x estimated required site person-years] x proportion of savings in the appraisal period.

[55] This is the period for the whole of the decommissioning programme.

[56] Calculated using the time profiles of avoided waste generation in Annex C.

89. The NDA have calculated high and low estimates of the volumes of subsurface material that might be disposed of on-site subject to environmental permitting, see Annex C.

90. These on-site disposals reduce the amount of waste that requires to be transported and processed for disposal at dedicated LLW disposal facilities, resulting in associated cost savings.

### *Assumptions*

91. NDA guidance[57] provides estimates for the cost of disposing radioactive waste and is based on costs such as container purchase, transportation and disposal charges. These are given as:

- between £3,100 and £7,500 per $m^3$ of LLW; and
- £500 per $m^3$ of VLLW.

92. The NDA have calculated high and low estimates of transport and disposal savings based on the high and low estimates of volumes of waste to be transported (see paragraph 89 and Annex C) multiplied by the transport and disposal costs above (paragraph 91) [58].

93. As before, the time profiles of avoided waste transport/disposal follow the profiles of avoided waste generation, given in Annex C. Annex D presents further details.

94. One respondent to the consultation noted that the impact assessment omitted cost savings from not needing to import rubble to fill voids left on site. Winfrith has confirmed that they expect to have sufficient rubble from demolished buildings to fill any voids. We anticipate that the same will apply at the other sites and therefore that there would be savings from not needing to purchase clay and topsoil to fill voids. These savings have not been included in the analysis but they would be expected to be much lower than the savings from disposal and transport of the excavated waste, since such waste can only be disposed of in a few designated disposal facilities in the country, while topsoil or clay may be available from local sources and so require minimal transport.

### *Quantified Estimates[59]*

95. **Table 4** shows the estimated savings from reduced transport and disposal of waste (undiscounted and discounted). Annex D provides further details. The annual profile of transport and disposal savings would be expected to follow the same pattern as the annual profile of avoided waste (figure C1, Annex C188). This demonstrates that savings, utilising the central estimate, are likely to sum to £350million, undiscounted (£250 million, discounted to 2022 present value).

[57] Lifetime Cost Assumptions for LLW Activities (Revision 2 February 2020).

[58] Note that there are no anticipated "on site disposals at the GE Healthcare site and therefore no transport and disposal savings for this site.

[59] As explained in paragraph 92, cost savings from transport and disposal of waste = cost of disposal x avoided volume of waste in the appraisal period

**Table 4: Estimated savings from reduced transport and disposal of waste from 2024-2043 (rounded to 2 significant figures)**

| Site | Transport and disposal savings (2024-2123)[60] (2020 £m, undiscounted) | Duration | Proportion of savings occurring in the period 2024-2043 | Estimated transport and disposal savings (2024 - 2043) (2020 £m, undiscounted) | Estimated transport and disposal savings (2024 - 2043) (2020 £m, 2022 present value) |
|---|---|---|---|---|---|
| Winfrith | 26 (12 – 40) | Until 2032 | 100% | 26 (12 – 40) | 21 (9 - 33) |
| Magnox (Total for all 10 sites) | 470 (150–790) | Until 2080 | 34% | 160 (50 - 270) | 110 (30 - 180) |
| Dounreay | 160 (80 – 240) | Until 2040 | 100% | 160 (80 – 240) | 120 (60 – 180) |
| **Total** | **660 (240 – 1,100)** | | | **350 (150 – 550)** | **250 (110 - 390)** |

### *4.3.4 Costs associated with greenhouse gas emissions associated with transport and disposal of waste.*

#### *Background*

96. Reductions in the volume of excavated waste are expected to reduce greenhouse gas emissions associated with its treatment, transport and disposal.

#### *Assumptions*

97. The NDA estimates that the amendments might result in a reduction in the generation of LLW and VLLW of around 58,500m$^3$ over the period 2024-2043. We assume that a standard indusry factor[61] of 1.25 tonne/m$^3$ and be applied to convert this volume to tonnes of waste. The NDA has also provided time profiles of the reduction in waste generated, see Annex C[62].

98. We assume no carbon recovery occurs through incineration or metals treatment in the baseline. Based on analysis by the Low Level Waste Repository (LLWR) [63], we assume that treatment of LLW at the LLWR results in GHG emissions of 1,055 kg$CO_2$e/tonne and that treatment of VLLW at the LLWR (and other disposal sites) results in emissions of 199 kg$CO_2$e/tonne.

99. To estimate transport emissions savings, we also assumed that all LLW would have been transported to the UK's LLW repository while all VLLW would have been transported to the nearest appropriate disposal facility. Note that the site facilities at Dounreay are adjacent to the site, and so the distance has been assumed to be about 5km this case. Rigid HGV emissions for average loading are 0.10749 kg $CO_2$e per kilometre-tonne[64].

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[60] Note 100-year time period in this column (2024-2123)

[61] http://www.wrap.org.uk/sites/files/wrap/WRAP%20Waste%20Reporting%20Guidance%20Update%20-%20FINAL1.pdf

[62] As before, there are no anticipated on-site disposals for the GE Healthcare site and therefore no associated GHG savings.

[63] http://llwrsite.com/wp-content/uploads/2016/08/NWP_REP_083-Carbon-Emissions-Assessment-Issue-2-July-2016.pdf

[64] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2021 (Freight sheet Q63)

100. We take our carbon values from government guidance[65]. **Table 5** shows the assumed volumes of avoided waste over the period 2024-2043 and the average distances to the nearest LLW and VLLW facilities.

**Table 5: Assumed volumes of avoided waste (2024-2043) and distances to nearest LLW and VLLW facilities**

| Site | Volume LLW avoided 2024-2043 (m3) (central estimate) | Volume VLLW avoided 2024-2043 (m3) (central estimate) | Distance to LLWR or Dounreay vaults (km) | Distance to nearest VLLW facility (km) |
|---|---|---|---|---|
| Winfrith | 4,284 | 0 | 584 | 307 |
| Dounreay | 27,675 | 0 | 5 | 5 |
| Magnox sites (all) | 24,528 | 2,203 | 410 (average) | 200 (average) |

***Quantified Estimates[66]***

**Table 6: Estimated GHG savings associated with avoided transport and processing of waste over the period 2024-2043**

| Site | GHG savings associated with transport and processing 2024-2043 (MtCO2eq) | Monetised value of GHG savings 2024-2043 2020 £m (undiscounted) | Monetised value of GHG savings 2024-2043 2020 £m, 2022 present value |
|---|---|---|---|
| Winfrith | 0.006 | 1.6 | 1.3 |
| Dounreay | 0.037 | 10 | 7.6 |
| Magnox sites (all) | 0.034 | 10 | 6.8 |
| **Total** | **0.08** | **22** | **16** |

101. **Table 6** shows the estimated GHG savings from avoided transport and processing of waste over the appraisal period. We estimate that 0.08 $MtCO_2e$ would be saved from leaving subsurface material in situ over the appraisal period 2024-2043. The total undiscounted savings is approximately £17m - 27m with a central estimate of £22m.

102. This estimate does not take account of any potential changes in carbon factors for transport or processing of waste that might occur over the assessment period, which may arise from, for example, improved fuel efficiency of vehicles or variations to the methods of processing radioactive waste.

### *4.3.5 Costs associated with additional environmental monitoring on nuclear sites*

***Background***

103. Under both the current and the proposed frameworks, the nuclear site licence operator is expected to monitor radioactivity and contamination at various locations on the site to

[65] The economic analysis of greenhouse gas savings is based on the "central" values in the Government publication: "Valuing greenhouse gas emissions in policy appraisal and evaluation", September 2021. The range comes from the lower and upper estimates of volume of material to be excavated.

[66] Cost savings from reduced emissions = carbon values x (emissions estimate for transport and processing by site) whereby the emissions estimates are estimated as ((Volume of waste x multiplier to tonnes per m3 x processing GHG factor) + (Km travelled x tonnes x GHG transport factor)) x fraction of waste avoided in the appraisal period

ensure that environmental safety requirements are met, however, we expect the proposed amendments to increase the requirement for environmental monitoring and therefore to increase costs.

104. The proposals for disposal facilities (the LLW Exclusion) do not result in additional environmental monitoring.

***Assumptions***

105. Under the current framework, around five years of intensive environmental monitoring is required to demonstrate the "no danger" point has been reached. The BEIS estimated annual cost is £0.4m, based on information provided by the NDA[67] (£2m over 5 years). This monitoring is expected to start around five years before the "no danger" point. Under the proposed framework, around 30 years of less intensive environmental monitoring will be required, costing around £0.29m per year (2020 prices) and starting around five years before the site exits nuclear third-party liability (at the decommissioning exclusion point). The longer monitoring period required for the proposals is to verify the radioactive decay of material left in-situ. Different sites are scheduled to reach the decommissioning exclusion and "no danger" points at different times, as shown in Annex B, Table 20. Annex E provides further details[68].

***Quantified Estimates[69]***

106. For Winfrith, the change in monitoring requirements under the proposals results in an estimated net increase in environmental monitoring costs of £4.6m[67] (undiscounted) over the appraisal period 2024-2043. As set out in Annex E, we have assumed a similar pattern of environmental monitoring costs for Dounreay and the Magnox sites, but starting at a later date, resulting in estimated increases in monitoring costs of £2.4m and £7.9m respectively. Both figures are undiscounted. All results are detailed in **Table 7**.

107. Figure E1, Annex E shows the annual profile of net environmental monitoring costs (i.e. the environmental monitoring costs that apply under the proposals to adopt the Decommissioning Exclusion minus the costs that would apply under the current "no danger" route out of nuclear third party liability).

**Table 7: Estimated costs associated with increased the requirement for environmental monitoring for nuclear sites (rounded to 2 significant figures)**

| Nuclear site | Estimated costs associated with increased environmental monitoring during the appraisal period (2024-2043) | |
|---|---|---|
| | Undiscounted (2020 £m) | Discounted (2020 £m, 2022 present value) |
| Winfrith | 4.6 | 3.0 |
| Dounreay | 2.4 | 1.3 |
| Magnox sites | 7.9 | 4.6 |
| **Total** | **15** | **8.9** |

67 The "Site Decommissioning and Remediation: Stage B: Winfrith Site End State Determination" report ES(17)P154 estimates environmental monitoring costs under the current framework as £2m (undiscounted) and spread over the period 2023-2029 (5 years) . Under the proposals, environmental monitoring costs are £8m (undiscounted) and spread over the period 2023-2053 (30 years). The figures quoted about (£4.1m) apply to the appraisal period, which is 2024-2043 and so does not include all of the 30 year environmental monitoring period.

68 As noted before, there are no on-site disposals anticipated at the GE healthcare site and therefore no associated additional environmental monitoring costs.

69 For calculation details, see Annex E.

### *4.3.6 Costs associated with exiting the nuclear third-party liability regime and ending the nuclear licence for nuclear sites.*

***Background***

108. Under the proposals, we anticipate that nuclear sites will exit the requirement to have nuclear third party liability cover earlier than at present and will also exit the nuclear licence earlier. In both cases, there are associated cost savings for the operator. Different sites are scheduled to reach these points at different times, as shown in Annex B, Table 20.

***Assumptions***

109. Insurance premium savings for nuclear sites would start from the point at which the site meets the Paris Convention Decommissioning Exclusion Criteria (footnote 7) and continue to the point at which the "no danger" criterion would have been reached under the existing legislative framework (see the key dates table in Annex B). We do not have figures for annual insurance premiums for the third-party liability regime. The liability levels are currently assumed to be circa €1,200million (£1,008m)[70] for operational sites, or €160million[71] (£134m) for "intermediate risk prescribed sites" as set out in law[72]. The nuclear sites in this impact assessment would be classified as intermediate risk prescribed sites", as they have been defuelled and the spent fuel has been removed[73].

110. As described in paragraph 736373, we have elected to present the benefits for the period 2024-2043. This covers the entire period of clean-up work at Winfrith and Dounreay and two of the Magnox sites. **We do not have a reliable estimate for the annual insurance premia paid by these sites as this information is confidential. We have decided to scale the estimated premia for "intermediate risk" sites by the ratio of liability for intermediate sites to that of low risk sites, for which we have estimates[74]. We therefore assume an annual liability saving of £390k-£460k per site from the date at which the Decommissioning Exclusion applies until the date at which the "no danger" criterion would have been met (see Annex B, Table 2010for dates)[75].**

111. Following consultation, GE Healthcare stated that part of one of their sites would be expected to be affected by these proposals, with savings to insurance costs of around £140,000 per year for around 10 years from around 2026[76]. The annual liability cover savings assumed to arise from the adoption of the decommissioning exclusion are presented in table 8 and Figure F1 (in Annex F) shows the estimated profile of liability cover savings.

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[70] Conversion factor 1€ = £0.84 (20/10/2021).

[71] "Nuclear Third-Party Liability: Defining Intermediate Risk Prescribed Sites – Consultation", BEIS, August 2017, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/636789/Intermediate_sites_consultation_paper_-_11_August_2017_v2.pdf

[72] Note that NIA65 refers to the "Sterling equivalent of" these figures, given in euros.

[73] See further requirements in section 5 of The Nuclear Installations (Prescribed Sites And Transport) Regulations 2018 https://www.legislation.gov.uk/uksi/2018/42/contents/made, which camecame into effect on 01/01/2022 when the 2016 Nuclear Installations (Liability for Damages) Order amecame into effect.

[74] As discussed in paragraph 118, the estimate of annual liability premia for low risk sites is £170-200,000. The liability levels of intermediate risk sites are 160m€ and those of low risk sites 70m€, so we assume an annual premium of 170,000*160/70 = **£389,000** to 200,000*160/70 = **£457,000.** These values have been rounded in text above.

[75] The GE Healthcare nuclear licensed site pays for its own liability cover. Up until 01/01/2022, the NDA had insurance cover for this liability. However, from 01/01/2022, the UK Government has taken on this liability for nuclear sites in the NDA estate. This means that the liability savings from the Decommissioning Exclusion presented in this IA are an over-estimate. The liability savings for the LLW disposal facilities are not affected by this; these companies will take out private insurance.

[76] No other savings are expected for this site, as it will be cleaned to the "no danger" criterion, since its next planned use is likely to be for housing or commercial buildings.

112. It should be noted that the estimates of liability savings in paragraphs 110 and 111 are likely to be rather high; the sites are expected to exit the specific nuclear third party liability regime (which is expensive) but they will still require third party liability cover under ordinary law. The cost of this liability cover is unknown and has not been subtracted from the savings in paragraphs 110 and 111 above.

113. The reduction in regulatory costs associated with nuclear regulation would start from the point at which ONR revokes the licence and continue until the point at which the "no danger" criterion would have been reached (as shown for each site in Annex B, Table 20). These have been termed as 'standstill' costs and include the cost of the nuclear licence, security and compliance with nuclear regulation. The standstill costs have been based on data for nuclear sites such as Cyclife UK Limited[77], Chapelcross[78] and Dounreay and cover aspects such as regulatory charges, security requirements, maintenance of the nuclear staffing requirements, corporate management and assurance costs. The figures received ranged between approximately £1m and £3m per year. The analysis adopts a conservative figure of £1m per year for standstill costs for each Magnox site beyond the point of assumed de-licensing[79]. For Winfrith, which is a relatively small site, the assumed annual saving is approximately £0.6m, while for Dounreay, which is a highly complex site, the assumed annual saving is approximately £4.2m[80]. **Table 8** shows the assumed annual savings associated with exiting nuclear third party liability and ending the licence (see also Figure F2 in Annex F). **As before, note that the liability savings are an over-estimate; up until 01 January 2022, the NDA had insurance cover for this liability. However, from 01 January 2022, the UK Government has taken on this liability for nuclear sites in the NDA estate**. This means that the liability savings from the NDA sites presented in this IA are an over-estimate. The liability savings for the GE Healthcare site and LLW disposal facilities are not affected by this; these companies will take out private insurance, but note the caveats in **paragraph 112**.

**Table 8: Assumed annual liability and licensing savings**

| **Site** | **Assumed liability savings (annual) £m** | **Assumed licence savings (annual) £m** | **Dates (savings from date 1 to date 2 inclusive[81])** |
|---|---:|---:|---|
| Winfrith (NDA) | 0.4-0.5 | 0.6 | 2032-2047 |
| Dounreay (NDA) | 0.4-0.5 | 4.2 | 2041-2099 |
| GE Healthcare | 0.1 | 0.0 | 2026-2035 |
| 1st Magnox site (NDA) | 0.4-0.5 | 1.0 | 2035-2089 |
| 2nd Magnox site (NDA) | 0.4-0.5 | 1.0 | 2040-2089 |
| **Total** | **1.7 – 2.0** | **6.9** | |

114. Under the proposals, HSE (Health and Safety Executive) would assume regulatory responsibilities for conventional health and safety, including the protection of workers

77 Formerly Studsvik-Lillyhall, a metal recycling facility.

78 Chapelcross is thought to be typical of the Magnox sites in terms of the standstill costs. We anticipate that, as clean-up progresses, the licence costs would reduce somewhat and for this reason have selected the lower end of the range of licence costs.

79 Information from the NDA, dated 29/09/2020.

80 Information from the NDA, dated September 2020.

81 See Annex B

under the Ionising Radiations Regulations after the ending of the nuclear licence. HSE have confirmed that they do not charge an annual charge for regulation (unlike ONR); however, if a site is found to be in breach of regulations, they charge fees to recover the costs of its interventions. No additional costs arising from complying with these safety regulations are expected under HSE because the ONR already implements them – the regulator changes but not the underlying regulations.

115. Under the proposals, regulation by the relevant environment agency would continue when the nuclear licence is revoked. The Environment Agency, Scottish Environment Protection Agency and Natural Resources Wales have confirmed that they do not expect their costs to increase.

***Quantified Estimates[82]***

116. **Table 9** shows our estimates of the total liability and regulatory savings accruing to the nuclear site licensed companies. The total estimated savings are £49 million (2020 prices), undiscounted (£27million, discounted to 2022 present value). Note that the liability savings estimates are likely to be on the high side, because of the decision for HMT to cover nuclear third party liability for the NDA sites from 01 January 2022, as described in paragraph 113.

**Table 9: Liability and regulatory savings for nuclear sites during the appraisal period (rounded to 2 significant figures)**

| Site | Estimated savings (licence + liability) | |
|---|---|---|
| | Undiscounted (2020 £m) | Discounted (2020 £m, 22022 present value) |
| Winfrith | 13 (13 – 14) | 7.9 (7.6 – 8.1) |
| Dounreay | 15 (15 – 15) | 7.5 (7.4 – 7.5) |
| GE Healthcare | 1.5 | 1.2 |
| 1st Magnox site | 20 (19 - 20) | 11 (10 - 11) |
| 2nd Magnox site | | |
| **Total** | **49 (48 – 50)** | **27 (27 – 28)** |

### *4.3.7 Costs associated with liability costs for low level waste facilities.*

***Background***

117. There are four low level waste disposal facilities that may be eligible to apply for exclusion from the nuclear third party liability regime if the Low Level Waste Exclusion is adopted. These are: the East Northants Resource Management Facility (ENRMF), Clifton Marsh and FCC Lillyhall and Port Clarence. All four are located in England.

***Assumptions***

118. If excluded from the nuclear third party liability regime, we estimate that low level waste disposal facilities would save around £170,000-£200,000 per year in liability premia costs[83]. As before, these savings may be over-estimates; once excluded from the

[82] For both the total liability and total license savings, estimates are calculated by (assumed annual saving x appraisal period).

[83] Based on private correspondence from the only current insurer, 11/09/2020. (Note that there are only four sites that could be eligible for the LLW Exclusion, and, at the time of writing, only two of them have started accepting waste of nuclear origin. Both sites are insured by this insurer.)

nuclear third party liability regime, the disposal facilities will still require third party liability cover under ordinary liability law. The cost of this cover is unknown and has not been subtracted from the figures above. These savings would be expected to start in 2024 (about a year or so after the legislation comes into effect). We anticipate that the operational period of these sites is around 40 years[84]. The sites received permits to accept radioactive waste at different times. **Table 10** below shows the estimated closure dates for these facilities[85]. The total liability savings for each disposal site are calculated by multiplying the annual savings by the period over which they accrue.

**Table 10:1 Assumed closure dates for LLW disposal facilities**

| Disposal facility name | Date at which the first permit to accept radioactive waste was received | Assumed closure date | Estimated period over which disposal facility will make liability savings |
|---|---|---|---|
| East Northants | 2002 | 2042 | 2024-2041 |
| FCC Lillyhall | 2011 | 2051 | 2024-2050 |
| Clifton Marsh | 2012 | 2052 | 2024-2051 |
| Port Clarence | 2021 | 2061 | 2024-2060 |

### *Quantified Estimates[86]*

119. To obtain the undiscounted savings from the LLW Exclusion, we multiply the annual savings118118 by the period for which savings apply, given in **Table 10**. **Table 112 11** shows the estimated liability savings for the four LLW disposal facilities if excluded from the nuclear third-party liability regime (but note the caveats in paragraph 118, above).

**Table 112: Estimated nuclear third party liability savings for eligible LLW facilities from 2024-2043 (rounded to 2 significant figures)**

| LLW Disposal facility | Estimated nuclear third party liability savings from 2024 to 2043 | |
|---|---|---|
| | **Undiscounted (2020 £m)** | **Discounted (2020 £m, 2022 present value)** |
| East Northants | 3.5 (3.2 – 3.8) | 2.5 (2.3 – 2.7) |
| FCC Lillyhall | 3.9 (3.6 – 4.2) | 2.7 (2.5 – 2.9) |
| Clifton Marsh | 3.9 (3.6 – 4.2) | 2.7 (2.5 – 2.9) |
| Port Clarence | 3.9 (3.6 – 4.2) | 2.7 (2.5 – 2.9) |
| **Total** | **15 (14 – 17)** | **11 (10 – 11)** |

120. Figure F3 in Annex F shows the time profile of liability cover savings for the sites that are expected to arise from adoption of the LLW Exclusion.

### *4.3.8 Summary of costs and benefits*

121. **Table 123 12** shows a summary of the costs and benefits for the appraisal period 2024-2043.

[84] The East Northants site, for example, started operation in 2002 and has applied for an extension to operate until 2046 https://www.augeanconsultation.co.uk/.

[85] Note that existing sites could be expanded, in which case the lifetimes would be longer.

[86] For both the total liability and total license savings, estimates are calculated by (assumed annual saving x appraisal period).

**Table 123: Estimated costs and savings for the period 2024-2043 (undiscounted 2020 £m rounded to 2 significant figures unless specified otherwise)**

| | Winfrith | Magnox (10 sites[87]) | Dounreay | GE Healthcare Amersham (back part of site) | Low Level Waste Facility Sites | Total | Total (2020 £m, discounted to 2022 present value) |
|---|---|---|---|---|---|---|---|
| **Costs** | | | | | | | |
| **Familiarisation costs** | N/AA | N/AA | N/AA | N/A | N/A | **0.017** | **0.016** |
| **Environmental Monitoring costs** | 4.6 | 7.9 | 2.4 | N/A | N/A | **15** | **8.9** |
| ***Total Costs*** | ***4.6*** | ***7.9*** | ***2.4*** | ***N/A*** | ***N/A*** | ***15*** | ***9*** |
| **Savings** | | | | | | | |
| **Excavation savings** | 39 | 170 | 73 | N/A | N/A | **280** | **200** |
| **Transport/ disposal savings** | 26 (12 - 40) | 160 (50 - 270) | 160 (80 - 240) | N/A | N/A | **350 (150 - 550)** | **250 (110 - 390)** |
| **Greenhouse gas savings** | 1.6 (1.3 - 1.9) | 10.2 (6.4 - 14) | 10.4 (9.5 - 11.4) | N/A | N/A | **22 (17 - 27)** | **16 (12 - 19)** |
| **Liability cover** | 5.4 (4.9 - 5.8) | 5.8 (5.4 - 6.3) | 1.3 (1.2 - 1.5) | 1.5 | 15 (14 - 17) | **29 (27 - 32)** | **19 (17 - 20)** |
| **Regulatory savings** | 8.0 | 14 | 13 | N/A | N/A | **35** | **19** |
| ***Total Savings*** | ***80 (65 - 95)*** | ***360 (240 - 470)*** | ***260 (180 - 340)*** | ***1.5*** | ***15 (14 - 17)*** | ***720 (510 - 930)*** | ***500 (350 - 650)*** |
| **Total net savings** | **75 (60 - 91)** | **350 (240 - 470)** | **260 (180 - 340)** | **1.5** | **15 (14 - 17)** | **700 (490 - 910)** | **490 (340 - 640)** |

Note that figures may not appear to sum correctly due to rounding.

## *4.4 Un-monetised Assessment*

### *4.4.1 Reduction of the volume of low-level waste (LLW) and very low-level waste (VLLW) requiring disposal*

122. The UK currently has 0.996 million cubic metres of capacity for VLLW in permitted disposal facilities for radioactive substances and 1.16 million $m^3$ capacity in LLW facilities[88]. From our estimation of avoided waste generated, we find that the proposals would allow around 58,500 cubic metres of LLW and VLLW to remain in situ during the appraisal period and much higher volumes – approximately estimated at over 1.4 million $m^3$, as Sellafield is decommissioned. The proposals would reduce the volume of LLW and VLLW waste produced, therefore reducing demand for storage space in waste repositories which have limited capacity. This would lead to further indirect savings, such as greenhouse gases and land use, from the avoidance of constructing additional waste facilities. Annex C, Table 22 shows the estimated reduction in the volumes of LLW and VLLW. Based on an unpublished study by Nuvia for the NDA[89], the cost of

[87] As mentioned in Annex B, there is a rolling programme of decommissioning for the Magnox sites and only two of them are expected to be fully delicensed within the appraisal period.

[88] Permitted land fill capacity = 0.996 million $m^3$, capacity at Dounreay 0.175 million $m^3$ and capacity in the LLWR is 0.989 million $m^3$. (Email from LLWR 05/09/2021. These figures do not include the CLESA capacity, which is reserved for specialised waste. Note that these facilities also take NORM waste (naturally occurring radioactive matter) from the oil industry.

[89] "A cost estimate for the successor to the Low-Level Waste Repository", unpublished Nuvia report for NDA, 01/04/2009.

designing and building a new LLW facility is estimated as **£400m** (undiscounted), and the most likely date for construction under the current framework would be in the mid-2040s, which is outside the appraisal period. The discounted savings would be expected to be around £170m. **These savings are indirect and have not been included in the analysis**.

### *4.4.2 Reduction in traffic associated with transport of wastes and material to fill voids*

123. LLW and VLLW being removed from site and taken to waste repositories are most likely to be transported by road. Furthermore, equal amounts of material may be required to fill in the voids left from the excavation. Based on an assumed lorry load of 30 tonnes, there could be significant reductions in lorry traffic around 3,800 lorry journeys over the period 2024-2043 under the proposals, or an average of around 190 per year across all the nuclear sites being decommissioned in GB. The reduction in traffic will lead to a local reduction in associated air pollution.

### *4.4.3 Reduction in risk of accidents to workers excavating waste and risk of traffic accidents relating to transport of material to waste facilities*

124. These proposals will reduce the risk of accident to workers and the public during nuclear site clean-up due to a reduction in land remediation and transport of waste. However, no UK nuclear sites have yet reached the final stages decommissioning and clean-up yet, so it has not been possible to estimate the reduction in risk of accidents reliably. Fatal accidents in construction industry are rare. From HSE data, 0.33% of construction workers reportedly suffered non-fatal injuries in 2019[90] and 0.0018% suffered fatal injuries[91]. Similarly, accidents involving pedestrian and HGVs are also infrequent with 0.014 accidents per million kilometres travelled[92].

### *4.4.4 Assessment of reduction in time to remediate and re-develop sites*

125. In practice, it is extremely difficult to re-use sites while the nuclear site licence is in place. Under the proposals, ONR would be able to revoke the licence sooner than it can currently. The site would continue to be regulated by the relevant environment agency and the operator could **apply** to the local authority for planning permission for a new use while the environmental permit is in place[93]. Annex B Table 20 shows the **potentia**l reduction in time to re-use or redevelop each site **subject to planning permission.**

### *4.4.5 Assessment of equalities impact*

126. As discussed above, the main impacts of these measures would be:

- a potential increase in the number of disposals of low or very low-level radioactive material on-site, subject to environmental permitting;

[90] 2019/20. http://www.hse.gov.uk/statistics/tables/index.htm#riddor, Table 3: Non-fatal injuries to employees and the self-employed in Great Britain, by broad industry group 1974-2020/21p. The 2019 figure has been selected because covid restrictions may have led to a reduction in construction work in 2020/2021.

[91] 2019/20. http://www.hse.gov.uk/statistics/tables/index.htm#riddor, Table 1: Fatal injuries to employees and the self-employed in Great Britain, by broad industry group 1974-2020/21p. The 2019 figure has been selected because covid restrictions may have led to a reduction in construction work in 2020/2021.

[92] 2019. Calculated from the number of accidents involving pedestrians and total vehicle kilometres of GB-registered vehicles. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/647872/ras10012.ods

[93] This permission would be subject to consultation between the relevant Planning Authority and the Environment Agency, as well as appropriate assessments of exposures to ionising radiation and control of any radioactive waste that might arise from new development.

- associated reduced excavation of material;
- associated reduced transport of radioactive waste;
- associated reduced traffic impacts for local residents;
- reduced costs for nuclear third party liability cover and nuclear licence fees once former nuclear sites reach internationally agreed criteria;
- potentially, earlier redevelopment of former nuclear sites;
- reduced costs for nuclear third party liability cover for qualifying disposal facilities for low level radioactive waste of nuclear origin.

127. The protected characteristics listed in the 2010 Equalities Act are: age, disability, gender reassignment, marriage and civil partnership, pregnancy and maternity, race, religion or belief, sex, and sexual orientation. The measures in these proposals are not anticipated to have any special impacts on any of these groups – all members of the local community will be impacted equally. For completion, we have sourced data on age, birth rate, ethnic minority percentage and activity limiting health problems for the first three sites likely to be decommissioned, see **Table 13**:

**Table 134: Demographic information for the nuclear sites**

| Site | Local authority | % Over 65 | % Ethnic minority | Birth rate per 1,000 | % with activity limiting health problems or disabilities | Source of information |
|---|---|---|---|---|---|---|
| Winfrith | Dorset County Council | 28% | 4.4% | 7.8 | 20-26% | [94] [95] [96] |
| Dounreay | Highland | 23% | 0.6% | 9.7 | 18.6% | [97] [98] [99] |
| Trawsfynydd (1st Magnox site to be fully decommissioned) | Gwynedd | 23% | 3.3% | 10.9 | Not clear - statistics presented are 12.7% but this seems to be using a different measure | [100] [101] [102] |
| | | | | | | |
| England average | | 18.5 | 16.9 | 10.7 (UK figure) | Comparable figures not found | [103] [104] [105] |
| Scotland average | | 19.3 | 5.9 | | | As above |
| Wales average | | 21.1 | 5.2 | | | As above |

128. Data may refer to different dates between 2011 and 2020 and so cannot be robustly compared but it is clear that all three councils have a high percentage of elderly people, a low percentage of ethnic minority residents, and that Dorset and Highland councils have a high percentage of people who have health concerns that impact daily life and a relatively low birth rate (and therefore a low percentage of pregnant women). It must be noted that Highland council and Gwynedd council cover a wide area and therefore the population data for the whole council may not be representative of the population in the immediate vicinity of the site.

129. **As mentioned in paragraph 3351, these proposals would not result in any increase in the risk to public health over the current baseline**. And as mentioned in paragraph 41, under the proposals, once the nuclear liability regime ceases to apply,

[94] https://www.dorsetcouncil.gov.uk/your-council/about-your-council/dorset-council-plan/understanding-dorset

[95] https://webarchive.nationalarchives.gov.uk/ukgwa/20160105160709/http://www.ons.gov.uk/ons/resources/map1smalldailyactlimitsengland2011_tcm77-296713.png

[96] https://www.dorsetcouncil.gov.uk/your-community/your-community/statistics-and-census

[97] https://www.nrscotland.gov.uk/files//statistics/council-area-data-sheets/highland-council-profile.html

[98] https://www.scotlandscensus.gov.uk/search-the-census#/explore/snapshot

[99] “Mainstreaming Equality and Equality Outcomes Progress Report 2017 2019” Highland council

[100] https://www.plumplot.co.uk/Gwynedd-population.html

[101] Key statistics for Gwynedd – Births, deaths and components of change 2014

[102] https://statswales.gov.wales/Catalogue/Equality-and-Diversity/Ethnicity/ethnicity-by-area-ethnicgroup

[103] https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates/bulletins/annualmidyearpopulationestimates/mid2020#age-structure-of-the-uk-population

[104] https://en.wikipedia.org/wiki/Ethnic_groups_in_the_United_Kingdom

[105] https://data.worldbank.org/indicator/SP.DYN.CBRT.IN?locations=GB

third party liability (under ordinary law) would then apply to the site, providing an alternative but nevertheless still robust legal regime for third party damage or injury.

