THE POWER OF SONI

Prepared for SONI Ltd

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Contents

Executive Summary

As part of the UK's Net Zero commitment, the Northen Irish electricity sector is currently undergoing significant transformation, which is expected to continue over the coming decades. As transmission system operator (TSO), SONI has a central role in enabling this transformation. Building on significant progress already made, SONI's future plans and actions relating to both the development of operational policy and long-term transmission network planning are critical to Northern Ireland achieving its statutory policy targets.

This report quantifies the value to Northern Ireland of two actions that are central to SONI's Operational Policy Roadmap: the progressive relaxation of two system-wide constraints that currently limit renewable integration, System Non-Synchronous Penetration (SNSP) and Minimum Units Online (MUON).

We model the Northern Ireland system for 2025–2050 using LCP Delta's EnVision model, comparing a counterfactual that keeps today's constraints with factual scenarios that relax SNSP and MUON at different rates. The results show that relaxing both SNSP and MUON together generates consumer cost savings with a net present value of **£3.8 billion** in Northern Ireland. The savings are due to lower constraints costs, as relaxing SNSP and MUON constraints reduces the need to run higher cost thermal units purely for system stability. Our assessment of benefits is robust across sensitivities for low and high commodity prices. Relaxing the constraints reduces exposure to volatility, as a more flexible generation fleet can respond better to price changes, and reduces carbon emissions from the power sector, as more renewable production can be accommodated. We note that these are benefit estimates and do not include any allowance for increases in SONI's internal costs.

We also assess how these system-wide impacts translate into consumer electricity bills. In our central outlook, the regulated domestic tariff falls from **29.7 p/kWh** today to **26.9 p/kWh** by the end of the next price control period, a reduction of about **9%**. Translating SONI's actions into bills impact, relaxing the SNSP and MUON constraints delivers benefits of **1.4–1.8 p/kWh by 2032**, depending on assumed commodity prices, rising to **3.2–4.0 p/kWh by 2050**. Based on the Utility Regulator's typical domestic consumption of **3,200 kWh**, this equates to a bill saving of around **£48–£60 per year** in 2032 and **£106–£136 per year** by 2050 per household. Large industrial users could expect to see six-figure annual savings by 2050.

1 Introduction

As part of Northern Ireland's Net Zero commitment, the Northen Irish electricity sector is currently undergoing significant transformation, which is expected to continue over the coming decades. As transmission system operator (TSO), SONI has a central role in enabling this transformation. Building on significant progress already made, SONI's future plans and actions relating to both the development of operational policy and long-term transmission network planning, are critical to Northern Ireland achieving its statutory policy targets.

In this context, SONI has commissioned Frontier Economics ("Frontier") and LCP Delta ("LCP") to quantify the value of some of its planned actions to facilitate Northern Ireland's energy transition, looking at consumer costs and socio-economic costs, as well as carbon emissions.

The remainder of this report is structured as follows:

- Section 2 introduces the transformation of the electricity sector expected in Northern Ireland, and the importance of SONI in facilitating this transformation;
- Section 3 explains the results of our analysis, showing the impact of the changes facilitated on consumer costs on an absolute basis; and
- Section 4 explains how these changes translate into changes in electricity bills for consumers.

2 The changing electricity system

To quantify the value of SONI's planned actions to facilitate Northern Ireland's energy transition, it is essential to first understand:

- the extent of the sector transformation that is required; and
- the critical role that SONI plays in enabling this transformation.

2.1 The transformation of the Northern Irish electricity sector

The **Energy Strategy - Path to Net Zero Energy**[1], published in December 2021, set Northern Ireland on a path to deliver its share of the UK's Net Zero commitment. It introduced a target to meet at least 70% of electricity consumption from a diverse mix of renewable sources by 2030. A key pillar of the Energy Strategy is also to 'Create a Flexible, Resilient and Integrated Energy System', including a need to review and monitor the security and resilience of the changing energy system, and implement measures on system flexibility services.

The **Climate Change Act (Northern Ireland) 2022**[2] then set in place the legal basis for Northern Ireland's emissions targets and sectoral plans. The Act establishes a net zero emissions target by 2050, along with interim milestones for 2030 and 2040. Notably, the Act requires the Department for the Economy to ensure that at least 80% of electricity consumption is from renewable sources by 2030. This is a significant step up from today, where renewables account for less than half of electricity consumption.

In June 2025, DAERA published the first draft **Climate Action Plan (2023-2027)**[3] for consultation. The plan sets out policies and proposals across eight sectors (energy, transport, business and industrial processes, residential and public buildings, waste, agriculture, land use/land-use change and forestry (LULUCF), and fisheries), designed to keep NI within the 2023-27 carbon budget.

This policy development, coupled with technological advances, point to a fundamental transformation of the electricity system.

The move away from fossil fuels and the introduction of new technologies will substantially **increase electricity demand**. Key drivers include:

1 Northern Ireland government (2021), Energy Strategy - Path to Net Zero Energy, Available here

2 Northern Ireland Government (2022), Climate Change Act (Northern Ireland) 2022, Available here

3 Department of Agriculture, Environment and Rural Affairs (2023), Climate Action Plan (2023–2027), Available here

- the growth in use of electric vehicles, with 80% of new cars and vans expected to be zero-emission by 2030 and 100% by 2035[4];
- rising data centre consumption across the island of Ireland, projected to grow by around 5% annually[5]; and
- the electrification of heat in homes, public buildings, and industry through heat pumps and heat networks.

According to SONI estimates, electricity demand could rise by 20% by 2030[6] and by 120% by 2050[7].

Policy requires this rising demand to be met predominantly with renewable generation, with a target of **80% of electricity consumption coming from renewable sources by 2030**. The draft Climate Action Plan sets indicative growth targets for both wind and solar generation, including significant deployment at the distribution network level. Beyond 2030, offshore wind is expected to play an important role, with the Offshore Renewable Energy Action Plan (OREAP)[8] setting an initial target of at least 1 GW of capacity. The ambition of achieving around 80% renewable electricity by 2030 is expected to bring **more generation capacity onto the distribution grid**, including technologies such as rooftop solar PV and wind turbines connected at distribution level.

With rising demand and a greater share of renewables, the system will need significant investment in **flexibility solutions**, such as energy storage, demand response, and smart grid technologies, both to reduce peak loads (which will avoid costly network upgrades) and ensure supply during periods of low renewable generation.

Another important change will be **increased interconnection capacity**, allowing Northern Ireland and the wider island of Ireland to integrate more closely with Great Britain and continental Europe. For NI, this includes the LirIC interconnector, which has already received Cap and Floor approval from Ofgem. Two further interconnectors are planned in the Republic of Ireland:

- the Celtic Interconnector, the first direct link between Ireland and continental Europe, where construction has already started; and
- MaresConnect, which is undergoing final authorisation procedures.

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4 UK Government/Department for Transport & OZEV (2024), Pathway for zero emission vehicle transition by 2035 becomes law, Available here

5 Electricity demand from data centre is expected to increase until 20235 and then is assumed to stay relatvel stable until 20250. centres are SONI and EirGrid (2025), All-Island Resource Adequacy Assessment 2025–2034, Available here

6 SONI and EirGrid (2025), All-Island Resource Adequacy Assessment 2025–2034, Available here

7 This is according to the most conservative scenario (constrained growth). EirGrid and SONI (2024), Tomorrow's Energy Scenarios 2023, Available here

8 Department for the Economy (2025), Offshore Renewable Energy Action Plan (OREAP), Available here

2.2 The role of SONI in enabling this transformation

To enable this transformation, significant investment is needed to upgrade and strengthen Northern Ireland's electricity networks and ensure the right technologies are connected to support the expected changes. As Northern Ireland's TSO, SONI has a central role in planning, operating, and developing the grid, and that role will grow more complex as the energy transition accelerates.

2.2.1 SONI's role as a TSO

SONI manages the high-voltage grid in real time, transporting electricity from generators to distribution networks, while maintaining system stability, security, and efficiency. It continuously balances supply and demand, safeguards frequency and voltage, coordinates outages, and procures system services. Together with EirGrid, SONI operates the all-island Single Electricity Market through SEMO and SEMOpx, scheduling and dispatching resources across the day-ahead, intraday, and balancing markets. SONI also undertakes resource-adequacy assessments and operates the capacity market, alongside Eirgrid.

SONI manages connections to the transmission network in Northern Ireland, issuing offers, defining access rights, and acting as the contractual interface for generators, storage, large demand users, interconnectors, and other connecting parties.

Alongside its day-to-day operations, SONI also supports long-term transmission network planning. It identifies system needs, scopes and evaluates reinforcements, completes outline design and consenting, and then hands approved projects to the transmission asset owner (NIE Networks) for delivery and commissioning. This plan-led approach keeps grid development aligned with demand growth, renewable integration, and policy objectives.

As an independent system operator, SONI collaborates closely with the electricity DSO (NIE Networks), the gas TSO, statutory bodies, local authorities, communities, and industry to facilitate the energy transformation.

2.2.2 SONI's role in the transformation of the electricity system

SONI therefore plays a critical role in enabling the transition of Northern Ireland's electricity system and in meeting statutory policy targets.

As part of its long-term network planning, SONI's Transmission Development Plan for Northern Ireland (TDPNI) 2023-2032 recognises that significant upgrades are required to the electricity transmission network to ensure that it evolves to meet future needs efficiently and reliably. The TDPNI incorporates a number of major investments, such as modernising parts of the grid in Greater Belfast and upgrading the transmission system in County Antrim.

The real-time operation of the grid, SONI's other core responsibility, is focused around maintaining three related areas, each of which are likely to become more complex as the transition continues:

- **Dynamic stability**: The ability of the power system to maintain stable operation when faced with disturbances such as sudden changes in generation or demand, faults, or equipment failures. It covers frequency stability, voltage stability, transient and small-signal stability, and risks specific to inverter-based resources (IBRs) like oscillatory and resonance stability.
- **Reserve & ramping**: This is related to the system's ability to keep supply and demand balanced in real-time. Reserve is the generating (or demand-side) capacity available to the system operator within a short interval of time to respond to imbalances between supply and demand, ensuring the power system frequency remains within safe limits. It is essential for real-time frequency control, allowing the system to cope with variability in demand, renewable generation, and power transfers across HVDC interconnectors, as well as sudden events like the loss of a large generator or interconnector. Ramping is the rate at which power flows can change.
- **Operational security**: This is related to keeping the grid within safe technical limits for voltage, thermal loading, and short-circuit levels, both in normal operation and under contingencies. It ensures that electricity can flow reliably while protecting assets and customers from potential disruptions

While many of SONI's activities are needed to support the transition, dynamic stability is a key priority. At the moment, dynamic stability is primarily maintained through two key system-wide constraints[9].

- **System Non-Synchronous Penetration (SNSP):** a cap on the instantaneous share of non-synchronous resources (wind, solar and HVDC imports) relative to demand and HVDC exports.
- **Minimum Units Online (MUON):** a requirement to keep a minimum number of conventional synchronous generators online in each jurisdiction to provide essential services such as voltage control (reactive power capability) and inertia (the natural resistance of rotating mass that helps keep system frequency near 50 Hz).

These constraints are necessary to ensure secure operation. However, they also limit the amount of renewable electricity that can be accommodated at any moment, and therefore will pose a material operational barrier to meeting the Climate Change Act (Northern Ireland) 2022 target that 80% of electricity consumption comes from renewable sources by 2030. As renewable capacity continues to grow, the frequency and duration with which these constraints

[9] Other constraints include a system-wide inertia floor (23 GVA·s) and a RoCoF limit of 1 Hz/s.

"bind" will increase unless they can be progressively relaxed while maintaining system security.

The EirGrid-SONI Operational Policy Roadmap (2025–2035)[10] sets out clear priorities and actions that demonstrate SONI's commitment to addressing these challenges. An important part of the Operational Policy Roadmap is the progressive relaxation of SNSP and MUON so that higher levels of renewable generation can be integrated safely. The key milestones targeted are:

- **SNSP**: increasing the operational limit from 75% to 95% by 2030, reaching 100% by 2035; and
- **MUON**: gradually reducing the minimum number of conventional units to three or fewer by 2030, with the goal of operating with no conventional units online by 2035.

10 EirGrid and SONI (2025), Operational Policy Roadmap 2025-2035, Available here

3 Valuing SONI's impact on the electricity system

SONI has committed to clear operational policy actions to allow the current SNSP and MUON system-wide constraints to be progressively relaxed, while maintaining system security. As these are the central levers of the EirGrid-SONI Operational Policy Roadmap, our analysis of the value of SONI's impact on the electricity system focuses specifically on the value to the Northern Ireland electricity system of relaxing these two system-wide constraints.

This section first details our approach to valuing SONI's impact, before setting out the results of our analysis, and then summarising.

3.1 Approach

To assess the potential future impact of progressively relaxing the SNSP and MUON system-wide constraints, we have undertaken detailed modelling of the Northern Irish electricity system over the 2025-2050 period. Specifically, we estimate the impact of SONI achieving the targets to relax the SNSP and MUON constraints by comparing a counterfactual scenario, in which SONI takes no action, with a factual scenario that includes SONI's operational policy actions. This approach assumes that the difference between the two represents the value of SONI's actions.

Scenarios

In collaboration with SONI, Frontier and LCP developed the detail of a number of factual scenarios to be modelled, each representing different assumed levels of SNSP and MUON, capturing different levels of ambition and timing in SONI's actions. To test robustness, we also vary assumptions for external factors, such as forecast commodity prices, enabling us to assess the impact of SONI's actions across a range of conditions.

The full range of counterfactual and factual scenarios are shown in Figure 1.

Figure 1 Counterfactual and factual scenarios modelled

Scenario	Description	Commodity prices
Counterfactual	▪ SNSP remains at 75%, ▪ Three thermal units on the NI system, and seven on the all-island system	Low, medium and high prices
Factual 1 and 2: SNSP	see table below	Medium prices
Factual 3 and 4: MUON	see table below	Medium prices
Factual 5: SNSP & MUON	▪ SNSP follows profile of Factual 2 ▪ MUON follow profile of Factual 4	Low, medium and high prices

Factual 1 and 2: SNSP

	2025	2026 H2	2027 H2	2029 H2	2030 H2	2035 H2	> 2035
Factual 1 - SNSP	75%	80%	85%	90%	95%	95%	95%
Factual 2 - SNSP	75%	80%	85%	90%	95%	100%	100%

Factual 3 and 4: MUON

	2025	2027	2032	2034	> 2035
Factual 3 – MUON (ROI, NI)	4, 3	3, 2	2, 1	1, 1	1, 1
Factual 4 – MUON (ROI, NI)	4, 3	3, 2	2, 1	1, 1	0, 0

Source: Frontier Economics, LCP Delta, SONI

Note: We note that the SNSP increase and the MUON decrease are modelled across the whole island of Ireland.

The counterfactual (CF) scenario assumes that SNSP remains at 75% out to 2050, with seven thermal units remaining on the all-island system, three of which are in Northern Ireland. We consider three different sets of commodity prices to account uncertainty in global fuel and carbon markets.

