Cost Benefit Analysis Framework to Appraise SSEN's Alternative Flexibility Options to Accelerate Network Connection

Prepared for SSEN

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Contents

Executive Summary

Distribution Network Operators (DNOs) face a challenge of accommodating rapid growth in demand for network capacity, due to a combination of traditional sources of demand from new residential and commercial developments, as well as new pressures from the electrification of heating and transport, and growth in embedded generation and batteries. The rate of growth in demand has led to connections queues, and subsequent delays, for some new connections. Any delays to new connections can result in significant opportunity costs for connecting parties.

In its recent ED3 Framework Decision, Ofgem has decided to prioritise the delivery of "proactive load investment" ahead of system need in ED3 and that a flexibility first approach to defer investment is "not appropriate in ED3".[1] Ofgem has stated that, where the need for reinforcement seems inevitable, it is preferable to prioritise the delivery of investment ahead of need to develop a pipeline of reinforcement and enable the supply chain to sufficiently scale in the longer term. While network reinforcement will certainly be necessary to accommodate growth in connections and demand for network capacity from low carbon technologies, flexibility can still provide benefits from releasing capacity, enabling shorter connection times, utilising network capacity more efficiently, and minimising outages.[2]

Scottish and Southern Electricity Networks (SSEN) has commissioned NERA to prepare a Cost Benefit Analysis (CBA) framework, to help assess the societal value of flexible resources as a potential means of unlocking the network capacity needed to provide new and/or expanded network connections more quickly than traditional reinforcement (and possibly, in some cases, more cheaply).

While flexibility of various types can potentially bring benefits from faster grid connections, we focus on assessing the benefits that investments in Consumer Energy Resources (CERs) can achieve. CERs are consumer resources that generate or store electricity or have flexible loads and might include measures such as installing rooftop solar, installing batteries or utilising EV chargers to flexibly shift load. CERs can support the release of distribution network capacity, while also achieving other societal benefits, such as lowering wholesale energy costs or lowering the costs to NESO to operate the wider power system.

In some instances, investment in long term flexibility services may not just provide a short-term benefit, but it may allow for an efficient alternative to network reinforcement. In such cases, SSEN would need to trade-off the ongoing, long-term cost of flexibility services against the cost of reinforcing its network to decide whether to reinforce. Given the current need for network reinforcement over ED3, for the purposes of this study we consider a situation where SSEN would undertake network reinforcement regardless of the flexibility intervention considered. Instead, we focus on how flexibility services can speed up new connections ahead of the completion of required network reinforcement.

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1 Ofgem (30 April 2025), ED3 Framework Decision, para. 4.17, and 6.16.

2 As noted by Ofgem in its ED3 Framework Decision, Ofgem agrees "there is still an important role for DSO-procured flexibility in the ED3 period, particularly where this enables faster connections, helps to manage outages and faults, or is the optimal solution in the long-term."

Ofgem (30 April 2025), ED3 Framework Decision, para. 6.13.

We develop a CBA framework to assess the net societal benefits of using flexibility services to speed up new connections

We develop a framework to help SSEN identify the social benefits and costs of deploying different flexibility services to speed up new connections of demand and generation projects ahead of network reinforcement investment. This framework would support SSEN in assessing whether any flexibility interventions are justified for a given part of the network and which flexibility options are the most socially beneficial.

We apply this framework to two illustrative scenarios. For each we consider four different illustrative options SSEN could apply to unlock earlier connections where this is insufficient network capacity in place:

- Scenario 1 involves the hypothetical connection of a new 400 home housing development in Bilsham;
  - Option A Battery Solution: SSEN procures flexibility services from new battery providers to manage the immediate load requirements for the new development;
  - Option B Community Smart Access: installation of heat pumps, energy efficiency measures, and flexibility services within new housing developments to place a lower load on the network;
  - Option C House Retrofitting: installation of heat pumps, energy efficiency measures, and flexibility services within existing housing stock to place a lower load on the network;
  - Option D Existing Flexibility Services: SSEN procures flexibility services from existing flexibility service providers already available to SSEN to manage the immediate load requirements for the new development;
- Scenario 2 involves the connection of an illustrative 0.05 MW rooftop solar PV project;
  - Option A Battery Solution: SSEN procures flexibility services from new battery providers to manage the immediate network capacity requirements for the new generation project;
  - Option B Access Product Offer: SSEN offers a curtailable connection to the new generation project requiring it to scale back its export when network capacity is constrained;
  - Option C Demand Shifting: SSEN procures demand shifting services from existing providers already available to SSEN to manage the immediate load requirements for the new generation project; and
  - Option D Invest in New Demand Shifting Service: SSEN procures demand shifting services from new providers to manage the immediate load requirements for the new generation project.

We find deploying flexibility services to speed up new demand and generation connections can create net benefits for society

Scenario 1: New Housing Development

We find there are clear positive net benefits to deploying flexibility services to speed up the connection of a typical housing development. The value of the faster connection is greater than the cost for three of the four flexibility options considered. However, we find under these specific modelling scenarios that the cost of retrofitting the existing housing stock is greater than the benefits unlocked and so has a net social cost for this sample development.[3]

Based on the existing costs of flexibility service procurement (as provided to us by SSEN), flexibility services offer the lowest-cost way to manage demand constraints at peak for the sample new housing development. In a future where DNOs procure much larger volumes of flexibility services, these costs of these services may vary (i.e. as more providers will need to install more capacity or incentivise end-customer participation). Investment in new assets (i.e. the installation of flexibility within the housing stock) may be a more cost-effective alternative for alleviating constraints if the required volume and price of flexibility services were to rise.

Scenario 2: New Local Generation Project

We find there are probably net benefits to deploying flexibility services to speed up the connection of a new 0.05 MW rooftop solar PV project. Based on illustrative figures, we find that all four options appear low cost, and so would deliver net benefits. However, this conclusion would need to be verified with more reliable information on the cost of procuring these services.

For both the scenarios we consider, we recommend SSEN develops locality specific estimates of the social benefits and costs for any future project it wishes to assess. These estimates will provide a more accurate assessment of individual estimates of benefits and costs for a specific project.

[3] This result reflects the assumptions made regarding the cost of retrofitting and the energy and carbon savings it could unlock. We utilise high level assumptions for this analysis and the results may vary if these assumptions were to change.

1. Introduction

NERA has been commissioned by Scottish and Southern Electricity Networks (SSEN) to prepare a Cost Benefit Analysis (CBA) framework, aiming at assessing the societal value of flexible resources as a potential means of providing network capacity needed to provide new and/or expanded network connections.

Distribution Network Operators (DNOs) face a challenge of accommodating rapid growth in demand for network capacity, due to a combination of new traditional residential and commercial developments, as well as data centres, underlying demand growth due to electrification of heating and transport, and growth in embedded generation and batteries. This situation has led to a connection queue that is causing delays in providing some connections to new loads. These delays result in significant opportunity costs for connecting parties, such as housing developers, data centre developers, and generators. This issue is expected to become increasingly common and more severe as decarbonisation policies lead to greater electrification of heating and transport demands.

While network reinforcement will certainly be necessary to accommodate growth in connections and demand for network capacity from low carbon technologies, SSEN wants to investigate the benefits flexibility can bring from enabling shorter connection times, utilising network capacity more efficiently, and minimising outages.

While flexibility of various types can potentially bring benefits from faster grid connections, the particular focus of this assignment is assessing the benefits that investments in Consumer Energy Resources (CERs) can achieve. While CERs can support the prompt release of distribution network capacity, they may bring other benefits too. These include advantages such as lower "upstream" wholesale energy costs and lower costs incurred by NESO to operate the national power system in real time, where CERs are serving the dual purpose of supporting the DNO and offering their capacity into national markets.

We understand that SSEN wants to gain a deeper understanding of and quantify the value that CERs from homes and businesses, such as heat pumps and small-scale batteries, can bring to the network and society as a whole. This is especially important when investments in demand-side flexibility resources can lead to lasting changes in energy consumption patterns or volumes, which may persist beyond the timeframe which the DNO requires flexibility, prior to completion of its reinforcement projects.

In this report, we develop a CBA framework that allows SSEN to appraise the societal benefits of deploying CERs to accelerate connections by releasing network capacity ahead of making physical investments to expand distribution infrastructure. This CBA framework would support SSEN in assessing whether any flexibility interventions are justified for a given part of the network and which flexibility options are the most socially beneficial.

The remainder of this report is set out as follows:

- In Section 2, we explain the context and potential benefits of using CERs, as well as Ofgem's guidance on conducting CBAs;
- In Section 3, we describe how SSEN could approach structuring the problem faced and identifying different options to consider for CBA;

- In Section 4, we identify the costs and benefits of each intervention option and how SSEN can approach valuing each cost and benefit;
- In Section 5, we discuss the sources of uncertainty in the CBA and how SSEN could conduct scenario analysis to ensure its choice of intervention is robust;
- In Section 6, we set out the result of our CBA and consider the role of distributional effects; and
- In Section 7, we conclude.

2. The Need for Network Reinforcement and the Role of Flexibility

2.1. The Value of Flexibility in Preventing Delays to Network Capacity

Achieving the energy transition will require substantial network investment to facilitate growth in network load. The switch towards low-carbon technologies, including the electrification of heat and transport via the uptake of electric vehicles and heat pumps, as well as investment in embedded renewable generation, is increasing the demand for distribution network capacity and so driving the need for network reinforcement.

Any necessary network reinforcement will take time for DNOs to deliver. Given the widespread take up of low carbon technologies and corresponding growth in network demand, network DNOs will need to prioritise which parts of the network to reinforce due to limitations in the supply chain as well as practical limits to the pace of delivery. Thus, some parts of the network will likely face capacity constraints while awaiting reinforcement.

If network capacity is constrained, DNOs may need to delay connections from new customers or delay existing customers from increasing their demand until reinforcement is completed. These connection delays risk harming progress on the energy transition via delays to the electrification of heating and transport, and/or delaying embedded renewable generation deployment.

Connection delays also have wider social consequences beyond their impact on the energy transition. Delays to new connections limits the development of new housing projects and/or new commercial and industrial sites. Delays to these developments will defer the wider economic and social benefits these developments bring (i.e. greater local housing availability or greater local job opportunities).

One means of mitigating delays for new connections is the use of temporary "flexibility" services to release network capacity before the additional reinforcement is completed. The use of such services would allow the DNO to connect customers earlier before work on the reinforcement is complete and thus unlock the benefits from new developments more quickly.

Flexibility services allow DNOs to temporarily meet new demand with existing network capacity. Actions to reduce peak demand on part of the network would give the network more headroom for new connections and so allow the DNO to connect new developments sooner. This flexibility may come from a variety of sources, including (but not limited to):

- Demand shifting through the use of locally installed batteries or demand side management by large energy users;
- Installation of embedded generation technologies which can support the distribution system;
- Offering of curtailable connections where a customer's load is reduced when the network is constrained; or
- Smaller scale Consumer Energy Resources (CERs), such as:
  - Demand reduction from investments in improvements to energy efficiency;

- Installation of storage technologies in customers' properties;
- Retail demand flexibility services (e.g. time of use tariffs or other incentives to shift demand away from peak and to non-peak times).

Depending on the cost of these flexibility services, they may be beneficial to society as a whole if the benefits from faster connections outweigh the costs of the flexibility services. This trade-off will ultimately depend on the relative cost and benefits of flexibility, which will in turn vary depending on local circumstances, as well as wider considerations about DNOs wider package of network reinforcement across the network.

2.2. Ofgem's RIIO-ED3 Framework Decision Regarding DNOs' Strategy to Manage Extra Demand

At RIIO-ED2, Ofgem supported the "flexibility first" principle, promoting lower-cost, non-network solutions to manage extra demand associated with the transition to net zero.[4]

In the recent ED3 Framework Consultation, Ofgem has expressed its concerns that, under the current framework, DNOs are not spending their allowances when they should instead invest in adding network capacity, and has suggested that it may be drawing back from this "flexibility first" approach.

In year one of ED2, total DNO load-related expenditure (LRE) averaged less than half the annual allowance, because, according to Ofgem, of lower demand than forecast in some areas and delivery and mobilisation challenges, including the supply chain.[5] Ofgem argues that in a period of high expected demand growth, such as that expected during ED3, high penetration of flexibility on the network to meet capacity requirements could lead to a risk of sub-optimal outcomes.[6]

Specifically, Ofgem has identified two potential issues in the ED3 consultation:[7]

- A focus on network flexibility to defer investment could result in a steeper trajectory for network reinforcement when demand growth accelerates rapidly. This could exacerbate existing skills shortages and supply chain challenges, resulting in higher costs and longer lead times. Ultimately, this may mean that the network capacity will not be available when it is needed.
- DNOs focusing on using flexibility to defer network reinforcement may not be optimal from a wider system perspective, i.e., system-wide benefits (and consumer value) of distribution-based flexibility for balancing in times of high demand and renewable generation may be larger than the savings from deferring distribution investment if the flex is coupled with sufficient network reinforcement to allow it to be used for system-wide needs.

Therefore, Ofgem has developed the view in its RIIO-ED3 consultation that, while there is a compelling case for using network flexibility as an interim solution to address capacity needs, especially when reinforcement has a long lead time, it is unlikely that network flexibility can serve

[4] Ofgem (6 November 2024), ED3 Framework Consultation, para. 6.23.

[5] Ofgem (6 November 2024), ED3 Framework Consultation, para. 6.10.

[6] Ofgem (6 November 2024), ED3 Framework Consultation, para. 6.26.

[7] Ofgem (6 November 2024), ED3 Framework Consultation, para. 6.26, 6.27, and 8.14.

as a long-term substitute for reinforcement in substations that are reaching capacity.[8] In the ED3 Framework Decision, Ofgem has stated that "DNOs should plan and build their network, enabling a smooth build profile that will meet net zero by 2050. The value of flexibility for the wider system can then be delivered through managing peak demand and intermittent low carbon generation efficiently".[9] Ofgem has also stated, in the ED3 Sector Specific Methodology Consultation, that it recognises the value flexibility can provide to deliver "rapid connection times where network build out cannot happen fast enough" but Ofgem "does not want DNOs to use flexibility to defer network investment in the long-term".[10]

Despite the fact that Ofgem is considering requiring DNOs to prioritise network reinforcement over flexibility in the RIIO-ED3 period, there still might be a case for deploying flexibility. If the DNO is resource constrained in deploying network upgrades (e.g. due to widespread network reinforcement), flexibility can help to facilitate new connections or capacity increases from existing connections. These connections may otherwise need to wait until network capacity is available and so face a delay to the new connection. Even if reinforcement of network capacity is required for these new connections, flexibility can help bring forward connection times while the required reinforcement is underway.