130. Despite the older than average demographics around the nuclear sites, the measures in these proposals are not anticipated to have any special impacts on any of the groups mentioned in the 2010 Equalities Act. For example, reduced traffic impacts near former nuclear sites would be a benefit to all local residents, irrespective of protected characteristics.

131. The measure has no role in other aspects of the Act, such as advancing equality of opportunity and fostering good relations between people who share a particular protected characteristic and those who do not share it.

#### *4.4.6 Labour market impacts*

132. The proposed regulatory change could reduce the number of jobs in the excavation and transport of LLW and VLLW, but we do not expect there to be significant impacts on labour markets. This is because the majority of radioactive waste is not subsurface and will therefore be removed as at present.

133. There may, however, be local impacts, as nuclear sites are typically located in places with relatively high unemployment and jobs in the nuclear sector generally pay better than other comparable construction jobs. However, it is not possible to quantify these effects reliably. No impacts are expected in the initial years following policy change as most radioactive waste will still require removal.

134. Under the proposals, sites are likely to be available for re-use earlier – in some cases, decades earlier than they might otherwise have been. Some sites will be used for recreational purposes, while site operators may apply for planning permission to redevelop others for commercial or industrial purposes. Since the nature of potential re-use is unknown and there is considerable uncertainty in forecasts of the labour markets in the 2030s and beyond, it is not possible to estimate the impact on jobs.

# Section 5: Direct costs and benefits to business calculations

### *5.1 Business Impacts*

135. Since the consultation stage impact assessment, the Business Impact Target (BIT) has been set for this Parliament. The following analysis is carried out in accordance with the prescribed methodology, however, it is indicative of the impacts of both the primary and secondary legislation required. The analysis below covers the appraisal period (2024-2043) and is presented as 2020 prices in 2022 present values for consistency with other measures within the Energy Bill. **Table 14** shows the best estimate impact of the proposals, which is the mid-point estimate between the high and low estimates.

136. Our analysis of business impacts takes into account our quantified benefits and costs to LLW sites and GE Healthcare. These are private companies, and as such, all have a direct impact on the BIT score and the annual direct cost to business. Other elements including, greenhouse gas savings and quantified costs and benefits which fall on organisations involved in the decommissioning and clean-up of nuclear sites, are excluded from the BIT calculation. This is because the NDA and regulators are public

bodies[106]. Furthermore, Site Licence Companies (SLCs) are arranged as subsidiaries of the NDA and have corresponding operational freedoms. As all are subsidiaries, we have assumed there are no impacts on businesses, with costs and benefits included only in the Total Net Present Social Value.

**Table 145: BIT analysis for the proposals (rounded to 2 significant figures)**

| **Cost of Option (£m, 2020 prices, 2022 present value)** | | | |
|---|---|---|---|
| **Total Net Present Social Value** 490 | **Business Net Present Value** 11 | **Net direct cost to business per year** -0.8 | **BIT Score** -3.8 |
| **Appraisal Period (Years)** 20 | | | |

### *5.2 Sensitivity to appraisal period*

137. Annex C Figure C1 shows the assumed annual profile of avoided waste generation from 2024-2090. As previously discussed, avoided costs follow this time profile. The NPV of the proposals is sensitive to the appraisal period due to the duration of decommissioning and clean-up activity that is covered within the estimates. Paragraph 73 73 explains our choice of appraisal period. **Table 15** presents the sensitivity of monetised savings over four different periods.

138. The different appraisal periods presented are: (a) 2024-2043 (20 years) (b) 2024-2033 (10 years), (c) 2024-2053 (30 years) and (d) 2024-2080 (57 years). As can be seen from Figure C1, Annex C, the last period includes the savings from the full decommissioning of all the Magnox sites and includes savings from Harwell (in the 2050s and 2060s). Savings from Sellafield have not been included but as described in paragraph 6767, these are expected to be large and to accrue in the hundred-year period 2024-2123.

139. **Table 15** (below) shows that the net present value increases as the appraisal period is increased from 10 to 57 years.

**Table 156: Sensitivity of benefits to the appraisal period (2020 prices, 2022 present value rounded to 2 significant figures)**

| Appraisal period | Dates | Years | Sites included | Total net present social value (£m) | Annual net impact on business (£m) |
|---|---|---|---|---|---|
| A | 2024-2043 | 20 | 2 Magnox sites (Trawsfynydd and one other), Dounreay, Winfrith and GE Amersham (back part of site) plus the four LLW facilities | 490 (340 – 640) | -0.8 |
| B | 2024-2033 | 10 | Part of one Magnox site, Winfrith, part of Dounreay, part of the GE Amersham | 310 (210 – 400) | -0.8 |

[106] The NDA and the regulators receive funds from central Government and from commercial activities.

| | | | | | |
|---|---|---|---|---|---|
| | | | site and the four LLW facilities | | |
| C | 2024-2053 | 30 | As A) above plus two other Magnox sites | 570 (410 – 740) | -0.7 |
| D | 2024-2080 | 57 | All the Magnox sites, Dounreay, Winfrith, Harwell and the LLW facilities. | 770 (560 – 970) | -0.9 |

140. As discussed in paragraph 67, savings from the Sellafield site have not been included. These savings are likely to be large, but estimates are more uncertain than those for the other sites, due to the complexity of the Sellafield site. The NDA and the Site Licence Company (Sellafield Ltd.) have provided very approximate estimates of savings from excavation, transport and disposal of waste from Sellafield over the next 100 years. These undiscounted figures are shown in Annex G and range from approximately £8,000m-£8,300m. Savings from the EdF sites have also not been included. These are expected to accrue after the mid-2040s[107].

### *5.3 Small and micro business assessment*

141. While a small number (less than 5) of small and micro businesses will be *indirectly* affected by this policy (as indicated on the summary page), no such businesses are expected to be directly affected by the regulatory change. The regulation covers licenced nuclear site operators, which as previously mentioned are large companies. For example, in 2019, Magnox Ltd employed 2,330 people and had a turnover of around £600m[108].

142. **Table 16** shows the number of current employees on a headcount basis at each decommissioning site we have considered. All the sites have finished defuelling. The headcount figures are based on surveys of the Nuclear Industry Association's membership, to estimate the number of employees engaged in the UK's civil nuclear industry. It shows that each site is in the medium to large category, with most sites employing more than 200 individuals[109], although these figures will include employment at businesses which have been contracted to supply services, in addition to workers at the nuclear site operators.

[107] We also anticipate, but do not know for certain, that the savings from excavation and waste disposal and transport will be lower for the EdF sites than for the NDA ones as the degree of radioactive contamination is believed to be lower. Non-discounted regulatory and liability savings would be expected to be similar to those for the Magnox sites.

[108] 2019 figures https://suite.endole.co.uk/insight/company/02264251-magnox-limited

[109] A large business will have >250 employees according to https://www.gov.uk/government/collections/mid-sized-businesses

**Table 167: Number of employees currently at each decommissioning site (2020)[110]**

| Decommissioning site | Headcount |
|---|---|
| Magnox Sites | |
| Berkeley | >150 |
| Bradwell | >100 |
| Chapelcross | >200 |
| Dungeness A | >200 |
| Hinkley Point A | >200 |
| Hunterston A | >200 |
| Oldbury | >250 |
| Sizewell A | >200 |
| Trawsfynydd | >150 |
| Wylfa | >250 |
| Harwell | >330 |
| Winfrith | >300 |
| Dounreay | >600 |
| GE Healthcare Amersham | Not known, likely to be low, however, GE healthcare is a large company |

143. In addition, the LLW Exclusion will affect three other businesses, all of which qualify as large (FCC Environment 2,400 employees in the UK, GdF Suez – 1,700 and Augean 200-500).

144. We expect indirect impacts on a small number (less than 5) of small and micro businesses from the reduced volume of clean-up activity to be limited as they are unlikely to be suited to perform most of the complex tasks involved. Excavation of substructures requires specialised equipment and a highly skilled workforce that small businesses are unlikely to have access to. We would therefore not expect a significant number of SMEs to contract for this work.

145. Despite not being directly impacted by this policy, we indicate below the indirect impact of this policy, specifically, on the four of the current approved hauliers for the Low-Level Waste Repository which are small and medium-sized enterprises (SMEs)[111]. The proposals will reduce the amount of waste that needs to be transported for disposal at dedicated facilities and paragraph 123 estimates that this could lead to around 190 fewer lorry journeys per year during the appraisal period based on a reduction of between around 5% and 20% of waste at each site requiring removal. In context, there were around 137 million GB-registered HGV journeys in 2020[112]. This reduction, therefore, represents a tiny proportion, overall and, for the four current SME hauliers, represents around one less journey per week per haulier on average. The indirect impact on small and micro businesses is, therefore, likely to be minimal and, given the indirect reduction of haulage journeys is necessary to achieve the objectives of the policy, we have not included any exemptions for SMEs.

110 NIA Jobs Map 2020, https://www.niauk.org/resources/jobs-map-2020/ .

111 Email from Low Level Waste Repository, 07/09/2020

112 DfT, Domestic Road Freight Statistics, United Kingdom 2020, available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1006792/domestic-road-freight-statistics-2020.pdf

# Section 6: Summary and Proposals

## *6.1 Summary*

146. BEIS has consulted on proposals to amend the regulatory framework for nuclear sites in the final stages of decommissioning and clean-up. Following consultation, we propose to amend the NIA65 to adopt international recommendations on the procedure for exiting the nuclear third-party liability regime and to end the licensee's right to surrender the licence unilaterally. We also propose to require that ONR consults with HSE when a licence is revoked or varied. We consider that these proposals will enable a more flexible and sustainable approach to site remediation.

147. The Steering Group considered a non-legislative change option in which ONR changes its guidance to include new criteria for exiting the period of responsibility for nuclear third-party liability. We concluded that this option was not viable, for a range of reasons, as discussed in paragraphs 39 to 40**Error! Reference source not found.Error! Reference source not found.**.[113]

148. As discussed in paragraph 73, the appraisal period selected (2024-2043) does not include:

a) expected savings from eight of the ten Magnox sites (which will accrue in the period up to 2080);
b) the full extent of savings in liability premia, which will continue after 2043. These savings extend from the date of meeting the Paris Decommissioning Exclusion criteria to the date at which the "no danger" criterion would have been met. Annex B shows these dates[114];
c) the full extent of savings from regulatory costs for Dounreay (which will apply from 2040) and for the Magnox sites (which will apply from 2035 for the first site, see Annex B);
d) savings from Sellafield, which is the largest and most complex site, but where assessment of sub-structures that could, potentially, be left on site is less well advanced than on the sites assessed here;
e) savings from the EdF sites, which are expected to accrue from the mid 2040s;
f) small savings from Harwell, in the 2050s; or
g) savings from defence sites regulated by ONR (unknown, but unlikely to have any impact before the 2040s at the earliest).

149. The most significant savings are likely to be from Sellafield, but these are also the most uncertain, since Sellafield is a highly complex site. The NDA and Site Licence Companies have provided very approximate estimates of savings from excavation, transport and disposal of waste from Sellafield over the next 100 years. These **undiscounted** figures are shown in Annex G and range from £7,500m-£7,800m. Given the uncertainty of the estimates of savings at Sellafield, these estimates are considerably less reliable than the ones presented in this impact assessment but illustrate the scale of the potential savings long-term.

## *6.2 Proposals*

150. We propose to adopt all the measures listed in paragraphs 41 to 49. Taking into account both primary and secondary legislation, this package of measures could result in indicative net benefits of £490m (range £340m – £640m) over 20 years (2020 prices,

[113] See Annex A for detail.

[114] But note that, as of 01/01/2022, the Government will take on the liability for the NDA estate, and for this reason, the liability savings in this IA (which were calculated based on the previous arrangements) are an over-estimate..

2022 present value year) and unquantified benefits beyond. There are also non-monetised benefits such as: a reduction in lorry traffic, reduced generation of low and very low-level waste, reduced pressure on radioactive waste disposal facilities and a more streamlined regulatory framework for site operators, who would have to consider a single set of clean-up requirements, rather than two sets, as at present.

### *6.3 Implementation Plan and Monitoring of Impact*

151. Based on the analysis presented here, we propose to develop new criteria for exiting the period of responsibility under the NIA65, to remove the licensee's right to surrender a nuclear licence unilaterally and to require ONR to consult with HSE when revoking or varying a nuclear licence. This will entail changes in primary legislation (the Nuclear Installations Act 1965) and new secondary legislation.

152. **We anticipate that operators of nuclear sites in the process of being decommissioned will amend their clean-up plans as soon as the legislation comes into force and that savings to the taxpayer will start at that point and continue following the pattern of excavation savings given in Annex C**.

153. We propose that BEIS monitors and evaluates the impact of these measures.

154. **Monitoring** - the ONR will provide BEIS with annual data on the number of successful applications for the Decommissioning Exclusion and delicensing. Licensees will provide annual data to BEIS on the estimated excavation and transport savings including data on the successful applications for permits to dispose of material on-site and the volumes of waste avoided in each case (applying the appropriate transport and disposal costs per m3).

155. Monitoring the impact of the LLW Exclusion will be straightforward since the BEIS Secretary of State will be the decision maker for the LLW Exclusion. A simple verification of how many disposal facilities have successfully applied for exclusion and an estimate of the savings for each site from the operators will be supplied to BEIS.

156. **Evaluation - Decommissioning Exclusion Regulations and the new delicensing procedures are not likely to be used on any significant scale until 2032, when Winfrith is expected to be fully delicensed**[115]. We would therefore expect that the first significant impact evaluation of these regulations will take place around 10-12 years after they come into effect.

157. An impact evaluation of the LLW Exclusion will be carried out five years post implementation as the exclusion is likely to be used within 1-2 years of implementation, resulting in savings to operators of those sites. New disposal facilities that might be eligible could be built in the next ten years. Therefore, an evaluation of the LLW Exclusion after five years, in line with the expectations set out in the Small Business, Enterprise and Employment Act 2015 is appropriate. This evaluation would include a review of the monitoring data and analysis of the number of sites excluded via the LLW Exclusion, plus estimates of the annual liability costs saved. If new facilities are built after five years, a further review will be undertaken. Evaluation activities will be undertaken by BEIS (or a contractor on BEIS' behalf) using data collected by BEIS post implementation.

[115] We do, however, anticipate that the proposed Decommissioning Exclusion Regulations and proposed new licence variation method will be used on parts of some nuclear licensed sites before this date. For example, the current proposal is to delicense part of the Trawsfynydd site in the mid/late 2020's. Moreover, the excavation and transport savings will start from the time at which the Decommissioning Exclusion regulations are in place, even though the regulations themselves will not be used until around 2032 (for Winfrith).

## Section 7: Separating out the impacts of different sub measures

158. The figures presented in section 6 are for the whole of the programme and are suitable for the impact assessment for the measures in primary legislation. We anticipate that the LLW Exclusion and plans to remove the licensee's right to surrender unilaterally will be in primary legislation, with new secondary legislation setting out the documents required for the application. We anticipate that most of the Decommissioning Exclusion will be in primary legislation but the final criterion[116] will be in new secondary regulations. The following sections consider the savings from implementing the LLW Exclusion and implementing the other measures (Decommissioning Exclusion plus licence surrender amendments) separately.

**a) New regulations for the final criterion of the Decommissioning Exclusion and amendments to licence surrender/revocation process.**

159. **Table 17** shows the estimated savings from the proposed new regulations which will set out the final criterion of the Decommissioning Exclusion and the proposed amendments to the licence surrender/revocation process together.

**Table 178: Savings from the new regulations for the final criterion of the Decommissioning Exclusion and licence surrender/revocation amendments, 2024-2043 rounded to 2 significant figures**

| | **Profile of savings** | **Undiscounted savings over 2024-2043 (2020 £m)** | **Discounted savings over 2024-2043 (2020 £m, 2022 present value)** |
|---|---|---|---|
| Liability savings | Annex F | 14 (13-15)[117] | 8.2 (7.6 – 8.8) |
| Regulatory savings | Annex F | 35 | 19 |
| Excavation savings | Follows pattern in Annex C | 280 | 200 |
| Transport and disposal savings | Follows pattern in Annex C | 350 (150 - 550) | 250 (110 – 390) |
| GHG savings | Follows pattern in Annex C | 22 (17 - 27) | 16 (12 – 19) |
| Environmental Monitoring (minus because these are **costs)** | Annex E | -15 | -8.9 |
| Familiarisation (minus because these are **costs)** | One off costs, see paragraph 82167 | -0.014 | -0.014 |
| **Total** | | **690 (480 – 900)** | **480 (330 – 630)** |

160. The regulatory savings have been included in this assessment. These are the savings from ending the nuclear licence earlier than currently.

[116] This criterion ("evaluation of any other aspect relating to the potential magnitude and severity of nuclear damage") is optional in the Decommissioning Exclusion but we propose to include it. We propose to use the same criterion for licence variation and revocation.

[117] As before, note that the liability savings estimates were calculated on the basis of private insurance, but that, since 01/01/2022, the UK Government has taken on responsibility for the liability for the NDA sites. The estimated liability savings from the Decommissioning Exclusion are therefore an over-estimate. The estimated liability savings for the LLW sites are unaffected as these operators have private insurance.

161. Ending the licence and ending the period for nuclear third party liability are two separate steps in NIA65.

162. Currently, under NIA65, the licensee can surrender the licence at any time, provided that no prescribed activities are required. But if it does so, ONR continues to regulate via “directions” until the “no danger” criterion, (described in paragraphs 5 to 7) is reached and the site can exit the nuclear third party liability regime. By adopting the OECD NEA decommissioning exclusion, we propose to provide licensees with an alternative route to the “no danger” route out of nuclear third party liability. We anticipate that licensees will choose to surrender their licences as soon as possible after the end of nuclear third party liability.

163. The Decommissioning Exclusion criteria 1-3 cover most, but not all, of the criteria that ONR would wish to assess to determine that the nuclear licence can be ended. The optional criterion 4, which allows the regulator to require assessment of “any additional aspect relating to the magnitude and severity of potential nuclear damage” is sufficient to plug these gaps. Thus, if a nuclear installation meets the requirements of all four criteria of the Decommissioning Exclusion, then ONR would also be content to end the licence (subject to administrative confirmations regarding nuclear security and views from the relevant environment agency and HSE).

164. For this reason, the regulatory cost savings associated with ending the licence earlier than at present have been presented together with the savings associated with the proposed regulations setting out the final criterion of the Decommissioning Exclusion.

165. Finally, note that there are increased environmental monitoring costs associated with on-site disposal (which we expect to take place as a result of these amendments) and these have been included in the table above.

166. **Table 18** shows the BIT analysis for the Decommissioning Exclusion and licence surrender amendments.

**Table 189: BIT analysis for the Decommissioning Exclusion and licence surrender/revocation amendments, 2024-2043 rounded to 2 significant figures**

| **Cost of Option (202020 prices, 22022 present value)** | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net direct cost to business per year** | **BIT Score** |
| 480 | 1.2 | -0.1 (indirect) | -0.3 |
| **Appraisal Period (Years)** | 20 | | |

**b) Low Level Waste Exclusion**

167. The undiscounted savings from the proposed adoption of the LLW Exclusion are estimated as £190,000[118] per site per year for each of 4 facilities (Port Clarence, East

[118] This is the central estimate, the range is £170,000-£200,000 per site per year.

Northants, Lilyhall and Clifton Marsh), resulting in undiscounted savings of £515m during the appraisal period of 2024-2043, with a range of £14m-£17m). As discussed in paragraph 118, we anticipate that these estimates are rather high, as the disposal facilities will still require third party liability cover under ordinary law once excluded from the specific nuclear third party liability regime and these costs are unknown and have not been subtracted from the estimates given above. The associated familiarisation costs are as described in paragraph 82**Error! Reference source not found.** and are estimated at around £2,000. The corresponding NPV over a 20 year appraisal period is £10.5m (range £9.6m-£12m). **Table 19** shows the BIT analysis.

**Table 19: BIT analysis for the LLW Exclusion**

| **Cost of Option (LLW Exclusion) (2020 prices, 2022 present value, rounded to 1 significant figure)** | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net direct cost to business per year** | **BIT Score** |
| 11 | 11 | -0.6 (indirect) | -3.2 |
| **Appraisal Period (Years)** | 20 | | |

168. However, the qualitative impact of the proposed LLW Exclusion Regulations is much more significant. In order for nuclear decommissioning to progress, sufficient permitted sites for the disposal of low level waste must be available. If private operators decide to refuse to accept waste of nuclear origin because of the nuclear third party liability costs associated with this, then very low level waste will have to be sent to facilities such as the low level waste repository or the Dounreay vaults. These facilities are intended for waste that requires a greater degree of protection than the waste sent to permitted landfills and accepting very low level waste would not be a cost effective or sustainable use of these facilities. Costs of disposal at the low level waste repository and the Dounreay vaults are higher than those of disposal at permitted landfills.

169. Note that the proposal is to introduce the LLW Exclusion via amendments to primary legislation, but to set out the documents required for application in secondary regulations.

## Annex A: Background to the interpretation of the “no danger” criterion in the NIA65

170. The NIA65 states that the “period of responsibility” for nuclear third-party liability can end “when the appropriate national authority gives notice in writing to the licensee that in the authority's opinion there has ceased to be any danger from ionising radiations from anything on the site or, as the case may be, on the part of it in question; the date when the appropriate national authority gives notice in writing to the licensee that in the authority's opinion there has ceased to be any danger from ionising radiations from anything on the site or, as the case may be, on the part of it in question.”

171. This criterion is known as the “no danger” criterion. It was interpreted in 2005 by the then regulator HSE and delicensing guidance was updated in 2008. In broad terms, the interpretation is not just “no nuclear danger” but also “near zero radiological risk”.

172. The delicensing criterion document of 2005 “attempts to achieve broad consistency with current scientific thinking, relevant guidance and other published material including the Radioactive Substances Act 1993 (and the exemption orders made under it), article 5 of the Basic Safety Standards Directive, and the International Atomic Energy Agency (IAEA) Safety Guide ‘Application of the Concepts of Exclusion, Exemption and Clearance’” (para. 2). It “forms a policy basis from which HSE can establish from its own assessment, from the licensee’s evidence, and through information from other regulatory bodies concerned with the site (e.g. the Environment Agency or the Scottish Environment Protection Agency), that any residual radioactivity on the site, above the average natural background, represents ‘no danger’” (para. 4). On the basis of existing, published guidance (for example, HSE’s “Tolerability of Risk” (TOR) and “Reducing Risks, Protecting People” (R2P2) publications), HSE considered that an additional risk of death to an individual of one in a million per year, was ‘broadly acceptable’ to society. Applying this to nuclear licensed sites, any residual radioactivity, above the average natural background, which can be satisfactorily demonstrated to pose a risk less than one in a million per year, would be ‘broadly acceptable’. For practical purposes, therefore, HSE used this criterion as the basis of what would be regarded as ‘no danger’ for the purposes of sections 3(6)(b) and 5(3)(a) of NIA65. Compliance with this criterion would normally mean that the nuclear regulator (then HSE, now ONR) could remove the site from regulatory control under NIA65 – i.e. allow the site to be delicensed (para. 10).

173. Paragraph 11 of the delicensing criterion document explained that legislation such as the Radioactive Substances Act 1993 (and the exemption orders made under it) and the Basic Safety Standards Directive (Euratom 96/29) that set standards for the protection of human health were also used to inform decisions on what constitutes ‘no danger’. Under the Radioactive Substances Act 1993, in line with government policy, regulators did not seek further reductions in discharges where exposures of members of the public were optimised and less than 20 microSieverts per year. Annex 1 of the Basic Safety Standards Directive (Euratom 96/29) allowed member states to exempt a practice where appropriate and without further consideration if doses to members of the public were of the order of 10 microSieverts or less per year. HSE was of the view that this dose limit broadly equates to the 1 in a million per year ‘no danger’ criterion as well as being consistent with other legislation and international advice relating to the radiological protection of the public.

174. Paragraph 1.4 of the 2008 delicensing guidance explained that the HSE policy was developed following extensive public consultation.

175. It is important to note that we do not propose to re-interpret the “no danger” criterion in NIA65. Instead, we propose to amend NIA65 so that there is an alternative route, based on internationally agreed criteria (the Paris Decommissioning Exclusion[119]), to exit the requirement for nuclear third-party liability and subsequently, to allow ONR to revoke the site licence.

176. In broad terms, the criteria in the Paris Decommissioning Exclusion are that there is no nuclear safety risk and that radiological risks to the public are low, with an effective dose to the public, even in accident scenarios, of less than 1mSv. The 1mSv dose limit was recommended by the International Commission on Radiological Protection in 1990 and 2007 (ICRP60 and ICRP 103 respectively) and is incorporated into UK law in many places, including Schedule 3 of the Ionising Radiations Regulations 2017[120]. The Decommissioning Exclusion also allows the regulator to take into account “any additional aspect relating to the magnitude and severity of potential nuclear damage” and we propose to include this option in the implementation.

177. The “no danger” route would remain as an option, for example, for sites which are not covered by the scope of the Paris Decommissioning Exclusion or for sites for which are not regulated by the relevant environment agency. For example, the Low-Level Waste Repository at Drigg in Cumbria would not be in scope of the Paris Decommissioning Exclusion since it is not a nuclear site in the process of being decommissioned[121]. In these cases, we propose to retain the existing “no danger” route to ending the period of responsibility for nuclear third-party liability.

178. Under the proposals, radiological protection of workers would continue under the Ionising Radiations Regulations, which would be administered by HSE instead of ONR. These regulations were updated to align with the most recent version of the Basic Safety Standards Directive in 2017. Radiological protection of the public would be regulated under the Environmental Permitting Regulations 2016 (in England and Wales) and under the Environmental Authorisations (Scotland) Regulations 2018 in Scotland.

[119] The OECD Nuclear Energy Agency’s “Decision And Recommendation Of The Steering Committee Concerning The Application Of The Paris Convention To Nuclear Installations In The Process Of Being Decommissioned”, 2014

[120] https://www.legislation.gov.uk/uksi/2017/1075/schedule/3/made: “Other persons
5. Subject to paragraph 6, for the purposes of regulation 12(1) the limit on effective dose for any person other than an employee or trainee referred to in paragraph 1 or 3, including any person below the age of 16, is 1 mSv in any calendar year”.

[121] Furthermore, no matter how much the radiation levels had decayed, the LLWR site would never meet the criteria in the Low-Level Waste Exclusion, since these apply to the radiation from the waste at the time at which it was first deposited in the facility. We therefore consider that the “no danger” route would be the most appropriate method for ending nuclear third-party liability for these sites unless the OECD NEA Steering Committee develops another route specifically for them in the future.

# Annex B: Key dates for each site

179. **Table 20** shows three key dates for each nuclear site: the date at which the site meets the Paris Convention Decommissioning Criteria under the proposals (and therefore exits the nuclear liability regime), the point at which the site is de-licensed (under the proposals) and the point at which "no danger" would be reached (under the current framework).

180. The final row shows the reduction in time to re-use or re-develop the site under the proposals.

181. **Table 20** shows the key dates for each disposal facility for low level radioactive waste that is affected by the proposals.

**Table 2010: Key dates for each nuclear site**

| Site | Winfrith | Magnox sites | Dounreay | GE Healthcare Amersham (part of site) |
|---|---|---|---|---|
| **Date at which "No danger" criterion met – under the current framework** | 2048 | 2090 | 2100 | Not applicable |
| **Period during which excavation and transport of waste are required under the current framework but not under the proposals[122]** | 2024-2032 | 2024-2080 | 2024-2040 | Not applicable |
| **Date at which Decommissioning Exclusion Criteria are met under the proposals** | 2032 | One site every five years from 2035 to 2080 | 2041 | 2025 |
| **Date at which site can be de-licenced (and assumed point when site can be reused in some way) under the proposals** | 2032 | One site every five years from 2035 to 2080 | 2041 | Not applicable – operator intends to delicense at no danger[123] |
| **Period for which regulatory savings can be made under the proposals** | 2033-2048 | Between 2035-2090, with savings increasing every 5 years as sites are delicensed | 2041-2100 | Not applicable |
| **Period for which liability premium savings can be made under the proposals** | 2033-2048 | As above | 2041-2100 | 2026-2035 |
| **Reduction in time to develop/re-use the site (years) under the proposals** | 15 | 10-55 | 59 | Not applicable operator intends to delicense at no danger |

[122] Note – this does not mean that there will be no excavation of waste during this period; it means that excavation of waste that could safely be left on-site, subject to environmental permitting, will not take place.

[123] To the best of our information at present. GE Healthcare may amend their proposals.

**Table 21:11 Key dates for disposal facilities for low level waste**

| | Date at which the first permit to accept radioactive waste was received | Assumed date at which the site might apply for the LLW Exclusion | Estimated closure date | Estimated period over which liability savings might be made |
|---|---|---|---|---|
| East Northants | 2002 | 2024 | 2042 | 2024-2041 |
| FCC Lillyhall | 2011 | 2024 | 2051 | 2024-2050 |
| Clifton Marsh | 2012 | 2024 | 2052 | 2024-2051 |
| Port Clarence | 2021 | 2024 | 2061 | 2024-2060 |

# Annex C: Estimates of avoided waste generation and annual profiles of avoided waste under the proposals

182. Under the proposals, some sub-structures, such as reactor bioshields[124], ponds and foundations may be suitable for disposal on-site, subject to environmental permit[125]. The NDA has provided estimates of the amount of sub-surface material that could potentially be left in situ.

### *Estimates of volumes of material at the 10 Magnox sites*

183. Bradwell is the Magnox site for which the NDA has the greatest amount of detail on estimated waste from sub-structures and buildings. It has been assumed that Bradwell is typical of the other Magnox sites, and costs and spend profiles developed for Bradwell have been scaled to the other Magnox sites. The installed capacities of the Magnox sites ranged from 240 megawatts (MW) (Chapelcross) to 980 MW (Wylfa). Bradwell's capacity was at the lower end of this range at 242 MW. It is important to note that the amount of waste is not directly correlated with the capacity of the plant, and the NDA consider that Bradwell is still typical of the others because of the design of the sites.

184. Based on architectural drawings, it has been assumed that between 5% and 20% of items such as reactor bioshields, ponds and other concrete structures are subsurface, and therefore candidates for leaving in situ. Applying these percentages to the waste inventory therefore yields a high and low estimate of the potential volumes of waste whose generation might be prevented if sub-surface material is left in situ under the proposals. Note that these are **packaged** waste volumes that include the effect of packaging for disposal.

### *Estimates of volumes of material at Winfrith*

185. Winfrith will be the first complex UK nuclear site to reach its end state and is the site for which we have the most accurate estimates of potential savings. Magnox Ltd has carried out a detailed characterisation of the sub-structures and soils[126], and has calculated the costs of reaching the "no danger" criterion based on engineering feasibility studies and proprietary cost models. This study took account of the complexity of excavation (based on the depth, accessibility and volume of material being removed). It includes estimates for hiring equipment, employment of suitably qualified personnel (based on standard industry cost) and ground water pumping. The report also includes a safety case to establish which parts of the lightly contaminated sub-structures/soils could potentially be left in situ.

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[124] Specialised concrete shield around a nuclear reactor.

[125] Material would only be considered suitable for on-site disposal if t has the right chemical and physical characteristics (i.e. non-putrescible, non flammable, chemically and physically relatively stable). An environmental permit will only be granted if the material is suitable. It should be understood that much of the demolition material will not be suitable for disposal on-site and will still need to be transported to appropriate disposal facilities. For example, nuclear sites often contain asbestos, which needs to be disposed of at permitted disposals.

[126] "Winfrith Interim End State Cost Model (for NDA Review).xls – spreadsheet received from Winfrith. The associated report "Site Decommissioning and Remediation: Stage B: Winfrith Site End State Determination" report ES(17)P154, Magnox Ltd does not separate out excavation and disposal costs.

### *Estimates of volumes of material at Dounreay, Harwell and Sellafield*

186. Characterisation reports of sub-structures and soils at the other sites under consideration are also available, but detailed modelling of the costs of excavation at these sites has not yet been undertaken. Instead, the Site Licence Companies have provided approximate estimates based on the characterisation of each site and engineering judgement.

