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NESO

Demand for Constraints Assessment

Final Report

14 March 2025

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Section 1:

Executive Summary

Section 1: Executive summary

Arup has modelled four cases of Demand for Constraints, reflecting variations in the number of boundaries and whether the demand is flexible or baseload.

Overview

This study has focussed on assessing the value delivered for consumers of a Demand for Constraints service. This service intends to bring forward new or relocated demand into areas of constraints; this could include hydrogen production, commercial demand (specifically data centres), industrial demand (i.e. electric arc furnaces) and energy storage.

Arup has modelled a counterfactual representation of the constraint costs between 2025 and 2035 utilising the FES 2024 Holistic Transition pathway; this has identified that constraint costs are increasing to 2029, slightly reduce in 2030 as additional network development is realised and then continue to increase in the 2030s. Key boundaries with constraints are those in Scotland (B0-B1, B3-B4 and B6) as well as East Anglia (EC5).

Arup has then modelled four cases including demand contracted through the Demand for Constraints service. The four cases provide possible scenarios for how demand may be contracted, with variations in the number of boundaries modelled (1, 3 and 4 boundaries) and whether the demand was flexible (100% flexible and 50:50 flexible and baseload).

In all cases it is assumed 50% of the demand is connected in 2028 and 50% in 2030. In all cases, a level of constraints is not resolved as it is expected that the NESO would resolve this through the Balancing Mechanism.

Scenario	Boundaries modelled	Minimum threshold that constraints are resolved above	Flex vs baseload	Timeline for demand connecting	Contract Option 1 total consumer cost savings (discounted) [1]	Contract Option 1 total consumer cost savings[1] %	Contract Option 2 total consumer cost savings (discounted) [1]	Contract Option 2 total consumer cost savings[1] %
Case 1	B0-B1, B3-B4, B6 & EC5	200MWh	50% flexible 50% baseload	50% in 2028 50% in 2030	£1.0bn	1.23%	£1.2bn	1.45%
Case 2	B0-B1	200MWh	50% flexible 50% baseload	50% in 2028 50% in 2030	£0.5bn	0.58%	£0.5bn	0.62%
Case 3	B0-B1, B3-B4 & B6	200MWh	50% flexible 50% baseload	50% in 2028 50% in 2030	£0.9bn	1.16%	£1.1bn	1.33%
Case 4	B0-B1	200MWh	100% flexible	50% in 2028 50% in 2030	£0.4bn	0.31%	£0.4bn	0.34%
Case 4a[2]	B0-B1	200MWh	100% flexible	50% in 2028 50% in 2030	£0.3bn	0.24%	£0.4bn	0.29%

Modelling cases

Source: Arup

[1] Consumer cost savings includes: constraint costs, changes in wholesale costs and renewable support obligations as well as the revenue received through the Demand for Constraints contract.

[2] Includes availability payment

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Section 1: Executive summary

All modelled cases of the Demand for Constraints service result in consumer savings between £0.4bn to £1.2bn when compared to the counterfactual model.

Overview

Savings can be achieved for consumers through several elements of the electricity bill. This includes constraint costs, wholesale costs and renewable support obligations. Further, savings can be achieved through the revenue raised through the Demand for Constraints contract itself. The following provides an overview of the total consumer value achieved through the contract and then the specific constraint costs savings. The majority of the total consumer value savings are attributed to avoided renewable support payments (i.e. via the CfD and RO schemes).

Total Consumer Value

In determining the value for consumers, two contract types have been assessed:

1. A fixed utilisation tariff (£/MWh) for excess electricity consumed) from demand facilities to NESO.
2. A utilisation tariff based on an agreed percentage discount from spot price from demand provider to NESO.

Both contract types were considered as part of a Cost Benefit Analysis to understand value to the consumer of the Demand for Constraint service based on the wholesale, constraint, and renewable support costs that form part of electricity bills.

In all cases explored, the Demand for Constraint service reduces costs incurred by consumers, driven mainly by the reduction in the premiums paid to renewable assets to curtail output in the Balancing Mechanism at times of constraints. The reduction in consumer costs range from ~£450m to £1.1bn (discounted) versus the counterfactual depending on the case, with greater savings achieved for cases where the demand contracted is greater (Case 1 resulting in the greatest savings).

In terms of the contract options, Contract Option 2 results in greater savings across all cases compared to Contract Option 1 as the payment by demand to NESO is greater, and so the pass through of these payments to NESO offsets a larger proportion of BSUoS costs.

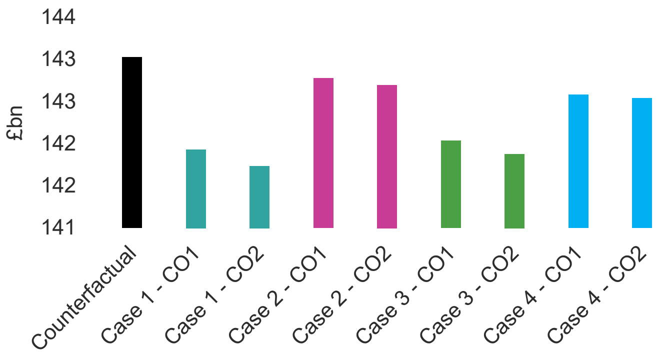
Constraint costs

In all modelled cases, constraint costs are lower than the counterfactual; savings range from £0.5bn to £2.5bn (2023 prices) across the modelled period of 2025-2035.

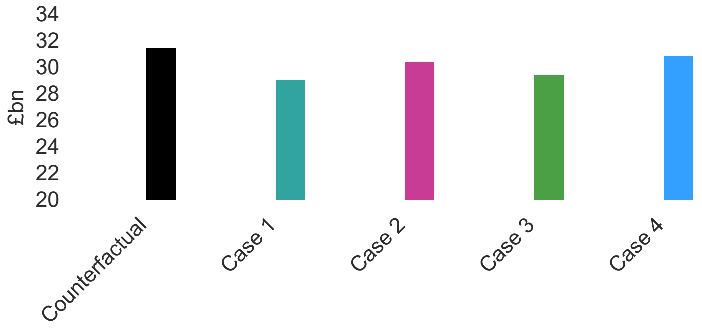
The biggest savings are seen in Case 1 which includes 50% baseload and 50% flexible demand in four electricity system boundaries. This results in savings of 8% (£2.4bn, 2023 prices) across the 2028-2035 period compared to the counterfactual. This is predominately driven by the baseload demand resolving higher levels of constraints.

Even in the lowest demand Case 2, which include lower demand in one boundary, there is a saving of £1.05bn (3%) compared to the counterfactual when baseload is included and £0.6bn when only flexible demand is added into the one boundary.

Key limitations of the modelling include the consideration of a single pathway (Holistic Transition) and simplified assumptions on asset bidding behavior and subsidy support.



Total discounted costs incurred by consumers between 2025-2035 £bn under the counterfactual and 4 modelled cases
Source: Arup analysis



Constraint costs £bn (2023 prices) under the counterfactual and 4 modelled cases

Source: Arup analysis

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Section 1: Executive summary

The achievability of these consumer savings is contingent on a range of regulatory, technical and commercial levers, this includes the availability of funding mechanisms, how competitive the contract would be with other available services and availability of grid connections and potential reinforcement costs.

Deliverability

The feasibility of achieving this demand uptake is reliant on new or relocated demand being available between the 2028 and 2030 window modelled. This means that the service would need to be targeting projects that are currently in the middle or late in their development timeline as those in early development are unlikely to be able to achieve these timelines. If demand is connecting later, it is likely to have a diminishing impact on the savings for consumers ahead of wider network development.

Across the technologies explored, there are several commercial, technical and regulatory deployment levers that will be required to support their business case and therefore be able to available through the contract. These include:

- Timely allocation of funding support, particularly for hydrogen and pumped hydro storage, through either the Hydrogen Allocation Round (HAR) or the LLES Cap and Floor process.
- The competitiveness of the contract compared to other markets. Several of the technologies would already be able to operate within other electricity markets, particularly the ancillary services and balancing markets. Arup would expect the Demand for Constraints contract to at least require the service to be given priority over other potential markets with penalties if the provider is unable to respond as agreed. Where possible within the requirements of the service, the ability to participate in other markets would likely appeal to more flexible assets such as BESS, however, Arup would expect large demand sources such as data centres to focus solely on this service.
- Availability of offtaker/wider infrastructure for the demand and the alignment of the constraint periods with their individual operational profiles particularly for those providing a flexible response. Further, for hydrogen that the offtaker meets the qualifying requirements for the funding support (HAR).
- Availability of grid connections and the associated reinforcement costs.

Arup has undertaken a high level assessment of these factors, however, it is recommended that NESO undertake a full assessment to determine how the benefits modelled through the four cases would be impacted in the event of delayed or lower demand materialising.

Recommended next steps

Arup recommend the following actions to be undertaken by NESO to manage the deployment risks and challenges:

- Explore possible procurement approaches as it is unlikely that a competitive auction approach can be adopted.
- Undertake a full assessment of the liquidity impact on this service on other potential services including current flexibility markets.
- Assess the potential implementation requirements (including control room requirements) of the contract.
- Explore how this service could be operated given that the NESO would need to recover revenue from contracted parties.

Section 2:

Methodology, assumptions and limitations

Section 2: Methodology, assumptions and limitations

Through the Demand for Constraints project, NESO are exploring two contract options to incentivise demand to locate in areas of high constraints. The objective of this study is to explore the consumer benefit and greenhouse gas emissions savings that could be achieved through the contract.

Electricity system constraints

Thermal constraints occur when the power flow through a transmission circuit (boundary) exceeds the power rating, resulting in energy behind that transmission circuit to be turned down. This is then replaced by generation being turned up in front of the boundary, nearer the location of demand. The increasing levels of renewable penetration in the GB market means that thermal constraints have been growing over time and will happen more frequently as renewables are far more location dependent than flexible and dispatchable generation and the investment to the transmission networks is delivered.

Demand for constraints project

The Constraints Collaboration Project is a NESO initiative aimed at addressing the increasing levels of thermal constraints on GB's electricity transmission system and the associated rising constraint costs, which are projected to reach £500m- £3bn annually by 2030.

The project seeks to collaborate with industry stakeholders to develop short term, market-based solutions that can be implemented ahead of significant physical infrastructure reinforcements. During the first phase of the project, NESO engaged with industry experts to assess various proposals aimed at managing thermal constraints. This focused on two primary solution categories:

- Constraint Management Markets (CMM): Developing market mechanisms that incentivise generators and demand sources to adjust their output, thereby alleviating network constraints.
- Technical Solutions to Enhance Boundary Flows: Implementing technologies, such as expanded intertrip schemes and battery storage systems, to increase the transmission capacity across constrained network boundaries.

This study is focused on exploring the impact of a Demand for Constraints service, under the CMM option, to reduce the volume of renewable curtailment by sending market signals for increased local demand during constraint periods and to incentivise strategic location of new assets and reduce redispatch costs.

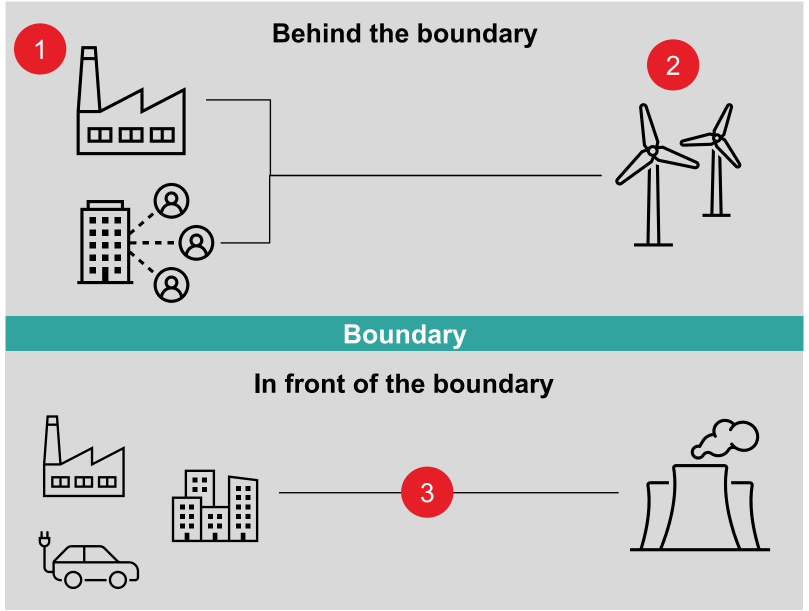
This would be achieved through a long-term contract whereby NESO can ask a demand source to increase its consumption at times of constrained network.There are two different proposed pricing structures for these contracts:

- A fixed utilisation tariff (£/MWh for excess electricity consumed) from demand facilities to NESO.
- A utilisation tariff based on an agreed percentage discount from spot price from demand provider to NESO.