2.3. Ofgem's CBA Guidance

Ofgem has published its latest guidance on the CBA, alongside the Business Plan Guidance, for the RIIO-3 price control for transmission and gas distribution.[11] In the guidance, Ofgem sets out the requirements the network companies need to meet when performing the CBA assessment that compares the value of the main investment options. While a RIIO-3 CBA guidance for electricity distribution is not available at this stage, we expect those used for transmission and gas distribution to form a starting point for Ofgem's ED3 guidance.

We provide a high-level summary of Ofgem's requirements for CBA below.

Identifying options: Ofgem's guidance requires companies to clearly identify the range of options that were considered to meet the stated investment aim, including: (i) where possible, a "do minimum option" that identifies an option with minimum initial investment; (ii) a deferral option: must consider the option of delaying investment.[12] However, Ofgem recognises that in some cases, the do minimum option and the deferral option may be equivalent, while in other cases, deferral may not be an option (e.g., mandatory expenditure).

Valuing costs and benefits: Ofgem also sets out guidance on valuing the relevant costs and benefits associated with each of the identify options:

8 Ofgem (6 November 2024), ED3 Framework Consultation, para. 6.29.

9 Ofgem (30 April 2025), ED3 Framework Decision, para. 6.13.

10 Ofgem also stated it does recognises there may be "some instances where flexibility is identified as the permanent alternative to network reinforcement", but it expects this to be rare in ED3.
Ofgem (8 October 2025), ED3 Sector Specific Methodology Consultation, para. 4.66 and para. 5.80.

11 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance.

12 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.1.

- *Expenditure costs:* Ofgem requires companies to include both capex and opex expenditure, to allow a clear comparison of capex and opex trade-offs and ensure an appropriate split is applied between capitalised and expensed expenditure.[13] Ofgem notes that "*companies should focus on identifying costs that materially drive investment decisions, rather than seeking to present a long list of cost items that contain many individually immaterial costs*".[14]
- *Societal costs:* Ofgem specifies default parameters for environmental costs.[15]
- *Benefits:* Ofgem requires companies to specify in which category the type of benefit belongs (e.g. environmental benefits, financial benefits and other benefits), as this determines the discount rate.[16]

Calculating Net Present Value (NPV): Ofgem requires that companies interpret the results of CBA models by comparing the NPV between the options rather than from the absolute NPV value of a certain option.[17] To calculate the NPV, Ofgem requires companies to apply the "Spackman approach", which we understand involves a two-step process:[18]

- Capital and operating costs should be first converted into an annual stream of revenues. For capital costs, this involves depreciating the investments over the relevant asset lives using the same depreciation profiles Ofgem uses when depreciating the costs entering the Regulatory Asset Value (RAV) and applying a return at the company's vanilla Weighted Average Cost of Capital (WACC) (i.e., a pre-tax cost of debt and post-tax cost of equity, weighted by gearing). Operating costs are typically recovered in the year they are incurred.[19]
- Then, companies should discount these costs, as well as any societal benefits, using the Social Time Preference Rate (STPR) provided in the HM Treasury Green Book.

Approach to uncertainty and sensitivity analysis: Ofgem expects companies to take into account uncertainty and risk, and provide quantitative and qualitative assessment that clearly outlines the companies' decision-making processes, including how the companies assess the investment risks.[20] In the case where the CBA outcomes are marginal, Ofgem requires companies

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13 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.14.

14 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.16.

15 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.18.

16 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.19.

17 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para 4.25.

18 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, paras 4.28-4.30.

19 Note, the RIIO framework sets a pre-defined capitalisation rate, equalising the accounting treatment of opex and capex. However, because this capitalisation rate is calibrated to the actual ratio of capital to operating costs proposed by companies, at the investment appraisal stage, it is important that CBA models do not presume a particular capitalisation rate. Simply, the appropriate capitalisation rate cannot be known when CBA modelling is undertaken as it depends on its results.

20 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.34.

to perform sensitivity analysis on key input assumptions, it also encourages companies to consider different future energy pathways where environmental factors are driving net benefits.[21] For sensitivity analysis, Ofgem expects companies to follow the HM Treasury Green Book guidance:[22]

> "*Sensitivity analysis is fundamental to appraisal. It is used to test the vulnerability of options to unavoidable future uncertainties. Spurious accuracy should be avoided, and it is essential to consider how conclusions may alter, given the likely range of values that key variables may take. Therefore, the need for sensitivity analysis should always be considered, and, in practice, dispensed with only in exceptional cases*".

Decision rule: Ofgem expects companies demonstrate their proposals provide the optimum solution which demonstrates value for customers, drawing conclusion on the sensitivity analysis where the CBA outcomes are marginal.[23]

Consistency with the Net Zero target: Ofgem requires companies to demonstrate that their proposed investments align with the UK Government's 2050 net zero target, considering how their proposed investments align with different future pathways.[24] Specifically, companies should use the most up-to-date Future Energy Scenarios (FES) pathway data.

As part of the CBA, companies should consider factors such as payback periods, economic justification, sensitivity to carbon prices, and asset lifetimes.[25] Ofgem advises companies to conduct further sensitivity analysis for preferred options that are highly sensitive to the above factors.[26,]

2.4. Our Proposed Framework for this CBA Assignment

Based on Ofgem's guidance, we propose the following steps for this CBA study:

- Step 1: Structuring the problem the CBA framework will need to answer. This involves evaluating and articulating the problem SSEN currently faces, where the need to reinforce the grid is generating a delay in connection.

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21 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.35.

22 HM Treasury (2008), The Green book, Appraisal and Evaluation in Central Government, p.32.

23 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, paras. 4.36 and 4.38.

24 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para 4.48.

25 Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para 4.48.

26 High sensitivity is defined as an option no longer being NPV positive or being only marginally NPV positive, the preferred option no longer offering a superior NPV compared to one or more alternative options, the payback period for the preferred option significantly increasing, or there is a high risk of the option becoming obsolete in the future.

Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para 4.49.

- Step 2: Identifying and characterising the options available to SSEN to accelerate the connection of new loads. We outline the range of actions that SSEN can undertake to enable faster connection when new loads cannot be provided without reinforcement, including CERs.
- Step 3: Identifying costs and benefits. This involves understanding and defining the relevant trade-offs that SSEN and wider society face under each option. Following Ofgem's guidance, we also identify those cost and benefits associated with each option. The list of costs and benefits also informs the information we recommend SSEN ideally gathers to enable it to apply this CBA framework in its decision-making.
- Step 4: Scenario analysis in the context of uncertainties. The costs and benefits associated with some options may not be deterministic and could be affected by future uncertainties like trends in future demand. We will consider a range of possible values for key parameters to ensure the CBA outcome is robust and flag some areas in which further analysis might be helpful for analysing the effects of uncertainties on the optimal strategy.
- Step 5: Evaluating and comparing alternatives. Finally, we will present the results of our analysis based on the modelling framework set out above and the data we received from SSEN for the flexible options identified.

In the following sections, we provide further discussion on each step outlined above.

3. Step 1 and Step 2: Structuring the Problem and Identifying the Options

In this section, we set out the problem the CBA needs to answer when SSEN anticipates the need for reinforcement to meet rising demand for network capacity, and identify the options SSEN has available to address the problem.

3.1. Step 1: Problem Structuring

To ensure the CBA framework is fit for context and sufficiently addresses the needs of the business, we have worked closely with SSEN to understand which questions the CBA framework needs to address.

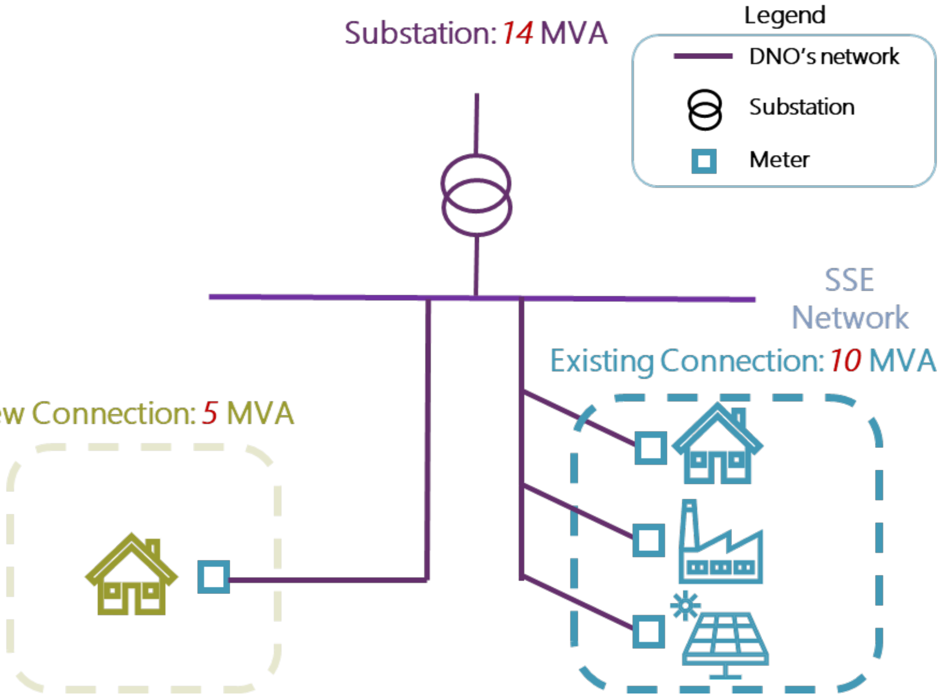
Based on our discussion with SSEN, we understand that the company, like other networks in Great Britain, is expecting rapid growth in demand. For example, the company expects the underlying trend in demand growth (e.g. new housing developments) will cause the need for additional capacity in many parts of its network. In addition, the government's proposed Local Power Plan (LPP) aims to promote 8 GW community-owned renewable generation projects, with a £3 billion budget.[27] SSEN is expecting to see large growth in renewable generation projects under the LPP proposal, which will lead to further connection delays within SSEN's network.

Therefore, we construct two hypothetical scenarios to help formulate the problems the CBA framework aims to answer. Specifically,

- **Scenario 1** (see illustrative example in Figure 3.1 below): This scenario assumes SSEN needs to connect a new housing development, located next to existing customers connected to SSEN's network (e.g., domestic premises, factories, distributed renewable generations, etc.). As an hypothetical test case, SSEN is considering a new housing estate in Bilsham, West Sussex, of 400 homes of mixed type to connect to the SSEN distribution network. The new housing development will add additional capacity requirement to SSEN's network. Specifically, SSEN estimates that, in this instance, connecting 400 homes would require 4.6MVA of additional network capacity. However, SSEN's existing network capacity is not sufficient to meet all the additional demand expected from the new housing development. Therefore, SSEN needs to expand its network capacity to accommodate this new housing development by reinforcing the network.
- **Scenario 2** (see illustrative example in Figure 3.2 below): This scenario assumes SSEN needs to connect a number of LPP projects, located next to its existing customers. The LPP projects impose additional export capacity requirements on SSEN's network, though these renewable projects are intermittent technologies that will not always use this network capacity. Similar to Scenario 1, SSEN's existing network capacity is not sufficient to meet both the export demand from the LPP projects and the demand from the company's existing customers. Consequently, SSEN cannot connect the LPP generators without reinforcing its network.

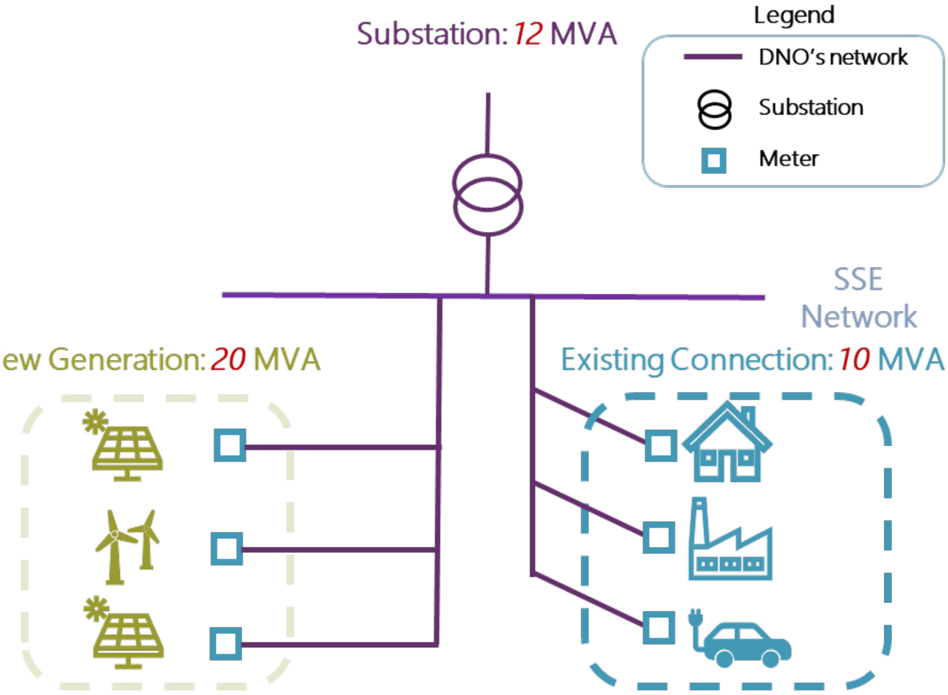
27 DESNZ (25 July 2024), Great British Energy founding statement, p.12.

Figure 3.1: Illustrative Figure for Hypothetical Scenario 1



Note: Capacity numbers are for illustrative purposes only.
Source: NERA Analysis.

