All-Island Resource Adequacy Assessment 2026–2035

SONI EirGrid

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Document overview

This document contains two sections:

Part A

This is a plain English summary of the All-Island Resource Adequacy Assessment with a focus on Northern Ireland.

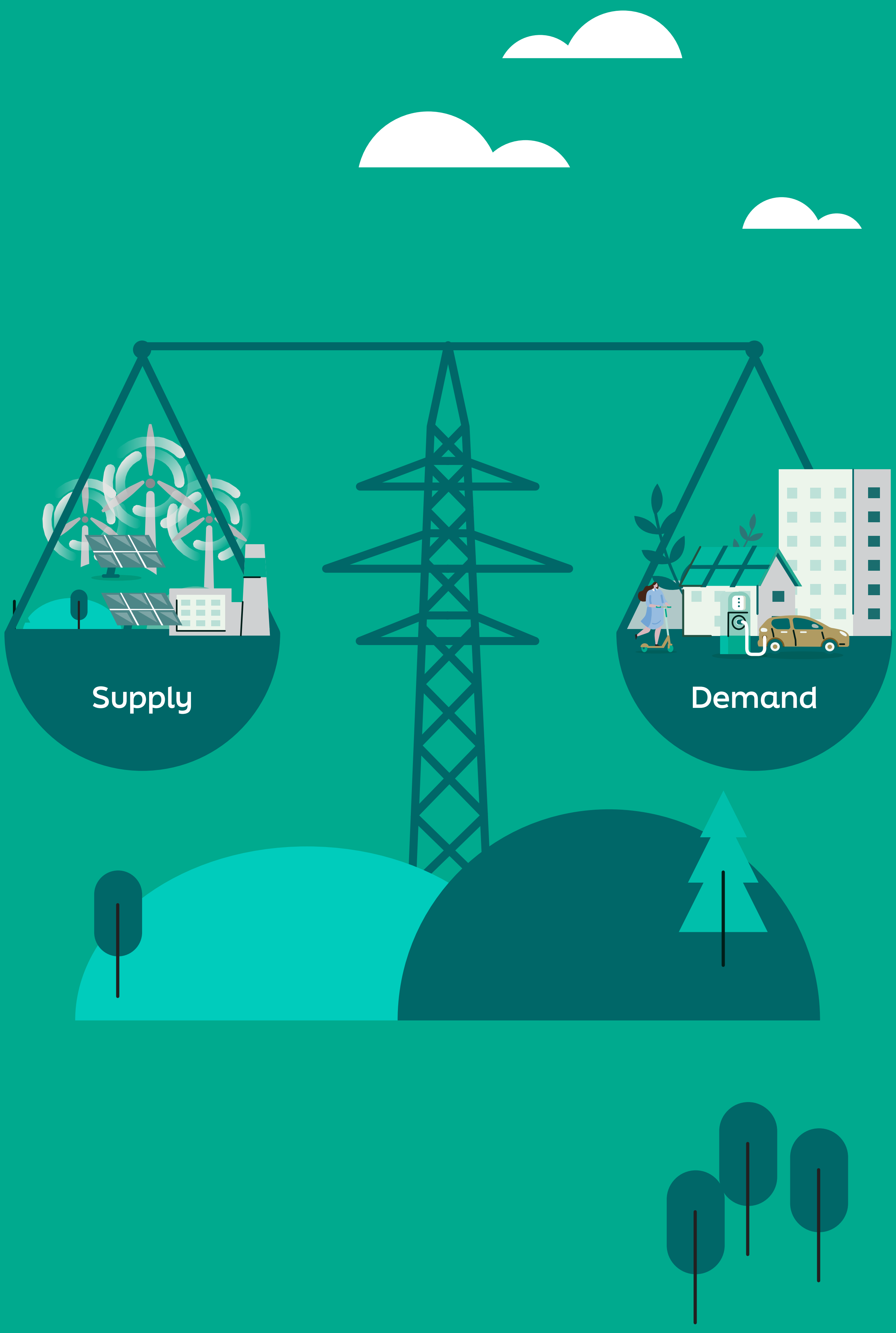
A separate plain English summary is available for Ireland.

Part B

This is the main report of the All-Island Resource Adequacy Assessment, meeting EirGrid's statutory and SONI's licence requirements in addition to relevant European regulatory requirements. This All-Island Resource Adequacy Assessment has been approved by the Utility Regulator in Northern Ireland, in accordance with the SONI licence requirement.

Contents

Part A
Plain English summary of the assessment for Northern Ireland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Introduction

Who we are

SONI is the Transmission System Operator (TSO) for Northern Ireland.