187. **Table 22** provides the NDA's estimates of volumes of LLW and VLLW from the excavation of sub-structures that might be left in place at each site (Winfrith, Dounreay, each Magnox site, Harwell and Sellafield) under the proposals. **These estimates are for the whole of the programme; for example, for the 10 Magnox sites, they include estimates of waste expected to be removed up to 2080.**

188. The NDA has also provided a time profile of avoided waste generation for Winfrith, Dounreay, the Magnox sites, Harwell and Sellafield, based partly on the NDA 2019 Radioactive Waste Inventory[127]. These figures have been combined to produce annual estimates of waste generated as shown in Annex C, Figure C1.

**Table 2212: Estimates of avoided generation of waste under the proposals from the NDA.**

| | Very Low-Level Waste (VLLW) volume avoided | | Low-Level Waste (LLW) volume avoided | | Proportion within the period 2024-2043 as calculated from the profiles in Annex D |
|---|---|---|---|---|---|
| | Volume – low estimate ($m^3$) | Volume - high estimate ($m^3$) | Volume - low estimate ($m^3$) | Volume - high estimate ($m^3$) | |
| Winfrith | - | - | 3,515 | 5,053 | 100% |
| Magnox estate | 6,400 | 6,400 | 44,255 | 98,265 | 34% |
| Dounreay | - | - | 25,180 | 30,169 | 100% |
| **Total** | **6,400** | **6,400** | **72,950** | **133,487** | |

189. **Table 22** (above) shows the avoided volumes of waste generated from decommissioning. These apply to the hundred-year period 2024-2123. The final column shows the proportion excavated under the current framework in the period 2024-2043. To estimate the total volume of waste whose generation might have been prevented between 2024 and 2043, we apply the percentages in the final column to the low and high estimates for both LLW and VLLW separately for each site and sum. Thus, the total volume of waste whose generation might be prevented between 2024 and 2043 is

[127] NDA. 2019 UK Radioactive Waste Inventory:. December 2019

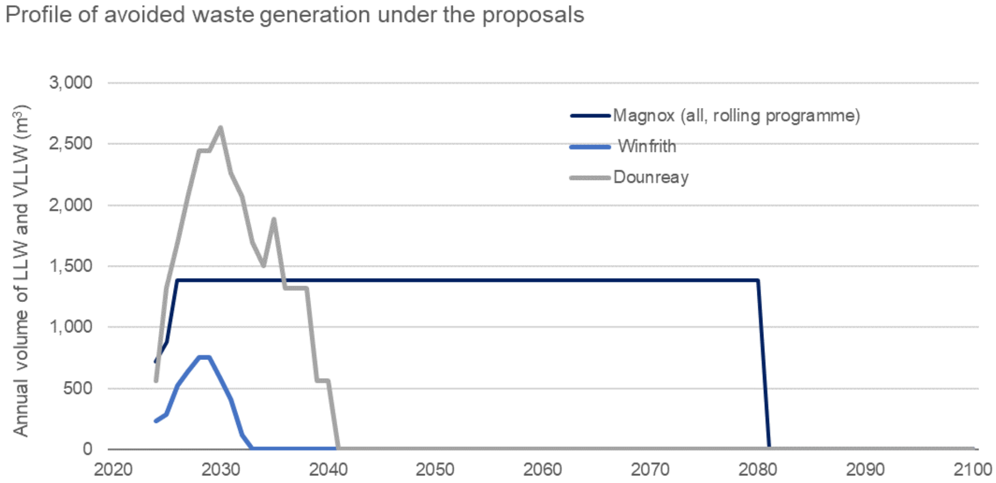
estimated as being between around 46,000 and 71,000$m^3$. The central value is approximately 58,000$m^3$.

190. It should be noted that most of the avoided waste generated has been classified as LLW, rather than VLLW. This is based on the NDA's best understanding at present.

191. The NDA has supplied annual profiles of the volume of avoided waste under the proposals **Table 2212** as shown in Figure C1. Note that the profile of savings from the proposals would be expected to follow the profile of avoided waste generation.

192. As shown in figure C1 (below), site excavation under the current framework is expected to be completed by 2032 (Winfrith), 2040 (Dounreay) and 2097 (Magnox sites).

**Figure C1: Annual profile of avoided waste generation under the proposals**



## Annex D: Estimated savings from transport and disposal of material left in situ under the proposals

193. Disposal costs are calculated by multiplying estimates of avoided waste generation (**Table 22**, Annex C) by disposal costs. Disposal costs were provided by the NDA (updated Dec 2019) and are shown in **Table 2313** (below):

**Table 2313: Disposal costs**

| | VLLW | LLW | |
|---|---|---|---|
| | | Low | High |
| Disposal cost £/m3 | 500 | 3,100 | 7,552 |

194. Results are shown in **Table 24** (below).

**Table 2414: Estimate of savings associated with not needing to transport and dispose of waste under the proposals (undiscounted and over the period 2024-2123) (2020 £m) (BEIS calculation using NDA estimates above), rounded to 2 significant figures**

| (2020 £m savings (undiscounted) | Savings from avoided transport of Very Low-Level Waste (VLLW) | | Savings from avoided transport of Low-Level Waste (LLW) | |
|---|---|---|---|---|
| | **Low estimate** | **High estimate** | **Low estimate** | **High estimate** |
| Winfrith | 0.0 | 0.0 | 12 | 40 |
| Magnox estate | 3.4 | 3.4 | 150 | 790 |
| Dounreay | 0.0 | 0.0 | 83 | 240 |
| **Total** | **3.4** | **3.4** | **240** | **1,100** |

195. **Table 25Table 2515** (below) shows NDA estimates of savings associated with not needing to transport and dispose of waste. These apply to the hundred-year period 2024-2123. The final column shows the proportion excavated under the current framework in the period 2024-2040.

**Table 2515: Estimate of savings associated with not needing to transport and dispose of waste under the proposals for use in the cost-benefit analysis (undiscounted) (2019) (rounded to 2 significant figures).**

| Site | Estimated undiscounted savings for transport, processing and disposal of all avoided waste (LLW and VLLW) 2020 £m 2024-2123 (**note: hundred-year period**) | Duration | Proportion of savings in the period 2024-2040 |
|---|---|---|---|
| | Estimated by NDA | | |
| Winfrith | 26 (12 – 40) | Savings occur up to 2032. | 100% |
| Magnox (10 sites) | 470 (150 – 790) | Savings occur up to 2080 | 34% |
| Dounreay | 160 (80 – 240) | Savings occur up to 2040. | 100% |

## Greenhouse gas savings associated with transport savings

196. **Table 26** shows the distance to the nearest disposal facility for LLW and VLLW for each site

**Table 2616: Distance to nearest LLW and VLLW facility for each site**

| **Site** | | **Distance to: (km)** | |
|---|---|---|---|
| | | **LLW Repository or Dounreay vaults** | **Nearest VLLW Facility** |
| Magnox sites | Bradwell | 562 | 26 |
| | Berkeley* | 408 | 212 |
| | Chapelcross* | 107 | 81 |
| | Dungeness A | 624 | 266 |
| | Hinkley Point A | 498 | 302 |
| | Hunterston A | 285 | 259 |
| | Oldbury | 419 | 223 |
| | Sizewell A | 571 | 187 |
| | Trawsfynydd | 314 | 191 |
| | Wylfa | 360 | 237 |
| Dounreay | | 5 | 5 |
| Winfrith | | 584 | 307 |

# Annex E: Environmental Monitoring Periods

197. Under the current framework, monitoring of radioactivity will be required for around 5 years, starting 5 years before the point of “no danger”. The only site for which we have clear information on monitoring under the proposals is Winfrith, and, in this case, a 30 year monitoring period will be required, but with a lower annual cost (because the specification of the equipment is likely to be lower). We have estimated that this monitoring will start 5 years before the “decommissioning exclusion criteria” are met.

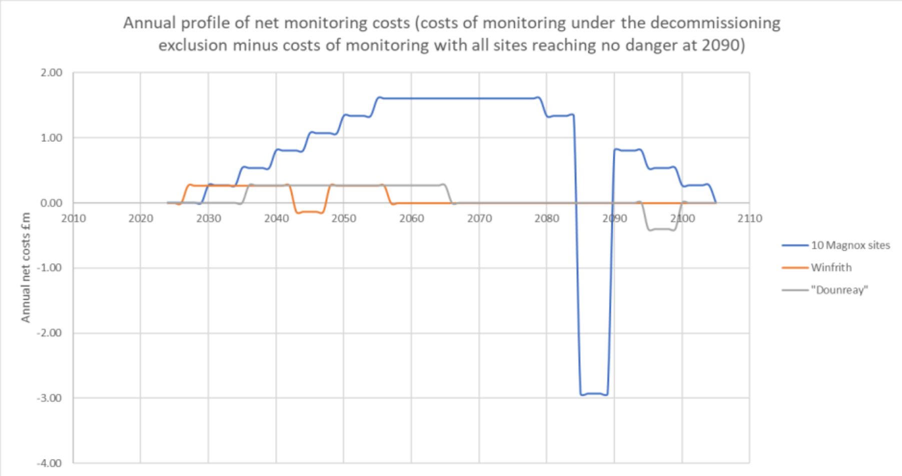
198. In the absence of other data, we have assumed that the same arrangements will apply at Dounreay and at the Magnox sites.

199. Given that the Magnox sites will be delicensed on a rolling basis from 2035 to 2080, the environmental monitoring periods will also be staggered. See **Table 27** (below).

**Table 2717: Environmental monitoring periods under the current framework and the proposals for each site**

| Site | Under current framework | | Under new proposals | |
|---|---|---|---|---|
| | Environmental Monitoring Start Date (5 years before the “no danger” point) | Environmental Monitoring End Date | Environmental Monitoring Start Date (5 years before the Decommissioning Exclusion point) | Environmental Monitoring End Date |
| Winfrith | 2043 | 2047 | 2027 | 2056 |
| Dounreay | 2095 | 2099 | 2036 | 2065 |
| Magnox site 1 (Trawsfynydd) | 2085 | 2089 | 2030 | 2059 |
| Magnox site 2 | 2085 | 2089 | 2035 | 2064 |
| Magnox site 3 | 2085 | 2089 | 2040 | 2069 |
| Magnox site 4 | 2085 | 2089 | 2045 | 2074 |
| Magnox site 5 | 2085 | 2089 | 2050 | 2079 |
| Magnox site 6 | 2085 | 2089 | 2055 | 2084 |
| Magnox site 7 | 2085 | 2089 | 2060 | 2089 |
| Magnox site 8 | 2085 | 2089 | 2065 | 2094 |
| Magnox site 9 | 2085 | 2089 | 2070 | 2099 |
| Magnox site 10 | 2085 | 2089 | 2075 | 2104 |

**Figure E1: Annual profile of net environmental monitoring costs (costs under the decommissioning exclusion minus costs that would apply under "no danger")**



# Annex F: Profile of Liability Savings and Regulatory Savings

200. The dates in Annex B can be used to establish the time profile of liability savings and regulatory savings.

201. We assume that liability savings from the proposed Decommissioning Exclusion Regulations will start at the date at which the Decommissioning Exclusion is reached for each site and will continue until the “no danger” condition would have been reached for that site. These dates are given in Annex B. For the Magnox sites, there is a rolling programme of decommissioning (as described in Annex B). See Figure F1 for the annual profile. Note, however, that these were calculated on the basis that the NDA sites would have private insurance to cover nuclear third-party liability. As of 01/01/2022, the UK Government has taken on this responsibility for the NDA sites (but not for GE Healthcare). For this reason, the figures given below are an over-estimate.

202. We assume that regulatory savings will start from the year at which each site is delicensed (see Annex B) and continue to the year at which the “no danger” criterion would have been reached for that site. See Figure F2 for the annual profile.

203. We assume that low level waste facilities that are eligible for the LLW Exclusion will apply as soon as the regulations come into effect and that savings site will start in 2024 and continue throughout the appraisal period of 2024-2043. As discussed in paragraph 167167, the annual savings per site are £190,000. See Figure F3.

**Figure F1: Profile of liability cover savings from the Decommissioning Exclusion**

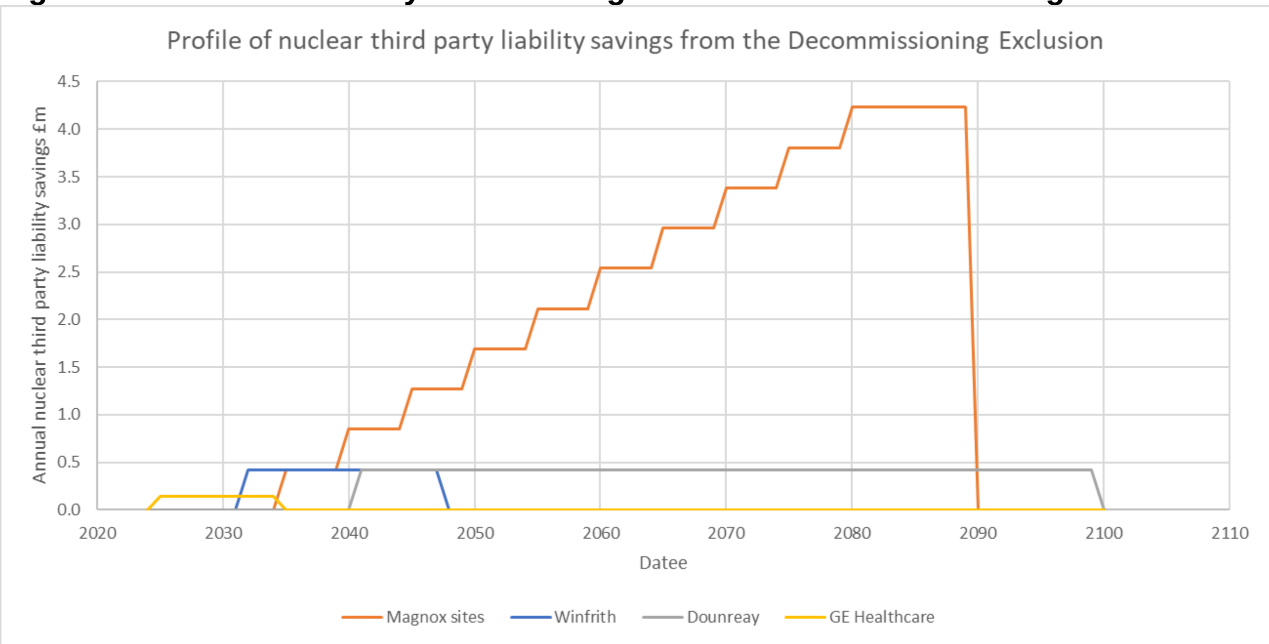


**Figure F2: Profile of Regulatory Savings (nuclear licence fees and costs)**

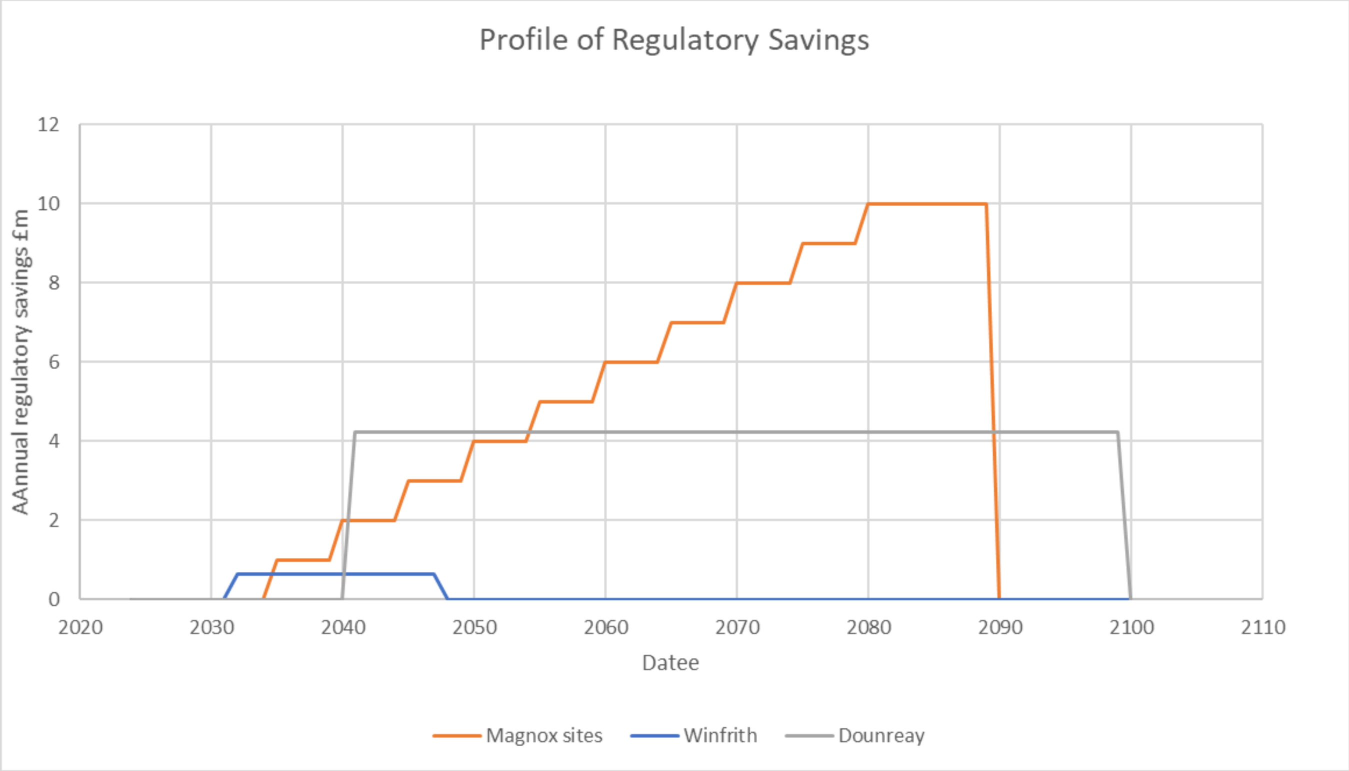
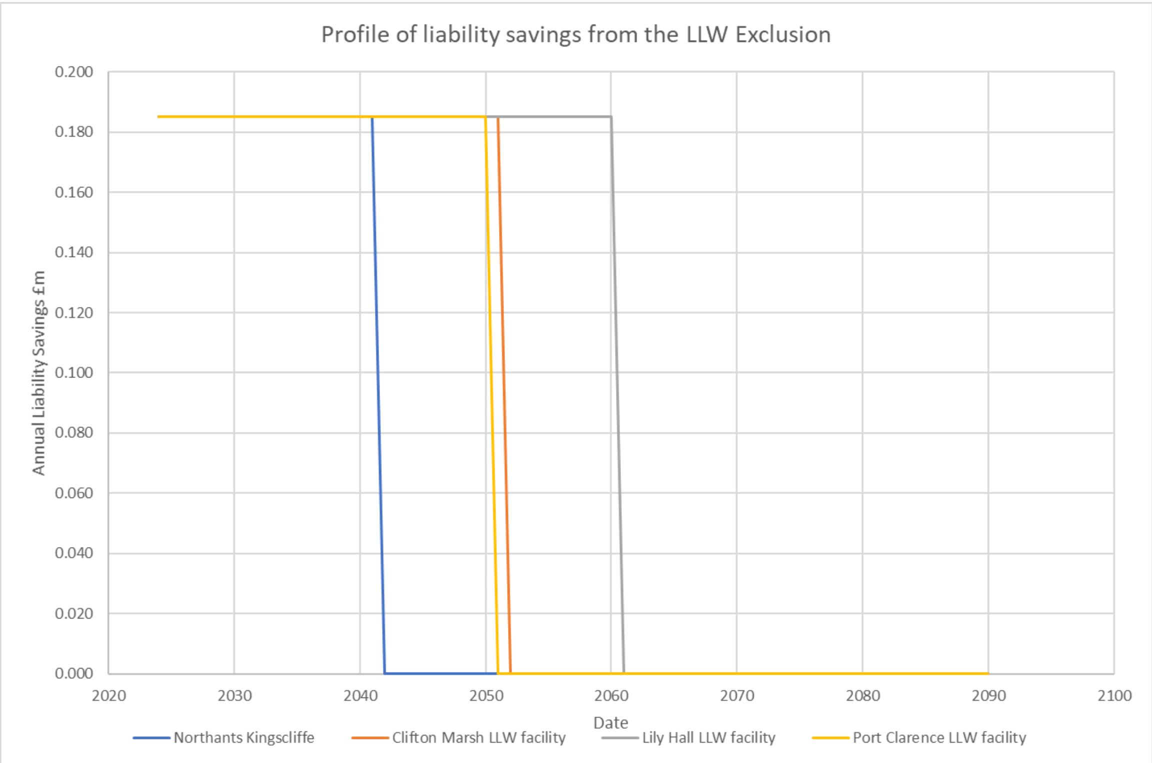



**Figure F3: profile of liability cover savings from the LLW Exclusion**



# Annex G: Estimated savings from excavation, transport and disposal of material left in situ under the proposals at Sellafield and Harwell over the next 100 years

204. **Table 2818 28** (below) shows the undiscounted estimated savings due to reduced excavation and transport and disposal costs at Sellafield and Harwell under the proposals. These estimates are based on data from the NDA. Characterisation of contaminated soils and sub-structures at Sellafield is less well advanced than at other sites, which explains the large degree of uncertainty in these figures. Estimated regulatory savings have not been provided, but would be expected to be small relative to the excavation and transport/disposal costs. These figures have not been used in this impact assessment but are included to provide an estimate of the scale of potential savings from the proposals at Sellafield.

**Table 2818: Undiscounted estimates of excavation, transport/disposal savings and regulatory savings at Sellafield and Harwell over the next 100 years under the proposals (rounded to 2 significant figures)**

| Site | Estimated savings for excavation, transport, processing and disposal 2020 £m (undiscounted) over the period 2024-2123 (**note: hundred-year period**) | |
|---|---|---|
| | Low | High |
| Sellafield | 8,000 | 8,300 |
| Harwell | 33 | 48 |

**Title:** Downstream Oil Supply Resilience Bill - Final Impact Assessment
**IA No**: BEIS008(F)-18-CNRD
**RPC Reference No:** RPC-BEIS-5173(1)
**Lead department or agency:** Department for Business, Energy and Industrial Strategy.
**Other departments or agencies:**

# Impact Assessment

**Date: 06/07/2022**
**Stage:** Final
**Source of intervention:** Domestic
**Type of measure:** Primary legislation
**Contact for enquiries:** EnergyBill2021@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Most Likely Option** (2019 prices 2020 present value) | | | |
|---|---|---|---|
| **Total Net Present Value** | **Business Net Present Value** | **Net cost to business per year** (EANDCB in 2019 prices) | **Business Impact Target Status** |
| **£ 21.5m** | **-0.3m** | **£0.03m** | Not a regulatory provision |

**What is the problem under consideration? Why is government intervention necessary?**

There is a risk of disruption to the UK fuel supply market from the sudden loss of any one of a number of critical supply infrastructure sites. In recent years there have been operational and financial events leading to sudden closures or disruptions at UK oil refineries, terminals and pipelines. The risk of market disruption has increased with the closure of commercially redundant assets, which reduces the ability of the market to replace lost supplies. In 2020, the sector was significantly impacted by the Covid-19 pandemic putting operational and economic strain on all downstream oil operators. Market failures in the sector prevent consumers from fully insuring themselves against fuel supply disruptions and limit the incentives on suppliers to mitigate these risks. The assessment is that the magnitude of the risk requires government action.

**What are the policy objectives and the intended effects?**

The objective is to improve the resilience of the downstream fuel supply market and reduce the risk of disruption to economic activity from the loss of fuel supplies. The package of measures will improve the ability of government and industry to manage these risks. Mandating the provision of information to government will allow better risk assessment and design of mitigating measures.

**What policy options have been considered, including any alternatives to regulation?**

Government has explored the scope for encouraging voluntary action by the sector but there is insufficient support from market participants, as the necessary spend would not have a commercial return. This reflects the market failures in the sector. The government also explored options like full regulation of the downstream oil sector with a licensing regime and a new regulatory body to enforce standards and mandate resilience solutions, similar to the model applied to gas, electricity, telecoms and water sectors among others. Unlike these networked sectors, there is no natural monopoly in the downstream oil sector and therefore the government considers that the underlying rationale for an economic regulator is missing and that such a regime would be disproportionate to the risk. The Preferred Option is a package of measures that enables the government to collect evidence on the fuel supply risks and, subject to individual value for money assessments, take action to mitigate these when required. The package will complement existing resilience measures to reduce the risk of failure in major infrastructure nodes, such as the lease contract for the reserve tanker fleet and a programme to provide military drivers for fuel tankers. The measures are backstop powers including financial assistance which is excluded from regulatory powers.

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:** December/2025

| | | | | |
|---|---|---|---|---|
| Does implementation go beyond minimum EU requirements? | N/A | | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** N/A | | **Non-traded:** N/A | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______ Date: 24/06/2022

# Summary: Analysis & Evidence

**Description:** Enable government to collect evidence on risks to fuel supply chain and take action to mitigate these. Costs and benefits expressed relative to *do nothing.*

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 10 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low: 1.3** | **High: 49.1** | **Best Estimate: 24** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | 0.02 | | 0.04 | **0.3** |
| **High** | 0.02 | | 0.09 | **0.8** |
| **Best Estimate** | 0.02 | | 0.04 | **0.3** |

**Description and scale of key monetised costs by 'main affected groups'**

Ongoing costs over the appraisal period are small and arise from providing information to the government (£0.4m). These costs would mostly fall directly on businesses in the downstream oil industry (above a certain threshold).

**Other key non-monetised costs by 'main affected groups'**

The costs of the Resilience Direction measure have not been included in the NPV because it is designed as a backstop measure, with no immediate intent to use. However, illustrative costs are provided in the main body of the IA. However, the policy has been designed to minimise costs to the industry.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | 0.0 | | 0.2 | **2.1** |
| **High** | 0.0 | | 5.8 | **49.5** |
| **Best Estimate** | 0.0 | | 2.9 | **24.7** |

**Description and scale of key monetised benefits by 'main affected groups'**

The key benefit is the reduced risk of a loss of fuel supplies for consumers (e.g. for transport purposes) and those who consume oil-intensive goods and services. Petroleum products are essential for UK economic activities, and an indicative monetised impact of disruption has been estimated using a stylised approach based on oil to GVA intensity ratios and adjusted by the annual risk of failure. BEIS estimates that the closure or disruption of a key supply point could lead to a supply shortfall of refined petroleum products to regional markets lasting between 3 to 10 days, and BEIS illustrates the current risk of economic impact arising from the disruption. This framework has been applied to develop a range of benefits arising from the provision of information measures, with the aim of illustrating how even minimal reductions to the duration of a disruption would provide benefits to user that are multiples of the costs of the measures for the industry.

**Other key non-monetised benefits by 'main affected groups'**

The benefits of the Resilience Direction are not monetised, but the measure would be applied subject to value for money considerations. The benefits of increased public confidence in national fuel supply resilience, which may reduce the risk of panic buying during an incident have also not been monetised.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | 3.5 |
|---|---|---|

The analytical framework for estimating the economic cost of an oil disruption is stylised and only provides an indicative estimate of the economic impact. Many uncertainties such as scale, duration and frequency of supply disruptions as well as the degree of substitutability must be considered when calculating the scale of the economic impact from a supply disruption. These uncertainties have been factored in by developing high and low estimates based on the most conservative end of the range of benefits - aimed primarily at illustrating how benefits are likely to be a multiple of the costs under all plausible scenarios.

**BUSINESS ASSESSMENT**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** 0.04 | **Benefits:** 0 | **Net:** -0.04 | 0.17 |

# Contents

# 1 RATIONALE FOR THE PROPOSED RESILIENCE MEASURES

## 1.1 Problem Under Consideration

1. The downstream oil sector comprises over 200 companies involved in the refining, importing, distribution and marketing of oil products[1] (particularly transport fuels), with many more involved in retail. The UK market for oil products is a mature market and between 2008 and 2019 demand has fallen by just under 9% and was relatively flat in more recent years. The Covid-19 pandemic led to a sharp temporary decline in demand for oil products as lockdown measures were introduced in the Spring. As these measures were eased over the summer demand recovered strongly.

2. At the UK level, the refining sector is also facing high levels of global competition and has gone through a process of restructuring to stay internationally competitive.[2] To maintain returns on their investments, companies throughout the sector have strived to maximise utilisation of their assets. The consequence has been:

    - fragmented supply chains with major oil companies, which used to run vertically integrated well-to-pump operations, divesting themselves of categories of assets or outsourcing some operations; and
    - relatively high utilisation rates and closures of redundant and inefficient assets. For example, currently there are six UK oil refineries, down from a high of 19 in 1975. UK refining capacity is down nearly one-third compared to 2008.

3. The fall in the number of key UK infrastructure assets has reduced the industry's spare capacity. This spare capacity resulted from historical investments and upgrades which used to be commercially viable but now have become less economical. The spare capacity acted as system resilience, and therefore the rationalisation and efficiency measures to minimise redundancy has increased the risk of a market disruption in the downstream oil sector[3] given the lower capacity to react to sudden supply and demand shocks. Covid-19 has increased spare capacity in the short term but has not removed the medium term challenge.

4. Risks that can lead to supply shocks include: operational accidents, industrial action, security threats including cyber-attacks, insolvency leading to liquidation, and severe weather. Failures of this sort in the infrastructure serving a regional market could be large enough to impact the efficiency of the market mechanism, halting the ability of the system to allocate fuel supplies, and generate substantial economic and social impacts.

5. Infrastructure failures are low-probability, infrequent events (see Section 2) but they could have a large economic impact, as crude oil and oil products support key sectors in the UK. The impact of Covid-19 has increased the commercial pressure on the sector.

6. In 2019, about 44% of the UK's energy consumption was from crude oil or oil products, and petroleum-based fuels provided 96% of the energy for the transport sector, with very limited substitutability. The importance of oil products makes it paramount to achieve an optimal level of supply security. Despite the reduction in demand for oil products during the Covid-19 pandemic, they remain essential to UK economic activity.

7. Owners of key assets take measures to mitigate risks where commercially viable but cannot avoid them entirely. In addition, the market adapts to supply shocks, and can adjust and redirect product flows to ensure delivery to customers. However, the current capacity for immediate response is limited as logistical and contractual constraints may make it impossible for the market to fulfil normal levels of demand. Transporting oil products over greater distances to supply a region where infrastructure has been disrupted can also place increased strain on the supply infrastructure not disrupted elsewhere – for example, if road tankers transporting oil products need to travel further to alternative supply locations,

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[1] http://www.ukpia.com/industry_information/industry-overview.aspx

[2] For example, with regards to competitiveness of the market and retailers passing through changes in crude prices, in January 2013, the Office for Fair Trading published the results of a Call for Information to investigate whether or not competition problems existed in the road fuels market. This included investigating concerns that pump prices rise quickly when the wholesale price goes up but fall more slowly when it drops. Their analysis found very limited evidence of this, and in general found that at a national level competition in the market is working well.
http://webarchive.nationalarchives.gov.uk/20140402142426/http://www.oft.gov.uk/OFTwork/markets-work/othermarketswork/road-fuel-CFI/

[3] **Downstream oil sector** refers to any persons involved in any part of the: import, supply, storage, distribution and or retail of crude oil and or oil products, into or within the United Kingdom (UK).

they will take longer to deliver fuel which in turn reduces the amount of tanker capacity available to the rest of the market at that point in time.

### *Current government measures*

8. The Government has analysed the level of resilience provided by the downstream oil sector (see Section 2 for an assessment of the baseline risks) and has already introduced measures to manage fuel supply disruptions.

9. The National Emergency Plan for Fuel (NEP-F) is part of the Government's suite of contingency planning for critical services and mitigates the worst impacts of major and sudden supply disruptions. The Plan sets out the Government's overall approach to maintaining continuity of supplies of fuel, and crisis measures to protect emergency services and other priority users if supply cannot be maintained. Measures that the Government can take to support supply include:

    - relaxing competition rules to enable suppliers to agree collective action, to support the development of alternative supply routes;
    - relaxing limitations on fuel tanker drivers' hours, to increase the capacity of the distribution system;
    - authorising the use of reserve road tankers, to provide extra capacity to the market and enable longer supply routes;
    - ordering the release of compulsory oil stocks during an international shortage of fuel; and
    - as a last resort, deploying military tanker drivers, to maintain fuel deliveries, including to enable use of the reserve tanker fleet if necessary.