Figure 3.2: Illustrative Figure for Hypothetical Scenario 2



Note: Capacity numbers are for illustrative purposes only.
Source: NERA Analysis.

3.2. Step 2: Option Identification

Through discussions with SSEN, we have identified a range of specific flexibility applications that SSEN might consider in its CBA analysis, as potential solutions to the problems outlined in Step 1. We outline the relevant options for each scenario in Section 3.2.1 and Section 3.2.2 below.

In its guidance, Ofgem asks companies to identify both the "do minimum option" and the "deferral option" in the CBA where possible (see Section 2.3). Applying Ofgem's requirement in this context:

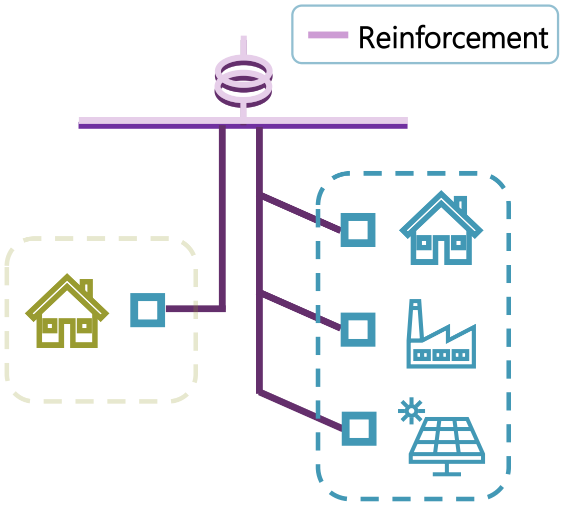
- We assume the do minimum option (or the baseline option) in both scenarios is for SSEN to reinforce the network and do nothing more.
- As we discuss in Section 2.2 above, we assume that the trend of rising demand for network capacity means that reinforcement cannot be permanently avoided. However, it may be possible to accelerate the connections currently being sought using flexibility options as a temporary measure, or marginally defer the connection while the DNO focuses its limited resources on other investment projects.
- While the possibility of permanently deferring reinforcement investment seems unlikely to be viable in conditions of rising demand, which reflects Ofgem's concerns in its recent Sector Specific Methodology Consultation on the flexibility first approach, some of the flexibility options considered would reduce customer demand permanently. This would allow SSEN to defer / scale down future reinforcements in the affected parts of its network.

3.2.1. Scenario 1 – options to connect additional demand

To meet the additional demand because of the new housing development, together with SSEN we have identified the following options aimed at reducing the time required to connect the development.

Do minimum / baseline option: Under this option, SSEN can reinforce its network to accommodate the demand from the new development (Figure 3.3 below). However, this might mean a delay in connecting the new houses given the existing connection queue and the limited supply chain capacity.

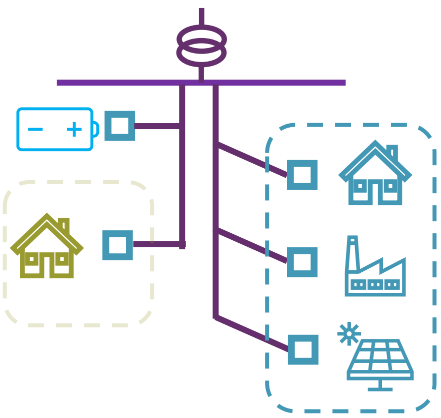
Figure 3.3: Scenario 1 – Do Minimum / Baseline Option



Source: NERA Analysis Based on Discussion With SSEN.

Option A (Battery Solution): SSEN can procure flexibility services from battery providers to connect the new housing development earlier, before the required reinforcement completes (Figure 3.4 below). By procuring the deployment of battery storage systems, SSEN can bridge the gap between the immediate energy needs of the new development and the time it takes to complete necessary network reinforcements. This means that even before the infrastructure upgrades are finalised, the battery can provide additional power to meet peak demand.

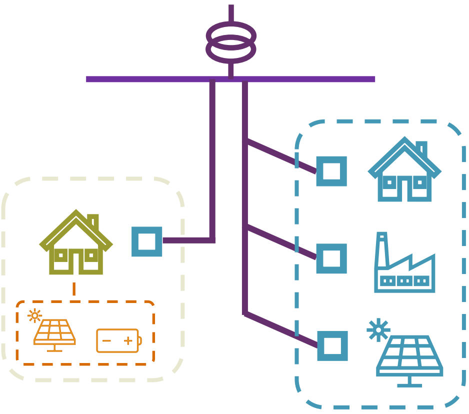
Figure 3.4: Scenario 1 – Option A Battery Solution



Source: NERA Analysis Based on Discussion With SSEN.

Option B (Community Smart Access): We understand that Community Smart Access schemes are a flexibility option under consideration by SSEN, aimed at encouraging the installation of heat pumps, more energy efficient housing developments, and flexibility services, thus resulting in a reduced overall peak demand. By using Community Smart Access schemes, SSEN can agree to connect these developments earlier, provided that developers commit to building homes that meet higher energy efficiency standards, as they will place a lower load on the network (see Figure 3.5 below). In addition to better insulation and energy-efficient construction practices, the Community Smart Access schemes encourage the incorporation of on-site flexibility coordination points to optimise energy usage.

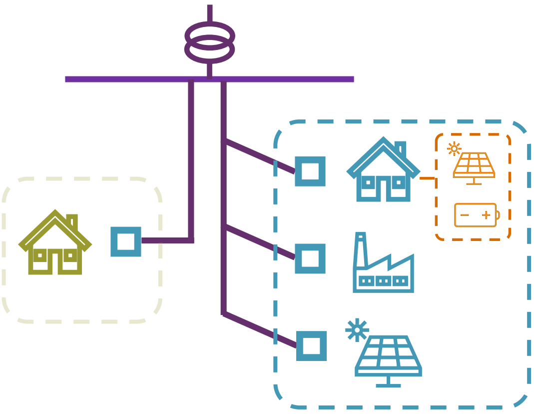
Figure 3.5: Scenario 1 – Option B Community Smart Access



Source: NERA Analysis Based on Discussion With SSEN.

Option C (House Retrofitting): SSEN can coordinate with a third-party to retrofit houses with heat pumps, improved insulation, and on-site flexibility coordination points (Figure 3.6 below). By investing to make existing houses more energy efficient and helping them to provide flexibility services, SSEN can reduce energy consumption in existing homes, which is crucial in managing the overall demand on the energy network.[28] By freeing up capacity that can be allocated to the new housing developments, the connection of this new development may happen sooner, even before the necessary network reinforcements are completed. It can also achieve the objective of releasing the capacity required to connect the new housing development, before the required reinforcement can be completed.

Figure 3.6: Scenario 1 – Option C House Retrofitting



Source: NERA Analysis Based on Discussion With SSEN.

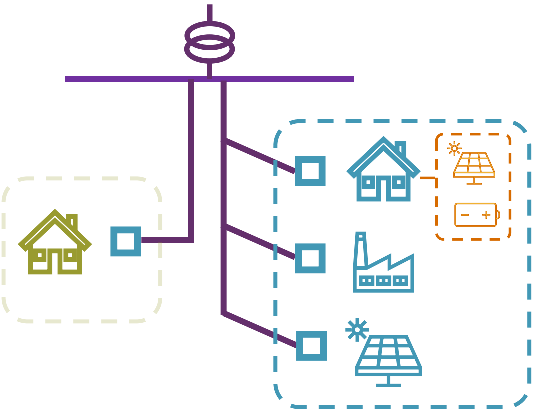
Option D (Existing Flexibility Services): SSEN might also consider procuring support from existing flexibility resources to accommodate demand from the new housing development before the relevant reinforcement work completes (Figure 3.7 below). In contrast to the previous flexibility options (i.e. Option A to Option C), this option does not require further investment in

[28] Retrofitting of the existing housing stock primarily focuses on improving energy efficiency (e.g. installation of new insulation) or electrifying heat (e.g. replacing a gas boiler with a heat pump) rather than the installation of flexible technology. However, electrification and improved efficiency alone is unlikely to reduce peak demand of the house and in fact may act to increase it. Hence, we include the installation of flexible technology as part of the retrofitting process.

new flexibility services but instead relies on existing flexibility resources that are already available to SSEN, such as demand-side response, deferred EV charging, and other technologies that can adjust energy consumption or generation in real-time.

Provided these flexibility services already exist (e.g. the infrastructure is already installed, but SSEN would need to procure the services via flexibility services contracts), these resources can be activated to provide additional capacity during peak demand periods, ensuring that the energy needs of the new housing development are met even before the necessary reinforcement work on the network is completed.

Figure 3.7: Scenario 1 – Option D Existing Flexibility Services



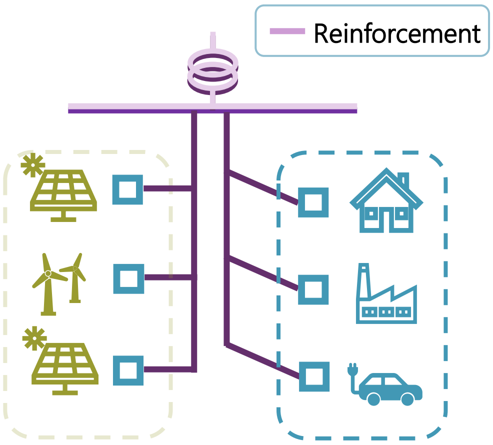
Source: NERA Analysis Based on Discussion With SSEN.

3.2.2. Scenario 2 – options to connect additional generation

Scenario 2 assumes SSEN needs to connect renewable energy projects under the government's LPP proposal. As the LPP projects create export capacity requirement on SSEN's network, the flexibility solutions to connect these projects differ slightly to the options we identified in Scenario 1.

Do minimum / baseline option: SSEN can reinforce its network to accommodate the LPP projects (see Figure 3.8 below). However, this may mean a delay in connecting these projects given the connection queue and/or supply chain constraints.

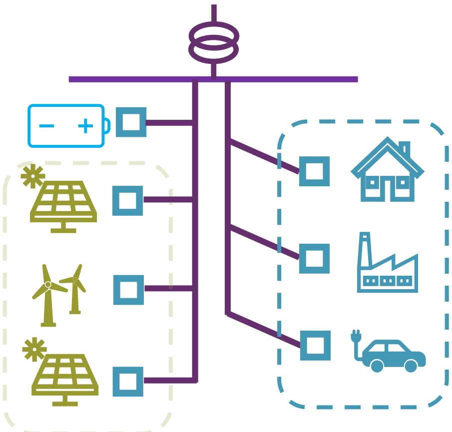
Figure 3.8: Scenario 2 – Do Minimum / Baseline Option



Source: NERA Analysis Based on Discussion With SSEN.

Option A (Battery Solution): SSEN can procure flexibility services from battery providers next to the LPP projects to connect these projects before the required reinforcement completes (Figure 3.9 below). As opposed to Option A under Scenario 1, in this case SSEN would utilise the battery provider's service to absorb extra supply when the network reaches its maximum export capacity.

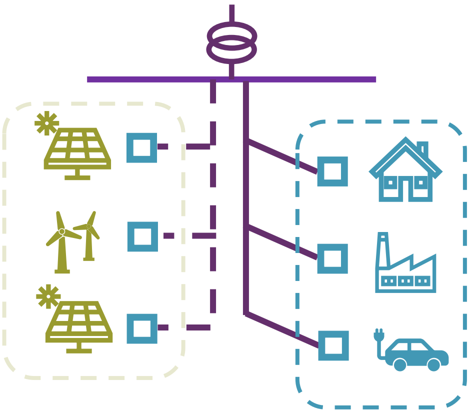
Figure 3.9: Scenario 2 – Option A Battery Solution



Source: NERA Analysis Based on Discussion With SSEN.

Option B (Access Product Offer): SSEN can offer a curtailable connection to the LPP projects before the required reinforcement completes (Figure 3.10 below). The curtailable connection allows SSEN to require the LPP projects to scale back their export to the grid when network capacity is constrained, e.g. in low demand / high generation conditions.

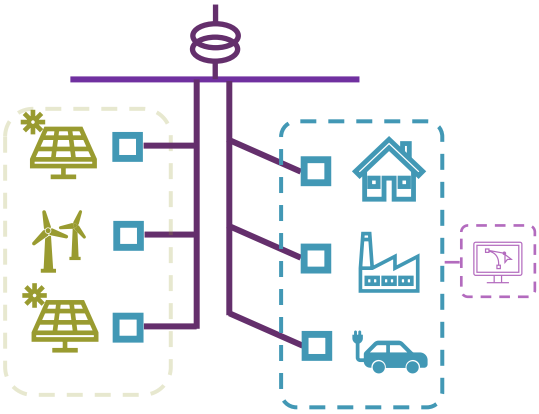
Figure 3.10: Scenario 2 – Option B Access Product Offer



NERA Analysis Based on Discussion With SSEN.

Option C (Demand Shifting): SSEN can procure demand shifting servicers from existing suppliers to shift loads towards peak generation periods before the required reinforcement completes (Figure 3.11 below).[29]

Figure 3.11: Scenario 2 – Option C Demand Shifting

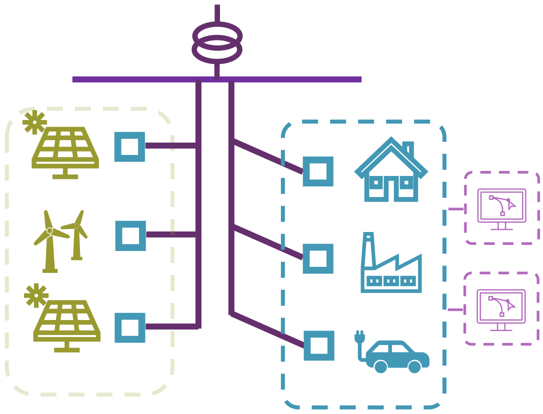


NERA Analysis Based on Discussion With SSEN.

Option D (Invest in New Demand Shifting Service): SSEN can invest in new load shifting services to shift loads towards peak generation periods before the required reinforcement completes (Figure 3.12 below).