These options are likely to provide cheaper electricity for the demand user than they would receive otherwise.

The objective of this study was to model several cases of the contract demand to understand the potential value that can be delivered for consumers through the deployment of a Demand for Constraints contract.

How the contract would work in the event of a constraint



1. New or relocated demand behind the boundary through Demand for Constraints contract paying a discounted £/MWh for their electricity demand. This flexible demand is available to provide turn up during periods of constraints.
2. Previously constrained renewable generation is no longer constrained and provides electricity to new demand. Renewable generators are no longer paid the premium by NESO for being constrained
3. Other generation is still turned up in front of the boundary to meet demand requirements

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Section 2: Methodology, assumptions and limitations

Arup have modelled a counterfactual case and several cases, varying the level of demand, boundaries, flexibility and constraint resolution threshold to understand the potential consumer savings under the two contract options.

Overarching methodology

To assess the consumer savings delivered under the contract, Arup have followed the approach identified to the right. This has focussed on modelling a counterfactual model and several cases to understand the cost benefit assessment of the two contract types for consumers.

The cases have varied the number of boundaries and the level of flexibility of demand.

1 Base case market modelling

Using Plexos, Arup have modelled the energy system between 2025 to 2035 to provide baseline levels for constraint costs, consumer welfare and other relevant market outcomes. This has provided a counterfactual that the Demand for Constraints is compared against.

This has been based on FES 2024 Holistic Transition pathway and does not include new demand that would be contracted through the Demand for Constraint contract. Electricity network boundary assumptions are in line with Electricity Ten-Year Statement 2023, which incorporates the Holistic Network Design (HND) and the Network Options Assessment (NOA) refresh.

Full modelling assumptions are detailed in the following slides.

2 Demand for constraints assessment

Utilising both the baseline results and the current known projects, Arup have undertaken an assessment of the possible new or relocated demand that could be included within the most constrained boundaries (this is above the assumptions made within FES 2024 Holistic Transition). This has looked at a range of technologies, including hydrogen, data centres, electric arc furnaces, large-scale electric boilers, energy storage and EV fleets.

This assessment has considered:

- The level of demand that could be provided based on current and known future projects
- Whether the demand source be online during the contract window (2025-2035)
- Where the demand source is typically located
- The typical profile of demand
- The response time of the demand source in terms of hours/days

The assessment has identified the potential demand that could connect as identified on the later slides.

3 Demand for constraints market modelling

With the additional demand included, the power market has been remodelled using Plexos to provide revised levels for constraint costs, consumer welfare and other relevant market outcomes to compare to the counterfactual.

4 Cost Benefit Analysis

Comparing the counterfactual to the demand for constraints model, a CBA has been undertaken to compared consumer welfare in the counterfactual to the contract scenarios. This has considered both quantitative measures (including consumer welfare, carbon emissions) and qualitative measures, such jobs, GVA etc.)

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Section 2: Methodology, assumptions and limitations

Arup have used Plexos to model a counterfactual and demand for constraints model for the period of 2025-2035. The underlying model is based on demand and generation in FES 2024 Holistic Transition.

Power Market Modelling methodology

To conduct the modelling, Arup has utilised PLEXOS Energy Modelling Software to build a model of the GB electricity system. A model of the GB system has been constructed to enable an understanding of the impact of changing boundary capabilities over time as network reinforcements are deployed, and the subsequent impact on power flows and the operating profiles of generators.

To do this, several "Nodes" have been created to represent areas of GB behind or between certain boundaries. These nodes comprise of demand and generation sources reflective of the area behind (or between) the applicable boundary (or boundaries) and are linked to a "Region", which is GB.

A "stack" approach has been taken for generation; whereby each applicable "source" of generation is assigned to each node as a single PLEXOS generator. This is opposed to individual units representing each individual generator. Each generation source will comprise of several units reflective of the capacity growth trajectory assumed. The exception is for existing baseload generators which are represented as standalone units.

"Lines" in PLEXOS represent transmission lines in the network. Lines have been used to represent the flows along transmission lines possible across the boundaries studied. A max flow capacity has been defined for each line, which represents the maximum boundary capability. This capability changes over time as network reinforcements are deployed.

To model the impact of the contract, Arup has performed two model runs one unconstrained run that assumes no limitations on the network, and a constrained run, which considers the physical constraints of the transmission network. These runs yield congestion volumes. The topology of the unconstrained model is the same as the constrained with no line limitations (i.e. single node model).

The Short Term Schedule of PLEXOS (i.e. short term dispatch model) has been utilised to model the days of the horizon at hourly granularity. The Short Term Schedule determines the optimal, least cost generation mix to serve demand.

Demand

The annual and peak load demand data was broken down and allocated to each boundary/group of boundaries modelled using the Building Block data provided in the FES 2024 databook for the Holistic Transition pathway.

The annual and peak load demand data for each boundary/group of boundaries was then utilised alongside base demand profiles from ENTSO-E to create hourly demand profiles using the PLEXOS Demand Grower tool.

Model component	Summary
Modelled topology	The following boundaries are individually modelled: B0-B1, B2, B3-B4, B5, B6, B7, B8, B9, NW2, SW1, SC1, EC5 and Rest of GB (RoGB).
Baseline demand	Demand is based on FES 2024 Holistic Transition pathway and broken down by individual boundaries based on the FES dataset
Generation capacity and location	Generation is based on FES 2024 Holistic Transition pathway and broken down by individual boundaries based on the FES dataset
Transmission line capabilities	Boundary capacities are based on the Electricity Ten-Year Statement (ETYS) 2024/ Clean Power 2030, which includes ASTI projects.
Model time period	2025 – 2035
Interconnector assumptions	All operational interconnectors, current in construction interconnectors and third window projects.
Generator SRMC	SRMC is based on generator LCOE from DESNZ Electricity Generation Cost publications.
Market arrangements	Markets operate under existing arrangements and no cases have considered the implications of market reforms

Model assumptions

Source: Arup

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Section 2: Methodology, assumptions and limitations

The counterfactual model has identified that constraint costs are increasing to 2029, slightly reduce in 2030 as additional network development is realised and then continue to increase in the 2030s. Constraints are highest in B0-B1, B6, EC5 and B3-B4.

Initial power marketing modelling results

The initial modelling results have indicated that the most constrained boundaries are: B0-B1 (North Scotland), B6 (England-Scotland Border), EC5 (East Anglia) and B3-B4 Scottish Central Belt; this aligns with the system constraints volumes presented in ETYS 2024.

In B0-B1, over the 10 years constraint costs total £6.3bn peaking in 2029 due to by renewable generation connections in 2029 ahead of network reinforcement in 2030; costs then continue to rise again as further generation connects in the boundary in 2033.

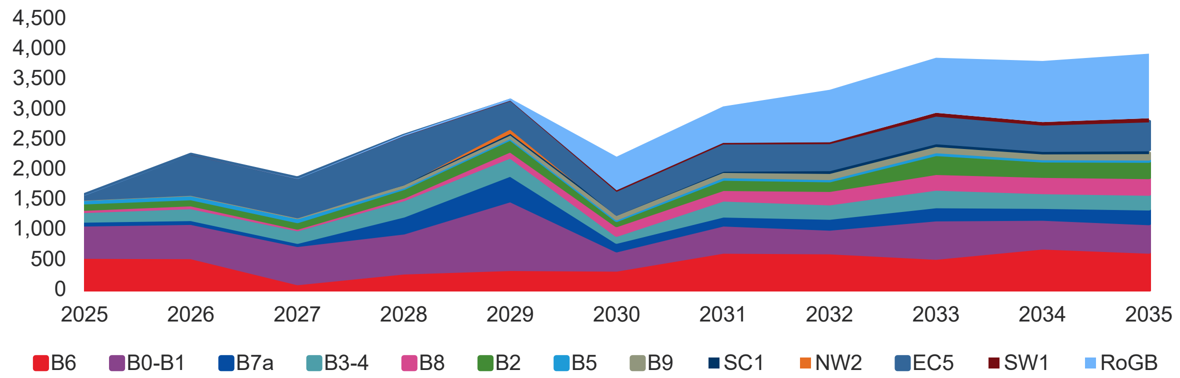
In B6, constraint costs rise significantly in the early 2030s, peaking at £701m in 2034 and totalling £5.3bn across the 10 years.

Similarly, B3-B4 constraint costs peak in 2029, reduce in 2030 with network reinforcement and then return to higher levels in the early 2030s, with constraints averaging £231m per annum across the modelled period.

Outside of the Scottish Boundaries, constraint costs at EC5 are significant in the late 2020s, particularly in 2028, and then remain relatively constant throughout the result of the modelled period.

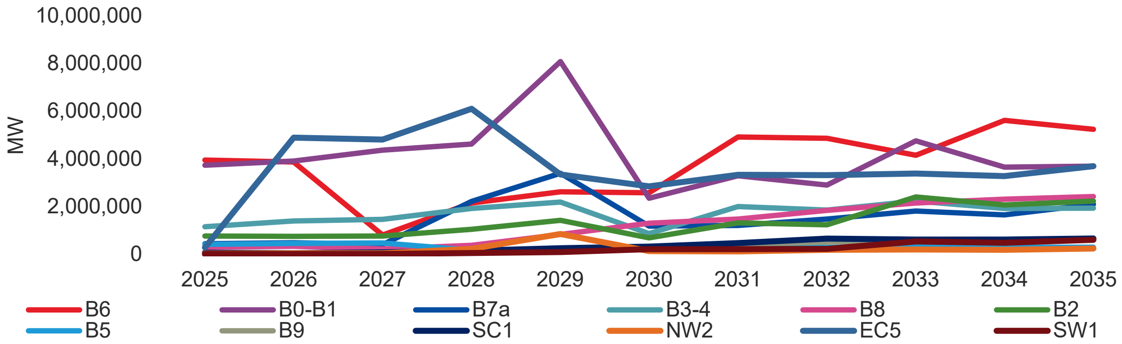
The RoGB (Rest of Great Britain) reflects all other boundaries which have not been individually modelled; whilst this presents a large constraint cost, when separated into individual boundaries the materiality on a per boundary basis is much lower compared to the other boundaries.

For the purposes of the contract assessment, Arup have focussed on B0-B1, B6, B3-B4 and EC5.



Counterfactual model, constraints costs for all boundaries (£m)

Source: Arup



Counterfactual model, constraints volume (MWh) 2025-2035.

Source: Arup

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Section 2: Methodology, assumptions and limitations

On average, constraints are only experienced for 17% of the periods within the year. For B0-B1, when these constraints are experienced, 50% of the constraints are less than 1240MWh on an hourly basis.

