Quantitative analysis of Ofgem Access Options: Connection Boundary and TNUoS SDG

Ofgem

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FINAL REPORT

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1. EXECUTIVE SUMMARY

In this report, we summarise findings from our quantitative analysis of Ofgem's proposed reforms to the distribution network connection boundary policy and to Transmission Network Use of System (TNUoS) charges.

These proposed reforms have been developed in the first phase of Ofgem's Access and Forward-Looking Charges Significant Code Review (the SCR). The objective of the SCR is to develop a set of charging structures that allow network capacity to be allocated and used flexibly and efficiently, reflecting users' needs and allowing consumers to benefit from new technologies and services, while minimising potential costs to consumers.

Our analysis is intended to consider quantifiable impacts on consumers and market participants to help inform Ofgem's Minded-to Position. Ofgem's decision will be principles-based, combining this analysis with its own evidence base and stakeholder engagement to reach a position.

Ofgem's proposals

The current connection charge at distribution level is a 'shallow-ish' charge. New connectees must pay for the costs of sole use assets and make a contribution to the costs of wider reinforcement. Ofgem has asked us to model three policy proposals for the connection boundary at the distribution level:

1. **Voltage rule**: A shallow-ish connection boundary is retained but the voltage rule is amended such that new connectees only contribute to reinforcement at the same voltage level as their own connection.
2. **A hybrid option** which includes different connection boundary arrangements for demand and generation: Under this option, demand customers connecting to the network would face a shallow connection charge, while generators connecting to the distribution network would continue to face a similar connection charge but with the amendment to the voltage rule as discussed above.
3. **Shallow connection boundary**: The connection boundary is changed from shallow-ish to shallow.

Ofgem's proposals for change to the TNUoS charges are two-fold:

1. **Small-embedded producers (≥1MW):** Ofgem would change the charging structure for embedded producers with capacity between with 1 MW and 100 MW[2] such that these producers would pay Generator TNUoS rather than the existing EET credit received by embedded producers in the majority of England and Wales.
2. **Micro-generation embedded producers (<1MW):** Ofgem would keep the same charging structure for embedded producers with capacity of below 1 MW but would remove the floor on the charge at zero. This would affect producers in Scotland and northern parts of England and Wales who currently pay no charge but would face charge for export during Triad periods under the proposals.

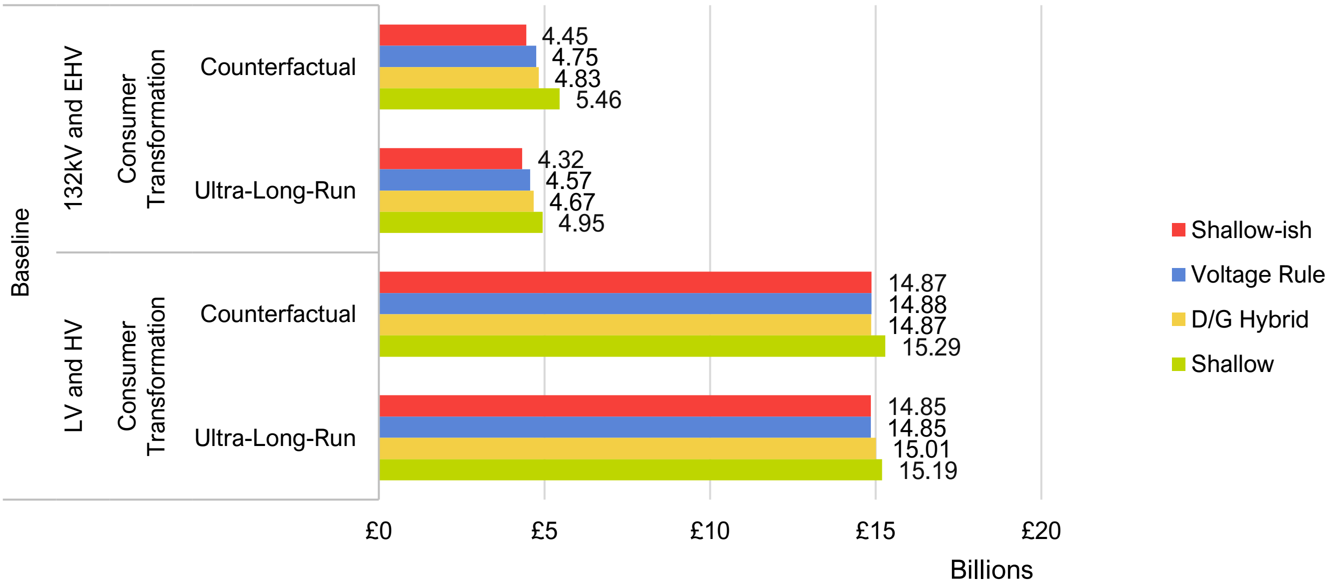
Connection boundary modelling results

We focus our modelling of the impacts of the proposed reforms to the connection boundary on the effect on distribution network costs. In alignment with economic theory, we find that a shallower connection boundary leads to an increase in network costs as locational connection signals are dampened (see Figure 1.1).

However, when we incorporate a notional change to distribution use of system (DUoS) charges, designed to replace some of the locational signals, this reduces the impact of the reform. We note that Ofgem are continuing to develop proposals for reforms to the DUoS charges and that carefully designed signals could reduce additional costs observed under a shallower connection boundary further.

[2] The change would also apply to any embedded producers with capacity greater than 100 MW but without a bilateral embedded generation agreement (BEGA) that would have previously been exempt from paying Generator TNUoS.

Figure 1.1: Present Value of distribution network costs for different DUoS and connection options, under the CT scenario



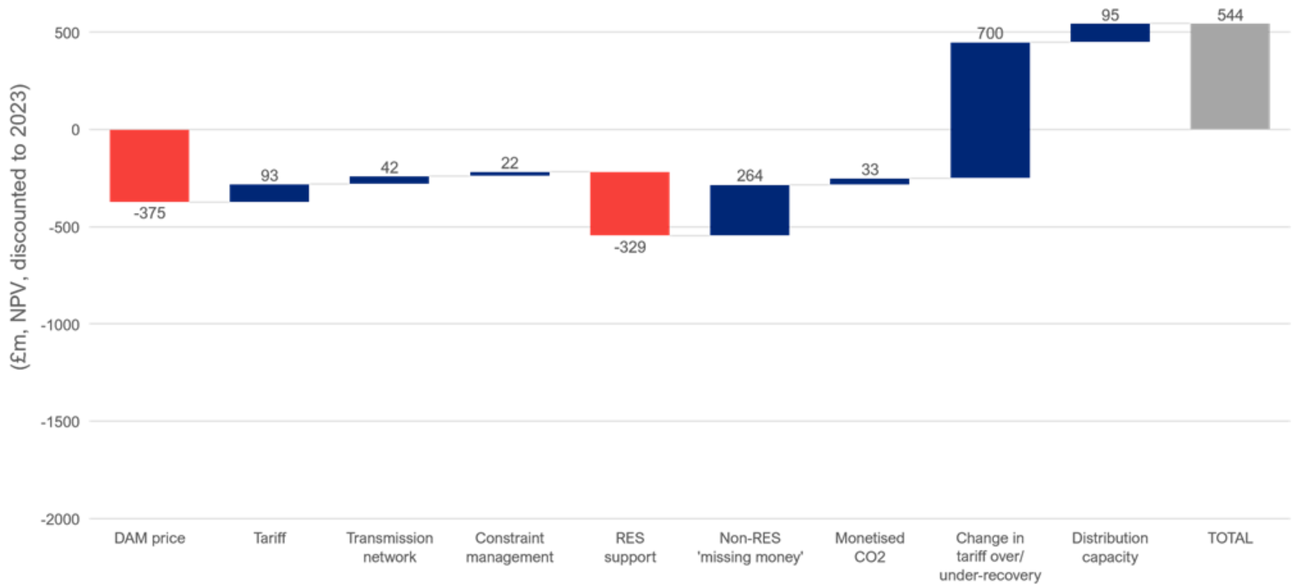
We also note that Ofgem has identified potential benefits of a change to the connection boundary which go beyond direct network cost impacts. Firstly, Ofgem consider that a reduction in the depth of the connection boundary could strengthen incentives on distribution network operators (DNOs) to identify alternatives to network reinforcement such as contracted flexibility. Ofgem consider that this could help to stimulate the emergence of flexibility markets. We model a sensitivity in which we assume the costs of flexibility alternatives to be higher than the assumed costs included in the baseline, which demonstrates the expected increase in overall network costs.

Secondly, Ofgem considers that a reduction in the depth of the connection boundary could alleviate challenges for new user connections, particularly for the connection of low carbon technologies, and therefore supporting the path to net zero emissions. In that context, our analysis is designed to support Ofgem's decision by setting out the potential cost increases that would need to be outweighed by wider benefits under the proposed reforms.

TNUoS modelling results

Under our central scenario ('Consumer Transformation'), we find that the TNUoS reform proposals lead to overall consumer welfare benefits of approximately £544m (NPV, discounted to 2023) through a combination of positive and negative impacts in different areas of the market (see Figure 1.2).

Figure 1.2: Total impact of the TNUoS reform option on consumer welfare under our central scenario (NPV, discounted to 2023)



We find a small increase in the average wholesale price, driven by the changes in incentives for producers to dispatch during expected Triad periods. On the other hand, the response to this increase in the price allows consumers to reduce tariff costs slightly as more flexible consumption shifts demand away from these peak periods.

We find that the reforms drive a shift in the location of embedded-generation capacity, in particular a move of onshore wind capacity away from Scotland and towards zones further south. This introduces small system efficiencies such that there is a small reduction in transmission and distribution network costs. Carbon emissions also decrease slightly.

We also carry out analysis of the potential impact on revenues of different types of producers. This allows us to consider the change in support costs for renewable technology that would be needed to ensure that there is no reduction in the total level of capacity of each type of producer. Similarly, by estimating the revenues of non-renewable producers, we can estimate the potential change in 'missing money' for these producers, which would need to be recovered through the capacity mechanism for example.

Our modelling suggests that support costs for renewables would increase, mainly due to the loss of revenues for Scottish embedded renewable producers.[3] We find that non-renewable generators would capture higher revenues through tariff changes and the small wholesale price increase.

Finally, our modelling does not incorporate feedback loops between the TNUoS charges and user investment and operational decisions. Over the appraisal period to 2040, this can lead to a divergence between the amount of revenue recovered under the counterfactual in comparison to the proposed option. As differences between modelled and required revenues would in practice be passed through to Demand TNUoS charges or to revenues of generators (and ultimately to impacts on the wholesale market price and/or support scheme costs) via Generator TNUoS, we assume that a difference in tariff revenue over/under-recovery between the counterfactual and the option would ultimately lead to consumer welfare impacts.

We model two alternative FES backgrounds ('Steady Progression' and 'Leading the Way'). We observe very similar trends under these backgrounds but with differences in the relative importance of each. Under the Steady Progression background, overall consumer welfare benefits increase by £644m (NPV, discounted to 2023) but

[3] We model total capacity of each technology exogenously, based on the FES scenarios and this may overestimate the additional costs of support as it does not allow for 're-optimisation' of capacity.

under the 'Leading the Way' background, we find welfare disbenefits of approximately £126m (NPV, discounted to 2023).

Our modelling framework has been designed to capture a broad range of potential costs and benefits. In doing so, we have had to make several simplifications and assumptions that are built into analysis. We discuss the impacts of these assumptions in Section 3.5. For example, by holding the total level of capacity of each technology constant in line with the respective scenario, we do not allow the model to re-optimise the allocation of capacity between technologies. Neither do we reflect the potential for an overall increase or reduction in low carbon capacity for example. In place of this, we set out analysis of impacts on the revenues of different technologies and in different locations in order to inform consideration regarding how investment decisions would be affected.

2. INTRODUCTION

Ofgem commissioned CEPA to develop quantitative analysis of its proposed reforms under the SCR.[4] This analysis is intended to feed into Ofgem's Consultation on its Minded-to Position.

The objective of the SCR is to develop a set of charging structures that allow network capacity to be allocated and used flexibly and efficiently, reflecting users' needs and allowing consumers to benefit from new technologies and services, while minimising potential costs to consumers.

The SCR is considering the 'forward looking' elements of charging which are intended to provide economic signals to users of the system regarding their investment and operational decisions. These signals may impact on how and where users decide to connect to the electricity system, as well as when and where they choose to generate and consume electricity once they are connected.

2.1. What is the change being considered?

The SCR covers a broad range of charging policy. Ofgem has separated its policy development into two phases of decision making which are progressing on different timings. In this Analytical Report, we focus on Ofgem's draft policy considerations in the following areas:

- **Distribution Network Connection Charging reforms:** In particular, the depth of the connection boundary for those connecting to the distribution network.
- **TNUoS Charging reforms:** In particular, how TNUoS charges are applied to embedded generation.

Distribution Network Connection Charging reforms

Those who wish to connect to the distribution network must currently pay a connection charge for doing so. The methodology for connection charges is set out in Schedule 22 of the Distribution and Use of System Agreement (DCUSA).[5]

A key element of any connection charging methodology is the definition of the connection boundary. This boundary defines the extent to which customers contribute to the consequential costs of their connection. Under a 'shallow' connection boundary, new connectees only pay for the assets of which they are sole users. Any requirements for wider reinforcement to the network to accommodate the new connection is funded through use of system charges that all users of the network contribute to. Under a 'deep' connection boundary, customers pay for the assets that they are the sole users of ***and*** for any costs of wider reinforcement.

The existing arrangements for charging on the distribution network lie somewhere in the middle of this range. Termed 'shallow-ish', new connectees pay for their own assets and make some contribution to reinforcement costs but with a proportion of wider reinforcement funded through use of system charges. This is different to arrangements for connections to the transmission system which includes a shallow connection boundary.

The contribution of new connectees towards reinforcement of the existing distribution network is determined by the 'voltage rule'. The voltage rule states the number of voltage levels above the connection that a connectee must contribute to in the case that reinforcements are required at these voltage levels. Under the existing arrangements, the voltage rule states that new connectees must make a contribution to wider reinforcement works that are needed at the same voltage level as their connection, plus the one above.

[4] See: https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges

[5] See: https://www.dcusa.co.uk/wp-content/uploads/2020/04/SCHEDULE-22-v12.1.pdf

Ofgem are considering reforms to the connection boundary at the distribution level to respond to the concern that current arrangements may result in prohibitive upfront charges that may slow down progress towards net zero. They also believe that the existing arrangements may lead to incremental reinforcement that does not take into account wider reinforcement needs, and thus may stifle the development of alternatives to reinforcement such as flexibility markets. Finally, they identify the inconsistency of the connection boundary at transmission and distribution voltages as a potential distortion to connection decisions of users who can decide to locate on either.

Ofgem asked us to model three reform options:

1. **Voltage rule**: A shallow-ish connection boundary is retained but the voltage rule is amended such that new connectees only contribute to reinforcement at the same voltage level as their own connection.
2. **A hybrid option** which includes different connection boundary arrangements for demand and generation: Under this option, demand customers connecting to the network would face a shallow connection charge, while generators connecting to the distribution network would continue to face a similar connection charge but with the amendment to the voltage rule as discussed above.
3. **Shallow connection boundary**: The connection boundary is changed from shallow-ish to shallow.

Ofgem has noted important interactions between the connection charging arrangements and DUoS charges, which also send signals to users about where to locate on the network.

To reflect potential interactions between distribution connection charging arrangements and DUoS, Ofgem asked us to model the connection options against two different DUoS 'backgrounds'. Firstly, we model the connection charging options against the existing DUoS background without reform. Secondly, we model connection charging options against DUoS signals which are based on the 'ultra-long-run' charging methodology. Under this approach, unit costs of expansion are averaged across all voltage levels but the allocation of costs to different charging timebands varies by location. Final unit costs are averaged by either Grid Supply Point or Bulk Supply Point. This is only intended as a notional DUoS policy change to test sensitivity of the outcomes. It does not represent Ofgem's policy intent.

TNUoS reforms

TNUoS charges cover the costs of building and maintaining the onshore and offshore transmission system in England, Wales and Scotland. Generators and suppliers are charged TNUoS according to an agreed set of methodologies.[6,7]

Ofgem's proposed reforms to TNUoS are focused on the TNUoS charging structures for embedded generators[8] with capacity of less than 100MW. Under the current arrangements, these embedded generators receive the embedded export tariff (EET). The EET charges include the negative of the Demand TNUoS Triad tariffs plus the Avoided GSP Infrastructure Credit (AGIC). A floor of zero is applied to the charges, such that generators only receive credits in relevant zones. No charges are levied on generators who would otherwise face a positive charge. In effect, embedded generation in central and southern distribution zones receive a credit for export of generation over three Triad periods,[9] while embedded generation in Scotland and the north of England do not pay any TNUoS charge or receive any credits.

Ofgem considers that these arrangements introduce a distortion that encourages embedded generators to connect to the distribution network rather than the transmission network and may not reflect the additional costs of locating

[6] You can read more about how TNUoS charges are currently applied to generators here: https://www.nationalgrideso.com/document/138046/download

[7] We assume that suppliers pass on these charges to their customers. You can read more about how TNUoS charges are applied to suppliers here: https://www.nationalgrideso.com/document/135056/download

[8] Embedded generators are those connected to the distribution network. We use the two terms interchangeably in this report.

[9] You can read more about Triad charges here: https://www.nationalgrideso.com/document/130641/download

on certain parts of the system where the EET charge is set to zero. Connecting to the distribution network would allow users to avoid high generation TNUoS charges in Scotland and, to a lesser extent, in the north of England.

The charging approach for embedded generators may also focus the incentives of embedded generators on dispatch during Triad periods in central and south England and Wales. Ofgem consider that system conditions other than the highest peak periods captured by Triads increasingly drive transmission costs, such that the existing Triad-based approach may not drive operational decisions that are the most efficient for the system.

Under Ofgem's proposed reforms, instead of the current system of EET credits for dispatch during Triad periods, all embedded generation above 1 MW would pay the same TNUoS charges as transmission-connected generators. Ofgem consider that this would remove a distortion in user decisions regarding the voltage level of connection and would encourage dispatch decisions that take into account transmission cost drivers, therefore resulting in more efficient use of the system.

Ofgem's proposals would also introduce changes for embedded generators with capacity less than or equal to 1 MW. The floor on the charge would be removed such that all micro-generators face the EET (i.e. the negative of the locational Demand Triad plus the AGIC), regardless of whether this is a tariff or a credit. This effectively means that micro-generators in Scotland and some northern distribution zones will face a charge for export during Triad periods where previously their charge was capped at zero.

Access Rights

We note that Ofgem have also developed proposals for reforms to access rights arrangements which include proposals for time-profiled, shared and defined non-firm access rights. These options are set out in more detail in Ofgem's Consultation on its Minded-to Position.

Ofgem consider these options to be 'low regrets' reforms and have therefore focused on qualitative assessment to reach their position on reform. We do not include any reforms to access right arrangements within our modelling for this report.

2.2. Structure of this report

In this report, we set out our quantitative analysis of the costs and benefits of Ofgem's proposed reforms to Distribution Connection charging and TNUoS charging, in support of Ofgem's impact assessment. Our analysis considers the impacts on consumers and market participants. The quantitative analysis is intended to capture several of the expected costs and benefits of the reforms but there are also important impacts that are not possible to quantify within this modelling framework. The analysis is intended to support Ofgem's principles-based assessment of policy reform.

The remainder of this report is set out as follows:

- **Section 3** provides a high-level summary of the methodological framework for modelling of the options. We set out more detail on our methodology in the technical Methodology Note which accompanies this report.
- **Section 4** summarises the modelled impacts of Ofgem's proposed reforms to the connection boundary.
- **Section 5** summarises the modelled impacts of Ofgem's proposed reforms to TNUoS charging.
- **Section 6** presents high-level conclusions from the analysis.
- **Appendix A** provides a full set of charts of the analysis under the SP and LW backgrounds.

3. SUMMARY OF METHODOLOGY

In this section we summarise key elements of our modelling methodology. Alongside this report, we also publish a more detailed Methodology Note. Our modelling methodology is designed to support Ofgem's principles-based assessment. The model captures several of the key anticipated benefits and negative impacts of reform, but it does not attempt to capture the full range of anticipated impacts, some of which are not possible to quantify within the defined modelling framework. We summarise the key limitations of the modelling in Section 3.7.

3.1. Modelling framework

Our approach combines several models, some of which have been developed explicitly for the purposes of this analysis, and others which have been developed elsewhere. Together, these models are used to calculate the impacts of charging options on the system and on consumers, both of which are combined to calculate a net present value (NPV) welfare impact. The modelling framework is also used to estimate impacts on different network users, in different locations and at different voltage levels.

At a high level, the process is as follows. Distribution network cost models developed by the Energy Networks Association (ENA) cost model subgroup are used to calculate the unit costs of network capacity expansion at different network locations. A combined LV, HV and EHV network charging model then takes unit cost inputs to calculate a set of distribution network charges for each user archetype under each option.

Separately, the ESO has modelled TNUoS charges out to 2040 under the counterfactual charge structure and based on Ofgem's proposed reforms. The ESO modelled these charges to 2040, drawing on the 2019 Two Degrees FES scenario.

We have developed a bespoke wholesale market model which takes the range of network charges and incorporates them into generation and demand cost functions, and therefore into the dispatch merit order. We model the impacts of each option on the generation or consumption of different types of users and, consequently, on wholesale market prices.

The model includes behavioural responses through price elasticities of demand, driven by a combination of behavioural response to network charges and to wholesale market prices. Drawing on the relevant literature, we have developed a set of assumptions on the behavioural response for a set of aggregated user archetypes. These behavioural assumptions feed into the market model and inform the extent to which different consumers respond to tariff and wholesale price signals in their consumption decisions.

The market model takes the total level of installed capacity of each technology in each modelled year directly as an input from the relevant FES scenario. However, subject to defined bounds, the model does allow for new renewable and low-carbon capacity to choose where to locate on the transmission and distribution networks based on derived revenues in different locations.

The model outputs allow us to estimate captured revenues for each technology type and compare these against estimates of the costs that that technology type needs to recover. In doing so it can provide an estimate of any additional revenues that might be required for each technology in each location to enable the level of investment specified in the FES scenario.[10] We use this to estimate revenues that would need to be recovered through renewable support mechanisms and to estimate 'missing money' for non-RES generators that would need to be recovered through the capacity market for example.

We have adapted the wholesale market model to estimate the approximate costs of transmission reinforcement between seven key transmission zones. It is important to note that our modelling of the transmission network is a relatively simple representation. It is only intended to capture network investment costs against this pre-defined set of key transmission network boundaries, without representing the detailed layout and capacity constraints of the transmission network.

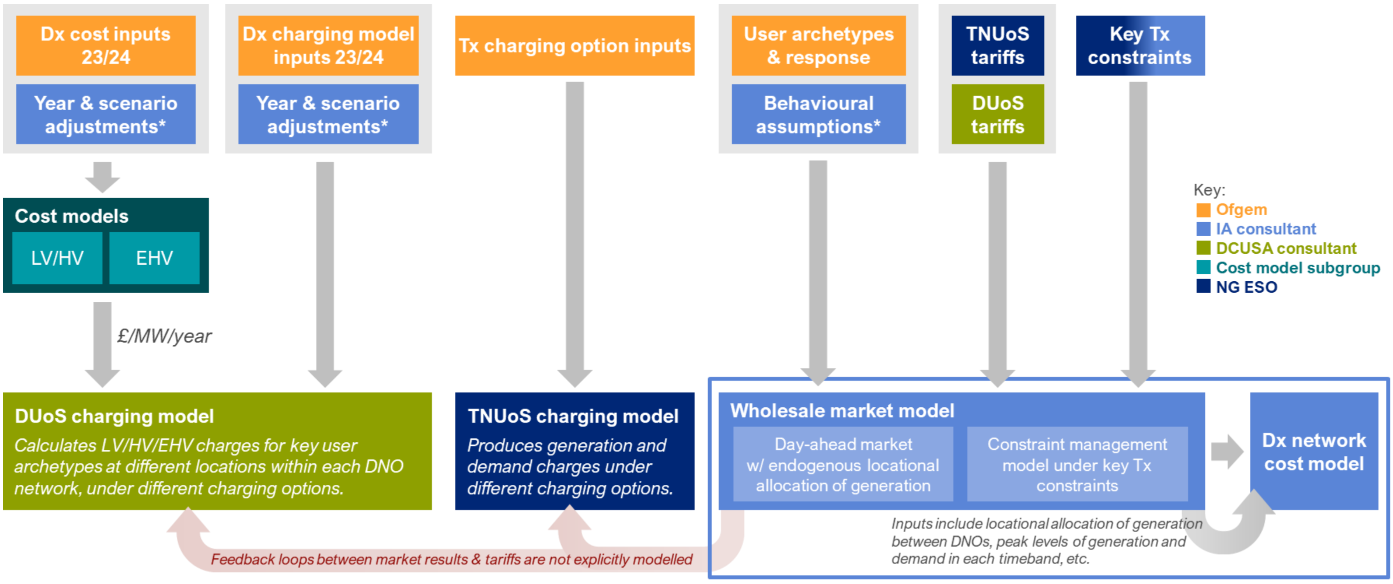
[10] Alternatively, it can estimate the surplus revenues relative to that needed to cover costs where relevant.

We run an unconstrained and constrained version of the market model. The unconstrained run simulates the day-ahead market (DAM) and estimates the DAM price. The constrained run then incorporates transmission capacity limits between zones, and is used to measure the level of, and the costs associated with transmission network constraints. By incorporating unit costs of expansion of the transmission network, it also optimises constraint management by weighing the costs between curtailment actions and transmission network reinforcement.

We have also developed a distribution network model which takes generation and demand outputs from the market model, inclusive of estimated behavioural responses. The distribution network model estimates the impacts of the options on the need for, and costs of, distribution network reinforcement. The model also allows DNOs to resolve capacity constraints using an alternative to network reinforcement based on a simplified representation of DNO-contracted flexibility services.

After running both the market and distribution network models, network and wholesale market costs are combined to calculate an overall NPV welfare impact on consumers. Our analysis of revenue impacts on different users also allows us to develop consider the impact on revenues captured by producers of different types, in different locations, and under different scenarios.

Figure 3.1: Model framework representation



*Calibrated using a dummy run of the wholesale market model

3.2. Time horizon and temporal granularity for analysis

Modelling is conducted for the period 2024-2040.[11] We model three spot years (2024, 2029 and 2040) within the market model, and we interpolate between these in order to estimate impacts over the full period. We model each individual year within our modelling period within the distribution network model. While the distribution network model is based on representative hours within each timeband, our market model models each year with hourly granularity.

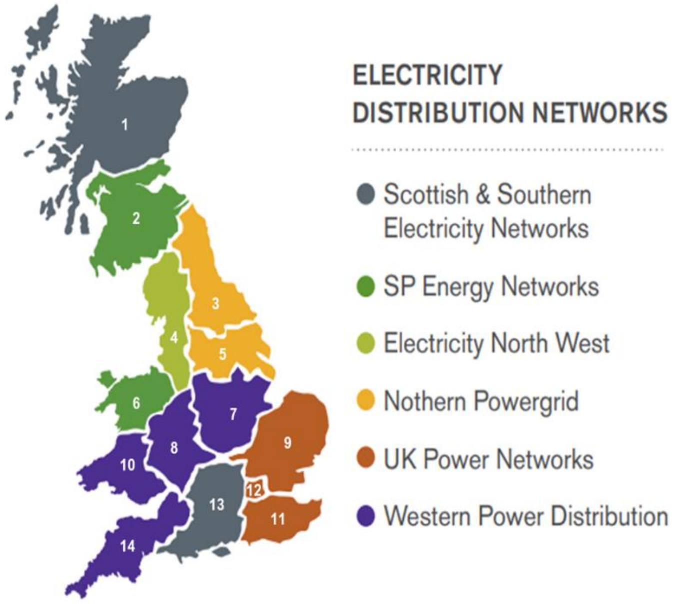
3.3. Spatial granularity of modelling

The DAM prices are determined for the system with no consideration of network constraints from the unconstrained market model run. This market timeframe is represented by a GB-wide deterministic dispatch model.

[11] Note that our model works in calendar rather than charging years (consistent with the FES). We model 2024 as a representation of the first year of implementation.

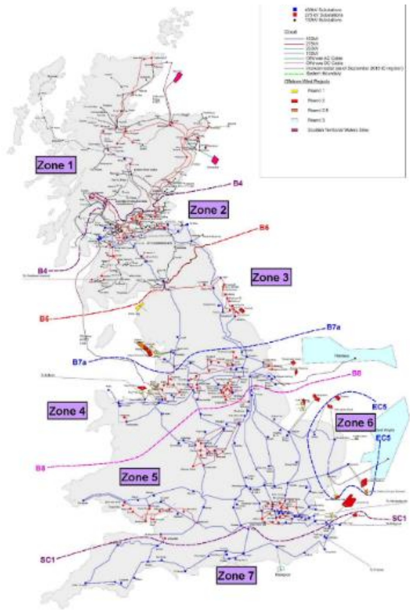
Our market model incorporates dispatch with a number of bespoke features. One of these features is the explicit modelling of separate distribution network zones, as well as seven key transmission network zones.[12] We illustrate these zones in the figures below. Capacity constraints between transmission zones are considered in the constrained model run.

Figure 3.2: Distribution network zones modelled



Source: ENA

Figure 3.3: Transmission network zones modelled

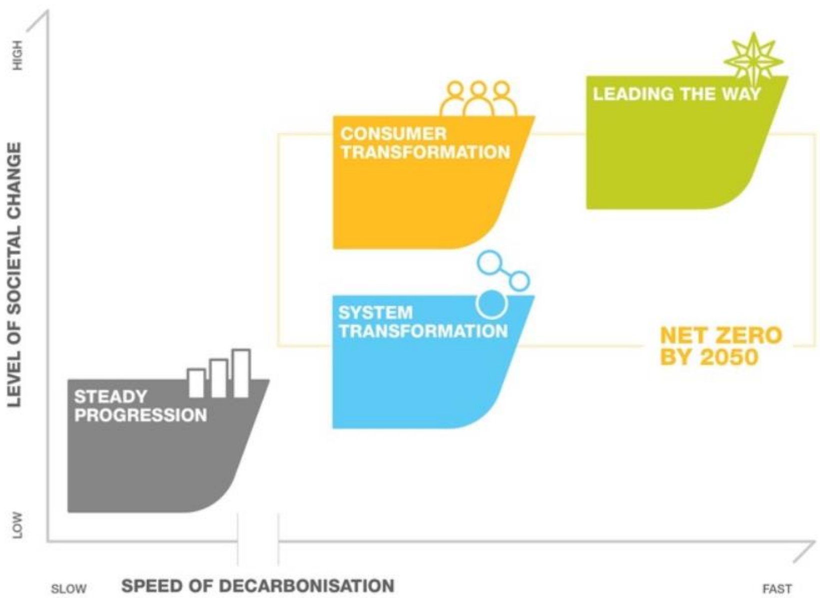


Source: National Grid ESO

3.4. Scenarios under which analysis is being conducted

We draw on the ESO's FES 2020 scenarios for the purposes of modelling. The FES 2020 includes the scenarios shown in Figure 3.4 below.

Figure 3.4: FES 2020 scenarios



[12] Based on the suggestion of the ESO's NOA team.

The FES scenarios vary in two dimensions: the speed of decarbonisation and the level of societal change. The Consumer Transformation (CT) and System Transformation (ST) scenarios deliver Net Zero decarbonisation commitments. However, CT is more decentralised and achieves this through a more significant level of societal change and with a greater adoption of electrified consumer technologies. Leading the Way (LW) goes beyond the Net Zero targets, while Steady Progression (SP) makes progress towards net zero objectives but does not meet them. The level of societal change under SP is lower than both CT and ST.

We model CT as a central scenario for the analysis. We also run the SP scenario and LW scenarios as alternative backgrounds to CT. This allows for consideration of the impacts of policy reforms under a wide range of potential future outcomes.

3.5. Modelling limitations

Our modelling framework has been designed to capture a very broad range of potential impacts, including impacts on DAM outcomes, policy support costs, network constraints, and transmission and distribution network investment. To achieve this breadth of analysis, several assumptions and simplifications have been introduced into the model which may impact on the outcomes observed. These modelling choices may also limit the extent to which the framework is able to capture some of the potential benefits and disbenefits of Ofgem's proposed reforms. In several cases, we have supplemented the modelling with additional analysis to address these limitations. For example, while we do not model re-optimisation of capacity between technologies, our investment analysis demonstrates the impacts of reform on revenues of different technology types. We summarise the key limitations of the modelling framework in Table 3.1.

Table 3.1: Limitations of the modelling

Assumption	Modelled approach	Possible implications on modelled outcomes	Supplementary analysis (where applicable)
Exogenous level of total capacity of each technology	In the model, we take the total level of capacity of each producer and consumer technology from the FES scenarios. Note that our model does allow new capacity to choose where on the system to locate within defined bounds (see below).	Our model does not allow 're-optimisation' of the choice of technology in response to revenue outcomes. In practice, investors may respond to revenue signals by shifting investment from one technology to another. Therefore, our modelling may over-estimate the impacts of reforms on RES support costs that must cover revenue requirements for a fixed set of capacity. This simplification also has implications for our assessment of carbon impacts of the proposed reforms. As we incorporate the same level of capacity of each technology within the analysis, we do not reflect any reduction in capacity or shift between RES and non-RES technologies. Instead, we assume that policy support will increase to meet any additional revenue shortfall. The carbon emission impacts that we present in this report are therefore limited to 'operational' impacts, i.e., resulting from dispatch and re-dispatch of a given capacity mix.	Based on our modelling results, we have analysed the revenue impacts for each type of technology in each location on the system. This allows insight to be drawn regarding the likely impacts on investment into different technologies and for a discussion of implications for the modelled outcomes.
Bounding of the locational allocation of capacity	Our model allows renewable capacity to choose where to locate on the system in response to expected revenues. However, the ability of users to choose where to locate is bounded relative to the locational allocation of capacity in the FES.[13] The bounds that we apply widen over the appraisal period relative to the FES. This reflects the increasing uncertainty of factors that may impact on the choice of where to locate new renewable capacity.	Our modelling of the locational allocation of capacity does not reflect the complexity of locational choices which exist in reality. Where our bounds are narrower than would be the case in reality, this may constrain investor decision making, limiting the impact of locational investment signals sent under the counterfactual and the policy option and vice versa. As Ofgem expect their proposed TNUoS reforms to provide more consistent locational signals for embedded generation, this may have consequences for the modelled benefits of reform.	We supplement our modelling with revenue analysis (described above) which can provide further insight on how different types of technology may respond to locational signals. This includes geographic decisions of where to connect on the network as well as decisions regarding the voltage level at which to connect.