[29] While demand shifting is a subset of wider flexibility processes (as flexibility services aim to shift demand and/or generation up or down to manage network constraints), we have used a different approach to estimate the cost of demand shifting and so differentiate demand shifting as an option.

Figure 3.12: Scenario 2 – Option D Invest in New Demand Shifting Service



NERA Analysis Based on Discussion With SSEN.

4. Step 3: Identifying Costs and Benefits

Having defined the available options under both Scenario 1 and Scenario 2, in this section we outline the relevant categories of cost and benefit associated with each option.

Because we assume network reinforcement is unavoidable in all options in both scenarios, due to the underlying trend growth in demand for network capacity, the costs and benefits we identify in this section are those *relative* to the do minimum / baseline scenario in which SSEN reinforces the network as originally planned and does nothing more. In other words, we focus on the additional costs and benefits associated with each flexibility option to speed up connections while SSEN reinforces its network, and other longer-term benefits that might arise from investments in flexibility resources to accelerate connection times.

This consideration is key to ensuring the cost benefit analysis only considers the costs incurred or benefits gained that would otherwise have not occurred if the option to use flexibility to accelerate connection times had not been taken.

As this cost benefit analysis is undertaken from a societal perspective (i.e. from the point of view of society as a whole rather than from the point of view of SSEN for example), for each flexibility option we seek to estimate the social cost and social benefit associated with that option. Hence, we recommend the estimated costs and benefits exclude any costs or benefits that are simply transfers between parties (e.g. higher profits or tax revenues) and only include changes in costs and benefits affecting overall social welfare.

As the analysis is undertaken on a UK society level, it is also important to consider the additionality of the costs and benefits to the country as a whole, when considering any indirect spillover benefits or costs. For instance, while there may be evidence that new housing can create employment in the local area, some of this new employment may displace employment from other areas to the local area, rather than creating entirely new employment. These effects would need to be accounted for, to ensure the analysis does not overstate the net benefits of the new housing.[30]

Given the exact costs and benefits associated with each flexibility option will vary over time and occur in the future, the NPV of each option must be taken to allow for a comparison of the net benefits of each flexibility option (and vs. the do-nothing baseline). As per Ofgem's guidance, the HM Treasury Green Book Social Time Preference Rate (STPR) should be used as the discount rate:[31]

4.1. Scenario 1: Costs and Benefits to Connect Additional Demand

For the four alternative flexibility options SSEN considers under Scenario 1 (see Section 3.2.1), we have identified societal costs and benefits associated with each option and our approach for estimating theses costs and benefits.

We apply each of these four options to the specific 400 home housing development project in Bilsham shared with us by SSEN. Peak demand of the new development, when combined with

[30] See for further example on how to account for this: HM Treasury (2008), The Green book, Appraisal and Evaluation in Central Government, p.94.

[31] HM Treasury (2008), The Green book, Appraisal and Evaluation in Central Government, Table 5.

expected growth to existing demand, would breach the capacity limit of the existing network as Table 4.1 below shows. Under the do-nothing option, the housing development could not connect to the network until 2030 after SSEN has completed network reinforcement works. However, the shortfall in network capacity is relatively small, such that the overall requirement for flexibility resources to be available at the peak time would be only around 2.3 MW, relative to existing network capacity of 30 MVA. The duration of the peak is also relatively short, only lasting 2.3 hours.

Table 4.1: Demand Requirements for the Sample 400 Home Development

	25/26	26/27	27/28	28/29	29/30
Diversified Peak Demand of Existing Demand (MVA)	20.3	23.8	25.4	27	28.7
Diversified Peak Demand of New Development (MVA)	3.68	3.68	3.68	3.68	3.68
Capacity Limit of Existing Network (MVA)	30	30	30	30	30
Availability Requirement at Peak (kW)	-	-	-	666.4	2332.4
Duration of Peak (hours)	-	-	-	1	2.3

Note: Existing demand is assumed to follow the Current Transformer scenario from the 2024 Distribution Future Energy Scenarios. Demand is derated by an 80 per cent diversity factor in-line with SSEN's normal framework.
Source: SSEN analysis.

4.1.1. Common Benefits Across Options

Avoided housing delay: Each option will accelerate the connection of the housing development. Therefore, the incremental benefit of this option relative to the do minimum / baseline option is the avoided delay in realising the societal benefits of the additional housing:

- To estimate the net benefits of building housing, we assume the social value of a house is equal to its sales price, less the construction costs to build it as per the Ministry of Housing, Communities and Local Government (MHLCG) guidance on development appraisal.[32] Given the option brings forward the building of the new housing, rather than leading to the creation of new housing, the net benefits of this option reflect the differences in NPV between a new development built earlier vs. the same development taking place with a delay;
- In addition to the direct benefits to the purchaser of the housing, there may also be wider social benefits from a new housing development. For instance, local employment benefits from increasing population in an area, or health benefits from improving the quality of housing stock. We have not included estimates of such benefits in our analysis, given the size of these

[32] MHCLG, formerly DLUHC, (March 2023), DLUHC Appraisal Guide, URL: https://www.gov.uk/government/publications/dluhc-appraisal-guide/dluhc-appraisal-guide. Visited on 12 February 2025.

benefits will likely depend to specificities on the location of the development and sufficient evidence is needed to justify their inclusion;

- It is important to include any forecast changes in real housing prices and construction costs over time. We source house price forecast and construction data from publicly available sources.[33] If more specific, local estimates of both pricing forecasts are available (e.g. developer estimates), then these could be used instead.
- The CBA should only attribute benefits to any of the options if the network constraint is the source of the delay in connection rather than other sources of delay. Similarly, if the local network constraint only leads to a redistribution of construction of new housing (e.g. the developer builds a different housing estate elsewhere rather than this specific site), then this could be accounted for in the assessment of benefits by netting off the net benefits of the different site.

4.1.2. Option A Battery Solution

We consider here the costs and benefits associated with SSEN's decision to install batteries to connect the new housing development earlier, before the required reinforcement completes.

Incremental benefits:

Avoided housing delay: Option A will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs). We value these avoided delays using the same method as set out above.

Incremental costs:

Expenditure: SSEN will need to make payments to the battery provider to install a new battery at the designated location, for the provision of flexibility services. We expect the battery provider to charge SSEN a fee for such services that allows it to recover its total costs, deducting any perceived profits it may be able to generate in the future (i.e. after the relevant reinforcement work is completed and the battery is no longer needed by SSEN to serve the particular new housing development, or any other services it can provide alongside the flexibility services when not needed by SSEN). However, these future profits may or may not be accounted for by the battery provider when deciding on the price to charge SSEN for flexibility services:

- If the markets for the flexibility services (as well as any other additional wholesale and ancillary services) the battery provider could provide are liquid and competitive, and there are no "missing markets", the future income that the developer would expect to earn after the end of its contract with SSEN would price in the full, societal value of the battery, after is no longer needed to support the DNO's network because the reinforcement has been delivered;
- However, if the markets into which the battery would sell after the flexibility contract ends are not "complete" (e.g. because the future value of batteries will come from ancillary service markets that have not been created yet), there may be unpriced, "positive externalities" that the battery provides to the power system, but cannot be monetised by the developer. The profits anticipated by the developer after the end of its contract with the DNO will tend to

33 See Appendix A.1 for further details.

underestimate the benefits of this option, because the future value of the battery's contribution is understated;

- It is important to ensure that only the additional, full system costs and benefits from installing a battery are included in the analysis. For instance, suppose that installing a 1 MWh battery to support SSEN's network displaces the installation of 0.8 MWh of battery capacity elsewhere in the system, e.g. because the battery is partially substitutable with others, but not perfectly substitutable because it may not be located optimally from the perspective of balancing the national system, and/or resolving transmission constraints. In this case, then only the additional costs (i.e. the costs of 0.2 MWh of capacity) should be included;
- For this CBA, we assume a 9.32 MWh battery (a 4 hour battery with a 2.33 MW discharge capacity battery is installed to provide sufficient capacity at peak demand in 2029 (see Table 4.1 above), and that this battery offsets one-for-one the need for battery capacity in the wider power system. This assumption means there would be no economic cost from locating the battery where it is required to support SSEN's network. This assumption also relies on there being no shortage of battery projects coming to market, such that the process of competition reduces the revenues they can earn from wider activities (e.g. wholesale market and ancillary services) down to the level that covers their full development and operational costs, including a required return on capital. Hence, revenues exactly cover its installation costs and operating costs and so provides no net benefits or costs. Ideally, any net cost from the siting of the battery in the development could also be included, but we assume this cost is zero for the purposes of this CBA:
  - It is difficult to directly estimate the cost of siting a battery sub-optimally on the network. Ideally, SSEN could model the electricity market, accounting for local constraints, to estimate how the location of a battery may affect its potential revenue generation. However, this is likely to be disproportionate within a CBA modelling exercise for a particular battery project;
  - An alternative approach would be to use market evidence on the pricing of flexibility contracts from battery developers, from market evidence, but this would not factor in the impact of unpriced externalities;
- In this case, we assume SSEN must pay for the battery to provide availability during peak hours (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £150 per MW per hour of available flexibility capacity procured by SSEN per year. SSEN must also pay the battery for any utilised capacity (in line with the requirements set out in Table 4.1 above) at a cost of £200 per MWh.
  - We use the prices of availability and utilisation of "Secure" flexibility services previously procured by SSEN in 2023/24 as provided to us by SSEN. These prices reflect wider flexibility services beyond those provided by batteries so the price a battery provider would require may differ. These costs reflect the average cost to SSEN of procuring these flexibility services. We acknowledge that there may be regional differences in these costs driven by local market segmentation and liquidity. We do not consider the cost of procurement to SSEN itself (i.e. any overheads), and we assume the marginal cost of procuring additional services is zero given SSEN is already procuring flexibility services across its network.

- We understand from SSEN that the price of these services is often equal to the cap which suggests there the potential presence of market power in the procurement of flexibility services. If market power if present, then the price of flexibility services may not reflect the social value of these services due to the potential presence of mark-ups above the cost of providing the services. The inclusion of mark-ups above cost would lead our CBA to overstate the social costs of procuring these services as profits represent a transfer between parties.

4.1.3. Option B Community Smart Access

Below we describe the cost and benefits associated with SSEN's decision to rely on more energy efficient housing developments in order to speed up new connections.

Incremental benefits:

Avoided housing delay: Option B will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs).

Avoided energy costs: Under Option B, the new housing will be built to a higher energy efficiency standard, and be heated using heat pumps. At the same time, installed flexibility services (e.g. domestic batteries or smart appliances) will reduce peak demand. We assume in the counterfactual; the housing would be gas-heated, as there is no mandatory requirement from the government to install heat pumps at this stage. There will therefore be permanent savings from lower gas usage (though higher electricity volumes) required to heat the houses:

- We forecast the changes in energy consumption by calculating the saved gas use and additional electricity use from switching from gas heating to an air source heat pump;
- To value these energy savings, we apply DESNZ's published long-run marginal costs of electricity and gas.[34] These values reflect the long-run marginal cost of providing additional electricity and gas (but excluding any associated carbon costs to avoid double counting with carbon valuation) rather than the retail prices consumers face which also contain fixed costs, taxes, and profits;[35]
- As the new houses will be equipped with on-site flexibility services, the house owners will be able to participate in the flexibility market. Therefore, the upgraded houses also generate permanent value of consumer flexibility services from using the newly installed technologies to support the wider power system, even after the distribution reinforcement has been completed;
- Community Smart Access schemes also generate permanent value from increased consumer flexibility services from the newly installed technologies being able to support the wider power system. For the purposes of this CBA, we assume the monetary benefits of the installed flexibility services in the retrofitted houses equal the cost SSEN would otherwise pay to procure equivalent flexibility services from other sources. We assume the costs of these services from other sources equal the costs set out below in Option D. This assumption may understate

34 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 9 and Table 10.

35 DESNZ (October 2023), Valuation of energy use and greenhouse gas emissions, Background documentation, p.14.

these benefits if the newly installed household flexibility services can provide further benefits beyond the avoided flexibility services to meet peak demand.

Avoided carbon emissions: Under Option B, the new housing will switch from gas to electricity, thus permanently reducing the level of carbon emissions (non-monetised) associated with the gas saved.

- To calculate the size of the carbon savings, we apply DESNZ's published marginal electricity grid emission factor and the gas emissions factor.[36] The marginal electricity emissions factor varies each year as it reflects DESNZ's projection of the UK's grid power mix. As such, the carbon emissions savings from avoided gas consumption increase over time, as DESNZ forecasts the renewable generation take-up for the grid to increase over time;
- To value these carbon savings, we apply the DESNZ's published carbon values which capture the wider social benefits from avoided carbon emissions.[37]

Incremental costs:

Expenditure: There will be additional costs to convert the new houses to heat pumps and/or install on-site flexibility services. We understand from the Local Energy Markets Alliance (a facilitator of Community Smart Access schemes) that the average costs of making new homes energy efficient is approximately £10,000 per home.

4.1.4. Option C House Retrofitting

Under Option C, SSEN could invest to make existing houses more energy efficient, to reduce peak demand. We describe below the benefits and costs associated with this option.

Incremental benefits:

Avoided housing delay: Option C will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs);

Avoided energy costs: Similar to Option B, Option C would convert existing houses from gas heating to heat pumps, and the installation of flexibility services (e.g. domestic batteries or smart appliances) will reduce peak demand. This creates permanent savings from lower gas volumes (though higher electricity volumes) required to heat the houses;

- We estimate the size and value of these energy savings using the same method as set out under Option B;
- Also, similar to Option B, the retrofitting also generates permanent value from increased consumer flexibility services from the newly installed technologies being able to support the wider power system. For the purposes of this CBA, we assume the monetary benefits of the installed flexibility services in the retrofitted houses equal the cost SSEN would otherwise pay to procure equivalent flexibility services from other sources. We assume the costs of these services from other sources equal the costs set out below in Option D. This assumption may

36 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 1 and Table 2a.

37 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 3.

understate these benefits if the newly installed household flexibility services can provide further benefits beyond the avoided flexibility services to meet peak demand.