We are licensed and regulated by the Utility Regulator. We don't generate or sell electricity, rather our expert engineers plan and operate the electricity transmission system to ensure that power can flow from where it is generated to where it is needed. This means, as the TSO, we rely on organisations that secure contracts to generate electricity to ensure it is available when we need it.

About the All-island Resource Adequacy Assessment

The All-Island Resource Adequacy Assessment looks at the balance between electricity demand and supply on the island of Ireland for the next 10 years.

It is an evolution of the Generation Capacity Statement (GCS) and implements an updated methodology, which is required to:

- Represent the evolving power system, where the mix of technologies on the system is becoming increasingly diverse, with increasing levels of renewable generation, energy storage, demand side flexibility and interconnection. The new methodology ensures our analysis appropriately reflects the contribution from each technology to the reliable operation of the power system.
- Align with the European modelling framework and regulatory requirements under the European Clean Energy Package[1]. This ensures our analysis is more consistent with other European countries.

The updated methodology (first implemented in the 2025-2034 report) better assesses the benefits we get from renewables across a range of climate conditions. It also better reflects how we model the support we will get from interconnectors, as well as energy storage solutions.

This is a plain English summary of the report for Northern Ireland.

1 https://energy.ec.europa.eu/topics/energy-strategy/clean-energy-all-europeans-package_en

Why do we Need the All-Island Resource Adequacy Assessment?

Since 2016, SONI has warned of an increasing tightness between supply and demand. If the margin between supply and demand becomes tight, we will experience system alerts. A system alert is the lowest level alert, with no immediate impact for electricity users, however it means we will need to work proactively to mitigate the risk of more serious impacts. Continuing to map the island's electricity needs is an important part of our work in order to plan the future of our energy security.

This report allows industry, government, regulators and other stakeholders to facilitate the transition to renewable energy, supporting social and economic growth into the future, while ensuring the secure and resilient operation of the electricity system.

This year's report also includes a new Economic Viability Assessment (EVA). This is part of a phased pathway towards full incorporation into next year's adequacy assessment and allows us to comply with EU Regulation 2019/943 Article 24.

Stakeholder Feedback

As part of this year's All-Island Resource Adequacy Assessment, SONI and EirGrid each consulted on the methodology, inputs and assumptions as well as the new Economic Viability Assessment (EVA). This also included a public webinar, industry stakeholder engagements and workshops with other European TSOs.

We would like to thank our stakeholders from across the energy industry who have engaged with us throughout these consultation processes.

The Assessment

In forecasting the future supply demand balance, SONI considers multiple factors including:

Demand: What Northern Ireland needs

The electricity required to supply homes, businesses and industry, accounting for the winter peak, historic demand trends, economic forecasts, Government targets, new loads such as electric vehicles and heat pumps, along with anticipated growth in data centres and other new technology loads.

Generation: What can supply the demand?

Electricity can be supplied from conventional generators, renewable energy, interconnection with Great Britain, energy storage, support from Ireland, demand side units and also new technologies coming through capacity and future renewable energy auctions. In assessing this, we also need to consider the impact of forced (unplanned) and scheduled (planned maintenance) outages of generators and interconnectors, in addition to the variability of renewable generation and the availability of imports from neighbouring regions.

Adequacy: Is there a gap?

Following our analysis of the likely demand and generation, we need to understand the balance between the two, known as the 'adequacy'.

Adequacy is assessed against a standard called the 'Reliability Standard'. The Reliability Standard is expressed using Loss of Load Expectation (LOLE), which is the number of hours per year that a country's electricity production is not expected to meet its demand. It's important to note that the LOLE measurement does not necessarily mean that electricity consumers will be without supply for any period. The Reliability Standard for Northern Ireland is 4.9 hours LOLE, as set by the Department for the Economy (DfE).

The output from this assessment is a forecast of LOLE and an indication of whether or not the system requires additional capacity to operate securely. If the system is outside the standard, SONI then assesses how much capacity (in megawatts) is required to meet the Reliability Standard.

Following on from last year's approach, SONI has continued to assess the adequacy from both a base and secure perspective.

The base assessment identifies the minimum amount of generation capacity that is likely to be required to meet the median demand over the next ten years.

The secure assessment identifies the generation capacity that is likely to be required to meet the median demand under more challenging conditions (than the base assessment) over the next ten years.

SONI considers the secure assessment is most prudent and should be considered as the central scenario for adequacy assessments, noting that capacity auctions remain the mechanism for determining specific auction requirements.