## 1.2 Policy objectives and rationale for intervention

10. BEIS has a primary objective of ensuring that Great Britain[4] has energy supplies that are reliable, affordable and clean. In the downstream oil sector reliable energy supplies translates into ensuring fuel supply resilience, i.e. the ability to i) protect against, ii) react to, and iii) recover from any fuel supply disruption.

### *Market functioning in the downstream oil sector*

11. BEIS has assessed the extent of intervention required to maintain resilience in the downstream oil sector by reviewing the functioning of the market.

12. On the demand side, many consumers cannot effectively express their willingness to pay for secure supplies of fuel. In the UK, more than two-thirds of oil is consumed for transport purposes. Plane operators and large haulage companies can contract on a long-term basis for fuel supplies, and thus express their willingness to pay for secure supplies. However, most owners of private vehicles purchase motor fuel (diesel and petrol) on a "spot" basis, with little incentive or ability to contract long-term at the retail level or to hold stocks for periods of supply disruption.

13. Along the supply chain, wholesale fuel suppliers typically cannot increase prices in the short-term to respond to regional shortages, as their supply contracts are tied to internationally traded prices. Moreover, they can invoke force majeure contract clauses in the event of major disruptions. This limits their liability by enabling them to "walk away" from their supply obligation and consequently reduces their incentive to invest in resilience measures.

14. Fuel retailers may also not expect to capture the full value of scarcity during a disruption, limiting the incentives for them to invest in resilience measures. For example, the more visible players in the sector (e.g. oil majors, supermarkets) might be sensitive to media reporting of price rises and profiteering, which could damage their reputation and limits their ability to increase prices sufficiently in the event of a fuel shortage.

15. The competitive pressure and fragmentation in the retail sector also create barriers to collective action. In earlier stages of policy development, the department explored voluntary measures (see paragraph 20) to obtain regular information from the industry to monitor resilience in the sector. However, the risk

[4] The Bill provisions will cover the United Kingdom but BEIS has responsibility for fuel supply only in Great Britain.

of incurring extra costs without similar commitments from other companies meant that not all companies were willing to sign up to voluntary measures.

16. BEIS concluded that the level and types of market failures identified in the sector limit the efficiency of the pricing mechanism and the capacity of the sector to provide an optimal level of resilience against fuel supply disruptions.

## *Resilience improvements*

17. BEIS has identified three themes of solutions to address the risks that have emerged from the evolution of the downstream oil sector over recent years and from the market failures discussed above:

- Monitor: allowing BEIS to have information from the downstream oil sector to better understand the impact of potential disruptive events, and to use the information to support industry in improving fuel supply resilience;
- Protect: ensuring that owners of critical fuel infrastructure are financially sound and operationally capable, to align this sector with protections that apply in other critical service sectors; and
- Ensure: working with industry to develop their ability to maintain fuel supply in case normal supply arrangements are seriously disrupted.

18. BEIS has considered different approaches to implementing these solutions and has used minimising any disruption to market functioning as a key criterion to assess them.

## *Option considered: Full regulation of the sector*

19. BEIS considered full regulation of the downstream oil sector, with a licensing regime and new regulatory body to enforce standards and mandate resilience solutions. This is the model which applies to gas and electricity, telecoms and water sectors among others. Unlike these networked sectors there is no natural monopoly in the downstream oil sector and the underlying rationale for an economic regulator of this type is missing. A regulatory regime did not therefore seem proportionate or appropriate to the level of risk and types of market failures in the sector.

## *Option considered: Voluntary action*

20. BEIS analysed and explored whether the resilience of the downstream oil sector could be improved with voluntary action, but found insufficient support from market players, suggesting it would not be effective.

*Monitoring fuel supply resilience with voluntary action*

21. Several companies reported that they would comply with regulation but would not provide information to monitor supply resilience on voluntary terms. Lack of collective action across the sector would prevent BEIS from systematically identifying critical points, developing contingency plans or supporting decision making during an emergency.

*Ensuring and protecting fuel supply resilience with voluntary action*

22. BEIS has explored whether it could promote investment on a voluntary basis in fuel supply resilience across the downstream oil sector. BEIS found that stakeholders were reluctant to incur additional costs on a voluntary basis, due to strong competition. BEIS concluded that a voluntary agreement would be unstable, as operators could avoid the additional costs, but still benefit from the increased resilience. For instance, if some operators fund an emergency tanker fleet on a voluntary basis, other operators not participating in the scheme would also benefit from the release of reserve tankers during a supply disruption.

## *Evolution of the Preferred Option*

23. In October 2017, BEIS consulted on a draft proposal supported by an Impact Assessment (hereafter “the Consultation IA”)[5]. During the formal consultation, BEIS provided an initial view of the expected costs and benefits of each intervention. BEIS then published a Government consultation response setting out its thinking. Since then, BEIS has continued to engage with stakeholders, to develop its policy proposals and how they would be implemented. BEIS has considered calls from the industry for a

[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/69758/1779-downstream-oil-short-term-resilience.pdf

light-touch approach and has designed solutions that align with the structure of the fuel supply market and minimise any impacts on market dynamics or competitiveness.

24. The most significant change resulting from this work is that BEIS no longer intends to use this Bill to take forward the measures relating to 'industry schemes'. In the consultation document and government response, the lead scheme proposed under this power was the transfer of the costs and management of the Reserve Tanker Fleet (RTF) from government to industry. BEIS has concluded that the complexities and additional costs of setting up an industry-run scheme currently outweigh the benefits and it is more appropriate for BEIS to continue to lease and manage the RTF capability at this time.

25. The refinement in how the framework is applied and the government's decision to maintain public funding of the RTF has substantially reduced the scope of the regulatory intervention, so the range of benefits estimated differs substantially from that estimated in the Consultation IA (see a summary in Section 5).

26. Having assessed how the downstream oil sector market works and alternative approaches to improve fuel supply resilience, BEIS considers that the best option to Monitor, Protect and Ensure the sector is to introduce the following regulatory measures and powers:

   i. **Monitor**: Enhance information reporting to government to monitor fuel supply resilience (**"Information Reporting"**);

   ii. **Protect**: Enact a power that allows government spending to support supply resilience improvements (**"Government Spending"**);

   iii. **Ensure**: Enact a power to direct individual companies to take action that may be necessary to support resilience (**"Resilience Direction"**).

27. The Preferred Option at this stage is to introduce all the measures as a package in the form of a new primary legislation: the "Energy Bill" (hereafter the Bill). The Bill will apply to all operators and infrastructure in the Downstream Oil Sector with a supply handling capacity above the thresholds outlined in the Bill. The Bill will provide Government with the tools to identify fuel supply risks and support industry in ensuring fuel supply resilience, with further backstop powers to protect fuel supply resilience when required. BEIS will continue to work with industry to refine the proposed measures, so that the disruption to market functioning is minimal.

28. This final version of the Impact Assessment (hereafter the Final IA) outlines BEIS' final thinking on the rationale underpinning the Bill and the analysis of the potential impacts. The Government Spending power would come into place only under certain conditions, for example in conjunction with issuing a Resilience Direction, and the backstop nature of this spending direction means that the measure is not separately assessed in this Final IA.

29. The analysis begins by assessing the baseline risk, expressed as a risk- adjusted[6] economic impact arising from a disruption of fuel supplies to final customers. The costs and, where they can be quantified, benefits of the various measures are then assessed in turn with an overall summary of cost and benefits finally provided[7]. As detailed in the following sections, BEIS concludes that the costs of the regulatory intervention are well below the possible economic benefits of reducing disruptions to fuel supplies.

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[6] The risk adjusted impact is the annual economic impact obtained by adjusting the full impact of a single disruption according to the probability of occurrence.

[7] This Impact Assessment analyses only the Regulatory measures and does not further assess the Government Spending measure proposal, although it forms part of the Preferred Option. For further information about the Government Spending proposal, refer to the Consultation IA or to the Government Response to stakeholder comments.

# 2 REVIEW OF BASELINE LEVELS OF RISKS AND IMPACTS

30. BEIS considers that the benefits of improved resilience in the downstream oil sector arising from implementing the Preferred Option can be measured in terms of a lower economic impact caused by a fuel supply disruption event. BEIS has assessed the baseline level of risks of supply disruption following a three-step methodology that estimates:

    1. The likelihood of a sudden interruption to fuel supplies or closure of key infrastructure due to operational or financial risk;
    2. The volume and duration of fuel supply disruptions; and
    3. The estimated economic impact of a given supply disruption.

31. The analytical framework to assess the monetary impacts of a disruption is based on the methodology that Deloitte developed in their "Downstream oil - short term resilience and longer-term security of supply" report.[8] BEIS considers the Deloitte based methodology the best approach available to provide a stylised, indicative assessment of the range of economic costs of disruption with an analytical effort proportionate to the intervention. Deloitte's methodology was also used in the Consultation IA to produce initial estimates of economic impacts and has been refined following feedback from stakeholders (see paragraph 48 onwards for details).

32. The measures in the Preferred Option will complement the benefits of the existing measures, and for this reason BEIS illustrates the baseline risk of disruption before any intervention of government. Similarly, BEIS estimates the benefits by considering how each measure can reduce the baseline level of risk on its own and by operating in parallel with other measures.

33. The key sources of evidence used to estimate the baseline risks[9] are:

    - Statistical data collected by BEIS on the supply chain through surveys (some on a statutory basis, some voluntary);
    - Data from external commercial providers;
    - External expert reports, such as the Deloitte study of the UK petroleum retail market;[10]
    - Information submitted to BEIS through the industry consultation.

## 2.1 <u>Step 1 - Identifying the likelihood of a fuel supply disruption</u>

34. Disruption events in the downstream oil sector vary significantly. Often there are small scale disruptions that the industry can cover by drawing on spare asset capability and/or stocks to avoid a disruption to consumer supplies. These buffers can delay and often completely absorb fuel supply disruptions, and are referred to as "**Operational Disruption Events**". These types of disruptions are excluded from any estimation of risk, as the supply to consumers is unaffected.

35. For the purposes of this IA, only large unplanned disruptions of assets lasting for three weeks with no operational capability during the disruption have been included. Following Deloitte's approach,[11] these are referred to as **"Consumer Disruption Events"**, i.e. where there is not enough spare capacity in the sector to cover the supply shortfall, leading to a market disruption[12]. The constraint in responding to these incidents relates to supply logistics within the UK meaning there are risks of regional shortages. Given oil product markets are global in scope, with diverse sources of supply, it is judged that there is no plausible prospect of shortage of fuel available for import to the UK.

36. The main disruption events in the sector include:

    - **Major operational incidents** e.g. there have been fires at four refineries as well as the Buncefield oil terminal over the last 18 years. The Buncefield fire disrupted fuel supply to

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[8] https://www.gov.uk/government/publications/downstream-oil-short-term-resilience-and-longer-term-security-of-supply

[9] For more information on data sources see Annex A, "Data Sources".

[10] "Study of the UK Petroleum Market", Deloitte, 2012 https://www.gov.uk/government/publications/study-of-the-uk-petroleum-retail-market

[11] Deloitte approach considers *"an unscheduled disruption to the entire refining unit caused by mechanical failure. As part of this scenario, […] the "pipeline and docking facilities are unaffected to isolate the impact of a loss in refining capacity. […] The disruption is assumed to last three weeks, although the duration of an unplanned shutdown due to significant mechanical failure could be much longer. Although this is a comparatively short disruption, this would be considered a major infrastructural event"*

[12] see more details in "Annex C, Estimating supply shortfalls: Methodology"

Heathrow for months and while the airport has multiple supply routes and suppliers were able to find work-rounds over time, there was an estimated cost to the aviation industry of £250m.[13] The 2007 fire at Coryton refinery on the Thames estuary (which closed in 2012) reduced fuel throughput by >50% and led to local shortages. The 2018 fire at the Shell Higher Olefin plant;

- **Financial failure (insolvency)** e.g. Petroplus, which led to Coryton refinery's closure in 2012 (without supply disruption);
- **Malicious/criminal disruption**, including cyber and conventional attack, control by unfriendly states and illegal pipeline tapping. The cyber threat is currently being assessed - risks are low but can change. Tappings[14] have become more frequent, although there is some indication that rapid detection due to new industry investment in leak detection systems has started to reverse this trend and none have yet led to major incidents; and
- **Industrial action[15]** e.g. tanker drivers. This has been the major cause of supply disruption in recent years. As part of its contingency planning, the Government is working with the downstream oil industry, including haulage companies, to maintain a capability within the Armed Forces to make fuel deliveries in the event of a serious disruption to normal deliveries due to industrial action by fuel tanker drivers.[16]

37. These risks include accidents, industrial action and maintenance overruns, and are referred hereafter as "operational failures". This IA also assesses the risk of financial failure of the operating company, followed by an inability to maintain supply, which could cause a significant market disruption, as both operational and financial failure could lead to a Consumer Disruption Event.

*Estimating the likelihood of operational and financial failure leading to a loss of supply*

38. BEIS has assessed the evidence on the likelihood of both operational and financial failure. The assessment distinguishes between refineries, terminals and jetties and involved consulting the Health and Safety Executive as well as officials across BEIS (see Table 1 for a summary)[17].

39. The risks of operational failure are based on the best available evidence. This considers historical reporting of significant incidents as well as stakeholder views. The probability assessment also reflects the increased risk arising from the closure of commercially redundant assets in recent years, which has reduced the ability of the market to replace any lost supply (i.e. probabilities do not entirely reflect the historical occurrence of disruption events). The likelihood of a loss of operations incident leading to loss of supply is 1 incident every 10 years, spread across the 6 UK refineries (see Table 1). This means that the probability of a major disruption at each individual refinery is 1 in 60 years on average.

40. The corresponding estimates for a financial failure leading to loss of supply across UK refineries is 1 in 25 years (see Table 2). Estimates of the risk are lower for smaller fuel terminals used for storing and loading fuel and jetties (ports) used for loading/unloading fuel to/from tanker ships. For the risk of financial failure, a key uncertainty is future changes to market conditions. North-Western European refineries are known to be under financial pressure due to international competition; aging assets now producing a mix of fuel products which does not match demand; falling demand in recent years; and tighter environmental standards. Future oil prices and refining margins are uncertain and hard to predict, but increased volatility may increase the risk of insolvency. The long-term trend of decreasing oil demand[18] could lead to short-term increases in spare capacity (reducing risk). However, under-utilised infrastructure ceases to be economical and tends to be closed relatively quickly, either through managed closures or insolvency.

41. To estimate the expected annual risk of a supply disruption, the probabilities of operational and financial failure have been combined to calculate the probability of exactly one Disruption Event (either

[13] http://www.hse.gov.uk/comah/buncefield/miib-final-volume1.pdf

[14] Hot tapping, or pressure tapping, is the method of making a connection to existing piping without the interruption of emptying that section of pipe or vessel.

[15] The Trade Union Act 2016 introduces a 40% support requirement in important public services, which includes "transport services". This does not necessarily mitigate the risk of disruption. It does however include provisions to extend the notice period ahead of industrial action to 14 days, which allows increased time for contingency planning in response.

[16] https://www.gov.uk/guidance/preparing-for-and-responding-to-energy-emergencies#downstream-oil.

[17] Annex B "Likelihood of Loss of operations and Financial Failure" contains further details about the BEIS analysis.

[18] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/541332/LONG_TERM_TRENDS.pdf

operational or financial) occurring in any given year.[19] This was then weighted by the number of assets that if disrupted would lead to a supply shortfall (e.g. for terminals and jetties, the majority of assets could close, and the intra-regional infrastructure would have sufficient spare capacity to maintain supplies). This creates a combined national risk for one Consumer Disruption Event of:

- around 1 in 7 years or 13% for refineries on the basis that each refinery would lead to a supply shortfall if disrupted; and
- around 1 in 50 years or 2% (average) for terminals and jetties.[20]

### Table 1: National Likelihood of Loss of Operations leading to a Consumer Disruption Event

| Asset type | National Risk 1 in X years* | Evidence |
|---|---|---|
| Refinery | 10 | *Table 1, Summary of interruption scenarios*, Deloitte 2010 Report,[21] and historical experience. |
| Terminal | 115 | Terminals should be lower risk than refineries as they avoid the high-temperature and high-pressure refining processes and are typically smaller, with less product on site. It is judged that the national risk of loss of operations to be every 1 in 25 years, but that this will only lead to a loss of supply in around 22% of cases as in most cases alternative supply sources would have the capacity to completely mitigate the disruption. Therefore, the national risk loss of supply from terminals is 1 in 115. |
| Jetties | Immaterial | Judgement informed by stakeholder feedback. |

*Equals the probability of loss of operations multiplied by the proportion of the asset population that would could create a supply shortfall if disrupted (see Annex B and C).

### Table 2: National Likelihood of Financial Failure leading to a Consumer Disruption Event

| Asset Type | National Risk 1 in X years* | Evidence |
|---|---|---|
| Refineries | 25 | Judgement informed by stakeholder feedback. Aggregate assessment as ownership patterns and structures vary across the sector. |
| Terminals | 92 | Terminals should be lower risk than refineries, as they are not exposed to refining margins, and critical supply terminals are likely to have healthy throughput volumes. It is judged that the national risk of financial failure to be every 1 in 20 years, but that this will only lead to a loss of supply in around 22% of cases, in most cases alternative supply sources would have the capacity to completely mitigate the disruption. |
| Jetties | Never | Typical owners e.g. ports are unlikely to be at risk of sudden insolvency and liquidation. |

*Equals the probability of financial failure multiplied by the proportion of the asset population that would create a supply shortfall if disrupted (see Annex B and C).

## 2.2 Step 2 - Identifying the duration and the volume disrupted

*Estimated volume of a supply shortfall*

42. For UK refineries, the immediate term supply shortfalls to their regional supply envelopes have been estimated. Allowing for the variation between refineries, BEIS estimates that the immediate supply shortfall which could not be compensated for by the surrounding infrastructure averages 6-7[22] million

[19] BEIS has looked at the probability of "at least one" Consumer Disruption Event and "exactly one" Consumer Disruption Event. BEIS choses to use "exactly one" as the difference between the two probabilities is very small, and because this provides a useful modelling simplification.

[20] An average for terminals and jetties has been used to protect commercially sensitive data.

[21] Deloitte 2010 report, section 4.2.6 - Downstream oil – short term resilience and longer terms security of supply. https://www.gov.uk/government/publications/downstream-oil-short-term-resilience-and-longer-term-security-of-supply

[22] All BEIS calculations use 6.5m, the midpoint between the two estimates.

litres/day (2 to 3%[23] of total daily supply to the UK market). In the short-term these estimates could differ due to the reduction in fuel demand caused by the Covid-19 pandemic, but BEIS expects that in the medium term the magnitude of disruption will revert towards the pre-Covid level. Due to the commercially sensitive nature of the information, BEIS cannot disclose the individual sites or the impacts by region[24].

43. BEIS also estimates that the intra-regional infrastructure would have sufficient spare capacity to maintain supplies in most cases of terminals and jetties closure. Only a minority of assets could generate a shortfall of supply and for these sites, BEIS estimates that the immediate impact would average around 3 million litres/day.

44. For each category of assets in the downstream oil sector, the estimated volume of supply disruption per day has been adjusted for the likelihood of a Consumer Disruption Event at each asset (see Table 3), to derive an quantitative impact adjusted for its probability (often referred to as "risk-adjusted" impact).

### Table 3: Annual risk adjusted supply disruption per day

| | **Annual risk adjusted supply disruption (million litres per day)** |
|---|---|
| **Refinery** | **0.86** *[(1/10 years + 1/25 years probability) x 6.5 million litres/day]* |
| **Terminals and Jetties** | **0.06** |

*Duration of a supply shortfall*

45. "Duration" for the purposes of this IA is defined as: the period of adjustment following a Consumer Disruption Event before a functioning fuel market is re-established. Duration does not necessarily imply supply of fuel is restored to pre-disruption levels by that point, but that a functioning fuel market has been re-established.

46. Reflecting the uncertainty around the duration of a Consumer Disruption Event, an illustrative range has been created to outline the possible lengths of supply disruptions that consumers could face:

- **3 Days** – Based on a very rapid response by the hauliers to re-optimise and re-allocate tankers from other areas in the UK, leading to a very diffuse supply shortfall spread out across the whole of UK. The supply chain is assumed responsive and wider logistics infrastructure is favourable while prices might ration demand quickly without there being an extended disruption.
- **6 days** – Hauliers and other suppliers take a couple of days to react and then re-optimise the supply chain, as logistics slows changes to delivery arrangements. As a result, prices take longer to fully adjust and ration demand.
- **10 Days** – Industry response is focused on using resources local to a discrete failure and supply chain adjustment is unwilling to compromise existing delivery patterns in other regions or is constrained by other logistical factors. Supply chain is unresponsive, and prices cannot adjust sufficiently to avoid an extended disruption.

47. BEIS recognises the stylised and indicative nature of these ranges but for the purposes of this IA they are considered a reasonable representation of how the downstream oil sector could react to a Consumer Disruption Event. There are commercial incentives to bring additional supply into tight local markets as soon as possible. However, retailers are only able to price in part the scarcity of supplies, and panic buying could run down stocks quickly, so rationing could last longer even with the best efforts of downstream oil sector operators. The range also reflects the variation in disruption volume and local factors, such as the availability of road fuel tankers to supply current volumes from alternative supply points.[25]

[23] Total daily supply to the GB market averaged about 240 million litres/day in 2019 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/540915/DUKES_3.2-3.4_alternative_units.xls

[24] Annex C "Estimating Supply Shortfalls: Methodology", describes in more detail the approach that BEIS followed.

[25] More details about BEIS assessment are contained in Annex D, "Market Response to a Supply Disruption".

## 2.3 Step 3 – Estimating the economic impact of a disruption

48. BEIS estimates the economic impact of a disruption using the concept of "oil intensity", based on the oil product intensity methodology developed in a report by Deloitte.[26] Oil Intensity applies the concept of energy intensity (which expresses the quantity of energy required to produce a unit of economic output), to estimate the economic output arising from each unit of oil. Oil Intensity is defined as the ratio (Ratio A) between refined oil product demand and economic output as measured by the Gross Value Added (GVA)[27]:

$$\textbf{Oil Intensity} = \left(\frac{\textbf{Oil product demand}}{\textbf{GVA}}\right) \qquad \textbf{\textit{Ratio A}}$$

49. BEIS considers it plausible to assume that Oil Intensity is fixed in the "immediate term" (the days following an oil supply disruption), given the lack of available substitutes for oil products, especially in the transport sector. On this basis it is reasonable to expect that a fall in available refined oil products will impact economic activity in proportion to the (inverse) oil intensity of output:

$$\textbf{\textit{Ratio B (Inverse of Oil Intensity)}} = \left(\frac{\textbf{GVA}}{\textbf{Oil product demand}}\right)$$

50. This approach implies that all economic activity requires some oil product consumption (either directly or indirectly) in fixed proportions, and that there is limited or no scope to i) replace oil with other energy sources, and/or ii) reallocate oil product stocks to economic activities with the highest value. A shortage in product available will reduce economic activity, and we define the impact as a function of the volume of oil disruption and of the amount of economic activity restricted per volume.

**Volume of oil disruption x Ratio B (Inverse of Oil Intensity) = Economic Impact**

51. In the Consultation IA, the "best estimate" of economic impacts was assessed assuming that directly and indirectly all economic activities are disrupted by a Consumer Disruption Event – i.e. if 1% of oil product demand is disrupted then 1% of total economic activity is disrupted. This value was driven by the need to illustrate the order of magnitude of the potential risks that underpin the rationale for intervention.

52. Stakeholders suggested that the potential fuel supply disruptions could unfold in many ways and therefore the range of economic impacts is wide and uncertain. BEIS has carefully considered stakeholders' feedback and has incorporated their points by expressing the economic impacts as a range that reflects the most plausible scenarios. Additional consideration has also been given to the essential nature of fuel for economic activity, with adjustments made for sectors that are less reliant. Also, where BEIS estimates benefits of reduced disruption using this framework (see Section 3), it relies on the low end of the range for the economic impact per litre of product disrupted, to illustrate with a stylised approach how the benefits are multiples of the costs under any plausible range of assumptions. These additional considerations implicitly factor in the variation in the substitution of oil demand in each sector; the seasonality of oil consumption; the day of the week; the weather; the region impacted (among other factors) and other uncertainties that could vary the impact of a Consumer Disruption Event.

53. The costs to the UK economy from fuel supply disruptions are likely to be exacerbated through the impact of panic buying, particularly in the transport sector. Consumers use panic buying as a means to self-insure from fuel disruptions which increases fuel demand beyond the steady state level. This can result in more acute shortages at both the regional and national level as constrained supply faces spikes of heightened demand. The multiplier effect of panic buying cannot be quantified currently.

54. This refined approach confirms that even in a very cautious scenario of impacts, the order of magnitude of the economic benefits (adjusted for their probability) is a multiple of the costs of the intervention. Where BEIS has enough evidence of the potential improvements to resilience, it has developed a range of benefits expressed as a reduction in the economic impact.

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[26] Deloitte 2010 report - Downstream oil – short term resilience and longer terms security of supply. https://www.gov.uk/government/publications/downstream-oil-short-term-resilience-and-longer-term-security-of-supply

[27] Gross Value Added (GVA) is the value generated by any unit engaged in the production of goods and services. GVA plus taxes (less subsidies) on products is equivalent to Gross Domestic Product (GDP). The main input datasets for regional GVA include administrative data and data from structural surveys.

55. Stakeholders could not suggest an alternative robust methodology and whilst BEIS acknowledges the limits of the methodology we still consider it to be the most valid and proportionate approach for the purposes of illustrating the magnitude of impacts and demonstrating that the benefits of reducing oil disruptions are multiples of the costs to the industry.

56. Table 4 below shows UK GVA and oil consumption split by sector[28] and is used to inform considerations of which sectors are most impacted by a fuel disruption. The transport sector consumes the most oil in the UK and is a factor in virtually all other economic activity. In the UK, about 71% of commuter journeys[29] use modes of transport that rely on fuels derived from oil, such as cars and buses. Similarly, about 79% of domestic freight goods are moved by road.[30] This demonstrates that oil is an essential input into a portion of economic activities far larger than the 38% of energy consumption provided by oil.

### Table 4: UK GVA by sector and oil consumption

| Sector | GVA (% UK) | Oil Consumption (% UK) |
|---|---|---|
| **1. Energy Industry Use** | 3.2% | 6.8% |
| **2. Transport** | 2.1% | 72.3% |
| ***Of which air transport*** | *0.3%* | *18.1%* |
| ***Of which other Transport*** | *1.9%* | *54.2%* |
| **3. Industrial** | 16.4% | 3.1% |
| **4. Public Administration** | 18.7% | 1.0% |
| **5. Commercial** | 58.6% | 2.1% |
| **6. Agriculture** | 0.7% | 1.2% |
| **7.Other** | 0.3% | 13.4% |

*Source: Dukes 3.2 Commodity balances 2019 https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2020 and Office for National Statistics Gross Value Added by Industry (recategorized to match as practically as possible the industry categories used in the Dukes table) https://www.ons.gov.uk/economy/grossvalueaddedgva/datasets/nominalandrealregionalgrossvalueaddedbalancedbyindustry*

57. BEIS has used this evidence to adjust the Ratio B calculation and obtain an illustrative range of impacts (see Table 5). The low estimate relaxes the assumption of no substitution across the economy by removing the economic output (GVA) generated by sectors that are likely to be less oil dependent. The "commercial" and "public administration" sectors have a low share of oil consumption relative to their share of GVA and for simplicity it is assumed "air transport" could refuel at alternative locations – the GVAs of these sectors are therefore assumed unaffected.[31] This leaves only around 23% of UK GVA affected. It is then assumed that the remaining sectors are completely dependent on oil consumption. The high impact estimate replicates the approach followed in the Consultation IA and assumes that at worst, no economic activity could happen across all sectors (e.g. because of their dependence on transport) if oil consumption was completely disrupted.

### Table 5: Calculating the oil intensity ratio

| | **Ratio B (2020 Values) (£m)** |
|---|---|
| **High** | $\frac{\text{GVA}}{\text{Oil Product Demand}} = \frac{\text{£1,767,646m}}{\text{73,110,550 TOE}} = \mathbf{0.02}$ |
| **Low** | $\frac{\text{23\% of GVA}}{\text{Oil Product Demand}} = \frac{\text{£402,757m}}{\text{73,110,550 TOE}} = \mathbf{0.006}$ |

[28] For an explanation of the approach used, see Annex E: Approach to grouping GVA and energy demand by sector

[29] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/905988/nts0409.ods

[30] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/669313/tsgb0401.ods

[31] In the air transport sector, it was assumed that, as the market for jet fuel is national rather than sub-national, planes should be able to refuel in alternative locations if necessary and the cost of these is likely to be relatively marginal. In practice this will vary depending on location, and for example, the mix of short and long-haul flights with refuelling in alternative locations more practical for short haul flights.

58. Ratio B is used to assign a monetary value to the risk adjusted volume of disruption per day, the (inverse) oil intensity ratio and the duration of disruption (see Table 6). Taking the high and low estimates of Ratio B, an illustrative example of the range of the economic impacts of a supply disruption in 2022[32] has been provided. BEIS estimates that the risk-adjusted range is around £15m-£210m in 2022.

### Table 6: Baseline Economic Impact of a Consumer Disruption Event in 2022 (£m, 2020 prices, 2022 PV, discounted)

| | **Risk adjusted Volume disrupted (million litres/day)** | **Inverse Oil intensity ratio (Ratio B) (2020)[33]** | **3 day disruption (£2020m)** | **6 day disruption (£2020m)** | **10 day disruption (£2020m)** |
|---|---|---|---|---|---|
| **Refinery** | **0.86** | **0.006 – 0.024** | **(0.86 + 0.03) × conversion factor to TOE × (0.006 or 0.024) × 3 days = £15m – £65m[34]** | **(0.86 + 0.03) × conversion factor to TOE × (0.006 or 0.024) × 6 days = £30m – £125m** | **(0.86 + 0.03) × conversion factor to TOE × (0.006 or 0.024) × 10 days =£50m – £220m** |
| **Terminal or Jetty** | **0.03** | | | | |

59. The Preferred Option will provide benefits by reducing the baseline economic impact of a supply disruption and any panic buying associated with this. The baseline economic impact that BEIS illustrates here can be lowered in any given year through a combination of reducing the risk (i.e. the probability) of a disruption, the volume disrupted and/or the duration of a disruption. The potential for measures set out in the Preferred Option to reduce these impacts are considered in the next sections.

32 All 2022 impacts are discounted to 2020 values.

33 UK GVA and oil product demand grow at different rates and therefore the oil intensity ratio changes each year. BEIS have modelled the growth in GVA and oil product demand across the appraisal period. Oil product demand as estimated in the 2019 BEIS Energy and Emissions projections. Real GDP data for 2001-2019 is from the Office for National Statistics (ONS) time series ID ABMI. Growth rate projections for 2020-2024 are from the Office for Budget Responsibility (OBR) July 2020 Fiscal Sustainability report central scenario – Table 2.2. Growth rate projections for 2025-2035 are from the OBR March 2019 Long-term economic determinants report accompanying excel workbook.

34 Values are rounded to the nearest £5m

# 3 MONITORING FUEL SUPPLY RESILIENCE (INFORMATION AND DATA REPORTING)

## 3.1 Description of Preferred Option

60. BEIS will introduce a power to request additional information in eight main areas[35]:

a) Monthly, quarterly and annual surveys;

b) Provision of Daily Forecourt Wet Stock Management Data; and

c) Other data provision.

61. BEIS will reduce the burden on Small and Micro businesses by exempting operators that supply less than 1000 tonnes/annum from the monthly survey (see detailed discussion in section 5.4). Forecourt owners with no monitoring technology currently installed will not have to provide daily wet stock management data to BEIS.

## 3.2 Rationale

62. Information and data reporting will enable BEIS to collect, compile, retain and share (with other government departments only) information from the downstream oil sector for the purposes of fuel supply resilience (refer to Section 1 of the consultation document for a detailed description of the proposed regulatory intervention).

63. BEIS needs to look at the aggregated supply requirements across all medium and large companies, to understand the ability of infrastructure assets to increase or maintain supply in the event of a disruption event. The current level of information provided is insufficient to achieve a complete, accurate and holistic view of the downstream oil system, and prevents the government from supporting industry in responding to a disruption in an effective and timely manner. Information will be used to identify critical points which may give rise to disruptions, develop contingency plans and support decision making during an emergency.

64. BEIS has assessed the proposals for new surveys so that they minimise the burden placed on businesses. BEIS has looked at information that is already collected under existing legislation and worked to ensure that additional requests are proportionate to risks.