Avoided carbon emissions: Similar to Option B, under Option C, the new housing will switch from gas to electricity, thus permanently reducing the level of carbon emissions associated with the gas saved.

- We value these carbon savings using the same method as set out in Option B.

Incremental costs:

Expenditure: There will be additional costs to convert existing houses to heat pumps and/or install on-site flexibility services. We understand from the Local Energy Markets Alliance (a facilitator of Community Smart Access schemes) that the average cost of retrofitting existing homes is approximately £20,000 per home.

4.1.5. Option D Existing Flexibility Service

Below we describe the costs and benefits associated with SSEN's decision to procure existing flexibility services to accommodate demand from the new housing development before the relevant reinforcement work completes.

Incremental benefits:

Avoided housing delay: Option D will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs).

Incremental costs:

Expenditure: There will be costs to procure sufficient volume of flexibility from the existing market to accommodate the additional demand from the new housing development.

- We assume SSEN must pay for the flexibility services to provide availability during peak hours (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £150 per MW per hour. SSEN must also pay the battery for any utilised capacity (in line with the requirements set out in Table 4.1 above) at a cost of £200 per MWh. [38]
  - As we lack data to differentiate the cost of procuring services for Option A and Option D, our analysis implicitly assumes Option A and Option D are equivalent.

4.1.6. Summary of Options

Table 4.2 below summarises the relevant incremental costs and benefits associated with each option under Scenario 1.

[38] Prices reflect the availability and utilisation costs of "Secure" flexibility services as provided by SSEN. See Scenario 1, Option A for further detail.

Table 4.2: Identified Costs and Benefits Associated with Each Option under Scenario 1

	Option A Battery Solution	Option B Community Smart Access	Option C House Retrofitting	Option D Existing Flexibility Services
Incremental benefits (relative to baseline)	• Avoided delay in realising the societal benefits of additional houses	• Avoided delay in realising the societal benefits of additional houses • Permanent savings from lower gas system volumes to heat houses • Permanent value of consumer flexibility services from using the newly installed technologies to support the power system • Permanent reduction in carbon emissions	• Avoided delay in realising the societal benefits of additional houses • Permanent savings from lower gas system volumes to heat houses • Permanent value of consumer flexibility services from using the retrofitted technologies to support the power system • Permanent reduction in carbon emissions	• Avoided delay in realising the societal benefits of additional houses
Incremental costs (relative to baseline)	• Payment to battery provider to provide the flexibility services and locate battery "sub-optimally"	• Costs to make new houses more energy efficient and/or install on-site flexibility services • Cost of additional electricity consumption to replace gas heating	• Costs to make existing houses more energy efficient and/or install on-site flexibility services • Cost of additional electricity consumption to replace gas heating	• Payments to existing flexibility service providers and retailers to procure flexibility services

Source: NERA Analysis Based on Discussion With SSEN.

4.2. Scenario 2: Costs and Benefits to Connect Additional Generation

For the four alternative flexibility options SSEN might consider under Scenario 2, we have identified the following societal costs and benefits associated with each option. We outline below our approach to estimating theses costs and benefits.

We apply each of these four options to an illustrative 0.05 MW community rooftop solar PV project. If the specific LPP projects in question are based on different technologies, then SSEN could adjust the estimates of the costs and benefits accordingly (i.e. adjust the costs and load factor of the generation project). For simplicity, we assume that all the generation of the PV project would be exported at the time of the local constraint. To the extent to which the community building or nearby demand can absorb the generation and reduce the impact of the constraint on the project's generation output, the cost of the intervention will fall.

We assume that generation project is installed in 2027 under any of the four options. Under the do-nothing option, the new generation project could not connect to the network until 2030, after SSEN has completed network reinforcement works.

4.2.1. Common Benefits Across Options

Avoided generation project delay: Each option will accelerate the connection of the local generation project, hence they have the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs):

- To value this additional electricity generation, we apply DESNZ's published long-run marginal costs of electricity.[39] These values reflect the long-run marginal cost of providing additional electricity (but excluding any associated carbon costs to avoid double counting with carbon valuation) rather than the retail prices consumers face which also contain fixed costs, taxes, and profits;[40]
- In practice, the average marginal costs, as forecast by DESNZ, may not always align with the value the new generation project brings. For instance, depending on the type of generation project connected, the generation patterns of the project may differ from the average (e.g. a peaking plant will tend to produce when prices are high or solar generation will tend to coincide with solar generation from other plant and so may tend to produce when prices are low). Hence, it may be possible to provide further sophistication to this modelling using power market modelling (if available) to account for any correlations between the output of the generation project and market prices;
- We net off the additional costs (in NPV terms) from incurring construction and operating costs earlier.

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39 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 9.

40 DESNZ (October 2023), Valuation of energy use and greenhouse gas emissions, Background documentation, p.14.

Avoided carbon emissions: Each option will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators. These benefits are not captured by the long run marginal cost of electricity.

- To calculate the size of the carbon savings, we apply DESNZ's published marginal electricity grid emission factor;[41]
- As noted above, if there is any correlation between the pattern of generation between the generation project and the wider generation mix, the actual emission factor may differ from DESNZ's forecast average. Hence, it may be possible to provide further sophistication to this modelling using system modelling (if available) to account for any correlations between the output of the generation project and marginal grid emissions factor;
- To value these carbon savings, we apply the DESNZ's published carbon values which capture the wider social benefits from avoided carbon emissions.[42]

4.2.2. Option A Battery Solution:

<u>Incremental benefits:</u>

Avoided generation project delay: Option A will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs).

Avoided carbon emissions: Option A will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators displacing others.

<u>Incremental costs:</u>

Expenditure: SSEN will need to make payments to the battery provider to install a new battery at the designated location, for the provision of the flexibility services. We assume this cost is the same as Option A under Scenario 1 (though with a 0.20 MWh capacity battery, with 0.05 MW of discharge capacity):

- As in Option A under Scenario 1, for this CBA we assume that the battery is able to earn revenues that exactly recover its installation and operating costs and so provides no net benefits or costs. Ideally any net cost from the sub-optimal siting of the battery versus where its installing would otherwise locate it could also be included;
- Instead, SSEN must pay for the battery to provide 0.05 MW of availability for 1,000 peak hours a year (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £150 per MW per hour. SSEN must also pay the battery for 0.05 MW of utilised capacity for two peak hours a year (based on SSEN's suggestion of when SSEN would need to curtail the project) at a cost of £200 per MWh.[43]

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41 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 1.

42 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 3.

43 Prices reflect the availability and utilisation costs of "Secure" flexibility services as provided by SSEN. See Scenario 1, Option A for further detail.

4.2.3. Option B Access Product:

Incremental benefits:

Avoided generation project delay: Option B will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs):

- However, we expect the volume of output will be very slightly lower than that under the other options, given the expected curtailment of generation from the LPP facilities when SSEN's network is constrained. We assume SSEN would need to fully curtail a generation project for two hours a year (based on information provided by SSEN). Hence, under a curtailable connection we deduct the generation benefits during these two hours;
- For simplicity, we assume that the hours where SSEN would curtail the curtailable connection are at system peak and uses the peak summer, daytime electricity price in GB between 2023 and 2025 (to reflect the price when solar PV generation would be highest). This assumption may be conservative if the time at which the generator is constrained does not align with GB's system peak, which is unlikely in this case considering the constraint arises when wind output is highest. It is possible to provide further sophistication to this modelling using power system modelling (if available) to account for any correlations between the curtailment of the generation project and wider market prices.

Avoided carbon emissions: Option B will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators displacing output from others. However, this benefit may be very slightly lower than under the other options, given the expected curtailment of generation from the LPP facilities. Hence, we deduct the carbon savings benefits for the two hours of system peak when the generator is curtailed.

Incremental costs:

Expenditure: Providing the LPP projects with curtailable connections may require SSEN to separate the work to connect the LPP projects and the work to reinforce the wider network. Therefore, we expect there may be loss of economies of scope under this option. However, we do not include the resulting increase in costs in the CBA as these costs will be heavily project specific.

4.2.4. Option C Demand Shifting:

Incremental benefits:

Avoided generation project delay: Option C will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs).

Avoided carbon emissions: Option C will allow the LPP projects to start generating earlier, so will also achieve the incremental benefit of avoided carbon emissions from these renewable generators displacing others.

Incremental costs:

Expenditure: There are likely costs associated with payments to suppliers to incentivise consumer load shifting. Consumers may already shift their load in response of time of use electricity tariffs. However, such voluntary behaviour may not necessarily be sufficient to address the additional capacity requirements imposed by the generation of the LPP projects, as customers' increases or reductions in load are unlikely to occur at the time when SSEN's network requires them. Therefore, we expect additional payments will be needed to incentivise consumers to shift the required amount of load to periods when the distribution network is constrained.

- For this CBA, we estimate the costs of demand shifting based on the average difference in peak and off-peak time of use tariffs for domestic customers (Economy 7 tariffs) multiplied by two to account for the retailer's margin and any additional costs to provide flexibility. We assume SSEN must pay the demand shifting provider to provide 0.05 MW of availability for 1,000 peak hours a year (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £370 per MWh. SSEN must also pay the demand shifting provider for 0.05 MW of utilised capacity for two peak hours a year (based on SSEN's suggestion of when SSEN would need to curtail the project) at the same cost of £370 per MWh. SSEN could use any alternative cost data which is more specific to the cost of demand shifting and any differential prices for availability versus utilisation if it is available.

4.2.5. Option D Invest in New Demand Shifting Service:

Incremental benefits:

Avoided generation project delay: Option D will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs).

Avoided carbon emissions: Option D will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators displacing others.

Incremental costs:

Expenditure: There are likely costs associated with payment to suppliers to incentivise consumer load shifting and to install any new load shifting technology. Consumers may already voluntarily shift their load in response to differences in electricity prices, however, such voluntary behaviour may not necessarily be sufficient to address the additional capacity requirements imposed by the generation of the LPP projects or not occur at the time when SSEN's network requires such load shifting behaviour. Therefore, we expect additional payments will be needed to incentivise consumers to shift the required amount of load to the required periods to accommodate the generation of the LPP projects.

- For this CBA, we assume the costs of installing new demand shifting technologies aligns with the cost of installing a 0.20 MWh new battery with 0.05 MW discharge capacity (in line with Option A for Scenario 1, though for a different capacity). We assume that the demand shifting technology is able to earn revenues that exactly recover its installation and operating costs and so provides no net benefits or costs. Ideally any net cost from the sub-optimal siting of the demand shifting technology versus where its installing would otherwise locate it could also be included;

- For this CBA, we estimate the costs of demand shifting based on the average difference in peak and off-peak time of use tariffs for domestic customers (Economy 7 tariffs) multiplied by two to account for the retailers margin and any additional costs to provide flexibility. We assume SSEN must pay the demand shifting provider to provide 0.05 MW of availability for 1,000 peak hours a year (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £370 per MWh. SSEN must also pay the demand shifting provider for 0.05 MW of utilised capacity for two peak hours a year (based on SSEN's suggestion of when SSEN would need to curtail the project) at the same cost of £370 per MWh. SSEN could use any alternative cost data which is more specific to the cost of demand shifting and any differential prices for availability versus utilisation if it is available.

4.2.6. Summary of Options

Table 4.3 below summarises the relevant incremental costs and benefits associated with each option under Scenario 2.

Table 4.3: Identified Costs and Benefits Associated with Each Option under Scenario 2

	Option A **Battery Solution**	**Option B** **Access Product Offer**	**Option C** **Demand Shifting**	**Option D** **Invest in New Demand Shifting Service**
Incremental benefits (relative to baseline)	• Realising the value of output from the LPP facilities earlier – Equals to the value of the electricity generated plus the value of avoided, non-monetised carbon emissions, less the increased NPV from earlier construction and operating costs	• Realising the value of output from the LPP facility earlier – Equals to the value of the electricity generated plus the value of avoided, non-monetised carbon emissions, less the increased NPV from earlier construction and operating costs	• Realising the value of output from the LPP facilities earlier – Equals to the value of the electricity generated plus the value of avoided, non-monetised carbon emissions, less the increased NPV from earlier construction and operating costs	• Realising the value of output from the LPP facilities earlier – Equals to the value of the electricity generated plus the value of avoided, non-monetised carbon emissions, less the increased NPV from earlier construction and operating costs
Incremental costs (relative to baseline)	• Payment to battery provider to provide the flexibility services and locate battery "sub-optimally"	• Reduction in value of output due to curtailed generation when network constrained • Losses of economic of scope from breaking the work to connect the LPP and the work to reinforce the network	• Payment to supplier to cover the costs of consumer load shifting based on the differential in time-of-use tariffs for domestic customers	• Payment to supplier to cover the costs of consumer load shifting based on the differential in time-of-use tariffs for domestic customers and locate demand shifting services "sub-optimally"

Source: NERA Analysis Based on Discussion With SSEN.

5. Step 4: Scenario Analysis in the Context of Uncertainties

When there are uncertainties in the CBA, we recommend SSEN conducts scenario analysis to ensure its choice of flexibility service is robust to the input assumptions used. Scenario analysis is particularly important if the choice between different interventions is marginal. In this section, we discuss key potential sources of uncertainty in the CBA and how SSEN could conduct scenario analysis to ensure its choice of intervention is robust.

Carbon values and energy costs

In this CBA, we assume that carbon values and long-run energy costs align with the "Central" scenarios as published by DESNZ. Green Book and Ofgem guidance requires that SSEN conducts sensitivity analysis on these inputs due to the uncertainty of long-run carbon values and energy costs. We provide such sensitivity analysis alongside the base results in Section 6 to assess how changes in these values and costs affect the choice of intervention.

Peak demand growth assumptions

There is uncertainty regarding how peak demand will grow for existing connections, as this will depend on the UK's pathway of decarbonisation and electrification. Ofgem guidance requires that DNOs consider conducting sensitivity analysis using different demand growth and energy pathways to measure how these assumptions change the choice of intervention.[44]

It may be more feasible to alter the scale of certain interventions relative to others (e.g. procuring existing services allows flexibility of volume up until all existing capacity is used versus the installation of new services). There is a benefit from the flexibility (or "optional value") of an intervention as it allows the DNO to adapt to new information on demand requirements and adjust the flexibility services it procures. For example, even if a particular intervention is superior in the most likely scenario, another option may provide greater optionality in case a different scenario materialises and this optionality may lower costs in the alternative scenarios. SSEN could also account for the option value interventions have when deciding on the chosen option.