Five different factual scenarios are also modelled. These are split into three categories.

- **Scenarios testing the effects of relaxing the SNSP constraint (higher SNSP):**
  - Factual 1 (F1) assumes a moderate increase in SNSP, rising from 75% in 2025 to 95% by 2030 and remaining constant thereafter.
  - Factual 2 (F2) follows the same path as Factual 1 until 2030, then continues to 100% SNSP by 2035.
- **Scenarios testing the effects of relaxing the MUON constraint (lower MUON):**
  - Factual 3 (F3) assumes a moderate reduction in the MUON, with the requirement decreasing to three units in ROI and two in NI by 2027, to two and one respectively by 2032, and to one unit in each jurisdiction by 2034.
  - Factual 4 (F4) follows the same path as factual 3, and then assumes that the MUON drops to zero.
- **Scenario testing both the effects of higher SNSP and lower MUON:**
  - Factual 5 (F5) combines Factual 2 (SNSP to 100%) and Factual 4 (MUON to zero), representing the most ambitious pathway.

With the exception of Factual 5, each factual scenario is assessed under a central commodity price assumption. Factual 5, on the other hand, is modelled under three different sets of commodity prices (consistent with those under which the counterfactual scenario is modelled). The assumptions underpinning each of these scenarios can be found in Annex B .

Key modelling outputs

Our modelling focusses on the impact of SONI's actions on consumer costs within the Northern Irish electricity system, as well as SONI's impact on carbon emissions. However, we also model the impact on socio-economic costs within the system. Annex D provides further details on how socio-economic costs differ from consumer costs, as well as the results of this further analysis.

The modelling involved modelling the whole of ISEM and then assigning the costs to either ROI or NI. For most elements, the proportion of costs was assigned based on the proportion of demand in the two regions. The exception to this was policy costs – where costs were assigned based on the contracts of specific plants (with e.g. NIRO costs assigned to NI). Customer bills are made up from a number of different categories. We have based our analysis on the PowerNI regulated tariff. In setting the tariff, UR breaks customer bills down into five categories:

1. **Wholesale costs**, which consist of:
   a. **Wholesale energy cost** – the price suppliers pay for electricity purchased from generators on the wholesale market.
   b. **Capacity charge** – The capacity charge is a payment made to electricity generators for making their generation capacity available to meet peak demand, ensuring system reliability. Charges are levied by suppliers on customers' daytime (7am – 11pm) consumption.
   c. **Imperfections charge – covering:**
      i. **balancing costs:** payments to generators and other flexibility providers for actions that keep supply and demand in balance; and
      ii. **constraint costs:** payments to resolve locational constraints and maintain system stability.
   d. **Other wholesale charges** – including a residual error volume price currency cost price, AOLR fee, SEMOpx and ECC charge.
2. **Northern Ireland Renewables Obligation (NIRO)** – An obligation on suppliers in Northern Ireland to purchase renewable obligation certificates (ROCs) from renewable generators. These costs are passed on to customers. We do not subdivide this cost category.
3. **Use of system charges,** consisting of:

a. **Supplier Transmission Use of System (STUoS)** – Charge levied on suppliers to recover the 75% of the efficient costs of the Transmission Owner (TO), incurred to upgrade and maintain the electricity network.[11]

b. **DUoS** – Charge levied on suppliers to recover the efficient costs of the DSO.

4. **Levies,** including:
   a. **System Support Services (SSS)** – A charge designed to cover both SONI's internal costs,[12] and the costs required to provide Ancillary Services.[13]
   b. **Other levies** – The Public Service Obligation (PSO) levy, designed to support Public interest objectives, and $CAIR_t$ tariff, designed to fund the Moyle interconnector.[14]
5. **Supplier charge** – Additional revenue to fund the electricity supplier's efficient costs and allowed profit margin of 2.2%.

To carry out detailed system modelling for some of these cost categories, we rely on LCP's EnVision model. EnVision is a widely used electricity market model, used by UK institutions such as BEIS, National Grid ESO and Ofgem. It is fully configured to represent the Integrated Single Electricity Market (I-SEM) and has been used extensively by LCP and Frontier. Annex A provides more detail on EnVision[15]. Figure 2, illustrates the costs faced by electricity customers which are captured through EnVision (those highlighted in yellow).

The EnVision modelling involved modelling the whole of ISEM and then assigning the costs to either ROI or NI. For most elements, the proportion of costs was assigned based on the proportion of demand in the two regions. The exception to this was policy costs – where costs were assigned based on the contracts of specific plants (with e.g. NIRO costs assigned to NI).

For costs not estimated within EnVision, we take one of two modelling approaches:

- **Detailed approach** - In the case of Use of System costs, SSS charges and supplier margin, we produce a detailed forecast of the future evolution of costs; and
- **Simple projection** – We assume that the other costs, highlighted grey in Figure 2, will remain constant in real terms for the next price control.

11 The remaining 25% of costs are levied on generators as part of the GTUoS charge.

12 85% of SONI's internal costs are recovered through the SSS charge, with the remaining 15% recovered through the GTUoS charge.

13 In the latest two financial years, the SSS charge has included a "CEP court ruling" element. This is to recover SONI's potential liability in meeting the High Court of Ireland's verdict that certain generators who were constrained downwards were not sufficiently remunerated under the Clean Energy Package.

14 We note that both the CAIRt and PSO charges have been negative in recent years, resulting in payments to customers.

15 We note that the EnVision model requires a series of exogenous assumptions on demand, RES capacity, the prices of carbon, gas and hydrogen, and the costs of technologies that are assumed to be built endogenously (dispatchable generation capacity and storage). Annex B details the assumptions used.

Figure 2 Costumer bill analysis and how

Power NI category	Sub-category	Description
Wholesale costs	Wholesale energy price	Modelled by LCP's envision software. To calculate the impact on customer bills, we divide by total metered demand to get the p/KWh charge faced by consumers.
	Capacity charge	
	Imperfections charge	
	Other wholesale charges	These costs are assumed to remain constant in real terms going forwards.
NIRO	NIRO	Modelled by LCP's envision software, as part of policy costs. To calculate the impact on customer bills, we divide by total metered demand to get the p/KWh charge faced by consumers.
Use of System	STUoS	Projected forward based on revenue forecast presented by the UR in NIE Network's final determinations. We use the forecast for Transmission revenue to project STUoS and the distribution revenue forecast to project DUoS.
	DUoS	
Levies	SSS	We account for future changes in System Support costs due to the introduction of FASS, as well as projecting SONI internal costs forwards.
	Other Levies	These costs are assumed to remain constant in real terms going forwards.
Supplier margin	Supplier Margin	Assumed to remain constant as a share of total costs.

Key: Frontier modelling output | LCP modelling output | Low value – simple projection used

Source: Frontier Economics based on Power NI's regulated tariff

The EnVision model also allows us to forecast carbon emissions over the 2025 to 2050 period. The model reports total emissions under each scenario[16], as well as the average grid emissions intensity.

3.2 SONI's impact on the electricity system

This section presents the results of the modelling and shows how relaxing the system-wide operational constraints SNSP and MUON affects consumers' electricity costs in Northern Ireland:

- first, we describe which components of consumer costs vary in the factual scenarios (relative to the counterfactual) and why;
- second, we present the quantified consumer cost results for each factual scenario; and
- finally, we discuss the impact of constraint relaxation on carbon emissions.

3.2.1 Overview of variations by component of consumer cost

Wholesale electricity costs:

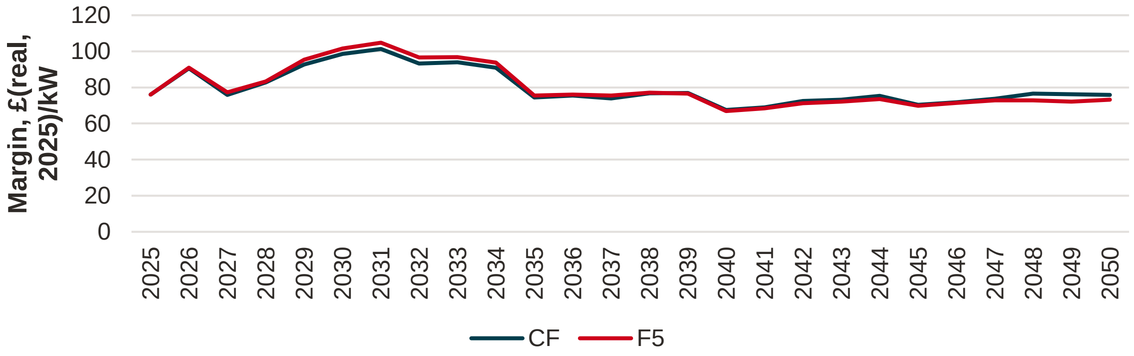
SNSP and MUON are system-wide operational constraints and therefore do not directly impact wholesale prices, which are determined before considering these constraints. The main way in which changes to SNSP and MUON could have an impact on wholesale costs is if they led

16 Carbon emissions are accounted in the countries were they are generated

to changes in the capacity mix. Since we assume renewable capacity is exogenous, this would imply change in storage and dispatchable generation capacity.

This change would only occur if relaxing SNSP and MUON significantly affected the profitability of these assets. The profitability of storage and peaking units is essentially unchanged across scenarios (an example for a 2 hour BESS unit is shown in Figure 3). As a result, the wholesale component of consumer costs remains stable across the counterfactual and all factual scenarios.

Figure 3 Profitabilty of a 2hr BESS scenario in CF and F5



Source: EnVision Model, LCP

Note: The chart shows the profitability of a 2-hour duration battery in counterfactual scenario F5, which is the scenario with the most relaxed constraints. In the intermediate scenarios (F1 to F4), the effect is even smaller

Capacity costs

For the capacity costs, a similar logic applies. If expected profits were to change materially, CM bids for storage and dispatchable generation capacity could change, by changing capacity prices and costs. In practice, because there is are no significant change in profitability, we see no material change in capacity market costs.

Constraints Costs

Relaxing SNSP and MUON reduces the need to run higher-cost thermal units purely for system stability, leading to a reduction in constraint costs.

Balancing Costs

Relaxing the SNSP and MUON constraints does not directly determine balancing costs. However, because the balancing price (Imbalance Settlement Price – ISP) is shaped by both balancing actions and constraint management, easing these constraints can indirectly influence the ISP and its relationship with the wholesale price.

When only SNSP is relaxed (scenarios F1 and F2), the model shows a slight increase in the balancing price. This is because under the counterfactual, the ISP is typically above the wholesale price, meaning that suppliers have an incentive to over-procure in the ex-ante market to avoid exposure to higher balancing prices. This causes the system to be long more often and leading to negative balancing costs for the TSO. As the constraints are relaxed, the ISP converges towards the wholesale price, these incentives fade, and balancing costs move closer to zero.

The MUON constraint alone has the opposite effect. In the counterfactual, to meet the MUON requirement, synchronous units are kept online but only partially loaded, giving them flexibility to increase output for balancing actions at low cost. This keeps the balancing price lower and close to the wholesale level. Balancing costs remain negative because the ISP is still above the wholesale price, meaning the system tends to run long. When the MUON constraint is removed, this stabilising effect weakens. The ISP rises further above the wholesale price, which strengthens the incentive for market participants to stay long. As a result, balancing costs become even more negative than in the counterfactual.

When both constraints are relaxed together (scenario F5), the SNSP effect dominates. Balancing costs rise slightly as the ISP aligns more closely with the wholesale price. Overall, the change in balancing costs remains small compared with the much larger consumer savings from lower constraint costs.

Policy costs

We assume that RES capacity is exogenous and therefore does not vary across scenarios. Any change in policy support costs would arise only if the profitability of RES schemes shifted materially, resulting in different RESS auction prices. Because RES generators will not earn from changes in constraint actions, any such effect is expected to be minimal.

Consistent with this, our modelling shows no change in policy costs.

Use of system costs, SSS charge and supplier margin

We make the simplifying assumption that the consumer cost categories modelled outside of LCP's Envision model do not vary by across scenarios.[17]

In practice, it is likely that relaxing the SNSP and MUON constraints would lead to slightly higher ancillary costs (i.e. higher costs in the factual scenarios compared to the counterfactual), offsetting the reduction in imperfections charges to some extent. However, at

[17] Note that we assume that some cost categories – namely VAT and the Supplier charge – remain fixed across scenarios in percentage terms, and therefore vary in p/KWh terms. We assume all other elements remain fixed in terms of their p/KWh levels.

this point it is difficult to assess the size of potential variation across the scenarios, particularly given that FASS is still under development.[18]

3.2.2 Consumer costs: results

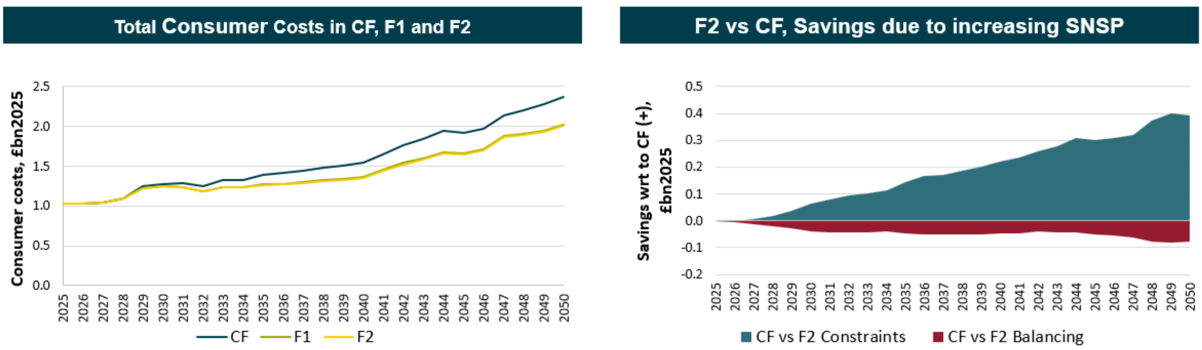
Effect of relaxing the SNSP constraint (factual scenarios 1 and 2)

Our modelling suggests that raising the SNSP limit would produce clear future savings for consumers in Northern Ireland. Over 2025-2050, the net present value[19] of benefits is **£2.2bn in F1** and **£2.3bn in F2** (NI only), rising to **£10.5bn** and **£11.1bn** respectively on an all-island basis.

The **benefits of F1 and F2 are almost identical**. Moving SNSP from 95% (F1) to 100% (F2) yields only limited additional gains. In both scenarios, MUON units are still required by the system, which constrains the incremental benefit that the extra 5% SNSP can deliver.

As explained above, **these gains are principally driven by lower constraint payments**, as relaxing the SNSP requirement reduces the need to run higher-cost thermal units purely for stability. Balancing costs move in the opposite direction but only slightly, rising from negative values in the counterfactual to close to zero when constraints are relaxed. The modest increase in balancing costs does not offset the larger savings from lower constraint payments.