To obtain the most relevant information, SONI engages widely with industry participants, and we use the most up-to-date information at the time of submission to regulators. We 'freeze' the data on which the calculations are measured to ensure that we are providing an accurate assessment. The freeze date for this assessment was 30th June 2025 for both the demand and generation data.

Demand forecast for Northern Ireland

In developing demand forecasts in Northern Ireland, SONI looks at the policy drivers and has considered the impact of the Northern Ireland Executive's Energy Strategy — The Path to Net Zero Energy[2] 2021, Path to Net Zero – Action Plan 2025[3] and the Climate Change Act (Northern Ireland) 2022[4].

Demand Scenarios

When forecasting demand, we look at a range of scenarios so that we can understand the possible outcomes depending on a range of influential factors.

Median demand: The median demand forecast is based on an average climate conditions, median forecast of electrification of heat and transport, data centre load in the connection process along with the application of a central economic growth rate. This scenario is our best estimate of what might happen in the future.

Low demand: The low demand forecast is based on lower levels of new technology load growth, lower electrification of heat and transport, no data centre load and slower economic growth.

High demand: The high demand forecast is based on higher levels of electrification of heat and transport, potential additional data centre load that may connect to the system and a higher economic growth.

2 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf
3 Path to Net Zero – Action Plan 2025
4 https://www.legislation.gov.uk/nia/2022/31/enacted

Total Electricity Requirement Forecast

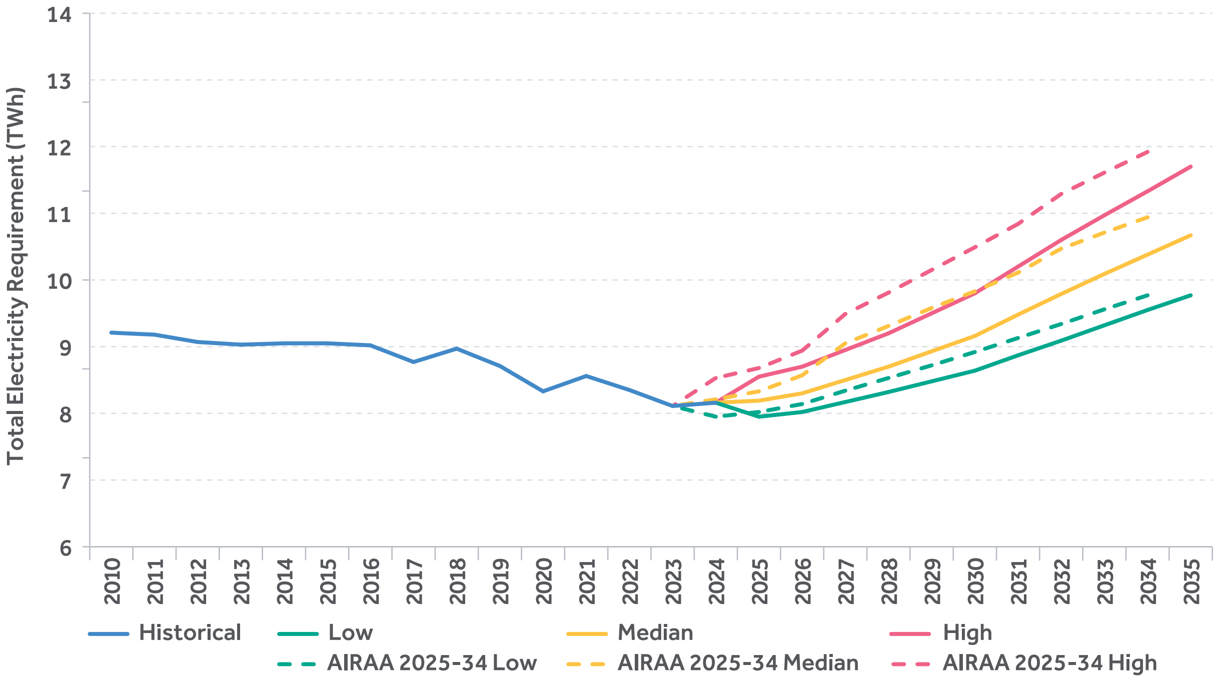
The Total Electricity Requirement (TER) is the sum of the electricity demand that is likely to be required by various sectors including residential, commercial, industrial and transport.

The latest forecasts show there is a reduction in the low, median, and high scenarios when compared to the forecast published in the AIRAA 2025-2034 due to revised projections for electric vehicle, heat pump and new technology loads. The overall trend remains the same with relatively low growth over the first few years increasing from the middle of the horizon as greater electrification is observed.