Initial power marketing modelling results

Frequency of constraints

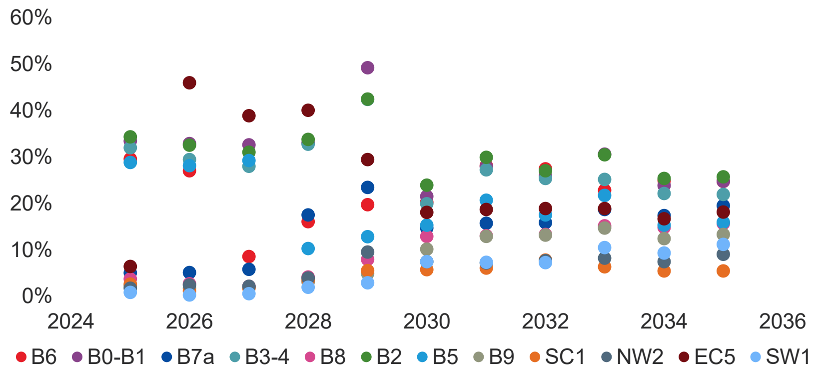
Across the 2025-2035 period and across all boundaries, constraints are experienced on average for 17% of the periods within a calendar year. Pre-2030 there is a greater spread across the boundaries in terms of the number of periods with constraints and then this narrows post 2030.

As presented within the chart, for the Scottish boundaries, this average is higher at 29% of the year experiencing constraints and then reduces to 24% post 2030. This means that for the demand that would be called upon through the contract, they would likely only be called upon for less than a third of the possible available hours within the year.

Size of constraints

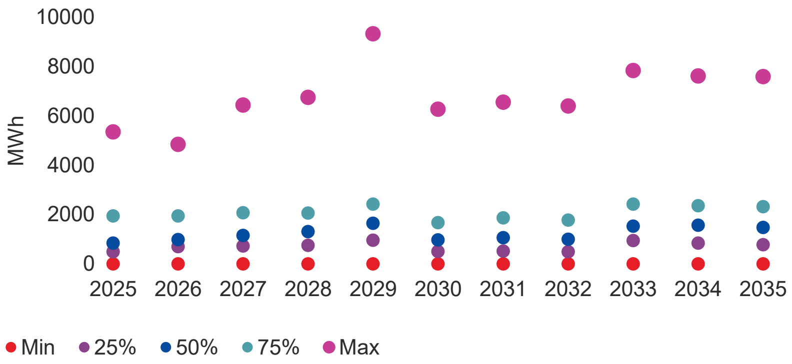
The scale of the constraints can considerably vary during the year, as presented by the bottom right chart with most of the period experiencing low or zero constraint values and then high spikes.

In terms of the counterfactual model, as seen in the top right chart for B0-B1, using percentiles, 25% of the constraints are, across 2025-2035, on average less than approximately 700MWh on an hourly basis. This means that for the demand that would be called upon through the contract, for a quarter of the constrained periods that they are contracted, they would provide demand less than 700MWh. The average 50th percentile of the constraints is 1240MWh and the average maximum constraint is 6822MWh across the ten years.



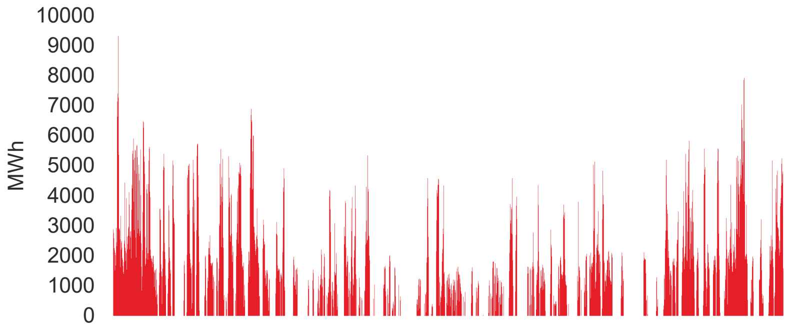
Counterfactual model, hours constraints within the year (%) 2025-2035

Source: Arup



Counterfactual model, constraints volume percentiles for B0-B1 (MWh)

Source: Arup



Counterfactual model, constraints volume for B0-B1 (MWh), 2029

Source: Arup

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Section 2: Methodology, assumptions and limitations

Based on technical capability, several technology types would be able to provide flexible demand, this includes hydrogen and energy storage. Other technologies such as commercial and industrial demand are better suited to providing baseload demand.

Demand for contract

Arup have undertaken an assessment of the technologies that would technically be able to respond in adjusting their demand during periods of constraints and/or provide additional baseload demand to support the resolution of constraints.

For each of these technologies, Arup have considered the status of development for these technologies and the current known portfolio of projects.

Of the technologies assessed, Arup have identified that the following technologies would technically be able to provide demand through the contract: hydrogen, commercial demand from data centres or the electrification of heating, industrial demand such as Electric Arc Furnaces (EAF) and the electrification of heating or processes, and energy storage. Arup have excluded electric vehicles as they are unlikely to develop to a sufficient scale (MWh) to be able to meet constraints in the near term.

Of these technologies, hydrogen and energy storage would be able to provide a flexible response, whereas commercial demand (i.e. data centres) and most industrial demand by nature as unlikely to be able to flex their demand, however, they would be able to provide additional baseload.

Technology	Suitable to meet contract	Baseload or Flexible demand	Rationale
Hydrogen	✓	Both	• Several projects are expected to develop over the 2025-2035 window and is growing in scale • Electrolysers can respond within a short time period (can go from cold start to full operation in less than 30 mins) as required by DfC • To act in a flexible style, they will need a sufficiently flexible offtaker otherwise will have to manage flex through commercials
Commercial demand	✓	Baseload	• The data centre market is experiencing significant growth in GB with the AI boom likely to accelerate this growth further • Hyperscale data centres could be well suited to participate in the Demand for Constraints service with large electrical loads and some locational flexibility
Industrial demand	✓	Both	• One existing and several planned EAF projects in GB are within the proposed Demand for Constraints timelines. EAFs can potentially offer some flexible demand due to cyclical nature of steel production (high demand during melting and refining, lower during tapping stage).
Energy storage - battery	✓	Flexible	• Possess the required capabilities to provide the service and not tied to specific locations (although grid connection could be a challenge in Scotland) • Need to understand how DfC interacts with other services provided by storage.
Energy storage – pumped hydro	✓	Flexible	Expect shorter duration storage to be more suited given deployment times and longer duration storage likely targeting Cap and Floor scheme.
Electric Vehicles	X	Flexible	Unlikely to have sufficient scale to meet constraints during the time period

Section 2: Methodology, assumptions and limitations

Four cases have been modelled reflecting different levels of demand contracted. The cases vary depending on the level of demand, the number of boundaries where demand is connected, the proportion of flexibility vs baseload demand and a minimum threshold to resolve constraints

Demand for contract

Demand

Under the Demand for Constraints contract, new (or relocated) demand is available during periods of constraint to utilise otherwise constrained renewable generation.

For the purposes of this assessment, this assumes the following technologies may be able to provide additional demand: hydrogen production, demand centres, industrial demand (including electric arc furnace) and energy storage (BESS and pumped hydro).

Arup have undertaken an assessment of the possible demand types and sizes that could connect into the boundaries.

Arup have modelled four different cases varying:

- The boundaries that demand is included into (B0-B1, B3-B4, B6 & EC5).
- Whether the demand is included as flexible or whether some is included as baseload demand (100% flexible vs 50% baseload: 50% flexible).
- The amount of boundaries that demand is added into (One, three or four boundaries).

These cases are summarised in the table to the right.

Scenario	Boundaries modelled	Minimum threshold above which DfC utilised	Average annual demand contracted across all boundaries (TWh)	Flex vs baseload	Timeline for demand connecting
Case 1	B0-B1, B3-B4, B6 & EC5	200MWh	3.5	50% flexible 50% baseload	50% in 2028 50% in 2030
Case 2	B0-B1	200MWh	0.8	50% flexible 50% baseload	50% in 2028 50% in 2030
Case 3	B0-B1, B3-B4 & B6	200MWh	2.8	50% flexible 50% baseload	50% in 2028 50% in 2030
Case 4	B0-B1	200MWh	0.7	100% flexible	50% in 2028 50% in 2030
Case 4a	B0-B1	200MWh	0.7	100% flexible	50% in 2028 50% in 2030

Modelling cases

Source: Arup

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Section 3: Methodology, assumptions and limitations

In cases where there is baseload and flexible demand, during periods of constraints baseload demand is utilised first to resolve constraints and then flexible demand is called upon up to the constraint resolution cap. In all cases, two contract options have been modelled.

Demand for contract

Baseload demand

To model the demand available via the Demand for Constraints service, the following approach was taken:

- Flexible demand: For applicable boundaries, establish the hourly constraint profile from the constrained model run and apply the volume of the constraint that can be addressed via the service according to the scenarios considered. This produced a Demand for Constraints hourly demand profile, which is then added to the original load profile used in the constrained model and the model re-run to understand the impact on constraints.
- Baseload demand: Based on the scenarios considered, an hourly baseload demand profile is created with an assumption for availability applied. This profile is added to the original load profile used in both the unconstrained and constrained models, and the models re-run.

For cases where baseload has been included, baseload demand is utilised first to resolve the constraints and if there is any additional constraint to be resolved (below the constraint resolution cap), flexible demand is called upon. This is represented in the figure to the right which provides an illustration of two possible scenarios showing the interaction between flexible and baseload constraints within the modelling:

- Scenario A: in this scenario the size of the constraint is equal to the constraint resolution cap. Baseload is called upon first. As the baseload demand is equal to the size of the constraint, no flexible demand is called upon.
- Scenario B: In this scenario, baseload demand is called upon first and as this is lower than the constraint resolution cap, flexible demand is called upon to resolve the remaining constraint under the demand for constraint contract. As in this scenario the size of the constraint is greater than the constraint resolution cap, therefore there is a certain proportion of constraint that is not resolved by either baseload or flexible demand.

Contract design

Two contract approaches have been modelled:

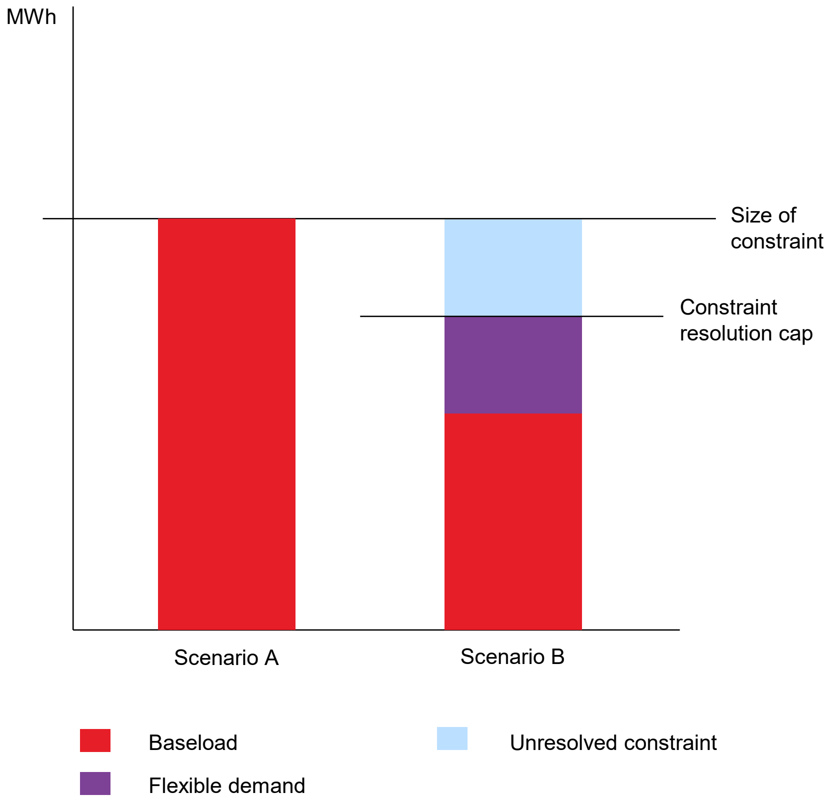
- Contract option 1: A fixed utilisation tariff (£/MWh for excess electricity consumed) from demand facilities to NESO.
- Contract option 2: A utilisation tariff based on an agreed percentage discount from day-ahead price from demand provider to NESO.