Costs of interventions

In some cases, there is uncertainty on the costs of each intervention. In addition to using the latest cost information available as a baseline, we recommend SSEN conducts further sensitivity analysis on the cost of each intervention, particularly if SSEN does not have direct procurement comparisons for the intervention.

For instance, current prices for flexibility service may not reflect the prices for flexibility services in the future. Potential differences in prices could be important if there is a large increase in demand for flexibility services (e.g. if numerous or all networks implement additional flexibility services to speed up new connections as envisaged in this report) or if the location and level of disaggregation of flexibility services differs from the current services provided by the market.

Locational differences in assumptions

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[44] Ofgem (30 September 2024), RIIO-3 Business Plan Guidance – Annex 1: Investment Decision Pack Guidance, para. 4.45.

Where possible, we recommend SSEN aligns input assumptions as closely as possible to the location chosen for the intervention. For instance, the level of house prices (and so the benefit of avoiding housing delays) are likely to differ across locations.

If more granular data is not available for a specific location, SSEN could conduct sensitivities on the inputs to account for potential location variation. For example, SSEN could reduce the assumed house price level versus the average across the local authority. These sensitivities could help to ensure that a given intervention is still desirable even if there is locational variation on the exact level of benefits or costs versus the assumed inputs.

Deferral of reinforcement

In the context of this CBA we assume that there is no potential for deferral of the network reinforcement if SSEN invests in any of the flexibility services. However, in some cases procuring flexibility services could allow SSEN to defer (or permanently reduce) reinforcement. This may reflect that there is uncertainty in how future demand growth will evolve and any investments in flexibility services may delay when reinforcement is required. If such benefits exist, our analysis understates the net benefits of each intervention.

To calculate the benefit of deferring reinforcement, SSEN would need to calculate the difference in NPV between the planned reinforcement (i.e. in 2030) and the delayed reinforcement. The calculation could also account for any additional costs required to delay the reinforcement (e.g. SSEN may need to procure the flexibility services for the years during which the reinforcement is deferred). Finally, SSEN could derate these total net benefits based on the probability that each intervention could defer the reinforcement. Any differences in the probability that a given intervention would defer reinforcement (and the costs incurred during such a deferral) may affect the overall net benefits of each option and so affect SSEN's choice of the optimal intervention.

Unmonetised benefits and costs

Some benefits and costs are not easily monetised or quantifiable for inclusion in the CBA. As per Green Book guidance, if a benefit or cost is not easily monetisable, then SSEN could still record these benefits or costs.[45] SSEN could assess the values of these benefits or costs in an alternative way (even if not in monetary terms) to understand the magnitude of the benefit or cost and how it may differ across each of the intervention options.

45 HM Treasury (2022), The Green Book, p. 88.

6. Step 5: Evaluation and Compare Alternatives

In this section, we present the results of the evaluation of each of the options for each scenario based on our CBA framework and the data provided by SSEN. We also provide sensitivities to these results based on adjusting DESNZ's carbon and energy inputs as discussed above in Section 5. Finally, we consider the potential distributional effects of the options considered and how Ofgem may account for such effects.

6.1. Scenario 1 Results

We find that the net benefits of avoiding a three-year delay to the 400 house Bilsham development are worth £3.95m (real 2024) in NPV terms. We find that all options, except for Option C (House Retrofitting), deliver positive overall net benefits (i.e. the net social cost of delivery is less than the net benefits of the avoided housing delay), as we show in Table 6.1 below.

Table 6.1: Scenario 1 Baseline Results

	Net Present Value (real 2024 £1,000s)
Common Benefits Across Options	
Benefits of avoided housing delay	3,947
Option A: Battery Solution	
Net benefits of battery installation	-41
Overall net benefits of option	3,907
Option B: Community Smart Access	
Net benefits of Community Smart Access	-727
Overall net benefits of option	3,221
Option C: House Retrofitting	
Net benefits of house retrofitting	-4,592
Overall net benefits of option	-645
Option D: Existing Flexibility Service	
Net benefits of existing flexibility service	-41
Overall net benefits of option	3,907

Note: Analysis assumes "Central" scenarios for DESNZ's carbon values, long-run marginal electricity cost, and long-run marginal gas costs scenarios.
Source: NERA analysis.

We find that both Option A and Option D can unlock the benefits of the avoided housing delay at a very low cost (c. £41,000 in NPV terms).[46] This reflects the site specific low volume of flexibility services required (availability of c. 33.3 MWh in 2028 and c. 268.2 MWh in 2029) to relieve the capacity at the substation during peak hours. These options are preferable to the alternative options even if the costs of procuring flexibility services / a new battery (either the price or the

[46] Note, we do not provide an estimate for the losses from siting a battery vs its optimal location on the wider grid. A battery solution would be less desirable depending on the size of these losses.

volume required) were order of magnitudes higher. If a flexibility or battery-based solution is not available within a specific local area, then Option B is preferable to doing nothing as the net costs of Community Smart Access are smaller than the net benefits of the avoided housing delays.

As a sensitivity, as discussed in Section 5, we replicate the same analysis above but using "Low" scenarios for carbon values and the long-run marginal costs of energy. We find under these "Low" scenarios, the net costs of Option B and Option C increase, as Table 6.2 shows below. The increase in net costs reflects that the value of the carbon savings from avoided gas use decrease with the lower carbon valuation scenario. Option B remains net beneficial to carry out, although Option A and Option D remain preferable to it. The other options are not affected by the changes in carbon values and energy costs.

Table 6.2: Scenario 1 Low Carbon Values and Energy Costs Results

	Net Present Value (real 2024 £1,000s)
Common Benefits Across Options	
Benefits of avoided housing delay	3,947
Option A: Battery Solution	
Net benefits of battery installation	-41
Overall net benefits of option	3,907
Option B: Community Smart Access	
Net benefits of Community Smart Access	-3,276
Overall net benefits of option	671
Option C: House Retrofitting	
Net benefits of house retrofitting	-7,141
Overall net benefits of option	-3,194
Option D: Existing Flexibility Service	
Net benefits of existing flexibility service	-41
Overall net benefits of option	3,907

Note: Analysis assumes "Low" scenarios for DESNZ's carbon values, long-run marginal electricity cost, and long-run marginal gas costs scenarios.
Source: NERA analysis.

We also repeat the same analysis above but using "High" scenarios for carbon values and the long-run marginal costs of energy. We find under these "High" scenarios, the net costs of Option B and Option C decrease, as Table 6.3 shows below. For Option B, the reduction in net costs is large enough that the option becomes net beneficial (i.e. the carbon and energy savings from Community Smart Access outweigh the cost of installation). In this instance, the Community Smart Access intervention should go ahead regardless of whether it helps to unlock new housing development or not (although SSEN could give priority to developments which can help to reduce housing delays from network constraints to also unlock the further benefits of avoided housing delays) and so SSEN could consider prioritising this intervention over other options. The net cost of Option C no longer outweighs the benefits of the avoided housing delay and so it may be beneficial to carry out the intervention assuming the remaining three options are not available.

Table 6.3: Scenario 1 High Carbon Values and Energy Costs Results

	Net Present Value (real 2024 £1,000s)
Common Benefits Across Options	
Benefits of avoided housing delay	3,947
Option A: Battery Solution	
Net benefits of battery installation	-41
Overall net benefits of option	3,907
Option B: Community Smart Access	
Net benefits of Community Smart Access	2,821
Overall net benefits of option	6,769
Option C: House Retrofitting	
Net benefits of house retrofitting	-1,044
Overall net benefits of option	2,904
Option D: Existing Flexibility Service	
Net benefits of existing flexibility service	-41
Overall net benefits of option	3,907

Note: Analysis assumes "High" scenarios for DESNZ's carbon values, long-run marginal electricity cost, and long-run marginal gas costs scenarios.
Source: NERA analysis.

As a sensitivity, we replicate the same analysis above, but we assume the required peak requirements are higher than those set out in Table 4.1 above. We assume, the kWh peak requirements are incurred one year earlier than assumed in the base case (i.e. peak requirements of 666 kWh in 27/28 and 5,365 kWh in 28/29) and that the peak requirements in 29/30 are triple the base case requirements in 29/30 (i.e. 16,094 kWh). Under this scenario, the cost of flexibility services increases as the volume of peak requirement increases so SSEN must procure more flexibility services. This decreases the net benefits of Option A and Option D and increases the net benefits of Option B and Option C (as we assume the Community Smart Access and retrofitting allows domestic customers access to domestic flexibility service which are more valuable due to the large peak requirement). The relative net benefits of each of the options do not change, and Option A and Option D remain the most preferable. We find that Option B only becomes preferable to Option A and Option D once there is a cumulative peak requirement of c. 57 MWh over the three years (versus the c. 6 MWh assumed in the base case).

Table 6.4: Scenario 1 Increased Peak Requirements Results

	Net Present Value (real 2024 £1,000s)
Common Benefits Across Options	
Benefits of avoided housing delay	3,947
Option A: Battery Solution	
Net benefits of battery installation	-150
Overall net benefits of option	3,797
Option B: Community Smart Access	
Net benefits of Community Smart Access	-617
Overall net benefits of option	3,330
Option C: House Retrofitting	
Net benefits of house retrofitting	-4,483
Overall net benefits of option	-535
Option D: Existing Flexibility Service	
Net benefits of existing flexibility service	-150
Overall net benefits of option	3,797

Note: Analysis assumes "Central" scenarios for DESNZ's carbon values, long-run marginal electricity cost, and long-run marginal gas costs scenarios.
Source: NERA analysis.

As a sensitivity, we replicate the same analysis above, but we assume the utilisation costs of flexibility services are £300 per MWh rather than £200 per MWh.[47] This increase in utilisation costs has a minimal effect on the net benefits of each option given utilisation represents only a small portion of the overall cost. Variations in the cost of availability are more consequential given the assumed 2 per cent utilisation to availability ratio. Increasing the assumed availability cost from £150 per MW to £200 MW increases the cost of Option A and Option D by c. £14m and reduces the cost of Option B and Option C by c. £14m (as we assume Community Smart Access / retrofitting avoids flexibility services payments that would otherwise be made).

6.2. Scenario 2 Results

We find that the net benefits of avoiding a three-year delay to a 0.05 MW rooftop solar PV project are worth c. £18,000 (real 2024) in NPV terms. We find that all options deliver positive overall net benefits and at a relatively low cost compared to the benefits unlocked (i.e. the net social cost of delivery is less than the net benefits of the avoided housing delay), as we show in Table 6.5 below.

47 Per discussions with SSEN, £300 per MWh represents a higher level of utilisation prices based on potential market developments.

Table 6.5: Scenario 2 Baseline Results

	Net Present Value (real 2024 £1,000s)
Common Benefits Across Options	
Benefits of quicker generation connection	18
Option A: Battery Solution	
Net benefits of battery installation	-2
Overall net benefits of option	16
Option B: Access Product	
Net benefits of Access Product	-0
Overall net benefits of option	18
Option C: Demand Shifting	
Net benefits of utilising existing demand shifting	-5
Overall net benefits of option	13
Option D: Invest in New Demand Shifting	
Net benefits of investing in new demand shifting	-5
Overall net benefits of option	13

Note: Analysis assumes "Central" scenarios for DESNZ's carbon values, long-run marginal electricity cost, and long-run marginal gas costs scenarios.
Source: NERA analysis.

The estimated costs of Option C and Option D exactly align, as for all these interventions we assume the same cost (the cost of procuring demand shifting services, as we assume any installation costs are recovered one-for-one from other revenues). For Option B, we find the cost of intervention is lower, as the cost is only felt for the hours there are local network constraints impeding generation (which is only 2 hours a year). For the other options, costs incurred both at the time of constraints (as utilisation payments) and for periods where there may be constraints (via availability payments). Ultimately, which of the sets of options are preferable will depend on if the market price in the peak hours is higher or not than the cost of procuring services to provide flexibility at the peak and how accurately SSEN is able to assess when the constraint would occur (and so minimise availability payments).

As a sensitivity, as discussed in Section 5, we replicate the same analysis above but using "Low" scenarios for carbon values and the long-run marginal costs of energy. We find under these "Low" scenarios, the net benefits of a faster connection decreases to c. £13,000 (real 2024) in NPV terms (as the value of carbon and electricity has fallen). The costs of each intervention vary minimally, with a slight fall in the cost of the Access Product due to a lower value of lost carbon from curtailed generation. The value of the lost electricity does not vary as we assume the peak electricity price does not change.

We also repeat the same analysis above but using "High" scenarios for carbon values and the long-run marginal costs of energy. We find under these "High" scenarios, the net benefits of a faster connection increases to c. £24,000 (real 2024) in NPV terms (as the value of carbon and electricity has increased). The costs of each intervention vary minimally, with a slight increase in the cost of the Access Product due to a higher value of lost carbon from curtailed generation. The value of the lost electricity does not vary as we assume the peak electricity price does not change.

6.3. Societal CBAs Do Not Consider Distributional Effects

Consistent with Ofgem's CBA guidance, we have used a societal CBA which takes into account the impacts of a given intervention on society as a whole rather than its distributional effects. They therefore show which of the investments best meet the wider interests of society as a whole, though they are indifferent to whether and the extent to which individual companies or groups of customers win or lose. While this approach is consistent with how Ofgem typically requires network companies to perform CBA modelling, it is possible to comment on the extent to which different groups would gain from or bear the costs of the options outlined above.

Any costs DNOs would incur to implement any of the options considered above to speed up grid connections will be recovered from the general consumer base through an increase in DUoS charges. However, in Scenario 1 the benefits of the investments fall mainly on the developers of housing or other projects which are able to access the grid more quickly, and (for example) realise the margin between the sale price of the property and its costs, and property owners because the sale of properties likely also creates consumer surplus.