## 3.3 Costs

65. BEIS has drawn on the UK Statistics Authority's (UKSA) Code of Practice[36] for survey control and on the GSS's recommended methodology for estimating the cost of complying with data reporting requirements.[37] BEIS has also considered cost estimates of familiarising with the new requirements. For the purposes of this IA, BEIS has assumed that the regulatory requirements and the relevant costs would be applied from 2023.

66. Feedback from industry stakeholders expressed at the consultation stage has also been considered. Some expressed concern that our assumed wage rates were too low, or failed to take account of non-wage costs, such as employer costs etc. This Final IA has responded to stakeholder feedback by uplifting wages by 30%, in line with recommendations (see Table 7). This nominal 2020 wage was then uprated using OBR estimates and forecasts to give real product wages for each year from 2023 to 2032, and these were used to calculate costs.

67. The calculated compliance costs combine estimates of the time taken to complete similar existing surveys with estimates of the opportunity cost of that time, which is based on the wage (excluding overtime) and

[35] Annex A of the consultation document contains more detail about the proposals.

[36] https://gss.civilservice.gov.uk/wp-content/uploads/2012/12/Code-of-Practice-for-Official-Statistics.pdf

[37] Further details can be found at https://gss.civilservice.gov.uk/policy-store/monitoring-and-reducing-respondent-burden-2/

non-wage cost of workers of different skills/functions, using data published in the Annual Survey of Hours and Earnings[38] (ASHE; Table 14.6a).

**Table 7: Occupation SOC10(4) Table 14.6a – Median Hourly Pay Excluding Overtime for Full-Time Employees**

| Occupation | ASHE Employment Description | 2019 rate (£/hr) | 2019 rate with 30% uplift (£/hr) | Downrated to 2020 nominal rate (£/hr)[39] |
|---|---|---|---|---|
| Director | Directors and chief executives of major organisations (code 1115) | 46.13 | 59.97 | 58.54 |
| Senior Manager | Managers and Senior Officials (code 1) | 22.18 | 28.83 | 28.15 |
| Middle Manager Junior Manager | Associate Professional and technical occupations (code 3) | 16.29 | 21.18 | 20.67 |
| Clerical | Administrative and secretarial occupations (code 4) | 12.03 | 15.64 | 15.27 |

### *Monthly, Quarterly and Annual Surveys*

*Monetised Costs:*

68. The costs of complying with data reporting obligations have been estimated by considering the minutes needed to respond to each return and the hourly wage rates of the employees that are expected to compile and review the information. BEIS has then estimated the total additional time (minutes) and the full annual cost to complete the return by looking at the amount of information required and the frequency of each return. The indicative wage rate per hour is based on ASHE data (see Table 7) and is converted into real wages using real product wage growth projected by the OBR.

69. BEIS has also considered familiarisation costs arising from this measure. It is assumed that in the first year of this measure, it will take 50% longer to understand the reporting requirements and provide the required information. The standard time requirements for each element of the proposed measure are outlined in Table 8. Familiarisation costs are therefore calculated by estimating the cost of the additional time to comply in the first year.

70. For the annual survey on infrastructure and logistics, it has been assumed that there will be a reduction in the time taken to fill out the annual survey after the first year. This reduction reflects that the survey is asking about infrastructure, and participants responses will not change significantly over time, allowing respondents to use their previous responses to the survey.

71. After calculating the compliance cost in year one, annual costs have been calculated (see Table 8) out to 2032. BEIS does not consider that there are any significant non-monetised costs.

[38] ASHE Table 14.6a. https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/datasets/occupation4digitsoc2010ashetable14

[39] 2019 ASHE prices with a 30% mark-up have been converted to nominal 2020 wages. These were estimated using the growth in the real product wage (OBR, Supplementary economy tables 1.6, October 2021)

## Table 8: Summary of Monitoring Fuel Supply Resilience Survey Assumptions and costs (£k, 2020 prices, 2022 PV)

| | | No. of Survey Returns | Additional Time (Mins) per reply | Level of Respondent completing Survey | Total annual hours required[40] | Total annual hours required in year 1[41] | Total annual hours required all in year 2 onwards[42] | Approximate annual cost in first year (2020 prices, 2022 PV)[43] (£k) |
|---|---|---|---|---|---|---|---|---|
| Survey on Supply and Demand | **Monthly Reporting** | | | | | | | |
| | Refiners | 8 | 210 | Middle Manager 60%, Clerical 40% | $(8 \times \frac{210}{60}) \times 12 = 336$ | $336 \times 1.5 = 504$ | 336 | $504 \times [(0.6 \times 22.30) + (0.4 \times 16.47)] =$ **10** |
| | Large Importers / Wholesalers | 20 | 105 | | 420 | 630 | 420 | **13** |
| | Large Importers / Wholesalers | 10 | 42 | | 84 | 126 | 84 | **3** |
| | Commercial Resellers | 20 | 105 | | 420 | 630 | 420 | **13** |
| | **Quarterly Reporting** | | | | | | | |
| | LPG (supply, distribution and/or retail) | 26 | 0[44] | Middle Manager 60%, Clerical 40% | $(26 \times \frac{0}{60}) \times 4 = 0$ | 0 | 0 | **0** |
| | Commercial Resellers | 38 | 60 | | 38 | 57 | 38 | **1** |
| Surveys on Infrastructure and Logistics | **Annual Reporting** | | | | | | | |
| | Refiners | 8 | 120 | Senior Manager 80%, Middle Manager 20% | $(8 \times \frac{120}{60}) \times 1 = 16$ | 24 | $16 \times 0.5 = 8$ | **1** |
| | Import Terminals | 36 | 120 | | 72 | 108 | 36 | **3** |
| | Inland Terminals | 19 | 120 | | 38 | 57 | 19 | **2** |
| | Regional Depots | 10 | 240 | | 40 | 60 | 20 | **2** |
| | Pipeline Operators | 10 | 120 | | 20 | 30 | 10 | **1** |
| | Airports | 26 | 120 | | 52 | 78 | 26 | **2** |
| | Hauliers (includes. LPG & Commercial | 20 | 180 | | 60 | 90 | 30 | **3** |
| | **Total** | | | | | | | **£51** |
| | **Total (excl. year 1 familiarisation costs)** | | | | | | | **£34** |

40 This is our baseline estimated total amount of hours required to complete each survey.

41 In the first year it is assumed that it will take 50% longer than the baseline to complete the survey.

42 After the first year, it is assumed that the time per reply reduces by 50% for the annual survey, as respondents will not have to significantly amend responses submitted the previous year.

43 The uplifted wage rates from 2019 (Table 7) have been uplifted by the real product wage.

44 The companies that will be caught by the new legislation are already reporting all the information on a voluntary basis (co-ordinated by their trade association UKLPG), so there will not be an additional reporting burden.

### *Provision of Daily Forecourt Wet Stock Management Data (WSMD)*

*Monetised Costs*

72. Some operating companies/suppliers/owners outsource the management of their wet stocks to third-party wet stock management companies. BEIS has already developed specific secure data feeds with these companies on a voluntary basis to supply data daily and in an emergency. As this measure is not being imposed on operators who do not have this technology installed, it is considered that downstream operators with this technology would incur negligible additional costs to meet the proposed Wet Stock Management Data (WSMD) reporting obligation, so costs have been assumed to be zero.

73. There are three main providers of wet stock management systems in the UK. Currently, two of these providers share daily anonymised feeds to BEIS, which typically covers over 50% of UK sites (4,500 out of 8,380) and over 65% of fuel throughput volumes. The remaining operator has agreed with its customers to provide data during a disruption only. Such providers will now have a statutory duty to provide data, reinforcing the commercial agreement. Introducing this measure would reduce the risk that companies no longer supply voluntary data and increases the daily data coverage reported to BEIS and allows BEIS to get full location information for a more granular monitoring of geographical impacts. It is estimated that these measures would increase coverage to around 60-65% of retail sites and 80-85% of national throughput, which is expected to continue to increase over our appraisal period as more companies choose to install wet stock management systems.

74. Forecourt owners and operators without the wet stock monitoring technology will be required to report only if they sell more than 1,000 tonnes of product a year, and then only during ad hoc requests made during periods of disruption. High throughput sites in major locations have more often invested in wet stock management systems than more isolated or rural locations, which will lead to better coverage on trunk roads and urban areas. However, requiring all forecourt owners to provide daily WSMD would have significantly increased the costs, as each forecourt without the monitoring technology would be required to purchase it annually with a cost of around £10,000.

### *Other data provision*

75. There are two key data provision requirements contained in this category:

- Provision 7, which relates to obtaining information from the downstream oil sector in case of an actual or threatened fuel disruption; and
- Provision 8, which implements the Security of Network and Information System Regulations (NIS Regulations) 2018 for the oil sector which aims to achieve a high common level of network and information security across the EU[45].

**Table 9: Summary of monetised costs, Monitoring Fuel Supply Resilience (£m, 2020 prices, 2022 PV)**

| The Preferred Option | Sum-Present Value (2023 – 2032) £m |
|---|---|
| Monthly and Annual Surveys (including familiarisation costs) | 0.28 |
| Of which, familiarisation Costs | 0.02 |
| Provision of Daily Forecourt Wet Stock Management Data (base case) | 0.03 |
| Total PV of costs | 0.31 |
| EANDCB (2023-2032) | < 0.05 |

[45] The UK approach to implement the NIS Directive has been prepared by the Department for Digital, Culture Media and Sport (DCMS) The final IA for the NIS directive is available at https://www.gov.uk/government/publications/nis-regulations-impact-assessment

*Monetised Costs:*

76. The burden of Provision 7 will depend on the nature of the downstream oil event, which is uncertain. The time taken to comply could be substantial in absolute terms but BEIS consider that it would be negligible relative to the counterfactual, since in an actual or threatened emergency the downstream oil sector would collect this information to monitor risks as part of internal business contingency planning. On this basis, it is considered that the cost to share this information with BEIS is negligible for most providers. BEIS may require forecourts without automatic wet stock monitoring systems to report manually during periods of disruption, if they supply more than 1,000 tonnes a year. This requirement would increase coverage from 90% to 98% of product sold. In the base case, BEIS estimates the expected cost per year per forecourt at £12; in the high case, with one long disruption in a typical year, the estimate is £173. The total costs of all the data measures over the ten-year period from 2023 to 2032 are estimated at around £310k in discounted present value terms in the base case (see Table 9).

### Benefits

77. BEIS considers that the benefits of the provision of information regulation will arise from improving government's capacity to identify potential supply outages, and target emergency response measures. Benefits will also arise from improving the effective enforcement of the other regulations on downstream oil resilience. For example, improved information will allow BEIS to reduce the likelihood of a disruption, and/or the volumes affected, and/or the duration of a disruption by:

- optimising the capability of the Reserve Tanker Fleet, ensuring that it is has the appropriate number of vehicles to mitigate the major risks and provides best value for money for the tax-payer;
- identifying where infrastructure is of national or regional importance, and assess how disruption at these sites could impact security of supply – this will help government and industry design and implement more effective mitigation strategies;
- identifying risks in advance and ensuring that government and industry can implement effective and proportionate contingency plans as early as possible.

78. BEIS considers that clearer, timely and more comprehensive information could reduce the duration of a Consumer Disruption Event in the downstream oil sector by up to one day. The disruptions to economic activities could vary significantly, and so more comprehensive information could bring benefits within a wide range

79. BEIS has considered the impacts on economic activity using the framework discussed in Section 2, which concludes that a disruption to fuel supplies could impact between a quarter (23%) and all economic activity. A reduction of one day would bring annual benefits (risk adjusted) of around £5m-£21m when compared to the baseline economic impacts set out in Table 6.

80. Costs are estimated at about £0.05m – less than 1% of the lower end of the benefits range. Even if better information reduces the duration of a disruption by a fraction of a day the benefits would be multiples of the annual costs. Given the uncertainties, BEIS has derived the low estimate as a nominal reduction of an hour and has derived the Best Estimate as a half a day impact. As the results show, even the most cautious estimate produces benefits that are multiples of the costs of the measure.

**Table 10: Illustrative reduction in cost of expected annual disruption, Monitoring Fuel Supply Resilience (£m, 2020 prices, 2022 PV)**

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| **High estimate** | 5.1 | 5.2 | 5.4 | 5.5 | 5.7 | 5.8 | 6.0 | 6.2 | 6.4 | 6.6 |
| **Low estimate** | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 |
| **Best estimate** | 2.6 | 2.6 | 2.7 | 2.8 | 2.8 | 2.9 | 3.0 | 3.1 | 3.2 | 3.3 |

# 4 ENSURING FUEL SUPPLY RESILIENCE: RESILIENCE DIRECTION

## 4.1 Description of Preferred Option

81. The Resilience Direction is a backstop measure that gives BEIS the power to direct downstream oil sector companies to achieve an outcome or take specific action to bring risks to fuel supply to acceptable levels. The use of the Resilience Direction would be specific to fuel supply resilience, and government intervention would need to be fair, reasonable and proportionate.

82. As previously noted, the Government Spending power would come into place only under certain conditions, for example in conjunction with issuing a Resilience Direction and is therefore not assessed separately.

## 4.2 Rationale

83. The Resilience Direction power would provide government with the tools to address the market failures in the sector identified in this IA, which are a serious concern given the scale of the potential impact on the economy. This measure is designed as a backstop power to address extreme circumstances.

## 4.3 Costs

84. The nature of the Resilience Direction brings uncertainties around its costs. BEIS expects a limited use of the power, given the backstop nature and the lack of government intention to use it immediately. If the government intends to use the power, it has to demonstrate that any Resilience Direction is fair, reasonable, proportionate, and does not result in undue impacts to market competition. These requirements limit the potential impact of the Resilience Direction. Government may put more reliance on using the proposed power to provide financial assistance to the downstream oil sector to ensure resilience measures are implemented. Any Resilience Direction will also be case specific and it is therefore difficult to determine an average annual cost.

85. Due to the considerable uncertainties, BEIS has not quantified costs for this element of the proposals in this IA and, instead, has provided two illustrative examples (not included in the overall NPV) to show the magnitude of potential interventions. These examples were developed from discussions with industry during the consultation workshops.

*Additional Jet Fuel Loading Rack*

86. Scotland has one major jet fuel supply point which has sufficient capacity to meet demand. Supply from (smaller) alternatives are less commercially viable, therefore over time these facilities have been rationalised as jet fuel facilities have been taken out of service. It is possible that further rationalisation or risks to fuel supply could lead government to consider working with industry to build resilience at alternative supply points. The costs would not be prohibitive (£50,000 to £100,000) but would not offer sufficient commercial return as they would be unlikely to offer lower cost supply than the incumbent supply point.

*Pipeline Interconnection*

87. In the UK, there are several examples of where pipelines run close to terminals, but no connection exists to allow the terminal to be supplied from the pipeline. Most often this is due to the owners of the pipeline not having any ownership interest in the terminal or the terminal having the ability to receive supply from another pipeline that the terminal owner has equity in. In these cases, there is limited commercial drive to install a new pipeline connection, as the pipeline owner may prefer to sell product to their own terminal rather than one belonging to a competitor. However, if supply from the one pipeline was disrupted, or rack capacity (the ability to load fuel into tankers for distribution) at a terminal lost, it would increase resilience to have the additional flexibility to supply between the different pipelines and terminals. The cost for these connections will vary depending on how close the pipelines are to the terminals and the pipeline receipt infrastructure already in situ. Given this

range of uncertainty, costs could range from as low as £50,000 but could also be as high as £1,000,000 per connection.

## 4.4 <u>Benefits</u>

88. The Resilience Direction would only be used if it is deemed necessary and proportionate. The use of this power will be as a last resort and consideration would be given to the value for money case. Benefits in the form of increased resilience in the sector would be considered against the costs of the direction, and the outcome of this assessment would form part of the decision to issue the direction.

89. In general, the downstream oil sector will benefit from increased resilience in a number of ways such as, but not limited to: reduced risk of incurring unexpected and significant costs from responding to disruption, reduced risk of failure to fulfil supply contracts, greater public confidence in the sector, and reduced risk of panic buying leading to surges in demand.

# 5 SUMMARY OF ANALYSIS AND SPECIFIC TESTS

## 5.1 Summary of Costs and Benefits

90. BEIS has assessed the Preferred Option detailing as much as possible the costs and benefits of each measure. The level of analysis provided for each measure is outlined in the Table below.

**Table 11: Summary of costs and benefits of the Preferred Option (£m, 2020 Prices, 2022 PV, discounted, appraisal horizon 2023-2032)**

| | THE PREFERRED OPTION | | | |
|---|---|---|---|---|
| | **Level of analysis** | **Familiarisation costs** | **Total costs (incl. familiarisation) to industry** | **Benefits to society** |
| Information and data reporting | The costs have been monetised, and a range of benefits have been estimated from the conservative end of the range | 0.02 | 0.3 | 24.7 |
| Resilience Direction | It is not possible at this stage for the IA to monetise the costs and benefits because this is a backstop power with government having no immediate intention for use. However, an illustrative example has been provided. | Not estimated | Not estimated | Not estimated |
| Total cost/ benefit | Low | 0.02 | 0.3 | 2.1 |
| | Central | 0.02 | 0.3 | 24.7 |
| | High | 0.02 | 0.8 | 49.5 |
| **Net Benefit (NPV)** | **Low** | | | **1.3** |
| | **Central** | | | **24.4** |
| | **High** | | | **49.1** |

### *Non-Monetised Costs*

91. BEIS has provided some illustrative examples of the potential costs of the Resilience Direction, which are not included in the final NPV because the measure is intended as a backstop measure, with no immediate intent to use. However, the policy has been designed to minimise costs to the industry.

### *Non- Monetised Benefits:*

92. Reflecting the approach to assessing costs, it has not been possible to quantify all the potential benefits of the new powers. For example, increased public confidence in national fuel supply resilience may reduce the risk of panic buying during an incident but this has not explicitly been monetised.

## 5.2 Businesses Directly Impacted (following BIT methodology)

93. The Preferred Option will generate direct costs and benefits for businesses in the downstream oil sector. Each regulatory proposal in the Preferred Option impacts a different range of operators, depending on the size and on the activity undertaken. The businesses impacted directly by the information and data reporting proposal include: refiners, importers/wholesalers, commercial

resellers, firms supplying/distributing/retailing LPG, import terminals, inland terminals, regional depots, pipeline operators, airports, hauliers and port authorities.

### *Direct costs*

94. The costs of information and data reporting have been estimated using the standard methodology used across government to estimate compliance costs. The compliance cost estimates account for the time taken to complete surveys and for the opportunity cost of that time, which is based on the wage (excluding overtime) and non-wage cost of workers of different skills/functions.

### *Direct benefits*

95. The policy will produce direct benefits to businesses in the downstream oil sector in terms of continued sales which would otherwise have been lost by a disruption, these have not been calculated directly with the principal benefits given in terms of the indirect effect on businesses who directly or indirectly rely on fuel supply.

## 5.3 EANDCB position

96. The total direct impacts for businesses are estimated using the Equivalent Annual Net Direct Costs to Business (EANDCB) calculation methodology. The calculations are based on deflated prices for 2019 and on a present value for 2020, to account for the deregulatory targets of the government. For this policy the EANDCB is calculated using the appraised direct costs and benefits over ten years. A breakdown of the EANDCB is provided in Box 1 below.

**Box 1: Equivalent Annual Net Direct Costs on Business (2019 prices, 2020 NPV) (£m)**

| | **Costs** | **Benefits** | **Net:** |
|---|---|---|---|
| Costs of data and information reporting | **0.03** | **0** | **-0.03** |

## 5.4 Contribution Towards Deregulatory Targets

97. The policy is a domestic regulatory provision and as such the EANDCB will count towards the Business Impact Target (BIT), the deregulatory commitment of the government. The current estimate of the EANDCB results in a £0.17m contribution against the BIT.

## 5.5 Small and Micro Business Assessment

98. BEIS expects that only the provision of information measure of the Bill will impact some Small and Micro Businesses. If including Small and Micro businesses would be necessary for resilience purposes, a direction to lower or eliminate the threshold could be done only through further regulation.

### *Information and data reporting for Small and Micro businesses*

99. BEIS expects Small and Micro businesses will be affected only if they are forecourts without automatic wet stock monitoring and supply more than 1,000 tonnes a year. In that case, ad hoc manual monitoring will be required during periods of disruption as discussed in para [75] at the end of section 3. The regulation also exempts forecourts that do not have wet stock monitoring capability already installed and which supply less than 1,000 tonnes a year.

**Table 12: Number of Small and Micro businesses obligated in the Preferred Option**

| *Note – Figures rounded to the nearest 10* | **Estimated Number of micro businesses (up to 10 FTE)** | **Estimated Number of small businesses (up to 49 FTE)** | **Total Number of businesses to be surveyed** |
|---|---|---|---|
| **Supply Companies** | | | |
| Refiners | 0 | 0 | <10 |
| Importers / Wholesalers | 0 | 0 | <30 |
| LPG Suppliers | <10 | <20 | <30 |
| Commercial Suppliers | <5 | <10 | <40 |
| | | | |
| **Infrastructure Operators** | | | |
| Refineries | 0 | 0 | <10 |
| Import Terminals | <5 | <5 | <40 |
| Inland Terminals | 0 | 0 | <20 |
| Pipeline Operators | 0 | <5 | <10 |
| Airports | 0 | 0 | <30 |
| | | | |
| Hauliers | 0 | <10 | <20 |
| | | | |
| Forecourt Operators | Around 400 | Unknown | Around 400 |

100. The Companies Act 2006 defines a Small and Micro business according to turnover and balance sheet total. Using either of these definitions based on turnover may mean that some companies, particularly infrastructure operators which handle substantial volumes of oil product, would no longer be exempted. However, BEIS considers that the volume of supply handled is a more effective criteria to set the threshold to exempt Small and Micro businesses in a way compatible with the aims of the regulation.

101. BEIS has estimated the number of Small and Micro businesses (defined by employment levels) that will be included in the information and data reporting measures (see Table 12). For forecourt operators this is operators supplying more than 1,000 tonnes of oil products a year and so in scope of ad hoc reporting requirements; for other companies it is operators handling more than 50,000 tonnes of product a year.[46] This shows that a significant proportion of suppliers of LPG and commercial suppliers have employment levels that classify them as Small or Micro businesses but would be required to meet the reporting commitments.

102. In order to achieve a large part of the aims of the legislation BEIS considers necessary including in the scope of the Bill Small and Micro Businesses that handle more than 50,000 tonnes of product per year, and forecourt operators supplying more than 1,000 tonnes a year. The threshold is designed to capture most fuel supplies in terms of volume in order to monitor fuel resilience consistently across the country. For example, LPG suppliers deliver to remote, off-grid locations, meaning that local and vulnerable populations are reliant on these companies for fuel supplies, and tracking supply information will be essential for improving resilience. BEIS assesses that the frequency and type of data provision requirements makes costs proportionate across businesses.

103. Based on analysis of the number of employees, it is estimated that about 10-15% of the total annual cost of data collection would be borne by Micro businesses and about 10-15% by Small businesses.

[46] 1. Data is taken from the FAME database of UK and Irish financial company information and business intelligence provided by Bureau Van Dijk. There are companies where information on the number of personnel employed was not available in the FAME database, for these companies an estimate has been provided.

Over the appraisal period (2023 to 2032) the total sum of the present value of these costs to Small and Micro businesses is £0.04m.

## 5.6 Distributional Impacts

104. In the Preferred Option the costs of improving fuel supply resilience fall directly on the downstream oil industry but will likely ultimately be paid for by consumers of oil products rather than taxpayers in general. This is in line with the principle that the costs of improving resilience are born by those who consume most fuel.

105. BEIS has considered how this proposal impacts household expenditure on petrol, diesel, and other motor oils as a percentage of total household expenditure. Only households in the bottom percentile of the population spend a markedly higher percentage of their total expenditure on motor oils compared to the national average (see Table 13). However, given the small cost of the preferred option, it is unlikely that any significant impact will arise from the measures proposed.

**Table 13: Petrol, diesel and other motor oils as % of Total Household Expenditure[47]**

| All Households | Lowest ten per cent | 2nd Decile Group | 3rd Decile Group | 4th Decile Group | 5th Decile Group | 6th Decile Group | 7th Decile Group | 8th Decile Group | 9th Decile Group | Highest ten per cent |
|---|---|---|---|---|---|---|---|---|---|---|
| 4.6% | 6.1% | 5.0% | 4.6% | 4.8% | 4.4% | 4.4% | 4.4% | 4.4% | 4.6% | 3.3% |

## 5.7 Competition Impacts

106. The government is committed to ensuring that the regulatory measures outlined in this IA do not have any disproportionate impacts on competition. Where BEIS anticipates any material impacts, the government would engage closely with stakeholders at the secondary legislative stage and asses in detail if any costs are justified by the need to achieve the fuel resilience goals.

107. The precise impact on competition of the measures is still uncertain because many of the details will be defined in secondary legislation. Using the available evidence, we have competed an initial assessment of each measure:

- **Monitor**: BEIS have tailored the frequency and depth of the surveys to the type of information and operator, so that no unnecessary information is requested from firms. BEIS is also excluding small and micro businesses to avoid the risk of imposing extra burden on them, unless data provision is material to monitor fuel supply resilience. Additionally, the government has removed the burden for companies to provide wet stock management data if operators do not currently have the technology installed. To avoid the risk of anti-competitive behaviours, information collected by government will be held securely and used only for monitoring fuel supply resilience.
- **Ensure**: If the government intends to issue a Resilience Direction, it must demonstrate that any Direction is fair, reasonable, proportionate, and does not result in undue market competition impacts. These requirements limit the potential impact of the Direction, even where there is a strong value for money case to reduce the risk of fuel supply disruption.

## 5.8 Judicial Impacts

108. BEIS does not expect that the Preferred Option will generate legal challenge in response to any of the proposed measures. The Resilience Direction measure would be the most likely to generate legal challenge, but any proposed interventions using this power would need to be fair, reasonable and proportionate (see Paragraph 88) and BEIS expects that this requirement minimises the risk of legal challenge.

[47] Source: ONS

109. With respect to the impact of criminal and civil penalties, BEIS expects that the number of cases per year would be less than 1 case in every 10 years. This is based on experience in i.) collecting data, ii.) directing companies and iii.) the culture in the sector.

110. BEIS assesses that Information on commercial activities in the energy sector has been collected and published without significant issue for over sixty years. There is no record of significant non-compliance with the reporting regime. The government enjoys close working relationship with industry and fora exist in which developments to data collection are discussed.

111. BEIS has also considered that the powers proposed to direct companies working in the oil sector are similar to those used in the UK's Compulsory Oil Stocking (CSO) regime[48]. The CSO policy has been in operation for over forty years and there has not been a court led enforcement action to date. The administration and enforcement provisions allow for official led informal action to resolve issues before a legislative route is pursued. BEIS also notes that no cases have been brought to court under the Offshore Safety Act of 1992, which again directs companies in this sector to behave in certain ways.

112. Finally, BEIS considers that the sector inclines towards compliance. The principal desire is that regulatory obligations apply equally across all companies and that sanctions exist should one company attempt to obtain a commercial advantage through non-compliance. Sector companies have responded well to these proposals, with no indication yet of these measures being significantly controversial

113. Given the internal review process, BEIS considers the likelihood of cases reaching the courts is negligible. Experience shows that reputation is important to sector operators and should be sufficient to ensure compliance or limit the very majority of disputes to Crown Courts.

[48] The government obligates companies to hold over 10 million tonnes of oil for resilience purposes and this places considerable costs on companies.

**Title:** Amendments to Change of Control Powers in Existing Petroleum and Carbon Storage Licences
**IA No:** BEIS031(F)-22-EDR

**RPC Reference No:** RPC-BEIS-5173(1)

**Lead department or agency:** Department for Business, Energy and Industrial Strategy (BEIS)

**Other departments or agencies:** Oil and Gas Authority (OGA)

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage:** Final Stage

**Source of intervention:** Domestic

**Type of measure:** Primary legislation

**Contact for enquiries:** energybill2021@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| £0m | £0m | £0m | Not a regulatory provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

The Oil and Gas Authority's (OGA) existing ex-post powers cannot prevent undesirable changes of ownership and control of carbon storage or petroleum licensees. Undesirable changes of control can harm both industry and government which are compounded by current weak remedy powers. Primary legislation is required to replace the ex-post power with an ex-ante power so that the OGA can identify and prevent an undesirable change of control rather than seek to remedy it after it has taken place.

**What are the policy objectives of the action or intervention and the intended effects?**

The intended outcome is an improvement in the OGA's ability to ensure that the governance, technical and financial capability of a carbon storage or petroleum licensee is preserved following a change of its controlling parent company. The intervention will ensure a faster, more certain process either to agree to a desirable change of control or, alternatively, to forestall or remedy an undesirable change of control.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

Option 1: The 'do nothing' option would result in the OGA continuing to seek to manage changes of control using the existing ex-post regime which has been shown to be largely ineffective in preventing the harms, to both wider industry and government, that flow from an undesirable change of control.

Option 2: Enhanced sanctions: No additional sanction powers have been identified that could be applied under the current licences or law. Primary legislation could be used to introduce a power to reverse or nullify an undesirable change of control. We do not currently consider such a significant measure would be proportional.

Option 3: A non-regulatory approach would be to secure the agreement of the licensees of over 700 existing licences to voluntarily modify the terms of their licences. Agreement would likely not be reached with some licensees and the process of separate negotiation would be costly and inefficient for all.

Option 4: The preferred option of a modification to the licences through primary legislation is more certain in effect and more efficient for both the OGA and licensees.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:**

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | No | | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** Nil | **Non-traded:** Nil | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

# Summary: Analysis & Evidence — Policy Option 4

**Description: Provide the OGA ex–ante powers to prevent an undesirable change of control.**

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2019 | PV Base Year 2020 | Time Period Years | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** | **High:** | **Best Estimate:** 0 |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | | | | |
| **High** | | | | |
| **Best Estimate** | 0 | | 0 | **0** |

**Description and scale of key monetised costs by 'main affected groups'**

The primary legislation will not in itself have any direct costs on businesses. It makes provision for the existing change of control process to be subsequently moved from an ex-post to an ex-ante basis by the OGA. Once operational, it is assumed that there will be small administrative costs for submitting ex-ante applications for changes of control for a small number of companies who would not have done so under current ex-post arrangements and the existing, less formal, 'letters of comfort' process. The body of the IA includes indicative costs for the potential future costs to businesses. Lastly, in exercising its licence powers, the OGA must act proportionately and will therefore only make substantial ex-ante interventions (with the additional costs to itself or to the applicant) to prevent the risk of a significant harm. By the nature of the oil and gas industry, a significant harm of this type, if not prevented, could lead to harms valued at tens or hundreds of millions of pounds.

**Other key non-monetised costs by 'main affected groups'**

It will be more likely under these proposals that undesirable changes of control will be forestalled, resulting in any pre-completion costs of the parties being lost. It is not considered proportionate to monetise these costs which could vary considerably depending on the transaction and extent of work undertaken by the parties prior to consent being sought from the OGA. In addition, it is expected that undesirable companies will be deterred from applying for consent and/or disincentivised from incurring significant pre-application costs.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | | | | |
| **High** | | | | |
| **Best Estimate** | 0 | | 0 | **0** |

**Description and scale of key monetised benefits by 'main affected groups'**

The primary legislation will not in itself have any direct benefits for business (nor any direct quantifiable benefits to the OGA). Once operational, the clearer application process and refreshed guidance has the potential to reduce administrative costs and therefore be beneficial to business compared to the existing arrangements.

**Other key non-monetised benefits by 'main affected groups'**

The measure will improve the business environment for quality mergers and acquisitions and reduce the risk that co-licensees will be burdened with an undesirable partner. The substantial administrative and legal costs to the OGA and industry for addressing undesirable changes of control would reduce. In addition, the change will avoid the current very substantial costs of undesirable ownership; reduced investment and cover for liabilities, obstruction of investment plans of the co-licensees and generally undermine investor confidence. These costs will vary by circumstance but, due to the nature of the oil and gas industry, will usually be of the order of tens if not hundreds of £ millions. Additionally, the proposed measure is likely to have environmental merits, as the OGA will be better equipped to ensure that the UK's offshore infrastructure remains in the hands of companies with the best ability to either decommission it in due course or pave the way to reuse for decarbonising measures such as carbon capture.

| **Key assumptions/sensitivities/risks** | **Discount rate** | N/A |
|---|---|---|

The primary legislation will not in itself have any direct impacts on business. The proposed new arrangements will be established, operated and enforced by the OGA. An assessment of potential impacts from implementation are included to provide information on the potential effect of the measure. An underlying assumption is that as global demand for oil and gas reduces, an increase in undesirable changes of control will be proposed which would otherwise undermine positive investment. This IA assumes that there will be full compliance with the legislation i.e. all companies will seek consent from the OGA prior to completing a change of control and not proceed if consent is not granted.