Figure 4 Consumer costs in Counterfactual, Factual 1 and Factual 2



Source: EnVision model, LCP

Effect of relaxing the MUON constraint (factual scenarios 2 and 3)

Lowering the Minimum Units Online requirement on its own yields more modest savings for consumers. Over 2025-2050, the net present value of benefits is approximately **£0.4bn in F3** and **£0.5bn in F4** for Northern Ireland, and **£2.2bn** and **£2.3bn** respectively on an all-island

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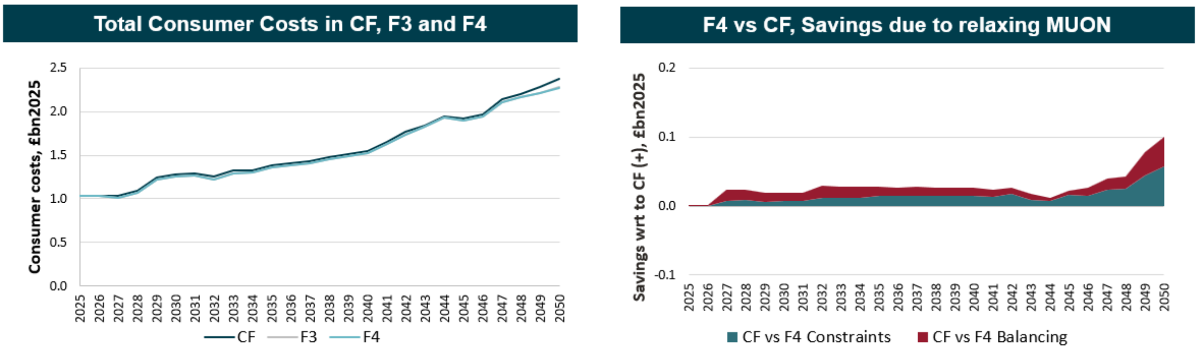
[18] FASS refers to the "Future Arrangements for System Services" program which will replace the current DS3 system Services regime. See section 4.1 for more details.

[19] We have used a discount factor of 3.5%, as per the Green Book guidance.

basis. These gains are small when set against the benefits from increasing SNSP because the **SNSP limit is currently the more binding constraint**. Even if the system is no longer required to maintain a formal minimum number of synchronous units online, many of those units are still needed in practice, since under Factual 3 and 4, only 75% of generation can come from renewables at any given point in time.

The savings are **driven by slightly lower constraint payments**. Balancing costs also move in a favourable direction as constraint pressures ease, but the changes are small and build only gradually over time.

Figure 5 Consumer costs in Counterfatcual, Factual 3 and Factual 4



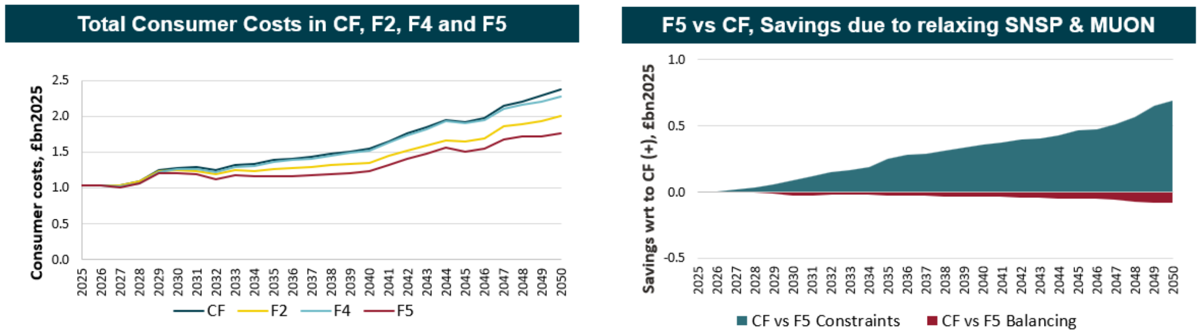
Source: EnVision model, LCP

Effect of relaxing both the SNSP and MUON constraints (factual scenario 5)

Combining a higher SNSP with a lower MUON (F5) delivers the strongest consumer savings. Over 2025-2050, the NPV of benefits is **£3.8bn** in Northern Ireland (£18.4bn on an all-island basis), surpassing the sum of the effects from Factual 2 and Factual 4. This is because relaxing both constraints together prevents the remaining constraint from becoming binding; addressing only one leaves a constraint in place and limits renewable output and the associated savings.

The benefit comes principally from a **reduction in constraint payments** as fewer thermal units are required to run out of merit for stability. Balancing costs move only modestly and slightly offset the savings, consistent with the ISP converging toward the wholesale price as discussed above.

Figure 6 Consumer costs in Counterfactual and Factual 5



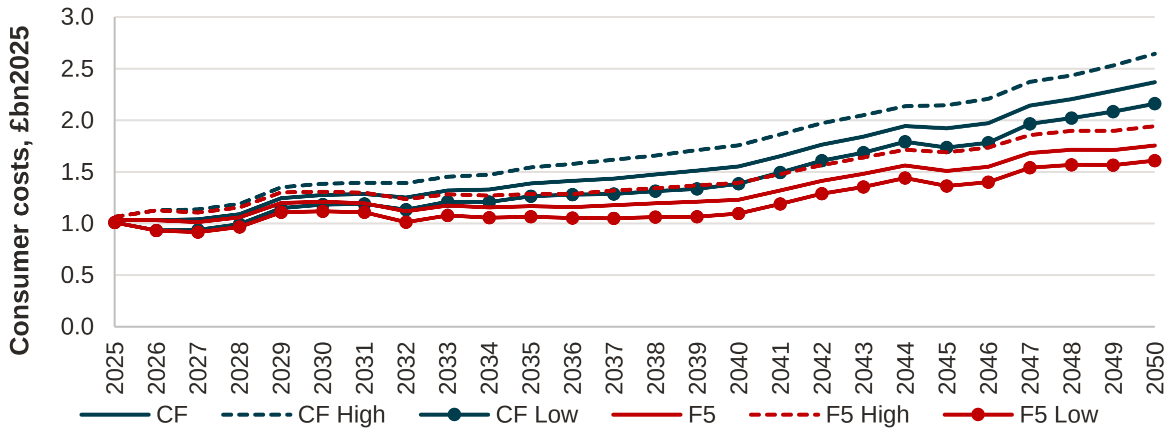
Source: EnVision model, LCP

We also tested the impact of Factual 5 relative to the counterfactual with high- and low-commodity-price sensitivities, varying gas and carbon costs for both the counterfactual and Factual 5. As expected, higher fuel prices increase consumer costs, while lower prices reduce them.

The impact of changing gas and carbon prices is more pronounced in the Counterfactual scenario (in NPV terms, £-2.3bn with low commodities, and +£2.7bn with high commodities) compared to Factual 5 (in NPV terms, £-1,9bn with low commodities, and £2.2bn with high commodities). In Factual 5, where there are no MUON or SNSP constraints, this impact is slightly dampened because a wider range of plants, including those less exposed to gas and carbon price fluctuations, can operate. When prices are high, alternative technologies such as biomass and waste generation are available to manage constraints; when prices are low, domestic gas plants tend to run in merit more often relative to GB imports, which reduces both constraint volumes and costs.

Overall, relaxing both constraints not only lowers average consumer costs but also dampens exposure to high commodity-price, narrowing the range of outcomes.

Figure 7 Consumer costs in CF (low, med and high) and F5 (low, med and high)



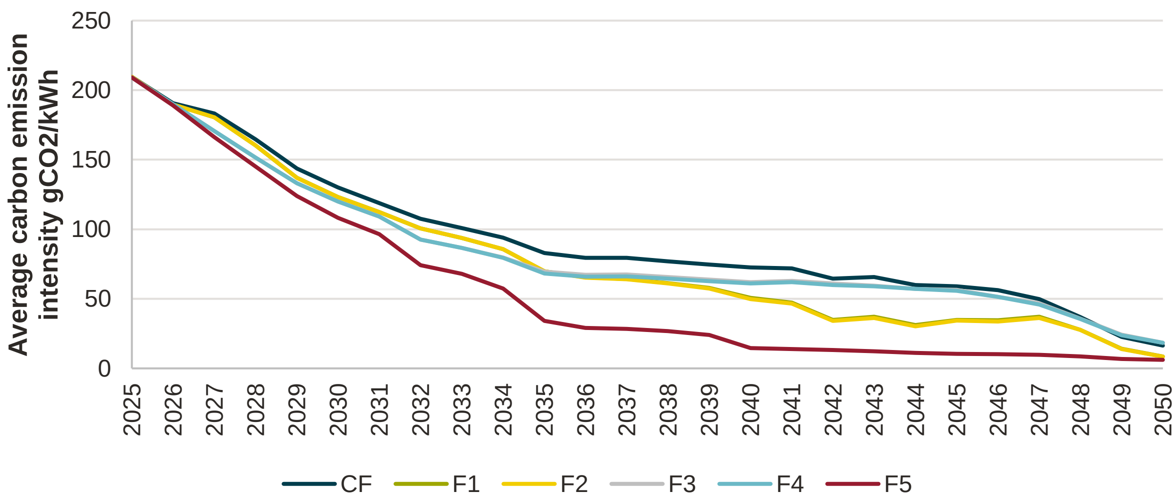
Source: EnVision mode, LCP

3.2.3 Results - carbon emissions

Relaxing SNSP and MUON accelerates decarbonisation. As these constraints are eased, thermal units are no longer run purely for stability, allowing renewables to supply a larger share of demand. The modelling shows grid carbon intensity falling in all cases, with the greatest reduction when both SNSP is raised and MUON lowered together (F5).

Overall, constraint relaxation brings the system to low or near-zero grid emissions sooner, while also reducing exposure to fossil fuel costs and volatility.

Figure 8 Average grid carbon intensity in all scenarios



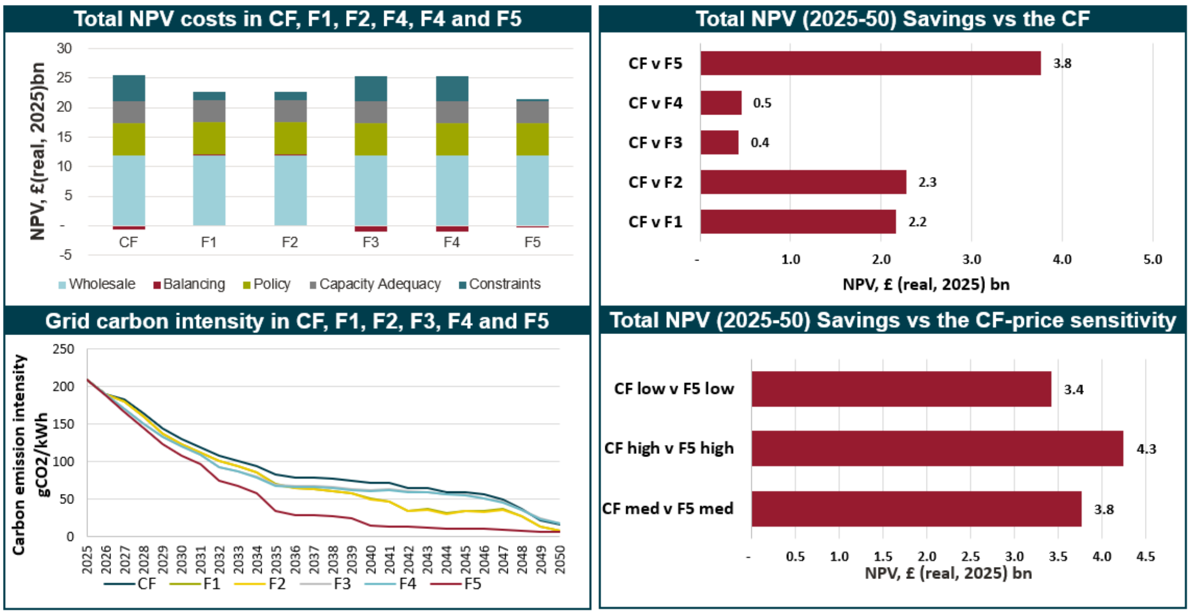
Source: EnVision model, LCP

3.3 Summary

The charts in Figure 9 summarise the main results of the SONI's modelled activities on consumer costs.

- Relaxing both SNSP and MUON together (F5) delivers the largest reduction in consumer costs, with savings of around £3.8 billion in Northern Ireland. Most of this benefit comes from lower constraint payments.
- Relaxing only one of the constraints delivers limited benefits because the other typically remains binding. This is particularly clear when only MUON is adjusted, as in F3 and F4.
- Under both low and high commodity price sensitivities, F5 continues to deliver benefits when compared to the counterfactual.
- Relaxing SNSP and MUON accelerates decarbonisation. As these constraints are eased, thermal units are no longer run solely for stability, allowing renewables to supply a larger share of demand. Grid carbon intensity falls in all scenarios, with the largest reduction when SNSP is raised and MUON lowered together (F5).

Figure 9 Summary of results



Source: EnVision model, LCP

4 SONI's impact on electricity bills

While it is clear that significant transformation of the Northern Ireland electricity sector is required, and that SONI has a key enabling role in this transformation, it is essential that this is done in a way that minimises the cost to consumers. In fact the UR's approach document for the upcoming price control[20], emphasises that the price control determination *"must facilitate the path to net zero as part of a fair, affordable and inclusive transition"*.

We have therefore also sought to estimate:

- how Northern Irish electricity bills could evolve over the next price control period, based on the PowerNI regulated tariff, using factual scenario 5; and
- how the value of SONI's impact on consumer costs translates into electricity bills, in terms of both p/kWh and £ per annum bill savings.

The following sections take each of these in turn, setting out our modelling approach and results.

4.1 Forecast evolution of regulated tariff over the next price control period

We have estimated the evolution of domestic customer bills over the next price control period. This shows a reduction in costs from 29.7p/kWh today to 26.9p/kWh at the end of the next price control – roughly a 9% reduction.

In the following sub-sections, we first describe our methodology (section 4.1.1) for estimating historic and future bills, and then present and explain the results (section 4.1.2).

4.1.1 Approach

As described in Section 3.1, we model the majority of the customer bill using LCP's EnVision model. We model the remainder of the customer bill using either a detailed approach (for the largest remaining cost categories) or a simple projection (for the smaller elements).

Bill elements modelled by LCP's EnVision model

The cost categories captured by LCP's EnVision model currently make up around 59% of the domestic customer bill. For our central forecast, we model these categories based on the Factual Scenario 5 as set out in Section 2 above, assuming medium commodity prices. We

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20 The Utility Regulator (2024), SONI price control 2026-2031: Approach document. Available here

convert £m total consumer costs from Envision into a p/kWh charge faced by customers by dividing by a forecast of metered demand in each year.[21,22]

Bill elements modelled outside of the EnVision software

We model the cost categories not estimated within EnVision (which made up 38% of customer bills in 2025) using the p/kWh values from the 2025 Power NI regulated tariff as a baseline.