This distinction between those bearing the costs and realising the benefits raises questions regarding fairness and equity in the distribution of costs and benefits. Since Ofgem has a legal obligation to "protect the interests of existing and future consumers", it may consider it not acceptable for consumers to bear the financial burden while developers benefit from earlier grid access.[48]

While a concentration of benefits or costs on individual parties does not affect the calculation of the societal CBA, Ofgem may still require DNOs to consider distributional effects. For instance, Ofgem requires DNOs to set a the high-cost cap (HCC) for demand and generation connections.[49] Connecting customers must pay in full for any wider reinforcement costs triggered by their connection above the HCC. Any costs below the HCC are shared between the connecting customer and the DNO (i.e. via DUoS bill payers). The HCC is currently set at £1720 per kVA for demand connections and £200 per kW for generation connections. The HCC protects wider bill payers from contributing an excessive amount to customer specific costs. DNOs could apply similar considerations when implementing flexibility to ensure the costs are not excessively socialised in cases where the benefits are accrued by small number of parties.

However, these distributional effects may be necessary to achieve the societal benefits we have identified. Notably, we understand from discussion with SSEN that the necessity for a secure revenue stream from the DNO is fundamental to the success of an initiatives like Community Smart Access schemes.

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48 As noted by Ofgem: "The interests of such consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases in the security of the supply of gas and electricity to them and in the fulfilment by the Ofgem, when carrying out its functions." Source: Ofgem website (power and duties).

49 The cap for generation connections is referred to as the 'high-cost project threshold'.
Ofgem (May 2025), Appendix 1 – Demand HCC Development Methodology.

In addition, the question of who should finance the decarbonisation of heat remains contentious. Ofgem does not possess the authority to mandate the removal of gas boilers from the energy system. While the push towards reducing reliance on gas boilers may align with government objectives to promote heat pump deployment, this strategy risks introducing a tension within Ofgem's regulatory framework, as it must balance these objectives with its mandate to protect consumers.

In light of these complexities, it is therefore important to consider the distributional effects alongside welfare effects when considering these options. It also requires careful balancing of Ofgem objectives, including ensuring the reasonable electricity demands of new housing developments are met and meeting environmental objectives, which could justify certain expenditures by DNOs.

7. Conclusions

In this report, we develop a framework to help SSEN identify the social benefits and costs of deploying different flexibility services to speed up new connections of demand and generation projects ahead of network reinforcement investment. We apply this framework to two scenarios:

- Scenario 1 involves the connection of a new 400 home housing development in Bilsham; and
- Scenario 2 involves the connection of an illustrative 0.05 MW rooftop solar PV project.

We find there are clear positive net benefits to deploying flexibility services to speed up the connection of the example housing development. We find that the faster connection is worth £3.95m (real 2024) to society in NPV terms. This benefit is greater than the cost for three of the four flexibility options considered (installation of a new battery, Community Smart Access, and utilising existing flexibility services). We find in these scenarios that the cost of retrofitting the existing housing stock is greater than the benefits unlocked and so has a net social cost for this sample development.

Out of the three options with positive net benefits, we find the procurement of a new battery provider and the use of existing flexibility services to be the lowest cost options (reflecting the same flexibility service costs used for the two options) and as such are the most socially beneficial options for this sample development. If these options were not available, then the Community Smart Access option would be preferable to the status quo as it still delivers positive net benefits (though at a greater cost than these two options).

Our analysis may understate the costs of installing a new battery as it does not include any cost for the sub-optimal location of a battery (i.e. how much less revenue / system benefits can a battery generate from its location near the housing development versus its optimal location on the grid). We recommend SSEN develops estimates of this cost to ensure the battery installation option remains optimal.

Based on existing costs of flexibility service procurement (as provided to us by SSEN), flexibility services offer a low-cost way to manage demand constraints at peak. We note that in a future where DNOs procure much larger volumes of flexibility services, these costs of these services may increase (i.e. as more providers will need to install more capacity or incentivise end-customer participation). This option may no longer remain the lowest cost option if the prices of these services were to rise in the future.

We also find there are positive net benefits to deploying flexibility services to speed up the connection of a new 0.05 MW rooftop solar PV project. We find that the faster connection is worth c. £18,000 (real 2024) to society in NPV terms. We find all four options are low cost and so would deliver net benefits. However, we note that these low costs may partially reflect data availability issues as we do not have clear estimates of the cost of procuring these services. As such, we recommend SSEN develops further estimates of the costs of procuring these services for any future project.

For both the scenarios we consider, we recommend SSEN develops locality specific estimates of the social benefits and costs for any future project it wishes to assess. These estimates will provide a more accurate assessment of individual estimates of benefits and costs for a specific project.

Appendix A. Detailed Approach to CBA Modelling

A.1. Scenario 1: Costs and Benefits to Connect Additional Demand

A.1.1. Common Benefit Across Options

Avoided housing delay: Each option will accelerate the connection of the housing development . Therefore, the incremental benefit of this option relative to the do minimum / baseline option is the avoided delay in realising the societal benefits of the additional housing:

- To estimate the net benefits of building housing, we assume the social value of a house is equal to its sales price, less the construction costs to build it as per the Ministry of Housing, Communities and Local Government (MHLCG) guidance on development appraisal.[50] Given the option brings forward the building of the new housing, rather than leading to the creation of new housing, the net benefits of this option reflect the differences in NPV between a new development built earlier, vs. the same development taking place with a delay;
- In addition to the direct benefits to the purchaser of the housing, there may also be wider social benefits from a new housing development. For instance, local employment benefits from increasing population in an area, or health benefits from improving the quality of housing stock. We have not included estimates of such benefits in our analysis, given the size of these benefits will likely depend to specificities on the location of the development and sufficient evidence is needed to justify their inclusion;
- We assume that each of the options can speed up the connection time of the new housing project by 3 years based on SSEN's assessment of the network constraints to the sample housing development;
- The sample housing development includes 400 new homes. We assume the type of housing (e.g. detached, semi-detached, etc), is in line with existing stop within the Arun local authority (within which Bilsham is located). If more specific, local estimates of the type of housing are available, then these could be used instead. We use the breakdown of housing type to estimate the house prices and construction costs for the development;
- We source the price of new housing from an ONS dataset, which breaks down the median price of new building housing by house type (i.e. detached, semi-detached, etc.) and local authority.[51] As the housing will be built in the future, it is also necessary to forecast any real growth in house prices relative to general inflation. As per MHLCG guidance, we assume house prices grow in line with the OBR's latest house price forecast and grow in line with nominal

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50 MHCLG, formerly DLUHC, (March 2023), DLUHC Appraisal Guide, URL: https://www.gov.uk/government/publications/dluhc-appraisal-guide/dluhc-appraisal-guide. Visited on 12 February 2025.

51 ONS (September 2024), Median house prices for administrative geographies (newly built dwellings), URL: https://www.ons.gov.uk/peoplepopulationandcommunity/housing/datasets/medianhousepricesforadministrativegeographiesnewlybuiltdwellings. Visited on 12 February 2025.

Note, similar house price data is available for Scotland from Registers of Scotland: https://www.ros.gov.uk/data-and-statistics/house-price-statistics

GDP growth beyond that (with the forecasts than converted to real terms based the OBR's forecasts of the GDP deflator).[52] If more specific, local estimates of both house pricing and pricing forecasts are available (e.g. if the developer estimates the likely sales price), then these could be used instead;

- We assume that the developer will incur construction costs over the two years prior to when the housing development is completed. We assume the construction costs to build a new semi-detached house are in line with estimates published by the Housing Forum.[53] For other housing types, we scale this cost in line with the size of the housing type relative to a semi-detached house.[54] We assume construction costs grow in line with industry forecasts.[55] If more specific, local estimates of construction costs and construction inflation forecasts are available (e.g. if the developer estimates the construction costs), then these could be used instead;
- The CBA should only attribute benefits to any of the options if the network constraint is the source of the delay in connection rather than other sources of delay. Similarly, if the local network constraint only leads to a redistribution of construction of new housing (e.g. the developer builds a different housing estate elsewhere rather than this specific site), then this could be accounted for in the assessment of benefits by netting off the net benefits of the different site.

A.1.2. Option A Battery Solution

We consider here the costs and benefits associated with SSEN's decision to install batteries to connect the new housing development earlier, before the required reinforcement completes.

<u>Incremental benefits:</u>

Avoided housing delay: Option A will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs). We value these avoided delays using the same method as set out above.

<u>Incremental costs:</u>

Expenditure: SSEN will need to make payments to the battery provider to install a new battery at the designated location, for the provision of flexibility services. We expect the battery provider to charge SSEN a fee for such services that allows it to recover its total costs, deducting any perceived profits it may be able to generate in the future (i.e. after the relevant reinforcement work is completed and the battery is no longer needed by SSEN to serve the particular new housing

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52 As per MHCLG guidance, we use the latest OBR forecast for house prices. Beyond the outlook of the OBR's forecast, we assume house prices grow with nominal GDP from the OBR's long term forecast.

OBR (March 2025), Economic and Fiscal Outlook March 2025; and OBR (March 2024), Long Term Economic Determinants.

53 The Housing Forum (2024), The Cost of Building a House.

54 We source relative sizes by housing type using the sizes published in MHCLG (2018), English Housing Survey 2018-19: Size of English homes.

55 BCIS (March 2025), BCIS building forecast. URL: https://bcis.co.uk/news/bcis-construction-industry-forecast/, accessed on 24 April 2025.

development or any other services it can provide alongside the flexibility services when not needed by SSEN). However, these future profits may or may not be accounted for by the battery provider when deciding on the price to charge SSEN for flexibility services:

- If the markets for the flexibility services (as well as any other additional wholesale and ancillary services) the battery provider could provide are liquid and competitive, and there are no "missing markets", the future income that the developer would expect to earn after the end of its contract with SSEN would price in the full, societal value of the battery, after is no longer needed to support the DNO's network because the reinforcement has been delivered;
- However, if the markets into which the battery would sell after the flexibility contract ends are not "complete" (e.g. because the future value of batteries will come from ancillary service markets that have not been created yet), there may be unpriced, "positive externalities" that the battery provides to the power system, but cannot be monetised by the developer. The profits anticipated by the developer after the end of its contract with the DNO will tend to underestimate the benefits of this option, because the future value of the battery's contribution is understated;
- It is important to ensure that only the additional, full system costs and benefits from installing a battery are included in the analysis. For instance, suppose that installing a 1MWh battery to support SSEN's network displaces the installation of 0.8MWh of battery capacity elsewhere in the system, e.g. because the battery is partially substitutable with others, but not perfectly substitutable because it may not be located optimally from the perspective of balancing the national system, and/or resolving transmission constraints. In this case, then only the additional costs (i.e. the costs of 0.2MWh of capacity) should be included;
- For this CBA, we assume a 9.32 MWh battery (a 4 hour battery with a 2.33 MW discharge capacity battery is installed to provide sufficient capacity at peak demand in 2029 (see Table 4.1 above), and that this battery offsets one-for-one the need for battery capacity in the wider power system. This assumption means there would be no economic cost from locating the battery where it is required to support SSEN's network. This assumption also relies on there being no shortage of battery projects coming to market, such that the process of competition reduces the revenues they can earn from wider activities (e.g. wholesale market and ancillary services) down to the level that covers their full development and operational costs, including a required return on capital. Hence, revenues exactly cover its installation costs and operating costs and so provides no net benefits or costs. Ideally, any net cost from the siting of the battery in the development could also be included, but we assume this cost is zero for the purposes of this CBA:
  - It is difficult to directly estimate the cost of siting a battery sub-optimally on the network. Ideally, SSEN could model the electricity market, accounting for local constraints, to estimate how the location of a battery may affect its potential revenue generation. However, this is likely to be disproportionate within a CBA modelling exercise for a particular battery project;
  - An alternative approach would be to use market evidence on the pricing of flexibility contracts from battery developers, from market evidence, but this would not factor in the impact of unpriced externalities;

- In this case, we assume SSEN must pay for the battery to provide availability during peak hours (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £150 per MW per hour of available flexibility capacity procured by SSEN per year. SSEN must also pay the battery for any utilised capacity (in line with the requirements set out in Table 4.1 above) at a cost of £200 per MWh.
  - We use the prices of availability and utilisation of "Secure" flexibility services previously procured by SSEN in 2023/24 as provided to us by SSEN. These prices reflect wider flexibility services beyond those provided by batteries so the price a battery provider would require may differ. These costs reflect the average cost to SSEN of procuring these flexibility services, there may be regional differences in these costs driven by local market segmentation and liquidity. We do not consider the cost of procurement to SSEN itself (i.e. any overheads), we assume the marginal cost of procuring additional services is zero given SSEN is already procuring flexibility services across its network.
  - We understand from SSEN that the price of these services is often equal to the cap which suggests there the potential presence of market power in the procurement of flexibility services. If market power if present, then the price of flexibility services may not reflect the social value of these services due to the potential presence of mark-ups above the cost of providing the services. The inclusion of mark-ups above cost would lead our CBA to overstate the social costs of procuring these services as profits represent a transfer between parties.

A.1.3. Option B Community Smart Access

Below we describe the cost and benefits associated with SSEN's decision to rely on more energy efficient housing developments in order to speed up new connections.

Incremental benefits:

Avoided housing delay: Option B will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs).