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** 0 | **Benefits:** 0 | **Net:** 0 | 0 |

## Section 1: Problem Under Consideration

Overview of Regulatory Framework

1. The Oil and Gas Authority (OGA)[1] was established as a government company in 2016 to regulate the UK oil and gas industry, in conjunction with other regulatory authorities, and has a range of powers to deliver this remit.

2. The Petroleum Act 1998 vests all rights to the UK's petroleum resources in the Crown and provides the OGA with the power to grant licences that confer exclusive rights to *'search and bore for and get'* petroleum to such persons as they see fit. Each of these licences confers such rights over a limited area and for a limited period of time. The Act (by way of the Infrastructure Act 2015) also provides the legislative basis for the OGA Strategy[2] and the requirement for the OGA and industry to act in accordance with it.

3. In granting licences to companies, the OGA considers whether they will support the Central Obligation in the OGA Strategy; namely, to secure the maximum value of economically recoverable petroleum as well as support the wider North Sea Transition deal, enabling the Oil and Gas sector to transform its UK supply chains, jobs, and local communities. Furthermore, it ensures that the sector will assist in meeting the net zero target by reducing greenhouse gas emissions from sources such as flaring and venting and power generation and supporting carbon capture and storage projects.

4. Licences can be held by a single company or by several working together, but in legal terms there is only ever a single licensee regardless of how many companies it may comprise. All companies on a licence share joint and several liability for obligations and liabilities that arise under it. Under the Energy Act 2016, the OGA is also the licensing authority for offshore carbon dioxide storage, except within the territorial sea adjacent to Scotland, which Scottish ministers authorise.

5. It is important that a company holding a petroleum or carbon storage licence is well governed and able to meet its financial and technical obligations. Many licensees are, in practice, owned by a parent company which exerts control over the licensee's governance, financial, and technical capability. Before it first issues a licence, the OGA satisfies itself that the prospective licensee and its owners, if any, are suitable to hold a licence and will meet their obligations. The OGA bases its consideration on published guidance[3].

Current 'Change of Control' Arrangements

6. During the life of a licence, it is quite likely that ownership and control of the licensee will transfer to a new parent company as a result of merger and acquisition (M&A) activity, concluded by way of share sales. This is often referred to as a 'change of control' of a licensee, defined in the OGA's production and development licences as any event by which a person who did not have control of a licensee when that licence was granted, or last assigned, comes to control that licensee. Control is defined in the licences, and references sections 450 and 451 of the Corporation Tax Act 2010, and in summary is where a person can exercise control of the licensee's affairs. This is stated as including, amongst other things, possessing or being entitled to acquire one third or more of the shares in the licensee.

7. In general, the OGA supports this and other M&A activity, as a way of securing that valuable investment opportunities are held by companies with the will and the means to invest in them. However, the OGA is also concerned that such transactions may put at risk the delivery of a licensee's commitments, liabilities, and obligations, including commitments under the OGA Strategy and that they therefore require close scrutiny. Additionally, in the OGA's view, reliable, long-term investors are attracted by other demonstrably reliable, long-term investors, and by stable and predictable regulatory systems. The OGA, therefore, sees risks to the broader confidence of

[1] The North Sea Transition Authority is a business name of the Oil and Gas Authority

[2] Oil and Gas Authority: The OGA Strategy - 2020 - Publications - News & <br/>publications (ogauthority.co.uk)

[3] Oil and Gas Authority: Licensee criteria - Licensing system - Licensing & <br/>consents (ogauthority.co.uk)

investors, and consequently the OGA's statutory duties and objectives, from changes of control that increase risks to the delivery of licence commitments.

8. Under current arrangements, the licences do not impose any requirement for OGA approval of a change of control of a licensee before that change of control takes place. However, in an effort to ensure that the governance, technical, and financial capability of the licensee is not undermined by the change of control, the licences do grant the OGA the power, having examined the change, to require that a further change of control takes place, and failing that, a power of revocation of the licence.

9. This may mean the complete revocation of the licence, or partial revocation in respect of the licensee concerned, which in practical terms amounts to the removal of that licensee from the licence, while the licence continues in the hands of its former partners. In taking its decision, the OGA may also consider the fitness of directors and other persons (real or corporate) who exercise control over the Licensee post the change of control[4].

10. The existence of the change of control powers means that the majority of licensees and/or the entities proposing to acquire control of a licensee have requested a comfort letter from the OGA before the proposed acquisition completes, asking that the OGA set out that it is not minded to exercise the powers. The OGA is generally willing to consider such requests but will not fetter its own discretion and any comfort given will be based on the information available to the OGA at the time and limited accordingly. Given the potential impact of a change of control on joint venturers and other relevant persons (as that term is defined in the OGA Strategy), the OGA will normally seek representations from those parties at the start of its considerations with respect to exercising the change of control powers or the issuance of a comfort letter.

11. Over the past three years there has been an average of 12 changes of control each year. Over the past two years, three changes have been completed without prior notification to the OGA and requests for a letter of comfort. As the basin continues to mature and overall production levels decline, there is a trend towards larger, more established companies gradually exiting the market or reducing ownership of licensees, creating opportunities for new, often smaller and/or more diverse types of investors.

Problems with Current Arrangements

12. The current arrangements are now viewed by both the OGA and the majority of industry as being largely ineffective in preventing the harms, to both wider industry and government, that would flow from an undesirable change of control.

13. The main problem is that the OGA's powers engage only after the change of control has taken place (i.e. it is ex-post) and so cannot prevent an undesirable change concluding. This flaw is compounded by the weak remedy that the powers provide which is limited to requiring a further change of control to an unknown third party rather than to restore the status quo (with added uncertainty that the remedy will, in fact, lead to a cure).

14. In addition, the ex-post process takes a considerable amount of time - usually a minimum of one year and quite likely two years. During that time, an undesirable owner of the licensee is free to create the harms that the power is seeking to prevent, which could ultimately be detrimental to the UK economy and result in losses to wider society such as reduced economic activity and jobs. These harms include:

   - restricting investment in activity that would increase economic recovery and/or leading to the premature decommissioning of existing oil/gas fields (both against the OGA strategy and potentially posing risks to security of supply);

   - undertaking further changes of control of licensees (which risks further negative harms to society and the OGA has to undertake a separate process to consider);

[4] Oil and Gas Authority: Licensee criteria - Licensing system - Licensing & <br/>consents (ogauthority.co.uk)

- failing to accumulate funding for future liabilities (such as decommissioning), despite this being a breach of contract;

- directly or indirectly obstructing the investment plans of their co-licensees or burdening them (and, onshore, landowners) with additional liabilities including decommissioning (which could lead to wider negative harms as not all licensees will have the resources to make up for the defaulting licensee and could restrict their own investment);

- defaulting on their decommissioning obligations, leaving co-licensees to cover the costs[5];

- undermining investor confidence in the commercial environment, making the UK a less attractive place for financially robust and otherwise fit incumbent licensees, new companies or supply-chain companies to invest; and

- decreasing the value of the assets of the licensee thereby making any eventual forced further sale notice or revocation under the existing licence powers a less effective remedy.

15. By the nature of the oil and gas industry, the cost implications of the above scenarios will usually be of the order of tens, if not hundreds, of millions of pounds, and it is highly likely that these costs would ultimately fall to the taxpayer or society.

16. Further, the existing ex-post power brings no certainty of a satisfactory outcome - it does not return control to the original owner; may pass control to an even more unsuitable owner and can be enforced only by the threat of revocation of the licence which could, at that point, be worthless. A revocation may crystallise operational and financial harm to co-licensees and, possibly, the government. Consequently, even where there is a strong case supporting the use of existing powers to force a further sale or revocation, the need to balance this benefit against the likely effectiveness of the remedy, harm to others and proportionality generally, may result in a decision to accept the harms and take no action.

Summary of Proposed Measure

17. Due to the problems and harms caused by the current ex-post arrangements, it is proposed that they be replaced with new ex-ante powers which would enable the OGA to ensure that the governance and technical and financial capability of a carbon storage or petroleum licensee is preserved following a change of its controlling parent company. The intended effect of the change would be a more rapid and certain process either to agree to a desirable change of control or, alternatively, to forestall or remedy an undesirable change of control.

18. The OGA has informally consulted with industry, setting out the rationale for the proposed changes, their likely form, and the expected benefits. All three stakeholder groups (onshore, offshore and carbon storage) have engaged in the discussions, resulting in largely positive or neutral feedback with no negative responses. Existing petroleum licensees are increasingly aware of the risks to themselves of an undesirable change of control of their co-licensees and the weakness of their contractual rights to prevent this. Many carbon storage licensees are already petroleum licensees and recognise the need for a move to ex-ante powers. Further, the Crown Estate land rights leases, which an OGA licensee must hold to obtain an OGA licence, already contain an ex-ante change of control power.

## Section 2: Rationale for Intervention

19. The OGA currently have ex-post powers to ensure that the market maximises value and efficiency from use of national resources whilst crucially reducing the risk of negative externalities (resulting from the harms of inefficient use). These harms could include damage to economic value of the national resource (resulting from sub-optimal investment) and undermining investor confidence in the UK. However, as the industry has developed, ex-post powers are proving ineffectual at containing

[5] Under the Decommissioning Relief Deed, at least 50% of these costs will be met by the public purse − increasing the likelihood that decommissioning will need to be funded from the public purse if the Petroleum Act decommissioning regime is unable to impose these liabilities on co- or previous, licensees.

harms of damaging changes of control. The rationale for intervention is built around the following market failures:

Information asymmetry

20. The current ex-post arrangements, including no formal requirement to notify the OGA of prospective changes, nor assessment of the governance, technical, and/ or financial capabilities of the current and new licensee prior to the event, leads to an information asymmetry between the licensee(s) and the OGA. This informational imbalance leads to difficulties in the OGA effectively identifying changes of control which may be detrimental. Additionally, the OGA's current inability to withhold consent to changes in control taking place, could result in adverse selection, in that undesirable owners obtain control of licensees.

21. Under current arrangements, the frequency of undesirable changes may increase as the UK Continental Shelf (UKCS) further matures and M&A activity increases, resulting in more new entrants and more diverse types of investors. An alternative measure ensuring minimisation of the information asymmetry (and thus removing the market failure) is best achieved through government intervention as the OGA is a public body and current powers are limited.

Externalities

22. The substantial and costly negative externalities resulting from an undesirable change in ownership are described in paragraph 14. These externalities mean that the commitments made under a licence and other obligations in the OGA Strategy are not fulfilled, which are the key vehicles through which the OGA delivers its statutory duties and objectives. Beyond the direct impact of undesirable ownership on the licenced area and co-licensees, there are adverse impacts on wider investor confidence, making the UK a less attractive environment for production related investment and supporting supply chain activity.

23. HMG intervention is required to replace the ineffective ex-post power with an alternative measure which would address the information problem and enable the OGA to identify and prevent an undesirable change of control and any resulting negative externalities.

## Section 3: Policy Objective

24. The government's overall objective is to improve the OGA's ability to ensure that the governance, technical and financial capability of a carbon storage or petroleum licensee is preserved following a change of its controlling parent company thereby ensuring that the externalities and damage resulting from undesirable changes are avoided. Ultimately, the proposed changes to the current approach are expected to result in a faster and more certain process for OGA either agreeing to a desirable change of control or, alternatively, to forestall or remedy an undesirable change of control.

## Section 4: Description of Options Considered

Option 1 – Do nothing

25. Under the 'Do nothing' (counterfactual) option, the OGA would continue to attempt to prevent undesirable changes of control by using the existing ex-post provisions in the licence. As described above, however, these provisions act too late, can be manipulated to prevent a decision on licence revocation being made for several years and may not result in a satisfactory outcome in any event. Given the harms that undesirable new controlling companies will cause and the increasing risk that such companies will seek to control licences as the basin matures, this option is increasingly untenable. Further, the existing ex-post approach does not fit well with the Crown Estates' Lease ex - ante change of control provisions for Carbon Storage since the OGA and Crown Estate both need to form a view on the desirability of a change of control but at different times.

Option 2 – Enhanced ex-post remedy/sanctions powers

26. One regulatory approach could include enhancing the current ex-post remedy/ sanctions measures. However, we have not identified any additional sanction powers that could be applied under the current licences or law. Primary legislation could be used to introduce a power to reverse or nullify an undesirable change of control (rather than the current revocation if there is a failure to make a further sale). We understand that this remedy is contained in other legislation such as the recent National Security and investment Act 2021 and is used for changes of control that have serious implications for security or competition. Criminal sanctions could be adopted to underpin this approach or as a standalone sanction.

27. Option 2 alters the property rights of the existing owner (#1). The current licence powers (and the powers proposed) allow for an onward sale by the new owner (#2) of the licence holding company to another new company – owner #3 (absent which the licence can be revoked). The current licence powers do not insist that the on-sale is back to owner #1 and the OGA's experience is that these generally have no appetite to take back ownership. Option 2 powers of this scale and impact would be a major and radical change to the existing rights of owner #1, likely be very controversial and would require several additional, complex clauses in the current Bill to be effective. We do not consider that enhanced remedy or sanctions would be the best regulatory approach, and it is expected that Option 4 better meets the objectives set out in section 3. Should Option 4 fail to provide sufficient deterrent for undesirable changes of control, the issue of stronger sanctions would be revisited.

Option 3 – Non-regulatory approach

28. A non-regulatory approach could be taken to secure the agreement of all the licensees of over 700 existing licences (there are commonly three or more licensees on each licence) to voluntarily modify the terms of their licences. However, agreement would likely not be reached with some licensees. Even for the majority of licensees who support the change, the process of separate negotiation and replacement of contracts would be costly and inefficient for all. This option would not achieve the objective of the change and its delivery would be inefficient.

Option 4 – New ex-ante powers under primary legislation

29. A regulatory approach could be taken to replace the ex-post power with an ex-ante power to enable the OGA to identify and prevent an undesirable change of control rather than seek a remedy after a transaction has completed. Primary legislation would be required to accomplish this change via modification of the Licenses. The change would introduce a more specific approach to change of control with a clear application process and (prior to implementation) refreshed guidance. The introduction of dedicated information requirements for the industry and more clarity on the criteria for an acceptable new controlling company will make the process more objective and measurable. By placing the current, informal, "letter of comfort" process into the licence, the ex-ante approach would be underpinned by a well proven process which produces reasonable, defendable decisions. Ex-ante powers would also improve upon the existing ex-post powers (which for a complex or contested case has no time constraints) by introducing set durations for applications and decisions.

30. This is the preferred option as it is more certain in affect, and more efficient for the OGA and licensees.

## Section 5: Summary of Preferred Option and Implementation Plan

31. The preferred option is a regulatory approach to put primary legislation in place which will make provision for the existing change of control powers in Petroleum and Carbon Storage Licences to be moved from an ex-post to ex ante basis.

32. By moving to an ex-ante application and consent basis for change of control, the OGA will be able to identify and deter an undesirable change of control quickly. If the change of control nevertheless completes without the OGA's consent, decisions on sanctions (of revocation of the licence or fines under the OGA Strategy) will be more immediate and avoid the long delay in the current process during which the new controller of the licence is free to do harm. There will also be clearer grounds on which to seek a court order for an injunction to prevent the change of control.

33. The new arrangements are likely to come into effect shortly after enactment of the proposed legislation. The OGA's Regulation Directorate who currently administer the ex-post regime will be responsible for ongoing operation and enforcement. The new approach will be very similar, but more clearly defined, to the current informal "letter of comfort" approach used by the majority of licensees seeking a change of control.

34. Clear guidance for industry on the new approach will be published and arrangements made to support the familiarisation process for both industry and OGA staff. It is intended that industry will be consulted on the development of the guidance.

35. For changes in control that are underway and span the introduction of the new approach (i.e. those whose completion is less than three months from the time the provisions come into force), the OGA will ensure arrangements are in place for them to be processed on an accelerated basis.

## Section 6: Direct Costs and Benefits to Business Calculations

Proportionality of Analytical Approach

36. The analysis contained in this Impact Assessment is considered proportionate to accompany primary legislation, which will not, in itself, result in any direct costs or benefits to business. The legislation makes provision for the existing change of control process to be moved from an ex-post to an ex-ante basis. The proposed new arrangements will be established, operated, and enforced by the OGA and are likely to come into effect shortly after enactment of the proposed legislation.

37. Furthermore, in exercising its licence powers, the OGA must act proportionately and will therefore only make substantial ex-ante interventions (with the additional costs to itself or to the applicant) to prevent the risk of a significant harm of the type described in paragraph 14. Therefore, further detailed analysis will be produced on a case-by-case basis providing detail on costs and benefits.

38. Therefore, this IA has considered the nature and current best estimates of expected costs and benefits of the measure upon implementation by the OGA. The key analytical risks and uncertainties are identified in Section 7 below.

39. As a statutory regulator, the OGA will also include an assessment of the impacts of the measure as part of its obligations under the Business Impact Target (BIT) framework, as required by the Small Business, Enterprise and Employment Act (2015). Any updates or refinements to the analysis contained in this Impact Assessment will be reflected in the OGA's subsequent annual assessment. Based on this current assessment, the measure is expected to have very small direct impacts on businesses and well below the +/-£5m Equivalent Annual Net Direct Cost to Business (EANDCB) threshold for regulatory provisions requiring independent verification.

Description of the counterfactual (Option 1)

40. It is expected that there will be continuing demand for change of control as aggregate UK oil and gas production volumes decline. This has resulted in larger established companies gradually exiting the market or reducing ownership of licensees, with an increase in new entrants which are often smaller and/or more diverse in terms of the type of investors.

41. In recent years there has, on average, been 12 changes of control per year and it is estimated that this could increase in coming years to a maximum of around 20 applications each year[6]. In the vast majority of cases, an ex-ante letter of comfort has been sought from the OGA. The OGA estimates that its current resource cost is on average £1,200 per letter of comfort, covering staff time to review the submitted documentation from companies and prepare the letter.

42. Companies also currently incur costs in reviewing the existing OGA guidance and preparing documentation in support of requests for letters of comfort. It is expected that all of the required information is readily available as part of the proposed transaction and therefore costs relate only to

[6] This is based on historical cases and informed estimates from OGA of likely demand. It is a best estimate assumption for costing purposes.

compiling it in a format for submission to the OGA. As such, it is assumed that these costs are equivalent to those incurred by the OGA at £1,200 per case.

43. Ultimately, under the current ex-post powers, the costs related to the impacts of undesirable changes of control can, whilst varying with the circumstances, be of the order of tens, if not hundreds, of millions of pounds.

<u>Monetised Costs - Preferred Option (Option 4)</u>

44. We have only been able to monetise the costs for option 4. It is likely that costs under option 2 would be largely similar to those under the counterfactual (in that companies would still provide letters of comfort and follow the same procedure). Costs under option 3 are less clear and would depend on the amount of negotiation required to reach an agreement, as well as the time needed to amend contracts.

*Ongoing administrative and familiarisation costs*

45. If implemented, acquiring companies will incur costs in familiarising themselves with the new guidance and preparing applications to the OGA seeking consent to the proposed change of control. As outlined, that majority of companies currently review existing OGA guidance and seek a letter of comfort from the OGA, which is estimated at £1,200 per company per request. In the majority of cases, the proposed ex-ante powers are therefore not expected to increase administrative costs to companies relative to those under current arrangements (i.e. the counterfactual).

46. In practice, the proposed ex-ante approach could reduce administrative costs for the majority of companies compared to the current arrangements. This is because the ex-ante measure will introduce a more precise approach with a clear application process and bespoke change of control guidance, effectively placing the less clearly defined letter of comfort process into the established licence procedures. However, for the purposes of this Impact Assessment a prudent assumption is made that the change is cost neutral for those companies that would otherwise have sought a letter of comfort from the OGA.

47. Under the proposed ex-ante approach, the OGA will also seek representations from co-licensees. This will be in the form of a letter, seeking responses to a set of questions. It is expected that co-licensees will welcome this opportunity as, in some instances, it will help avoid far more significant costs resulting from the harms of an undesirable change of control. For the purposes of this Impact Assessment, it is assumed that there will be one co-licensee per transaction and the administrative cost in reading and responding to the letter will be half that incurred by the acquiring company submitting change of application i.e. £600 per case. To estimate this additional cost to industry, it is assumed that there will be between 10-20 applications, with a central estimate of 15 applications. This is based on recent experience of 12 cases each year and the potential for this to increase to around 20 applications. **Annual administrative costs to industry overall for submitting representations are therefore estimated at £6,000 to £12,000 with a central estimate of £9,000.**

48. Over the past two years, three companies have not requested a letter of comfort prior to a change of control taking place. All companies will now be required to seek ex-ante consent from the OGA and we assume there is full compliance with the legislation. For the purpose of cost estimates we have therefore made a prudent assumption that two companies each year read the guidance and submit an application of consent that would not have sought a letter of comfort under current arrangements (i.e. the counterfactual) at the standard assumed cost of around £1,000 per case. **Annual familiarisation and administrative costs to industry overall for submitting change of control applications are therefore estimated at around £2,000.**

*OGA cost recovery – fees scheme*

49. Currently, resource costs incurred by the OGA in administering the informal 'letter of comfort' and ex-post change of control process are recovered via the OGA levy paid, which is paid by all licensees. As outlined above, these costs are estimated at £1,200 per case. If the ex-ante powers become operational, the OGA intends to recover its costs via a new fee payable by the applicant licensee, resulting in a fairer allocation of costs to those parties directly involved in the transaction. The OGA

levy on licensees would be reduced by an equal amount resulting in no additional cost to industry overall.

50. The OGA has existing powers to charge fees to oil and gas and CCS licensees for defined services under the Energy Act (2016) and the addition of fees for the change of control process would be made via a Statutory Instrument. While the structured ex-ante process should also be less costly for the OGA to administer, for the purpose of this assessment a prudent assumption is made that there will be no change in the average cost to be recovered for cases where a change of control is approved.

Non-Monetised Costs - Preferred Option (Option 4)

51. The intended effect of the measure is that OGA consent for undesirable changes of control will not be granted. This would result in the loss of any costs incurred by parties to the change prior to the consent being rejected. It is not considered proportionate to attempt to monetise these costs which could vary considerably depending on the transaction and extent of work undertaken by the parties prior to consent being sought from the OGA. Furthermore, it is likely that these costs would also be incurred by licensees in the counterfactual.

Monetised Benefits - Preferred Option (Option 4)

52. We have only been able to assess the potential benefits for option 4. Under option 2, benefits would be lower than option 4, given that the negative externalities in the current ex-post system could persist. For option 3, as with the costs, the potential benefits are less clear, and would depend on the number of licensees who agree to have their licences changed and the timescale this is achieved over.

53. The primary legislation will not have any direct impacts on business, rather it will enable the OGA to utilise the ex-ante approach whenever necessary. The preceding section quantified small administrative and familiarisation costs to business under circumstances where the OGA does exercise the new powers. However, the clearer application process and refreshed guidance does have the potential to reduce administrative costs and therefore be net beneficial to business compared to the existing arrangements. In particular, for those applications that are finely balanced, the simplified process and the more certain, shorter, timeframe of the ex-ante application should result in lower administration costs by reducing the current recursive and un-timebound procedure.

Non-Monetised Benefits - Preferred Option (Option 4)

54. The proposed ex-ante framework seeks to identify and prevent an undesirable change of control rather than attempt an ex-post remedy long after the transaction has completed. For licensees as a group, the approach will introduce a more certain process for the OGA decision and its timeframe. This will reduce the risk of delay and the need for contingency arrangements for applicants. The proposals will improve the business environment for quality mergers and acquisitions and reduce the risk that co-licensees will be burdened with an undesirable partner.

55. The intended effect of the measure is to entirely deter or failing that substantially reduce the number of undesirable changes of control occurring. The administrative and legal costs (including costs of external legal counsel) to the OGA in addressing with undesirable changes of control would therefore reduce accordingly compared to under current arrangements. These avoided costs (benefits) can be very substantial. In addition, an undesirable change of control is likely to reduce investment and cover for liabilities, obstruct the investment plans of the co-licensees and generally undermine investment confidence. Moreover, it is expected that undesirable companies will be deterred from applying for consent and/or disincentivised from incurring significant pre-application costs. Crucially, any such sunk costs to companies are likely to be far outweighed by the avoided costs (benefits) to other companies and government from the harms that would transpire in the event of an undesirable change. The costs will vary with the circumstances but due to the nature of the oil and gas industry, the implications will usually be of the order of tens, if not hundreds, of millions of pounds.

56. In addition to preventing the harms discussed above in Section 1 whilst the ex-post process is being implemented, this ex-ante approach would bring further benefits. It is not considered proportionate to attempt to quantify these impacts, which include the following:
   - Making it more difficult for a less scrupulous, incumbent owner to realise higher value and avoid their liabilities and obligations by transferring control to an unsuitable owner.
   - Making a more timely decision at a single point of time ahead of the forthcoming transfer -.
   - Providing a tailored power to require information and a strong incentive for both the transferor and transferee to provide timely responses since the change of control could not take place until the analysis is complete.
   - Incentivising both the transferee and transferor to properly consider the impact of the change of control on the OGA's objectives and discouraging proposals that have little prospects of passing the OGA's tests.
   - Remove from consideration many of the questions of proportionality and effectiveness of any ex-post remedy since there will be no need for a remedy as a decision to refuse consent would maintain the status quo. Similarly, should the decision be judicially reviewed the harm done to the companies (and any damages sought) would likely to be lower than if the consideration had been paid and the new owner been active for a year or more after completion.
   - Delivering a more predictable and timely procedure for divestment of assets.

57. The overall net impacts are likely to be positive but will be relatively very small, particularly in the context of the costs and revenues related to oil and gas extraction activities

## Section 7: Risks and Assumptions

58. The primary legislation will not in itself have any direct impacts on business. The proposed new arrangements will be established, operated and enforced by the OGA. An assessment of potential impacts from implementation are included in this document to provide information on the intended effect of the measure. An underlying assumption is that absent government intervention, an increase undesirable changes of control will be proposed as the industry matures, which would otherwise undermine positive investment.

59. A key uncertainty is the number of proposed changes of control in future years. As outlined above, this is not a major determinant of administrative costs to industry overall as the majority of these costs are incurred under current arrangements.

60. This Impact Assessment assumes that there will be full compliance with the legislation i.e. all companies will seek consent from the OGA prior to completing a change of control and not proceed with if consent is not granted. The ex-ante powers cannot however prevent a change of control from occurring if consent were withheld, or not requested. The intended effect of the legislation is to deter these actions by companies and therefore to result in zero undesirable changes upon implementation of the measure. This will be monitored by the OGA as set out in Section 9 below.

## Section 8: Wider economic and societal impacts

<u>Wider economic impacts</u>

61. The proposed changes will support the government's objectives for the UK oil and gas industry and the Central Obligation set out in the OGA Strategy; to secure the maximum value of economically recoverable petroleum as well as support the wider North Sea Transition deal, enabling the Oil and Gas sector to transform its UK supply chains, jobs, and local communities. Furthermore, it ensures that the sector will assist in meeting the net zero target by reducing greenhouse gas emissions (from sources such as flaring and venting and power generation and supporting carbon capture and storage projects).

62. As a result of removing the negative externalities and preventing damage to investor confidence, there could be a range of wider benefits safeguarded. This includes investment in oil and gas production activities, supporting the UK supply chain and labour market capacity, capability and skills. Continued investment also supports innovation, competitiveness and the export of goods and services to international markets. In addition, continued investment supporting domestic production strengthens the resilience and security of oil and gas supplies. The industry also has a vital role to play in the UK energy transition as part of the North Sea Transition Deal announced in March 2021 with the aim of driving to net zero emissions as quickly as possible.

Small and micro business assessment

63. The number of small (10-49 employees) or micro-businesses (1-10 employees)[7] which currently own licensees is unknown, and it is not possible to estimate the number of prospective owners within these size-bands in coming years. It is important that a company with ownership of a licensee is well governed and is able to meet its financial and technical obligations, regardless of employee size-band. The financial (and technical) capability of an owner is of primary concern in assessing the desirability of ownership in terms of ability to fulfil licence and other legal obligations and the number of employees is not a reliable indicator of that capability.

64. The cost of acquiring control of a company via M&A share sales and the financial (capital and operating) costs incurred by companies involved in the production of oil/gas and related to carbon storage facilities (while variable by transaction, field and activity) are orders of magnitude higher than the relatively very small administrative costs for submitting an application for change of control to the OGA. The administrative costs of the change of control process should not therefore disproportionately impact any prospective owners or act as a barrier to investment.

65. It would not therefore be desirable to exempt small/micro businesses (as defined) as the harms that the measure aims to prevent could be caused by a company of any size. Moreover, the harms caused to the wider industry from undesirable ownership would have a large and disproportionate impact on smaller companies directly affected. An exemption could also lead to unintended consequences in that it could offer a means by which otherwise undesirable owners could secure effective control of a Licensee resulting in the harms to both industry and government that the proposed changes aim to address.

Trade impacts

66. The proposed approach will provide a shorter and more predictable regulatory procedure for changing the control of assets which will support desirable M&A activity in the industry. There are not expected to be any adverse trade impacts from this measure.

Competition impacts

67. There are not expected to be direct competition impacts from the proposed approach. The regulatory procedures will treat all proposed changes in the same way. A more stable and predictable regulatory system helps create a conducive environment for quality M&A activity that supports reliable long-term investment and increases the international competitiveness of the UK industry.

Equalities Assessment

68. The OGA has a general duty (The Public Sector Equality Duty) under section 149 of the Equality Act 2010 in carrying out its functions to have due regard to the need to:

- eliminate unlawful discrimination, harassment and victimisation;
- advance equality and opportunity between different groups; and

[7] BIS, Better Regulation Framework, Interim Guidance, March 2020
The Better Regulation Framework (publishing.service.gov.uk)

- foster good relations between different groups.

69. Consideration has been given to whether the proposed changes would have an adverse impact on persons with protected characteristics. Our assessment is that, given the corporate nature of relevant persons (as defined in the OGA Strategy) and the general application of the proposals, it is not anticipated that there would be such an impact.

## Section 9: Monitoring and Evaluation

70. The number of changes of control of licensees are already monitored by the OGA and the vast majority of cases each year are considered satisfactory. The OGA either has forewarning that the change of control is being planned via engagement with incumbent licensees and the letter of comfort process or, where a letter of comfort is not sought ex-ante, retrospectively becomes aware that a change in ownership has completed.

71. The proposed ex-ante approach aims to ensure that OGA consent is sought prior to change in control and where consent is not given, the change does not go ahead. It is expected that undesirable companies will be deterred from applying for or continuing with a change of control without the OGA's consent. The intended effect is therefore to have zero undesirable changes of control upon implementation of the measure. This will be closely monitored by the OGA within existing arrangements and resources.

72. A secondary measure of success will be a reduction in the OGA resource cost required to remedy an undesirable change of control. Monitoring and recording these costs will be implemented by the OGA as part of establishing the new approach.

73. In summary, the success of the measure could be measured by improved compliance with the legislation (i.e. applications are submitted to the OGA on an ex-ante basis for all prospective changes of control); faster decision making on undesirable changes; and, more effective and timely remedies for undesirable changes.[8]

74. The policy could have to be reviewed sooner if the industry reacted in an unexpected way (whereby there could be an increase in the number of cases if it becomes easy to avoid legal liabilities, rather than the current situation of a few undesirable cases). Then, as described under option 2, a regime in which undesirable changes of control could be voided would be considered. The legislative requirement for such a power would be substantial.

[8] As an example, under the proposals, a breach of the licence will have clearly taken place immediately if the change of control takes place without consent. The process will be on a firmer footing legally and actions taken more rapidly, potentially including the possibility of seeking an injunction to prevent an immediate harm.

# Energy Bill 2022 – Application to the territorial sea of requirement for nuclear site licence

## Policy background

In its 2018 policy paper, *Implementing geological disposal – working with communities: An updated framework for the long-term management of higher activity radioactive waste*, the UK Government reiterated its commitment to geological disposal as the best means to manage the most hazardous radioactive waste for the long term. A Geological Disposal Facility (GDF) is a highly engineered facility capable of isolating radioactive waste within multiple protective barriers, deep underground, so that no harmful quantities of radioactivity ever reach the surface.