STUoS and DUoS charges are projected forwards using the revenue forecast presented in NIE Networks' Final Determinations main document, published by the UR.[23] Table 7 of the report shows the UR's projection of NIE Network's transmission and distribution revenues from Financial year 2024/25 through to 2030/31. This shows a revenue growth over this period of 65% for transmission revenues and 23% for distribution revenues, in real terms. We use this projection to forecast the tariff increase out to calendar year 2030, accounting for expected growth in demand during the period. Specifically, we use the growth in distribution revenues to forecast the increase in the DUoS tariff, and use the increase in transmission revenues to forecast STUoS tariff growth. Since our forecast also includes the calendar years 2031 and 2032, we then extrapolate the revenue requirements in these years based on the percentage growth observed in the years for which the UR forecast was available.

The current **System Support Services (SSS)** charge consists of SONI internal revenues, Ancillary services, the CEP court ruling charge, and a K factor.[24] We assume that on average the K factor will be zero going forwards. For the other components, our assumptions vary:

- **SONI internal revenues:** Because SONI is in the process of submitting its business plan for SRP27, exact projections of its costs, and resultant revenue recovery, are not currently available. Therefore, we have used SONI's real terms percentage growth rate in revenue over the past 3 years to project its growth going forwards. This future stream of revenue is then divided by demand to calculate this element of the SSS charge, in p/kWh, over the period.
- **Ancillary services costs**: The ancillary services element will be significantly impacted by the introduction of the Future Arrangement for System Services (FASS) programme.

21 Our metered demand assumption is based on AIRAA median demand, rescaled by a correction factor. AIRAA provides estimates of total energy requirements (TER). Historically AIRAA's forecast differed from metered demand due to losses and behind the meter generation. Therefore to forecast metered demand we assume the same percentage difference between the AIRAA forecast and metered demand that has been observed historically. Capacity charges are levied on daytime demand (defined as being between 7am and 11am) only. We therefore adjust the demand forecast down for this category.

22 In the case of the imperfections charge, we added a small uplift to the figures produced by the EnVision model, in order to bring them into line with observed actuals.

23 The Utility Regulator (2024), Northern Ireland Electricity Networks Ltd- Transmission and Distribution 7th Price control. Available here

24 The Utility Regulator (2025), Regulated entitlement values 2025-2026 Tariff Year. Available here.

This is an all-island program, led by SONI and Eirgrid, to replace the current DS3 System Services regime. It's go-live date is currently expected to be December 2026. We have assumed FASS will be implemented at the start of 2027, and have used SONI's internal forecasts of Ancillary Services revenue recovery under FASS to project charges forward. These show a near doubling in real terms revenue requirements. Again, we account for demand growth to calculate this element of the SSS tariff in p/kWh.

- **CEP court ruling charge**: This element of the SSS tariff is designed to raise revenue for SONI to cover potential historic liabilities relating to the High Court of Ireland's 2023 ruling on the SEM Committee's interpretation of the Clean Energy Package (CEP). The judgement, relating to both the SEM and the renewables support schemes in the Republic of Ireland, could mean that SONI is liable to pay some generators in NI for loss of revenue in relation to redispatch down. The decision has been appealed to the Supreme Court of Ireland and is currently being considered by the European Court of Justice. Therefore, the outcome (even in the Republic of Ireland) remains uncertain. For simplicity, we assume that the High Court's decision will be upheld by the Supreme Court, and then implemented by the UR by the end of Financial year 2025/26. The CEP tariff for Financial Year 2025/26 is set to cover all SONI's historic liabilities, including those arising during this financial year. From this point on, additional costs associated with redispatch down (both the wholesale market and renewable support cost element) are included in the cost estimates produced by LCP's EnVision model, and so are captured elsewhere in our customer cost analysis. We therefore assume that the historic element of the CEP charge will fall to zero.

Finally, we forecast the **Supplier charge** based on its current percentage share of the PowerNI tariff. Across 2025, this was an average of 8.25% of the overall customer bill, which we have projected forward out to 2032.

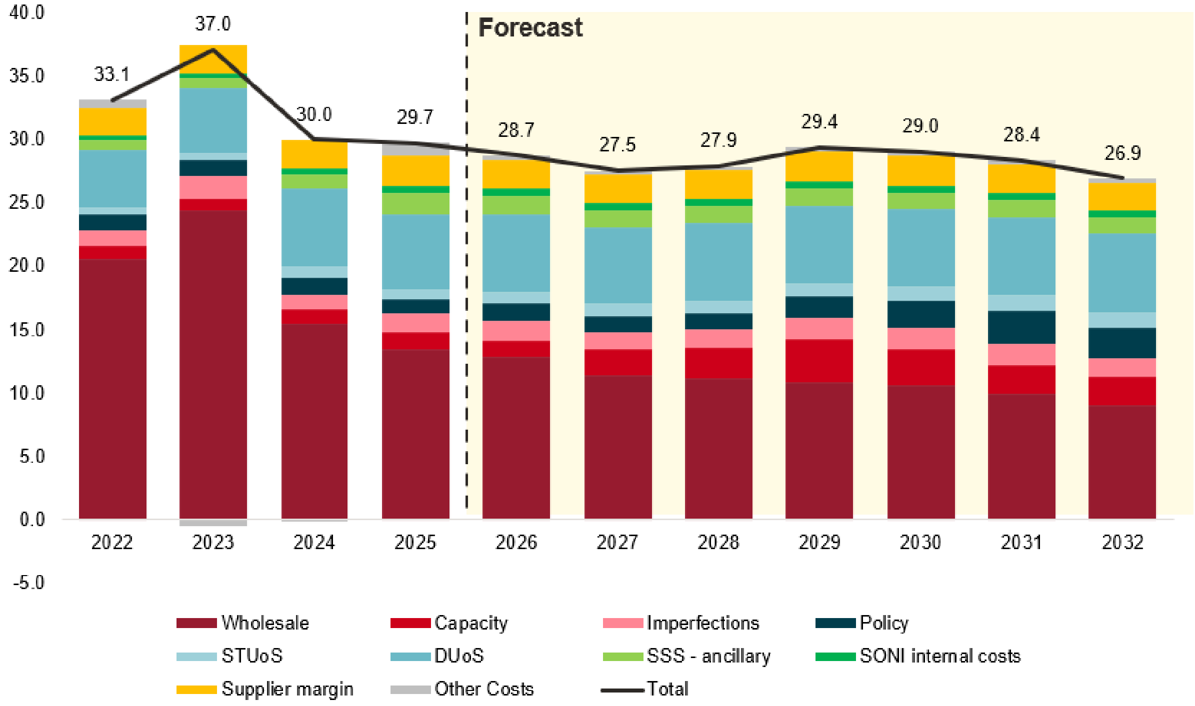
4.1.2 Results

We estimate that domestic customer tariffs will fall in real terms by around 2.8p/KWh (~9%) between 2025 and 2032, as shown in Figure 10. This is based on factual scenario 5, under medium commodity prices.

This reduction in customer bills is the result of a mixture of different effects:

- Wholesale costs and SSS charges per kWh are forecast to fall by 33% and 18%, respectively.
- These effects are forecast to be partially offset by increases in the capacity charge (up 65%), policy costs (up 94%), and use of system charges (up 13%).

Figure 10 Historic and forecast regulated tariff – p/KWh real terms (2025 prices)



Source: *Frontier Economics and LCP Delta analysis*

■

4.2 Impact of SONI's actions on customer bills

We now turn to consider how the size of the bill impact of SONI's actions in relation to SNSP and MUON. SONI's actions are forecast to show benefits of between 1.4p/KWh and 1.8p/KWh by the end of the next price control (2032) and between 3.2p/KWh and 4.0p/KWh by 2050, under the factual 5 scenario (see Figure 11). For domestic customers, this could translate to bill savings of between £48 and £60 per annum, with a central case of £53 per annum,[25] by 2032 and between £106 and £136 per annum, with a central case of £119 per annum, by 2050, assuming consumption remains at 3,200 kWh per annum and VAT remains at 5%.[26] Benefits to non-domestic consumers will depend on their level of consumption. The largest customers - those with consumption over 20,000 MWh of consumption per annum – might expect to save more than £1.4m per annum, by 2050.

25 This central case refers to the bill savings under the medium commodity price scenario.

26 This assumption is consistent with the UR's assumptions in the PowerNI tariff price cap documents (for example see here). In reality, domestic consumption is likely to grow significantly due to the uptake of electric vehicles and heat pumps. However, to ensure comparability, we have conservatively kept the assumed consumption level at 3,200kwh.

In the following subsections we set out our methodology for calculating these benefits (section 3.2.1), and our results (section 3.2.2)

4.2.1 Approach

As described in section 3.2.1, the only cost components in LCP's Envision model that vary between the factual scenarios and the counterfactual are balancing and constraint costs. We assume that the other elements of the customer bill – those described in Section 4.1.1 – will not vary by scenario, other than cost elements which are held constant as a percentage of total bills, namely:

- The **Supplier Charge,** which we hold constant at 8.25% under all scenarios, and is therefore larger where other costs are larger.
- **VAT,** which is held at 5% in all scenarios.

Our methodology to estimate the bill impact resulting from SONI's actions is to:

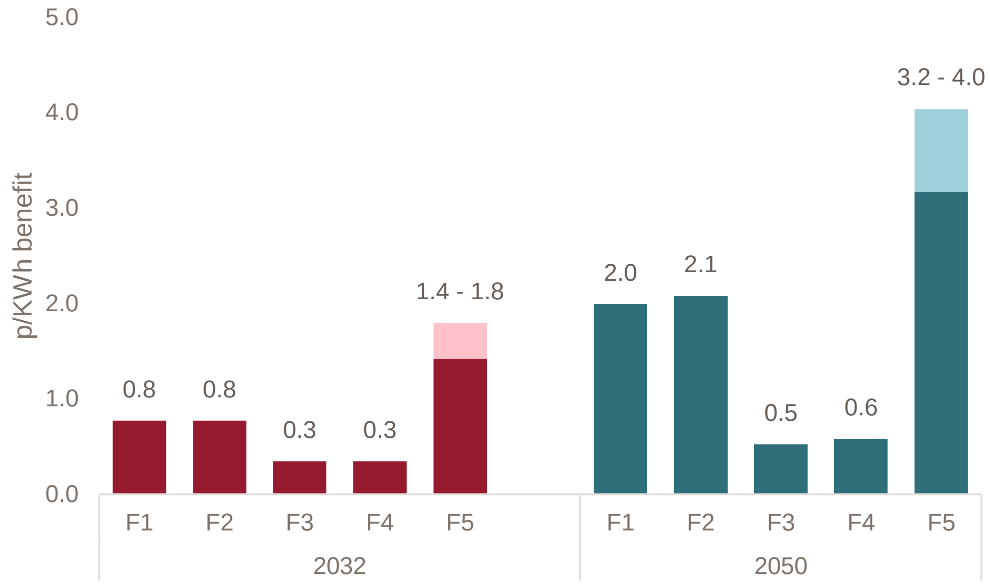
- Convert system-wide constraint and balancing cost projections in the counterfactual and each factual scenario into a p/kWh charge, using a forecast of metered demand.
- Calculate the difference between each factual scenario and the counterfactual scenario.
- Uplift this difference to account for the fact that the supplier charge should be 8.25% of the (pre VAT) customer bill, and that VAT will be 5% of the final bill.

The result of these steps is the net benefit of SONI's actions, under each factual scenario, in p/KWh. We then multiply these costs by assumed consumption values to give an approximate quantification of the bill savings customers can expect in £ per annum.

4.2.2 Results

Figure 11 sets out the benefits of SONI's actions under each scenario in p/kWh terms, in 2032 (the end of the next price control) and 2050. Under factual scenario 5, we calculated the impact under the low, medium and high commodity cost scenarios, with the range presented in Figure 11. Factual scenario 5 shows a benefit of between 1.4p/kWh and 1.8p/kWh in 2032, and a benefit range from 3.2 p/kWh to 4.0p/kWh by 2050. Other factual scenarios show smaller customer bill reductions, of between 0.5p/kWh and 2.1p/kWh by 2050.

Figure 11 Benefits of SONI actions by factual scenario (p/KWh, real terms)



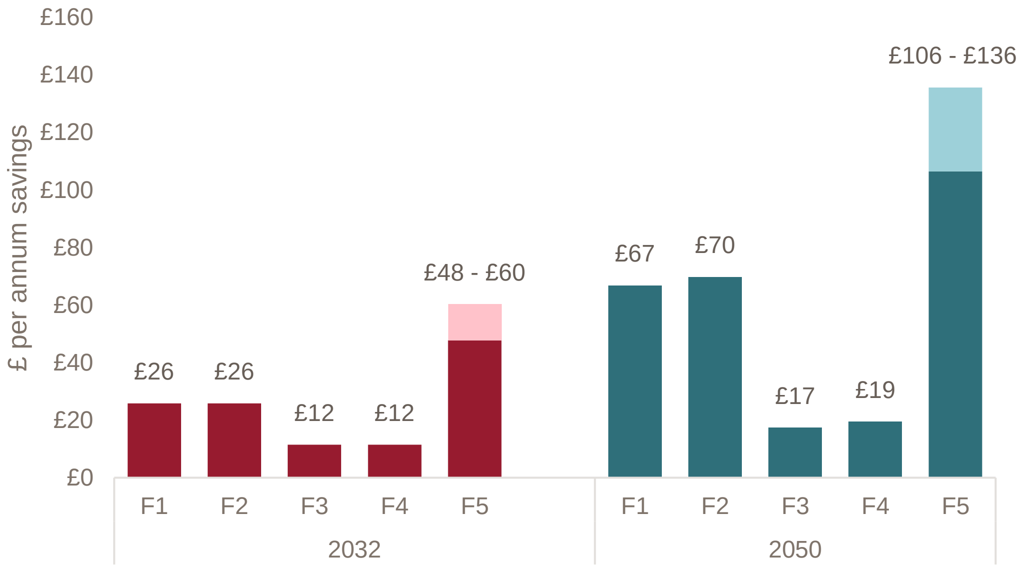
Source: Frontier Economics and LCP analysis

Figure 12 translates these benefits into the £ per annum saved by a typical domestic customer, assuming domestic consumption of 3,200 KWh throughout the period (the assumption currently used by the UR to convert p/KWh charges into an estimate for annual bills).[27] In reality, domestic consumption is likely to grow significantly due to the uptake of electric vehicles and heat pumps. However, to ensure comparability, we conservatively keep the assumed consumption level constant.

Our analysis suggests that SONI's actions could save domestic customers between £48 and £60 per annum by 2032 and between £106 and £136 per annum by 2050, based on factual scenario 5. The benefits under other factual scenarios, i.e. where only the MUON constraint or SNSP constraint is relaxed, range from up to £17 per annum to up to £70 per annum.

[27] For example, see here.

Figure 12 Bill reductions per year for domestic customers



Source: Frontier Economics and LCP analysis
Note: Assumes consumption remains at 3,200 KWh per annum

Finally, we also estimate benefits for various categories of non-domestic customers, based on consumption estimates for these groups between 2021 and 2025. Table 1 details the estimated impact of SONI's actions for these customers under factual scenario 5, assuming medium commodity costs, showing first the assumed consumption in MWh, and then the total bill impact in 2032 and 2050.