Under both of these contract options, the demand user will pay the NESO for below wholesale market price electricity.

Contract price

For each case, the base position uses a £5/MWh utilisation tariff under contract option 1 (based on industry feedback during the CCP consultation), and a 50% discount to day-ahead price under contract option 2.

Arup have conducted further price sensitivity analysis on cases 2 and 4, to understand the impact on consumer cost savings of varying the price structures. Contract Option 1 has been tested at £10/MWh, £15/MWh and £20/MWh, based on reductions from the day-ahead price observed in the model. Contract Option 2 has been tested at a 25% and 75% discount from the day-ahead price.



Baseload vs flex

Source: Arup

Section 3: Methodology, assumptions and limitations

A Cost Benefit Analysis has been conducted to establish the potential annual consumer cost savings for the Demand for Constraints proposal. The CBA takes into account the impact on wholesale, constraint and renewable support costs. All other consumer bill costs are assumed to remain constant.

Cost Benefit Analysis (CBA)

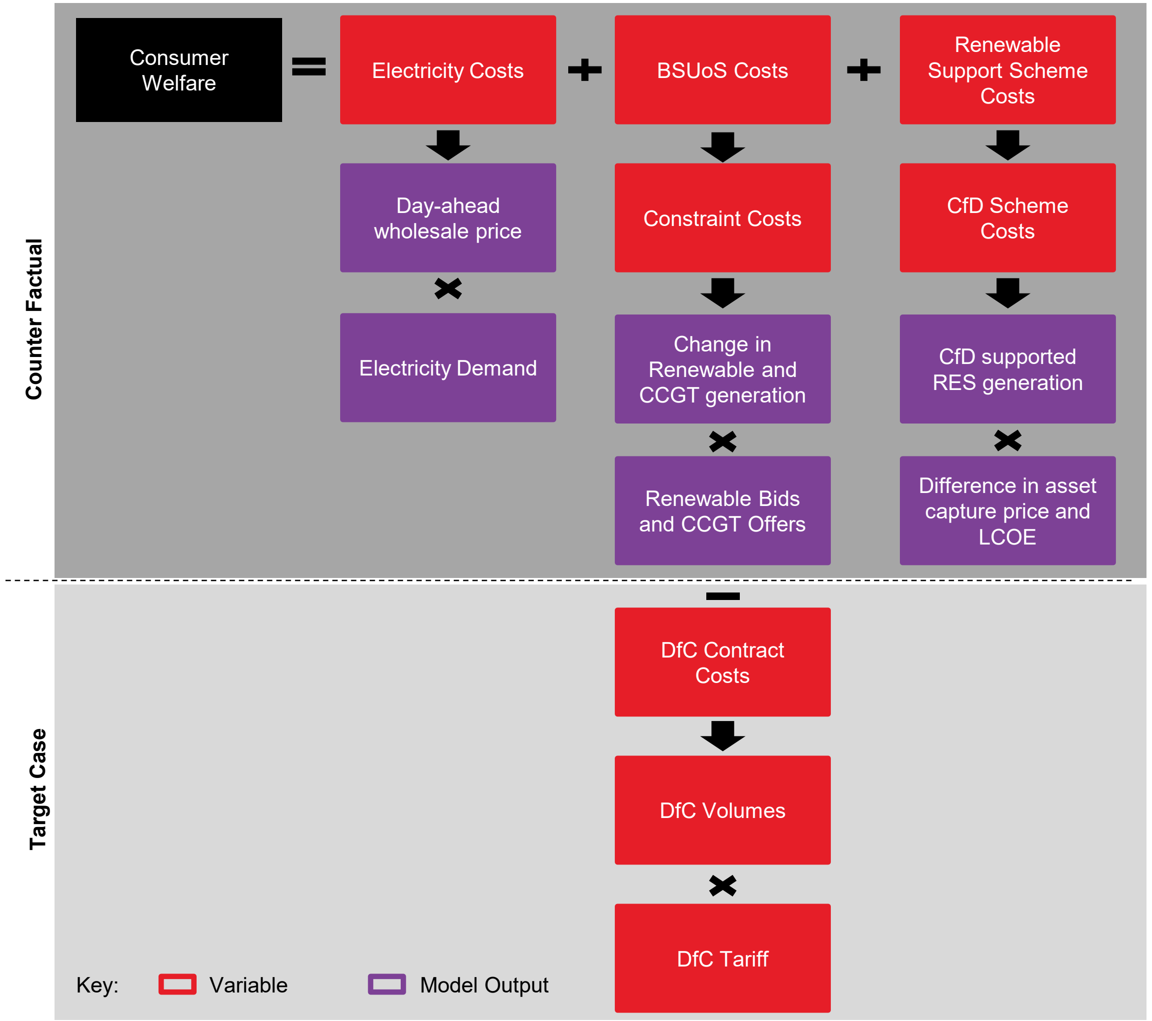
The CBA has compared consumer welfare in the counterfactual, where there is no demand for constraints service, to a number of cases, with the Demand for Constraint service. Consumer costs have been discounted by 3.5% as per Green Book guidance.

The consumer welfare calculation, set out to the right, is the sum of electricity costs, BSUoS costs and renewable support scheme costs. The key sources and assumptions for each element are as follows:

- **Wholesale electricity costs:** Day-Ahead wholesale electricity prices from the unconstrained model.
- **BSUoS costs:** The analysis has focussed on the change in the thermal constraint cost element of BSUoS costs with all other BSUoS costs assumed to remain constant. Constraint volumes are derived from the decrease in renewable generation and increase in CCGT generation between the unconstrained and constrained model runs. These volumes are then multiplied by renewables bids and CCGT offers. We have assumed a 29% premium on CCGT offers and mark downs on renewables based on historical market data on renewables bidding behaviour.
- **Renewable support costs:** Arup has established the proportion of renewable assets currently supported by a CfD and assumed that 100% of future wind assets, and 50% of solar assets are CfD backed. The consumer costs associated with renewable support schemes is calculated as CfD supported RES generation multiplied by the delta between annual wholesale price and LCOE (as proxy for CfD strike price) based on DESNZ renewable electricity generation costs.
- **Demand for Constraints payment:** Under Contract Option 1, the volumes procured via the service are multiplied by a £5/MWh fixed utilisation tariff. We assume this will pass through to BSUoS charges and is therefore deducted from the constraint costs. For Contract Option 2, a 50% discount to the wholesale price is assumed. Both have been derived from market testing conducted by NESO. Price sensitivities for both contract options have been carried out as outlined in Section 3.3.

Arup has also evaluated the change in carbon emissions and grid carbon intensity, as well as qualitatively opining on the wider benefits and risks associated with the proposed Demand for Constraints service, such as wider decarbonisation, job creation and the mechanics of the service.

We have not considered the cost of local grid reinforcement needed to integrate these demand connections, as these are site specific, but note this could have material impact.



Consumer Welfare Calculation

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Results and discussion

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Section 3: Results and discussion

Consumer costs savings are observed in all cases versus the counterfactual, driven mainly by lower constraint costs. The savings achieved in each case are influenced by the level of demand contracted, demand types participating (i.e. flexible and/or baseload) and contract option.

Total Consumer Value achieved

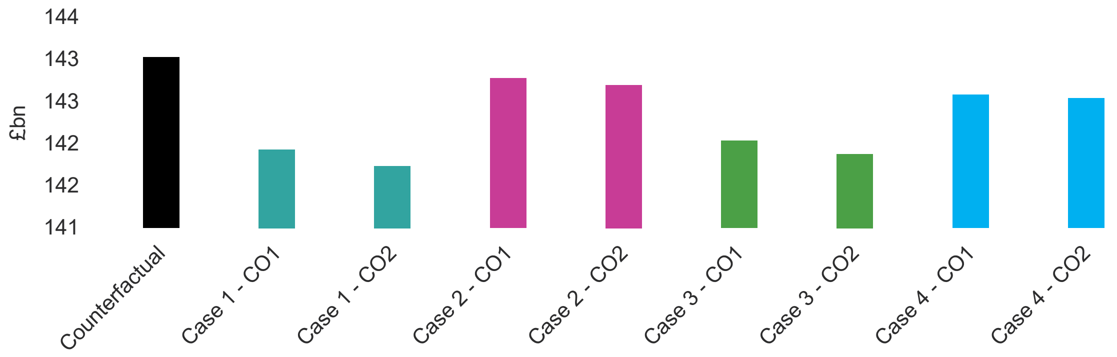
The CBA shows that for all cases considered, the Demand for Constraint service would reduce the costs consumers face via their electricity bills, ranging from around £500m to £4bn across the 2028-2035 period. The level of savings achieved varies across the cases and is influenced by a combination of the level of demand procured via the service, whether baseload demand is considered eligible and the tariff paid by participating demand sources. The total discounted costs and savings observed are summarised in the charts opposite.

The savings are driven mainly by reduced renewables curtailment actions in the Balancing Mechanism (BM) through the availability of additional demand behind constrained boundaries. This results in lower constraint costs as the costs NESO incurs to take action in the BM are reduced (via avoided premium payments to bid off renewable generators). Further savings are achieved through the payments by demand to NESO to consume electricity during constrained periods if these payments are passed through to BSUoS costs.

The lowest level of savings are observed for Case 4, where only flexible demand is procured behind one boundary (B1). This case sees savings average annual savings of less than 1% (~£61m).

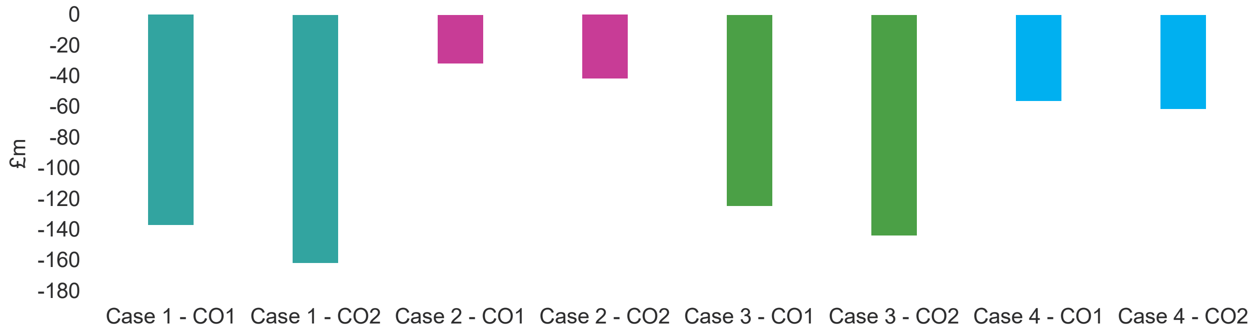
In terms the two contract options investigated, Contract Option 2 results in greater savings across all cases as a result of the higher Demand for Constraint tariff paid to NESO. Across the cases modelled, the savings achieved via Contract Option 2 are around 0.30% greater than for Contract Option 1 on an average annual basis.

Arup would expect that if the P462 modification (removal of subsidies from bid prices in the balancing mechanism) is implemented that the constraint cost savings from the avoided premiums paid to renewable generators would be reduced significantly.