[13] For a description of how our locational capacity bounds work, please see our accompanying Methodology Note.

	In the modelling itself, we do not allow for capacity to re-allocate between the transmission network and the distribution network.	We do not directly model the potential for investors to respond to the change in signals by deciding to locate capacity on the transmission rather than distribution network (or vice versa).	
Simplified representation of transmission network	We incorporate a set of transmission boundaries into our market model. However, our model is not designed to be a detailed representation of the transmission network. Instead, we engaged with the ESO to identify and model six key projected transmission boundaries on the system. Transmission boundaries tend to evolve over time, driven by the evolving generation background. This evolution is not modelled.	Our constrained model run does not reflect the complex and evolving set of transmission boundaries that are observed on the transmission network in practice. No intra-zone constraints (i.e., within each transmission zone) are modelled. By modelling a set of key boundaries, we capture the potential of reforms to impact on the need for network investment to some extent, but we are likely to under-estimate this need given the simplification of the network. This limitation will apply equally to the counterfactual and to the policy option, such that the overall effect is limited to the differential in transmission capacity requirements between the two.	No supplementary analysis undertaken.
No feedback loop between transmission network development and charges	Our model does not include a feedback loop between network investment, user behaviour and network charges. TNUoS tariffs are modelled by the ESO under the 2019 FES Two Degrees scenario. TNUoS tariff modelling reflects the change in policy regarding charging of embedded generators and consequential impacts on other users. However, the modelling of TNUoS charges does not take into account the outcomes that we model regarding investment and dispatch decisions. As the policy options do not affect DUoS charges, these charges are the same under the option and the counterfactual.	In practice, additional network capacity is funded through network charges, and network charging models take into account developments regarding investment and dispatch decisions when forecasting charges (which are designed to recover revenue). As our modelling makes use of a different set of scenarios than the ESO's TNUoS modelling, we can observe a disconnect between the level of revenue which is recovered in each set of models (i.e., this may lead to over- or under-recovery of revenue requirements over the period of analysis). In practice, an under-recovery of revenue would be reflected in higher charges for consumers and/or producers relative to the modelled outcomes. An over-recovery would lead to a reduction in charges relative to modelled outcomes. In practice, this under- or over-recovery would result in impacts on end consumers, either directly through tariff increases/decreases or indirectly, as producers pass on changes to tariffs, e.g., through the DAM price or through	We capture the differences in total revenue recovery between the two sets of models and treat this as a consumer welfare impact. This assumes that the revenue over- or under-recovery would be passed through to consumers.

		a change to the level of subsidy they require through support schemes.	
Simplified representation of distribution network charging application	We include three 'levels' of connection in our modelling: 1. Direct transmission-connected, 2. Direct distribution-connected (regardless of capacity), and 3. Behind-the-meter ('BtM') generation (which we assume is located onsite or in a consumer's home).	This approach does not capture certain nuances within the existing definition of charges. Currently, distribution-connected generation that has capacity of greater than or equal to 100 MW and a BEGA pay Generator TNUoS. However, our model assumes that these generators pay/receive the same as smaller embedded generators that face the EET.[14] We are therefore over-estimating the impact of reform slightly as, in our model, the current EET arrangements for smaller embedded generators are applied to a subset of customers who would actually pay Generator TNUoS under the counterfactual. Based on FES data, large-embedded generation (with capacity at least 100 MW and with a BEGA) represented less than 8% of total generation capacity in 2019. Given the relatively small size of this specific customer group, we consider the impacts on outcomes are likely to be limited. Our model also misses a small amount of nuancing of the proposed TNUoS reforms with regards to the application to embedded generation with capacity of less than 1 MW (microgeneration) that is not BtM. We treat this directly distribution-connected micro-generation in the same way as small-embedded generation, meaning that under the reform option it pays Generator TNUoS rather than the EET charge. The majority of microgeneration is BtM in the FES scenarios and therefore the impact of this assumption is	No supplementary analysis undertaken.

[14] There are two types of smaller embedded generators that face the EET under the current arrangements: those with transmission entry capacity (TEC) less than 100 MW who have BEGAs with the ESO; and those that have capacity of less than 100 MW (including micro-generators) without TEC who do not have BEGAs.

very limited. In 2019, more than 99.9% of total microgeneration was BtM.

4. IMPACTS OF CONNECTION BOUNDARY OPTIONS

In this section, we present the modelled impacts of Ofgem's proposed reforms to the depth of the connection boundary for distribution network connections. We present impacts on the costs of developing the distribution network. We focus on the impacts modelled under the central CT scenario but also present the impacts under the SP and LW backgrounds, where the impacts are similar in relative terms.

Our modelling focuses on the direct impacts of reforms to the connection boundary on the costs of the distribution network. Several of Ofgem's anticipated benefits of this reform are not possible to quantify within this modelling framework. For example, Ofgem anticipate the potential for reform of the connection boundary to make it easier for low-carbon technologies to connect to the distribution network. In this sense, it is important to note that our modelling provides only a part of the picture. It is intended to inform Ofgem's principles-based assessment by estimating the network cost impacts and allowing Ofgem to make an informed decision of whether any additional network costs are likely to be outweighed by broader, non-quantifiable benefits.

4.1. Approach

Impacts of connection boundary options have been assessed predominantly within our distribution network model. This model includes an estimate of the locational investment decisions that will be made for new capacity within a distribution network zone, which is determined by signals provided through connection charges and any locational elements of DUoS charges. By varying the modelled depth of the connection boundary and incorporating different DUoS approaches it is possible to estimate how these policy reforms could affect the need for distribution network reinforcement within our modelling period.

The distribution network model includes a simplified representation of all fourteen distribution licence areas, incorporating the inputs prepared by the DNOs themselves as part of the SCR's cost model working group. This allows us to represent in detail the 132kV and EHV networks (including individual primary and BSP substations, and the circuits that connect them), as well as an aggregated representation of the entire HV and LV networks downstream of each primary. This requires an assumption that all of the HV and LV networks below a primary are entirely homogenous. While this is an important assumption, it is consistent with the approach taken within the network cost model that produces the unit costs that drive tariffs. While the assumption is proportionate in the context of this broad modelling requirement, it does mean that more caution is required when interpreting results regarding impacts on the HV and LV networks.

The distribution network model accounts for the sources of demand and generation throughout the modelled networks, including existing domestic and non-domestic demand on the LV networks, current and future sources of embedded generation, and the deployment of other low-carbon technologies (LCTs) such as electric vehicles and heat pumps. The deployment of embedded generation and LCTs, and profiles of consumption and production, are determined by the wholesale market model. For consistency between connection boundary options, we use a single run of the market model (for each scenario) to generate the inputs for all of the options. We use the counterfactual run that does not incorporate any other change to tariff design such that the impacts of the proposed connection boundary reforms can be considered independently. The distribution network model considers import and export requirements from the network in six seasonal/time-of-day time bands (peak, day and night for summer and winter). For more information on the distribution network impacts methodology, please refer to our Methodology Note.

Connection boundary options

We reflect four different connection boundary options within the model:

1. Under the **shallow-ish counterfactual**, the model reflects the existing voltage rule. This states that users contribute for reinforcement at the voltage level to which they connect, as well as the voltage level above.

2. The first policy option **amends the voltage rule** such that customers only face connection charges for reinforcement for the voltage level to which they are connected. Contribution to higher voltage levels is no longer required.
3. The second option is a **hybrid option**, which removes connection charges completely for demand (i.e., a shallow connection boundary), and retains connection charges for generation but including the amended voltage rule mentioned above.
4. The final option introduces a **shallow connection charge**, removing all connection charges associated with reinforcement.

Our model only incorporates the shared elements of the network such that the costs of sole use assets are not included. A completely shallow connection boundary therefore includes no connection charge for the connectee in our modelling, only the element which is shared through DUoS.

DUoS options

We have modelled the four connection boundary options against two different DUoS tariff backgrounds.

1. The DUoS counterfactual status-quo CDCM and EDCM charges.
2. Charges set using a notional version of a possible DUoS policy change.

The assumptions about how DUoS charges are set interact heavily with the modelling of connection boundary options, since it is ultimately the balance between connection charges and locational DUoS which signals to a user where on the network they should choose to locate their new capacity.

In the DUoS counterfactual, charges do vary by voltage level but, apart from this, are assumed not to affect locational decisions. In practice, EDCM charges *do* vary by location, but we understand from Ofgem's stakeholder engagement and policy development that these are rarely accounted for within locational decisions because they are too volatile to provide a stable signal. Therefore, the model considers the average EDCM import and export charge for each voltage level within each distribution network zone as part of the locational decision-making process.

The notional policy option is one specific combination of features that Ofgem has been considering as part of an "ultra-long-run" (ULR) cost model, which would ultimately replace both the CDCM and EDCM. This uses locationally specific estimates of network asset value and utilisation to drive locational DUoS charges. The notional option used within this modelling has the following features:

- The £/kVA/year locationally-specific unit costs are initially averaged across all voltage levels, such that users are not exposed to signals that reflect any deviation away from average costs of capacity (e.g., due to very long or short overhead lines or cables).
- No "spare capacity indicator" is used. This means there is no signal for users to favour areas of the network which currently have more capacity.
- While the total £/kVA/year cost for each location is the same (within each voltage level) the allocation of costs to timebands (and demand vs generation dominance) may be different for each location.
- This allocation to timebands is initially done for each primary substation but, as a final step, £/kVA/year costs for each timeband are averaged across each Bulk Supply Point (BSP) or Grid Supply Point (GSP) group.

It is important to note that this DUoS policy option is only used for the purposes of assessing the connection boundary reforms against a revised DUoS charging background. It does not reflect Ofgem's policy intentions for DUoS reform under the SCR.

Limits and constraints on locational decision-making

Our modelling can estimate the way in which DUoS and connection charges will affect the locational decisions made by users about where to site new demand and generation capacity. However, these charges are only one, potentially small, part of the complicated set of factors that would inform these decisions. For example, for embedded renewable generation, locational decisions will be strongly influenced by the energy yield (e.g., the wind or solar resource at each location), the ability to get planning permission (which may be significantly more challenging in certain locations), and other factors like accessibility.

Modelling these other factors is outside of the scope of this analysis. This may lead to our model overestimating the extent to which connection charges and DUoS drive locational decision making. In addition, there are other aspects of connection charging policy which we have not modelled (such as the high-cost cap) or have modelled in a relatively simple way (such as cost apportionment factors). There may even be other signals provided by a DNO to users which influence where to connect, such as indications of where there is more spare capacity available for new connections.

To address these limitations, we have incorporated a set of assumptions and constraints within the model to avoid outcomes that may be unrealistic:

1. We assume there is a limit as to how much new capacity can be accommodated at each location within a finite period of time, with at most one new demand and generation connection per year, and at most two new demand and generation connections within each 5-year period.
2. We prevent certain types of generation from deploying in more urban parts of the network and restrict them to more rural locations. For example, we assume onshore wind can only be deployed in rural areas.
3. We assume that capacity will be split across voltage levels in a broadly similar way in the future as it is today. This limit is strongest for demand, where we assume that the apportionment of new capacity across voltage levels will be very similar to how it is today. For generation, we allow some additional flexibility.
4. We impose some limits on which type of generation can be deployed at each voltage level. For example, we assume that in the future, large scale wind and solar will not connect directly to the LV circuits of the distribution networks.
5. Finally, we include disincentives on decisions that would lead to very extensive reinforcement (i.e., more than two additional reinforcements of the existing asset). This seeks to account for factors such as the high-cost cap[15] as well as the prospect that extensive reinforcement would cause project delays.

4.2. System impacts

This section presents the system impacts of the options, expressed in terms of the present value (PV) of the cost of reinforcement and managing the distribution networks. The PVs calculated in this section reflect the approach taken in general within RIIO. A proportion (25%) of the capex is expensed and assumed to be incurred in the year in which the reinforcement is required. The remainder of the capex is annuitised over a forty-year period.

Impacts on costs of accommodating new connections

We summarise the overall impacts on network costs in Figure 4.1. The modelled impact of a shallower connection boundary on distribution network costs results in a disbenefit, with higher system costs.

This is because the locational investment signals for new capacity are dampened as the connection boundary becomes shallower relative to the counterfactual, which provides a stronger and more direct signal. The increase in system costs is greatest for a completely shallow connection charge, but is more modest under the amended

[15] The high-cost cap requires that for generation connections that trigger reinforcement costs in excess of £200/kW, the entirety of the cost above the threshold is paid for by the customer.

voltage rule, or within the "hybrid" option. For the shallow connection charge option, we observe an increase in system costs of approximately £1.4 billion with the counterfactual DUoS background, reducing to just below £1 billion when the notional change to the DUoS background is included. For the voltage Rule and hybrid options, the PV of costs increases by ~£0.3 billion and ~£0.4 billion respectively, under the counterfactual DUoS background, and ~£0.25 billion and ~£0.5 billion respectively, under the ULR DUoS background.

This is well aligned with our expectations. Cost-reflective deep connection charges generally provide the strongest locational signals for development of the network at lowest cost. Where these signals are weakened, and are not replaced, this will impact on user decision-making and increase network costs.

In most cases, larger cost increases are observed with the counterfactual DUoS background. Cost increases are more limited when using the notional ULR policy option as an alternative DUoS background. This also aligns with expectations. The ULR DUoS background replaces some of the signals sent by the deeper connection charge and hence reduces the extent to which costs increase when the depth of the connection charge is reduced.

The observed trends for an increase in cost are the strongest at the 132kV and EHV voltage levels. The higher voltage levels experience higher levels of deployment of large new connections which are influenced by the connection boundary signals to a greater extent. At the LV and HV voltage levels, general demand growth and deployment of technologies such as heat pumps and electric vehicles drive much of the additional need for capacity. We assume that the majority of this new demand will locate in similar locations to existing domestic and non-domestic demand and will therefore not be heavily influenced by changes to connection signals.

We do model locational decisions for a proportion of non-domestic demand which we assume to be larger and require new connections to the network. While we do not explicitly account for which subsectors of non-domestic demand do and do not require new connections, we expect that some larger consumers may be more responsive to locational signals.

We note once again that impacts at HV and LV levels are subject to a wider range of uncertainty. However, we believe that the impacts at these levels may partly reflect design of the notional policy option (e.g., the lack of a spare capacity indicator, or the averaging across BSP and GSP groups) which might be causing inefficient load-shifting in response to signals that are not fully cost reflective. This would need to be explored through more extensive analysis of different DUoS options. Under the status quo, the DUoS charge structures would not drive any locational variation in load shifting, since there is no locational variation in charges.

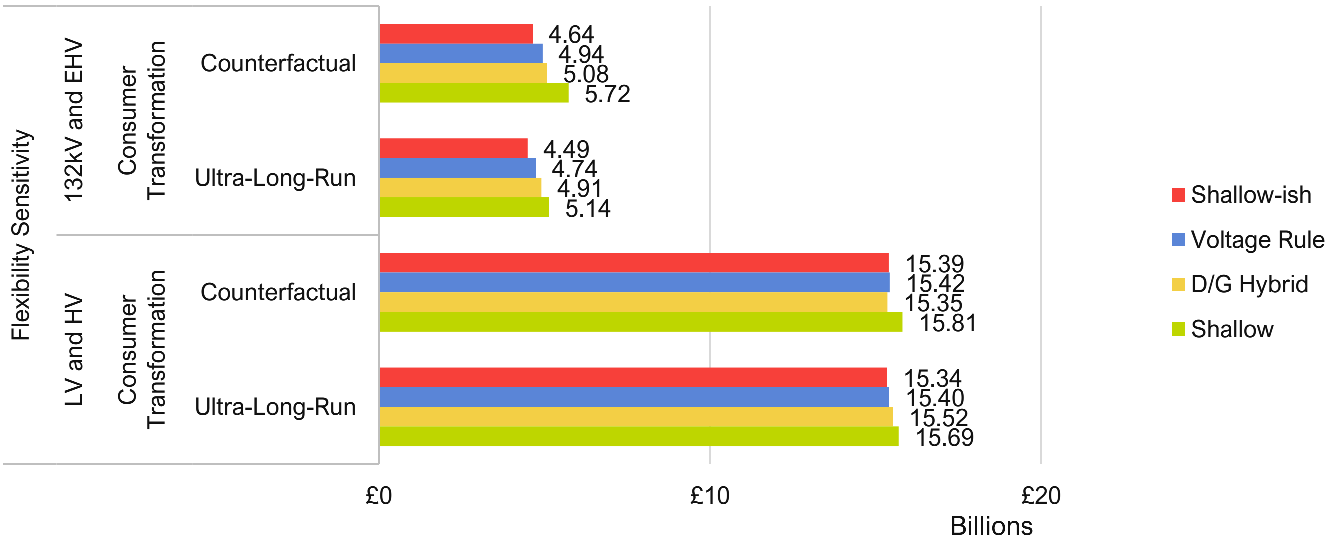
Figure 4.1: PV of distribution network costs for different DUoS and connection options, under the CT scenario

Impact of costs of flexibility (Sensitivity)

Ofgem has been developing qualitative thinking on whether flexibility services are more likely to emerge in the presence of a shallower connection boundary, i.e., as this would increase the incentive for DNOs to pursue alternatives to network reinforcement.

To support Ofgem's thinking, we have assessed a sensitivity where the cost of procuring flexibility services for distribution network management is higher than under the counterfactual (Figure 4.2), with an initial headline figure of £20,000 per MW of flexibility per timeband per year, compared to £10,000 per MW in the baseline. As expected, higher costs of the alternatives to network reinforcement provided by flexibility options increases the cost of reinforcing and managing the distribution network out to 2040. Under the sensitivity, costs increase by an additional £0.2 - £0.3 billion at the EHV voltage level and by around £0.5 billion at the LV and HV voltage levels under all connection boundary policy options relative to the network costs observed in Figure 4.1. This suggests that the emergence of flexibility services could help to mitigate some of the impact of a shallower connection boundary if changes to connection policy do stimulate the emergence of flexibility markets.

Figure 4.2: PV of distribution network costs for different DUoS and connection options, under the CT scenario, with increased costs of flexibility



Impacts under alternative background scenarios

We have also assessed the impacts of the different connection boundary options under SP and LW as alternative backgrounds to the central CT scenario. Different demand and generation backgrounds drive differences in absolute costs. Figure 4.3 and Figure 4.4 show these impacts.

Despite differences in these generation and demand backgrounds, the trends observed regarding the cost impacts of options are broadly aligned with those observed for the CT scenario. Overall cost impacts are slightly lower (15% - 30% depending on the option and voltage level) under the SP background, in part due to scaling with overall investment requirements. Cost impacts are generally a little higher under the LW background with the impact of the move to a shallow connection boundary increasing to around £1.7 billion and around £1.2 billion under the counterfactual and the ULR DUoS background respectively.

This suggests that the direction and approximate magnitude of changes to the connection boundary on costs are likely to be similar, independent of how the system develops out to 2040.

Figure 4.3: PV of distribution network costs for different DUoS and connection options, under the SP scenario

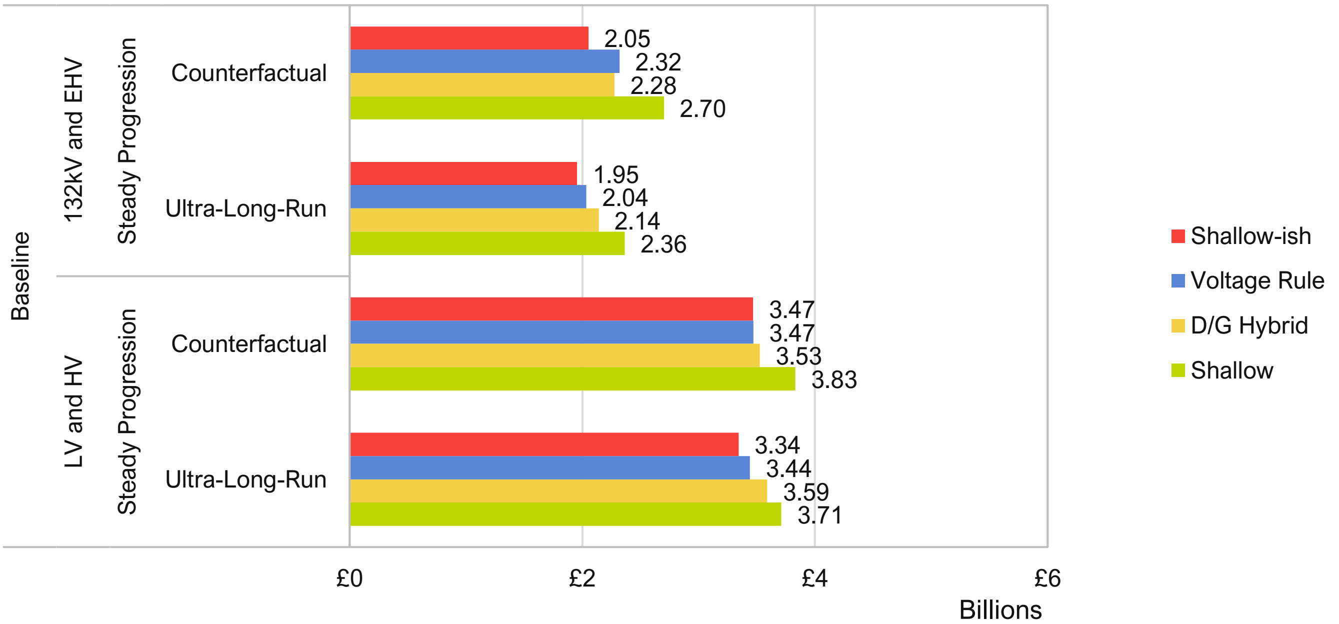
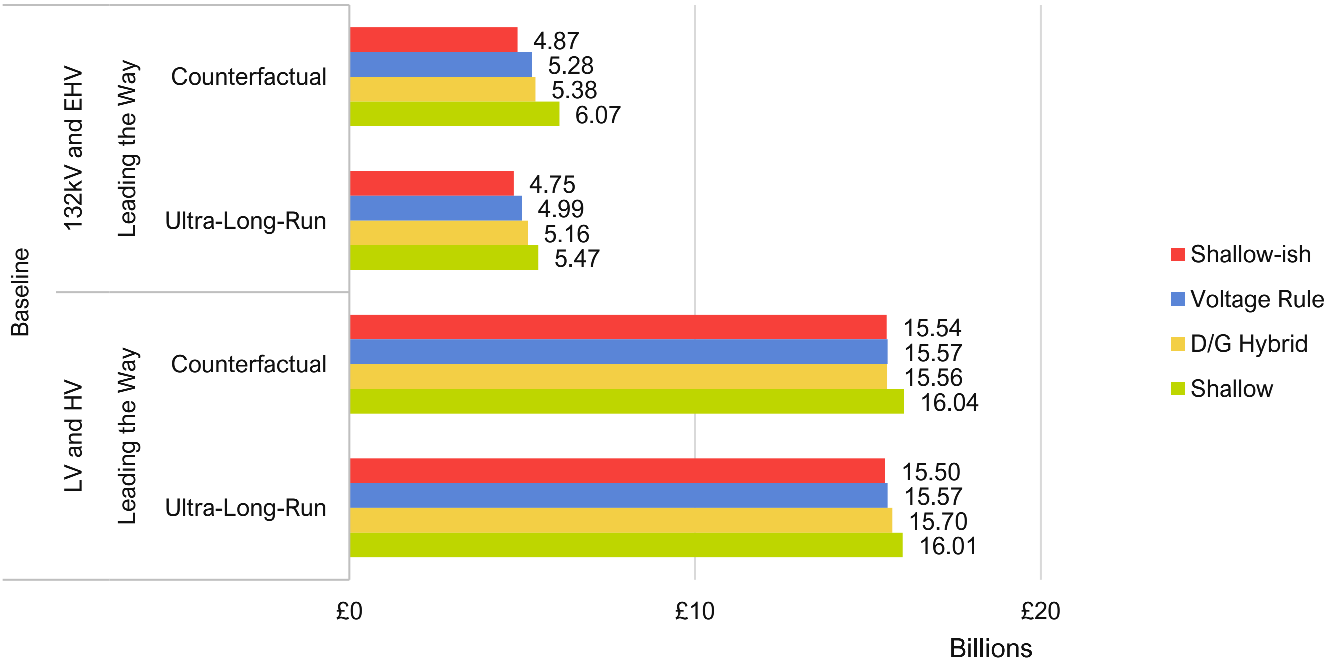


Figure 4.4: PV of distribution network costs for different DUoS and connection options, under the LW scenario



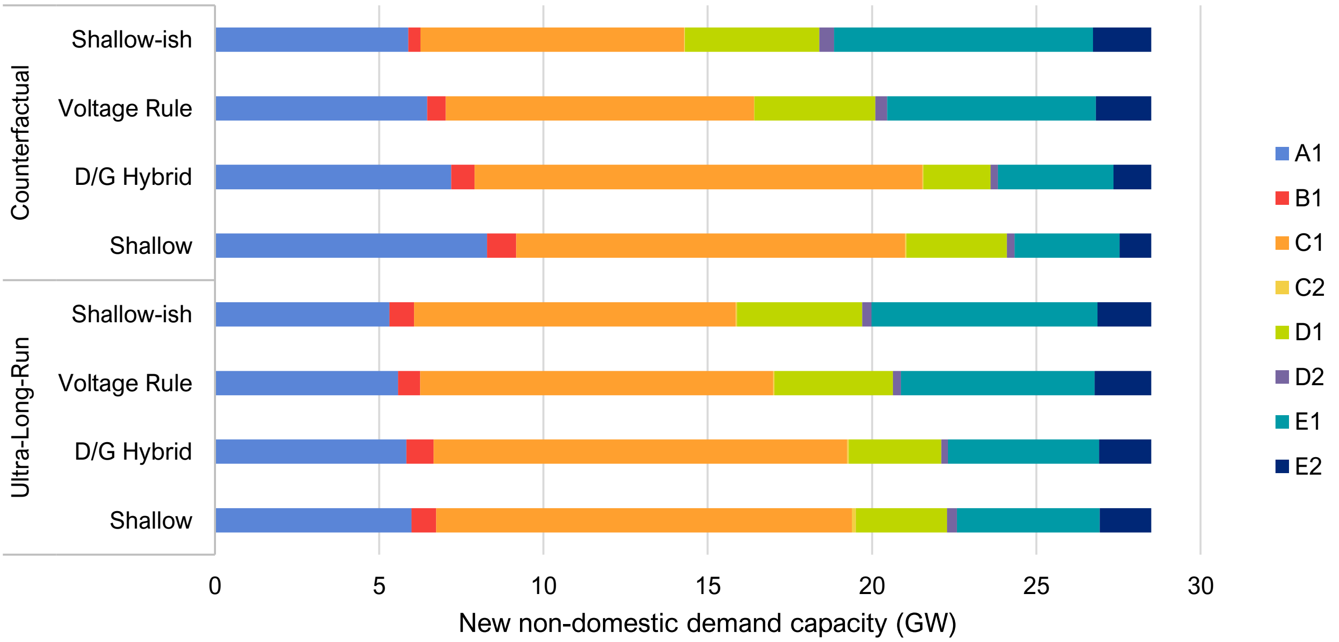
4.3. Impacts on connection decisions

The options will affect the decisions that users make about where to locate new capacity. Figure 4.5 provides an example for large non-domestic customer connectees. The figure shows the impacts of the reforms on the extent to which new, large demand customers choose to locate in rural vs urban parts of the network. A1 represents the most urban locations on the network through to E2 which represents the most rural. The results shown are for the CT scenario, under the baseline assumption regarding costs of flexibility.

The removal of the strong locational signal sent by a deeper connection charge leads to an increase in the amount of demand being deployed in more dense urban networks, with less being deployed in more suburban or rural networks. As these networks are likely to be demand-constrained, this helps to explain the increase in network costs discussed above.

These results also suggest that changing the connection boundary has a more significant impact on locational decisions in the presence of the counterfactual DUoS background compared to when the notional ULR DUoS background is used. Introducing more cost-reflective DUoS charges means that the relative impact of making the connection charges shallower is reduced, since there are still charges which help to replace locational signals to some extent. The dampening of the effect also aligns with the observed system cost impacts discussed above.

Figure 4.5: Capacity of new large non-domestic demand capacity for different DUoS and connection options, under the CT scenario, by network urban/rural character[16]



4.4. Non-modelled impacts

Our modelling has focused on the quantifiable impacts of the connection boundary options on distribution network costs. In alignment with economic theory, our modelling suggests that reducing the depth of the connection boundary will increase the modelled cost of reinforcing and managing the distribution network. If taken in isolation, these options would result in a disbenefit for customers.

However, Ofgem's expected benefits of reform are broader than the direct network cost impacts that we have quantified here. Ofgem anticipate several potential benefits of reform to the connection boundary including enhancing the ease of connections and pace of connections for many customers, particularly, new, low-carbon connectees. The current connection charging regime could therefore represent a barrier to the deployment of low-carbon technologies, such that reforming the boundary would remove (or reduce) this barrier leading to faster uptake and supporting the transition to net zero.

Ofgem's policy analysis also considers the extent to which reform to the connection boundary may stimulate flexibility markets by enhancing the incentives on DNOs to seek alternatives to reinforcement of the network. Our sensitivity considered the impacts of the costs of flexibility and demonstrated that a stimulated flexibility market would indeed alleviate some of the additional network costs identified from reform.

To that extent, our analysis only presents one side of the impacts of reform and is intended to inform Ofgem's principles-based decision on whether wider, non-quantifiable benefits are likely to outweigh the more direct network cost impacts.

[16] We have labelled each primary according to the 2011 Rural Urban Classification, with A1 being the most urban, and E1 and E2 being the most rural. Scotland used a different classification and labelling system, and we have made an assumption to map these over to the RUC2011 labels.

5. IMPACTS OF APPLYING TRANSMISSION NETWORK USE OF SYSTEM CHARGES TO EMBEDDED GENERATORS

In this section, we present the modelled impacts of Ofgem's proposed TNUoS reforms. We consider impacts on consumers and on market participants. The majority of our analysis focuses on the impacts modelled under the central CT scenario.

Many of the trends observed under the SP and LW backgrounds are consistent with that observed for CT. However, the relative magnitude of observed trends differs between scenarios. We summarise the impacts on overall consumer welfare under the SP and LW backgrounds in Section 5.5. We include charts showing outcomes under the SP and LW backgrounds in full in Appendix A.

5.1. APPLICATION OF TARIFFS

Before presenting the impacts of the TNUoS reforms, we summarise the way in which different tariffs are applied to each user type. Within our modelling framework, tariffs can either be applied as volumetric or as capacity-based charges. We assume that volumetric charges are factored into hourly dispatch and consumption decisions. We assume that capacity-based charges are not factored into dispatch decisions but do provide investment signals about where on the system users choose to locate.

For the counterfactual, we follow the methodology set out by the ESO to define the charges levied on different user types.[17] We summarise this application below:

- **Producers who pay Generator TNUoS[18]** face charges which depend on their technology classification (Intermittent, Conventional Low Carbon or Conventional Carbon). See Figure 5.1 for a summary of the application of charges to these different types of producers. The figure shows that some charges are partly determined by the annual load factor (ALF) of the producer. In theory at least, this may introduce some form of dispatch signal as a reduction in annual dispatch would lead to a lower charge. However, in practice, the highest and lowest annual load factors from the previous five years are discounted such that the ALF is determined based on the load factor in the central three of the previous five years. The dispatch signal is therefore dampened and unlikely to impact significantly on producer behaviour. We therefore model all elements of Generator TNUoS as a capacity-based charge.

- **Half-hourly settled demand customers[19]** face locational Demand TNUoS with charges according to their average demand over the three Triad periods with the highest net system demand in each year. In Scotland and the north of England and Wales, Demand TNUoS is negative[20] which introduces an incentive to increase demand during these periods. We model this signal directly – i.e., there is an incentive for consumers to avoid/increase demand during Triad periods where they are able to do so.

[17] For an accessible overview of the application of TNUoS charges, see the ESO's 'TNUoS in 10 Minutes': https://www.nationalgrideso.com/document/130271/download

[18] This includes both generators that are directly connected to the transmission network and large-embedded generators (with capacity greater than or equal to 100 MW and with a BEGA).

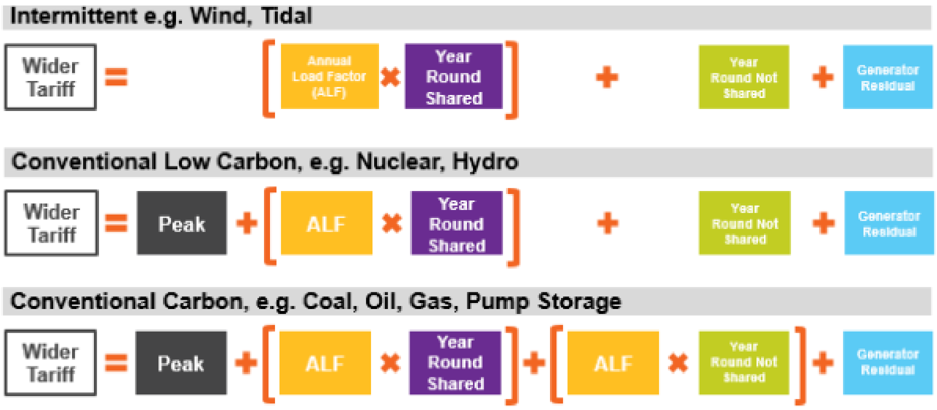
[19] As a result of modifications CMP266 and CMP318, we note that small customers (i.e. domestic and smaller non-domestic customers) that are half-hourly settled would continue to be charged under the non-half hourly settled arrangements described below. This means that the 'half-hourly settled demand customers' category effectively means 'large customers' regardless of settlement status.

[20] We note that Ofgem's Minded-to Decision on the Targeted Charging Review specifies that the locational element of the Demand TNUoS charge would be floored at zero. We understand that this change would apply equally to gross demand (i.e., not affecting changes to the EET) under both the counterfactual and the policy option such that the analysis set out in this report would be largely unaffected.

- **Non-half hourly settled customers** face locational Demand TNUoS based on their annual consumption between 4-7pm as a 'targeted' volumetric tariff within these hours. In Scotland and the north of England and Wales, Demand TNUoS is negative which introduces an incentive to increase demand during these periods. We model this signal directly – i.e., there is an incentive for consumers to avoid/increase demand during the 4-7pm period where they are able to do so.