Avoided energy costs: Under Option B, the new housing will be built to a higher energy efficiency standard, and be heated using heat pumps. At the same time, installed flexibility services (e.g. domestic batteries or smart appliances) will reduce peak demand. We assume in the counterfactual; the housing would be gas-heated, as there is no mandatory requirement from the government to install heat pumps at this stage. There will therefore be permanent savings from lower gas usage (though higher electricity volumes) required to heat the houses:

- We forecast the changes in energy consumption by calculating the saved gas use and additional electricity use from switching from gas heating to an air source heat pump. We use estimates of average gas consumption per household[56] and convert this to electricity use based on the relative coefficient of performance of an air source heat pump versus a typical gas boiler.[57] We assume there are no underlying changes in electricity consumption (i.e. for

56 Independent Gas Transporters' (2024), CSEP NExA Table Document.

57 UK Parliament POST (2023), Heat pumps.

non-heating purposes). We weight the changes in energy usage by the type of housing in the development to reflect larger properties use more energy for heating than smaller properties;

- To value these energy savings, we apply DESNZ's published long-run marginal costs of electricity and gas.[58] These values reflect the long-run marginal cost of providing additional electricity and gas (but excluding any associated carbon costs to avoid double counting with carbon valuation) rather than the retail prices consumers face which also contain fixed costs, taxes, and profits.[59] We assume the long run marginal electricity and gas costs align with DESNZ's "Central" scenarios;
- As the new houses will be equipped with on-site flexibility services, the house owners will be able to participate in the flexibility market. Therefore, the upgraded houses also generate permanent value of consumer flexibility services from using the newly installed technologies to support the wider power system, even after the distribution reinforcement has been completed;
- Community Smart Access schemes also generate permanent value from increased consumer flexibility services from the newly installed technologies being able to support the wider power system. For the purposes of this CBA, we assume the monetary benefits of the installed flexibility services in the retrofitted houses equal the cost SSEN would otherwise pay to procure equivalent flexibility services from other sources. We assume the costs of these services from other sources equal the costs set out below in Option D. This assumption may understate these benefits if the newly installed household flexibility services can provide further benefits beyond the avoided flexibility services to meet peak demand.

Avoided carbon emissions: Under Option B, the new housing will be made more energy efficient thus reducing permanent reducing the level of carbon emissions (non-monetised) associated with the energy saved.

- To calculate the size of the carbon savings, we apply DESNZ's published marginal electricity grid emission factor and the gas emissions factor.[60] The marginal electricity emissions factor varies each year as it reflects DESNZ's projection of the UK's grid power mix. As such, the carbon emissions savings from avoided gas consumption increase over time, as DESNZ forecasts the renewable generation take-up for the grid to increase over time;
- To value these carbon savings, we apply the DESNZ's published carbon values which capture the wider social benefits from avoided carbon emissions.[61] These published values vary each year and based on the scenario chosen. We assume the carbon values align with DESNZ's "Central" scenario;

<u>Incremental costs:</u>

Expenditure: There will be additional costs to convert the new houses to heat pumps and/or install on-site flexibility services. We understand from the Local Energy Markets Alliance (a

58 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 9 and Table 10.

59 DESNZ (October 2023), Valuation of energy use and greenhouse gas emissions, Background documentation, p.14.

60 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 1 and Table 2a.

61 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 3.

facilitator of Community Smart Access schemes) that the average costs of making new homes energy efficient is approximately £10,000 per home.

A.1.4. Option C House Retrofitting

Under Option C, SSEN could invest to make existing houses more energy efficient, to reduce peak demand. We describe below the benefits and costs associated with this option.

Incremental benefits:

Avoided housing delay: Option C will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs);

Avoided energy costs: Similar to Option B, Option C would convert existing houses from gas heating to heat pumps, and the installation of flexibility services (e.g. domestic batteries or smart appliances) will reduce peak demand. This creates permanent savings from lower gas volumes (though higher electricity volumes) required to heat the houses;

- We estimate the size and value of these energy savings using the same method as set out under Option B;
- Also, similar to Option B, the retrofitting also generates permanent value from increased consumer flexibility services from the newly installed technologies being able to support the wider power system. For the purposes of this CBA, we assume the monetary benefits of the installed flexibility services in the retrofitted houses equal the cost SSEN would otherwise pay to procure equivalent flexibility services from other sources. We assume the costs of these services from other sources equal the costs set out below in Option D. This assumption may understate these benefits if the newly installed household flexibility services can provide further benefits beyond the avoided flexibility services to meet peak demand.

Avoided carbon emissions: Similar to Option B, under Option C, the new housing will switch from gas to electricity, thus permanently reducing the level of carbon emissions associated with the gas saved.

- We value these carbon savings using the same method as set out in Option B.

Incremental costs:

Expenditure: There will be additional costs to convert existing houses to heat pumps and/or install on-site flexibility services. We understand from the Local Energy Markets Alliance (a facilitator of Community Smart Access schemes) that the average cost of retrofitting existing homes is approximately £20,000 per home.

A.1.5. Option D Existing Flexibility Service

Below we describe the costs and benefits associated with SSEN's decision to procure existing flexibility services to accommodate demand from the new housing development before the relevant reinforcement work completes.

Incremental benefits:

Avoided housing delay: Option D will accelerate the connection of the housing development, hence has the incremental net benefit of the avoided delay in realising the societal benefits of the additional houses (net of construction costs).

Incremental costs:

Expenditure: There will be costs to procure sufficient volume of flexibility from the existing market to accommodate the additional demand from the new housing development.

- We assume SSEN must pay for the flexibility services to provide availability during peak hours (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £150 per MW per hour. SSEN must also pay the battery for any utilised capacity (in line with the requirements set out in Table 4.1 above) at a cost of £200 per MWh. [62]
  - As we lack data to differentiate the cost of procuring services for Option A and Option D, our analysis implicitly assumes Option A and Option D are equivalent.

A.2. Scenario 2: Costs and Benefits to Connect Additional Generation

A.2.1. Common Benefits Across Options

Avoided generation project delay: Each option will accelerate the connection of the local generation project, hence they have the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs):

- To value this additional electricity generation, we apply DESNZ's published long-run marginal costs of electricity.[63] These values reflect the long-run marginal cost of providing additional electricity (but excluding any associated carbon costs to avoid double counting with carbon valuation) rather than the retail prices consumers face which also contain fixed costs, taxes, and profits;[64]
- In practice, the average marginal costs, as forecast by DESNZ, may not always align with the value the new generation project brings. For instance, depending on the type of generation project connected, the generation patterns of the project may differ from the average (e.g. a peaking plant will tend to produce when prices are high or solar generation will tend to coincide with solar generation from other plant and so may tend to produce when prices are low). Hence, it may be possible to provide further sophistication to this modelling using power market modelling (if available) to account for any correlations between the output of the generation project and market prices;

62 Prices reflect the availability and utilisation costs of "Secure" flexibility services as provided by SSEN. See Scenario 1, Option A for further detail.

63 DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 9.

64 DESNZ (October 2023), Valuation of energy use and greenhouse gas emissions, Background documentation, p.14.

- We net off the additional costs (in NPV terms) from incurring construction and operating costs earlier. We assume the construction and operating costs to build the LPP are those of a 0.05 MW rooftop solar PV project using values published by DESNZ;[65]

Avoided carbon emissions: Each option will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators. These benefits are not captured by the long run marginal cost of electricity.

- We assume the illustrative rooftop solar PV project has a load factor of 11 per cent, in line with the load factor for 10-50 kW solar PV projects as published by DESNZ. [66] To calculate the size of the carbon savings, we apply DESNZ's published marginal electricity grid emission factor.[67] The marginal electricity emissions factor varies each year as it reflects DESNZ's projection of the UK's grid power mix. As such, the carbon emissions savings from avoided electricity consumption decrease over time as DESNZ forecasts the renewable generation take-up for the grid to increase over time;
- As noted above, if there is any correlation between the pattern of generation between the generation project and the wider generation mix, the actual emission factor may differ to DESNZ's forecast average. Hence, it may be possible to provide further sophistication to this modelling using system modelling (if available) to account for any correlations between the output of the generation project and marginal grid emissions factor;
- To value these carbon savings, we apply the DESNZ's published carbon values which capture the wider social benefits from avoided carbon emissions.[68] These published values vary each year and based on the scenario chosen;

A.2.2. Option A Battery Solution:

Incremental benefits:

Avoided generation project delay: Option A will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs).

Avoided carbon emissions: Option A will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators displacing others.

Incremental costs:

Expenditure: SSEN will need to make payments to the battery provider to install a new battery at the designated location, for the provision of the flexibility services. We assume this cost is the same as Option A under Scenario 1 (though with a 0.20 MWh capacity battery, with 0.05 MW of discharge capacity):

[65] DESNZ (November 2023). Electricity generation costs 2023.

[66] DESNZ (November 2023). Electricity generation costs 2023.

[67] DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 1.

[68] DESNZ (November 2023), Valuation of energy use and greenhouse gas (GHG) emissions, Table 3.

- As in Option A under Scenario 1, for this CBA we assume that the battery is able to earn revenues that exactly recover its installation and operating costs and so provides no net benefits or costs. Ideally any net cost from the sub-optimal siting of the battery versus where its installing would otherwise locate it could also be included;
- Instead, SSEN must pay for the battery to provide 0.05 MW of availability for 1,000 peak hours a year (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £150 per MW per hour. SSEN must also pay the battery for 0.05 MW of utilised capacity for two peak hours a year (based on SSEN's suggestion of when SSEN would need to curtail the project) at a cost of £200 per MWh.[69]

A.2.3. Option B Access Product:

Incremental benefits:

Avoided generation project delay: Option B will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs):

- However, we expect the volume of output will be very slightly lower than that under the other options, given the expected curtailment of generation from the LPP facilities when SSEN's network is constrained. We assume SSEN would need to fully curtail a generation project for two hours a year (based on information provided by SSEN). Hence, under a curtailable connection we deduct the generation benefits during these two hours;
- For simplicity, we assume that the hours where SSEN would curtail the curtailable connection are at system peak and uses the peak summer, daytime electricity price in GB between 2023 and 2025 (to reflect the price when solar PV generation would be highest). This assumption may be conservative if the time at which the generator is constrained does not align with GB's system peak, which is unlikely in this case considering the constraint arises when wind output is highest. It is possible to provide further sophistication to this modelling using power system modelling (if available) to account for any correlations between the curtailment of the generation project and wider market prices.

Avoided carbon emissions: Option B will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided carbon emissions from these renewable generators displacing output from others. However, this benefit may be very slightly lower than under the other options, given the expected curtailment of generation from the LPP facilities. Hence, we deduct the carbon savings benefits for the two hours of system peak when the generator is curtailed.

Incremental costs:

Expenditure: Providing the LPP projects with curtailable connections may require SSEN to separate the work to connect the LPP projects and the work to reinforce the wider network.

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69 Prices reflect the availability and utilisation costs of "Secure" flexibility services as provided by SSEN. See Scenario 1, Option A for further detail.

Therefore, we expect there may be loss of economies of scope under this option. However, we do not include the resulting increase in costs in the CBA as these costs will be heavily project specific.

A.2.4. Option C Demand Shifting:

Incremental benefits:

Avoided generation project delay: Option C will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs).

Avoided carbon emissions: Option C will allow the LPP projects to start generating earlier, so will also achieve the incremental benefit of avoided carbon emissions from these renewable generators displacing others.

Incremental costs:

Expenditure: There are likely costs associated with payments to suppliers to incentivise consumer load shifting. Consumers may already shift their load in response of time of use electricity tariffs. However, such voluntary behaviour may not necessarily be sufficient to address the additional capacity requirements imposed by the generation of the LPP projects, as customers' increases or reductions in load are unlikely to occur at the time when SSEN's network requires them. Therefore, we expect additional payments will be needed to incentivise consumers to shift the required amount of load to periods when the distribution network is constrained.

- For this CBA, we estimate the costs of demand shifting based on the average difference in peak and off-peak time of use tariffs for domestic customers (Economy 7 tariffs) multiplied by two to account for the retailer's margin and any additional costs to provide flexibility. We assume SSEN must pay the demand shifting provider to provide 0.05 MW of availability for 1,000 peak hours a year (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £370 per MWh. SSEN must also pay the demand shifting provider for 0.05 MW of utilised capacity for two peak hours a year (based on SSEN's suggestion of when SSEN would need to curtail the project) at the same cost of £370 per MWh. SSEN could use any alternative cost data which is more specific to the cost of demand shifting and any differential prices for availability versus utilisation if it is available.

A.2.5. Option D Invest in New Demand Shifting Service:

Incremental benefits:

Avoided generation project delay: Option D will accelerate the connection of the local generation project, hence has the incremental net benefit of the avoided delay in realising the net benefits of the new project (i.e. generation profits of the LPP net of earlier construction and operating costs).

Avoided carbon emissions: Option D will allow the LPP projects to start generating earlier, there will also be incremental benefit of avoided (non-monetised) carbon emissions from these renewable generators.

Incremental costs:

Expenditure: There are likely costs associated with payment to suppliers to incentivise consumer load shifting and to install any new load shifting technology. Consumers may already voluntarily shift their load in response to differences in electricity prices, however, such voluntary behaviour may not necessarily be sufficient to address the additional capacity requirements imposed by the generation of the LPP projects or not occur at the time when SSEN's network requires such load shifting behaviour. Therefore, we expect additional payments will be needed to incentivise consumers to shift the required amount of load to the required periods to accommodate the generation of the LPP projects.

- For this CBA, we assume the costs of installing new demand shifting technologies aligns with the cost of installing a 0.20 MWh new battery with 0.05 MW discharge capacity (in line with Option A for Scenario 1, though for a different capacity). We assume that the demand shifting technology is able to earn revenues that exactly recover its installation and operating costs and so provides no net benefits or costs. Ideally any net cost from the sub-optimal siting of the demand shifting technology versus where its installing would otherwise locate it could also be included;
- For this CBA, we estimate the costs of demand shifting based on the average difference in peak and off-peak time of use tariffs for domestic customers (Economy 7 tariffs) multiplied by two to account for the retailers margin and any additional costs to provide flexibility. We source the average peak vs. off-peak tariff differential a price comparison website comparing tariffs for seven different energy retailers as of April 2025.[70] We assume SSEN must pay the demand shifting provider to provide 0.05 MW of availability for 1,000 peak hours a year (assuming a utilisation to availability ratio of 2 per cent as per SSEN) at a cost of £370 per MWh. SSEN must also pay the demand shifting provider for 0.05 MW of utilised capacity for two peak hours a year (based on SSEN's suggestion of when SSEN would need to curtail the project) at the same cost of £370 per MWh. SSEN could use any alternative cost data which is more specific to the cost of demand shifting and any differential prices for availability versus utilisation if it is available.

[70] Money Saving Expert website (April 2025), Is Economy 7 worth it? URL: https://www.moneysavingexpert.com/utilities/economy-7/. Accessed on 9 May 2025.

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