A GDF is vital to the successful decommissioning of the UK's civil nuclear legacy and our new build nuclear power programme which will support the Government's net zero ambitions and its Energy Security Strategy. A GDF will allow the Nuclear Decommissioning Authority (NDA) to complete the decommissioning and clean-up of the existing nuclear estate, retiring the ongoing liabilities of continuing to manage radioactive waste at the surface for generations to come.

A process is underway to identify a suitable site for a GDF in England and Wales. It is a consent-based approach which requires a willing community to be a partner in the project's development. It is the community that will have the final say in deciding whether or not they want a GDF in their area. The policy is clear that a GDF could be built either on land or under the seabed.

Due to the potential level of hazard involved in its operation, it is vital that a GDF is subject to robust regulation, and therefore in the 2018 policy paper the UK Government reiterated that a GDF would be a nuclear installation under the Nuclear Installations Act 1965 (NIA 1965) and would therefore require a licence from the Office for Nuclear Regulation (ONR).

This impact assessment considers changes to primary legislation to make clear that certain nuclear sites, located wholly or partially in or under the territorial sea adjacent to the UK are required to be licensed and made subject to regulatory oversight by the ONR in Great Britain and by the Secretary of State in Northern Ireland. As the ONR's powers in relation to nuclear sites are principally set out in the NIA 1965 and the Energy Act 2013 (EA 2013), amendments to both of these Acts are required. Whilst the policy driver for this change is to ensure a GDF is licensable, the legislative changes cover other nuclear sites located wholly or partially in or under the seabed.

## *Is this a qualifying Better Regulation regulatory provision[1]?*

New primary legislation to clarify that nuclear sites can be located in or under the territorial sea is not a Better Regulation regulatory provision. This clarification would not impose or amend any requirements on business activity. The clarifications also do not relate to the securing of compliance with, or the enforcement of, requirements which relate to business activity.

## *Discussion of impacts*

The purpose of this legislative amendment is to clarify that nuclear sites, which are in or under the territorial sea adjacent to the UK, are required to be licensed and regulated. This is a technical clarification which is intended to reduce the possibility of confusion. This will ensure clarity for communities in the siting process that a GDF constructed under the seabed will be licensed and regulated.

This legislative amendment is not expected to affect any decisions by the regulator to license, or regulate, any current or future nuclear sites. Therefore, there are no impacts which can be monetised as a result of this legislative amendment.

Whilst this legislative amendment is relevant to nuclear sites generally, not just prescribed disposal sites, the Government envisages that it will be most relevant to GDF policy because a GDF may be partially constructed under the territorial sea adjacent to the UK. Further secondary legislation is needed to add certain disposal facilities to the list of prescribed installations under the Nuclear Installations Regulations (NIR 1971). This will ultimately enable the ONR to license and regulate a GDF, if and when such disposal installations are prescribed. No new primary powers are required to make the necessary amendments to the NIR 1971.

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[1] Section 22(3) of the Small Business, Enterprise and Employment Act 2015 ("SBEE 2015") defines "regulatory provision" as:

> *(3)A "regulatory provision", in relation to a business activity, means a statutory provision which—*
> *(a)imposes or amends requirements, restrictions or conditions, or sets or amends standards or gives or amends guidance, in relation to the activity, or*
> *(b)relates to the securing of compliance with, or the enforcement of, requirements, restrictions, conditions, standards or guidance which relate to the activity.*

**Title:** Offshore Oil and Gas (Habitats Assessment and Emergency Pollution Planning & Response)
**IA No:** BEIS032(F)-22-EDR

**RPC Reference No:** RPC-BEIS-5173(1)

**Lead department or agency:** BEIS / OPRED

**Other departments or agencies:** Defra and DfT / MCA

# Impact Assessment (IA)

**Date: 06/07/2022**

**Stage:** Development/Options

**Source of intervention:** Domestic

**Type of measure:** Primary legislation

**Contact for enquiries:**
EnergyBill2021@beis.gov.uk

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| Not Quantified (N/Q) | N/Q | N/Q | Not a regulatory provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

A range of EU-derived legislation has contributed to the establishment of a comprehensive environmental regulatory regime for UK offshore oil and gas activities. This legislation was implemented into UK law under section 2(2) of the European Communities Act 1972 ("the ECA 72") which was repealed at the end of the Implementation Period. As the ECA 72 no longer applies in the UK, a large part of the current offshore oil and gas environmental regulatory regime is essentially 'frozen'. Consequently, BEIS / OPRED[1] no longer has any enabling primary powers to change secondary legislation which concerns matters that fall within OPRED's regulatory remit and extend to the United Kingdom's territorial waters and the Continental Shelf.

**What are the policy objectives of the action or intervention and the intended effects?**

The inclusion of suitable primary powers in the Energy Security Bill would ensure that the offshore oil and gas environmental regulatory regime remains fit for purpose by allowing the future introduction by OPRED of changes to secondary legislation which would ensure that the regime**: (i)** maintains high standards in respect to offshore habitats protection and pollution response; **(ii)** keeps pace with developing technologies such as offshore CO2 storage; **(iii)** implements changes resulting from any future case law judgements; and **(iv)** facilitates the offshore hydrocarbon sector's transition to net zero.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

**(a) Option 1 "Do-nothing" - Not including pertinent primary powers in the Energy Security Bill:** This would result in a large part of the offshore oil and gas environmental regulatory regime remaining 'frozen' - meaning OPRED would be unable to change secondary legislation.

**(b) Option 2 - Including pertinent primary powers in the Energy Security Bill:** This would enable OPRED (as the environmental regulator for the offshore oil and gas industry for over two decades) to change secondary legislation in order to meet the objectives as outlined above. Note that, because the inclusion of primary powers would not itself subject businesses to any new regulation, this policy option is a non-regulatory provision.

**Will the policy be reviewed?** It will be reviewed. **If applicable, set review date:** N/A

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | Yes / No | | | |
| Are any of these organisations in scope? | **Micro** Yes | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** N/Q | **Non-traded:** N/Q | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: ______________ Date: 24/06/2022

[1] OPRED - Offshore Petroleum Regulator for Environment and Decommissioning (which is part of BEIS)

# Summary: Analysis & Evidence

Policy Option 1

**Description:**

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2019 | **PV Base Year** 2020 | **Time Period Years** | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | 0 | N/Q | 0 | **0** |
| **High** | 0 | | 0 | **0** |
| **Best Estimate** | 0 | | 0 | **0** |

**Description and scale of key monetised costs by 'main affected groups'**

The primary powers in the Energy Security Bill will not in themselves incur any costs to Government or the offshore oil and gas industry. The powers will just enable OPRED to introduce future changes to secondary legislation. At this stage it is not possible to assess what the likely impacts might be because draft legislative measures have not been prepared. Therefore, no table summarising the cost impacts can be presented.

**Other key non-monetised costs by 'main affected groups'**

No immediate' non-monetised' costs for the reasons described in the response to the question directly above.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | 0 | 0 | 0 | **0** |
| **High** | 0 | | 0 | **0** |
| **Best Estimate** | 0 | | 0 | **0** |

**Description and scale of key monetised benefits by 'main affected groups'**

The primary powers in the Energy Security Bill will not in themselves lead to any direct benefits. The powers will just enable OPRED to introduce future changes to secondary legislation. At this stage it is not possible to assess what the likely impacts might be because draft legislative measures have not been prepared. Therefore, no table summarising the monetised benefits can be presented.

**Other key non-monetised benefits by 'main affected groups'**

The inclusion of suitable primary powers in the Energy Security Bill would enable OPRED to continue evolving the offshore regulatory regime so that it remains fit for purpose from an environmental protection perspective and can meet future challenges (e.g. those associated with the transition of the offshore oil and gas industry to a low carbon energy sector as part of net zero).

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | |
|---|---|---|
| N/A | | |

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** 0 | **Benefits:** 0 | **Net:** 0 | 0 |

# Evidence Base

## 1.1 Problem under consideration

1. The Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) is responsible for administering the environmental and decommissioning regulatory regime for offshore oil and gas activities in the UK.[1] Specifically, its remit includes**:**

    - handling domestic and international policy relating to the environmental regulatory regime for offshore oil and gas operations - working with other departments (e.g. Defra), environmental bodies (e.g. Statutory Nature Conservation Bodies such as the Joint Nature Conservation Committee) and international organisations (e.g. OSPAR[2]);

    - developing, administering and enforcing the offshore oil and gas environmental regulatory regime (including in respect to offshore gas unloading and storage and carbon dioxide storage);

    - implementing the oil and gas decommissioning regime and ensuring that the costs are met by the oil and gas companies and not the taxpayer;

    - managing the Strategic Environmental Assessment Programme for offshore energy projects; and

    - working with other regulators (e.g. the North Sea Transition Authority) to achieve reductions in greenhouse gas emissions from offshore oil and gas operations, in line with the commitments of the Energy White Paper, the North Sea Transition Deal and Net Zero Strategy.

2. A range of EU-derived legislation has contributed to the establishment of a comprehensive environmental regulatory regime for UK offshore oil and gas activities. This legislation was implemented into UK law under section 2(2) of the European Communities Act 1972 ("the ECA 72") which was repealed at the end of the Implementation Period (31 December 2020). As the ECA 72 no longer applies in the UK, a large part of the present offshore oil and gas environmental regulatory regime is essentially 'frozen'. Consequently, OPRED no longer has any enabling primary powers to change secondary legislation which concerns matters that fall within OPRED's regulatory remit and extend to the United Kingdom's territorial waters and the UK Continental Shelf.

## 1.2 Rationale for intervention

3. The primary powers to be included in the Energy Security Bill would allow the future introduction by OPRED of changes to secondary legislation to ensure that the offshore oil and gas environmental regulatory regime remains fit for purpose.

4. Only Government can put in place the powers and introduce subsequent secondary legislation.

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[1] Further information about OPRED and its responsibilities and priorities are accessible here: https://www.gov.uk/government/organisations/offshore-petroleum-regulator-for-environment-and-decommissioning/about

[2] OSPAR - Oslo / Paris Convention for the Protection of the Marine Environment of the North-East Atlantic

## 1.3 Policy Objectives

5. Currently, OPRED is unable to make changes to secondary legislation to enhance offshore habitats protection and pollution response and to also meet net zero challenges which could lead to international criticism, loss of public, NGO and investor confidence as well as fewer carbon savings.

6. The policy objectives are to enable OPRED to adequately**:**

   - ensure that the offshore oil and gas environmental regulatory regime remains fit for purpose by responding to changes in policy delivery required to meet the challenges of achieving net zero, including extending regulatory obligations for habitats assessment and emergency pollution planning and response to new technologies such as hydrogen production and storage; implementing lessons learned from any future offshore incident (e.g. a major oil spill); and implementing changes resulting from any future case law judgements; and

   - avoid extra burdens being passed on to the taxpayer by ensuring that fees are charged to the offshore oil and gas industry for the provision of specific regulatory services.

## 1.4 Policy Options

7. Two policy options have been identified**:**

   - **Option 1 "Do-nothing" - Not including pertinent primary powers in the Energy Security Bill,** meaning a large part of the current offshore oil and gas environmental regulatory regime would remain 'frozen' and the above objectives would not be met.

   - **Option 2 - Including pertinent primary powers in the Energy Security Bill** enabling OPRED (as the environmental regulator for the offshore oil and gas industry for over two decades) to make amendments to secondary legislation, enabling the objectives outlined above to be met.

## 1.5 Why primary powers are required in the Energy Security Bill

8. Having assessed primary powers in existing Acts, they are considered inadequate for the purposes of enabling OPRED to make future changes to secondary legislation to achieve the broad objectives set out in the 'Policy Objectives' section above. More specifically**:**

   **(i)** **The Pollution Prevention and Control Act 1999:** The powers only address pollution which does not fully encompass wider aspects associated with the environment such as encouraging biodiversity.

   **(ii)** **The Petroleum Act 1998:** None of the powers in this Act appear to be particularly relevant to the environment.

   **(iii)** **The European Union (Withdrawal) Act 2018 ("the 2018 Act"):** Relevant provisions in the 2018 Act enable the making of revisions to existing legislation appertaining to fees schemes that were introduced using powers under the Finance Act 1973 which fell at the end of the Implementation Period (IP). However, the 2018 Act's provisions on fees schemes cannot be used to introduce changes that relate to any regulatory services which were not previously charged for prior to the end of the IP.

9. Therefore, the inclusion of suitable primary powers in the Energy Security Bill is crucial to meeting the policy objectives.

## 1.6 Impacts

10. The primary powers OPRED is seeking for environmental regulation in the Energy Security Bill will not, in themselves, incur any immediate direct costs to Government or the offshore oil and gas industry. The powers will just enable OPRED to make future changes to secondary legislation. At this stage it is not possible to assess what the costs and benefits of the use of these powers by OPRED might be, because draft secondary legislation has not been prepared.

11. Prior to introducing future secondary legislation, OPRED would liaise with other relevant Government Departments and stakeholders to make sure that they were content with the legislative proposals. The proposals would also be accompanied by an assessment of their potential impact.

12. Details of existing legislation which could be the focus of future amendments and illustrations of what those amendments could potentially be, are outlined below.

**(1) The Offshore Safety Directive 2013/30/EU** which aims to reduce the occurrence and consequences of major accidents related to offshore oil and gas operations. The Directive is implemented by different legislation including **The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015**[3] to which future legislative amendments could comprise extending the application of the regulatory provisions to cover offshore gas unloading and storage (GUS), offshore carbon dioxide storage (CDS) and hydrogen production and storage operations or changing the fees provisions to reflect adjustments to OPRED's charging rates and any new regulatory aspects which may be chargeable.

**(2) The Habitats Directive 92/43/EEC and Wild Birds Directive 2009/147/EC** which aim to protect important habitats to ensure the conservation of a wide range of rare, threatened, or endemic animal plus plant species and wild bird species. These Directives are implemented for most offshore oil and gas - including GUS and CDS - activities by OPRED through **The Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001 (as amended)**. Future legislative amendments could comprise extending the application of the regulatory provisions to cover offshore hydrogen production and storage operations or incorporating provisions to be able to appoint Inspectors to monitor and investigate compliance with consents.

[3] The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 also made supplementary amendments to the Merchant Shipping (Oil Pollution Preparedness, Response and Cooperation Convention) Regulations 1998.

### 1.6.1 Impacts on small and micro businesses

13. The primary powers OPRED is seeking for environmental regulation in the Energy Security Bill will not incur any immediate direct costs to the offshore oil and gas industry. Because of this, there will be no impact on small and micro businesses.

14. Any future secondary legislation introduced by OPRED pursuant to powers in the Energy Security Bill will be assessed via proportionate levels of small and micro business analysis. Such analysis is not presented here, though some contextual information regarding the role of small and micro businesses in the offshore oil and gas sector is given below. Supporting evidence relating to small and micro businesses is not presented but will be gathered as part of any assessment of future legislation.

15. There are some small or micro businesses involved in offshore oil and gas ("hydrocarbon") operations, although those operations are highly complex and require considerable investment. Subject to having the requisite technical and financial resources in place, businesses of all sizes can participate in UK upstream hydrocarbon activities. However, in this context, small or micro businesses involved in offshore hydrocarbon operations are invariably subsidiaries of larger international parent organisations, thereby ensuring access to sufficient resources to support the undertaking of functions associated with the exploration and production of offshore hydrocarbons.

16. Where a small or micro business participates in offshore hydrocarbon operations, it will inevitably be one of several co-venturers ("parties") - comprising, in many cases, large multinationals (not necessarily the parent organisations (as referred to in paragraph 15) of any of the other parties) who would make an agreement among themselves regarding the governance of existing and future operations, including the requirement to comply with the existing, or any new, obligations under OPRED's offshore oil and gas environmental regulatory regime (the costs of which, in respect to each offshore field, would be very small in comparison to the magnitude of costs related to hydrocarbon production operations over the entire lifecycle of a field development). There is also nothing to stop parties apportioning the costs of complying with the environmental regulatory regime between themselves.

17. Therefore, it is not expected that any small or micro businesses would be impacted disproportionately by any future secondary legislation that is introduced by OPRED pursuant to powers in the Energy Security Bill.

18. It is important to note that the risk of major hazards and environmental effects is not proportionate to business size. Consequently, it is crucial that all businesses operating offshore, irrespective of size, are subject to the same environmental regulatory regime to ensure that they continue to provide a high level of protection for the marine environment. Nevertheless, as is the case for existing environmental legislation, to minimise the impact of any future regulatory requirements on the offshore hydrocarbons industry as a whole, detailed guidance on how to comply with new legal requirements would be prepared by OPRED.

19. Based on the above factors, an exemption for small or micro businesses from the obligations of the offshore oil and gas environmental regulatory regime is not considered appropriate.

## 1.7 Public Sector Equality Duty Assessment

20. No direct Equality Act 2010 impacts would result from the inclusion within the Energy Security Bill of OPRED's 'Offshore Oil and Gas (Habitats Assessment and Emergency Pollution Planning & Response)' provisions as the powers (once enacted) would solely relate to the offshore oil and gas environmental regulatory regime and enable OPRED to introduce secondary legislative measures (e.g. amendments to existing regulations) to ensure that the regime remains effective in its purpose.

21. OPRED will consider the impacts on those with protected characteristics as part of any future secondary legislation that results from the use of the Bill's powers.

## 1.8 Monitoring and Evaluation

22. Monitoring and evaluation will be completed as part of the Post Implementation Review provisions that would be included - as appropriate - in any future secondary legislation.

| | |
|---|---|
| **Title:** Offshore Oil & Gas Decommissioning Cost Recovery<br>**IA No:** BEIS033(F)-22-EDR<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** Department for Business, Energy & Industrial Stragey (BEIS)<br>**Other departments or agencies:** Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) | **Impact Assessment (IA)**<br>**Date: 06/07/2022**<br>**Stage:** Development/Options<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** EnergyBill2021@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2020 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| N/Q | N/Q | N/Q | Qualifying provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

The existing regime for recovering costs to government of decommissioning oil and gas installations was implemented at a time when the decommissioning process was still immature. In recent years, as operators have commenced decommissioning in the UK Continental Shelf (UKCS), it has become clear that the fee-charging regime does not sufficiently cover the full life cycle of the work required by the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) in delivering decommissioning services to industry. OPRED is looking to reform its charging regime to ensure it can comprehensively recoup all relevant costs from industry and maintain the effectiveness of the 'polluter pays' principle in UK environmental law.

**What are the policy objectives of the action or intervention and the intended effects?**

The objective of this measure is to ensure OPRED can fully recover from industry the cost of providing its services. Additionally, by regularising the charging regime, this measure aims to give operators greater foresight of their cash flows and enable them to undertake their decommissioning activities more efficiently. Finally, this measure serves to bring OPRED's charging regime for decommissioning activities in-line with existing regimes in place for recovering other environmental fees, reducing the administrative burden on operators.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

- **Option 1: Counterfactual – 'Do nothing'.** The current charging regime remains unchanged; OPRED continue to charge only when decommissioning programmes are approved or revised, based on an indicative fee per type of installation or pipeline.
- **Option 2: Introduce amendments to the charging regime with regular charging.** The charging process for decommissioning activities would be based on the application of an hourly rate system with charges being made at regular points. The process will be fully aligned with existing fee regimes within OPRED for offshore environmental fee recovery.
- **Option 3: introduce amendments to the charging regime without regular charging.** Charging will occur on completion of statutory function/activity, rather than regularly as proposed in Option 2.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:** N/A

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | | No | | |
| Are any of these organisations in scope? | **Micro** No | **Small** Yes | **Medium** Yes | **Large** Yes |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | | **Traded:** N/A | **Non-traded:** N/A | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

## Summary: Analysis & Evidence

Policy Options 2 and 3

**Description:** Amendments to the charging regime with or without regular charging

**FULL ECONOMIC ASSESSMENT**

| Price Base Year 2020 | PV Base Year 2022 | Time Period Years 10 | Net Benefit (Present Value (PV)) (£m) | | |
|---|---|---|---|---|---|
| | | | **Low:** N/Q | **High:** N/Q | **Best Estimate:** N/Q |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** N/Q | Optional | | Optional | **Optional** |
| **High** N/Q | Optional | | Optional | **Optional** |
| **Best Estimate** N/Q | N/Q | | N/Q | **N/Q** |

**Description and scale of key monetised costs by 'main affected groups'**

The net cost of each policy option under consideration is zero, as the total running costs are the same in every case. While Option 1 represents business-as-usual, Options 2 and 3 effectively transfer some of the decommissioning costs from the taxpayer to duty holders. This transfer is estimated to have a net present value of between £9m and £21m over ten years from the point of view of the taxpayer. From the point of view of society, there is no net gain or loss from implementing either of these two options, as the savings to the taxpayer are exactly equal to the additional costs to duty holders.

**Other key non-monetised costs by 'main affected groups'**

None.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** N/Q | Optional | | Optional | **Optional** |
| **High** N/Q | Optional | | Optional | **Optional** |
| **Best Estimate** N/Q | N/Q | | N/Q | **N/Q** |

**Description and scale of key monetised benefits by 'main affected groups'**

None.

**Other key non-monetised benefits by 'main affected groups'**

This measure will allow OPRED to reform its charging regime to ensure it can comprehensively recoup all relevant costs from industry and maintain the effectiveness of the 'polluter pays' principle in UK environmental law.

The key non-monetised benefits accrue to both OPRED, in their ability to now recoup the full costs from industry for their services as the regulator, and to duty holders who will benefit from more regular charging allowing them to better and more efficiently plan ahead through the alignment of cost recovery with other environmental fees charged by ORPED.

| **Key assumptions/sensitivities/risks** | **Discount rate (%)** | |
|---|---|---|

Due to the uncertainties around forecasting fee recovery and decommissioning costs, multiple scenarios have been modelled, with impacts monetised where possible, between 2022/23-2031/32, a 10-year period. The modelling shows how estimated decommissioning costs are affected by changes to OPRED's annual total running costs and to changes in the percentage of decommissioning cost that fall to the duty holders given the uncertainties in both.

**BUSINESS ASSESSMENT (Option 1)**

| **Direct impact on business (Equivalent Annual) £m:** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs:** N/Q | **Benefits:** N/Q | **Net:** N/Q | |

# Evidence Base

## Background

1. The decommissioning of offshore oil and gas installations and pipelines on the United Kingdom Continental Shelf (UKCS) is controlled through the Petroleum Act 1998, as amended by subsequent Energy Bills.

2. The UK's international obligations on decommissioning are governed principally by the 1992 Convention for the Protection of the Marine Environment of the North East Atlantic (OSPAR Convention). Agreement on the regime to be applied to the decommissioning of offshore installations in the Convention area was reached at a meeting of the OSPAR Commission in July 1998.

3. The Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), which sits within the Department of Business, Energy and Industrial Strategy (the “Department”), formerly the Department for Energy and Climate Change, has the responsibility for ensuring that the requirements of the Petroleum Act 1998 and international obligations are complied with. OPRED is also the competent authority on decommissioning in the UK for OSPAR (international regulations) purposes.

4. In line with the fundamental polluter pays principle of environmental law, those who are responsible for putting in place offshore oil and gas installations and pipelines to benefit from the extraction of hydrocarbons should pay for its decommissioning. Those responsible are referred to as ‘duty holders’ throughout this document. To avoid passing costs onto the taxpayer, under the Petroleum Act 1998, the Secretary of State has the power to make regulations to charge for the Department’s work in relation to regulating decommissioning – so in 2012 the Government made the Offshore (Oil and Gas) Installation and Pipeline Abandonment Fees Regulations 2012, which put in place the existing fee charging regime.

5. Under the existing fee charging regime, the OPRED charges industry a fee when submitting decommissioning programmes or requesting the revision of programmes, to recover its costs of carrying out functions in relation to the decommissioning of offshore (oil and gas) installations and pipelines.

### Policy objective, problem under consideration and rationale for intervention

6. The objective of this measure is to make amendments to the existing charging fee regime for OPRED services that are related to the decommissioning process, to ensure OPRED can fully recover from industry the cost of providing those services. These amendments are also intended to give operators greater foresight of their cash flows, enabling them to undertake their decommissioning activities more efficiently, by regularising the regime by which OPRED charges operators for using its services. Finally, the regulatory changes proposed here will bring OPRED’s charging regime for its decommissioning activities in-line with existing regimes in place for recovering other environmental fees, reducing the administrative burden on operators.

7. The existing regime was implemented at a time when the decommissioning process was still immature. In recent years, as operators have commenced decommissioning in the UKCS, it has become clear that the fee-charging regime does not sufficiently cover the full life cycle of the work of OPRED involved in delivering the service to industry which can take place over a period of 1 to 15 years. This is particularly evident for monitoring the execution of decommissioning activities, which is done to ensure these are consistent with the approved plans, and financial assessment to protect the taxpayer from the risk of funding decommissioning liabilities in the event of company default.

8. Due to aging infrastructure in a mature basin and the decline of oil price, operations are no longer achieving maximum recovery resulting in the levels of decommissioning activity significantly increasing year-on-year, and BEIS is currently unable to recover from industry its full costs of providing its regulatory functions due to the fact that under the current charging regime ORPED are only able to charge for services post decommissioning programme approval. At this stage, we cannot accurately quantify what the increase in decommissioning activity will mean in terms of cost increase for BEIS, as the timing of decommissioning activities is heavily dependent on oil and gas price fluctuations. However, as decommissioning accelerates within the UKCS, the proportion of activities undertaken by OPRED relating to post decommissioning monitoring and execution are expected to increase significantly.

9. The shortfall in recovered costs is currently met through central budgets, therefore falling on the taxpayer. The Department believes primary legislation is needed to better recover its costs for fulfilling its regulatory functions, to ensure the effectiveness of the ‘polluter pays’ principle and in line with HM Treasury’s guidance on Managing Public Money. The proposed changes to the fee charging regime and primary legislation would ensure OPRED can fully recover from industry the cost of providing its services. The changes will only affect businesses responsible for the development, operation and decommissioning of offshore (oil and gas) installations and pipelines. The costs of fulfilling these regulatory functions are referred to as ‘decommissioning costs’ throughout this document.

10. It is essential that BEIS recovers costs wherever possible, rather than them falling to the taxpayer and that the effectiveness of the ‘polluter pays’ principle is maintained in environmental law. The Department would not be seeking to make a profit from such a fee or charge but to fully recover its costs in carrying out those functions. As the Department facilitates the decommissioning process, it would be fair that the companies leading to this expenditure should contribute to such costs and enable BEIS to maintain those statutory functions.

## Description of options considered

This Impact Assessment considers two broad options to reform the existing decommissioning charging regime against a do-nothing counterfactual in which the existing charging regime remains in place.

### *Option 1: Counterfactual – ‘Do nothing’: The current charging regime remains unchanged (BAU)*

11. Under this option, the charging regime remains unchanged. OPRED continues to charge only when decommissioning programmes are approved or revised, based on an indicative fee per type of installation or pipeline.

12. BEIS will not recover its full costs from industry for executing its statutory functions and the shortfall will continue to be met through central budgets, therefore falling on the taxpayer.

13. With charges not being made at regular points, BEIS and industry will continue to find it challenging to manage the financial accounting process for the costs associated with the fee charging regime.

***Option 2: introduce amendments to the charging regime with regular charging***

14. Option 2 introduces amendments to OPRED's current charging regime, to charge for all services provided to industry under part IV of the Petroleum Act 1998 (the Act). This option ensures that the companies directly benefitting from the regulatory services fully meet the cost associated with its provision.

15. The charging process for decommissioning activities would be based on the application of an hourly rate system and the number of personnel undertaking the work with charges being made at regular points. The process will be fully aligned with existing fee regimes within OPRED for offshore environmental fee recovery. Charging regularly also has additional benefits, as it would help the Department and industry to better forecast and accrue costs.

16. The proposed changes under Option 2 would have no impact on small and medium-sized enterprises (SMEs), as none of the existing operators fall within this definition.

***Option 3: introduce amendments to the charging regime without regular charging***

17. Option 3 introduces amendments to OPRED's charging regime as described above for Option 2. However, charging would occur on completion of statutory function/activity, rather than regularly as proposed in Option 2. Therefore, the additional benefits achieved through regular charging would not be achieved.

18. The proposed changes under Option 3 would also have no impact on SMEs, as none of the existing operators fall within this definition.

## Summary and preferred option with description of implementation plan

19. BEIS believes it is appropriate for duty holders to meet the full costs of providing the regime which is in line with the polluter pays principle of environmental law. For this reason, Option 1 is therefore no longer tenable and is considered in this Impact Assessment only as the counterfactual against which the other options are assessed.

20. By inserting new charging powers into the Act, option 2 makes amendments to OPRED's charging regime, to align with the statutory functions of the Secretary of State which provide a service to industry under Part IV of the Act. This option ensures that those companies directly benefiting from the regulatory services meet the cost associated with its provision, and industry would be charged at regular points.

21. This would align better with OPRED's current environmental fee recovery regime, where operators are billed on a quarterly basis, and therefore would not place additional administrative burden on companies. Industry would therefore cover the costs incurred, rather than the taxpayer. The new regime would also enable better forecasting of costs and accruals in the accounts.

22. Option 2 would be implemented via a change in primary legislation to charge for all statutory provisions under part IV of the Act where OPRED acts on behalf of the Secretary of State. OPRED would be responsible for the implementation, ongoing operation and enforcement of the new arrangements. Secondary legislation will be implemented to cover the application of an hourly rate system.

23. Although Option 3 would allow the department to fully recover the costs of carrying out its statutory functions, and is therefore preferred to Option 1, there are the additional benefits under Option 2 which arise from charging industry more regularly. Irregular charging under Option 3 would not solve the current financial accounting issues with an inability to accurately forecast and accrue the costs. Therefore, Option 3 would not provide HMG and duty holders the full benefits of changing the fee charging regime.

24. Therefore, Option 2 is BEIS's preferred policy option.

## Monetised and non-monetised costs and benefits of each option (including administrative burden)

25. Based on estimated costs for 2021/22 only, the total annual running cost of OPRED is assumed to be £3.7m under all options, expressed in 2020 prices.[1] Of this, around £0.8m would still fall on the taxpayer under Options 2 and 3, as not all running costs, such as policy development, are recoverable. The remaining £3.0m represents the full cost recovery for providing OPRED services under Options 2 and 3. Based on data from the last three years, a range of cost estimates have been provided under Option 1 as to how much falls to the taxpayer versus duty holders. The breakdown of these decommissioning costs under the three options is shown in Table 1 below.

26. The present value of the costs under each option under consideration is zero, as the total running costs are the same in every case. While Option 1 represents business-as-usual, Options 2 and 3 effectively transfer some of the decommissioning costs from the taxpayer to duty holders. From the point of view of society, there is no net financial gain or loss from implementing either of these two options, as the savings to the taxpayer are exactly equal to the additional costs to duty holders.

*Table 1: Annual decommissioning costs for 2021/22 under the existing and proposed fee charging regime, in 2020 prices. Note that decommissioning costs may not always sum to £3.7m, due to rounding.*

| | **Option 1: Existing fee charging regime** | | **Options 2 and 3: Proposed fee charging regime** | |
|---|---|---|---|---|
| **2021/22** | **Duty holder** | **Taxpayer** | **Duty holder** | **Taxpayer** |
| Decommissioning cost | £1.1m - £1.6m | £2.1m – £2.6m | £3.0m | £0.8m |
| Total running costs | £3.7m | | £3.7m | |

[1] Cost estimates have been deflated back to the 2020/21 financial year, to obtain figures in 2020 prices.

## Risks and assumptions

27. Due to the uncertainties around forecasting fee recovery and decommissioning costs, multiple scenarios have been modelled, with impacts monetised where possible, between 2022/23-2031/32, a 10-year appraisal period. The modelling shows how estimated decommissioning costs are affected by changes to annual total running costs and to changes in the percentage of decommissioning cost that fall to the duty holders given the uncertainties in both.

28. Table 2 below presents the scenarios modelled in this analysis, which were informed by the estimated decommissioning costs in Table 1 for 2021/22. As mentioned, the decommissioning costs in Table 1 have been estimated using average recovered costs from the last three financial years. Annex A presents the estimated present-value decommissioning costs in all the modelled scenarios, in terms of 2020 prices.[2]

*Table 2: Modelled scenarios to account for uncertainties around decommissioning costs*

| Assumption | Assumption | Modelled Scenarios |
|---|---|---|
| 1 | Total annual running costs (real % annual increase from £3.4m) **under all three options** | 0%, 2.5% |
| 2 | Decommissioning cost to the duty holder (% of total running cost) **under Option 1** | 25%, 37%, 45% |
| 3 | Decommissioning cost to the duty holder (% of total running cost) **under Options 2 and 3** | 75%, 80%, 85% |

[2] Present value figures have been obtained by discounting all costs back to the 2022/23 financial year.