- **Under the current arrangements, embedded generators with capacity of less than 100 MW[21] receive the EET credit.** The EET is paid as a credit to embedded generators based on their half hourly metered export during Triad periods. The EET is capped at zero. This means that in Scotland and the north of England where a positive charge would otherwise apply (i.e., not a credit), there is currently no Generator TNUoS charge for embedded generation. Due to uncertainty regarding the exact timing of Triad periods, these charging arrangements introduce incentives to dispatch not only in actual Triad periods, but also in ***expected*** Triad periods. We model Triads probabilistically in order to reflect these dynamics.[22]

Figure 5.1: Application of charges to different classifications of producer



Source: ESO, 'TNUoS in 10 Minutes'

Under Ofgem's proposed reform option, we are modelling two key changes to these arrangements:

- For small-embedded generators (with capacity of 1MW or greater): The charging structure changes. The EET credit is removed and replaced with Generator TNUoS (assumed to be a capacity-based charge). This means that charges are no longer floored at zero such that embedded generators would face a charge where Generator TNUoS is positive.

- For micro-generators (with capacity less than 1MW): The charging structure will remain the same but the floor of zero on the EET is removed. In zones where the charge is currently set to zero, micro-generators will face a positive charge (rather than receiving a negative charge, i.e., credit) for export during Triad periods.

Summary of changes to TNUoS charges for embedded generators

We present the changes to the tariff structures modelled by the ESO in Table 5.1 to Table 5.3. Table 5.1 shows the removal of the floor on the EET that is applied to micro-generators (<1MW). These generators receive the EET credit for export during Triad periods. Hence, the removal of the floor has the impact of introducing a charge on export during Triad periods in Scotland and the north of England and Wales. Note that, by 2040, the modelled EET charge (zones 1 and 2) reaches over £80/kW in north Scotland (zone 1) and over £50/kW in south Scotland (zone 2).

[21] This includes both small-embedded generators (with capacity of 1MW or greater) as well as micro-generators (with capacity less than 1MW).

[22] See our accompanying Methodology Note for more detail on our approach for modelling Triads.

Table 5.1: EET charge applied to micro-generators (<1MW) in 2024 and 2040 (NB: negative = a credit for dispatch during Triad periods)

	2024		2040	
Distribution zone	**Embedded export charge (£/kW, Counterfactual)**	**Embedded export charge (£/kW, TNUoS reform option)**	**Embedded export charge (£/kW, Counterfactual)**	**Embedded export charge (£/kW, TNUoS reform option)**
1	0.00	36.48	0.00	80.61
2	0.00	22.20	0.00	52.93
3	0.00	7.96	0.00	15.97
4	0.00	0.58	0.00	3.76
5	0.00	0.10	-1.48	-1.48
6	-2.24	-2.24	0.00	0.12
7	-4.78	-4.78	-9.48	-9.48
8	-6.56	-6.56	-9.23	-9.23
9	-6.87	-6.87	-12.97	-12.97
10	-7.75	-7.75	-11.30	-11.30
11	-9.41	-9.41	-18.89	-18.89
12	-13.62	-13.62	-22.22	-22.22
13	-11.54	-11.54	-18.22	-18.22
14	-8.94	-8.94	-12.61	-12.61

Ofgem's proposed TNUoS reforms introduce a more fundamental change for the TNUoS charge applied to small-embedded generation (>1MW).[23] Rather than the existing EET credit, these generators will instead face an annual capacity charge, the exact definition of which depends on the specific type of generation (see Figure 5.1). Table 5.2 and Table 5.3 show the changes to the charges for these generators modelled by the ESO for 2024 and 2040, respectively.

These reforms have several impacts. First, by removing the EET credit for these generators, the reforms remove the operational incentive on embedded generators in the southern zones to export over expected Triad periods. Secondly, the introduction of a capacity charge effectively removes the zero charge (through the floor on the EET) that existed for embedded generation in Scotland and northern England and Wales. The modelled charges introduce a significant capacity charge for embedded generators in Scotland in particular. Finally, for generators in most zones south of Scotland, a capacity-based credit replaces the previous EET credit. The combination of these changes removes the dispatch signals which previously existed during Triads while introducing new, stronger incentives for embedded generation to locate in zones in central and southern England and Wales.

It is also important to note the differing impacts on different types of embedded generators. Low-carbon and intermittent generators in Scotland face a sizable capacity charge of up to around £22/kW in 2024 and almost £55/kW in 2040. Conventional generators in Scotland receive small capacity credits which increase in zones further south.

[23] In practice, large-embedded generators with capacity over 100 MW and with a BEGA are not affected.

Table 5.2: Change from EET credit to annual capacity charge for large, embedded generators (>1MW), 2024

Distribution zone	Embedded export charge (£/kW, Counterfactual)	Capacity charge (£/kW, Conventional generators, TNUoS reform)	Capacity charge (£/kW, Low Carbon generators, TNUoS reform)	Capacity charge (£/kW, Intermittent generators, TNUoS reform)
1	0.00	-0.34	20.39	22.37
2	0.00	-1.59	10.03	11.69
3	0.00	-2.06	1.84	2.50
4	0.00	-2.28	-0.28	0.10
5	0.00	-2.49	-2.40	-2.31
6	-2.24	-2.49	-2.40	-2.31
7	-4.78	-6.18	-6.76	-3.29
8	-6.56	-6.18	-6.76	-3.29
9	-6.87	-5.55	-5.88	-2.97
10	-7.75	-6.18	-6.76	-3.29
11	-9.41	-7.02	-7.39	-3.13
12	-13.62	-6.18	-6.76	-3.29
13	-11.54	-7.02	-7.39	-3.13
14	-8.94	-7.02	-7.39	-3.13

Table 5.3: Change from EET credit to annual capacity charge for large, embedded generators (>1MW), 2040

Distribution zone	Embedded export charge (£/kW, Counterfactual)	Capacity charge (£/kW, Conventional generators, TNUoS reform)	Capacity charge (£/kW, Low Carbon generators, TNUoS reform)	Capacity charge (£/kW, Intermittent generators, TNUoS reform)
1	0.00	-3.56	54.02	54.46
2	0.00	-5.72	29.17	29.91
3	0.00	-7.67	-0.24	-0.17
4	0.00	-8.32	-4.55	-4.26
5	0.00	-8.97	-8.86	-8.35
6	-2.24	-8.97	-8.86	-8.35
7	-4.78	-13.55	-18.44	-13.86
8	-6.56	-13.55	-18.44	-13.86
9	-6.87	-13.17	-16.37	-12.04
10	-7.75	-13.55	-18.44	-13.86
11	-9.41	-14.69	-19.48	-13.74
12	-13.62	-13.55	-18.44	-13.86
13	-11.54	-14.69	-19.48	-13.74
14	-8.94	-14.69	-19.48	-13.74

The changes to the charges set out above impact on the revenue which is recovered from embedded generators. There are also consequential changes to Generator TNUoS for all generators through the EU Adjustment factor element of the charge. This results in small changes to the charge faced by transmission-connected generators which apply equally to all generators regardless of location. This results in a decrease in the overall Generator TNUoS of about £0.3/kW in 2024 and an increase of around £1/kW in 2040. These charges do not affect operational or investment behaviour in our modelling.

5.2. Impacts on consumers

In this section, we consider impacts on consumers in three areas:

1. **Direct consumer impacts**: These are impacts that will feed directly into consumer bills. We consider the impact of reforms on the wholesale electricity price and direct changes to tariffs.
2. **System impacts**: These are impacts on efficiency of the system such as network reinforcement costs, constraint management, dispatch and curtailment of renewables and carbon emissions, and revenue that needs to be recovered through policy support.
3. **Bill impacts**: We summarise the impacts of the reforms on consumer bills and consider distributional effects.

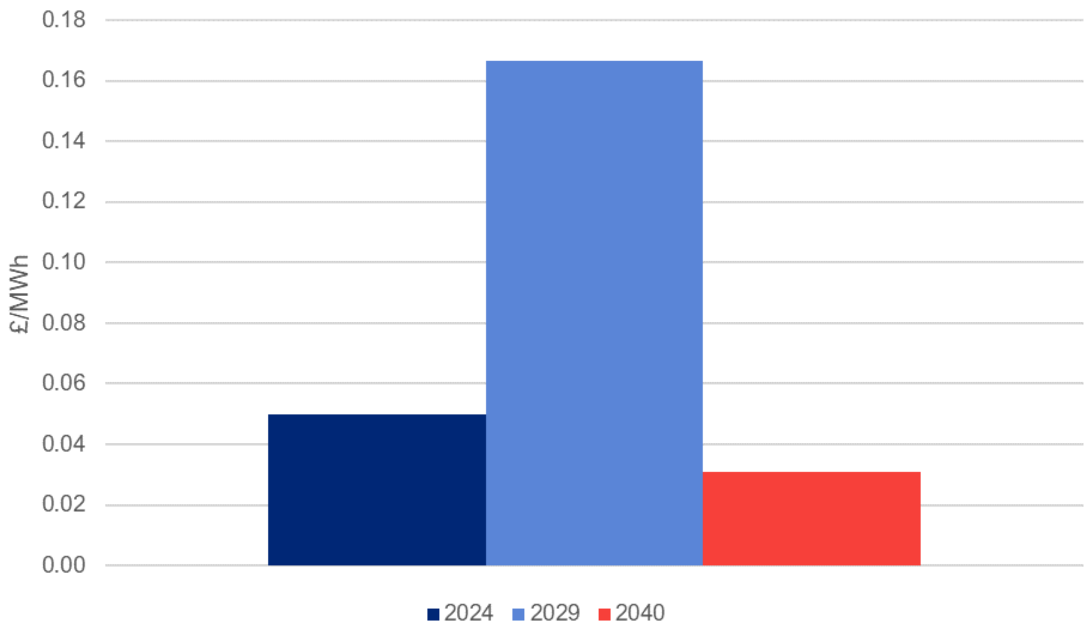
5.2.1. Direct consumer impacts

Wholesale market price impacts

Firstly, we consider the impact of reform on the DAM electricity price (Figure 5.2). We weight the DAM by total electricity demand in a given hour to provide a more appropriate estimate of the impact on electricity consumers.[24]

We find a small but sustained increase in the DAM across all three spot years of our analysis. The most substantial increase in the demand-weighted DAM is observed in 2029. However, even in this year the price increase is under £0.17/MWh, or less than 0.6% of the annual average DAM price in that year.

Figure 5.2: Change in demand-weighted average DAM price under TNUoS reform option



[24] The electricity price will have less of an overall impact on consumers when demand is low. By weighting the price by demand, we account for this.

This average price increase is driven by the change in behaviour of market participants during expected Triad periods. Ofgem's proposed reforms impact on the incentives for small-embedded generation and micro-generators to dispatch during Triad periods in two ways. They remove an incentive to export during expected Triad periods in southern distribution zones for small-embedded generators and introduce a new disincentive to export during expected Triad periods in Scotland and northern distribution zones for micro-generators. In most of England and Wales, these changes increase the price at which small-embedded generators (>1MW) are willing to dispatch during Triad periods. In Scotland and the north of England, the reforms reduce the extent to which demand during Triad periods is netted off by micro-generators.

Figure 5.3 and Figure 5.4 demonstrate the responsiveness of micro-generators in Scotland and the north of England in our model. They show the change in the average net demand in each hour of the day between November and February (the months in which Triads may occur).

Figure 5.3 shows the Scottish and northern zones where the EET floor is removed for small, embedded generators. Net demand generally increases in Triad periods under the reform proposals. The figure also shows the increase in net demand during Triads smoothing over time as uptake of consumer technologies allows customers to shift demand more effectively away from high price periods.

Figure 5.3: Change in demand net of BtM generation (Scotland and the north), November to February

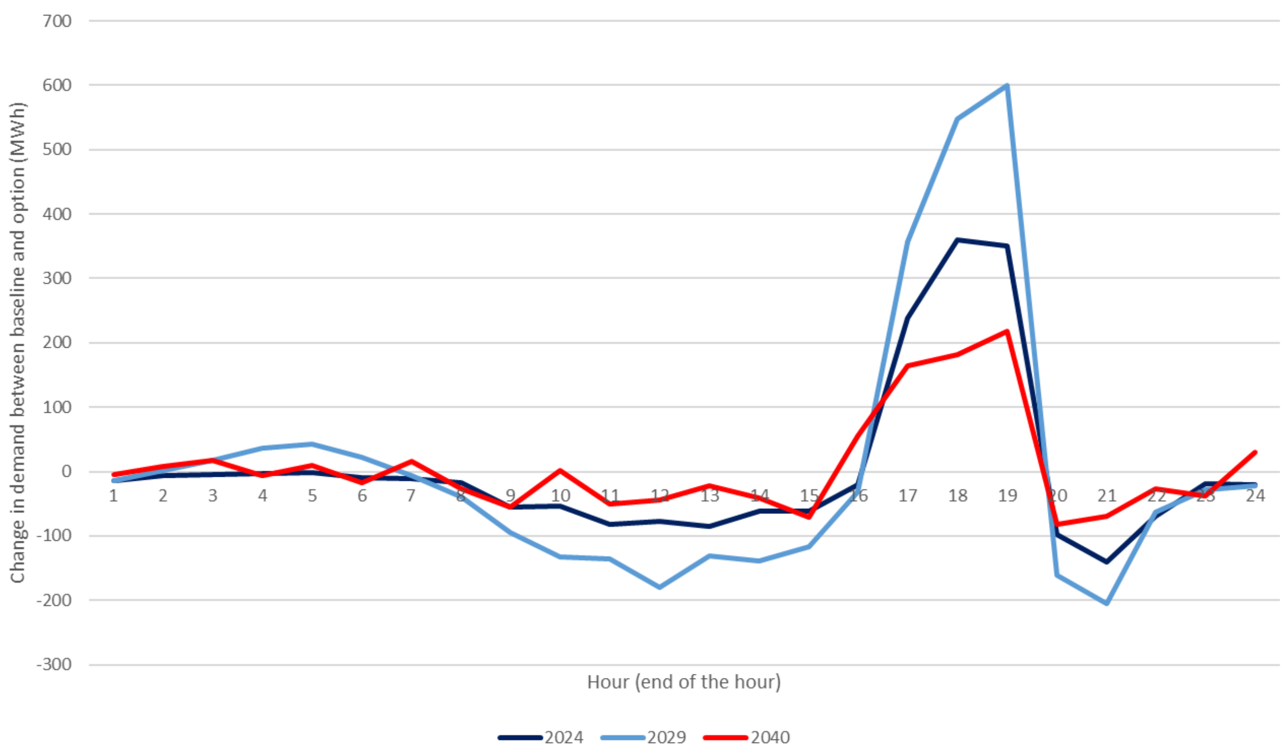
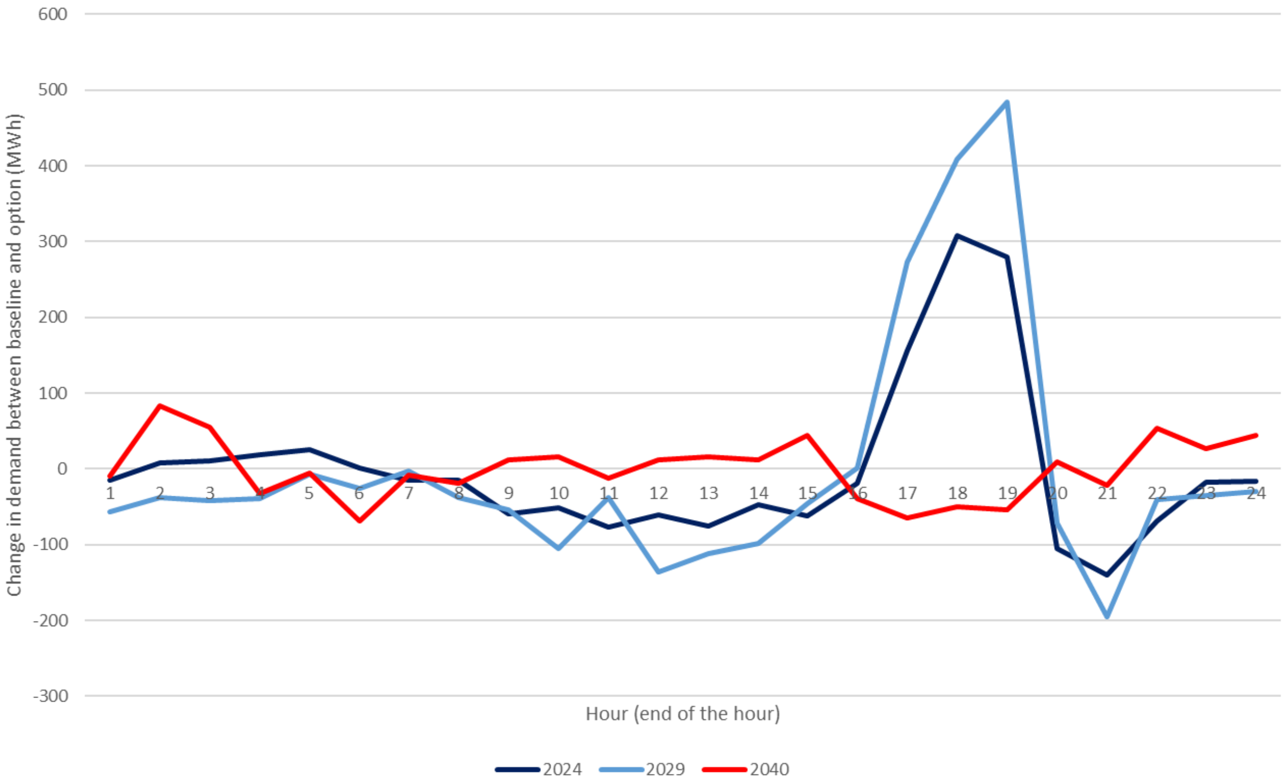


Figure 5.4 generalises this across all net demand on the system. It demonstrates that demand becomes sufficiently responsive such that net demand is actually slightly lower during the Triad periods in 2040 under the TNUoS reform option. This implies that it is the price of dispatch from small-embedded generators in England and Wales that is the primary driver of the average price increase by the end of the appraisal period. It also helps to explain why the price effect observed in Figure 5.2 and Figure 5.5 is less pronounced in 2040 than in 2029.

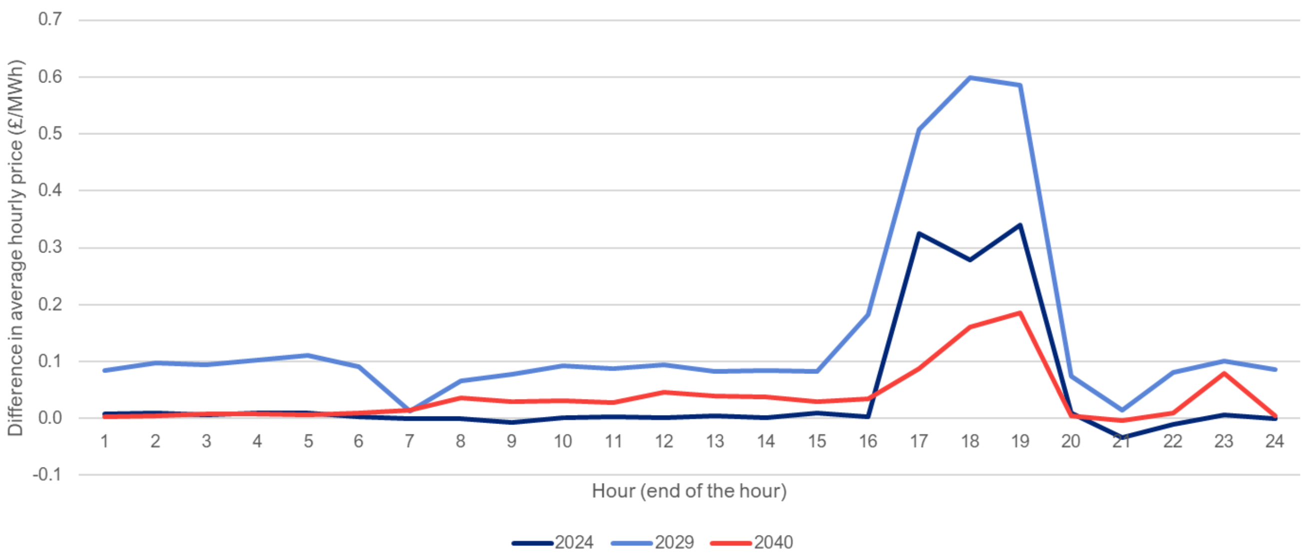
Figure 5.4: Change in demand net of BtM generation (all zones), November to February



As Triad periods generally represent periods of highest system demand, the potential for embedded generators to be the price setting unit of generation is relatively higher than in other periods. Overall, the combination of factors leads to the observed increase in the wholesale price in these periods and, in turn, the small increase in the overall annual average wholesale price shown in Figure 5.2.

We show the average DAM price in each hour of the day in Figure 5.5. This also reflects the dampening of the effect by 2040 when the prevalence of consumer technologies allows large consumers to respond to higher prices by shifting load away from the Triad period as well as small consumers to respond similarly during the 4-7pm period more generally (when they face both DUoS and TNUoS tariffs).

Figure 5.5: Impact of the TNUoS reform option on the annual average DAM price in each hour of the day



To the extent that the EET is not reflective of the capability of embedded generators to reduce system costs, the depression of the DAM during expected Triad periods under the counterfactual could be argued to be a market distortion. The change in the DAM price would be passed through to all producers who are dispatching during these periods. Therefore, the dampening of the price during these periods would reduce the overall market price captured by all producers who are exporting during periods of high system demand.

Demand tariff impacts

Ofgem's tariff reforms do not impact on the tariffs for demand customers directly. Therefore, in the absence of other changes, both the charging structure and the demand profiles would remain the same such that there would be no impact on consumer tariffs.

However, while the charging structures stay the same, demand tariffs are impacted to some degree by the level of revenue recovery from generation tariffs. In addition, demand profiles respond to incentives other than the demand tariff itself. In the previous section, we discussed the increase in the DAM price during expected Triad periods.[25] This represents a marginal increase in the incentive on demand customers to avoid consumption during these periods and we observed that consumer technologies allow consumers to shift some of their load away from these periods by 2040. For those consumers who are sufficiently flexible, the shift away from high DAM prices will also result in a reduction in tariffs in proportion to the load reduction during the Triad periods (and for smaller consumers, the 4-7pm period more generally). Tariff impacts can therefore be considered as a by-product of the change in the market price at peak/Triad periods.

We observe this impact in our modelling. Overall, the marginal increase in avoidance of demand during expected Triad periods (and 4-7pm peak periods more generally for smaller consumers) results in a benefit to consumers of about £93m (NPV, discount to 2023) over the appraisal period (see Figure 5.15). This benefit is dependent on shifting of load, and therefore is focused primarily on customers with technologies that allow them to shift load away from peak periods.

5.2.2. System impacts

Transmission network reinforcement and constraint management

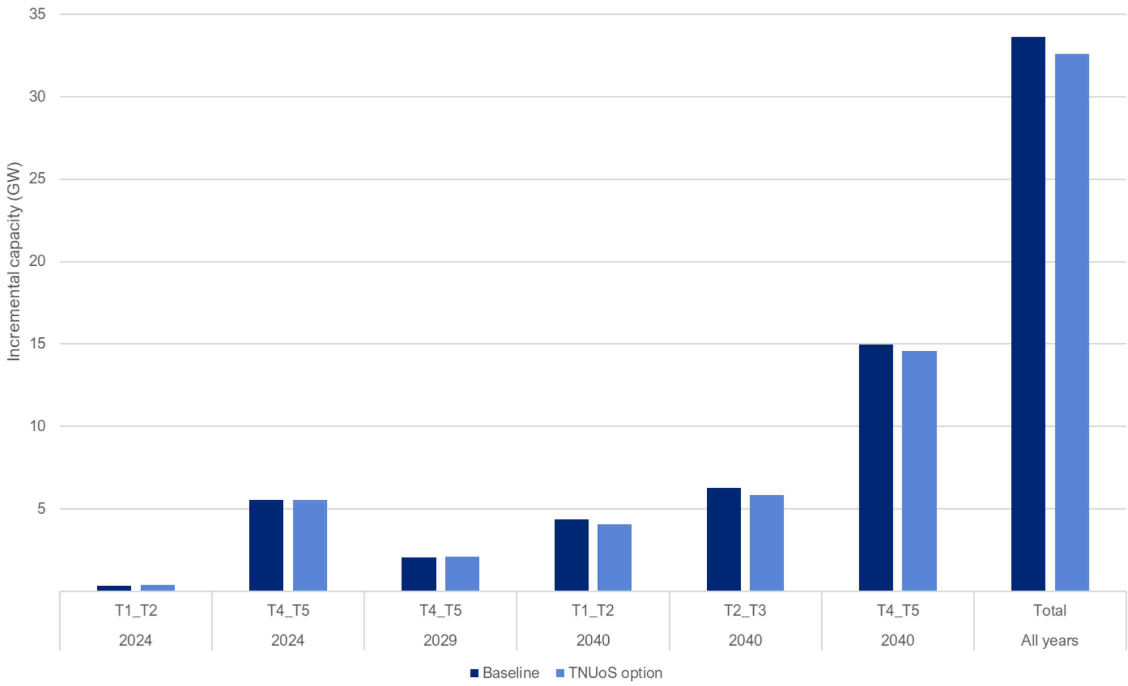
Ofgem's proposed TNUoS reforms may impact on system constraints by changing the investment signals for embedded generators regarding where on the system they locate. The reforms introduce a new capacity charge for small-embedded generators in Scotland in particular (see Table 5.2 and Table 5.3). In doing so, the reforms will reduce the incentive to locate in those regions in favour of investment in generation capacity further south. As electricity demand is weighted towards the south of Great Britain, this could alleviate potential system bottlenecks.

As we show in Figure 5.13, we observe a shift in the location of new generation capacity in our model. Under the TNUoS reform option we observe less investment in embedded generation capacity in Scotland and a corresponding increase in distribution zones further south.

Figure 5.6 demonstrates the impact that this has on the need for transmission capacity investment in the model. While capacity investment requirements across these boundaries are similar in 2024 and 2029, we observe a reduction in the level of transmission capacity required in 2040. This is driven not only by the boundaries in north Scotland (T1_T2) and south Scotland (T2_T3) but also across the boundary between transmission zones T4 and T5. The reduction in capacity across the T4_T5 boundary results from the increase in embedded generation capacity in distribution zones D7 and D8. As these distribution zones are located within T5, the additional capacity reduces the dependence on capacity being transported from T4 and further north by the year 2040.

[25] These periods generally align with the 4-7pm period in which smaller consumers face Demand TNUoS.

Figure 5.6: Transmission network investment by boundary and year under the baseline and the TNUoS reform option



As well as transmission network capacity, the change in the location of additional generation capacity affects the need for constraint management actions to be carried out by the ESO. Further to the reduction in transmission network capacity, we also find a small decrease in the ESO's constraint management costs of around £22m (NPV, discounted to 2023).

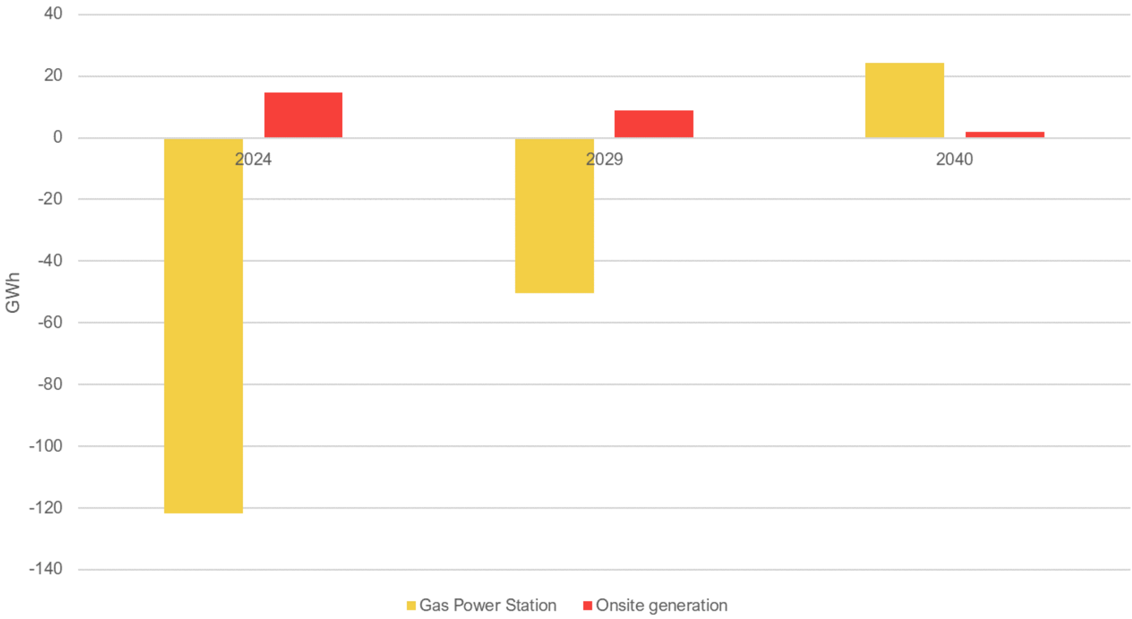
Dispatch of conventional generation and carbon emissions

In the DAM timeframe, conventional generators will respond to the DAM price and use of system charges to bid into the wholesale market. Under the counterfactual, embedded conventional generation receive a marginal incentive to dispatch in expected Triad periods through the EET. When the EET credit is removed and replaced by a capacity-based charge this will reduce the propensity of embedded conventional generation to dispatch in expected Triad periods.

Where re-dispatch is required, this will be delivered by flexible producer capacity. In the early years of the appraisal period, a good proportion of the flexibility will be provided by conventional gas generation and onsite (BtM) generation. In later years, alternative flexible technologies such as hydrogen, batteries and demand side response increasingly contribute flexibility for re-dispatch purposes.

Figure 5.7 shows the combination of these factors on the total dispatch of gas power stations and onsite generation under the TNUoS reform option relative to the baseline. In 2024 and 2029, we observe a reduction in the total dispatch of gas power stations under the TNUoS reform option. In 2040, and to a lesser extent 2029, the need for re-dispatch is also affected by the investment in transmission capacity shown in Figure 5.6. The reduction in transmission capacity under the TNUoS reform option by 2040 leads to a slight increase in the dispatch of gas power station capacity to help balance the system in 2040.

Figure 5.7: Dispatch of carbon emitting generation under the TNUoS reform option relative to the baseline



Overall, the reduction in dispatch of conventional generators leads to a consequential reduction in carbon emissions. In our modelling, we find that the TNUoS reforms leads to an average annual reduction of around 39,000 tCO2e over our modelling period. When the reduction in CO2 over the period is monetised at BEIS's central CO2 price estimate, this leads to a consumer welfare benefit of just over £33m (NPV, discounted to 2023).

Distribution network impacts

The TNUoS reforms impact on the network in two different ways:

1. They lead to a different locational and voltage level allocation of new generation and demand capacity across the country. This may lead to some DNO networks facing more onerous demand for capacity, while others face less onerous demand, compared to the counterfactual.
2. They alter user behaviour in operational timescales, with different response to Triad signals in different zones. Although these signals are intended to reflect the costs of the transmission system, they also have impacts on the distribution network.

It is challenging to isolate these impacts while also producing consistent outputs. However, a rule of thumb arises from the fact that there is more new capacity deployed on the EHV and 132kV voltage levels than on the HV and LV voltage levels. We would expect the HV and LV system costs will be affected to a greater extent by changes in operational behaviour than by changes in locational capacity. EHV and 132kV voltage levels will be affected by both impacts, although the results suggest that the first effect is often stronger than the second.

In Section 5.3.2, we show that the reform leads to an overall shift in embedded generation from Scotland (D1 and D2) to north and central England and Wales. Where reforms lead to a reduction in generation capacity in export-dominated distribution zones and/or an increase in capacity in demand-dominated distribution zones, this will alleviate capacity requirements, leading to a reduction in the requirement for additional distribution network capacity.

For example, the observed shift of onshore wind capacity away from the north of Scotland (D1) alleviates export capacity requirements in that zone. We also observe an increase in embedded solar capacity in the West Midlands (D8) which helps to balance increasing demand from electric vehicles and heat pumps, alleviating pressure on import capacity in that zone.

However, these observed benefits are balanced against additional costs of capacity in much of northern England. These cost increases result from the increase in embedded generation that we observe in those zones as they become increasingly export-dominated as renewable capacity grows out to 2040.

In addition to the change in the geographic allocation of embedded capacity, we also observe impacts on investment in the distribution network due to changes in user behaviour in operational timescales. In Section 5.2.1, we showed the increase in net demand in Scotland and northern distribution zones during Triad periods (as well as 4-7pm peak periods more generally) under Ofgem's reforms (see Figure 5.3).

In our modelling, we find that this additional demand during peak demand periods drives a small increase in investment requirements at HV and LV levels. This leads to increases in HV and LV network costs in Scotland, northern England and north Wales (D1-5) while HV and LV investment requirements fall in most other distribution zones.

In general, under the CT scenario, we find that impacts of the reforms are more significant at HV and LV level. However, our modelling of the HV and LV networks is more dependent on assumptions about the nature of spare capacity on these voltage levels, and therefore we consider that these results should be subject to a broader range of uncertainty than the impacts associated with the EHV and 132kV voltage levels.

In the chart below, we present the impacts of the reforms on requirements for investment in distribution network capacity. As we identify the changes to the incentives for micro-generators in Scotland and northern England as a key driver of the need for investment, we split the impacts depending on whether the ESO's modelling suggests that the distribution zone receives an EET charge in *either* 2024 or in 2040[26] under the TNUoS reform option.[27] The six northern-most distribution zones in our modelling meet this condition (D1 to D6).

While this presentation masks some of the detail in respect of impacts on investment in individual distribution zones, it demonstrates a general trend for an increase in investment requirements in zones where the new arrangements introduce a new charge on export of small-distributed generators during Triad periods.