By 2050, we estimate a bill saving in the range from £215 per annum for the smallest non-domestic customers (those consuming less than 20MWh per annum) to £1.4m for the largest non-domestic customers.

Table 1 Non-domestic customer bill reductions due to SONI actions

	Assumed consumption (MWh)	2032 benefit (£)	2050 benefit (£)
I&C < 20 MWh	6	95	215
I&C 20 – 49 MWh	30	499	1,128
I&C 50 – 499 MWh	133	2,186	4,937
I&C 500 – 1,999 MWh	976	16,035	36,219

	Assumed consumption (MWh)	2032 benefit (£)	2050 benefit (£)
I&C 2,000 – 19,999 MWh	5,217	85,708	193,594
I&C ≥ 20,000 MWh	38,991	640,498	1,446,738

Source: Frontier Economics and LCP analysis

Annex A – LCP Delta's EnVision model

A.1 The EnVision model

Our I-SEM modelling will be conducted using LCP Delta's EnVision modelling framework. This model was originally developed for the UK government in 2010, and has been continually updated since. It includes fully integrated modelling of Ireland and GB, including the latest policy developments in both markets. It is specifically designed to capture the dynamics of all markets: wholesale, capacity, balancing, system constraints and ancillary services.

The framework is widely used and plays a key role in both the GB and Irish markets, providing the analysis required to run the GB capacity auctions, used for a wide range of UK government analysis and being used to analyse significant investment decisions in Ireland and GB over recent years.

Both the Ireland and GB markets are modelled in full detail. To properly assess the risks and opportunities, a stochastic modelling approach is utilised. The dispatch model stochastically simulates variations of key inputs, including wind generation, solar generation and demand.

For all analysis LCP Delta maintains up to date datasets of assumptions across the Irish and GB markets, including the latest commodity price forwards, plant announcements, policy updates, the most recent capacity auction results and recently announced renewable support contracts and targets.

Wholesale market forecasting

Dispatch methodology

LCP Delta's wholesale forecasts are generated using an internally developed dispatch algorithm which allows units to consider their ramp rates, start costs and minimum run times in their dispatch decisions. The approach allows for each unit to bid according to its own dynamics and costs, rather than a top-down optimisation approach, to better reflect the day ahead auction process and generators transitioning into the shorter-term balancing market.

Stochastics

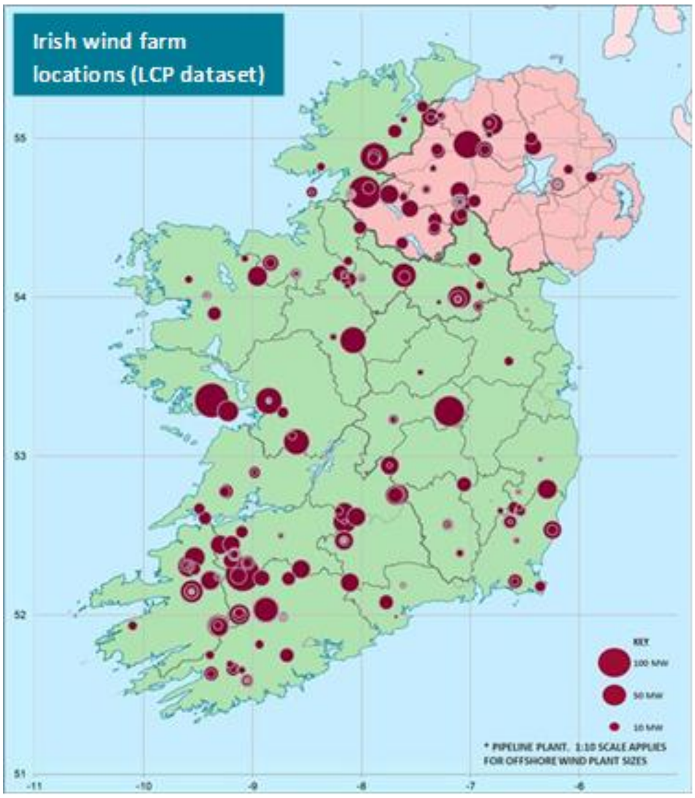
The high wind penetration relative to the system size of Ireland mean "best estimate" scenarios are unable to represent the complexity of operating the system. LCP Delta typically models 10-20 simulations of the market, with wind generation, solar generation and demand varying across each simulation.

This stochastic approach allows us to provide best estimates for each modelling output but also provide a range around these. Importantly, it allows us to capture tail events, which can provide a significant source of value, especially for peaking generation, while not under or over-estimating their likelihood.

The dispatch model also incorporates a sequential approach, modelling a full 365 days for each year in each stochastic simulation. This means it captures a full range of intermittency profiles and the resulting running profiles from flexible generation. This is particularly important for flexible assets such as battery storage and gas peaking plant because running profiles and revenues will vary considerably under different renewable conditions.

Intermittency

LCP Delta models wind and solar plant output stochastically by sampling from a large historic database (40 years) of wind speeds and solar intensities at granular locations. These historic weather patterns are converted into locational load factors for intermittent plant. Sampling historic locational weather data allows the model to capture the correlation in wind generation over different locations across Ireland and GB.



LCP Delta's locational load factor approach allows effective assessment of portfolio benefits of specific collections of intermittent plant such as reduced balancing market risk from uncertain generation output.

Interconnection

The material size of current interconnection with GB as a proportion of the Irish market means any simulation of Ireland requires simulation of GB and assumptions on the development of power markets and prices on the continent.

The interconnector methodology runs the Irish market with interconnectors taking prices directly from a parallel GB energy market run. GB is run at the same level of granular detail as Ireland, including detailed stochastic modelling of wind, solar and demand. Running these markets side by side captures any correlation in demand and renewable generation between the two markets. The modelling also includes future interconnection deployment and the impacts this has on the Irish market.

Interconnection to France (via the Celtic interconnector) is also modelled in detail. This includes capturing the development of French electricity demand and capacity mix and the correlations between ISEM and France in demand, wind and solar generation.

Storage

LCP Delta has developed a specific proprietary algorithm to simulate the dispatch of storage assets in the wholesale and balancing markets. Storage assets optimise their behaviour and decide on their dispatch based on the fundamentals of their technical characteristics and active market participants.

This approach allows the storage asset to consider the period as an optimisation problem, looking at projected prices based on market fundamentals and identifying arbitrage opportunities of charging/discharging based on the specific parameters and constraints of the asset. The period to optimised over varies for different types of storage assets. For example, a battery storage asset will be optimised over one day, whereas a pumped storage asset may be optimised over a week (depending on its duration).

This fundamentals-driven approach naturally lends itself to effectively capturing the impacts of varying battery duration and degradation, as well as the effects of cannibalisation. This is a particularly important phenomenon for batteries – the opportunities available to a battery asset are highly dependent on the competition for those opportunities and the asset's own degradation.

Electrolysis

Electrolysis for the production of green hydrogen has the potential to play a key role in the net zero transition, maximising the potential of renewable generation by minimising curtailment. The modelling captures the dispatch of electrolysis in detail, simulating it as a form of flexible demand. It is "dispatched" based on the assumed market price for hydrogen, which is typically set based on the cost of producing blue hydrogen from SMR CCS (assuming this is the marginal source of hydrogen production), hence is linked to the gas price (and allowing for any assumed government support). The appropriate level of long-term deployment of electrolysis can be estimated based on determining the level where additional electrolysis capacity and additional wind capacity provide the same system benefit.

Balancing market forecasting

- A feature under I-SEM is the balancing market, which has a similar structure to that of GB. LCP Delta has extensive experience modelling the GB balancing market and has implemented a similar methodology for the Irish market.
- The modelling of balancing services uses a fundamentals-driven approach. The requirement for each service is determined based on the underlying system drivers, and then the value available to service providers in satisfying these requirements is set by a

market price. This approach is important in a system which will evolve dramatically over the coming years, with significant increases in renewable penetration and the continued emergence of new flexible technologies. Though calibrated against historical market outcomes, this fundamentals-driven approach is robust to the evolution of the system and captures important dynamics such as the cannibalisation of revenues through increased competition.

To simulate the Balancing Market's energy balancing the model reruns each day (across each of the stochastic simulations), applying shifts to net demand. This shift represents the net imbalance volume (NIV) and is made up of changes in outturn demand and intermittent generation due to forecasting inaccuracy. The shifts applied to each day are sampled from a distribution, and take into account:

- Total wind generation, solar generation and demand. For example, the size of the NIV portion due to wind uncertainty will tend to grow over time as more wind comes on the system.
- Parameters for the forecasting accuracy of wind, solar and demand, including an assumption for improvements in forecasting accuracy over the long term.
- The set of NIVs sampled for a given day also capture the autocorrelation between hours. For example, wind forecasts may be more likely to be high in a given hour if they were high in the previous hour.

Once the set of shifts in net demand have been applied, flexible plant submit bids or offers and are turned up or down to satisfy the shift amount. Each plant's bids and offers are calculated based on its dynamics (e.g. minimum stable generation, minimum response time) and costs (e.g. fuel costs, start costs). The balancing system price in each period is determined by the bid/offer of the marginal plant being turned up or down.

Importantly, the Balancing Market is not simulated as a single auction. Doing so can overestimate or underestimate the contribution of a certain types of technology, e.g. cheaper, but less flexible, CCGTs. Flexible units, such as battery storage, can turn up or turn down at very short notice, and capture a portion of BM revenue that is not available to less flexible units. The BM is simulated in stages, to represent different time horizons leading up to "real time".

Ancillary services forecasts

Within ISEM the DS3 framework is currently used to define the value of the ancillary services required to support a low-carbon grid.

The modelling utilises technology level capability assumptions together with the tariffs and awarded contracts to calculate payments on a unit-by-unit basis. These services are modelled in full with payments calculated based on a unit's physical or day ahead market position as appropriate.

Key to the valuation of these services is the modelling of System Non-Synchronous Penetration (SNSP) whose value determines the "temporal scarcity scalar" to be applied to these payments. At high SNSP levels (i.e. high levels of wind generation) the scalars significantly increase the payments for these services.

SNSP levels are driven by the amount of renewable generation and interconnector imports. A stochastic approach, whereby the uncertainty in the output of solar and wind farms is captured, is required. This must be well parameterised with correlations in renewable outputs between GB and Ireland reflected to correctly calculate day ahead market prices hence scheduling of interconnector flows.

The tariffs for the DS3 services are currently regulated, with an annual spend cap of €235m. It is assumed that the services will move to competitive procurement from 2026, after which tariffs are expected to drop to a level sufficient to cover the opportunity costs involved from plant providing the services.

As the modelling framework calculates the total expenditure for the full DS3 program it can assess the impact of each option and how future tariffs will be affected.

Investment decisions

Due to the small system size of Ireland, individual investment decisions can be very material to model outputs. LCP Delta models investment decisions by simulating the Irish CRM (capacity remuneration mechanism) auctions.

The Irish CRM can provide a fixed income stream for new build assets. The auction is simulated in full detail, calculating each participant's bid based on net revenue forecasts that include wholesale, balancing, DS3 and constraint revenues. For the Irish CRM, also captured is the locational element which currently requires minimum levels of capacity in the Dublin and Northern Ireland regions.

This modelling is key in determining the future capacity mix of the system, including the timings of retirements and new build.

Constraint modelling

- Ireland has a unique structure of locational and system constraints. Constraints include:
- limits on flows between Northern Ireland and Republic of Ireland (though these will be somewhat alleviated by the expansion of the N-S interconnector),
- operational limits on the level of generation in certain regions at certain demand levels,
- the level of operating reserve held,

- the SNSP (system non-synchronous penetration) limit, which establishes the proportion of generation that can come from non-synchronous sources (e.g. wind) and still safely operate the system.

LCP Delta’s modelling framework ensures each of the system constraints are settled off the back of the system’s final wholesale market position (replicating how the market operates in reality). These are typically satisfied by turning up/down flexible generation and sometimes curtailing non-synchronous generation such as wind.

This approach allows us to provide forecasts on the potential locational revenues for assets in I-SEM.

Annex B – Detailed modelling assumptions for EnVision

The power-market modelling was undertaken using LCP Delta's EnVision model, described in detail in Annex A . This annex sets out the exogenous assumptions used in the EnVision model. The assumptions were agreed with LCP Delta and SONI, drawing on the most authoritative and up-to-date data sources available.

The remainder of this section sets out the assumptions on:

- commodity prices;
- electricity demand and installed RES and interconnection capacity; and
- cost of capital of batteries and dispatchable generation.

B.1 Commodity prices

The modelling requires a set of commodity price trajectories for natural gas and carbon for the period 2025-2050. These are key drivers of wholesale electricity costs and therefore of customer bills. Our assumptions combine short-term market data with long-term projections from government sources, ensuring that the scenarios are both evidence-based and forward-looking. These assumptions are summarised in Table 2 below.

Table 2 Summary of commodity prices assumptions

Commodity	Price scenario	Short-term assumption up to July 2028	Long-term assumption up to July 2050
Natural gas	Low	Traded forward prices - up to 20%	DESNZ (2024) low scenario
	Medium	Traded forward prices	DESNZ (2024) central scenario
	High	Traded forward prices + up to 20%	DESNZ (2024) high scenario
Carbon	Low	Traded EU ETS prices	WEO (2024) 'Stated policies' scenario
	Medium	Traded EU ETS prices	WEO (2024) average of 'Stated policies' and 'Net Zero by 2050' scenario
	High	Traded EU ETS prices	WEO (2024) 'Net Zero by 2050' scenerio

Source: Frontier Economics

Note: DESNZ (2024) refers to the Department of Energy Security and Net Zero's 'Fossil Fuel Price Assumption 2024' report. WEO (2024) refers to the International Energy Agency's World Energy Outlook. Traded forward prices are extracted from Bloomberg as of July 2025.

The price of hydrogen is calculated based on the cost of producing blue hydrogen (Steam Methane Reforming with Carbon Capture and Storage).

In the remainder of the section, we lay out in more details our assumption on:

- natural gas prices; and
- carbon prices.

All prices in the modelling are presented in 2025 GBP real terms. Nominal values have been deflated using GDP deflators at market prices, consistent with the Office for Budget Responsibility's (OBR) latest forecasts published as part of the March 2025 Spring Statement.[28] These deflators are applied across the modelling horizon to ensure comparability of results in constant price terms. Where relevant, foreign currency values have been converted into sterling using the OBR's long-run exchange rate assumptions, set at 1.30 GBP/USD and 1.16 GBP/EUR, as published in March 2024.[29]

Natural Gas prices

Our natural gas price forecast combines UK traded forward prices[30] for the short term with long-term projections from the Department for Energy Security and Net Zero (DESNZ, 2024)[31].