Total discounted consumer costs 2025-2035 £m under the counterfactual and 4 modelled cases

Source: Arup Analysis



Annual average discounted consumer costs savings 2025-2035 £m under the counterfactual and 4 modelled cases

Source: Arup Analysis

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Section 3: Results and discussion

Demand assumptions and detailed total consumer cost savings and constraint cost savings results

		Discounted prices						2023 prices	
Scenario	Average annual demand contracted across all boundaries (TWh)	Contract Option 1 total consumer cost savings[2] (discounted)	Contract Option 2 total consumer cost savings[2] (discounted)	Contract Option 1 total consumer cost savings[2] (discounted)	Contract Option 2 total consumer cost savings[2] (discounted)	Total constraint costs savings[3]	Average constraint costs savings	Total constraint costs savings	Average constraint costs savings
		Total across model period		Annual Average[1]					
Case 1	3.5	£1.0bn	£1.2bn	£0.05bn	£0.05bn	£1.8bn	£0.23bn	£2.4bn	£0.30bn
Case 2	0.8	£0.5bn	£0.5bn	£0.30bn	£0.33bn	£0.8bn	£0.09bn	£1.1bn	£0.13bn
Case 3	2.8	£0.9bn	£1.1bn	£0.12bn	£0.14bn	£1.5bn	£0.18bn	£2.0bn	£0.25bn
Case 4	0.7	£0.4bn	£0.4bn	£0.05bn	£0.05bn	£0.42bn	£0.05bn	£0.6bn	£0.07bn
Case 4a	0.7	£0.3bn	£0.4bn	£0.04bn	£0.05bn	£0.42bn	£0.05bn	£0.6bn	£0.07bn

[1] All annual average reflects the savings achieved between 2028 – 2035
[2] Consumer cost savings includes: constraint costs, changes in wholesale costs and renewable support obligations as well as the revenue received through the Demand for Constraints contract.
[3] This reflects the constraint cost savings, which is one element of the consumer cost savings achieved.

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Section 3: Results and discussion

Across all cases, there is a reduction in constraint costs compared to the counterfactual. Across the 2028-2035 period, the savings range between £0.6bn (2023 prices) in the lowest case of one boundary and £1.1bn in the highest demand case, which includes both flexible and baseload demand.

Constraint costs savings

Under all modelled cases, compared to the counterfactual, there is a decrease in the overarching constraint costs incurred with savings ranging from £0.6bn to £1.1bn (2023 prices).

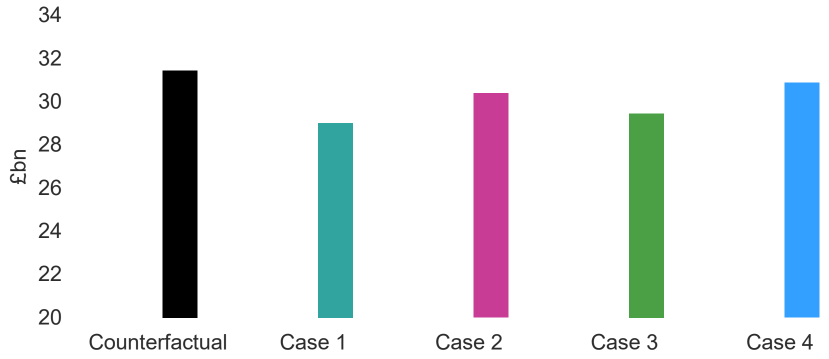
Case 2, which models an average 240MWh of demand being included into the one boundary (B0-B1) results in a 3% (£1.1bn) reduction in constraint costs compared to the counterfactual. When only flexible demand (averaging 240MWh on an hourly basis) is added into one boundary under Case 4 there is saving of £0.57bn (1%).

Case 3 models an average 328MWh being respectively added into three boundaries in Scotland with a combination of flexible and baseload demand resulting in a saving of 6% (£2bn). Case 1 then adds EC5 to the assumptions in Case 3 and results in a saving of £2.42bn (8%).

Deliverability

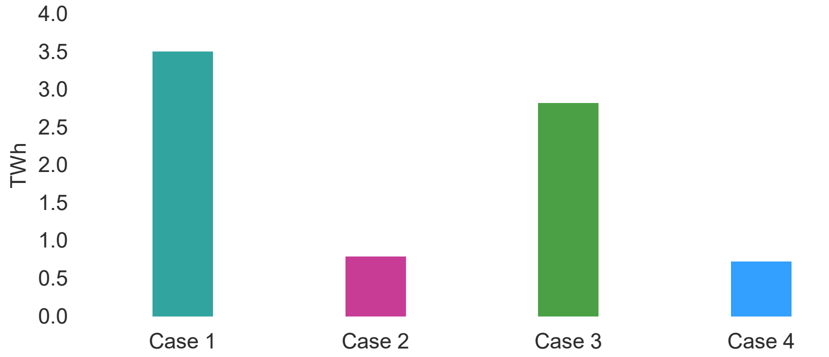
The ability to achieve these savings is ultimately contingent on the feasibility and timely uptake of demand. Across the different technologies assumed, there are a range of regulatory, technical and commercial factors that will be necessary to enable the deployment. These factors include:

- Timely allocation of funding support.
- How competitive the contract is compared to other markets.
- Availability of offtaker/wider infrastructure for the demand and the alignment of the constraint periods with their individual operational profiles.
- The ability to secure land, permitting and consenting within the designated boundary in a timely manner to meet the requirements of the contract.
- Availability of grid connections and the associated reinforcement costs.



Constraint costs £bn (2023 prices) under the counterfactual and 4 modelled cases

Source: Arup analysis



Annual average volumes procured (TWh) through the demand for constraints contract under the modelled cases.

Source: Arup analysis

Section 3: Results and discussion

3.1 Detailed case results

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Section 3: Results and discussion

Case 1 has the largest cost savings for boundaries where there is a 50:50 mix of flexible and baseload demand, with the largest savings observed for Contract Option 2. This smaller scale reduction is driven by a smaller volume of demand.

Total Consumer Value achieved

Basis of Case 1

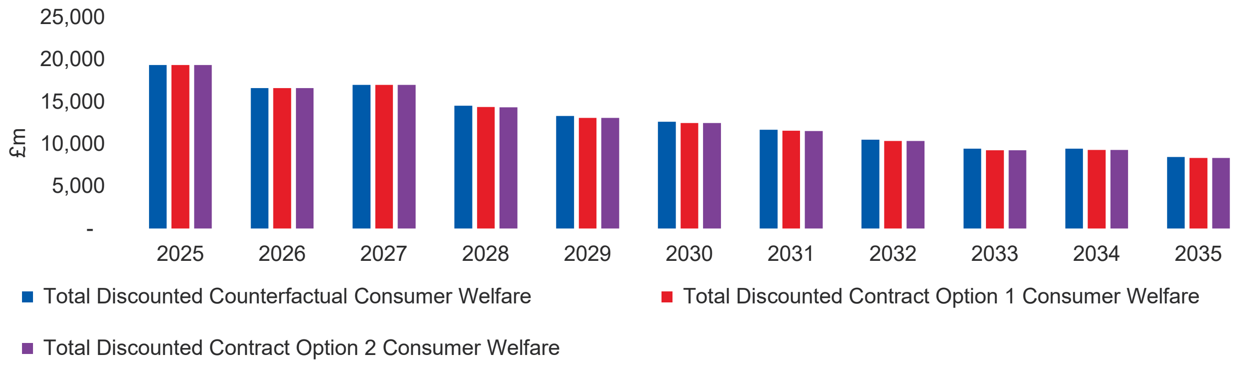
Boundaries modelled	Min threshold	Flex vs baseload	Connection
B0-B1, B3-B4, B6 & EC5	200MWh	50% flexible 50% baseload	50% in 2028 50% in 2030

Results

In Case 1, annual consumer costs reduce on average by 1.23% under CO1 and 1.45% under CO2. When compared to the Counterfactual, CO2 results in greater savings for consumers at £1.2bn (discounted) compared to the £1bn (discounted) saved under CO1, as a result of greater payments to NESO.

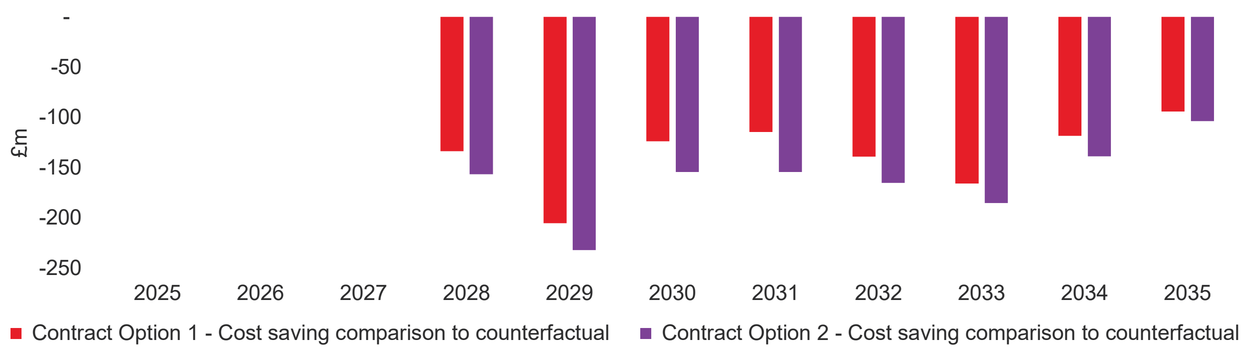
The individual elements of the consumer bill considered are impacted as follows:

- **Wholesale Electricity Costs:** Compared to the counterfactual, the annual average day-ahead wholesale price in both contract options is £73m higher. This is driven by the introduction of baseload demand which is visible at the day-ahead stage.
- **BSUoS Costs:** For both contract options, average annual constraints costs across the contract period are £163m (discounted) lower than in the counterfactual. Constraint costs decrease at 18% compared to the counterfactual at boundary, followed by a 16% reduction at B1.
- **Renewable Support Scheme Costs:** As more CfD payments are paid to non-curtailed demand, average annual renewables support scheme costs increase across the contract period, by £92k in both CO1 and CO2.
- **Emissions:** Carbon emission production remains largely unchanged between Case 1 and the Counterfactual as CCGT generators still need to be offered up, however, the grid carbon intensity will decrease by less than 2% as a result of the additional renewable generation and demand.



Discounted Consumer Welfare for Contract Option 1 and 2 – Case 1 vs counterfactual

Source: Arup analysis



Comparison of discounted contract option savings vs counterfactual

Source: Arup analysis

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Section 3: Results and discussion

In Case 2, annual consumer costs reduce on average by 0.58% under CO1 and 0.62% under CO2. As with Case 1, the largest savings observed for Contract Option 2.

Total Consumer Value achieved

Basis of Case 2

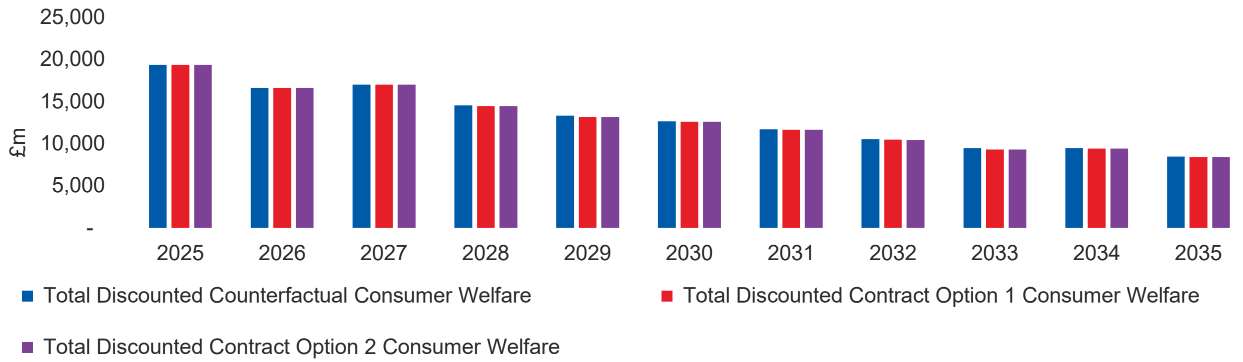
Boundaries modelled	Min threshold	Flex vs baseload	Connection
B0-B1	200MWh	50% flexible 50% baseload	50% in 2028 50% in 2030

Results

In Case 2, annual consumer costs reduce on average by 0.58% under CO1 and 0.62% under CO2. Compared to the Counterfactual, a £539m (discounted) savings for consumers is achieved under CO2 compared to £493m (discounted) saved under CO1.