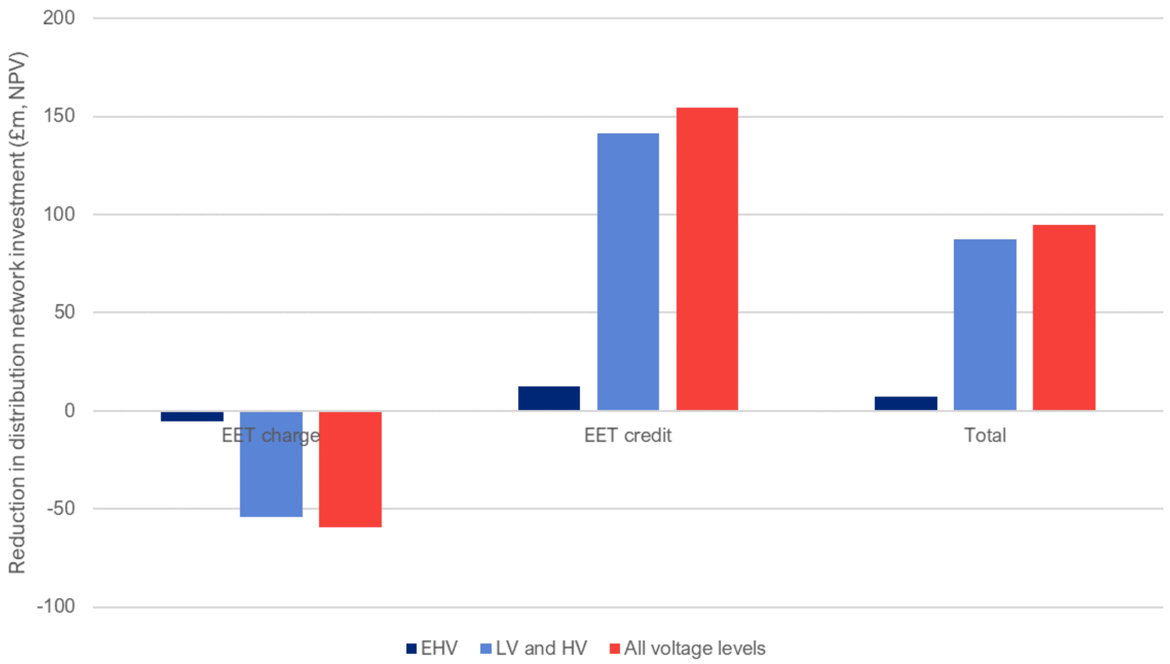
We find a reduction in the need for distribution network investment in southern zones in which an EET credit currently exists. This suggests that the combination of the shift of embedded generation capacity with a reduction in the incentive for embedded generation to export during expected Triad periods reduces the need for investment in distribution network capacity in these zones.

Overall, our modelling estimates a benefit to consumers of around £95m from a reduction in distribution network capacity over the period.

[26] The ESO's model linearly interpolates between 2024 and 2040 such that 2029 would not introduce any additional zones where embedded generators face a charge rather than credit.

[27] The ESO modelled tariffs in these two spot years only, interpolating linearly between 2024 and 2040 to generate tariffs in our additional spot year (2029).

Figure 5.8: Reduction in investment in distribution network capacity (positive = consumer benefit, i.e., a reduction in distribution network investment costs) (£m, NPV, discounted to 2023)



5.2.3. Modelled tariff over/under recovery

Network charges exist to allow network companies to recover the costs of building and maintaining the electricity network. Charges are set to recover this revenue as accurately as possible. In practice, relatively small annual over- or under-recovery of revenue exists. Annual under- or over-recovery is passed back to consumers through the Demand TNUoS residual.

However, the interaction between our model and the model used by the ESO to estimate TNUoS charges can lead to a more notable and asymmetric difference between revenues recovered by the ESO in the modelling and revenues which are intended to be recovered through the ESO's tariff forecasts. To feed into our modelling, the ESO modelled TNUoS charges that would be applied on consumers and producers with the overall objective of recovering network revenues over the period. The ESO modelled these tariffs both under the counterfactual and under the proposed TNUoS reform option. While modelling of charges in the near future could be achieved based on forecasts of tariffs which exist out to 2024/25 and are generally in line with the FES 2019.

However, to model charges out to 2040, the ESO needed to develop forecasts based on a forward-looking scenario. They used the FES 2019, Two Degrees scenario as a background for modelling of future TNUoS charges.

Actual recovery of revenue is affected both by the charges that are set for market participants and by the behaviours of participants regarding investment and operational choices. For example, under the counterfactual, transmission-connected generators and embedded generators face different charging structures. Revenue recovery will therefore be affected by the amount of capacity that decides to connect at each voltage level, and by the operational choices of embedded generators regarding timing of dispatch.

In practice, applied charges would adapt to changing context. Within a band of forecasting uncertainty, the annual charges would adjust to the total level of capacity and the breakdown of capacity at different voltage levels, as well as signals about how different types of capacity contribute to revenue through the charges.

However, given the need for interaction between separate models, this feedback loop does not exist within our modelling framework. That is, our model takes a single set of forecasted charges out to 2040, one for the counterfactual and one for the charging option. This introduces the potential for the forecast of charges to diverge from the producer and consumer capacity background such that revenue recovery requirements and modelled revenue recovery diverge.

Our modelling framework allows us to estimate the difference in revenue recovery between the counterfactual and the policy option, and hence the net amount of revenue that would be passed back through charges. The 2019 Two Degrees scenario is a relatively centralised scenario, driven predominantly by transmission-connected offshore wind. In comparison to the CT scenario, it therefore has a greater proportion of capacity located at transmission level and this leads to divergence of revenue recovery due to the different charging structures for embedded generation within the counterfactual and the TNUoS policy option. Overall, we identify an increase in total revenue recovery of £700m (NPV, discounted to 2023) under the option relative to the counterfactual. As we explain in Section 5.5, the more centralised SP and LW scenarios result in lower levels of tariff over-recovery.

We assume that revenue under and over-recovery would ultimately be passed back through to consumers, either through the direct impact on Demand TNUoS or indirectly through DAM prices or through support scheme costs.

Note that we would not expect the differences in revenue recovery that we observe in the model to exist in practice. In reality, the ESO would adjust its TNUoS forecasts in response to connection and dispatch trends such that revenue recovery would align with requirements under both the counterfactual and the policy option.

5.3. Impacts on market participants

In this section, we consider the impacts of the proposed reforms on market participants. We summarise the impacts on revenues of different types of producers before discussing the effects that this has on investment decisions, potential implications for net-zero and consequential impacts on support scheme costs.

5.3.1. Impacts on net revenues

In the analysis above, we summarised the absolute impacts on consumers, resulting from changes to the captured DAM price and changes to the tariffs that they pay. Impacts on producers will differ depending on several characteristics:

- **Technology type**: Flexible technologies are better able to respond to wholesale market and tariff signals. The revenue impacts on these types of producers will be affected by the opportunities that they have to respond to changes in wholesale prices and tariffs at different times of the day. These technologies can respond to signals both under the counterfactual and under the TNUoS reform option such that the overall revenue impact will depend on the relative opportunities within each. In Table 5.2 and Table 5.3 we showed the differences in application of Generator TNUoS depending on technology classification. This also has important implications for the revenue impacts on the reforms on different producer types.
- **Voltage of connection**: Proposed TNUoS reforms impact on the tariff treatment for small-embedded producers that will now pay Generator TNUoS rather than the previous EET arrangements. While there are small consequential changes for transmission-connected producers, these would apply equally to all producers and therefore not affect dispatch or investment decisions significantly.
- **Geographic location**: For embedded generators, the reforms will have quite different impacts depending on geographic location on the system. Embedded generation in Scotland and the north of England previously paid no TNUoS but will now face a Generator TNUoS charge. All small-embedded generators will be charged or receive credits which we assume to be completely capacity-based. Furthermore, previous operational incentives to generate in expected Triad periods will no longer exist.

In Figure 5.9 and Figure 5.10,[28] we summarise the impact on net revenues of transmission-connected producers. Figure 5.9 shows the total net revenue impact on each type of producer over the period of analysis while Figure 5.10 shows the total net revenue impacts over the appraisal period per unit of capacity (in £m/kW). These 'heat maps' demonstrate how different producers are impacted by reforms within our modelling.

[28] See Figure 3.3 for the definition of transmission zones.

Figure 5.9: Total impact on net revenues of transmission-connected producers over modelled period 2024 - 2040 (£m, NPV, discounted to 2023)

	T1	T2	T3	T4	T5	T6	T7	TOTAL
Offshore_wind	16.73	11.14	17.72	18.41	6.62	20.51	1.82	**92.94**
CCGT_existing	1.45	0.07	0.08	-1.60	11.83	-0.99	2.43	**13.27**
CCGT_new	-	-	-	4.41	-0.20	-	0.07	**4.28**
OCGT_existing	-0.02	-	-	0.08	0.17	-	0.14	**0.37**
OCGT_new	-	-	-	0.11	0.27	-0.09	0.02	**0.31**
H2_CCGT	-	-1.80	-5.39	-1.79	-1.81	-	-	**-10.80**
Onshore_wind	12.69	16.24	-	0.71	-0.01	-	-	**29.64**
Solar	-0.32	-0.22	-	0.01	-1.48	-0.18	0.28	**-1.90**
Nuclear	-	9.32	6.58	-2.59	-1.13	5.55	-0.54	**17.18**
Biomass	-1.52	0.43	-3.84	12.14	1.04	0.13	-	**8.38**
Hydro	-0.59	-0.14	-	-0.00	-6.79	-	-0.01	**-7.53**
Pumped_storage	-7.82	-2.73	-	-7.42	-	-	-	**-17.98**
Battery	-0.42	-0.83	-0.86	-0.62	-5.15	-0.63	-5.27	**-13.78**
TOTAL	**20.19**	**31.48**	**14.28**	**21.85**	**3.36**	**24.29**	**-1.07**	**114.38**

Figure 5.10: Impacts on net revenues of transmission-connected producers over modelled period 2024 - 2040 (£/kW, NPV, discounted to 2023)

	T1	T2	T3	T4	T5	T6	T7
Offshore_wind	5.74	6.73	8.14	5.54	2.77	8.24	2.47
CCGT_existing	2.17	1.20	1.20	-1.49	-0.65	-2.56	1.04
CCGT_new	-	-	-	2.97	-0.77	-	2.84
OCGT_existing	-3.13	-	-	0.51	1.08	-	0.51
OCGT_new	-	-	-	0.75	-0.54	-2.98	0.60
H2_CCGT	-	-5.82	-5.82	-5.82	-5.88	-	-
Onshore_wind	4.18	4.31	-	17.75	2.05	-	-
Solar	-2.66	-2.13	-	0.31	1.16	-1.93	0.83
Nuclear	-	10.41	5.20	-5.72	2.88	4.51	-2.74
Biomass	-0.51	3.85	1.09	4.56	4.12	4.12	-
Hydro	0.00	-1.29	-	0.23	-3.90	-	-6.69
Pumped_storage	-5.19	-4.63	-	-3.70	-	-	-
Battery	-3.94	-4.07	-1.50	-2.24	-1.63	-3.68	-3.61

Impacts on transmission-connected producers are relatively small as they do not face any direct changes to their charging structures. We find small positive net revenue benefits of around £114m for transmission-connected producers as a whole over the full period of analysis. We attribute these revenue increases to a combination of factors, including the direct changes to Generator TNUoS, captured wholesale prices during Triad periods, and merit-order dispatch and re-dispatch effects.

Transmission-connected batteries face small negative revenue impacts across all zones. This marginal change results from two indirect impacts of reform. Firstly, the tariff reforms result in indirect consequential changes to the EU Adjustment Factor within Generator TNUoS charges which increases these charges slightly, particularly in later years. Secondly, utilisation of batteries is slightly lower following reform such that market revenues are slightly lower under the reform option.

Figure 5.11 and Figure 5.12 present the same information for distribution-connected producers.[29]

[29] See Figure 3.2 for the definition of distribution zones.

Figure 5.11: Total impact on net revenues of distribution-connected producers over modelled period 2024 - 2040 (£m, NPV, discounted to 2023)

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14	TOTAL
CCGT_existing	0.86	2.05	3.32	5.39	7.09	8.91	15.79	-	2.74	6.77	-0.39	-	-2.05	0.88	**51.37**
CCGT_new	-	-	0.16	0.07	19.34	1.66	1.56	1.74	-	-	-0.04	-0.47	-	0.17	**24.18**
OCGT_existing	0.29	-	0.82	1.40	-	1.00	0.79	0.61	-0.13	-	0.10	-	1.73	3.20	**9.81**
OCGT_new	-	-	2.18	0.92	1.39	0.01	6.30	0.43	0.91	1.73	-0.12	-2.30	-0.37	1.02	**12.11**
GT	2.03	0.39	1.52	22.02	29.43	15.69	41.02	15.06	7.18	22.42	1.63	-0.63	7.58	4.96	**170.30**
H2_CCGT	-0.25	-0.24	0.04	0.86	1.93	1.39	2.43	1.12	0.77	1.47	0.26	0.03	0.64	0.45	**10.90**
Onshore_wind	-976.51	-881.88	69.47	75.79	150.77	42.58	174.08	5.76	-4.86	6.70	-7.40	-0.44	4.19	-4.42	**-1,346.16**
Solar	-63.89	-49.01	-3.60	-73.70	62.93	31.36	203.06	118.38	178.32	76.77	72.62	9.85	223.32	186.29	**972.71**
Biomass	-38.03	-39.50	-22.38	14.74	70.92	23.15	37.00	73.94	33.13	15.65	14.91	-2.80	9.77	17.08	**207.60**
Hydro	-489.19	-46.83	-0.22	0.59	0.56	5.89	0.54	22.00	0.19	57.80	0.11	0.07	0.42	1.80	**-446.26**
Battery	0.29	-0.23	0.05	0.08	0.10	0.39	0.09	0.12	-0.11	-0.02	-0.48	-0.06	-0.16	0.14	**0.19**
TOTAL	**-1,564.40**	**-1,015.25**	**51.37**	**48.17**	**344.47**	**132.03**	**482.66**	**239.16**	**218.15**	**189.29**	**81.20**	**3.25**	**245.07**	**211.58**	**-333.25**

Figure 5.12: Impacts on net revenues of distribution-connected producers over modelled period 2024 - 2040 (£/kW, NPV, discounted to 2023)[30]

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
CCGT_existing	15.62	56.76	52.83	68.82	50.08	54.80	71.31	-	26.25	42.10	0.26	-	-8.39	24.78
CCGT_new	-	-	54.26	53.92	50.69	37.70	64.60	60.28	-	-	-2.79	-55.02	-	18.57
OCGT_existing	72.29	-	49.73	50.20	-	41.30	80.60	75.19	-2.12	-	14.79	-	30.84	63.55
OCGT_new	-	-	52.22	51.66	49.18	39.15	64.02	76.43	40.94	53.99	-0.11	-51.61	1.98	36.07
GT	54.46	61.51	55.53	55.80	55.56	50.54	97.58	92.76	41.74	79.19	33.49	-27.22	57.21	85.06
H2_CCGT	-481.5	-248.9	7.98	47.59	81.17	81.49	130.26	128.43	74.64	108.63	63.08	12.07	70.16	126.06
Onshore_wind	-369.0	-226.4	8.36	35.79	60.13	38.31	52.29	47.92	-2.41	6.26	-35.84	-39.58	12.46	-7.22
Solar	-318.9	-162.4	-9.16	6.05	47.77	43.00	71.69	76.22	58.50	71.54	68.94	55.18	70.52	68.68
Biomass	-248.5	-117.8	12.44	46.88	72.55	60.65	82.81	89.54	49.86	66.18	32.48	-14.87	22.91	57.37
Hydro	-492.0	-265.0	-16.59	28.26	69.34	66.32	125.73	129.98	91.70	130.86	98.90	67.42	96.96	116.43
Battery	3,895.1	57.0	33.24	20.81	44.35	11.73	32.39	29.03	-44.04	-32.16	-182.32	-185.61	-73.09	34.71

Many of the impacts on embedded producers are more pronounced and the mechanisms for these impacts more direct. The impacts on renewable producers in Scotland (D1 and D2) that have been discussed previously are clear from Figure 5.12. We observe losses of up to £369/kW (in NPV terms) for onshore wind producers in Scotland over the period to 2040 for example. Embedded hydro producers in Scotland face negative revenue impacts per unit of capacity which are even higher than this.

The capacity of hydrogen generators and direct-connected batteries is relatively small such that small impacts on net revenues (see Figure 5.11) produce more pronounced impacts per unit of capacity.

The negative impacts on Scottish renewable producers are balanced against positive revenue impacts for most other technologies and for all technologies in most zones south of Scotland. The only exception is in D11, D12, and to a small extent D13, where the loss of the previous EET credits outweighs the Generator TNUoS credits for these technologies. Producers around the Midlands and in the South-West benefit the most from increases in revenues. Nevertheless, we observe an overall reduction in the net revenues of embedded generators as a whole of around £333m driven primarily by impacts on Scottish renewable generators.

5.3.2. Impacts on the choice of location for capacity investment

Our model allows for renewable capacity to choose where to locate in 2029 and 2040. The choice of location is dependent on expected revenues of that capacity in different locations. Where the differences in net revenues between options are large enough, location of investment therefore maps closely to the revenue analysis set out above.

[30] The revenue impact for batteries in D1 is worth further explanation. It is due to impacts on a very small amount of distribution-connected battery capacity in D1 which is located front of the meter within the FES. The total impact on revenues is small (see Figure 5.11). However, this small change in revenues applies over a very small amount of capacity. We consider this specific result to be an outlier which should be ignored.

In line with this, we do not observe any significant changes to the location of capacity at transmission-level. The differences in revenues are not large enough to drive such changes.

However, we do observe a change in the choice of location for embedded renewable generators. As the net revenues of these generators are also heavily dependent on resource availability, it often requires a significant change in revenue expectations to drive these choices. Nevertheless, the clearest trend that we observe is for new embedded onshore wind capacity that chooses to locate in Scotland under the counterfactual to instead locate in north and central England under the TNUoS reform option.

We also observe some movement of embedded solar capacity. The shift is away from the north-west and to neighbouring zones where levels of solar radiance are similar.

Figure 5.13: Increase/decrease of investment in technology specific capacity by year and by distribution zone (MW)

2029	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Biomass	-5.0	-2.5	-19.7	0.0	0.0	0.0	0.0	27.2	0.0	0.0	0.0	0.0	0.0	0.0
BTM_Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore_wind	-11.0	-388.1	101.7	85.4	133.6	0.0	74.1	2.2	0.0	0.0	0.0	0.0	2.0	0.0
Solar	0.0	0.0	0.0	-78.0	0.0	0.0	31.7	46.3	0.0	0.0	0.0	0.0	0.0	0.0
2040	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**	**D7**	**D8**	**D9**	**D10**	**D11**	**D12**	**D13**	**D14**
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BTM_Solar	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0
Onshore_wind	-418.1	0.0	0.0	0.0	21.4	0.0	373.1	13.1	0.0	0.0	0.0	0.0	10.5	0.0
Solar	0.0	0.0	0.0	-300.0	203.0	0.0	0.0	97.0	0.0	0.0	0.0	0.0	0.0	0.0

5.3.3. Investment, closure and repowering

In this section, we discuss potential implications for investment, closure and, in the case of onshore wind capacity, repowering. As net revenue impacts for transmission-connected generators are relatively small, we focus on potential investment in distribution-connected onshore wind and solar capacity where impacts are often more pronounced and where the FES includes significant increases in capacity to meet net zero.

In this section, we convert revenue impacts into £/MWh estimates and compare against LCOE estimates. We take these LCOE estimates from BEIS Technology Costs Report 2020 (BEIS 2020),[31] and in some cases supplement this with more detailed analysis included in the 2016 version of the report (BEIS 2016).[32]

In order to translate our estimated impacts per unit of capacity (as shown in the previous section) into estimated levelised revenue impacts (/MWh), we apply the capacity factors for embedded wind and solar generation that we extract by zone. Our estimates of the levelised revenue impacts for these technologies is shown in Figure 5.14.

Figure 5.14: Levelised revenue impacts for embedded onshore wind and solar technologies over modelled period 2023 - 2040 (£/MWh)

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Onshore_wind	-9.57	-5.06	-0.33	0.35	0.83	1.13	0.50	0.59	-0.22	0.12	-1.10	-1.34	-0.71	-0.20
Solar	-28.70	-13.50	-0.14	2.42	3.79	3.59	5.92	5.83	4.63	6.13	5.40	3.93	5.77	5.55

Distribution-connected onshore wind

BEIS 2020 includes a single estimate for the LCOE of onshore wind producers of £46/MWh based on a representative 51MW plant commissioning in 2025. The BEIS 2020 update represented a change from £60/MWh estimated for the same technology type in BEIS 2016 which BEIS assumed to represent an updated learning rate.

While BEIS 2020 only includes updated LCOE estimates for onshore wind with capacity above 51MW, BEIS 2016 included other plant sizes. For a plant of capacity with capacity between 100 – 1,500kW, BEIS 2016 estimated LCOE at £120/MWh for plant commissioning in 2025. If we apply the same rate of learning as BEIS included for the larger plant size, this leads to an estimate of £92/MWh for plant with capacity between 100-1,500kW.

[31] See: https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

[32] See: https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

The largest negative impact that we observe for onshore wind capacity is in north Scotland where we estimate a levelised revenue impact of approximately £9.57/MWh. This represents just over 20% of the LCOE estimates for larger onshore wind plant with capacity of greater than 51MW. It represents just over 10% of the LCOE of smaller onshore wind plant with capacity between 100 – 1,500kW. The impacts on capacity in south Scotland would be around 11% and 5.5% of LCOE for the larger and smaller representative capacities.

We expect that impacts of this order of magnitude could be important in relation to investment decisions for an individual plant. In the previous section, we discussed the potential for capacity to choose to locate in other parts of the country or for investment to shift between technologies. Nevertheless, when considered in isolation, the impacts on investment in onshore wind capacity in Scotland are important to consider.

The impacts on net revenue as a proportion of LCOE will change depending on the plant size as well as other factors. We also note that plant with capacity greater than or equal to 100MW and with a BEGA would have already been paying Generator TNUoS and so would not face any changes to charging structures.

To consider the potential impacts on likelihood of closure of existing onshore wind, we compare the revenue impacts against strike prices from the first CfD round.[33] The lowest strike price for any onshore wind project in this round was just under £80/MWh such that the revenue impacts observed above would represent up to 12% and 6.3% of these CfD strike prices in D1 and D2, respectively.

Given this, for onshore wind capacity with a CfD contract, we consider it unlikely that the impacts on revenues observed would lead to negative marginal revenues and hence to exit from the market other than in marginal cases. Nevertheless, it is important to note that the impacts on recovered revenues for existing onshore wind capacity in Scotland will be significant as demonstrated in Figure 5.12.

We would expect the costs of relocation of existing capacity on the system to be relatively large. For example, to relocate, capacity would have to identify an appropriate site, get planning permission and connection agreements, etc. While we do not have extensive evidence of the costs of relocating existing capacity relative to new investment, we would expect impacts on decisions of new investors to be a more likely outcome.

Finally, while we do not have direct evidence of the costs of re-powering, Renewable UK suggests that this may allow for somewhere in the region of a 20% saving on LCOE compared to investment in new capacity.[34] In the case of repowering decisions in north Scotland, the net revenue impacts that we observe could represent up to 26% of LCOE for a repowering decision for an embedded onshore wind generator such that this could lead to a decision not to re-power for some projects. The increases in revenues observed in most of England and Wales may make repowering more commercially attractive in those regions.

Distribution-connected solar

We observed impacts on distribution-connected solar generation ranging between a reduction in revenues of up to £28.7/MWh in north Scotland and £13.5/MWh in south Scotland. Drawing again on BEIS 2020 and BEIS 2016, we assume LCOEs of solar capacity that range from £44/MWh for capacity greater than 5MW up to £74/MWh for plant between 250-1,000kW, both based on plant commissioning in 2025.

For both sizes of plant, the reduction in revenues in Scotland would constitute a significant percentage of LCOE estimates. For a hypothetical solar plant with capacity of over 5MW, the loss of revenues could constitute over 60%

[33] The first CfD round was the last round in which onshore wind were eligible to participate. For results, see: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/407465/Breakdown_information_on_CFD_auctions.pdf

[34] See: https://www.renewableuk.com/store/ViewProduct.aspx?id=13831512 (note that a free registration is needed to download the document)

of LCOE estimates. However, we note that only about 3% of embedded solar capacity locates in Scotland under our counterfactual scenario. The capacity deployed in Scotland sits at the lower bound of the capacity allocation limits and so does not decrease any further under the TNUoS reform option. In practice, the impacts on net revenues of embedded solar capacity may be such that we would expect little to no such capacity to choose to locate in Scotland.

On the other hand, embedded solar capacity in other distribution zones face potential revenue increases of up to £6.13/MWh which we estimate to be around 14% and 8.2% of LCOE for large (greater than 5MW) and smaller (between 250-1,000kW) solar plant respectively. Given that well over 90% of the embedded solar capacity deployed in our modelling would benefit from an increase in revenues, we would expect additional investment in this capacity to outweigh the reduction in investment in Scotland.

5.3.4. RES support and implications for net zero

In our modelling framework, we do not make assumptions regarding future policy, including the levels of support that the Government may be willing to provide to meet the renewable capacity projected in each FES scenario. Rather, we measure the change in net revenues for renewable producers and estimate the impacts that this would have on the level of support that would need to be provided. To achieve this, we compare net revenues for each type of renewable producer in each location against the LCOE of that technology.[35] Where captured revenues exceed the LCOE, we assume that the technology does not require a CfD, or that any CfD does not include any built-in subsidy. Where captured revenues are not sufficient to meet the LCOE, we measure the level of support that would be needed to meet the LCOE for the capacity of that technology at a given location.

By developing these estimates under the baseline and the TNUoS reform option, we can measure the impact of the reform on the level of support that needs to be provided to deliver the level of capacity included in each of the FES scenarios.

In Section 5.3.1, we presented the impacts of the TNUoS reform option on producer net revenues. Overall, we observed a general trend for a small increase in revenues for transmission-connected producers, including renewable generators.

However, our modelling shows that the overall net revenue impacts on renewable producers as a whole are negative. In particular, we find that TNUoS reforms may result in a decrease in investment signals for distribution-connected onshore wind capacity in Scotland, while potentially also affecting the investment case for new distribution-connected hydro capacity to some extent.

Based on the net revenue impacts that we observed previously, we estimate a reduction in revenues for RES capacity of £329m overall (NPV, discounted to 2023) from market and tariff modelled outcomes. To reduce the risk that this could undermine investment in RES capacity, this could imply a need to provide a similar level of additional RES subsidy support relative to that required under the modelled counterfactual.

In Table 3.1 we discussed the bounds that are applied to the locational allocation of capacity of different technologies. These bounds cannot fully reflect the complexities of planning, land use, etc. out to 2040. While the additional revenue shortfall for RES capacity of £329m introduced by the reforms allows for an estimate of additional support, constraints regarding investment in renewable capacity in different parts of the country may introduce additional inefficiencies in the response of capacity to incentives such that the need for revenue support may increase, e.g., to overcome these constraints or to re-balance the revenue losses for Scottish renewable generators.

On the other hand, our model does not allow for 're-optimisation' of capacity of different technology types, i.e., it does not allow a reduction in revenues for onshore wind to be reflected in additional investment in solar capacity. Neither does it allow for additional investment in transmission-connected capacity instead of embedded-generation.

[35] We draw on BEIS Electricity Generation Costs (2020) to estimate LCOE of each technology: https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

As capacity re-optimisation is restricted, this may lead to an over-estimation of the revenue shortfall for RES capacity.

Challenges with the planning regime in England and Wales

Onshore wind developers currently face quite different sets of planning restrictions in Scotland compared to those in England and Wales. While planning and consenting in Scotland is not without challenges, the planning regime is generally more favourable for developers than in England and Wales. More broadly, Scotland has repeatedly reaffirmed its commitment to enabling onshore wind, e.g. through the Scottish Government's Onshore Wind Policy Statement.[36]

Wales also has potentially significant levels of onshore wind resource. However, most commentators believe that the Welsh Government's approach to date has not enabled this potential to be realised. However, more recently, the Welsh Government has revamped its approach to consenting and has published a National Development Framework which includes new processes for onshore wind consenting in the context of delivery of renewables ambitions for 2040.[37]

The current planning regime in England is generally considered to present more significant challenges for the development of onshore wind, and there has been little deployment of new onshore wind since 2015.

Our modelling does not incorporate an explicit constraint for planning and consenting. Instead, we bound the deployment of capacity in each zone against the levels of capacity deployment included in the relevant FES scenario. Therefore, where planning and consenting is considered to restrict deployment of capacity within the FES, our own modelling reflects this restriction.

In order to deliver net zero, investment in renewables will be required across the country. The FES demonstrates this is the case for embedded onshore wind. Under the FES CT scenario without any reform to SDG charges, a majority of new embedded onshore wind capacity deployment by 2040 is located in England and Wales.

Our analysis shows that Ofgem's proposed SDG reforms may exacerbate this challenge. Figure 5.13 demonstrates the additional investment in embedded wind capacity in England and Wales following the SDG reforms relative to the counterfactual. However, it is important to note that the planning and consenting arrangements in England are likely to present a challenge for the levels of deployment of embedded onshore wind required even in the absence of these reforms.

5.3.5. Non-RES missing money

We adopt a similar approach as for RES support costs to estimate the change in 'missing money' for non-RES producers. For new non-RES capacity, we compare captured revenues against LCOE to determine additional revenues that would need to be recovered through other forms of support (in particular the capacity mechanism). For existing non-RES plants, we compare captured revenues against going-forward costs, assuming that existing capacity would need to recover any shortfall in these costs to avoid exiting the market.

In line with the net revenue impacts observed in Section 5.3.1, we observe a reduction of £264m in the level of missing money for non-RES producers under the TNUoS reform option.

5.3.6. Non-modelled impacts

We note several simplifications which are built into our modelling which may affect outcomes.

[36] See: https://www.gov.scot/publications/onshore-wind-policy-statement-9781788515283/

[37] See: https://gov.wales/sites/default/files/publications/2021-02/future-wales-the-national-plan-2040.pdf

Choice of RES technology for capacity investment

Firstly, we model overall investment in capacity of each technology as exogenous, i.e., we take the total capacity of each technology directly from the chosen FES scenario and do not allow the level of investment in each type of technology to vary, for example, based on captured revenues.

In practice, the net revenue impacts observed in Section 5.3.1 of this report may lead to an increase in levels of investment in certain technologies (e.g., solar and biomass). Introducing consistent charging approaches for distribution and transmission-connected generation may also result in a shift from distribution-connected capacity to transmission-connected capacity, particularly in Scotland. While investment in distribution-connected onshore wind in some parts of the country may increase, we might expect the negative impacts on the revenues of Scottish embedded onshore wind generators to drive a decrease in onshore wind investment in GB overall. This is because of the prevalence of onshore wind in Scotland relative to other parts of the country and as the relative attractiveness of other RES technologies increases.

This re-assignment of renewable capacity may have knock-on impacts on overall outcomes. For example, higher levels of investment in solar capacity in the south may replace onshore wind capacity. This would impact on dispatch profiles and therefore, in turn, on hourly wholesale market prices, constraints and investment.

Perhaps the most important impact would be on the levels of RES support required to deliver the renewable capacity included within each scenario. Relative to the impacts on RES support that we discussed in Section 5.3.4., the ability for capacity to re-optimise between technologies could limit the extent of additional RES support needed.

Locational investment factors

There is a broad range of complex, interlinked factors which drive investor decisions regarding choice of technology and location of additional capacity. The scope of our model is limited to the electricity market and the modelling horizon goes out to 2040. Within that time horizon it is not possible to capture certain factors which may act as a driver of such decisions, such as planning and land-use policy, wider infrastructure development, etc. While the FES implicitly includes consideration of planning in its deployment of capacity,[38] neither we nor the ESO can predict with accuracy how planning regimes may change in the period to 2040 in the context of a push to Net Zero.

In practice, it is likely that there will be key determinants of the location of renewable capacity that are not captured in our model. Where these factors impact on locational decisions of investors, this would impact in turn on outcomes such as load factors, constraints and transmission capacity investment.

5.4. CONSUMER WELFARE IMPACT

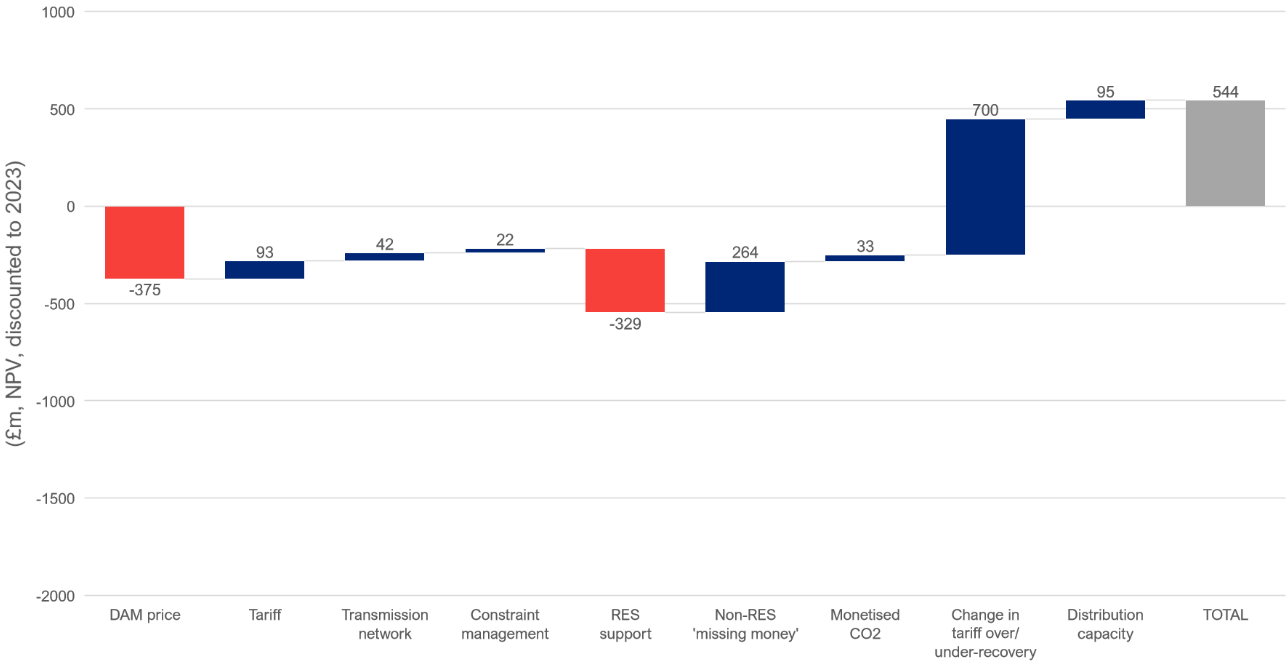
In this section, we bring together previous analysis to summarise the overall impact on consumers. We discuss the NPV impact on consumers as a whole before outlining bill impacts, and distributional effects for key customer groups.

5.4.1. Net present value welfare impact

In Figure 5.15 we show the combination of consumer welfare impacts under the CT scenario that have been discussed in Section 5.2 and 5.3.