In the medium term (up to July 2028), our forecast is based on traded forward contracts, with the central case calculated as the average of daily forward prices traded between 15 May and 15 July 2025[32]. The high and low price scenarios are defined around this central case. The high scenario applies a 15% uplift to the forward price curve, increasing to 20% by December 2026. The low scenario is symmetrical, applying equivalent reduction relative to the central trajectory.

From 2028 to 2035, the forward curves are extended to converge with long-term projections from DESNZ, which cover the period 2035 to 2050. From 2035 onwards, gas price assumptions follow the DESNZ's natural gas price forecast, with the low, central, and high scenarios corresponding to the DESNZ low, central, and high cases.

28 GDP deflators at market prices, and money GDP March 2025 (Spring Statement & Quarterly National Accounts) - GOV.UK

29 CP 1027 – Office for Budget Responsibility – Economic and fiscal outlook – March 2024

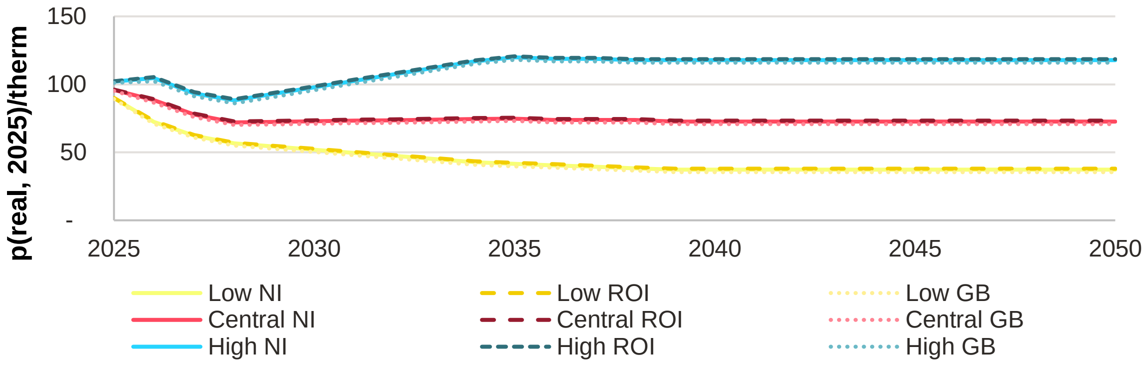
30 UK NBP Natural Gas Futures extracted from Bloomberg

31 DESNZ, Fossil Fuel Price Assumptions (2024)

32 We used the average of daily forward prices over two months to avoid capturing day-specific volatility.

An uplift is applied to prices to account for transport and interconnection costs, reflecting the additional costs of delivering gas to the NI and ROI market[33].

Figure 13 Modelling assumption, Gas prices (p/therm, 2025 real)



Source: Frontier Economics.

Carbon prices

Similarly, we base carbon price forecasts on traded forward prices in the short term and on long-term projections from the IEA World Energy Outlook (WEO)[34]. We developed separate forecasts for EU ETS prices (relevant to the island of Ireland) and UK carbon prices (relevant to the Great Britain market and, therefore, influencing interconnector flows with Ireland).

For the EU ETS, we use traded allowance prices to set short-term forecasts. We calculate the central case using a two-month average of daily trades. From the 2030s onwards, we align prices with WEO long-term projections: the low scenario follows the Stated Policies pathway, the high scenario follows the Net Zero by 2050 pathway, and the central scenario is the average of the two.

The UK has operated a separate carbon market since leaving the EU ETS. While UK and EU carbon prices were initially similar, they began to diverge in 2023, with UK allowances trading at lower levels. However, since May 2025, prices have re-converged, following the announcement of an informal agreement to link the two schemes.[35] Based on this, we assume UK carbon prices fully converge with EU ETS prices by 2030.

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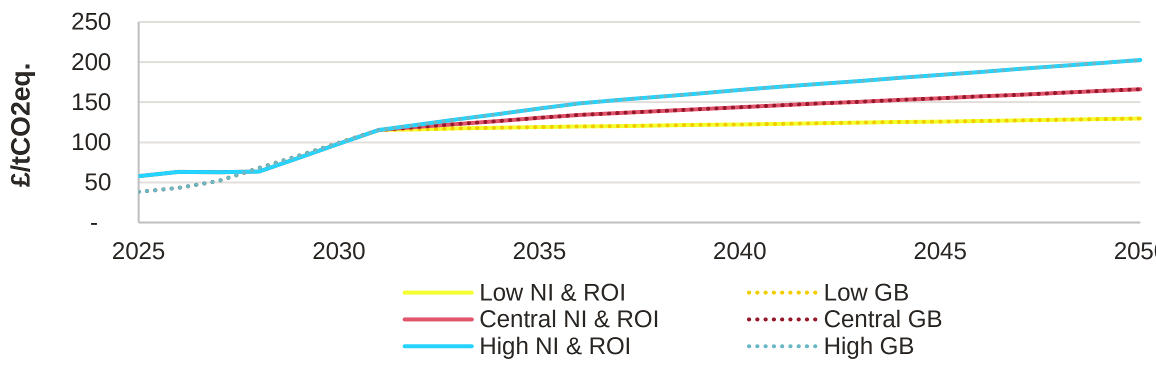
33 Yearly interconnection costs are estimated at 1.85 p/therm for Northern Ireland and 2.57 p/therm for the Republic of Ireland. These totals comprise exit and commodity charges at the Moffat interconnection point. Charges are based on the average of 2025/26–2029/30 published estimated tariffs and are assumed to remain constant in real terms to 2050.

34 IEA (2024), World Energy Outlook, Available here

35 A renewed agenda for European Union – United Kingdom cooperation Common Understanding, May 2025

Figure 14 Modelling assumption, Carbon prices (£/tCO2eq, 2025 real)



Source: Frontier Economics.

B.2 Demand and Capacity

The model also requires assumptions on electricity demand and installed renewable generation capacity. Battery storage and dispatchable generation plant capacity are determined endogenously within the model, although assumptions on capital (CAPEX) and operating (OPEX) costs are required for these technologies.

We base assumptions for electricity demand and renewable installed capacity on the All-Island Resource Adequacy Assessment (**AIRAA**)[36] and Tomorrow's Energy Scenarios (**TES**)[37], two studies developed jointly by EirGrid and SONI that together provide a comprehensive view of the future Irish electricity system.

- AIRAA evaluates the ability of the power system in Ireland and Northern Ireland to meet demand over the short to medium term (10 years), presenting three demand and generation scenarios. The most recent AIRAA, published in 2025, covers the period 2025–2034.
- TES explores a range of credible long-term pathways for the island's electricity system out to 2050. The latest version, TES 2023, was published in May 2024.

Our high-level approach consists of using the AIRAA 2025 'Median' scenario for the period up to 2034, and TES 2023 'Constrained Growth' scenario from 2035 to 2050. This combination provides a cautious yet credible outlook, avoiding the risk of overstating future demand growth or renewable deployment. To link the AIRAA medium term forecast with TES long-term forecast, we interpolate between them to ensure a smooth and consistent transition.

36 EirGrid and SONI (2025), All-Island Resource Adequacy Assessment (AIRAA) 2025–2034, Available here

37 EirGrid and SONI (2024), Tomorrow's Energy Scenarios (TES) 2023 – Final Report, Available here

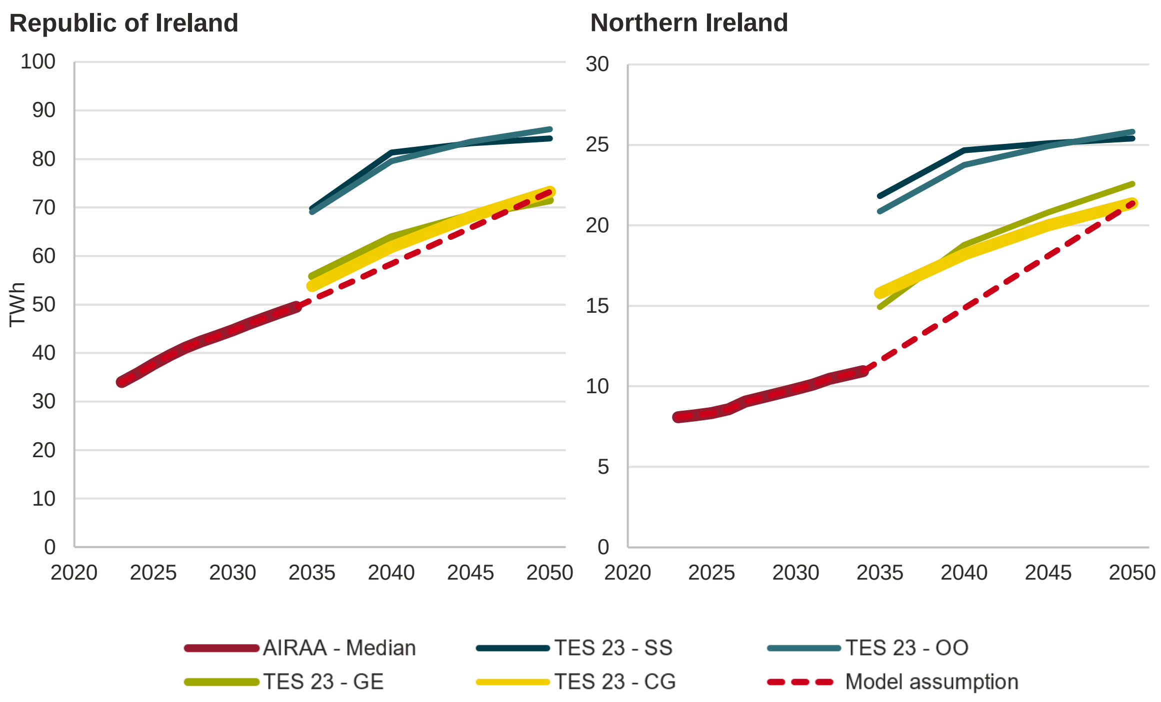
Furthermore, since TES provides data points only at five-year intervals, we apply a linear interpolation to derive annual values between these points where appropriate

In the remaining of the section, we set out the approach for demand and RES and interconnection installed capacity.

Demand

For the period 2025-2034, we use the AIRAA 2025 *Median* demand scenario and for 2035-2050, and apply the TES 2023 *Constrained Growth* scenario. As shown in Figure 15, to avoid a discontinuous step change in 2035 (especially in Northern Ireland), we apply a linear interpolation between AIRAA 2034 and TES 2050 values.

Figure 15 AIRAA and TES scenarios, Demand (TWh)

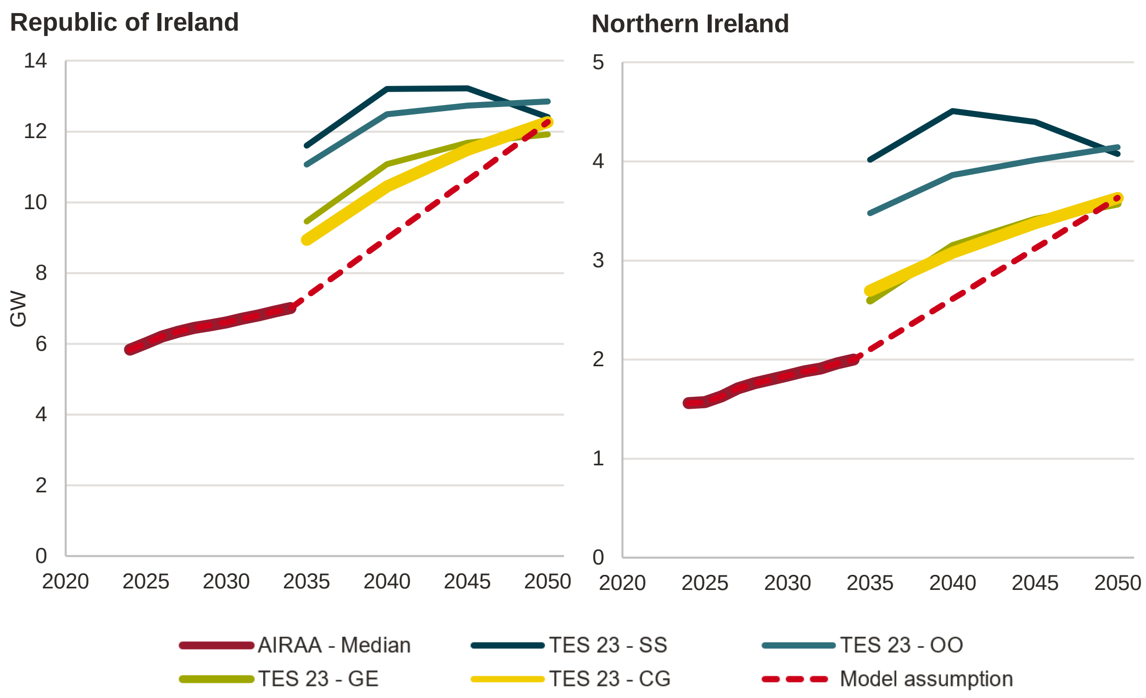


Source: AIRAA (2025) and TES (2023)

Peak demand

Consistent with the demand methodology above, we assume peak-demand follows the AIRAA 2025 Median scenario up to 2034, and then increase linearly to reach the TES CG value in 2025. This is shown in Figure 16 below.