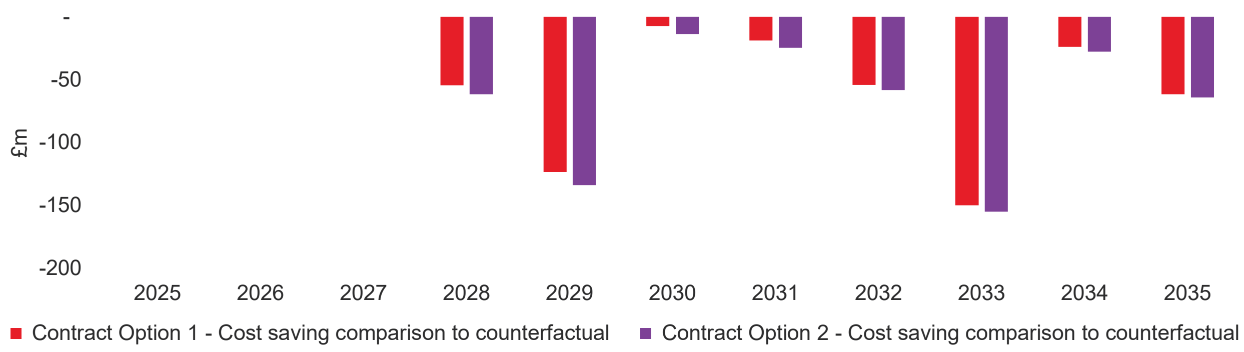
The individual elements of the consumer bill considered are impacted as follows:

- **Wholesale Electricity Costs:** The annual average day-ahead wholesale price in both contract options is £28m higher than the counterfactual, due to the introduction of baseload demand which is visible at the day-ahead stage. However, the increases are much smaller than for other cases where baseload demand is procured given demand is only being procured behind one boundary.
- **BSUoS Costs:** For both contract options, average annual constraints costs across the contract period are £71m (discounted) lower than in the counterfactual. Boundary B1, the only boundary which includes demand in this Case, sees a 17% decrease in constraint costs compared to the counterfactual.
- **Renewable Support Scheme Costs:** Average annual renewables support scheme costs increase across the contract period, by less than £1k in both CO1 and CO2, with more CfD payments made as less units are curtailed.
- **Emissions:** Carbon emission production remains largely unchanged between Case 2 and the Counterfactual as CCGT generators still need to be offered up, however, the grid carbon intensity will decrease by less than 1% as a result of the additional renewable generation and demand.



Discounted Consumer Welfare for Contract Option 1 and 2 – Case 2 vs counterfactual

Source: Arup analysis



Comparison of discounted contract option savings vs counterfactual

Source: Arup analysis

Section 3: Results and discussion

Case 3 has the lowest cost savings for boundaries where there is a 50:50 mix of flexible and baseload demand, as the exclusion of EC5 means there is a lower demand volume. Similarly to all other cases, the largest savings are observed under Contract Option 2.

Total Consumer Value achieved

Basis of Case 3

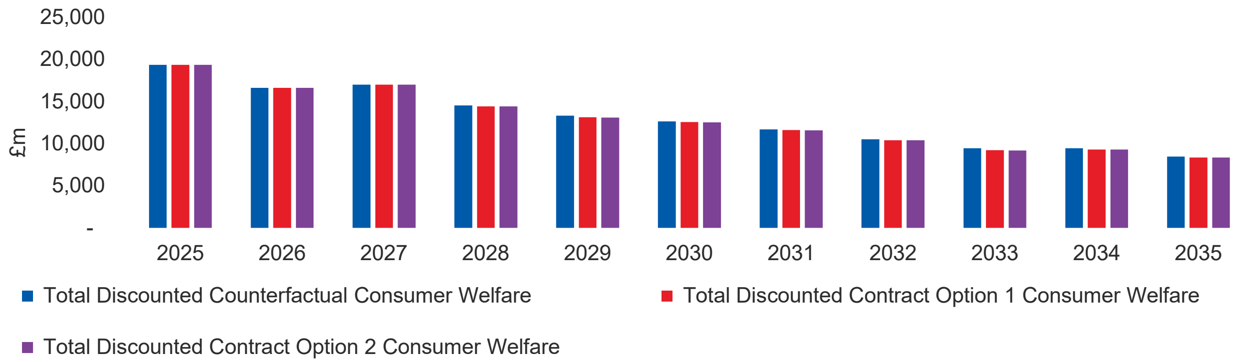
Boundaries modelled	Min threshold	Flex vs baseload	Connection
B0-B1, B3-B4 & B6	200MWh	50% flexible 50% baseload	50% in 2028 50% in 2030

Results

There is a 1.33% annual consumer cost reduction in CO2 under Case 3 and a 1.16% reduction in CO1. In comparison to the Counterfactual, CO2 results in a £1.1bn (discounted) saving for consumers compared to the £990m (discounted) saved under CO1.

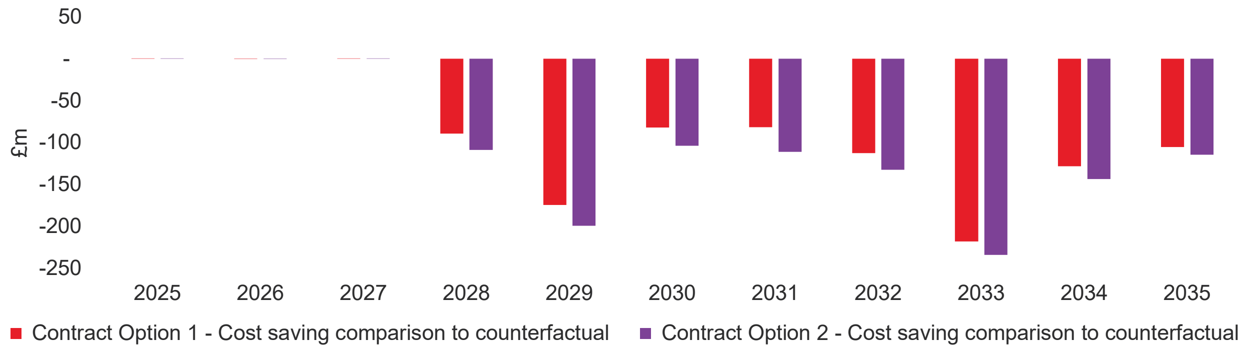
The individual elements of the consumer bill considered are impacted as follows:

- **Wholesale Electricity Costs:** The introduction of baseload demand results in an increased annual average day-ahead wholesale price of £51m counterfactual in both contract options.
- **BSUoS Costs:** In both contract options, average annual constraints costs across are £133m (discounted) lower than in the counterfactual. This is driven by Boundaries B4 and B1 which sees constraint costs reduce by 18% and 16% respectively, when compared to the counterfactual. Case 3 sees a smaller reduction compared to Case 1 where there is also a 50:50 split of flexible and baseload demand, as the exclusion of EC5 in Case 3 results in overall less demand contracted.
- **Renewable Support Scheme Costs:** In CO1 and CO2, average annual renewables support scheme costs increase by £91.7k.
- **Emissions:** Carbon emission production remains largely unchanged between Case 3 and the Counterfactual as CCGT generators still need to be offered up, however, the grid carbon intensity will decrease by less than 1% as a result of the additional renewable generation and demand.



Discounted Consumer Welfare for Contract Option 1 and 2 – Case 3 vs counterfactual

Source: Arup analysis



Comparison of discounted contract option savings vs counterfactual

Source: Arup analysis

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Section 3: Results and discussion

Case 4 results in the lowest consumer cost savings due to a combination of (a) demand only being procured behind one boundary and (b) only flexible demand being considered. Regardless, there is still savings observed, which indicate that a Demand for Constraints could be beneficial.

Total Consumer Value achieved

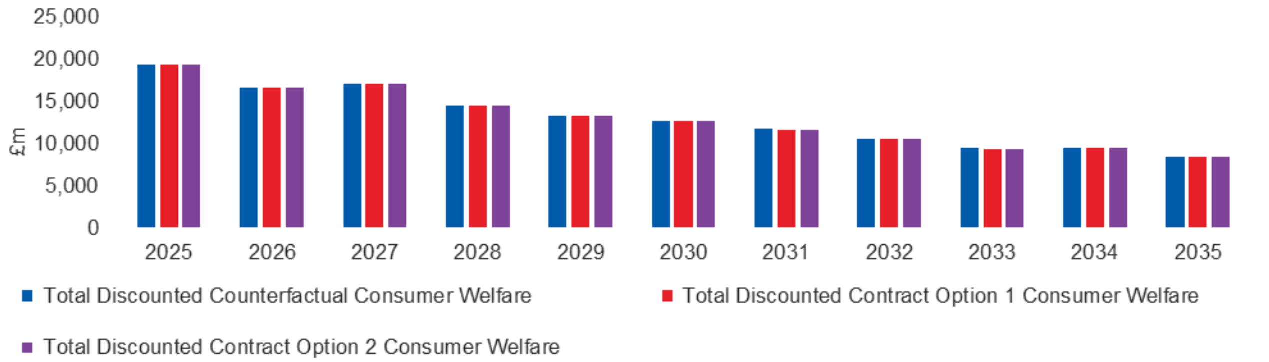
Basis of Case 4

Boundaries modelled	Min threshold	Flex vs baseload	Connection
B0-B1	200MWh	100% flexible	50% in 2028 50% in 2030

Results

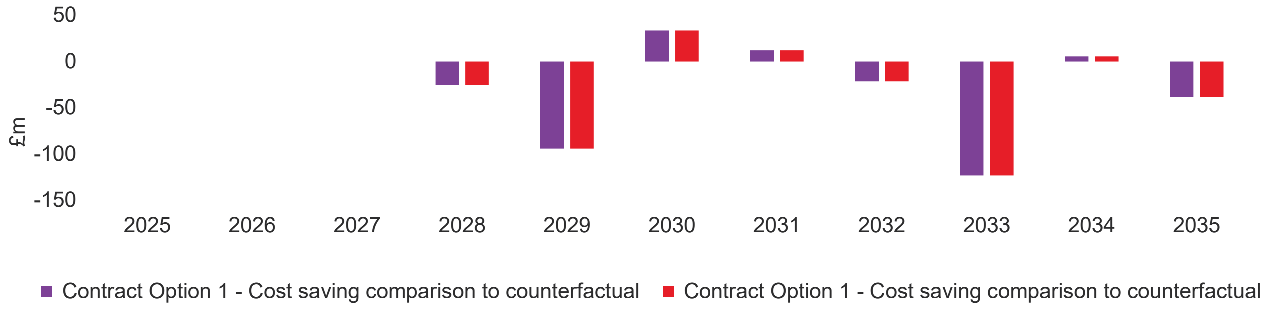
In Case 4, there is a similar level of consumer cost savings as for Case 2. However, since only flexible demand is procured, the annual consumer costs savings are slightly lower. On average annual consumer cost savings (discounted) are £56m for Contract Option 1 and £66m for Contract Option 2 versus the counterfactual. Contract Option 2 sees the greater savings since the payment from demand to NESO is higher. Annual consumer cost savings are around 0.02% lower than for Case 2 over the 2028-2035 period. The individual elements of the consumer bill considered are impacted as follows:

- **Wholesale Electricity Costs:** There is no change in wholesale day-ahead electricity prices compared to the counterfactual as only flexible demand is procured via the service.
- **BSUoS Costs:** As highlighted on the prior slide, constraint costs are reduced as the flexible demand procured supports the reduction of the amount of renewables curtailed in the BM. These savings drive the majority of the annual consumer cost savings with a smaller contribution from the payments from demand to NESO that are ultimately passed through to BSUoS costs.
- **Renewable Support Scheme Costs:** In CO1 and CO2, average annual renewables support scheme costs increase
- **Emissions:** Carbon emission production remains as same the Counterfactual as CCGT generators still need to be offered up and additional demand is met by renewables. The grid carbon intensity, however, will decrease by less than 0.3% as a result of the additional renewable generation and demand.