[38] E.g. in the FES 2020, the ESO says that: *'Scenarios with higher societal change have higher levels of onshore wind, although growth is more limited than offshore wind due to land restrictions and stricter planning regulations.'* See: https://www.nationalgrideso.com/document/173821/download

Figure 5.15: Total impact of the TNUoS reform option on consumer welfare under CT scenario (NPV, discounted to 2023)



We observe a negative impact on consumers resulting from the small increase in the average DAM price (Figure 5.5). While the impact on the DAM price that we observe is small, the overall impact is magnified by the number of consumers that face this price increase over the appraisal period.

We observe small benefits to consumers across other areas. These include a reduction in the overall tariff contribution of consumers, driven by a small shift of load away from Triad/peak demand periods which is driven by responsiveness to the change in the DAM price. We also observe some small system efficiencies in dispatch and re-dispatch which result in a reduction in transmission, distribution and constraint management costs, and a small reduction in CO2 emissions.

In addition to the wholesale price impact, the only other negative effect that we observe is the additional revenue that needs to be recovered through RES support scheme costs. This results primarily from the impact of the TNUoS reforms on the revenues captured by embedded onshore wind in Scotland and the north of England (see Figure 5.12). While most other renewable generators benefit from charging reforms and from the aggregate increase in the DAM price, the net effect is an increase in RES support payment requirements overall.

While the net effect on renewable generators leads to an increase in RES support requirements, the reforms lead to a reduction in 'missing money' for non-RES generators. This results from a combination of factors including tariff changes and the DAM price that flexible non-RES generators are able to capture, particularly during expected Triad periods. While some embedded conventional generators recover less revenue because of the loss of EET credits (e.g., non-RES generators in D12 (Figure 5.12)), the overall impact is an increase in non-RES revenues and a reduction in 'missing money'.

We discussed the presence of a change to the tariff over/under-recovery in Section 5.2.3. In practice, the additional revenue recovered by the ESO would be distributed back to Demand TNUoS and Generator TNUoS through a reduction in charges. The proportion that is reflected in a reduction in Demand TNUoS charges would result in a direct consumer welfare benefit. The remainder would be reflected in a reduction in Generator TNUoS, and in turn would benefit consumers indirectly, e.g., through a reduction in the costs of RES support. We therefore include the additional revenue recovery that we observe within the TNUoS reform option as a benefit to consumers.

5.4.2. Bill impacts and distributional effects

In this section, we present the impacts of the welfare impacts observed above on consumer bills. We break down bill impacts on different consumer archetypes and consider the distributional effects of reforms across these archetypes.

5.4.3. Consumer archetypes

To consider how the reforms impact on different types of consumer, we define several consumer archetypes, both for domestic and non-domestic consumers. We follow Ofgem's guidance on analysis of distributional effects.[39] For more detail on how we have assessed impacts on different consumer archetypes, please see our accompanying Methodology Note.

Domestic consumer archetypes

We define two sets of domestic consumer archetypes. First, we use the archetypes included in Ofgem's guidance which are intended to capture the full range of consumers in Great Britain. It is important to note that these archetypes are defined for existing consumers as of today. However, all archetypes will change preferences and behaviours significantly by 2040. For example, we note that only one of the archetypes defined in the table below explicitly includes adoption of electric vehicles. To consider potential bill impacts on different archetypes, we therefore needed to develop assumptions about which archetypes would be more likely to adopt technologies, such as EVs and heat pumps over time. We include these assumptions in our Methodology Note.

We summarise the consumers as defined for 2020 in Table 5.4.

Table 5.4: Ofgem consumer archetypes

Archetype		Numbers of hhlds	Heating fuel	Average hhld income (BHC) (GB avg: £34k)	Elec kWh (GB avg: 3,980)	Gas kWh (GB avg: 13,180)	Main attributes (key words)
A	A1	2,761,000	Mains gas	£48,000	3,250	9,650	High incomes, owner occupied, working age families, full time employment, low consumption, regular switchers.
	A2	2,916,000	Mains gas	£54,600	4,920	20,520	High incomes, owner occupied, middle aged adults, full time employment, big houses, very high consumption, solar PV, environmental concerns.
B	B3	3,674,000	Mains gas	£28,600	3,670	15,350	Average incomes, retired, owner occupied - no mortgage, electric vehicles, environmental concerns, lapsed switchers, late adopters.
	B4	2,323,000	Mains gas	£40,600	4,090	15,630	High incomes, owner occupied, part-type employed, high consumers, flexible lifestyles, environmental concerns.
C	C5	1,922,000	Mains gas	£15,200	2,570	11,270	Very low incomes, single female adult pensioners, non-switchers, prepayment meters, disconnected (no internet or smart phones).
D	D6	1,547,000	Mains gas	£18,100	3,920	12,340	Low income, disability, fuel debt, prepayment meter, disengaged, social housing, BME households, single parents.
	D7	1,205,000	Mains gas	£34,000	4,140	15,600	Middle aged to pensioners, full time work or retired, disability benefits, above average incomes, high consumers.
E	E8	2,356,000	Mains gas	£23,400	3,620	11,950	Low income, younger households, part-time work or unemployed, private or social renters, disengaged non-switchers.
	E9	3,093,000	Mains gas	£37,000	3,200	10,440	High income, young renters, full time employments, private renters, early adopters, smart phones.
F	F10	1,912,000	Oil, Electric	£38,900	5,750	0	Middle aged to pensioners, full time work or retired, owner occupied, higher incomes, oil heating, rural, environmental awareness, RHI installers, late adopters.
G	G11	1,510,000	Electric, Oil	£30,200	5,250	0	Younger couples/single adults, private renters, electric heating, employed, average incomes, early adopters, BME backgrounds, low engagement.
H	H12	644,000	Electric, Oil	£14,500	4,030	0	Elderly, single adults, very low income, medium electricity consumers, never-switched, disconnected, fuel debt.
	H13	526,000	Electric, Oil	£22,000	5,360	0	Off gas, low income, high electricity consumption, disability benefits, over 45s, low energy market engagement, late adopters.

Source: Centre for Sustainable Energy, 'Ofgem energy consumer archetypes'[40]

[39] See: https://www.ofgem.gov.uk/system/files/docs/2020/05/assessing_the_distributional_impacts_of_economic_regulation_1.pdf

[40] See: https://www.ofgem.gov.uk/system/files/docs/2020/05/ofgem_energy_consumer_archetypes_-_final_report_0.pdf

We supplement this with specific assessment of impacts on Ofgem's statutory groups, to whom Ofgem must have regard when making decisions, as well as consumers included within Ofgem's Consumer Vulnerability Strategy. These are summarised as follows:

- those with a disability,
- those of pensionable age,
- low income consumers (which we define as consumers in the bottom decile of income),
- those residing in rural areas,
- those who are unemployed,
- those with no internet access, and
- single parents.

Non-domestic consumer archetypes

We also assess impacts on different types of non-domestic consumers. Our analysis considers:

- Very small commercial customers connected to the LV network with average annual consumption of 6.7 MWh (based on the GB-wide median of commercial consumer demand[41]),
- Small commercial customers connected to the HV network with average annual consumption of 61.9 MWh (based on GB-wide mean of commercial consumer demand),
- Medium to large commercial/industrial consumers connected to the EHV network with average annual consumption of around 40.6 GWh (based on the mid-point of the medium and large consumption bands),
- Very large industrial consumers connected directly to the transmission network with average annual consumption of around 135.0 GWh (based on the mid-point of the very large consumption band),
- An example fleet EV consumer with 25 electric vehicles with annual consumption of just over 163.9 MWh, and
- An example fleet EV consumer with 50 electric vehicles with annual consumption of just over 299.2 MWh.

5.4.4. Impacts on domestic consumer bills

The range of impacts that we identified above will impact on consumers in different ways. In particular, price and tariff changes will impact on domestic consumers differently depending on the coincidence of their electricity demand with high price periods and with the 4-7pm periods in which TNUoS tariffs are targeted for domestic consumers. Consequences for bills for different types of consumer will change over time. Some consumers will be more likely to adopt and make use of technology that allows them to avoid higher price periods while others will have less ability to do so. We therefore assess the impacts of changes to the DAM price and to Demand TNUoS as separate items.

In addition to direct price and tariff impacts, other cost items presented in our welfare analysis will ultimately be passed through to electricity consumers. We combine the impacts of transmission and distribution network capacity investment, policy support costs and the observed tariff over/under-recovery in a combined 'indirect costs' item. All of these cost elements are treated as a volumetric charge within our bill impact analysis.

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[41] For commercial customers, we define our representative archetypes based on the BEIS Sub-national electricity sales dataset (2020). The distribution of commercial customers in this dataset is positively-skewed, with the majority of customers being 'very small' and with a few larger commercial consumers included, pushing up the mean. As such, we use the median to represent a typical 'very small' commercial consumer, and the mean to represent a typical 'small' commercial consumer.

Ofgem consumer archetypes

Figure 5.16 shows the absolute impact on bills (NPV) over the full appraisal period resulting from the combination of welfare effects. In alignment with observed welfare impacts, this figure shows that consumers face an increase in bills due to the impact of TNUoS reform on the DAM price but face an overall decrease in bills as a result of the combination of welfare impacts.

Figure 5.16: Total impact on bills for Ofgem's consumer archetypes (NPV, discounted to 2023)

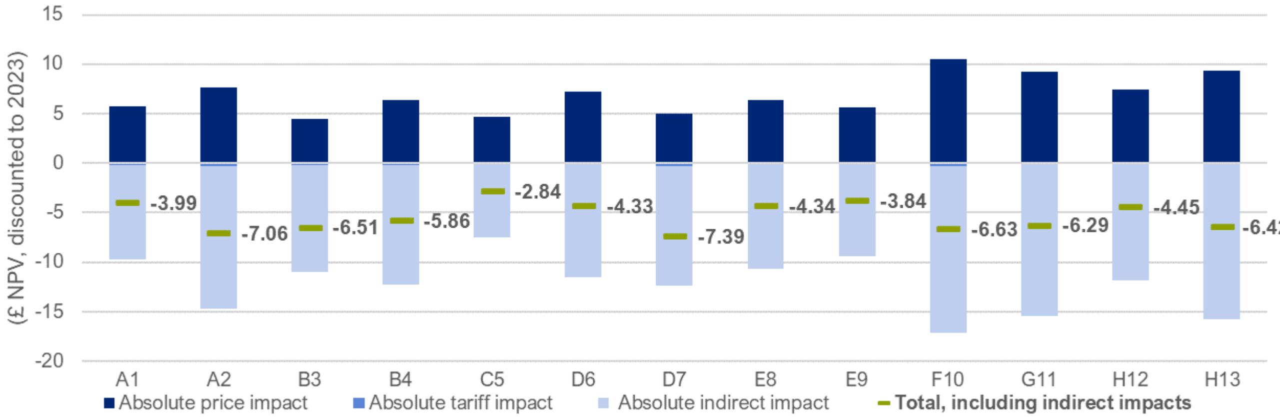


Figure 5.17 to Figure 5.19 break down the price and tariff impacts in each of the spot years within our analysis. The charts reflect the change in the DAM price shown in Figure 5.2 with more significant impacts in 2029 compared to other years.

The charts also show the increasing ability of some consumer archetypes to avoid high price and tariff periods and even to benefit from export of electricity to the grid during high-price periods. In our modelling, consumers who are able to shift demand more effectively, have adopted electric vehicles, particularly when combined with vehicle to grid (V2G) technology, but who do not use heat pumps for home heating, are the ones best able to minimise demand over peak demand periods and thus avoid peak prices. These consumers are able to mitigate the price increases observed and reduce the upwards impact on bills by 2040. Tariff impacts are also more pronounced for these consumers. As demand tariffs themselves do not change relative to the counterfactual, consumers who do not shift their demand in relation to price and tariff signals do not see a 'tariff' impact on their bills. Tariff impacts only arise as a by-product of load-shifting in response to small DAM price changes.[42]

In our modelling, particular beneficiaries are consumer archetypes B3 and D7 who meet these criteria.

Other consumer archetypes can avoid high price periods through V2G and load shifting to some extent but are less able to avoid some level of demand for home heating, especially where they do not combine this with thermal storage. This applies to archetypes A1, A2, B4 and F10 in our modelling.

Archetypes who do not adopt flexible technologies generally pay more by 2040, particularly after considering the fact that they are less likely to use electricity for transport and home heating than other consumers. This applies to archetypes D6, H12 and H13 for example.

[42] This means that the tariff impact shown as part of overall consumer welfare impacts for the TNUoS reform option (Figure 5.15) is concentrated on more 'responsive' consumers i.e., on consumers who are able to shift their demand most effectively. Particularly in the earlier years of our modelling horizon, non-domestic consumers tend to be most heavily represented in this group. These consumers are also more likely to have invested in micro-generators that can benefit from the EET, which does change in some zones as a result of the reform option.

Figure 5.17: Impacts on annual bills for Ofgem's consumer archetypes (2024)

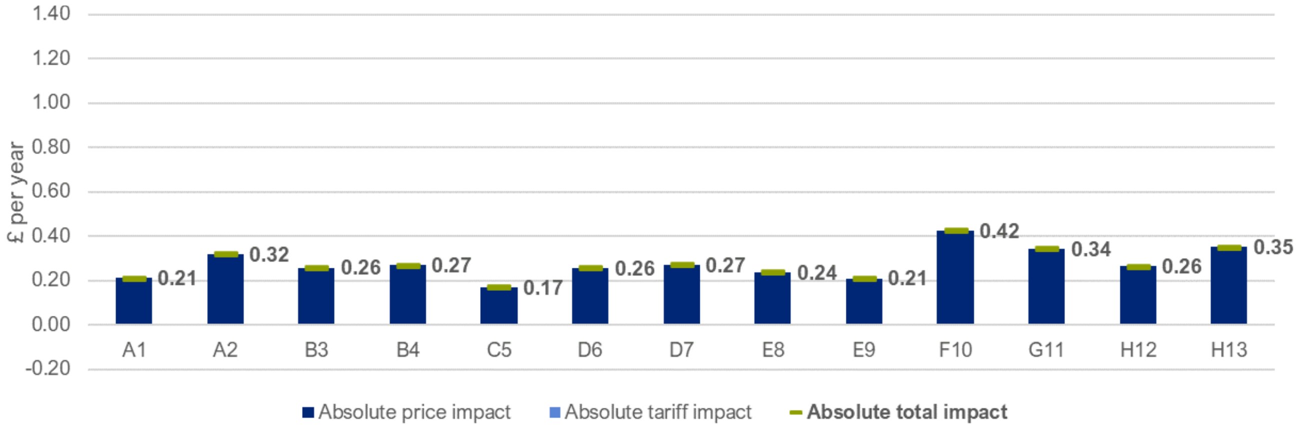


Figure 5.18: Impacts on annual bills for Ofgem's consumer archetypes (2029)

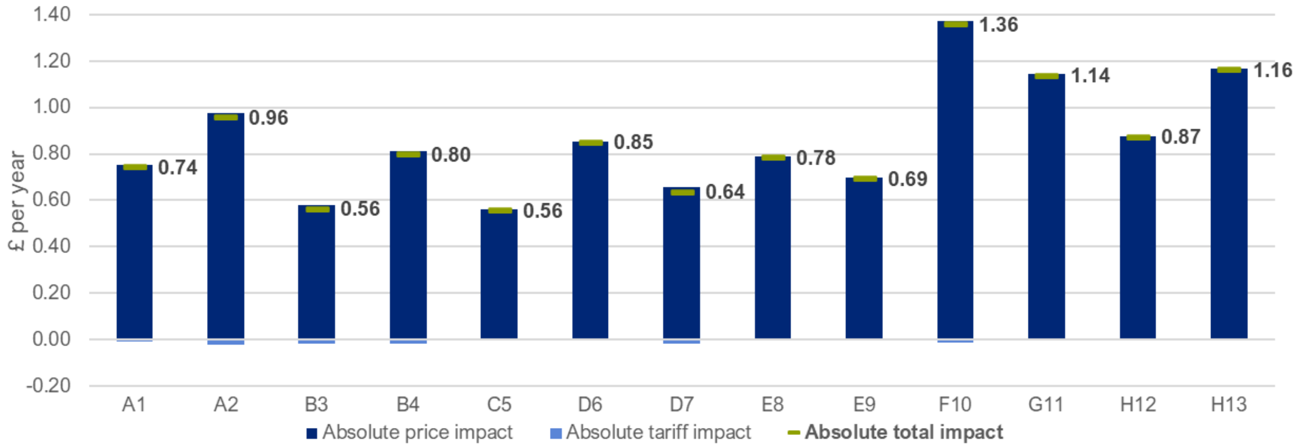
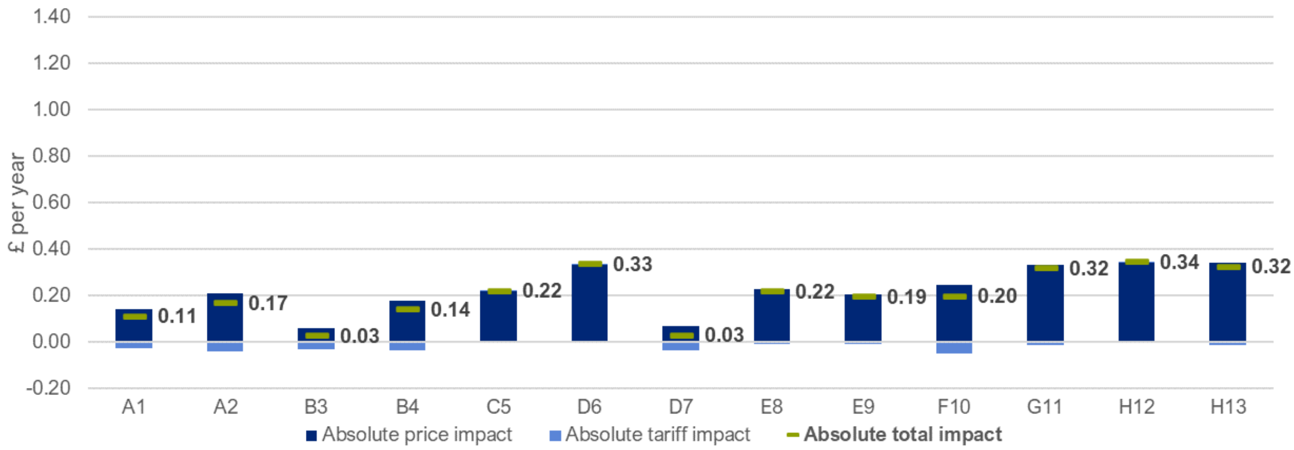


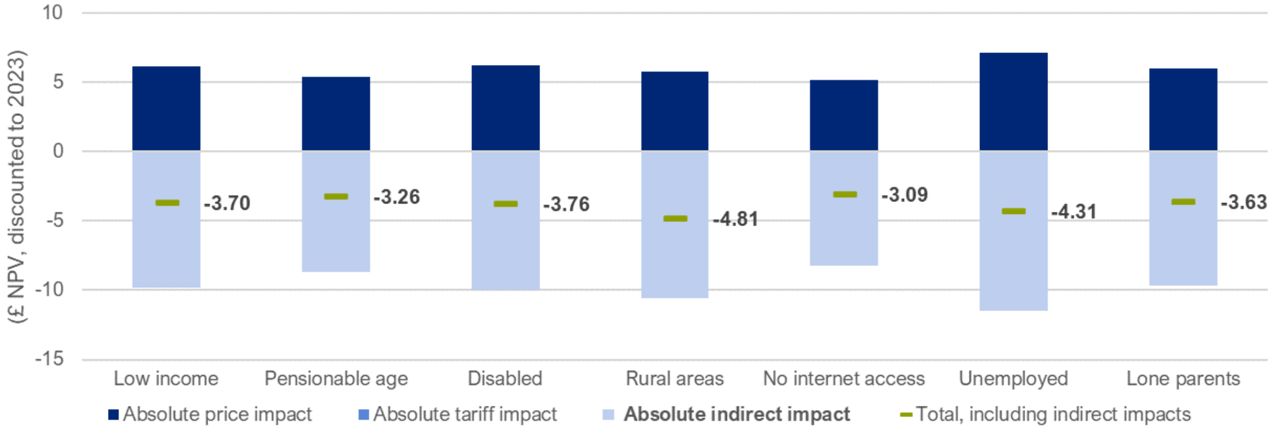
Figure 5.19: Impacts on annual bills for Ofgem's consumer archetypes (2040)



Ofgem statutory archetypes

In our modelling, Ofgem's statutory archetypes are generally later adopters of EVs and heat pumps and therefore are less responsive to higher price periods in the modelling. This means that they face bill impacts which are generally in proportion to the average total electricity consumption for that archetype.

Figure 5.20: Total impact on bills for Ofgem's consumer archetypes (NPV, discounted to 2023)



5.4.5. Bill impacts as a percentage of disposable income and equity weighted bill impacts

In Table 5.5 and Table 5.5 we present equity-weighted bill impacts in line with the methodology set out in Ofgem's guidance on assessing distributional impacts. We also show bill impacts as a percentage of disposable income.

Table 5.5 shows the price and tariff impacts only, both in absolute terms, in equity-weighted terms, and as a percentage of disposable income. This demonstrates the additional significance of price increases during peak demand periods which are difficult to avoid for lower income consumers (e.g., D6, H12 and H13).

Table 5.5 shows the positive equity-weighted bill impacts and impacts as a percentage of disposable income after taking indirect bill impacts into account.

Table 5.5: Equity-weighted domestic bill impacts and impacts as a percentage of income (price and tariff effects only)

	Impacts of price and tariff changes (£ NPV)	Total equity-weighted impact, including indirect impacts (£ NPV)	Impacts of price and tariff changes, as % of disposable income
		Ofgem archetypes	
A1	5.54	5.05	0.001%
A2	7.37	5.96	0.001%
B3	4.25	6.80	0.001%
B4	6.13	8.04	0.001%
C5	4.69	11.64	0.002%
D6	7.16	20.22	0.003%
D7	4.74	7.53	0.001%
E8	6.27	16.47	0.002%
E9	5.55	6.70	0.001%
F10	10.22	13.51	0.002%
G11	9.10	15.32	0.002%
H12	7.36	18.80	0.004%
H13	9.29	22.23	0.003%

Statutory archetypes			
Low income	6.11	29.97	0.005%
Pensionable age	5.38	6.66	0.001%
Disabled	6.21	7.71	0.002%
Rural areas	5.72	5.57	0.001%
No internet access	5.11	9.60	0.002%
Unemployed	7.12	11.55	0.002%
Lone parents	6.00	11.25	0.002%

Table 5.6: Equity-weighted domestic bill impacts and impacts as a percentage of income (including indirect bill impacts)

	Total impact, including indirect impacts (£ NPV)	**Total equity-weighted impact, including indirect impacts (£ NPV)**	**Total impact including indirect impacts, as % of disposable income**
Ofgem archetypes			
A1	-3.99	-3.64	-0.019%
A2	-7.06	-5.71	-0.025%
B3	-6.51	-10.40	-0.037%
B4	-5.86	-7.68	-0.028%
C5	-2.84	-7.04	-0.047%
D6	-4.33	-12.23	-0.060%
D7	-7.39	-11.73	-0.035%
E8	-4.34	-11.39	-0.043%
E9	-3.84	-4.64	-0.024%
F10	-6.63	-8.76	-0.041%
G11	-6.29	-10.59	-0.049%
H12	-4.45	-11.37	-0.077%
H13	-6.42	-15.37	-0.068%
Statutory archetypes			
Low income	-3.70	-18.13	-0.093%
Pensionable age	-3.26	-4.03	-0.028%
Disabled	-3.76	-4.67	-0.033%
Rural areas	-4.81	-4.69	-0.029%
No internet access	-3.09	-5.81	-0.037%
Unemployed	-4.31	-6.99	-0.046%
Lone parents	-3.63	-6.80	-0.044%

5.4.6. Impacts on non-domestic consumer bills

In this section, we present the absolute impacts on the bills of the range of non-domestic consumers that we include in the analysis. Figure 5.21 presents the total impacts on bills of commercial customers connected to the LV or HV networks and on our two representative Fleet EV customers. The chart shows bill impacts across the full appraisal period.

The chart shows the benefits of flexibility for Fleet EV consumers who are able to benefit from lower prices periods outside of peak demand. As Fleet EV consumers adopt V2G technology, they are able to arbitrage between high- and low-price periods to some extent.

Figure 5.22 shows impacts on large industrial and commercial customers connected at the EHV or transmission levels in £ thousands (NPV) over the full period of analysis. Similar to other consumer groups, these customers face increases in price, they also benefit from indirect effects such that the net impact is an overall reduction in bills.

Figure 5.21: Impacts on commercial non-domestic archetype consumer bills (NPV, discounted to 2023)

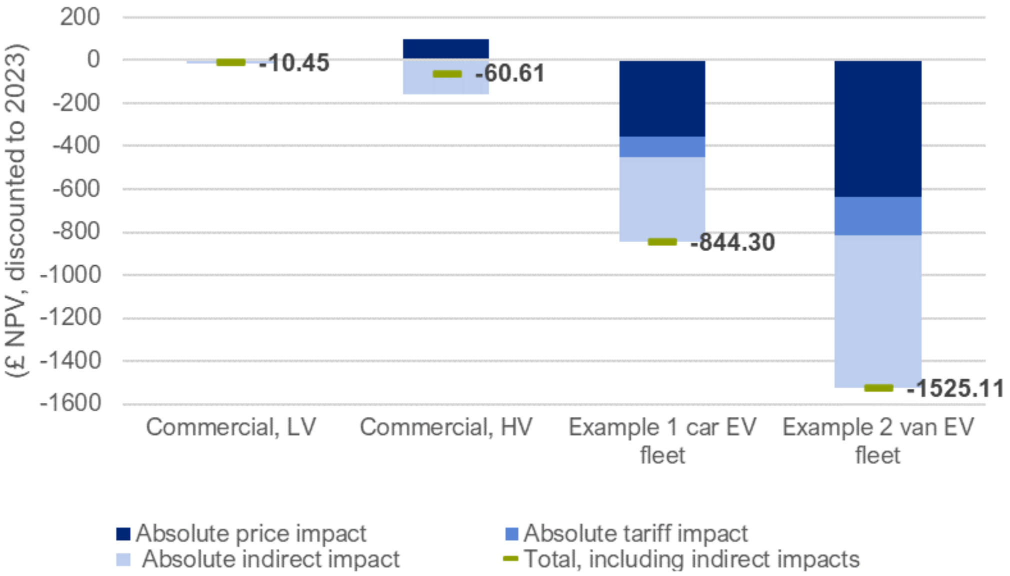
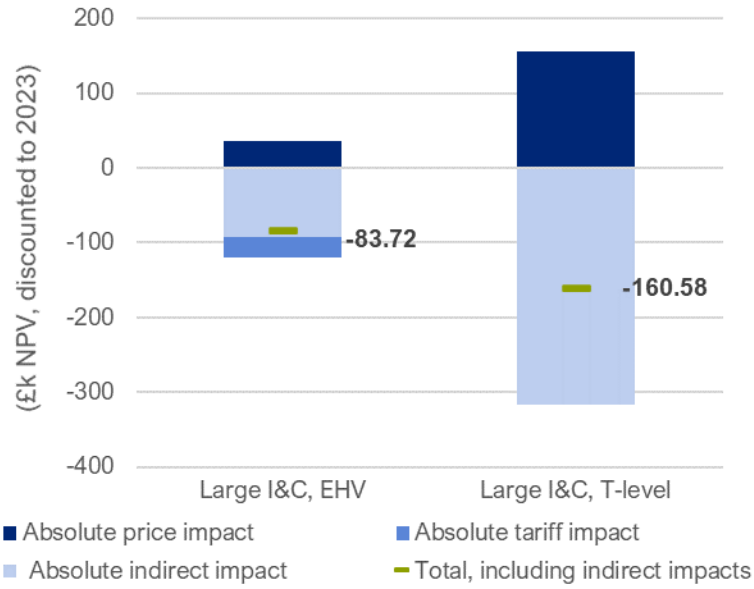


Figure 5.22: Impacts on large industrial and commercial non-domestic archetype consumer bills (NPV, discounted to 2023)



5.5. Consumer welfare impacts under the SP and LW backgrounds

High-level trends

In this section, we set out the impacts of the option on consumer welfare under the SP and LW backgrounds and discuss key differences. We provide a full set of charts which demonstrate the impacts under the SP and LW backgrounds in Appendix A.

We observe similar trends under the alternative backgrounds as we did under the central CT scenario. We see the same small increase in the average DAM price, driven primarily by behaviour during Triad/peak demand periods. We observe small reductions in transmission network capacity investment but a small increase in costs of constraint management actions under both alternative backgrounds.

We continue to observe negative impacts on total revenues captured by renewable generators, driven by revenue impacts on embedded generators in Scotland. This means that the costs of supporting RES increase as under the CT scenario. However, we also observe the same trend for an increase in the revenues captured by non-RES plant such that missing money decreases for non-RES capacity in the SP and LW alternative backgrounds.

The TNUoS reform proposals continue to lead to reductions in carbon emissions and in the costs of investment in distribution network capacity. We observe a small tariff over-recovery under both alternative backgrounds. We continue to assume that this over-recovery would be passed back to consumers through a reduction in tariffs or via lower wholesale prices.

Differences in drivers of overall welfare outcomes

While the high-level trends are very similar, the relative importance of each differs between scenarios and this leads to different overall outcomes than those observed for CT. The differences between the FES scenario backgrounds help to explain these trends. The CT scenario has the highest levels of electrification of the four FES scenarios and is the most decentralised, i.e. it delivers net zero objectives primarily through embedded renewable generation capacity and through engaged consumers who increasingly adopt technologies that allow them to shift demand in response to price signals.

The SP scenario is more centralised, with lower levels of renewables capacity and with less responsive consumers. While embedded generation and consumer uptake of load shifting technologies support achievement of emissions reductions objectives, they are generally less pronounced compared to the CT scenario.

The LW scenario has many similarities with CT but has lower overall levels of electrification as hydrogen plays a stronger role in meeting final energy demand.

When discussing the impact of the reforms on the DAM price (Section 5.2.1), we showed the dampening effect that responsive demand can have on price spikes during expected Triad/peak demand periods. By 2040, this helps to smooth the increase in price that we observe under the TNUoS reform proposals. This effect is not as pronounced in the LW background and is not observed to a significant extent under SP. The wholesale price impacts are therefore more pronounced, particularly within the SP background.

Price impacts also help to explain the trends observed for RES support and non-RES missing money. In both cases, higher average DAM prices will result in generation capturing higher market revenues and hence, needing to recover less from support schemes. In addition, both SP and LW represent more centralised scenarios relative to CT. We identified embedded renewable generators in Scotland as the primary losers from the proposed reforms to TNUoS charging. The SP background is less dependent on embedded RES capacity in Scotland, and this also applies to the LW background to a lesser extent. In both cases, the impact on revenues of Scottish onshore wind is balanced out to a greater extent by positive revenue impacts for other technologies. Unlike for the CT scenario, the combination of impacts on RES support costs and non-RES missing money under both alternative backgrounds are positive overall.

Another key difference is in the level of the tariff over-recovery between options. The ESO modelled TNUoS charges out to 2040 under a common scenario drawing on the FES 2019 Two Degrees. While not as ambitious as

LW in terms of carbon emissions reductions, Two Degrees is a transmission-dominated, centralised scenario, with renewable capacity driven predominantly by offshore wind expansion. The balance of transmission-connected and embedded generation under the Two Degrees scenario aligns more closely with SP and, to a lesser extent, LW than it does with CT. Given the enhanced consistency of the modelling of TNUoS charges out to 2040 with the balance of capacity on the system, the tariff over-recovery is less pronounced under the alternative backgrounds than observed for CT.

The balance of costs and benefits described above leads to an overall consumer welfare benefit of approximately £643m under the SP background and approximately £311m under the LW background.