Figure 16 AIRAA and TES scenarios, Peak demand (GW)



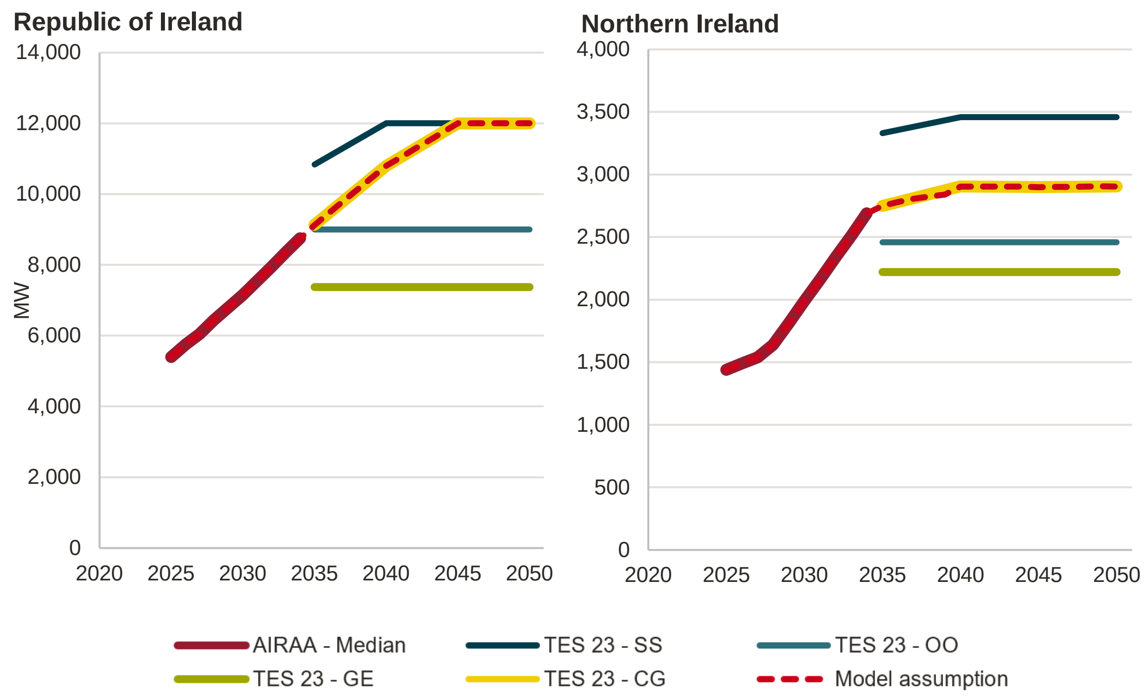
Source: AIRAA (2025) and TES (2023)

Onshore and offshore wind capacity

We again base the modelling assumptions for wind capacity on the AIRAA 2025 Median scenario and the TES 2023 Constrained Growth scenario. Where the two datasets are closely aligned in 2034 and 2035, we assume a direct transition between AIRAA 2034 and TES 2050 values. Specifically:

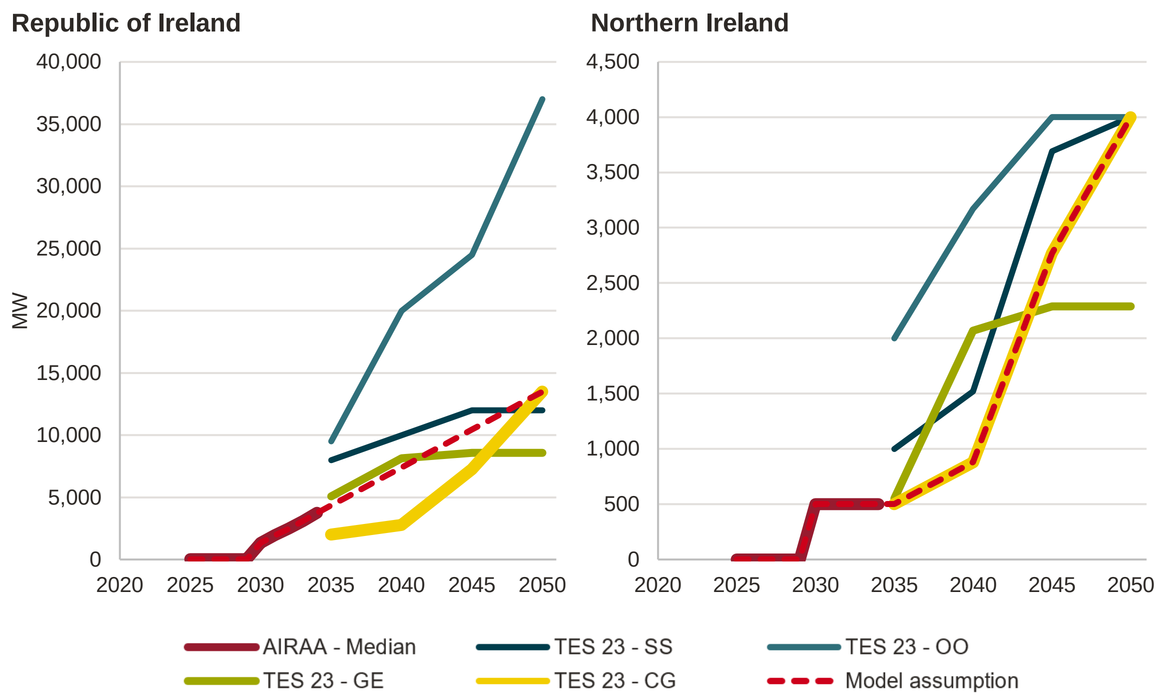
- for onshore wind capacity, we assume a direct transition between AIRAA and TES scenarios as shown in Figure 17; and,
- for offshore wind capacity, we assume a direct transition between AIRAA and TES for Northern Ireland but apply linear interpolation between 2034 and 2035 for the Republic of Ireland, as shown in Figure 18.

Figure 17 AIRAA and TES scenarios, Onshore wind capacity (MW)



Source: AIRAA (2025) and TES (2023)

Figure 18 AIRAA and TES scenarios, Offshore wind capacit (MW)



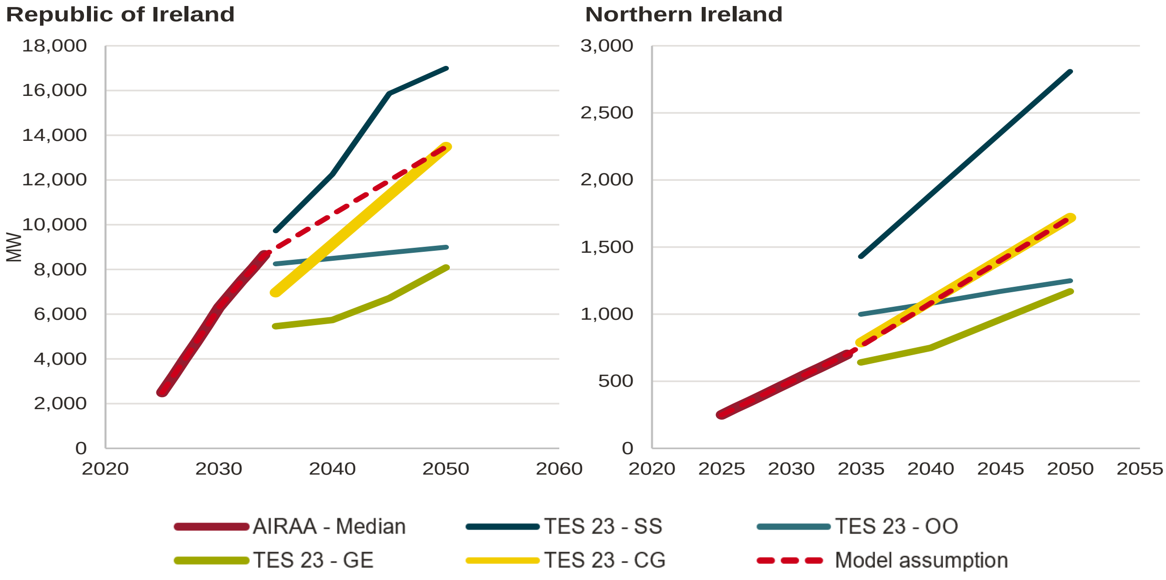
Source: AIRAA (2025) and TES (2023)

Solar capacity

We base the solar capacity assumptions on the AIRAA 2025 Median scenario for the period up to 2034, and the TES 2023 Constrained Growth scenario thereafter. As with wind, we assume a direct transition between the two sources where possible. Specifically:

- For Northern Ireland the AIRAA 2034 and TES 2050 projections are broadly consistent, and we therefore assume a direct transition between the two datasets; and,
- For the Republic of Ireland, the AIRAA 2034 value is above the TES 2050 projection. To avoid a discontinuous step, we apply linear interpolation between 2034 and 2050, assuming a gradual increase.

Figure 19 AIRAA and TES scenarios, Solar capacity (MW)



Source: AIRAA (2025) and TES (2023)

Interconnection capacity

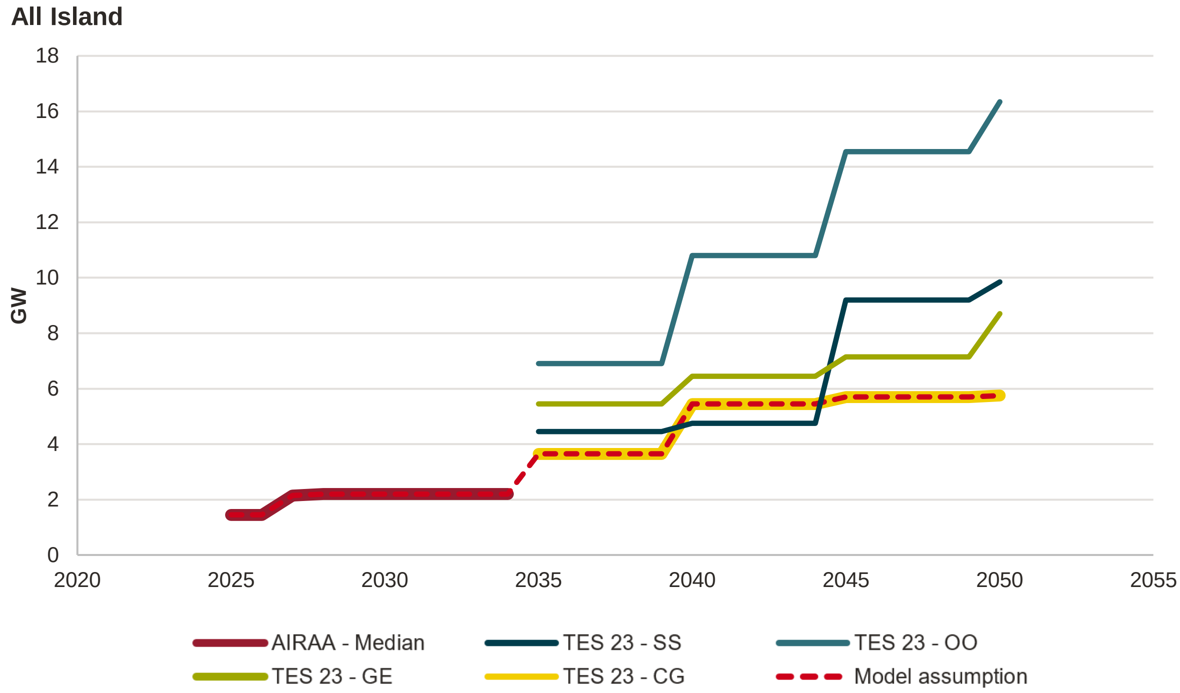
Consistent with our overall approach, assumptions on interconnection (import) capacity are based on the AIRAA 2025 "Median" scenario up to 2034 and the TES 2023 "Constrained Growth" scenario thereafter. We allow for a step increase in 2035, reflecting the fact that interconnectors are developed as discrete infrastructure projects rather than through a smooth build-out. Our modelling assumptions are presented in Figure 20 below.

As the model requires interconnection capacity to be allocated across countries, we make the following assumptions.

- ROI – France: The Celtic Interconnector comes online in 2027, with an additional 0.7 GW of capacity added by 2040.

- ROI – GB: The Mares Interconnector comes online in 2035, followed by an additional 0.5 GW in 2040 and 0.2 GW in 2045
- NI – GB: The Liric Interconnector comes online in 2035, with an additional 0.6 GW added in 2040, followed by increases of 0.05 GW in 2045 and 0.05 GW in 2050.

Figure 20 AIRAA and TES scenarios, Interconnector capacity (GW)



Source: AIRAA (2025) and TES (2023)

B.3 Cost of technologies

This section sets out the assumptions used for the capital and operating costs of new build technologies in the EnVision model. Assumptions are primarily based on the latest evidence from DESNZ and other published sources, supplemented by Frontier analysis where required.

Cost of thermal generation

We calculate technology costs on a net present value basis using commissioning costs drawn from Department for Energy Security and Net Zero (DESNZ) publications[38], combined with assumptions on the timing of cost outlays.

Capital costs are then converted into annualised financing costs using DESNZ's standard lifetime and hurdle rate parameters[39] for each technology.

Capex for gas turbine technologies is assumed to remain constant in real terms. As DESNZ no longer publishes updated cost projections for carbon capture and storage (CCS), the analysis relies on the most recent set of CCS cost estimates available from earlier government projections[40].

For hydrogen generation, we use DESNZ projections for combined cycle hydrogen turbine (CCHT) technology. Hydrogen open cycle hydrogen turbine (OCHT) plants are assumed to incur a 15% cost premium relative to open cycle gas turbine (OCGT) plants.

Table 3 Incidence of capex costs

Cost item	Assumed incidence
Power plant (and CCS) construction	40% in year 1 of commissioning 40% in year 2 of commissioning 20% in year 3 of commissioning
Pre-development costs	100% in year 1 of commissioning
Infrastructure costs	100% in year 3 of commissioning

Source: DESNZ 2023

Table 4 Capex assumptions

Technology	Capex (NPV £/kW, real 2024)
CCGT (H or G Class) (1,700 MW)	671
CCGT + CCS (1,700 MW)	1,657
OCGT (400 MW 500 hrs)	520
Hydrogen OCHT (400 MW)	589

Source: DESNZ 2023 and BEIS 2020.

Note: Hydrogen OCHT plants are assumed to have a 15% cost uplift compared to OCGT plants and the same hurdle rate as that published for CHT plants (9%).

Cost of battery storage

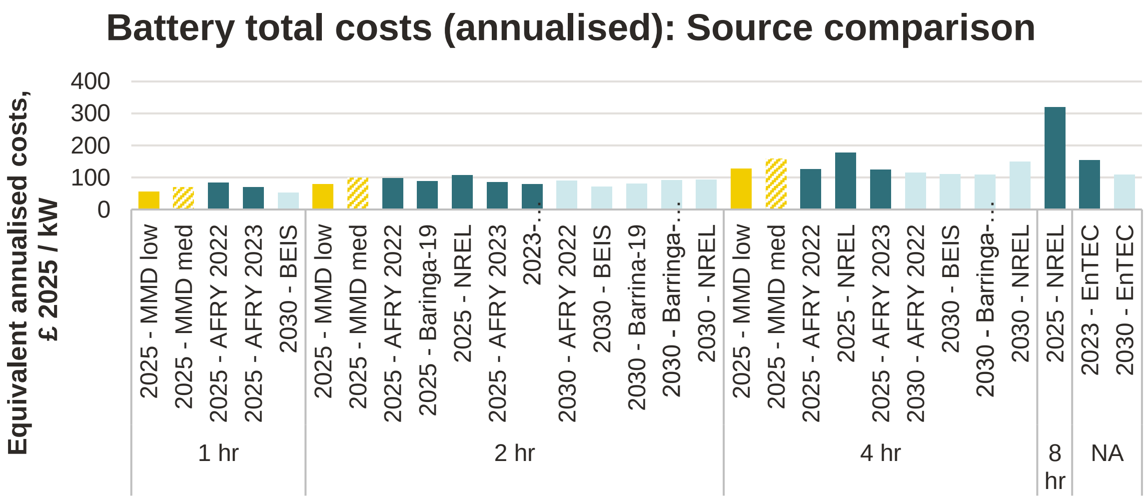
We reviewed a range of evidence on battery storage costs, as shown in Figure 21. Our modelling draws on the low scenario of the long-term cost projections prepared by Mott

[39] DESNZ (2023), Electricity Generation costs 2023, Available here

[40] BEIS (2020), BEIS electricity generation costs (2020), Available here

MacDonald for DESNZ (2018) [41]. While these are now dated, the low scenario matches reasonably closely to the recent evidence[42] which has included significant declines in battery costs since estimates were compiled.