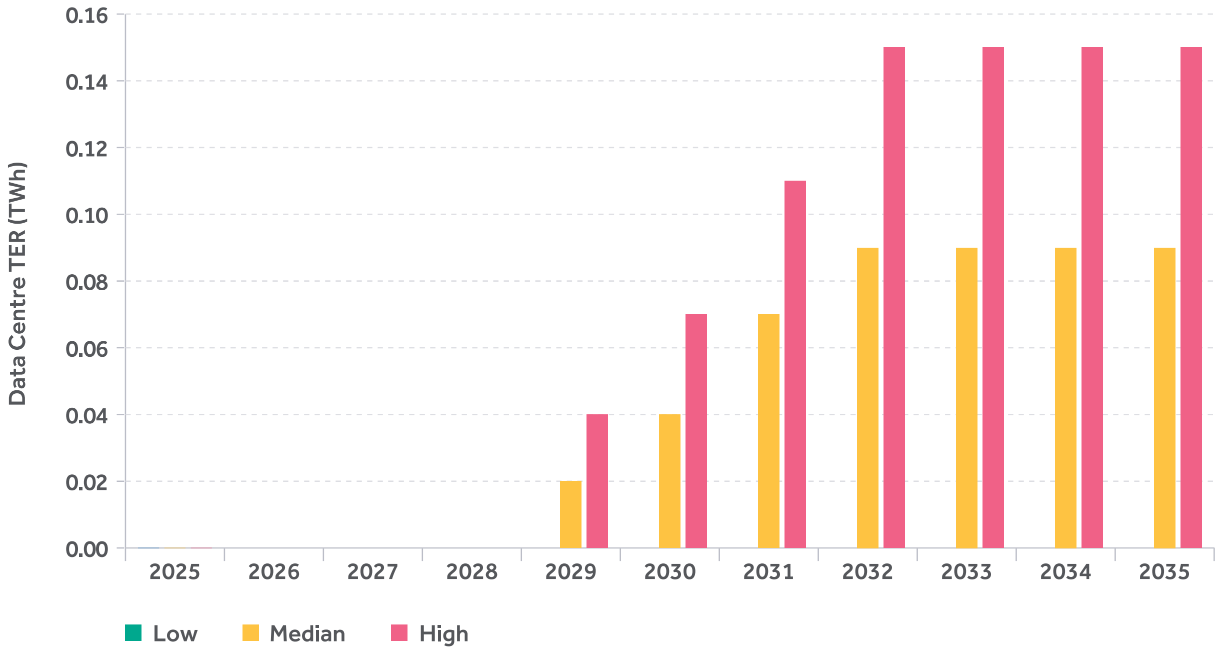
Peak Demand Forecasting

SONI has aligned with the European Resource Adequacy Assessment (ERAA) methodology and utilised the ENTSO-E Demand Forecasting Tool (DFT) to forecast the demand profile including peak demand. This tool utilises demand trends correlated to temperature, economic factors and includes forecasted heating profiles and EV charging profiles.

The peak forecast trend is consistent with the TER trend outlined above, with lower growth observed in earlier years and then increasing across the 10-year period. Demand flexibility has the capability to improve the adequacy of the electricity system by moving demand away from peak times. Off peak electric vehicle charging could reduce peak demand by around 4.3% in the median demand scenario.



Total Electricity Requirement for Northern Ireland



Northern Ireland TER expected from data centres across demand scenarios

Data centres

Following the publication of the UK Government's 'Compute Roadmap' targeting 'Developing Cutting-Edge AI Infrastructure: AI Growth Zones (AIGZs)'[5] SONI anticipates growth in this area. Due to the fact that the Compute Roadmap was published after the freeze date for this report (mid-July 2025) its effects have not been taken into account. However, it will be considered as appropriate for any future publications.

To capture the impact of data centres seeking to connect in Northern Ireland, SONI has based the demand forecasts on different build-out scenarios. The low demand scenario assumes no data centre load. The median demand scenario includes a realistic estimate of new data centre load in the connection process. In addition to this, the high demand scenario contains potential additional load from data centres that are due to connect to the system within the ten-year study period.

The median and high scenarios assume that data centre demand will not materialise until 2029.

Electrification of Heat and Transport

As Northern Ireland moves away from fossil fuel sources, an increasing proportion of heating and transport energy demand will be met by electricity. As a result, the demand forecast reflects electrification in the heat and transport sectors, with the low, median and high forecasts capturing differing rates of electrification.

Economic Forecast

The TER forecast is carried out with reference to economic parameters, primarily Gross Value Added (GVA) with variations applied for the low and high forecasts.