Figure 5.23: Total impact of the TNUoS reform option on consumer welfare under the SP background (NPV, discounted to 2023)

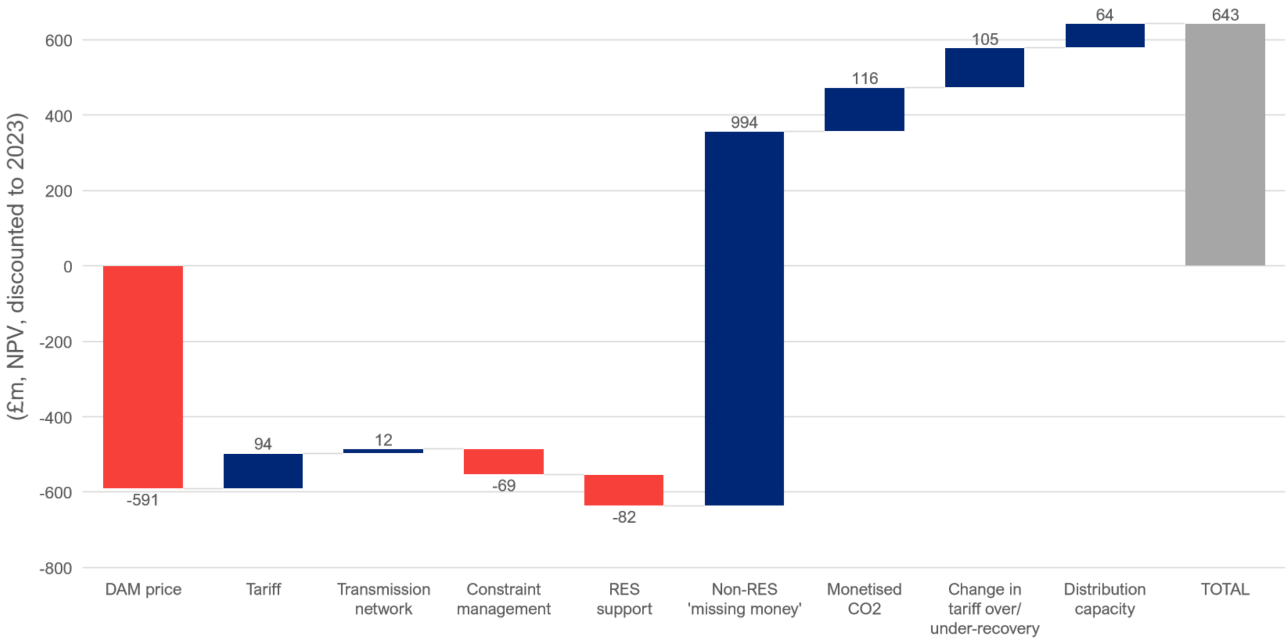
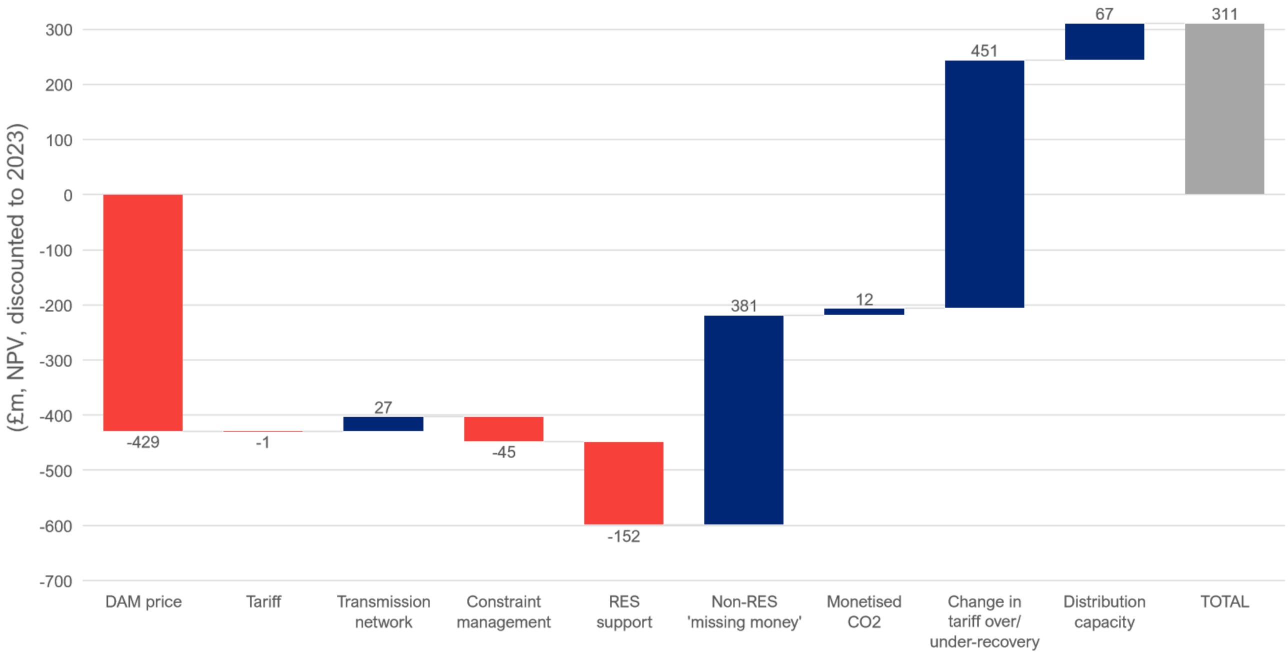


Figure 5.24: Total impact of the TNUoS reform option on consumer welfare under the LW background (NPV, discounted to 2023)



6. CONCLUSIONS

6.1. CONNECTION BOUNDARY OPTIONS

Our analysis of Ofgem's connection boundary policy options focuses on the direct quantifiable costs of additional reinforcement driven by the reduction in the strength of the locational signal as the depth of the connection boundary reduces. For the most radical version of the policy, which makes connection charges completely shallow, our analysis shows that these direct additional costs could equate to around £1.4 billion of consumer welfare disbenefit if introduced in isolation. Analysis of the connection decisions of new connectees demonstrates that this additional cost reflects user choices about where to locate on the network in response to the change in signals.

More modest reforms which amend the voltage rule, result in lower consumer welfare disbenefits, with this option reducing the disbenefit to £0.3 billion. A hybrid arrangement in which demand customers would face a shallow connection charge but generation customers would face the amended voltage rule leads to disbenefit of around £0.4 billion.

However, our analysis also demonstrates the interaction between connection boundary policy and the design of the DUoS charge structures that work alongside it. The notional design of the ULR DUoS charging background replaces some of the locational signals that are sent by the shallow-ish connection boundary under the counterfactual such that the impacts on network costs are alleviated slightly. The presence of the ULR charging background reduces the costs of moving to a shallow connection boundary to just under £1 billion under the CT scenario for example.

Ofgem is continuing to consider policy options for DUoS charging structures. Relative to the notional ULR DUoS background, there may be opportunities to strengthen the DUoS signals, e.g. by including a spare capacity indicator or by introducing granularity of the charging structures at the 'primary' level. If these features were included in the DUoS background signal, we anticipate further offsetting of the additional network costs introduced by the changes to the connection boundary.

We also discussed the potential importance of non-modelled factors on Ofgem's principles-based decision. Ofgem has considered whether a revision of the connection boundary could support the development of flexibility services that provide cheaper alternatives to network reinforcement. We presented results from a sensitivity in which the evolution of flexibility services is less pronounced, leading to more expensive flexibility options for DNOs. Under this sensitivity we found that network costs would rise by somewhere in the region of £0.7-0.8 billion across all connection boundary policy options under the CT scenario.

Finally, Ofgem has also signalled the potential importance of a change to the connection boundary to facilitate connections of low-carbon technologies. Ofgem must therefore consider the quantifiable impacts on network costs against the broader benefits that may support the transition to net zero.

6.2. TRANSMISSION NETWORK USE OF SYSTEM CHARGES TO DISTRIBUTED GENERATORS

Under our central scenario, we observe benefits to consumers of approximately £544m (in present value terms) from Ofgem's proposed TNUoS reforms. Under the SP background scenario, this overall benefit rises to £644m. We observe welfare benefit of £311m under the LW background scenario.

These are net welfare outcomes which are the product of several positive and negative trends. Higher wholesale prices impact directly on consumers but can be interpreted as the correction of a distortion which artificially dampens wholesale prices during peak demand periods. The increase in the DAM price is captured by producers in the market and encourages a shift of demand away from peak periods from those customers who are better able to shift load.

We also observe several system benefits, including a reduction in the level of investment required in both transmission and distribution capacity, and a reduction in carbon emissions.

Behind these high-level outcomes are winners and losers, both within electricity consumers and producers. Several of the key impacts on consumers will depend on the extent to which they can profile their demand to avoid high DAM price and tariff periods. While technologies that can allow consumers to shift load are likely to become increasingly prevalent, this could lead to benefits accruing more to higher income engaged socioeconomic groups than to less engaged customers with less flexible technologies.

The main distributional effects on producers are dependent on location, voltage level of connection and technology type. We observe negative revenue impacts for embedded onshore wind generators in Scotland with most other groups benefiting from less pronounced revenue increases.

Impacts on investment will be influenced by how policy responds to changes. Revenue impacts on RES generators lead to a need for additional RES support payments. This can be interpreted as the additional support required to achieve the levels of capacity within each scenario, or as the additional risk of support being insufficient to deliver the required level of capacity. We observe a reduction in the level of missing money that non-RES generators would need to capture through support, e.g., from the capacity market. These generators are better able to shift dispatch to benefit from high price periods and do not face the same negative impacts on revenue that we observe for embedded renewables in Scotland.

As we have noted throughout the report, our model does not reflect the full extent of complexity of the market. We make several assumptions and acknowledge several limitations of modelling which imply that results should be interpreted carefully and alongside supplementary analysis. This quantitative analysis is intended as a compliment rather than a substitute to Ofgem’s principles-based policy assessment.

Appendix A SP AND LW: DETAILED RESULTS (TNUOS SDG CHARGING REFORM)

In this appendix we present detailed charts and tables under the Steady Progression (SP) and Leading the Way (LW) FES alternative backgrounds.

A.1. Steady Progression

Figure A.1: Change in demand-weighted average DAM price under TNUoS reform option, SP

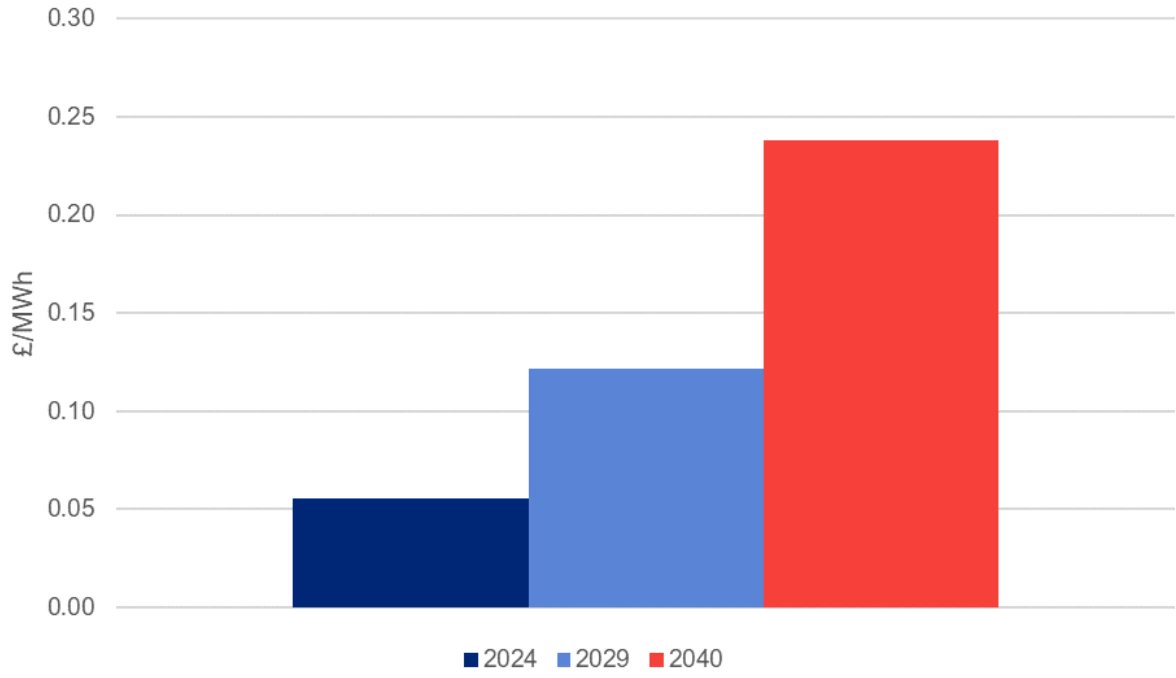


Figure A.2: Change in demand net of BtM generation (Scotland and the north), November to February, SP

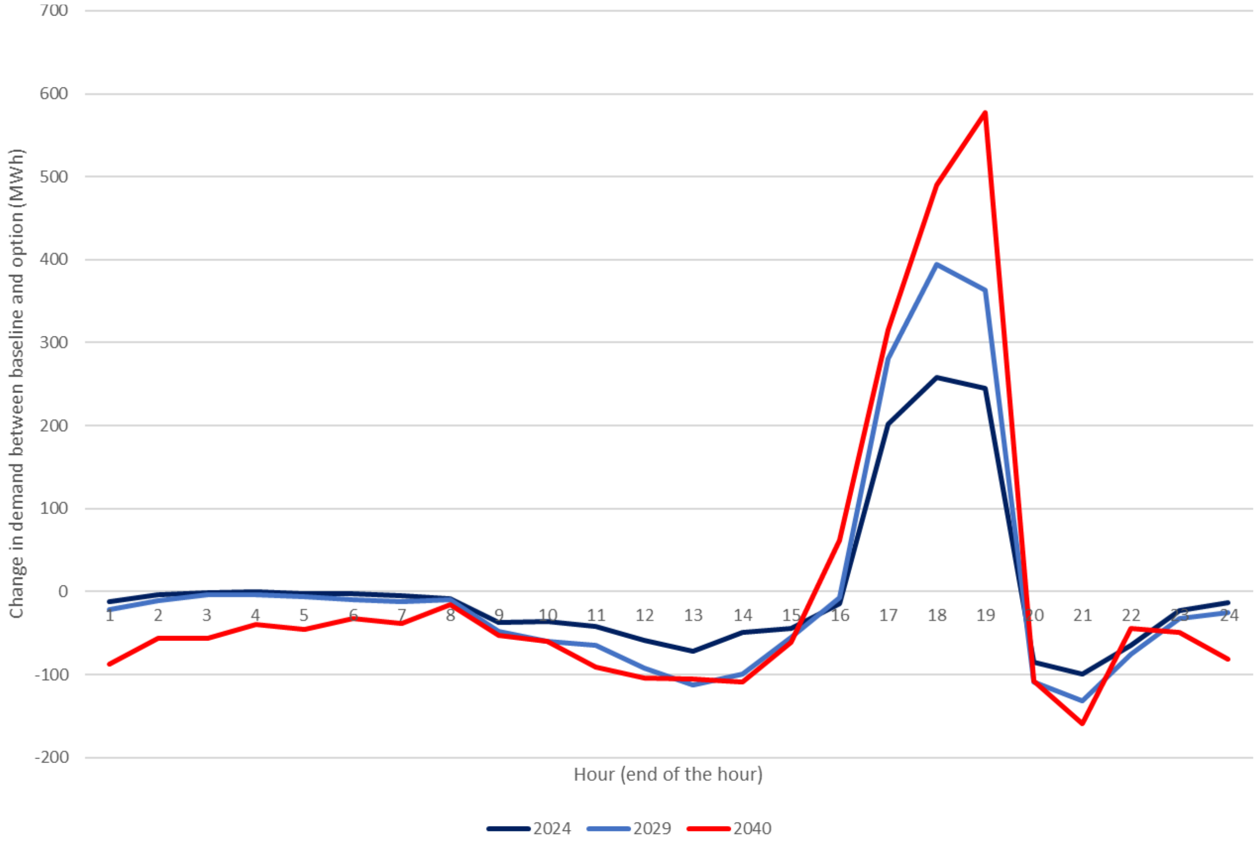


Figure A.3: Change in demand net of BtM generation (all zones), November to February, SP

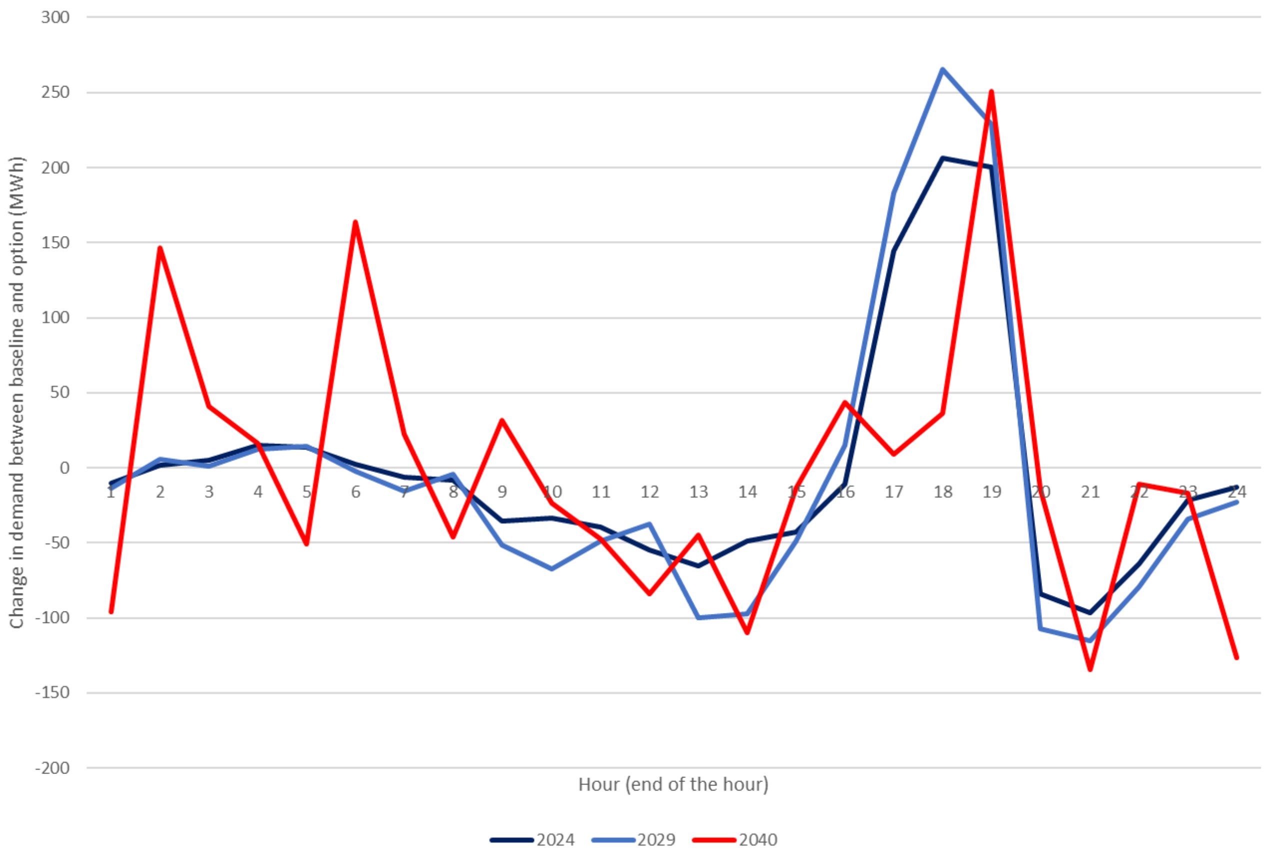


Figure A.4: Impact of the TNUoS reform option on the annual average DAM price in each hour of the day (SP)

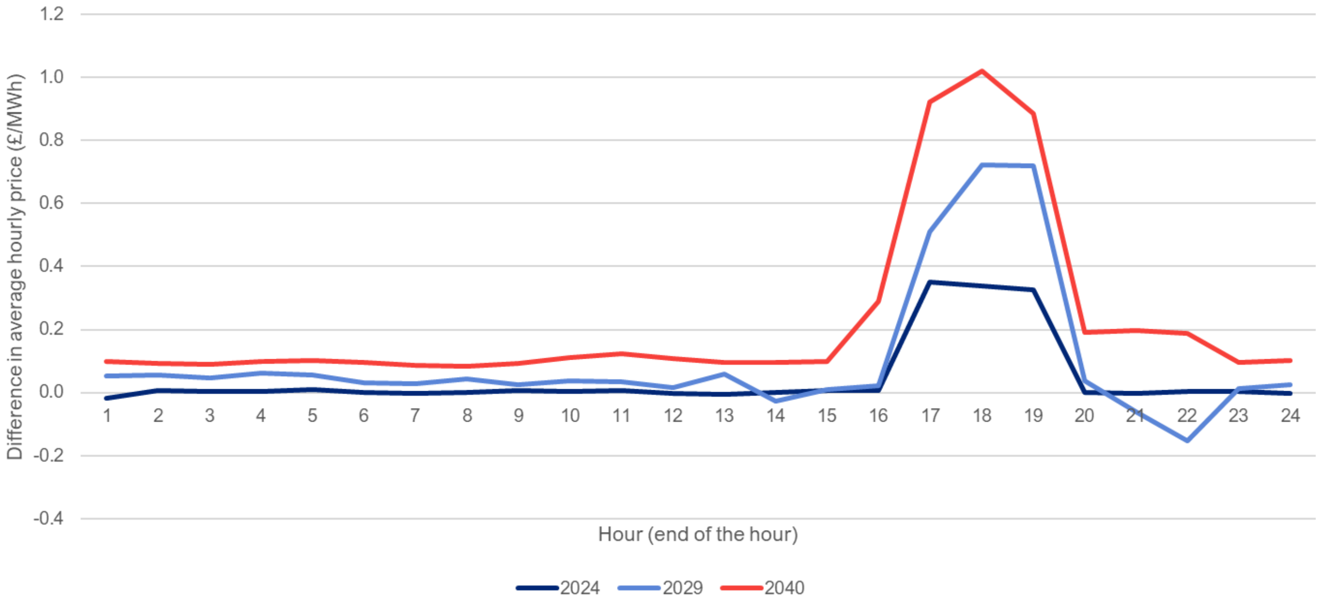


Figure A.5: Transmission network investment by boundary and year under the baseline and the TNUoS reform option, SP

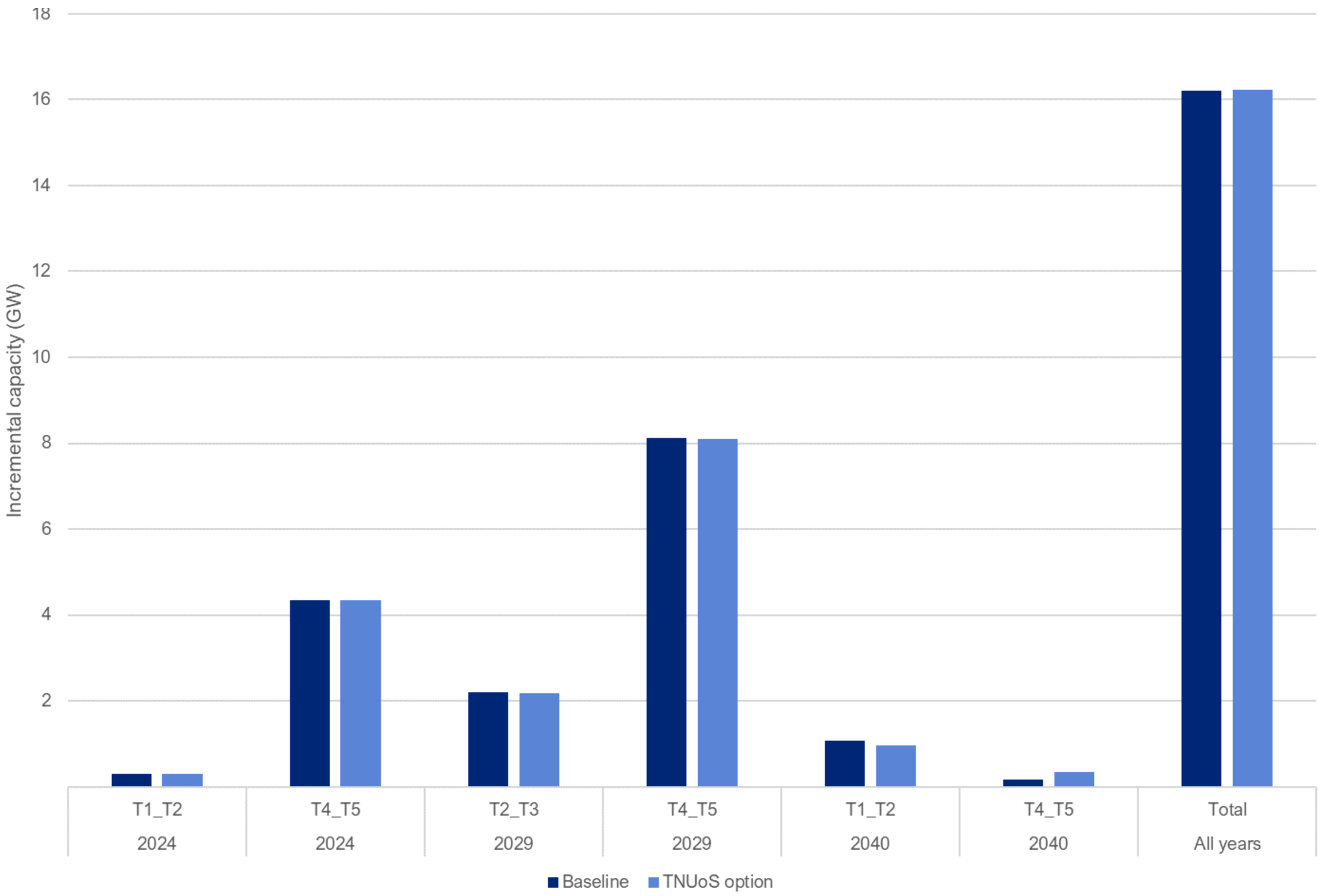


Figure A.6: Dispatch of carbon emitting generation under the TNUoS reform option relative to the baseline, SP

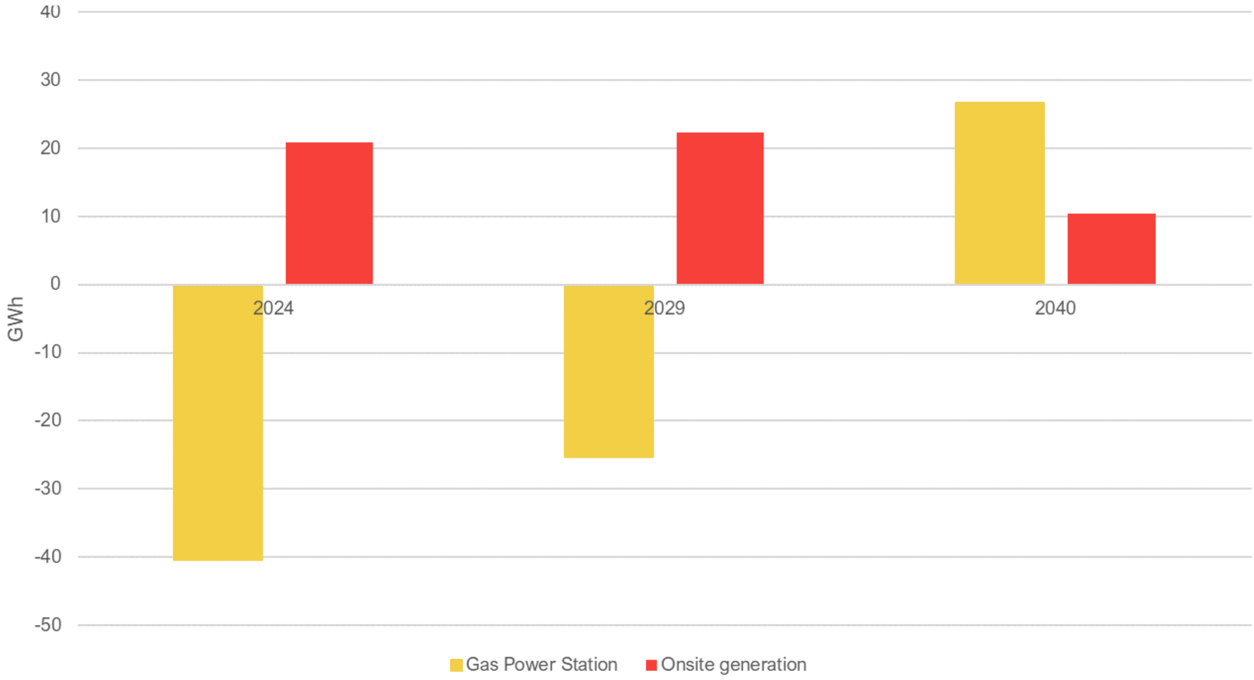


Figure A 7: Reduction in investment in distribution network capacity (positive = consumer benefit, i.e., a reduction in distribution network investment costs) (£m, NPV, discounted to 2023, SP)

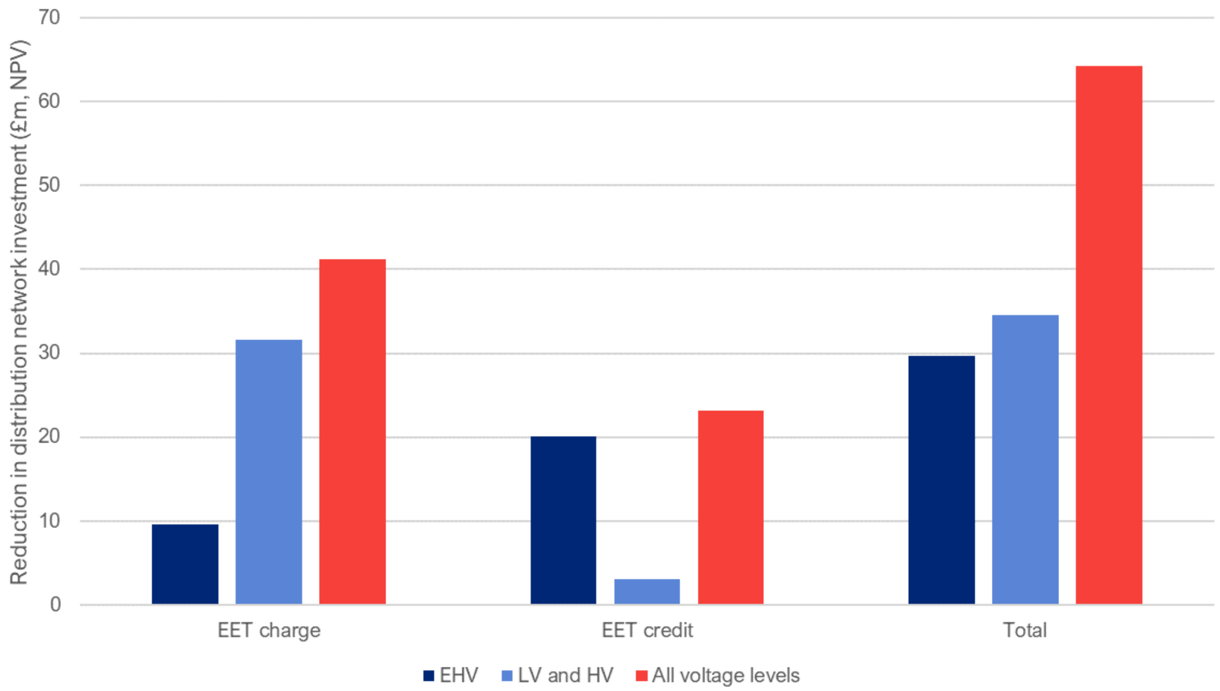


Figure A.8: Total impact on net revenues of transmission-connected producers (£m, NPV, discounted to 2023, SP)

	T1	T2	T3	T4	T5	T6	T7	TOTAL
Offshore_wind	23.91	10.78	53.14	172.50	17.17	-16.88	5.12	**265.74**
CCGT_existing	2.82	-0.05	0.16	4.28	8.10	-0.44	-1.23	**13.65**
CCGT_new	-	-	-	-15.13	-11.84	-	0.07	**-26.90**
OCGT_existing	-0.02	-	-	0.03	0.16	-	0.06	**0.23**
OCGT_new	-	-	-	-1.63	-3.83	-0.80	-0.06	**-6.32**
H2_CCGT	-	-	-	-	-	-	-	**-**
Onshore_wind	24.07	33.12	-	0.84	1.35	-	-	**59.38**
Solar	-0.23	-0.16	-	0.03	0.64	-	-0.17	**0.11**
Nuclear	-	7.02	11.35	-	18.88	9.27	6.29	**52.80**
Biomass	0.20	0.84	3.16	11.06	1.58	0.19	-	**17.04**
Hydro	1.70	0.04	-	0.12	0.07	-	-0.00	**1.93**
Pumped_storage	-1.54	-1.65	-	-6.08	-	-	-	**-9.27**
Battery	-0.10	-0.51	-0.85	-0.52	-4.71	-0.47	-6.29	**-13.45**
TOTAL	**50.80**	**49.44**	**66.95**	**165.50**	**27.56**	**-9.13**	**3.78**	**354.91**

Figure A.9: Impacts on net revenues of transmission-connected producers (£/kW, NPV, discounted to 2023, SP)

	T1	T2	T3	T4	T5	T6	T7
Offshore_wind	7.62	239.13	11.07	10.25	6.54	11.32	6.07
CCGT_existing	3.07	-1.09	3.00	-0.23	-0.47	-1.14	-1.05
CCGT_new	-	-	-	0.09	-0.97	-	2.50
OCGT_existing	-3.11	-	-	-2.71	1.73	-	-1.48
OCGT_new	-	-	-	-4.05	-3.64	-5.90	-2.35
H2_CCGT	-	5.88	-	8.78	5.05	-	-
Onshore_wind	-3.60	-3.55	-	0.86	1.50	-	-
Solar	6.25	6.24	-	6.49	6.25	6.25	-1.82
Nuclear	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Pumped_storage	-5.15	-3.76	-	-3.03	-	-	-
Battery	-3.60	-2.84	-1.59	-3.40	-1.42	-3.88	-3.31

Figure A.10: Total impact on net revenues of distribution-connected producers (£m, NPV, discounted to 2023, SP)

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14	TOTAL
CCGT_existing	2.88	2.99	6.46	6.93	5.49	12.72	16.07	-	1.60	9.06	-1.51	-	-2.27	7.32	**67.73**
CCGT_new	-	-	6.29	5.44	48.38	6.34	2.37	3.30	1.95	-	0.31	-0.71	-	0.49	**74.16**
OCGT_existing	0.30	-	1.70	2.72	1.72	2.16	1.51	-	-0.14	-	-0.06	-	0.87	1.43	**12.19**
OCGT_new	-	-	8.31	6.40	5.77	0.02	14.65	0.33	9.27	8.08	-0.11	-1.05	0.11	6.81	**58.61**
GT	4.94	1.82	7.28	107.28	147.46	87.05	178.28	66.63	40.51	106.24	9.24	-2.57	39.69	25.51	**819.36**
H2_CCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Onshore_wind	-963.25	-447.97	7.21	23.87	65.01	88.84	37.41	1.34	49.14	30.38	0.97	0.12	0.62	11.18	**-1,095.11**
Solar	-52.54	-39.70	-12.71	6.99	31.75	23.28	153.85	66.66	144.47	65.47	59.95	6.01	193.45	157.45	**804.37**
Biomass	-45.61	-43.30	-18.11	14.07	77.51	24.54	60.79	46.29	37.21	18.53	19.63	-3.07	14.50	19.76	**222.72**
Hydro	-372.45	-31.85	-0.16	0.45	0.43	4.77	0.40	0.09	0.15	4.01	0.09	0.06	0.35	1.35	**-392.31**
Battery	0.00	0.04	0.05	0.05	0.05	0.04	0.04	0.05	-0.01	-0.00	-0.04	-0.01	-0.04	-0.00	**0.20**
TOTAL	**-1,425.74**	**-557.98**	**6.31**	**174.20**	**383.58**	**249.75**	**465.36**	**184.70**	**284.14**	**241.77**	**88.46**	**-1.22**	**247.27**	**231.30**	**571.93**

Figure A.11: Impacts on net revenues of distribution-connected producers (£/kW, NPV, discounted to 2023, SP)

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
CCGT_existing	-	-	81.15	87.13	72.57	57.71	59.79	-	15.10	33.21	-5.32	-	-10.96	45.18
CCGT_new	-	-	62.09	68.93	11.72	-	-	55.05	29.40	-	-3.08	-63.77	-	31.83
OCGT_existing	-	-	73.34	79.85	75.77	60.32	92.13	-	-2.42	-	6.95	-	21.74	66.15
OCGT_new	-	-	67.71	69.68	-	-	75.01	60.01	31.68	48.58	-4.00	-29.76	-3.32	57.74
GT	-413.61	-238.81	-11.85	29.31	70.40	65.42	111.85	106.67	47.00	88.57	28.50	-60.47	56.78	97.81
H2_CCGT	-293.58	-160.32	-10.17	19.34	67.73	72.46	71.17	68.20	44.25	46.74	9.45	7.41	32.29	34.05
Onshore_wind	-	-	-	-	51.34	50.23	82.11	82.17	68.07	82.03	79.14	64.54	80.84	79.20
Solar	44.38	62.02	63.92	70.87	60.34	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	66.60	124.82	120.02	58.06	72.07	38.63	-15.60	35.80	67.09
Hydro	-480.21	-255.28	-14.72	29.29	69.69	-	-	-	-	-	-	-	-	-
Battery	22.31	54.04	64.87	66.13	64.39	55.84	34.60	29.29	-17.78	-14.95	-41.72	-113.14	-62.88	-5.10