Discounted Consumer Welfare for Contract Option 1 and 2 – Case 4 vs counterfactual

Source: Arup analysis



Comparison of discounted contract option savings vs counterfactual

Source: Arup analysis

ARUP

Section 3: Results and discussion

If the Demand for Constraints service was successful in deploying additional demand, wider benefits in the form of increased decarbonisation, energy security and economic output is possible, although likely limited if only a small number of assets are deployed.

Wider Benefits

As part of this project Arup also considered the wider benefits of the Demand for Constraints service on a qualitative basis. In summary, Arup expects the main wider benefits to fall into one of two categories: decarbonisation and energy security, and economic output.

Factor	Description
Decarbonisation and energy security	• The Demand for Constraints service could bring forward assets that support decarbonisation of the electricity system either through additional renewable generation or further storage capacity to support the integration and optimisation of renewable generation. These technologies can support the country's energy independence by contributing to a diversified energy mix as well as domestic hydrogen production can also support wider energy security • The service could support the wider decarbonisation of sectors; for example, hydrogen production assets enabled by Demand for Constraints would increase domestic hydrogen production, which in turn could support decarbonisation of industrial and transport sectors, whilst additional EAFs would support further green steel production in the UK. • Given the timeframe proposed for Demand for Constraints, there is the potential that the service could help accelerate decarbonisation if it supports the business case of the technologies that could potentially participate, however, it is important to note that only a handful of additional assets have been identified over and above the HT pathway assumptions, which could limit the level of further decarbonisation and support to energy security achievable.

Economic output	• The benefit for demand of the service is the potential to secure a discounted electricity price for consumption of power during periods when the electricity system is constrained. The proposed long term contract length also provides the demand sources with long-term certainty, supporting project finance requirements. Both factors would positively support the business case of the demand sources that would likely be targeted by NESO for participation, given the importance of electricity costs to their operation.
	• If the service can bring forward the deployment of such assets, this in turn would support the economic output through:
	  • Direct job creation to construct, operate and maintain the assets.
	  • Indirect job creation through data centres, hydrogen production, energy storage and electrification stimulating job growth in related sectors such as construction, utilities and technology services.
	  • Contribution to Gross Value Added (GVA) and Gross Domestic Product (GDP) through the revenues generated and employee compensation.
	  • Additional tax revenues via the demand's operations, employment and supply chains (e.g. corporate tax, business rates, income tax, National Insurance).
	  • Driving investment in and modernisation of infrastructure, for example, investment in power generation and transmission for data centres and gas network development for hydrogen. Data centres, in particular, can drive improvements in digital infrastructure and support digital transformation.
	  • Regional development and investment in areas which have historically been underinvested and/or industrial areas (e.g. former power plants) needing revitalisation, this is particularly relevant for hydrogen and data centre projects .
	  • Improving competitiveness of GB industry within the global market through securing cheaper electricity.

Section 3: Results and discussion

3.2 Price sensitivity assessment

Section 3: Results and discussion

In Case 2, increasing the utilisation tariff in contract option 2 to a 75% discount from the day-ahead price led to the largest scale increase in consumer cost savings, followed by an increase in the fixed utilisation payment at £20/MWh in contract option 1.

Price sensitivity assessment

We have conducted price sensitivities to assess the impact of varying the price structures under each contract option on consumer cost savings.

The sensitivities were applied to the following cases to provide a broad spectrum of how the different Cases respond to the price sensitivity:

- Case 2: 50:50 split of flexible and baseload demand added at 1 boundary (B0-B1)
- Case 4: 100% flexible demand added at 1 boundary (B0-B1)
- These cases represent a range of outcomes across different demand structures.

Price variations were tested as follows;

- Contract Option 1 (CO1) – The fixed utilisation payment of £5/MWh used as the base for all cases, with sensitivities at £10/MWh, £15/ MWh, and £20/MWh. These values provide a range below the modelled wholesale price in the counterfactual, which decreases out to 2035.
- Contract Option 2 (CO2) - The utilisation tariff set at a 50% discount from day-ahead prices in the base for all cases, is tested at 25% and 75%.

Results

The charts show the sum of cost savings (discounted) under each sensitivity, compared to the counterfactual over the years 2028-2035 for both contract options.

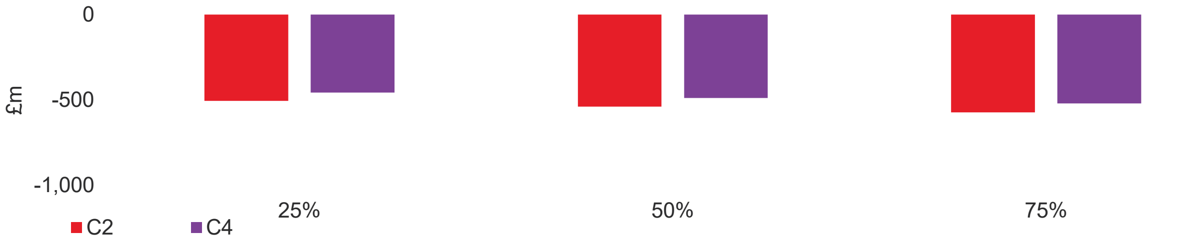
Under all three cases, the increase in the utilisation tariff discount to 75% in CO2 leads to the largest increase in consumer cost savings. Case 2 sees the highest savings, as the introduction of baseload demand, leads to a higher demand volume than the other cases with flexible demand, which results in a higher volume of payments from demand to NESO.

The increase in fixed utilisation payments to £20/MWh led to the second largest savings across the 2 cases, again with the biggest impact seen in case 2 due to higher demand volume.

CO1	Case 2	Case 4
£5/MWh	-£0.49bn	-£0.45bn
£10/MWh	-£0.52bn	-£0.47bn
£15/MWh	-£0.54bn	-£0.49bn
£20/MWh	-£0.56bn	-£0.51bn

Total NPV Cost Savings for Contract Option 1 Sensitivities – Counter Factual Vs Cases 2 and 4

Source: Arup analysis



CO2	Case 2	Case 4
25%	-£0.51bn	-£0.46bn
50%	-£0.54bn	-£0.49bn
75%	-£0.57bn	-£0.52bn

Total NPV Cost Savings for Contract Option 2 Sensitivities – Counter Factual Vs Cases 2 and 4

Source: Arup analysis

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Section 3: Results and discussion

The introduction of an annual availability payment results in a reduction in the consumer cost savings; when modelled in Case 4, this results in a 23% reduction in the savings. However, the availability payment could be determined in coordination with the utilisation payment to minimise the impact.

Availability payment sensitivity assessment

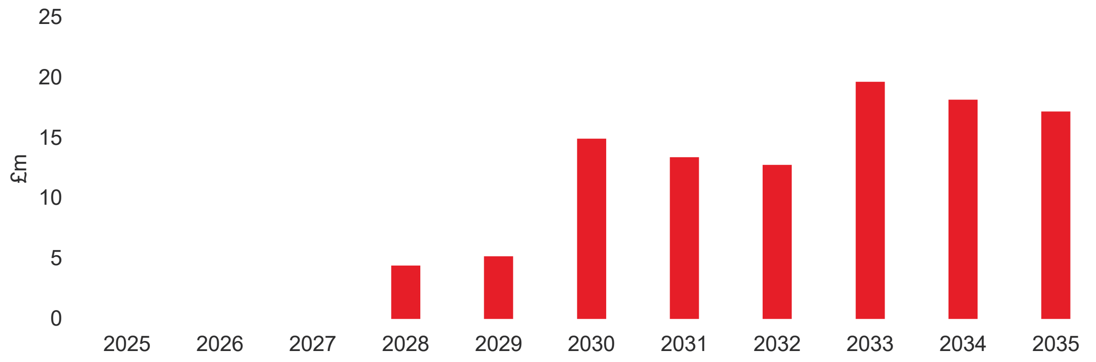
As this study is focussed on new or relocated demand, an assessment has been undertaken of the impact of an availability payment provided to the new demand. This availability payment has been modelled at a level to represent the potential connection costs that would be incurred by demand.

To assess the impact on the overall consumer cost savings, Case 4 has been modelled with and without the availability payment. Case 4 reflects Demand for Constraints contracted through only B0-B1 and with on average 240MWh added into the boundary across the period. Within the case, it has been assumed that a demand user would receive an annual payment of £30k/MW for every year that they are available (this is based on feedback received by NESO during the CMM consultation). Separate to the availability payment, the demand user is still required to pay for the electricity consumed as a result of the Demand for Constraints Contract Option 1, however, the utilisation payment level is unchanged.

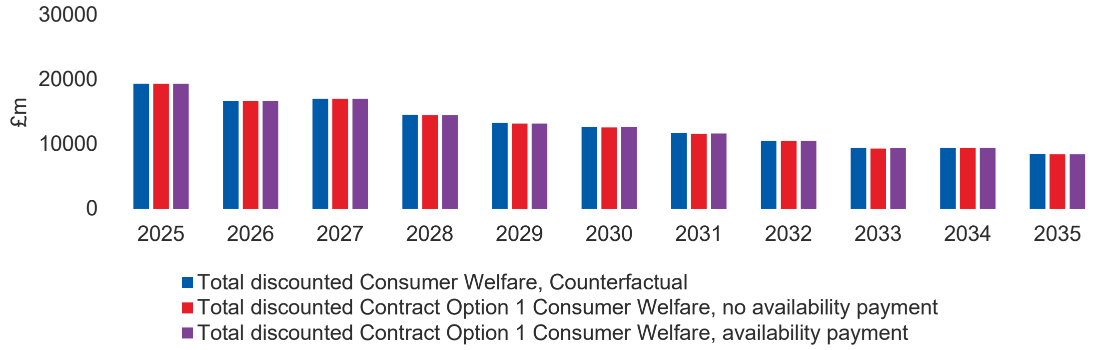
The chart presents the difference between Case 4 with and without the availability payment; across the modelled period, as the NESO makes the availability payment to demand the consumer cost savings are reduced by £106m (discounted) to £346m under Contract Option 1 compared to £451m without the availability payment in Case 4. This represents a 23% reduction in the savings that could be achieved for consumers when compared to Case 4 without the availability payment. The impact is greatest post 2030 when there is increased demand connected through the contract.

Design considerations

- The above approach assumes that the availability payment is determined independently of the utilisation payment. However, NESO could set an overall minimum level of consumer savings that they are trying to achieve such that the upfront availability payment is effectively deducted from the discounted electricity paid through the utilisation payment. Therefore, protecting the level of benefits achieved for consumers.
- The availability payment will need to be designed to ensure that the consumer savings are not eroded in the event that actual constraints are lower than forecasted constraints. Specifically, NESO will need to ensure that the balance of the availability payment and utilisation payments are appropriate in the context of forecasted constraints.



Reduced consumer cost savings (£m discounted) in Case 4 when an availability payment is used compared to Case 4 without an availability payment
Source: Arup analysis



Discounted Consumer Welfare for Contract Option 1 and 2 – Case 4 vs counterfactual

Source: Arup analysis

Section 3: Results and discussion

3.3 Deliverability assessment

Section 3: Results and discussion

The risks and challenges associated with deployment of the Demand for Constraints service are centred around deliverability, implementation, liquidity and how the contract will operate in practice.

Deployment risks and challenges (1/2)

Arup sees the following risks and challenges associated with the implementation and operation of the Demand for Constraints service.

Arup recommend the following actions to be undertaken by NESO ahead of the launch of the service based on these deployment risks and challenges:

- Explore possible procurement approaches as it is unlikely that a competitive auction approach can be adopted.
- Undertake a full assessment of the liquidity impact on this service on other potential services including current flexibility markets.
- Assess the potential implementation requirements (including control room requirements) of the contract.
- Explore how this service could be operated given that the NESO would need to recover revenue from contracted parties.