Figure 21 Comparision of sources for the cost of battery storage



Source: *Frontier Economics*

Note: *The years on the label refer to the year of commissioning. MMD low (2018) values are shown in solid yellow. Teal columns represent battery costs commissioned in 2025, while light blue columns represent the costs of batteries commissioned in 2030.*

We first calculate the commissioning-year capex and cost estimates for different battery durations for 2025 in real terms adjusting the value provided for 2020 using ONS CPI. While Mott MacDonald provides cost estimates for 1-, 2- and 4-hour batteries, we derive 8-hour battery costs by applying an uplift to the 4-hour estimate. This follows NREL evidence that, between 2035 and 2050, 8-hour batteries are about 66% more expensive than 4-hour batteries on a per kW basis[43].

Finally, we make additional assumptions for the decline in costs over time to 2050 due to technological improvements, based on LCP analysis as shown in Figure 22.

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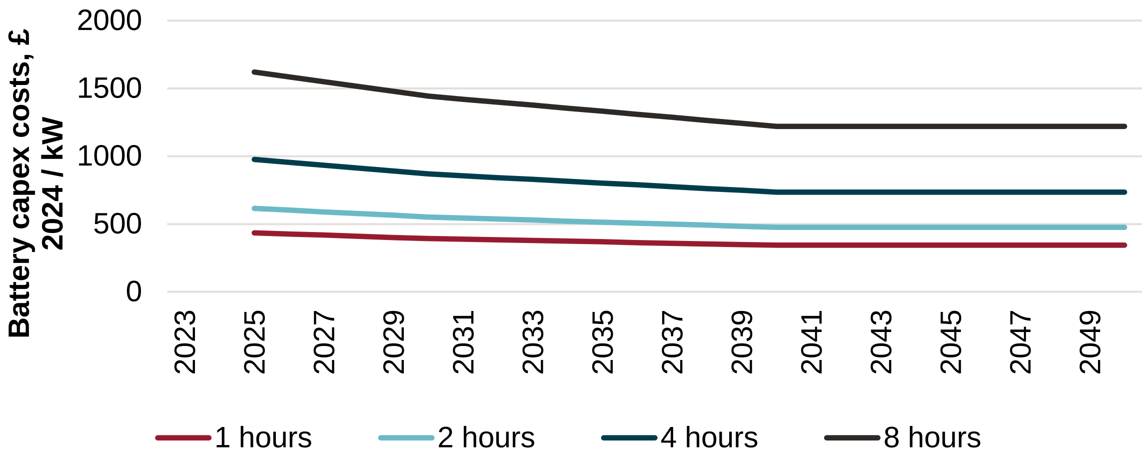
[41] Mott MacDonald, Storage costs and technical assumptions for DESNZ: Available here

[42] MODOENERGY (2024), Battery Business case and investment outlook, Available here; NREL (2025), Cost Projections for Utility-Scale Battery Storage: 2025 Update, Available here

[43] NREL (2024), Electricity Annual Technology Baseline, Available here

Figure 22 Assumed reduction in the cost of battery storage over time by duration



Source: LCP

Annex C – Detailed modelling assumptions for network costs

As set out in Section 2, not all elements of Power NI's regulated tariff are captured by LCP Delta's EnVision model. This annex sets out the assumptions we applied to forecast network-related components that feed into the regulated domestic tariff which sit outside of the EnVision modelling – namely, use of system costs, system services costs, SONI's internal costs, and suppliers' margins.

Where possible, our approach consists of taking historical charges and inflating by a growth rate consistent with regulatory sources such as published allowances and final determinations. We detail our calculations for each of the relevant cost lines below.

C.1 Use of System costs

Use of System Costs relate to charges used to recover NIE Network's costs in the Transmission and Distribution network. NIE Networks' Distribution costs are recovered through the DUoS tariff. 75% of transmission costs are recovered through the STUoS charge which is levied on suppliers and directly affects customer bills. The remaining 25% is levied on Generators through the GTUoS tariff.

Table 5 below, reproduces the UR's forecast of NIE Networks' revenue out to Financial year 2030/31.[44] It shows that, from 2024/25 out to 2030/31, NIE Network's revenues are expected to grow by 30% in total, with a steeper growth in the Transmission (65%) compared to the Distribution sector (23%).

To forecast the levels of the STUoS and DUoS across SONI's next price control, we take the current levels in 2025 as a baseline, which are published by SONI[45] and NIE Networks[46] respectively. We then project these forwards, accounting for:

- the revenue growth set out in Table 5, using the growth in transmission revenues to forecast STUoS and the growth in distribution revenues to forecast DUoS; and
- forecast growth in demand over the same period.

The result of this calculation is shown in Table 6.

44 Table 7 of The Utility Regulator (2024), Northern Ireland Electricity Networks Ltd- Transmission and Distribution 7th Price control. Available here

45 For example, see SONI (2025), TUoS Statement of Charges. Available here

46 For example, see NIE Networks (2025), Statement of Charges for the use of the Northern Ireland Electricity Networks Ltd Electricity Distribution System by Authorised Persons. Available here.

Table 5 UR forecast of NIE Networks revenue

21/22 prices	24/25	25/26	26/27	27/28	28/29	29/30	30/31	Change 24/25 to 30/31
Transmission	55	54	64	71	80	87	91	65%
Distribution	248	245	270	280	290	297	304	23%
Total	**303**	**299**	**334**	**351**	**370**	**384**	**395**	**30%**

Source: Table 7 of The Utility Regulator (2024), Northern Ireland Electricity Networks Ltd- Transmission and Distribution 7th Price control. Available here

Note: Figures are in real terms, using 2021/22 prices.

Table 6 STUoS and DUoS forecast

Cost element (p/kWh, real – 2025 prices)	2025	2026	2027	2028	2029	2030	2031	2032
STUoS	0.79	0.87	0.93	1.01	1.07	1.11	1.19	1.19
DUoS	5.85	6.11	6.08	6.13	6.13	6.11	6.16	6.16

Source: Frontier Economics

C.2 System support services

Ancillary services

Ancillary services will be significantly impacted by the introduction of the Future Arrangement for System Services (FASS) programme. This is an all-island program, led by SONI and Eirgrid, to replace the current DS3 System Services regime. It's go-live date is currently expected to be December 2026.

Our forecast of ancillary services is based on SONI's internal forecast of System Services costs under FASS, which covers calendar years 2027 through to 2031. We convert these forecast costs, into a p/KWh charge, using projected metered demand during the period.

This forecast does not cover calendar years 2026 or 2032, which are both part of our projection of customer bills. Therefore, we:

- Assume ancillary services revenue in 2026 will be the same, in real terms, as in 2025.

- Forecast ancillary services revenue in 2032 based on the growth rate in the previous two years.

The result of these forecasts is shown in Table 7 below.

CEP court ruling charge

The CEP payment is designed to raise revenue to cover the potential liability in Northern Ireland associated with the Irish High Court's 2023 decision on compensation payable to renewable generators who were redispatched downwards.

The CEP has historically been recovered as part of system support services charges, reflecting its role in covering constraint-related liabilities. This charge relates specifically to the loss of income from Northern Ireland subsidy mechanisms, and is distinct from the funds collected by SEMO via the imperfections tariff to address losses of market-related income. LCP's modelling of constraint costs incorporates both components of this ongoing liability. We therefore assume that the CEP payment will fall to zero after the end of the current regulatory year (2025/26).

Table 7 Ancillary services and CEP forecast

Cost element (p/kWh, real)	2025	2026	2027	2028	2029	2030	2031	2032
Ancillary services	0.85	0.83	1.35	1.33	1.34	1.30	1.27	1.23
CEP	0.88	0.71	-	-	-	-	-	-
Total	**1.73**	**1.53**	**1.35**	**1.33**	**1.34**	**1.30**	**1.27**	**1.23**

Source: Frontier Economics
Note: All figures are in 2025 prices

C.3 SONI's internal costs

Because SONI is in the process of submitting its business plan for SRP27, exact projections of its costs, and resultant revenue recovery, are not currently available. Therefore, we have used SONI's real terms percentage growth rate in revenue over the past 3 years (of 6.1%) to project its growth going forwards. This future stream of revenue is then divided by demand to calculate this element of the SSS charge, in p/kWh, over the period.

The results of this projection are shown in Table 8 below. This represents a placeholder assumption, reflecting the absence of finalised cost forecasts for the SRP27 period at the time of our analysis.

Table 8 SONI Interal costs forecast

Cost element (p/kWh, real)	2025	2026	2027	2028	2029	2030	2031	2032
SONI Internal costs	0.49	0.50	0.50	0.52	0.54	0.55	0.57	0.59

Source: Frontier Economics

C.4 Supplier charge

The supplier charge represents the return to suppliers for providing retail services such as billing, customer support, and working capital. In 2025, it accounted for 8.25% of the regulated tariff. To forecast this cost element, we assume this share remains constant over the forecast period, meaning the margin evolves proportionally with total tariff costs. This approach avoids introducing assumptions about future reviews or methodology changes.

Annex D - SONI's impact on the socio-economic costs of the Northern Irish electricity system

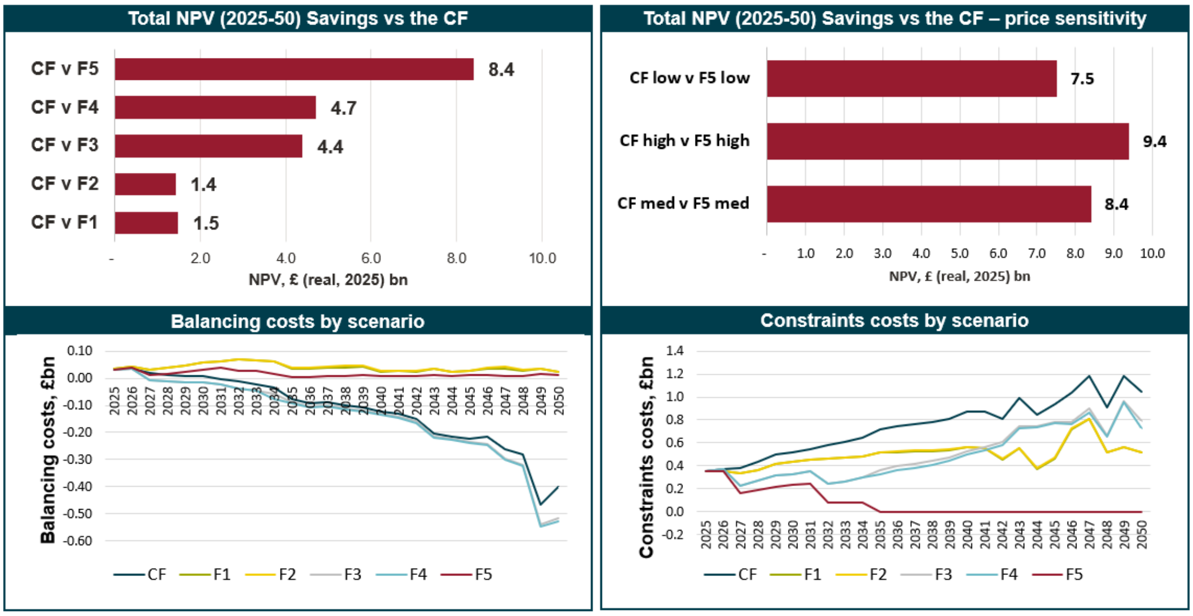
Socio-economic costs represent the underlying costs of building, operating and maintaining the all-island power system. Compared with consumer costs, socio-economic costs account for the welfare of all system participants. The two main differences between socio-economic and consumer costs concern profit margins and the valuation of carbon.

Producer surpluses are included in consumer costs, as they are ultimately passed on to consumers. However, they are excluded from system-wide costs, as they represent a gain for producers and therefore a benefit for society as a whole. In addition, system costs value carbon at its social cost, while consumer costs use the traded carbon price.

Moreover, the two definitions of costs are allocated slightly differently within Ireland: system costs are mainly based on the location of generation, while consumer costs are assigned according to demand distribution.

The savings pattern for system costs across the scenarios differs slightly from that of consumer costs in Northern Ireland. Scenarios 3 and 4 (MUON relaxation) deliver higher benefits than scenarios 1 and 2 (SNSP relaxation), whereas for consumer costs the opposite is true. This is because constraint costs decrease faster when relaxing MUON than when relaxing SNSP up to 2034, suggesting that when focusing on the location of generation (rather than demand), the MUON constraint is more binding in Northern Ireland.

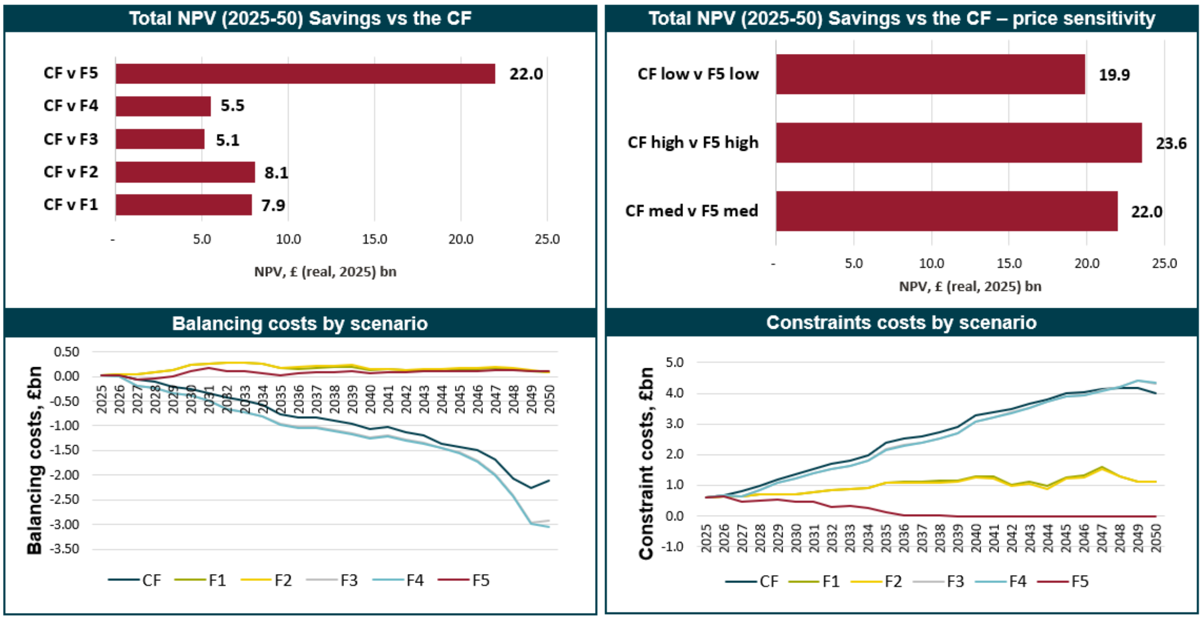
Figure 23 **Northern Ireland**: Summary of results



Source: EnVision model, LCP

Looking at the results for the whole island, system costs follow a similar pattern to consumer costs, with the benefits of relaxing SNSP being greater than those of relaxing MUON.

Figure 24 **All island:** Summary of results



Source: *EnVision model, LCP*