Figure A.12: Increase/decrease of investment in technology specific capacity by year and by distribution zone (MW), SP

2029	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Biomass	-3.7	0.0	-11.7	0.0	0.0	0.0	8.3	7.1	0.0	0.0	0.0	0.0	0.0	0.0
BTM_Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore_wind	-81.8	0.0	6.4	5.4	8.5	31.8	4.7	0.1	24.6	0.0	0.0	0.1	0.1	0.0
Solar	0.0	0.0	0.0	-4.6	0.0	0.0	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2040	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**	**D7**	**D8**	**D9**	**D10**	**D11**	**D12**	**D13**	**D14**
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BTM_Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore_wind	-217.8	126.2	15.1	12.8	20.1	31.4	11.4	0.5	0.0	0.0	0.0	0.0	0.3	0.0
Solar	0.0	0.0	-44.2	0.0	44.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure A.13: Levelised revenue impacts for embedded onshore wind and solar technologies (£/MWh), SP

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Onshore_wind	-10.56	-6.68	-0.22	0.97	2.00	1.89	2.50	2.52	1.15	1.51	0.46	0.48	1.45	1.16
Solar	-23.84	-13.02	-0.22	2.17	4.35	4.38	7.13	7.08	5.71	7.35	6.47	4.85	6.89	6.70

Figure A.14: Total impact of the TNUoS reform option on consumer welfare (NPV, discounted to 2023, SP)

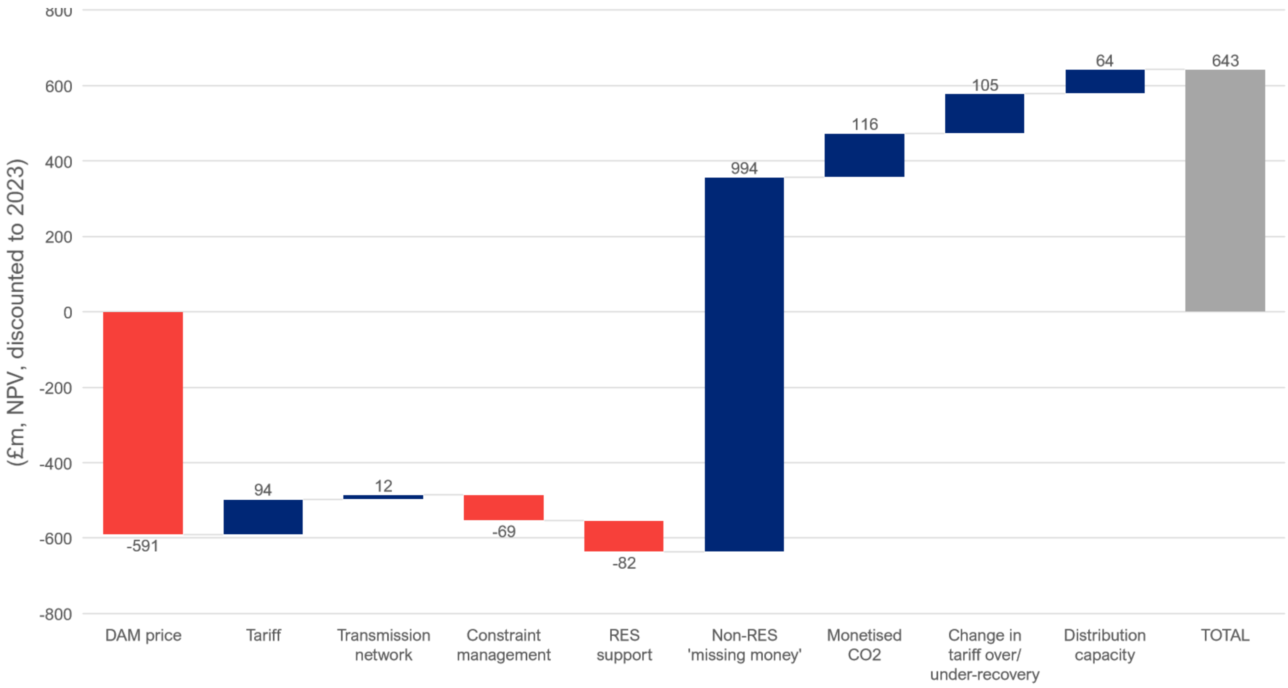


Figure A.15: Total impact on bills for Ofgem's consumer archetypes (NPV, discounted to 2023, SP)

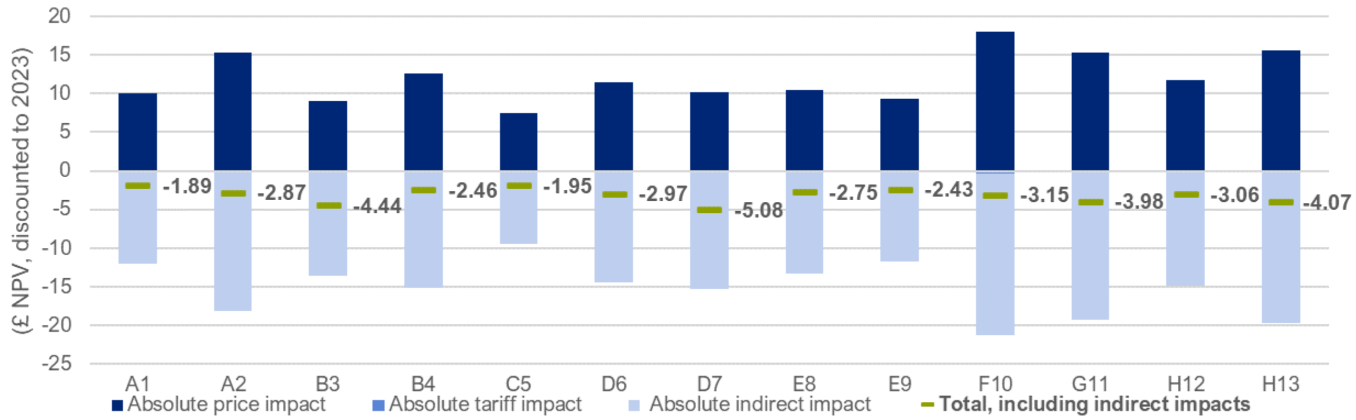


Figure A.16: Impacts on annual bills for Ofgem's consumer archetypes (Price and tariff only, 2024, SP)

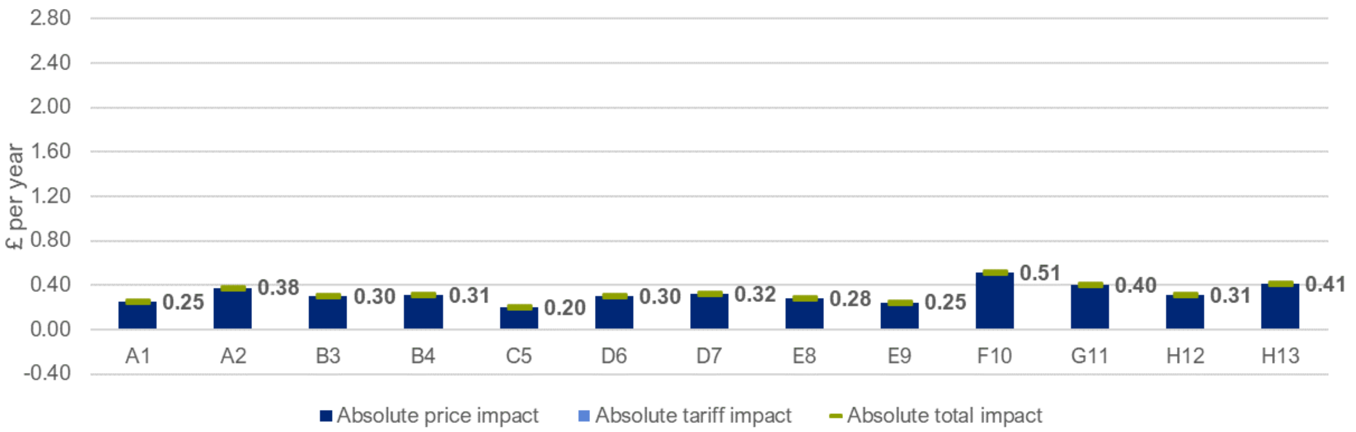


Figure A.17: Impacts on annual bills for Ofgem's consumer archetypes (Price and tariff only, 2029, SP)

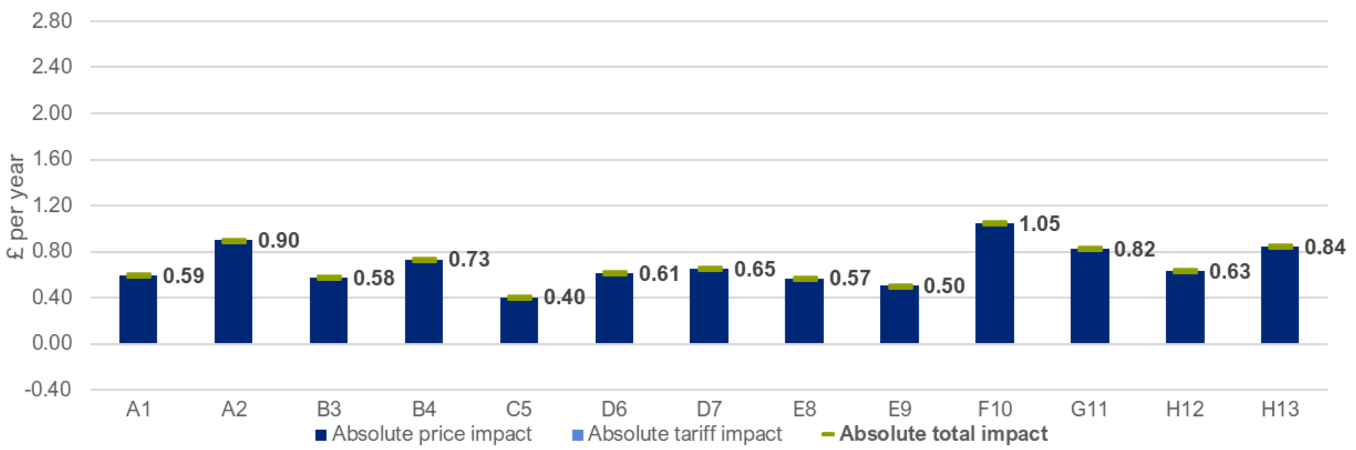


Figure A.18: Impacts on annual bills for Ofgem's consumer archetypes (Price and tariff only, 2040, SP)

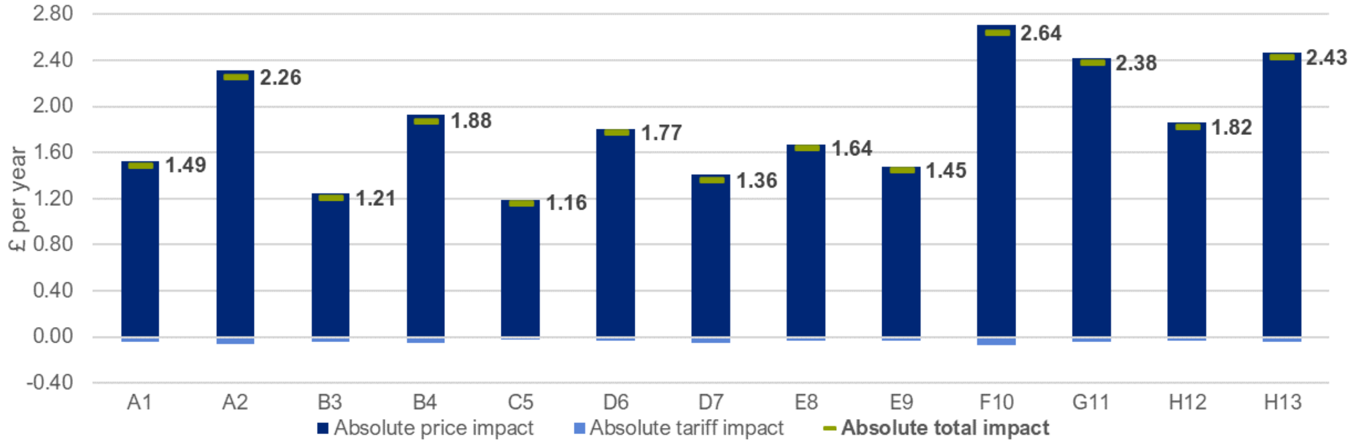


Figure A.19: Total impact on bills for Ofgem's consumer archetypes (NPV, discounted to 2023, SP)

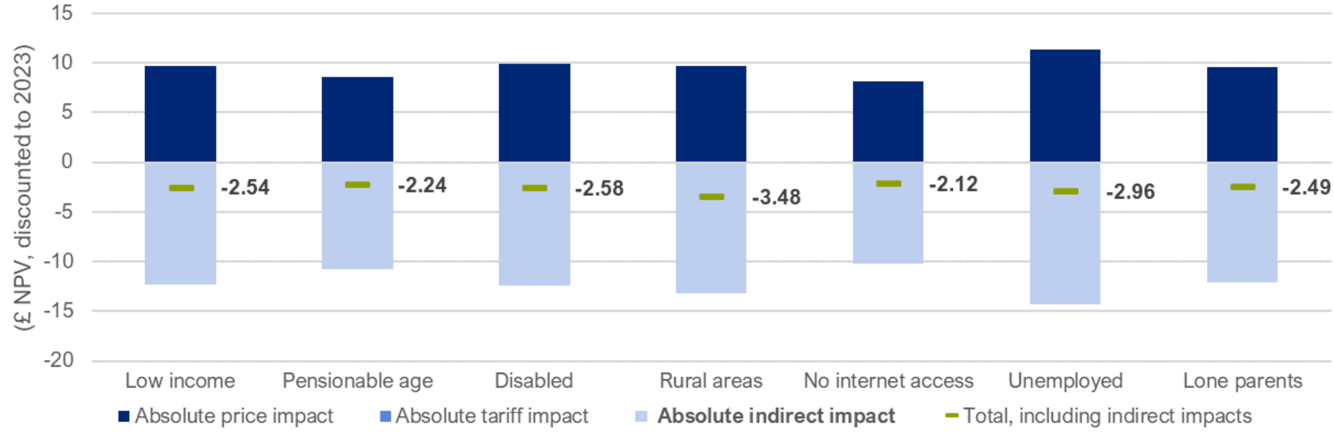


Table A.1: Equity-weighted domestic bill impacts and impacts as a percentage of income (price and tariff effects only, SP)

	Impacts of price and tariff changes (£ NPV)	Impacts of price and tariff changes (£ NPV)	Impacts of price and tariff changes, as % of disposable income
	Ofgem archetypes		
A1	9.92	9.05	0.002%
A2	15.02	12.15	0.002%
B3	8.90	14.22	0.003%
B4	12.41	16.27	0.003%
C5	7.39	18.32	0.004%
D6	11.27	31.84	0.005%
D7	9.97	15.83	0.002%
E8	10.41	27.33	0.004%
E9	9.20	11.13	0.002%
F10	17.75	23.45	0.004%
G11	15.10	25.42	0.004%
H12	11.59	29.60	0.007%
H13	15.42	36.89	0.006%

Statutory archetypes			
Low income	9.62	47.19	0.008%
Pensionable age	8.48	10.49	0.003%
Disabled	9.78	12.15	0.003%
Rural areas	9.57	9.32	0.002%
No internet access	8.05	15.11	0.003%
Unemployed	11.21	18.18	0.004%
Lone parents	9.45	17.71	0.004%

Table A.2: Equity-weighted domestic bill impacts and impacts as a percentage of income (including indirect bill impacts, SP)

	Total impact, including indirect impacts (£ NPV)	**Total equity-weighted impact, including indirect impacts (£ NPV)**	**Total impact including indirect impacts, as % of disposable income**
Ofgem archetypes			
A1	-1.89	-1.73	-0.023%
A2	-2.87	-2.32	-0.030%
B3	-4.44	-7.10	-0.044%
B4	-2.46	-3.23	-0.034%
C5	-1.95	-4.83	-0.057%
D6	-2.97	-8.40	-0.073%
D7	-5.08	-8.05	-0.042%
E8	-2.75	-7.21	-0.052%
E9	-2.43	-2.94	-0.029%
F10	-3.15	-4.16	-0.050%
G11	-3.98	-6.71	-0.059%
H12	-3.06	-7.81	-0.094%
H13	-4.07	-9.73	-0.083%
Statutory archetypes			
Low income	-2.54	-12.45	-0.113%
Pensionable age	-2.24	-2.77	-0.034%
Disabled	-2.58	-3.20	-0.040%
Rural areas	-3.48	-3.39	-0.035%
No internet access	-2.12	-3.99	-0.045%
Unemployed	-2.96	-4.80	-0.056%
Lone parents	-2.49	-4.67	-0.053%

Figure A.20: Impacts on commercial non-domestic archetype consumer bills, SP

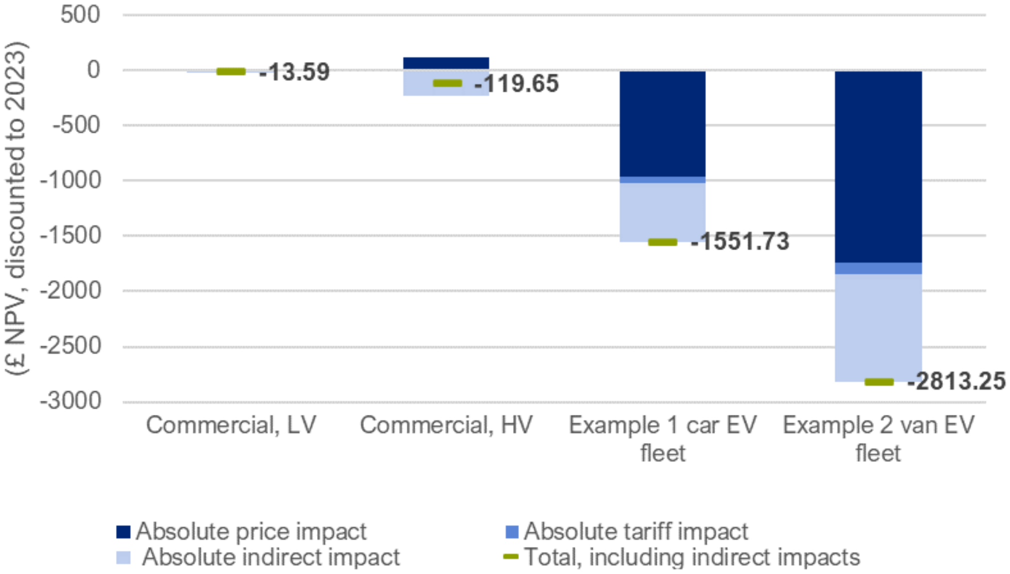
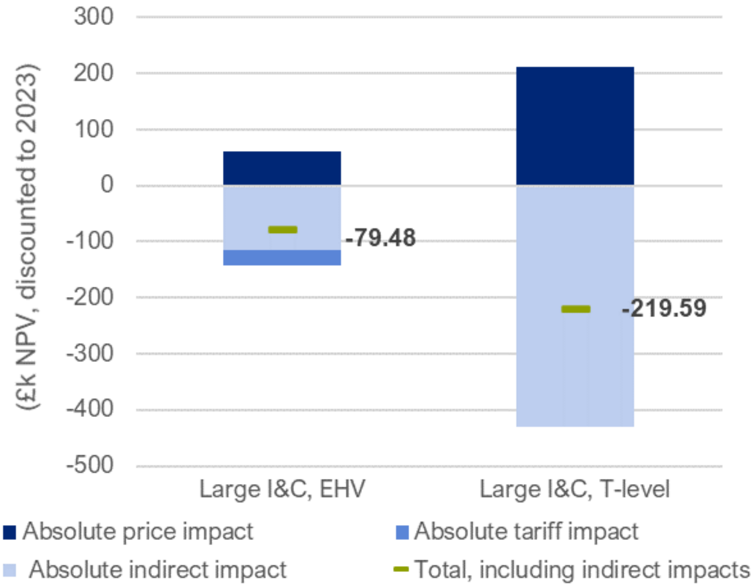


Figure A.21: Impacts on large industrial and commercial non-domestic archetype consumer bills, SP



A.2. Leading the Way

Figure A.22: Change in demand-weighted average DAM price under TNUoS reform option, LW

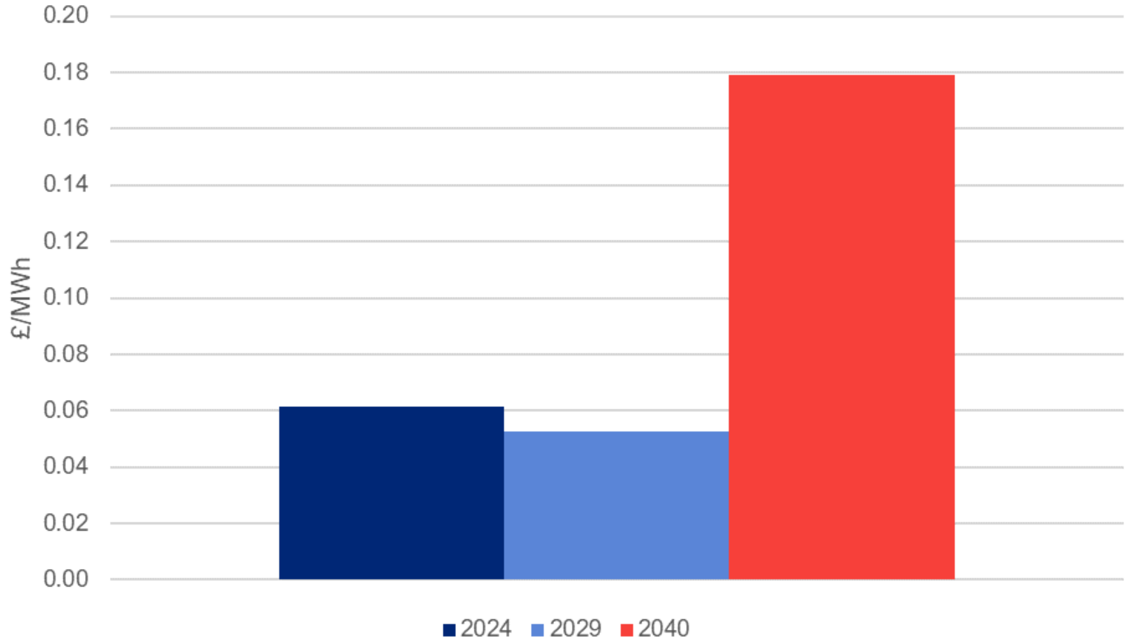


Figure A.23: Change in demand net of BtM generation (Scotland and the north), November to February, LW

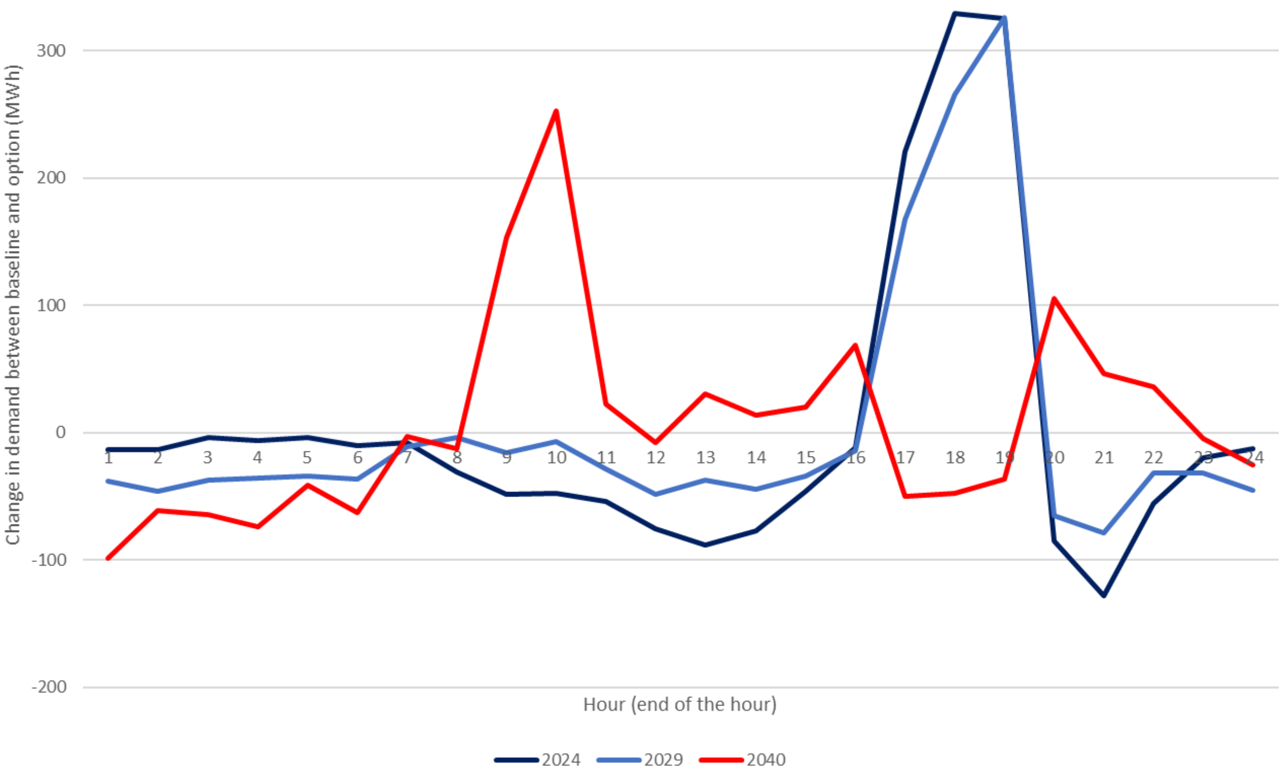


Figure A.24: Change in demand net of BtM generation (all zones), November to February, LW

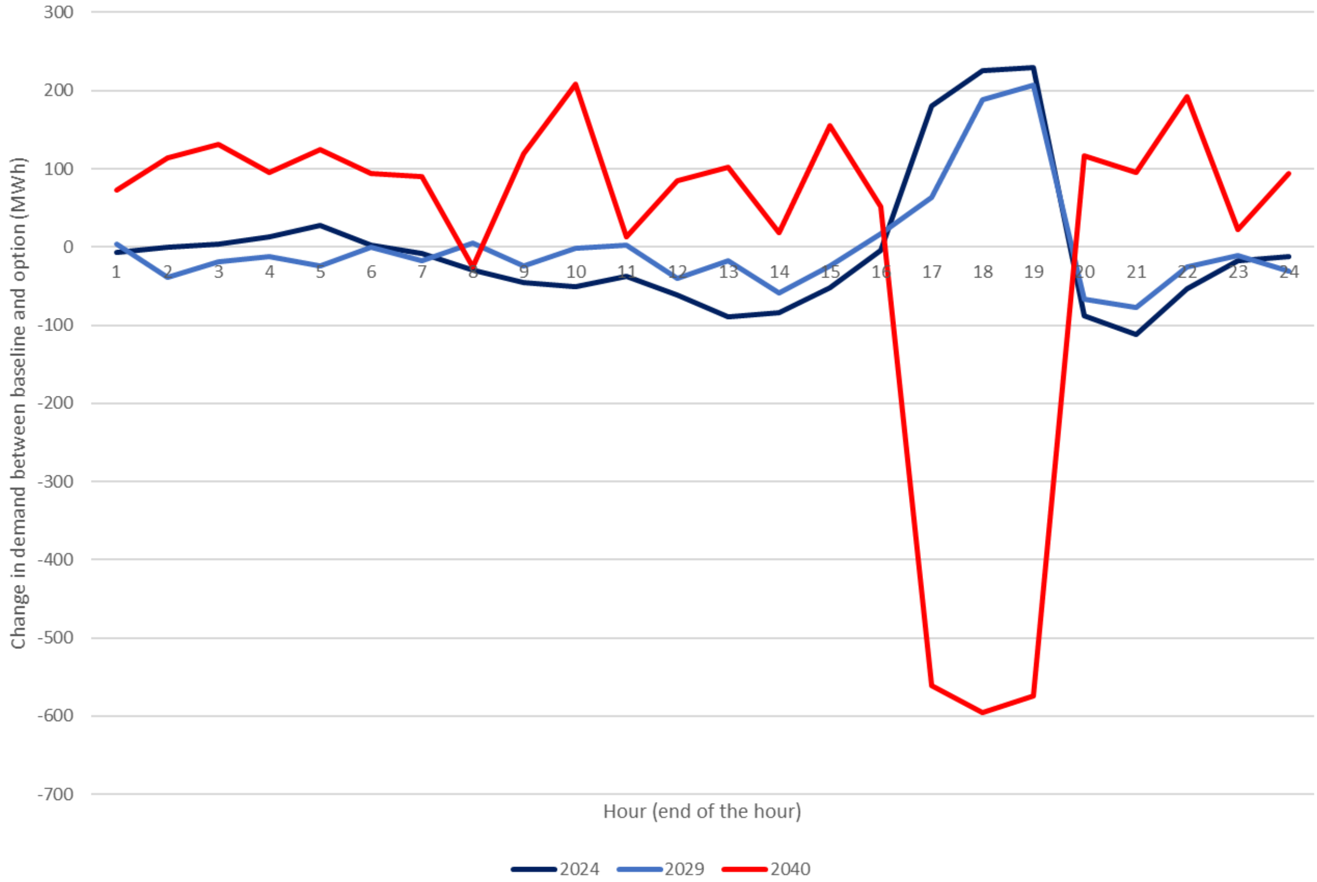


Figure A.25: Impact of the TNUoS reform option on the annual average DAM price in each hour of the day, LW

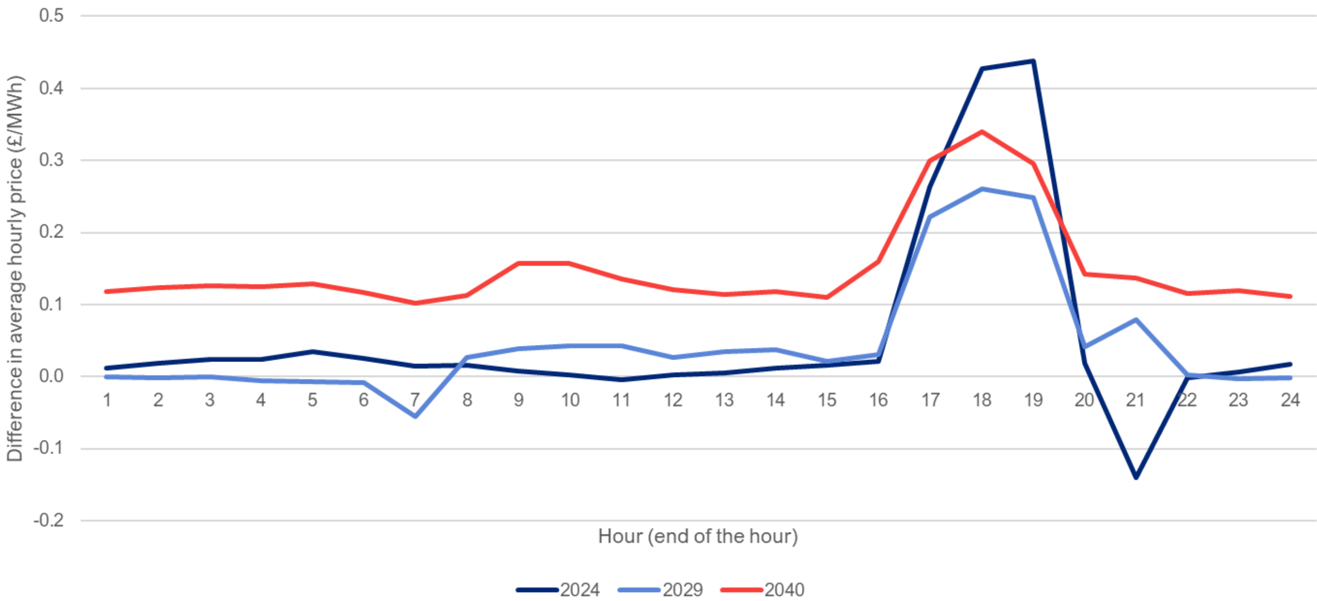


Figure A.26: Transmission network investment by boundary and year under the baseline and the TNUoS reform option, LW

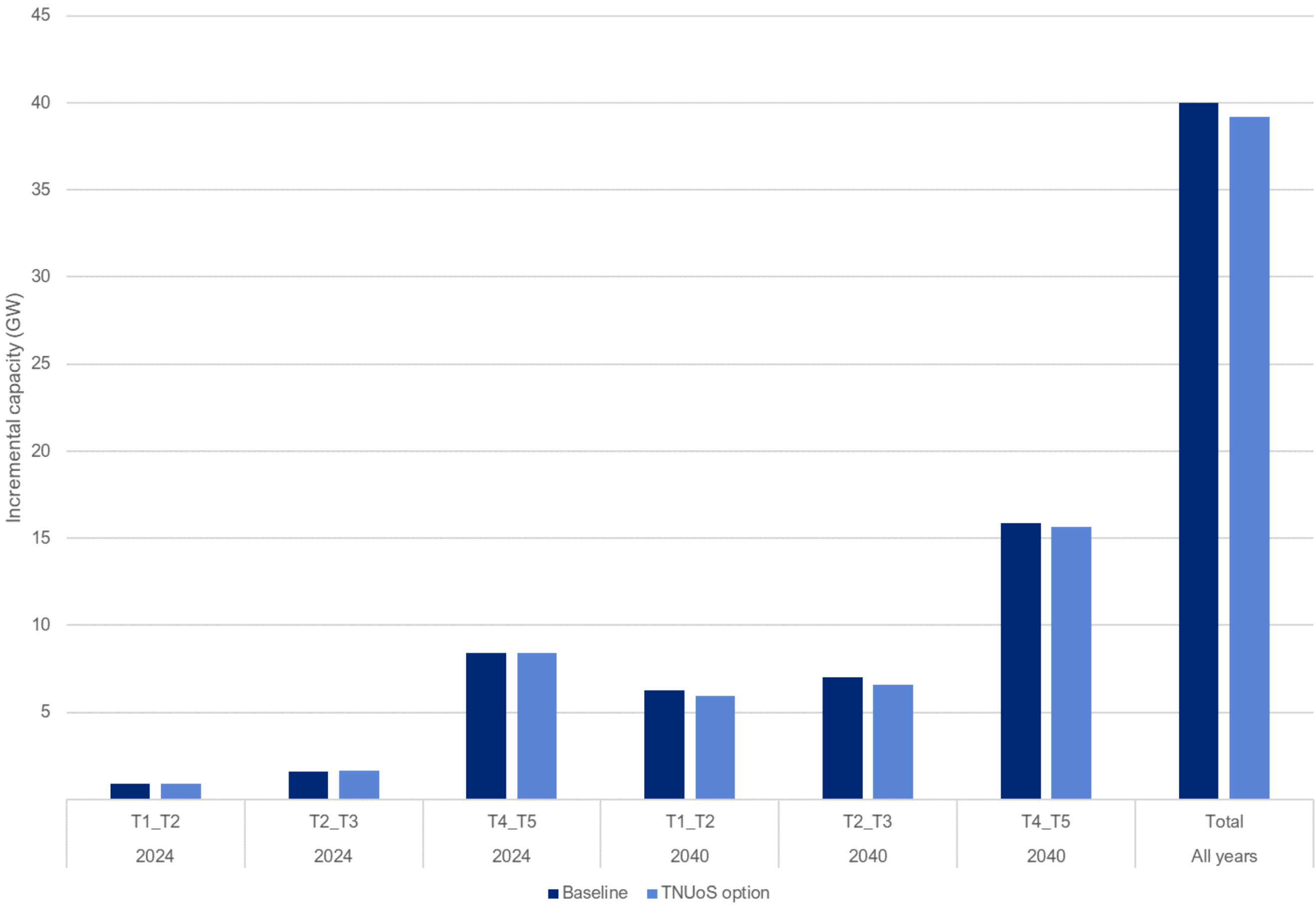


Figure A.27: Dispatch of carbon emitting generation under the TNUoS reform option relative to the baseline, LW