29. While there are no current plans to increase total running costs above £3.7m (the estimated running costs for 2021/22), a 2.5% real increase has been modelled to illustrate the potential impact of an annual increase. Costs to duty holders could potentially increase incrementally each year as decommissioning activity increases and OPRED undertakes a greater proportion of work post approval of decommissioning programmes.[3] This would be in line with any increase in total annual running costs. The 2021/22 decommissioning cost estimates presented in Table 1 have been used to inform the analysis which is used to assess the impacts of each policy option.

30. Based on the 2021/22 estimated decommissioning costs for Option 1, which as mentioned are estimated using data from the three preceding financial years, between 29%-44% of total running costs will fall on the duty holder. To account for uncertainty, three scenarios have been modelled: 25%, 37% and 45% where the highest (lowest) value was rounded up (down) to the nearest 5%, with 37% illustrating a central scenario.

31. Three scenarios have also been modelled for cost recovery under Options 2 and 3: 75%, 80% and 85%. Based on our estimates for 2021/2022, we would expect Options 2 and 3 to recover approximately 80% of total running costs (with the remaining 20% being unrecoverable costs). Two scenarios have therefore been modelled around this. We have greater certainty with our cost recovery for Options 2 and 3, since the proposals are to charge for all the work that is undertaken with regards to our statutory functions which accounts for circa 80% of OPRED's time.

32. Further details on the assumptions and figures used to model the results presented below can be found in Annex B.

[3] The future annual decommissioning cost to the duty holder under Options 2 and 3 may therefore be greater than £2.7m, in real terms, as decommissioning activities post-approval increase each year.

**Impacts of Option 1: the current charging regime remains unchanged (BAU)**

*Costs to duty holders/businesses*

33. Under the current charging regime, the UK Government would continue to charge only when decommissioning programmes are approved or revised, based on an indicative fee per type of installation or pipeline. Over the period 2022/23-2031/32, the present-value cost to duty holders is estimated to be between around £8m and £16m, in 2020 prices.

*Costs to UK Government*

34. Under the current fee charging regime, the UK Government would continue to incur costs. Between 2022/23-2031/32, the present-value cost to the UK government is estimated to be between around £18m and £24m, in real terms. Over the 10-year period, the UK Government is only able to recover between 25%-45% of total running costs from industry under the existing regime.

35. In addition, BEIS and industry would continue to find it challenging to manage their financial accounting process with issues around forecasting and accruing the regulatory costs of decommissioning. This is because fees are charged as one-off occurrences, with the timing for payment often uncertain until very close to the event.

**Impacts of Option 2: introduce amendments to the charging regime with regular charging**

*Costs to duty holders/businesses*

36. Under Option 2, duty holders would continue to pay fees or charges to the UK Government for fulfilling its regulatory obligations. However, the new regime would mean charging duty holders at more regular points and for all statutory functions associated with the regulatory obligations, to meet the full costs of providing the regime.

37. The estimated present-value cost to the duty holder under Option 2 for 2022/23-2031/32, is between around £24m and £31m, in real terms. This would be in line with any increase in total annual running costs.

38. As the new regime would be aligned with the environmental fee recovery regime already in place, it would not place additional administrative burden on the companies and therefore familiarisation costs would be minimal.

*Benefits to UK Government/taxpayers*

39. Under Option 2, the UK Government is able to fully recover from industry the costs of providing its services in executing its statutory functions. This is in line with the ‘polluter pays’ principle of environmental law.

40. The present value of costs recovered from industry under Option 2 would be between around £24m and £31m, in real terms, over the 10-year period. Therefore, compared to the current fee charging regime, this would result in a present-value cost transfer to government of between around £10m and £22m, in real terms, over the 10-year period.

41. This would equate to increasing the UK Government’s cost recovery from between 25%-45% to 75%-85% over the 10-year period. However, as mentioned previously, not all costs are recoverable. Therefore, between around £5m and £9m of present-value total running costs would continue to be met by Government, in real terms, over the 10-year period. These unrecoverable costs would therefore fall on the taxpayer.

42. In addition, by moving to charging at regular points, the department and industry will be better able to forecast and accrue the costs associated with the decommissioning fees. This would enable the Department to better monitor and manage the budgets related to decommissioning and mean duty holders are better able to forecast payments to ORPED.

**Impacts of Option 3: introduce amendments to the charging regime without regular charging**

*Costs to duty holders/businesses*

43. Under Option 3, duty holders would continue to pay fees to the UK Government for fulfilling its regulatory obligations. As under Option 2, Option 3 would introduce amendments to the charging regime. However, charging would occur on completion of statutory function/activity, rather than regularly as proposed in Option 2.

44. As under Option 2, over the 10-year period duty holders would be charged between around £24m and £31m, in real terms, a present-value increase of between around £10m and £22m compared to the current fee charging regime.

*Costs to UK Government*

45. As under Option 2, Option 3 enables the UK Government to fully recover from industry the costs of providing its services in executing its statutory functions. Full cost recovery from industry under Option 3 would be between around £24m and £31m, in real terms, over the 10-year period. This equates to cost recovery for the UK government of between 75%-85% of total running costs. The remaining 15%-25% will fall on the taxpayer in unrecoverable fees.

46. However, as charging would take place irregularly, the UK Government and industry would still struggle with forecasting costs and accruals. The UK Government would also experience lags with recovering costs, as they do under the existing regime.

## Direct costs and benefits to business calculations

47. The impacts of each policy option on business are outlined below. A qualitative description of impacts is included where it was not possible to monetise that impact.

48. While the overall monetised NPV of each policy option is zero, the impacts are presented in this section from the point of view of different stakeholders: duty holders and the UK Government.

49. For Options 2 and 3, the impacts have been compared against the current charging regime remaining unchanged (Option 1).

## Impact on small and micro businesses

50. This measure is not expected to affect micro businesses but could affect small businesses due to the amendments to the regularity of the charging mechanism. The ability to forecast and plan for spend relating to decommissioning fees, due to that increased foresight that the new regime will allow, is likely to make it easier and put less pressure on these smaller companies who do participate.

51. The exact number of small or microbusinesses in the exploration or production of the UK Continental Shelf is unknown. Businesses of all sizes can participate in UK upstream

(exploration and production) oil and gas activities in theory, but very few micro-businesses are likely to be affected as most would lack the requisite resources to participate in offshore work given the scale.

52. If a small business does wish to participate it is often the case that they would be one of several co-venturers who would make an agreement among themselves regarding the governance of existing and future operations. This would include the apportionment of operational costs and associated commercial benefits between the parties so that none of them would be solely responsible for meeting the full costs of the oil and gas operations.

53. Small businesses choosing to participate on this basis would expect to face the same type of costs as other entrants and consequently an exemption from the legislation is not considered necessary or appropriate. The proposal is to charge the operator for the activity undertaken and the arrangement for how this is split between the co-venturers would be agreed though commercial agreements. Note, that businesses will only be charged fees for regulatory work undertaken in fields where they are the operator and, as such, any charges will be proportionate to their share of equity of the infrastructure.

## Monitoring and Evaluation

54. The objective of this measure is to make amendments to the existing charging fee regime for OPRED services that are related to the decommissioning process, to ensure OPRED can fully recover from industry the cost of providing those services. These amendments are also intended to give operators greater foresight of their cash flows, enabling them to undertake their decommissioning activities more efficiently, by regularising the regime by which OPRED charges operators for using its services. Finally, the regulatory changes proposed here will bring OPRED's charging regime for its decommissioning activities in-line with existing regimes in place for recovering other environmental fees, reducing the administrative burden on operators.
55. OPRED undertakes a yearly evaluation and review of its cost recovery system. The decommissioning cost recovery will be included within the annual evaluation and review. The portal-based system to time record and produce accurate invoices is already in place for other OPRED services. OPRED also have an in-house fee review team who will administer the system and review the measure on an annual basis to ensure it is fit for purpose.
56. OPRED has an established fee review team who will administer invoices at regular periods with existing processes in place for these to be queried or reviewed and any future review of the policy will be factored into the associated guidelines to industry and whilst the detail is unknown the policy changes will be reviewed regularly. A time recording system is already in place and being used by the team. This will allow us to collect any additional information or data to support the policy objectives.

### Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

57. The approach used in this Impact Assessment is deemed to be proportionate for this measure, considering also the scale of expected impacts. Detailed consideration has been given to the rationale for intervention and how the options considered meet the policy objectives and key impacts have been identified with their distributional effect considered.

58. The analysis of impacts builds on the 2020 consultation IA on changes to the offshore oil and gas decommissioning cost recovery regime by acting on informal advice provided by the OPRED and BRU to quantify costs and benefits where possible.
59. We have also provided an initial assessment of risks and uncertainties and the key distributional impacts that are likely to occur.

## Wider impacts (consider the impacts of your proposals)

60. Any business that is affected by the introduction of this measure is already charged a fee for decommissioning activity and although they would be charged more as a result of the changes, the process is designed to be more transparent and is not anticipated to have an effect on wider incentives or behaviours.

61. An internal assessment, undertaken by OPRED, has also concluded that this measure will not have any disproportionate impacts on those with protected characteristics as per guidance as part of the Public Sector Equality Duty (PSED) Act because these changes pertain specifically to implementing a more targeted cost recovery system to allow for the full costs of OPRED's services to be recouped as opposed to drawing on government funding to account for the shortfall.

**Annex C** – Modelled decommissioning cost scenarios[1,2]

### Modelled decommissioning cost scenarios for Option 1 (2022/23-2031/32)

| | Modelled assumption | | Estimated cost (present value, £m, 2020 prices) Option 1: Existing fee charging regime | | |
|---|---|---|---|---|---|
| **Scenario** | **Total annual running cost (real annual % increase from £3.4m)** | **Option 1 - Decommissioning cost to the duty holder (% of total running cost)** | **Duty holder** | **Taxpayer** | **Total running cost** |
| **1** | 0% | 25% | 8.0 | 24.0 | 32.0 |
| **2** | 0% | 37% | 11.9 | 20.2 | 32.0 |
| **3** | 0% | 45% | 14.4 | 17.6 | 32.0 |
| **4** | 2.5% | 25% | 9.1 | 27.4 | 36.5 |
| **5** | 2.5% | 37% | 13.5 | 23.0 | 36.5 |
| **6** | 2.5% | 45% | 16.4 | 20.1 | 36.5 |

### Modelled decommissioning cost scenarios for Options 2 and 3 (2022/23-2031/32)

| | Modelled assumption | | Estimated cost (present value, £m, 2020 prices) Options 2 and 3: Proposed fee charging regime | | |
|---|---|---|---|---|---|
| **Scenario** | **Total annual running cost (real annual % increase from £3.4m)** | **Options 2 and 3 - Decommissioning cost to the duty holder (% of total running cost)** | **Duty holder** | **Taxpayer** | **Total running cost** |
| **7** | 0% | 75% | 24.0 | 8.0 | 32.0 |
| **8** | 0% | 80% | 25.6 | 6.4 | 32.0 |
| **9** | 0% | 85% | 27.2 | 4.8 | 32.0 |
| **10** | 2.5% | 75% | 27.4 | 9.1 | 36.5 |
| **11** | 2.5% | 80% | 29.2 | 7.3 | 36.5 |
| **12** | 2.5% | 85% | 31.1 | 5.5 | 36.5 |

[1] Note, the sum of the costs to the duty holder and taxpayer differ slightly under certain scenarios with the total running cost column. This is because the annual decommissioning costs have been rounded to one decimal place.

[2] Present value costs have been discounted back to the 2022/23 financial year and are given in terms of 2020/21 prices.

| | |
|---|---|
| **Title:** CNC Service Expansion and Police Support Mechanisms<br>**IA No:** BEIS035(F)-22-NP<br>**RPC Reference No:** RPC-BEIS-5173(1)<br>**Lead department or agency:** BEIS<br>**Other departments or agencies:** Civil Nuclear Constabulary (CNC) | # Impact Assessment (IA)<br>**Date: 06/07/2022**<br>**Stage:** Development/Options<br>**Source of intervention:** Domestic<br>**Type of measure:** Primary legislation<br>**Contact for enquiries:** EnergyBill2021@beis.gov.uk |

## Summary: Intervention and Options

**RPC Opinion: Green**

| **Cost of Preferred (or more likely) Option** (in 2019 prices) | | | |
|---|---|---|---|
| **Total Net Present Social Value** | **Business Net Present Value** | **Net cost to business per year** | **Business Impact Target Status** |
| N/Q | N/Q | N/Q | Not a regulatory provision |

**What is the problem under consideration? Why is government action or intervention necessary?**

The Civil Nuclear Constabulary (CNC) is a specialist armed police force responsible for the security of nuclear materials and certain UK civil nuclear sites. There is a need to reduce bureaucracy and streamline processes to enable the CNC to give a wider range of services beyond the civil nuclear sector and respond more efficiently to requests for assistance from other police forces in special demand events. It includes clarifying powers of arrest or executing warrants throughout Britain. Many nuclear sites decommissioning in the coming decade also creates potential for increased staff attrition over fears of reduced demand for work which could lead to future increased training and recruitment costs when new nuclear sites become operational. Since these issues have emerged from current legislative constraints, government intervention is necessary to resolve them. This is not a regulatory provision since it won't directly affect businesses.

**What are the policy objectives of the action or intervention and the intended effects?**

To (i) provide an improved, high-quality service by enabling the CNC to respond faster and more effectively to special demand requests from other police forces through reducing bureaucracy; (ii) clarify the powers of arrest or executing warrants throughout Great Britain, such as if an offence occurs in one jurisdiction (i.e. England and Wales) but the power of arrest needs exercising in another (e.g. Scotland); (iii) enable the CNC to bid for, and take up, additional work beyond the nuclear sector, such as other critical national infrastructure sectors, helping the CNC prevent unnecessary training and recruitment costs by retaining more of the CNC's specialist, highly trained and experienced staff within the organisation; and (iv) require the Civil Nuclear Police Authority to publish a three-year strategy every three years rather than annually.

**What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)**

**Option 1 (counterfactual) –** Do nothing. No amendments to the CNC's powers and remit in Energy Act 2004 will be made; the CNC will aim to use the existing levers and powers available to them.
**Option 2 –** Amend the Energy Act 2004 to provide a wider range of policing services beyond the civil nuclear sector.
**Option 3 –** Amend the Energy Act 2004 to clarify support mechanisms and amend cross-border enforcement powers.
**Option 4 (preferred option) –** Enact options 2 and 3 by pursuing primary legislation to amend the scope, remit and powers of the CNC in the Energy Act 2004.

**Will the policy be reviewed?** It will not be reviewed. **If applicable, set review date:** N/A

| | | | | |
|---|---|---|---|---|
| Is this measure likely to impact on international trade and investment? | No | | | |
| Are any of these organisations in scope? | **Micro** No | **Small** No | **Medium** No | **Large** No |
| What is the $CO_2$ equivalent change in greenhouse gas emissions? (Million tonnes $CO_2$ equivalent) | **Traded:** N/A | **Non-traded:** N/A | | |

***I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.***

Signed by the responsible Minister: Date: 24/06/2022

## Summary: Analysis & Evidence

Policy Option 4

**Description: Amend the Energy Act 2004 to provide a wider range of policing services beyond the civil nuclear sector, clarify support mechanisms and amend cross-border enforcement powers across Great Britain.**

**FULL ECONOMIC ASSESSMENT**

| **Price Base Year** 2019 | **PV Base Year** 2020 | **Time Period Years** | **Net Benefit (Present Value (PV)) (£m)** | | |
|---|---|---|---|---|---|
| | | | **Low:** Optional | **High:** Optional | **Best Estimate:** N/Q |

| **COSTS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Cost** (Present Value) |
|---|---|---|---|---|
| **Low** | | | | |
| **High** | | | | |
| **Best Estimate** | N/Q | | N/Q | **N/Q** |

**Description and scale of key monetised costs by 'main affected groups'**

For service expansion, there are no direct costs as the change to primary powers would only enable the CNC to enter a competitive bidding process and/or other contractual arrangements.

**Other key non-monetised costs by 'main affected groups'**

For service expansion, illustrative, non-monetised costs include adaption of the CNC's policing model to apply it to other critical national infrastructure sites, which will be regulated by different bodies; administrative costs for setting up new bidding processes, along with, for successful bids, training costs for different sectors, travel and subsistence, and relocation costs; and commercial support costs (given the CNC will need to allocate resources to bid for commercial contracts). Such costs would, however, be assessed by the CNC before bidding for new service provision, to ensure that it represents value for money for the public. For police support mechanisms and cross-border enforcement, no direct costs are expected.

| **BENEFITS (£m)** | **Total Transition** (Constant Price) | Years | **Average Annual** (excl. Transition) (Constant Price) | **Total Benefit** (Present Value) |
|---|---|---|---|---|
| **Low** | | | | |
| **High** | | | | |
| **Best Estimate** | N/Q | | N/Q | **N/Q** |

**Description and scale of key monetised benefits by 'main affected groups'**

For service expansion, there are no direct benefits as the change to primary powers would only enable the CNC to enter a competitive bidding process and/or other contractual arrangements.

**Other key non-monetised benefits by 'main affected groups'**

For service expansion, illustrative, non-monetised benefits include reduced recruitment and training costs which would otherwise be spent on new recruits once new nuclear power plants come online (should the wider service expansion mean more satisfied employees and reduced attrition). There would also be potentially lower costs for other critical national infrastructure sites due to increased competition should the CNC bid for services. For police support mechanisms and cross-border enforcement, other benefits would include faster emergency response, improving the quality of service (through streamlining), more efficient enforcement of offences and reduced administration costs by streamlining administrative barriers. There would likely be some minimal savings from reducing the frequency of the publication of the Civil Nuclear Police Authority's three-year strategy.

| **Key assumptions/sensitivities/risks** | **Discount** | N/A |
|---|---|---|

For service expansion, risks include detraction from core mission by expanding the potential scope of CNC staff responsibilities; and potential disillusionment of existing staff owing to new responsibilities.

**BUSINESS ASSESSMENT (Option 4)**

| **Direct impact on business (Equivalent Annual) £m: N/A** | | | **Score for Business Impact Target (qualifying provisions only) £m:** |
|---|---|---|---|
| **Costs: N/A** | **Benefits: N/A** | **Net: N/A** | N/A |

# Evidence Base

## Problem under consideration and rationale for intervention

*Background*

1. The Civil Nuclear Constabulary (CNC) is a specialist armed police force tasked with the protection of the UK's civil nuclear sites and nuclear materials. The Constabulary works in partnership with nuclear site licence companies (SLCs) and other partners to protect ten nuclear energy generation and decommissioning sites across the country. The CNC employs over 1,500 police officers and police support staff and is currently funded almost exclusively by SLCs via fees linked to the provision of service to the nuclear industry.

2. The CNC's scope and remit are defined in Chapter 3 of the Energy Act 2004. The Act establishes the Civil Nuclear Police Authority to govern the CNC, the Constabulary's function, jurisdiction and powers, and mandates inspection by Her Majesty's Inspectorate of Constabulary and Fire & Rescue Services. The severe consequences of a successful attack on civil nuclear sites or materials mean it is essential that the CNC continues to protect these assets effectively. The CNC also collaborates with other police forces as a counter-terrorism policing organisation through provision of ad-hoc assistance on a short-term basis, such as the UK's Strategic Armed Policing Reserve (SAPR) arrangement in providing armed CNC officers to non-civil nuclear policing for major events.

*Problem 1 Outline – Inefficient arrangements to support other police forces*

3. Although the CNC currently provides some support to other forces, there are legislative and administrative barriers that introduce avoidable costs and hinder the CNC's ability to respond to emergency incidents and other periods of unanticipated demand. Without intervention, the mechanism by which the CNC can engage in essential policing collaboration and provide assistance to other forces will continue to be inefficient, introducing avoidable costs and the risk that CNC officers are unable to swiftly and efficiently support other police forces in response to emergency incidents.

*Problem 2 Outline – Lack of clarity around the CNC's cross-border enforcement powers*

4. There is currently a lack of clarity around the CNC's powers to execute warrants or powers of arrest where a person who is suspected of committing an offence in one part of the UK (e.g. Scotland) needs to be apprehended in another part of the UK (e.g. England and Wales).

*Problem 3 Outline – Potential risk of increasing staff attrition among experienced and specialist staff concerned over declining nuclear sites in 2020s*

5. Over the coming decade, much of the current nuclear generating fleet is expected to enter decommissioning. Hinkley Point C is currently under construction and the Government has committed to reaching final investment decision on a further large-scale nuclear plant by the end of this parliament and has established a fund for retaining options for future nuclear technologies.[1] The CNC is a critical element in ensuring the security of the UK's electricity supply and a counter terrorism deterrent. However, the uncertainties over future demand profiles, timings and locations for CNC services at nuclear sites may lead to a loss of confidence of job security manifesting in increased attrition rates over the coming years. This could lead to the loss of experienced and specialist personnel within the workforce, reducing capability, and increased recruitment and training costs to replace these staff members which will be passed on to civil nuclear SLCs.

## Policy objectives

6. The intended outcomes are to amend the Energy Act 2004, and any consequential required legislative amendments, to:

[1] BEIS, Net Zero Strategy (2021), available: https://www.gov.uk/government/publications/net-zero-strategy

(a) provide an improved, high-quality service by enabling the CNC to respond more quickly and effectively to special demand[2] requests from other police forces;

(b) clarify the powers of arrest or executing warrants throughout Great Britain, such as if an offence occurs in one jurisdiction (i.e. England and Wales) but the power of arrest needs exercising in another (e.g. Scotland);

(c) enable the CNC to bid for, and take up, additional work beyond the nuclear sector, such as other critical national infrastructure sectors; and

(d) amend the legislative requirement for the Civil Nuclear Police Authority to publish a three-year strategy every three years rather than annually.

**Description of options considered**

7. The following options have been considered. Three of those – options 1, 2 and 4 – were considered as part of a public consultation[3] which ran from June to August 2021. Option 3 has additionally been assessed for this impact assessment.

Option 1 – Do nothing (counterfactual)

8. No amendments to the CNC's powers and remit in Energy Act 2004 would be made. The CNC would respond to the outlined challenges using the existing levers and powers available to them, with the aim of always meeting their regulatory requirements of civil nuclear protection.

Option 2 – Service expansion

9. Introduce primary legislation to allow the CNC to perform additional activities or functions, giving the CNC the power to bid for, and take up, such work should the demand arise. This would provide redeployment opportunities where demand arises in other critical national infrastructure sectors, providing increased job security and potentially improving staff wellbeing, helping to resolve problem 3.

Option 3 – Clarify support mechanisms and cross-border enforcement powers

10. Introduce primary legislation to clarify and streamline the CNC's options to provide support to other police forces in periods of special demand on their resources, and to clarify the powers of arrest or executing warrants throughout Great Britain since the CNC are not named in existing legislation. This would reduce bureaucracy and inefficiencies and allow more rapid and efficient assistance of other police forces through providing an alternative means to deploy officers in emergency scenarios outside of collaboration agreements and help to resolve problems 1 and 2.

Option 4 – Service expansion and clarify support mechanisms (recommended option)

11. Pursue primary legislation to amend the scope, remit and powers of the CNC, to enable the CNC to enact both options 2 and 3, as well as make the administrative amendment to the timetable for publication of the CNPA's three-year strategy.

**Summary and preferred option with description of implementation plan**

12. The preferred option is option 4 which is enacting primary legislation to combine service expansion and clarifying both support mechanisms to enable support to other police forces and cross-border enforcement powers. The legislative proposals in the preferred option would allow the CNC the flexibility to support other police forces in responding to periods of special demand,

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[2] Periods of special demand include: a) emergency/spontaneous deployments; b) planned deployments/events beyond a force's capacity; and c) specialist staff deployments beyond a force's capacity of specialist staff.

[3] Civil Nuclear Constabulary: Service Expansion and Diversification (2021), available at: https://www.gov.uk/government/consultations/civil-nuclear-constabulary-service-expansion-and-diversification

by enabling the Chief Constable to immediately authorise CNC support, clarify the powers of arrest or executing warrants throughout Great Britain and enable the CNC to explore alternative sources of future demand.

**Monetised and non-monetised costs and benefits of each option (including administrative burden)**

### Impacts of Option 1 – Do nothing (counterfactual)

13. Currently there are inefficiencies and limitations in how the CNC operate in support of other police forces during periods of special demand, which involve high administrative overheads and time-consuming approvals processes. Under this option, the CNC would continue to find it difficult to adequately and cost-effectively support other forces. Further, the force will continue to face the potential risk of higher staff attrition rates given the number of nuclear power plants beginning decommissioning over the coming decade. This option is our counterfactual.

### Impacts of Option 2 – Service expansion

14. The primary power enabling the CNC to expand beyond the nuclear sector does not, in and of itself, lead to any direct costs or benefits as work in other sectors would have to be bid for in a competitive process or entered into via other contractual arrangements. Illustrative unmonetized costs and benefits of service expansion are, however, included below.

*Benefits*

15. **Reduced recruitment and training costs** – The 2019 CNC staff survey results suggested a significant minority of staff were unhappy in their role, and it was suggested in the summer 2021 consultation responses that one way to improve job satisfaction among staff would be to expand service provision beyond the nuclear sector to give greater job security. This could lead to improved job satisfaction among staff, potentially, making it less likely staff would voluntarily leave their role. Reduced staff attrition would reduce recruitment and training costs otherwise spent on new recruits once new nuclear power plants come online while also ensuring as many experienced, skilled staff are in post as possible.

16. Giving the CNC powers to provide services to other sectors means they will have better and more flexible tools to deal with staffing levels, but they will need to bid for additional work. How these benefits are delivered and their scale – for the CNC and wider society – is therefore dependent on the timing and success of how these powers are enacted.

17. **Increased competition and efficiency** – Enabling the CNC to bid for services beyond the civil nuclear sector would lead to increased competition within other sectors which could lead to reduced costs for the owners of other critical national infrastructure sites.

*Costs and risks*

Costs are expected to be small, and will chiefly be comprised of:

18. **Adaption of policing model** – The CNC's operating model has been developed from close working with nuclear site operators and the Office of Nuclear Regulation. The policing model will need to be adapted to apply to other critical national infrastructure sites, which will be regulated by different bodies. The administrative cost of this, along with travel, relocation and subsistence costs, has not currently been quantified but will be assessed by the CNC before bidding for new service provision, to ensure that it represents value for money for the public.

19. **Commercial support costs** – The CNC will be required to allocate resources to bid for commercial contracts in order to realise the benefits in this option, since the legislation in itself will not provide additional services for the CNC.

20. **Detraction from core mission** – Delivering protective security to other sectors could detract the force from the delivery of its core nuclear security mission. This risk will be mitigated through using appropriate legislative controls to ensure the core mission remains priority. This will also be reflected in robust and effective governance processes and decision-making mechanisms for

task prioritisation and deployment of resources. Ultimately, the Chief Constable of the CNC will remain responsible for evaluating all additional deployments to ensure they do not jeopardise the delivery of the CNC's core mission. In addition, any request to provide services to other sectors beyond civil nuclear will require formal approval from the Secretary of State to ensure that any impacts on the CNC's core nuclear security mission have been fully assessed and mitigated.

21. **Potential CNC staff disillusionment** – There is a risk that in expanding the reach of CNC staff, some CNC staff become disillusioned with their new job requirements and leave the force, increasing staff attrition above what is expected. The results of the 2019 CNC staff survey suggest this is an unlikely outcome, and that the measures are likely to decrease overall staff attrition rates rather than increase them.

**Impacts of Option 3 – Clarify support mechanisms and cross-border enforcement powers**

*Benefits*

22. The key benefits of this option are expected to be:

23. **Faster emergency response** of CNC staff, by reducing and streamlining the administrative barriers currently faced in an emergency. Requests for CNC support will therefore take less time to clear, requiring only discussion and sign-off between Chief Constables, which could potentially be achieved in minutes, allowing a faster emergency response which will benefit society as a whole.

24. **Improving the quality of service** by streamlining processes and removing bureaucracy. This improved and more joined-up working with other police forces will improve the service provided by the CNC and benefit wider society.

25. **More efficient enforcement** of offences across Great Britain through giving clarity on cross-border enforcement powers, which will mean the CNC can apprehend individuals suspected of committing an offence in one jurisdiction (i.e. Scotland) while in another jurisdiction (i.e. England and Wales).

26. **Reduced administration costs** for the CNC and other police forces, by reducing and streamlining the administrative barriers currently faced in special demand scenarios. These will mean less overall need for a time-consuming collaboration agreement, reducing costs for both the CNC and other forces. This option also allows for closer collaboration with the UK policing sector and provides additional capacity as required by other forces.

*Costs and risks*

27. There are not expected to be any significant costs associated with this option beyond some minimal administration costs involved in setting up a new collaboration agreement which could then be re-used for each future event.

**Impacts of Option 4 – Service expansion and clarifying support mechanisms – recommended option**

28. The benefits and costs of option 4 are expected to be the total of options 2 and 3. This option delivers benefits associated with increased workforce retention and reducing administrative bureaucracy in the CNC operating model, resolving problems 1, 2 and 3. It also delivers effectiveness benefits in terms of reducing the operational risks outlined in problem 1. Together these changes would provide CNC officers with a more diverse range of work, provide CNC with a wider cost base (subject to demand for their services from other sectors), therefore improving efficiency and generating new opportunities to retain experienced staff as the current nuclear generating fleet transitions into decommissioning. The impacts of the amendment to the frequency of publication of a three-year strategy by the CNPA are expected to be minimal.

29. Making the changes is anticipated to be relatively low cost with low impacts while delivering significant benefits highlighted in this impact assessment. Furthermore, the administrative requirements involved in introducing two new pieces of primary legislation means it is more

efficient to combine options 2 and 3 together into one piece of primary legislation which can enact both and combine the benefits from both. This is why option 4 is our recommended option.

### Direct costs and benefits to business calculations

30. There are no direct costs and benefits to business because the legislation is directed at public bodies.

### Impact on small and micro businesses

31. There are no direct costs and benefits to small and micro business because the legislation is directed at public bodies.

### Wider impacts

32. An equalities assessment for these interventions was undertaken and concluded that the interventions are not expected to have any adverse or disproportionately negative impact on people who share a protected characteristic, and no steps to advance quality of opportunity and foster good relations are required. The changes will likely have the biggest impact on CNC officers, particularly Authorised Firearms Officers (AFOs) who constitute the majority of the workforce and are key to the operational delivery of the CNC's functions. The measures could result in benefits for the protected characteristics of age and sex should the CNC take up opportunities to expand the current AFO role profile, as older and female officers are less likely to meet the required fitness and operational standards for AFOs.

33. The interventions proposed are not expected to affect any wider incentives and behaviours, on consumers, employees or the public sector beyond those already stated in this assessment. The interventions proposed are not expected to cause any impacts on the environment.

34. The interventions proposed are expected to increase competition on bids for contracts for security at key infrastructure sites by expanding the scope of the CNC to allow them to work on sites beyond their current remit. Against the criteria on the Competition and Markets Authority competition assessment checklist, the interventions proposed are classed as not restricting competition and therefore no further competition assessment needs to be conducted.

### A summary of the potential trade implications of measure

35. The measure is not expected to have any impacts on international trade or investment.

### Monitoring and Evaluation

36. Should the programme be monitored and evaluated, the programme could be overseen by the CNC and could be monitored and reported through existing Programme Management Office (PMO) controls while findings would be shared with BEIS. Pilot testing would be conducted ahead of monitoring and evaluation rollout. Monitoring could be conducted annually to track changes in the key performance indicators which would be determined by the CNC but confirmed by BEIS. These would assist in ensuring the legislation is progressing as required and then, once passed, is having the intended effects. Monitoring metrics could include elements such as the number of staff employed by the CNC, annual updates in years new nuclear plants are projected to come online (if applicable), and annual staff survey results reporting staff job satisfaction. These metrics would inform evaluation activity and would also allow issues to be caught early and quickly, allowing changes to the intervention, additional legislation, or further policy levers to be pulled to correct emerging issues and ensure the project meets its objectives.

37. An impact evaluation could be completed after five years to assess whether the intervention has achieved the impacts it sought as outlined previously. It would also assess what difference the intervention made, and its role in causing the difference alongside other contexts, in relation to the intervention objectives. Monitoring could commence once the intervention commences in 2022 while the impact evaluation could be conducted at the end of Year 5 to give long enough for the anticipated benefits to be realised and any issues identified in the monitoring to be sufficiently resolved. Findings could influence whether to keep utilising the extended CNC staff remit and inform policy for key decisions regarding how best to organise armed and specialist-trained staff at present and future nuclear sites.