Factor	Description
Deliverability and Demand for Constraints service liquidity	• Most of these assets have construction timelines of 2-3 years with deliverability challenges, therefore, these timelines could be longer. This would shorten the contract term and reduce the impact of the service on consumer costs given its planned as an interim service. Even projects that could feasibly re-locate to take advantage of the service may encounter challenges i.e. grid connection that could result in extended deployment timelines. • The requirement for new/relocated demand could impact service liquidity if demand is either unable to deploy in reasonable timelines to benefit from the service or the service does not provide a strong enough financial incentive. Therefore, it is unlikely that NESO would be able to procure through a competitive auction and will need to consider alternative procurement options to ensure competitive pricing. Further, a competitive auction may be a challenge if 1) there is limited demand brought forward and the demand are aware of this 2) the demand technologies are vastly different and therefore do not create competitive tension. • For demand sources that typically already operate within the market such as BESS and pumped hydro, the ability to participate in other balancing and ancillary services markets alongside Demand for Constraints will be essential to ensure their interest in the service given the ability to stack revenues is key to their business case.

Impact on the liquidity of wider ancillary services markets	• The Demand Flexibility Service (DFS), Local Constraint Markets (LCM), and local flexibility markets operated are similar to the proposed Demand for Constraints service in that they procure flexible demand. The following provides an assessment of the impact to other markets:
	    • **DFS**, as currently designed, encourages the reduction or shifting of energy consumption but not demand turn up as is the case for Demand for Constraints. Any flexible demand contracted via Demand for Constraints will likely have the flexibility to reduce and shift consumption, and therefore consideration should be given towards the ability for providers to also participate in the DFS service to reduce consumption.
	    • **LCM** interim service, is where demand turn up is procured, again Arup would expect new demand to target the service that provides the strongest financial support, which could reduce liquidity in the service which is less appealing.
	    • **Distribution connected:** If new demand is distribution connected there is the potential for the Demand for Constraints service to impact local flexibility markets operated by DSOs such as Scheduled Utilisation, Operational Utilisation and local Active Network Management (ANM). The service would have to consider how to align with DSO requirements for flexibility and assess how liquidity in both services might be impacted. Arup would expect larger I&C demand that would be eligible for both markets to target whichever market is most lucrative. This could be mitigated to an extent by allowing demand assets to participate in both markets, where feasible.
	• If assets participating in Demand for Constraints are unable to operate in other markets, there could also be impacts on the liquidity of other balancing services markets such a frequency response, reserve and reactive power, especially if energy storage elects to bid for the service over other markets.

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Section 3: Results and discussion

The risks and challenges associated with deployment of the Demand for Constraints service are centred around deliverability, implementation, liquidity and how the contract will operate in practice.

Deployment risks and challenges (2/2)

Factor	Description
Implementation	• For flexible demand contracted through the service, implementation challenges would likely include development of the required control room processes, capabilities and systems to operate the service, including dispatch, demand forecasting, and settlement. • Developing a robust approach to baselining will also be essential to ensure new demand is truly additive and minimisation of gaming risks. The costs associated with implementation would need to be weighed against the expected benefits of the service. • Similarly, local grid reinforcement costs to accommodate additional demand could be considerable in some cases and this should be factored into any assessment of the service.

Contract mechanics	• There are several factors to consider in terms of how the Demand for Constraints contract would operate in practice, including:
	    • **Pricing**: the discount on wholesale electricity price will need provide a strong enough financial signal for new demand to come forward, whilst also not too commercially attractive that NESO over procures volumes and/or reduces liquidity in other balancing services markets.
	    • **Demand requirements**:
	        • The service will likely have to guarantee demand volumes over a long-term period, which could result in NESO securing demand volumes not ultimately required to address constraints. Consideration will need to be given to the quantum of volumes procured as to not lead to over procurement yet also be sufficient to attract new demand.
	        • Over procurement of demand could also result in the unintended consequence of export constraints changing into import constraints.
	    • **Impact of baseload demand**: baseload demand will generate additional demand outside of constrained hours, which could act to increase electricity prices (as observed as part of the modelling for this project).
	    • **NESO-demand-supplier interactions:** NESO cannot act as a supplier, and therefore the interactions between the source of demand, energy suppliers and NESO will have to be considered in terms of payment flows and contract settlement.
	    • **Terms and conditions:** Arup agrees with the findings from Phase 1 that a “sunset” clause and appropriate provisions in the agreement will be essential in light of potential market reforms. Clear requirements in terms of forecasting will also need to be set out to enable NESO to have an accurate view of likely demand available, including penalties if the demand source fails to provide the required demand as contracted.

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Section 3: Results and discussion

The deliverability of the demand under the modelled case is contingent on several factors, this includes availability of funding, grid connection, competitiveness of this contract compared to other markets, availability of offtakers and wider development requirements

Deliverability

The ability to realise the consumer welfare savings will be reliant on the deliverability of connecting the modelled demand. Case 1 has the greatest demand added, averaging at 3.5TWh of demand added on an annual basis with this spanning four boundaries through a combination of baseload and flexible demand.

Deliverability timelines

Given the near term constraint challenges, the modelled cases have assumed that demand will be connected between 2028 and 2030. For the technologies explored, the development timelines post Financial Investment Decision (FID) are likely to be between two and three years. Therefore, to provide a sufficient signal to new or relocated demand, the contract will need to be communicated to the market sufficiently ahead of project taking FID to provide them the opportunity to develop their business case with the contract in mind.

Required levers

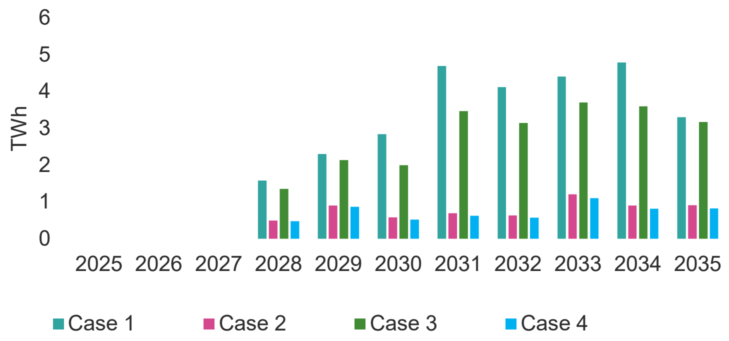
For this to be feasible, there are a range of different levers that will need to be implemented are summarised in the table to the right and detailed on the following slides.

These levers includes:

- **Funding availability:** several of the demand technologies are either technologies that have not previously been developed and therefore require government support (i.e. low carbon hydrogen) or have require significant capital investment (i.e. commercial/industrial demand and pumped hydro). Therefore, the availability and timing of funding will be critical to support a project taking FID.
- **Grid Connection:** the technologies at a minimum will require a demand connection, and for storage technologies will require an export connection. Both reinforcement costs and the timely availability of grid connections will be critical to support the business case of either new or relocated demand.
- **Competitiveness of other markets:** several of the technologies would already have the opportunity to operate within other electricity markets, particularly the ancillary services and balancing markets. Therefore, this contract would need to be commercially attractive compared to the available alternatives.
- **Availability of offtaker/wider infrastructure:** for several of the demand categories, they are either reliant on an available offtaker (i.e. hydrogen and data centres) or will need to be located near to wider infrastructure (i.e. natural gas network).
- **Wider development requirements:** each of the technologies will need to secure land, permitting and consenting within the designated boundary in a timely manner to meet the requirements of the contract.

Technology	Funding availability	Grid Connection	Competitiveness of other markets	Availability of offtaker	Development requirements
Hydrogen	✓	✓		✓	✓
Data centres	✓	✓		✓	✓
Industrial demand - EAF	✓			✓	✓
Other industrial demand	✓	✓		✓	✓
Energy storage – battery		✓	✓		✓
Pumped hydro storage	✓	✓	✓		

Deployment factors that may influence ability to meet contract requirements
Source: Arup analysis



Annual volumes procured (TWh) under cases

Source: Arup analysis

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Section 3: Results and discussion

For hydrogen and steel production, funding and/or government support will be essential to delivering these projects within the Demand for Constraints timelines, whereas key factors for data centres are centred around development and demand for data centre services.

Deliverability

Technology	Deployment factors: Funding availability	Grid Connection	Competitiveness of other markets	Availability of offtaker	Development requirements	Factor	Description	Lever owner
Hydrogen	✓	✓		✓	✓	Timely allocation of production funding	Currently all hydrogen production projects have required Hydrogen Allocation Round (HAR) funding to be commercially viable. The most recent funding round (HAR2) is due to deliver projects between 2026 and 2029. Whilst this funding round closed in April 2024, projects have yet to be shortlisted by DESNZ or receive funding. Timely allocation of this funding will be critical to enable hydrogen production to deliver at scale during the 2025-2035 period.	DESNZ
						Flexible offtaker	To allow hydrogen to provide flexible load during constraints, a flexible offtaker or storage will be required. Through the previous project 'Hydrogen Production from Thermal Electricity Constraint Management' it was identified that blending into the natural gas transmission network is likely to be the most commercially viable flexible offtaker. Currently hydrogen cannot be blended into the natural gas transmission network and therefore a positive policy decision (and updates to regulation) will be required for this offtaker route.	Project
Data centres	✓	✓		✓	✓	Customer demand	There will need to be sufficient further demand for data centre services in locations that sit behind constrained areas of the network to bring forward additional data centre projects that could participate in the service. The surge in cloud computing and AI will influence the development of further data centre projects. The recently announced AI Opportunities Action Plan could support this.	Project
Industrial demand - EAF	✓			✓	✓	Investment	Government support and private sector investment to help the industry transition to greener technologies such as EAFs and compete on the internation market will be essential.	Project/ Government
						Structural changes to steel industry	High energy costs limits the competitiveness of UK steel globally and there are only a handful of remaining steel production facilities in the UK. Domestic and international demand for UK steel will need to increase significantly to create the need for new/expanded steel production assets.	Project/ Government

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Deliverability

Technology	Deployment factors							
	Funding availability	Grid Connection	Competitiveness of other markets	Availability of offtaker	Development requirements	Factor	Description	Lever owner
Other industrial demand	✓	✓		✓	✓	Incentives to switch	There will need to be a strong business case for industrial heating/processes to be electrified, which will likely be underpinned by cost savings and emission reductions. Electrification will likely support both and the Demand for Constraint service would support further cost savings.	DESNZ
						Quantum of electrification	Given the smaller electrical loads of heat pumps and electric boilers versus other the other technologies considered, you would need more of these projects to get to a suitable level of demand for the service. Therefore it is unlikely a single project would have a sufficient level of demand to participate in a meaningful way.	Projects
Energy storage – battery		✓	✓		✓	Timely grid connection	Securing a grid connection before 2030 will be a challenge for new BESS projects, especially behind the B6 boundary in Scotland. Unless grid connection reform can alleviate the connection queue challenges, the extent to which BESS can play a role in the Demand for Constraints service may be limited.	Project / NESO
						Competitiveness of the service	Battery storage is typically active in multiple markets (wholesale, balancing, ancillary services) where assets can stack revenues. The Demand for Constraints service would need to be able to support equal or greater returns to BESS as part of the overall revenue stack.	NESO
Pumped hydro storage	✓	✓	✓			Timely allocation of Cap and Floor funding	Ofgem are expected to launch the process to allocate the cap and floor regime in 2025, with inviting projects for two delivery rounds, 2030 and 2033. They are currently designing the allocation process and expect to provide greater clarity in Spring 2025. Timely allocation of this funding will be critical to the delivery of new pumped hydro projects during the 2025-2035 period.	Ofgem
						Competitiveness of the service	Pumped hydro storage is able to provide a range of ancillary and balancing services (including frequency response and reserve). Therefore, for pumped hydro projects to utilise this contract, the contract would need to be either as or more commercially attractive than the other markets they are able to enter.	NESO

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