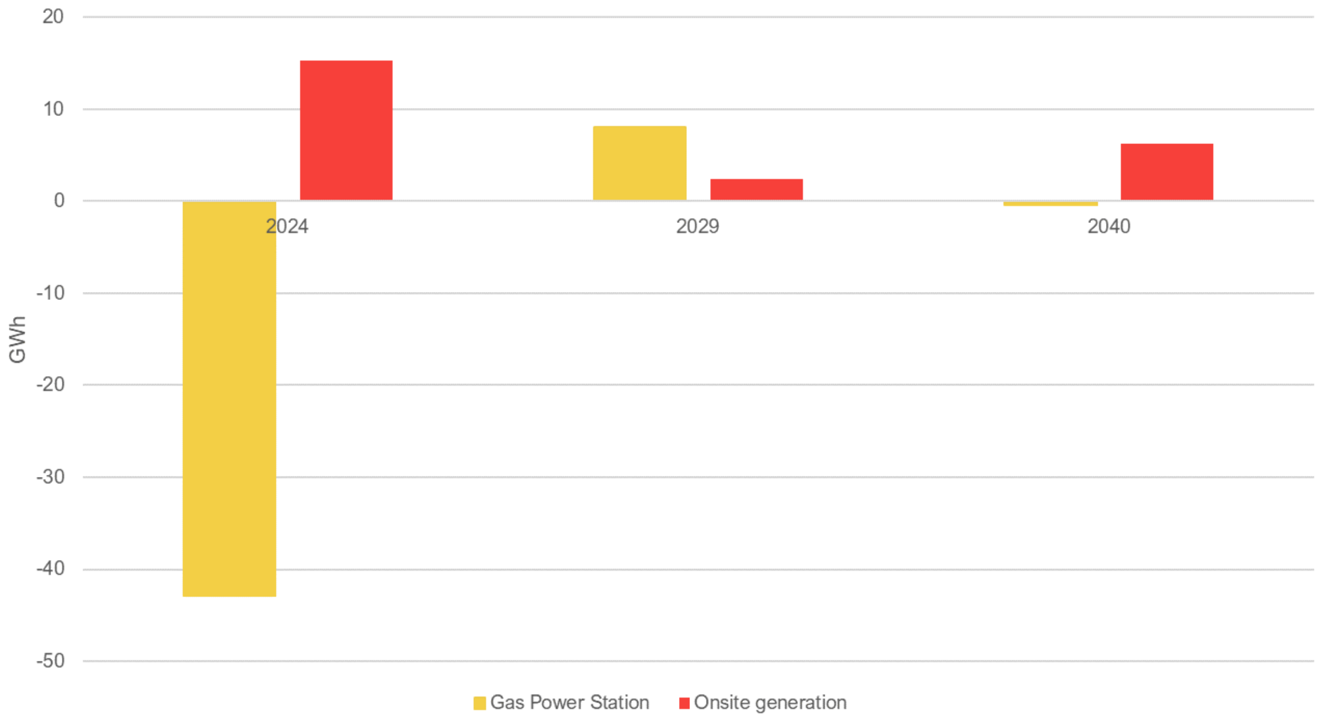


Figure A 28: Reduction in investment in distribution network capacity (positive = consumer benefit, i.e., a reduction in distribution network investment costs) (£m, NPV, discounted to 2023, LW)

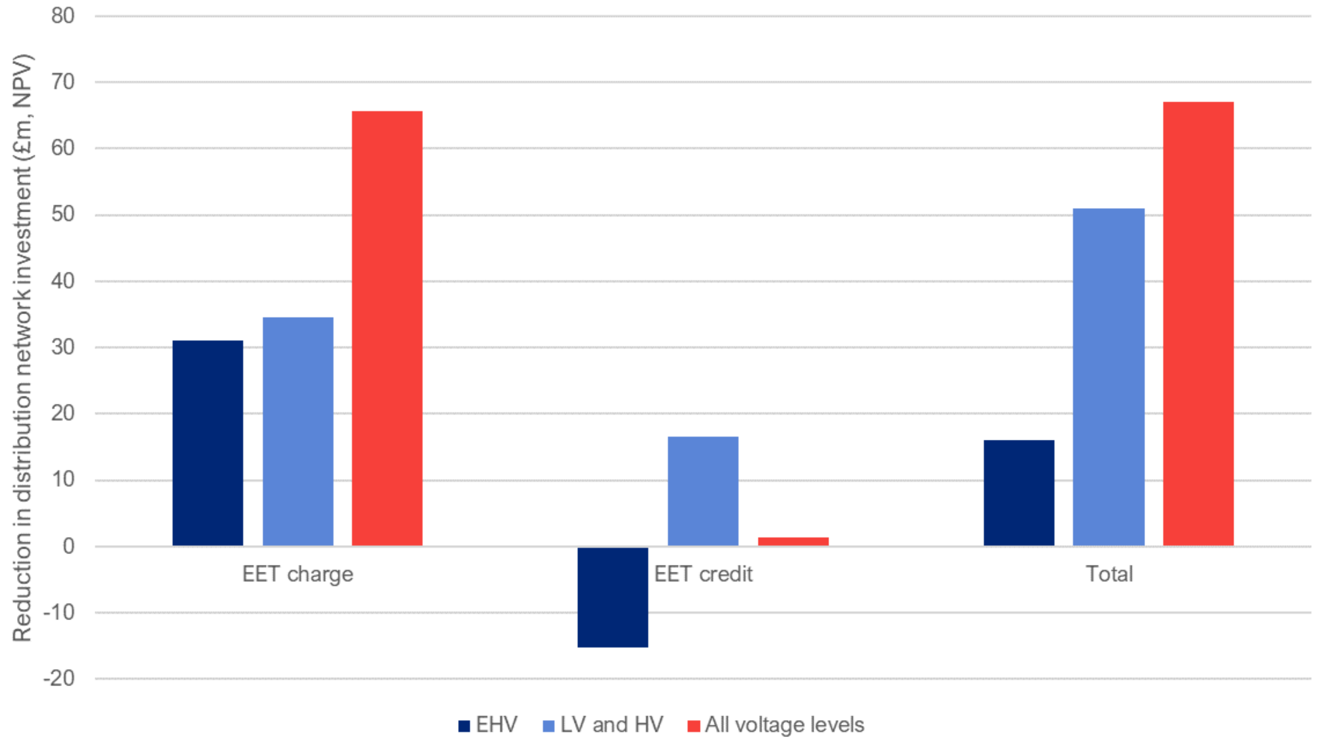


Figure A.29: Total impact on net revenues of transmission-connected producers (£m, NPV, discounted to 2023, LW)

	T1	T2	T3	T4	T5	T6	T7	TOTAL
Offshore_wind	17.56	11.34	26.12	22.62	4.38	33.08	1.19	**116.29**
CCGT_existing	1.40	0.08	0.08	6.48	18.35	0.47	2.39	**29.24**
CCGT_new	-	-	-	4.51	1.15	-	0.07	**5.73**
OCGT_existing	0.00	-	-	0.08	0.17	-	0.17	**0.42**
OCGT_new	-	-	-	0.12	0.41	-	0.02	**0.55**
H2_CCGT	-	-	-	-	-	-	-	**-**
Onshore_wind	12.64	6.56	-	0.14	-0.49	-	-	**18.85**
Solar	-0.39	-0.37	-	-0.23	-3.75	-	-0.21	**-4.95**
Nuclear	-	2.57	2.53	-	4.96	4.36	2.29	**16.71**
Biomass	-0.23	0.41	1.29	6.83	0.86	0.10	-	**9.26**
Hydro	-0.03	-0.00	-	0.00	-0.32	-	-0.03	**-0.38**
Pumped_storage	-11.20	-3.95	-	-8.47	-	-	-	**-23.62**
Battery	-0.45	-0.61	-2.92	-1.43	-7.46	-0.45	-4.35	**-17.66**
TOTAL	**19.31**	**16.03**	**27.10**	**30.66**	**18.25**	**37.56**	**1.55**	**150.44**

Figure A.30: Impacts on net revenues of transmission-connected producers (£/kW, NPV, discounted to 2023, LW)

	T1	T2	T3	T4	T5	T6	T7
Offshore_wind	4.00	4.54	5.01	3.23	1.80	4.12	1.83
CCGT_existing	2.09	1.33	1.22	1.44	1.33	1.20	1.09
CCGT_new	-	-	-	3.02	2.99	-	3.00
OCGT_existing	0.51	-	-	0.51	1.08	-	0.68
OCGT_new	-	-	-	0.85	0.75	-	0.61
H2_CCGT	-	1.40	-	2.76	-0.32	-	-
Onshore_wind	-	-3.38	-	-3.79	-3.08	-	-
Solar	1.72	3.35	-	-	1.90	3.54	3.30
Nuclear	-	0.01	-	2.58	4.20	4.20	-
Biomass	-	-	-	-	-0.45	-	-
Hydro	-	-	-	-	-	-	-
Pumped_storage	-5.54	-5.95	-	-4.23	-	-	-
Battery	-3.01	-2.98	-1.89	-2.09	-1.17	-3.02	-2.16

Figure A.31: Total impact on net revenues of distribution-connected producers (£m, NPV, discounted to 2023, LW)

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14	TOTAL
CCGT_existing	0.90	2.13	1.96	2.55	3.75	2.96	10.97	-	0.92	7.20	1.81	-	0.14	1.76	**37.08**
CCGT_new	-	-	-	-	19.35	1.63	1.21	0.88	-	-	0.17	-0.24	-	0.37	**23.37**
OCGT_existing	0.16	-	0.42	1.40	-	1.05	0.43	0.66	-0.03	-	0.15	-	2.76	0.61	**7.60**
OCGT_new	-	-	1.41	0.91	0.57	0.01	6.47	0.23	0.12	1.58	0.11	-1.09	0.13	0.84	**11.29**
GT	1.36	0.39	1.52	21.95	29.42	16.08	42.03	15.72	10.80	24.71	3.48	-0.52	10.29	5.56	**182.80**
H2_CCGT	-2.04	-2.69	0.35	11.27	26.69	18.68	34.09	15.05	10.30	20.51	3.42	0.34	8.58	5.75	**150.31**
Onshore_wind	-1,054.15	-718.85	22.65	39.75	94.60	41.75	139.25	4.09	4.31	16.28	-4.31	-0.27	2.63	1.75	**-1,410.52**
Solar	-66.31	-49.82	-50.23	-67.86	87.85	38.38	233.62	176.71	224.02	94.74	88.13	12.46	277.79	231.09	**1,230.58**
Biomass	-32.41	-55.69	13.09	14.66	97.49	21.50	35.84	25.83	31.20	14.89	13.79	-2.85	8.68	16.00	**201.99**
Hydro	-436.55	-36.46	-0.20	0.53	0.52	5.22	0.48	22.15	0.19	15.00	0.11	0.07	1.18	1.64	**-426.13**
Battery	0.34	0.04	0.04	-0.03	0.11	-0.02	0.21	0.28	0.02	0.01	-0.49	-0.13	-0.06	0.27	**0.58**
TOTAL	**-1,588.68**	**-860.95**	**-8.98**	**25.13**	**360.35**	**147.24**	**504.61**	**261.59**	**281.85**	**194.94**	**106.37**	**7.77**	**312.11**	**265.62**	**8.96**

Figure A.32: Impacts on net revenues of distribution-connected producers (£/kW, NPV, discounted to 2023, LW)

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
CCGT_existing	-	-	-	-	50.78	40.22	63.28	-	27.07	41.11	22.59	-	15.23	41.65
CCGT_new	-	-	49.34	50.03	-	43.23	83.77	80.92	-0.57	-	36.44	-	-	37.85
OCGT_existing	-	-	51.28	51.16	47.78	40.16	71.65	60.59	31.01	-	-	-	50.09	65.20
OCGT_new	-	-	55.45	55.64	55.56	51.28	99.55	96.19	-	-	20.66	-20.01	23.81	53.32
GT	-494.26	-256.35	5.30	45.42	81.44	81.59	138.44	138.96	57.42	85.43	56.22	-22.22	71.35	92.08
H2_CCGT	-387.28	-209.06	-25.43	8.41	36.36	42.24	67.50	71.96	82.16	117.28	73.52	28.62	82.74	139.53
Onshore_wind	-290.59	-147.36	-21.54	10.60	52.20	40.79	67.11	74.88	4.67	14.11	-26.96	-30.68	30.31	1.02
Solar	16.43	59.26	52.90	52.14	48.81	38.84	-	-	55.95	68.46	65.60	51.80	67.66	65.71
Biomass	-221.81	-107.57	18.46	46.61	68.88	65.42	124.76	129.88	91.59	62.21	31.40	-15.57	20.93	53.52
Hydro	-	-	-	-	70.22	60.26	78.02	70.16	47.07	113.06	98.77	67.31	95.52	115.68
Battery	3,827.42	21.22	28.43	18.46	42.27	8.93	58.74	54.14	-0.12	4.86	-182.39	-83.96	-42.14	61.90

Figure A.33: Increase/decrease of investment in technology specific capacity by year and by distribution zone (MW), LW

2029	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Biomass	-3.7	-17.2	0.0	0.0	20.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BTM_Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore_wind	-137.3	-150.5	74.3	62.3	97.5	0.0	53.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	-128.3	-0.3	0.0	0.0	0.0	128.7	0.0	0.0	0.0	0.0	0.0	0.0
2040	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**	**D7**	**D8**	**D9**	**D10**	**D11**	**D12**	**D13**	**D14**
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BTM_Solar	0.0	-0.9	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore_wind	-271.1	0.0	0.0	0.0	16.1	0.0	240.0	8.3	0.0	0.0	0.0	0.0	6.7	0.0
Solar	0.0	0.0	0.0	-430.3	288.4	0.0	0.0	141.9	0.0	0.0	0.0	0.0	0.0	0.0

Figure A.34: Levelised revenue impacts for embedded onshore wind and solar technologies (£/MWh), LW

	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Onshore_wind	-10.06	-5.32	-0.64	0.15	0.84	1.39	2.93	3.44	0.17	0.48	-0.70	-0.88	2.17	0.15
Solar	-24.03	-11.32	0.32	0.91	4.60	3.39	5.65	5.60	4.43	5.85	5.12	3.72	5.52	5.30

Figure A.35: Total impact of the TNUoS reform option on consumer welfare (NPV, discounted to 2023, LW)

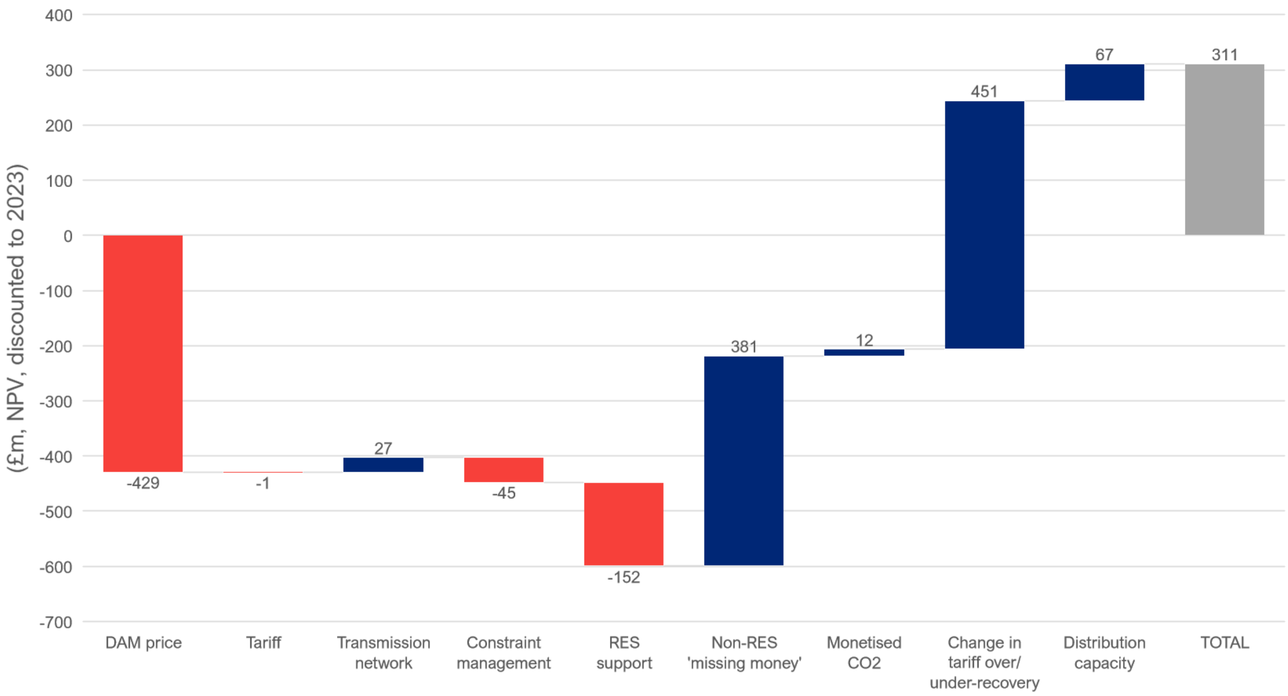


Figure A.36: Total impact on bills for Ofgem's consumer archetypes (NPV, discounted to 2023, LW)

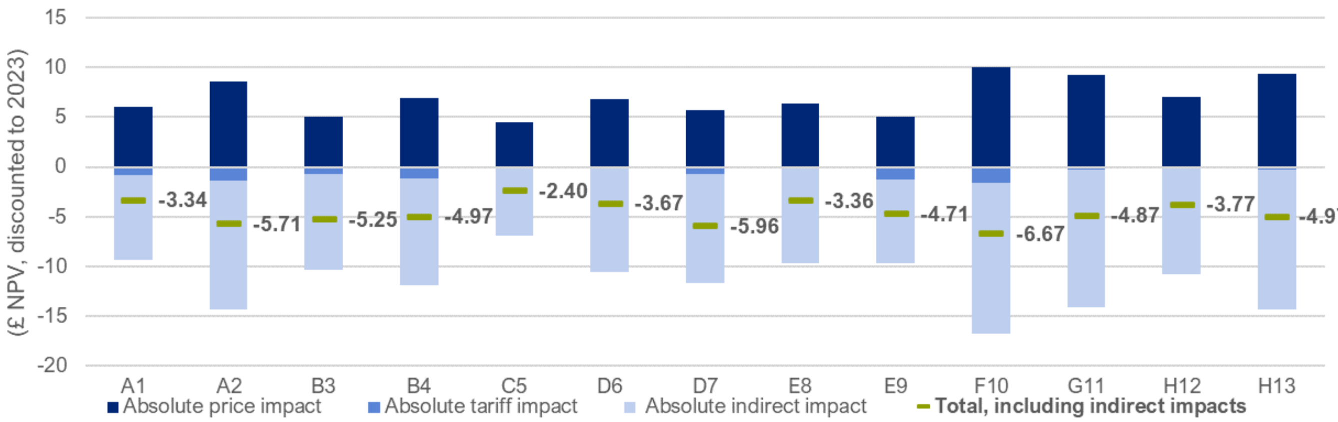


Figure A.37: Impacts on annual bills for Ofgem's consumer archetypes (Price and tariff only) (2024, LW)

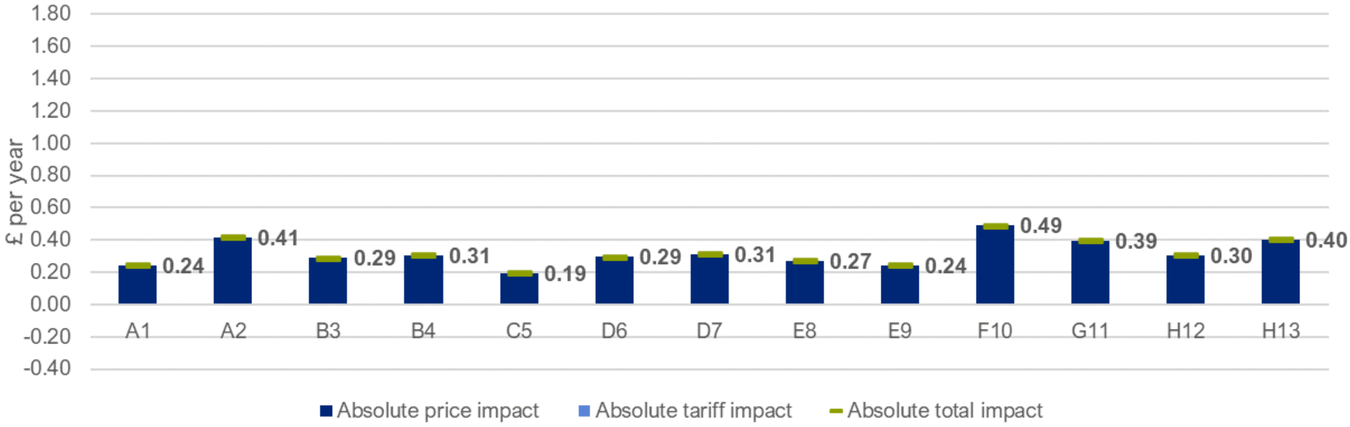


Figure A 38: Impacts on annual bills for Ofgem's consumer archetypes (Price and tariff only) (2029, LW)

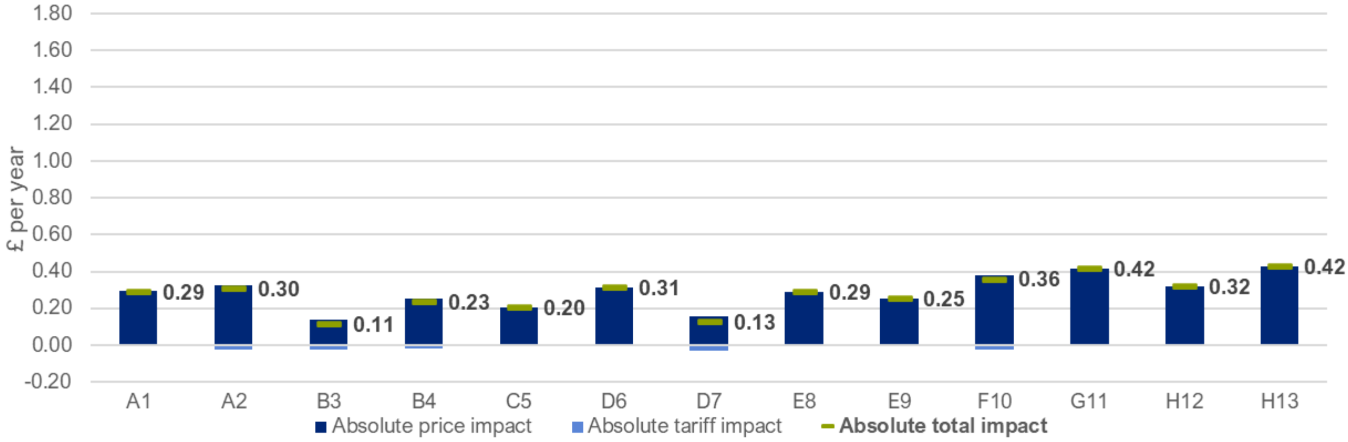


Figure A.39: Impacts on annual bills for Ofgem's consumer archetypes (Price and tariff only) (2040, LW)

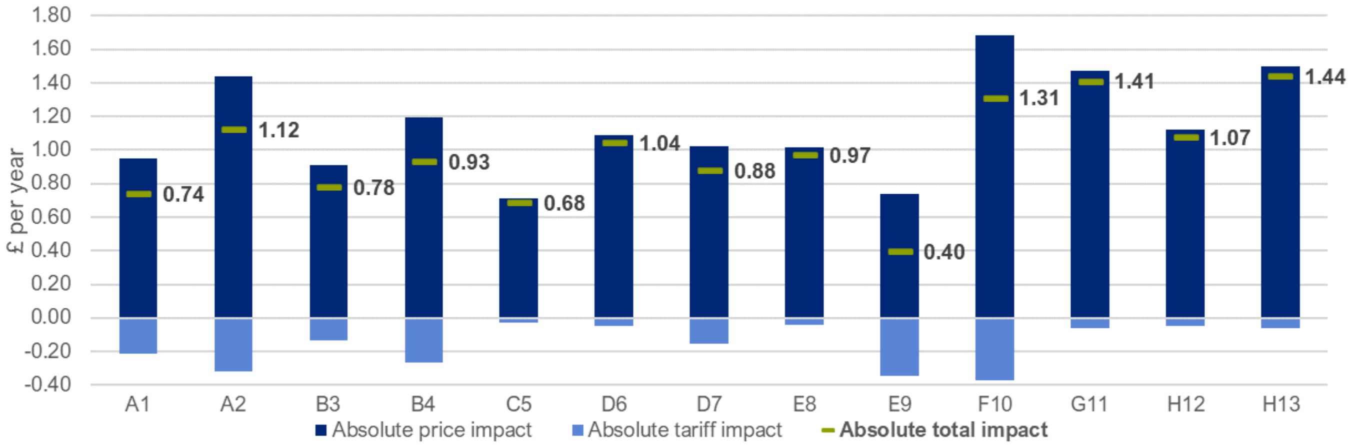


Figure A.40: Total impact on bills for Ofgem's consumer archetypes (NPV, discounted to 2023, LW)

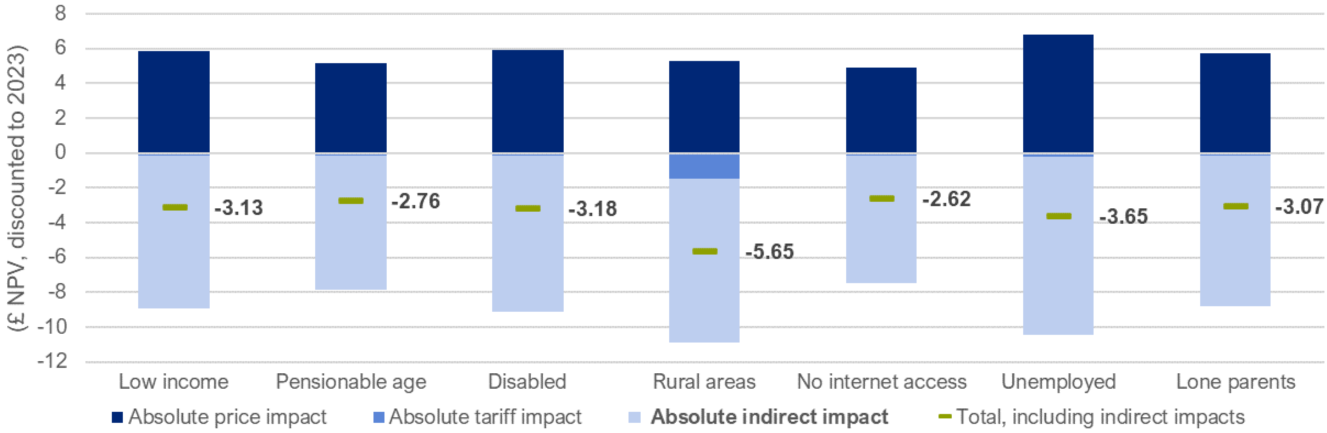


Table A.3: Equity-weighted domestic bill impacts and impacts as a percentage of income (price and tariff effects only, LW)

	Impacts of price and tariff changes (£ NPV)	Impacts of price and tariff changes (£ NPV)	Impacts of price and tariff changes, as % of disposable income
	Ofgem archetypes		
A1	5.21	4.75	0.001%
A2	7.23	5.85	0.001%
B3	4.41	7.04	0.001%
B4	5.79	7.59	0.001%
C5	4.35	10.79	0.002%
D6	6.64	18.76	0.003%
D7	4.93	7.83	0.001%
E8	6.16	16.17	0.002%
E9	3.71	4.48	0.001%
F10	8.46	11.18	0.002%
G11	8.94	15.04	0.003%
H12	6.83	17.44	0.004%
H13	9.12	21.83	0.004%
	Statutory archetypes		
Low income	5.67	27.80	0.005%
Pensionable age	4.99	6.18	0.001%
Disabled	5.76	7.16	0.002%
Rural areas	3.79	3.69	0.001%
No internet access	4.74	8.90	0.002%
Unemployed	6.61	10.71	0.002%
Lone parents	5.57	10.43	0.002%

Table A.4: Equity-weighted domestic bill impacts and impacts as a percentage of income (including indirect bill impacts, LW)

	Total impact, including indirect impacts (£ NPV)	Total equity-weighted impact, including indirect impacts (£ NPV)	Total impact including indirect impacts, as % of disposable income
Ofgem archetypes			
A1	-3.34	-3.05	-0.017%
A2	-5.71	-4.62	-0.023%
B3	-5.25	-8.39	-0.032%
B4	-4.97	-6.52	-0.025%
C5	-2.40	-5.96	-0.042%
D6	-3.67	-10.36	-0.054%
D7	-5.96	-9.45	-0.031%
E8	-3.36	-8.82	-0.038%
E9	-4.71	-5.69	-0.022%
F10	-6.67	-8.81	-0.037%
G11	-4.87	-8.20	-0.043%
H12	-3.77	-9.63	-0.069%
H13	-4.97	-11.90	-0.061%
Statutory archetypes			
Low income	-3.13	-15.35	-0.083%
Pensionable age	-2.76	-3.41	-0.025%
Disabled	-3.18	-3.95	-0.029%
Rural areas	-5.65	-5.51	-0.026%
No internet access	-2.62	-4.92	-0.033%
Unemployed	-3.65	-5.92	-0.041%
Lone parents	-3.07	-5.76	-0.039%

Figure A.41: Impacts on commercial non-domestic archetype consumer bills, LW

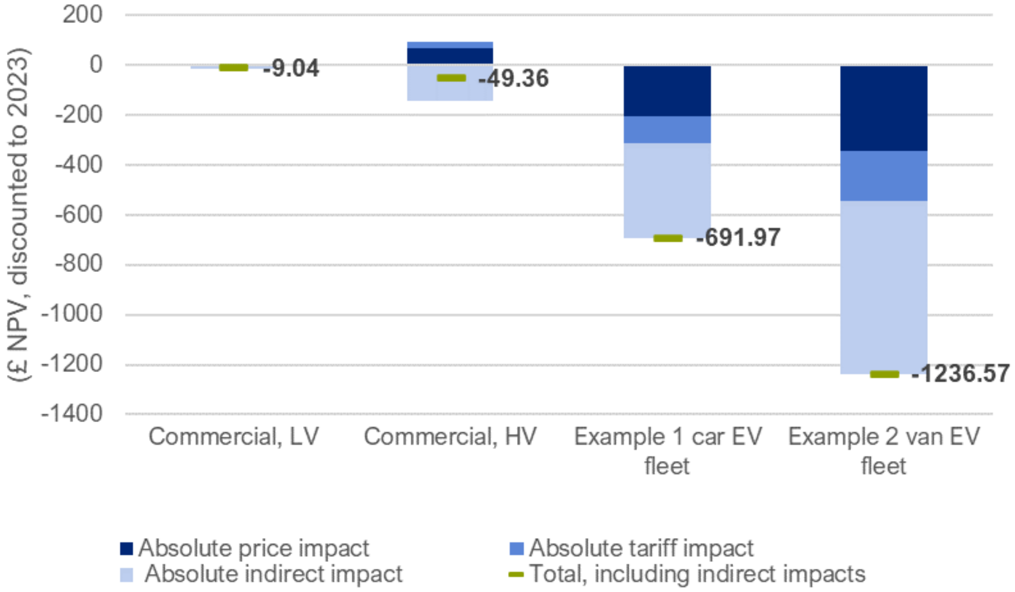
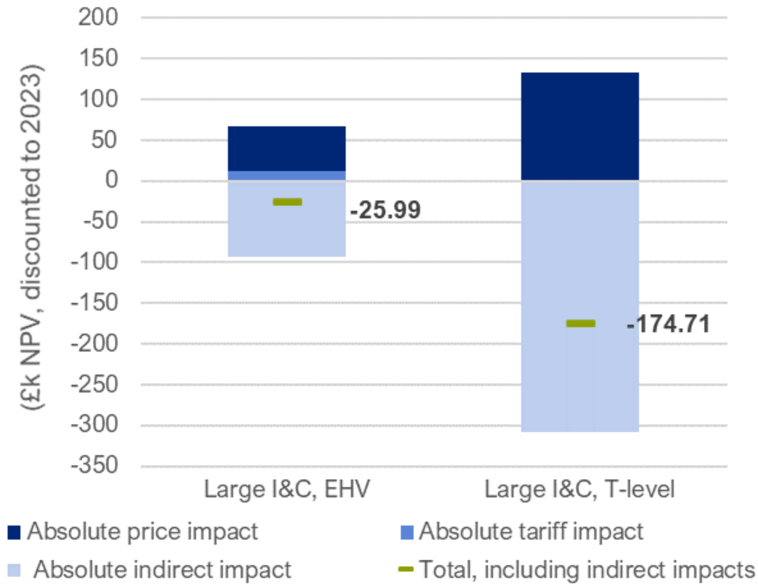


Figure A.42: Impacts on large industrial and commercial non-domestic archetype consumer bills, LW



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