5 UK Compute Roadmap – GOV.UK

Generation forecast for Northern Ireland

Availability

Generator availability continues to be below longer-term historical averages, and this is accounted for in our analysis. This is partially due to some units reaching the later stages of their operational lifetime.

The lower availability in recent years has presented a challenge to the operation of the power system, and any further decline in generator availability as existing units get older, could present similar risks in future.

Renewable Capacity

The Path to Net Zero – Action Plan 2025 highlights an action on the Department for Economy to launch the final design of a renewable electricity support scheme. In September 2025, the Department published the Final Scheme Design for a renewable electricity support scheme[6] — the Renewable Electricity Price Guarantee (REPG). Securing contracts for new renewable generation will support Northern Ireland in achieving its renewable energy targets, while also ensuring diversity and strengthening security of supply. In the short to medium term, onshore wind and solar photovoltaic are expected to be the most readily deployed technologies for Northern Ireland. In the medium to long term, offshore renewable energy offers a significant opportunity to develop additional large-scale renewable capacity.

Energy Storage

The energy storage portfolio in Ireland and Northern Ireland has evolved in recent years with increasing battery storage being introduced into the portfolio.

Through the SEM capacity market auctions, by 2030 Northern Ireland is assumed to have 240 MW of generation capacity attributed to storage technologies, and 220 MWh of storage capacity, this means storage can provide 240 MW of power for approximately 1 hour. There remains a strong pipeline of storage projects in Northern Ireland, and a sensitivity considering potential further delivery of energy storage shows there could be an additional 530 MW of storage by 2030. This could have a positive impact on the adequacy position in Northern Ireland.

Annual Run Hour Limitations (ARHL)

In 2017, the European Commission published a final decision on the Best Available Techniques (BAT) for large combustion plants, which has applied new standards on emissions. The standards mean new gas generating units could have Annual Run Hour Limitations (ARHL) of 500 or 1,500 hours depending on the units' technical characteristics (fuel source / efficiency).

There are a number of units in Northern Ireland subject to ARHL and the continued need to manage run hours across the units presents a significant challenge in terms of managing runs hours on units within annual and multi-year Annual Run Hour Limitations (ARHL). The central assessments in this report account for these limits, with sensitivity analysis used to examine variations of ARHL unit availability. The sensitivity results indicate significant benefit from the removal of ARHL, which could position Northern Ireland with a capacity surplus across the study horizon. A further sensitivity shows a negative impact on the adequacy position if availability of run hour limited units is worse than what is accounted for in the central assessment.

6 Final Scheme Design for a renewable electricity support scheme for Northern Ireland

Economic Viability Assessment (EVA)

This year's report includes an Economic Viability Assessment (EVA) which is new for this year's report. This is part of a phased pathway towards full incorporation into next year's adequacy assessment and allows us to comply with EU Regulation 2019/943 Article 24.

The EVA is a tool to measure the ability of generation units to cover their operating costs in an energy-only electricity market, a market without any additional measures like capacity markets. Capacity markets provide an additional revenue stream to generators which can allow generators to cover operating costs not covered by the energy-only electricity market.

If the EVA demonstrates that generating units are not able to cover their operating costs, they may stop participating in the market which may, in turn, lead to adequacy concerns. Therefore, the EVA could be used to assess the future need for additional measures like capacity markets.

As part of the phased pathway towards full incorporation of the EVA, this year's report focuses on the process of conducting an EVA and testing the process for different scenarios. Initial results show that across the scenarios, there is capacity that could be unviable due to insufficient revenues without additional measures like capacity markets. Future assessments will expand to incorporate the impact of economic viability into the adequacy assessment.

It is important to note that the EVA does not model future capacity market auctions. This assumption is to provide a perspective on viability without capacity market support and is not a comment on the likelihood of future capacity auctions.

Adequacy Forecast for Northern Ireland

Base and secure assessment

Using the median demand forecast, our best estimate of what will happen in the future, we have used two separate adequacy assessments — base and secure. Each assessment analyses 36 weather scenarios, with 30 different outage patterns for each weather scenario.

- **The base assessment** identifies the minimum amount of generation capacity that is likely to be required to meet demand, within the median scenario, over the next ten years. The base assessment considers the median forecasts for demand and renewables.
- **The secure assessment** identifies the generation capacity that is likely to be required to meet more challenging conditions (than the base assessment) while remaining within the median demand scenario, over the next ten years. The secure assessment starts with the base results but includes additional analysis to cover aspects such as harsh climate conditions, levels of import and plant availability (not considered in the base results).

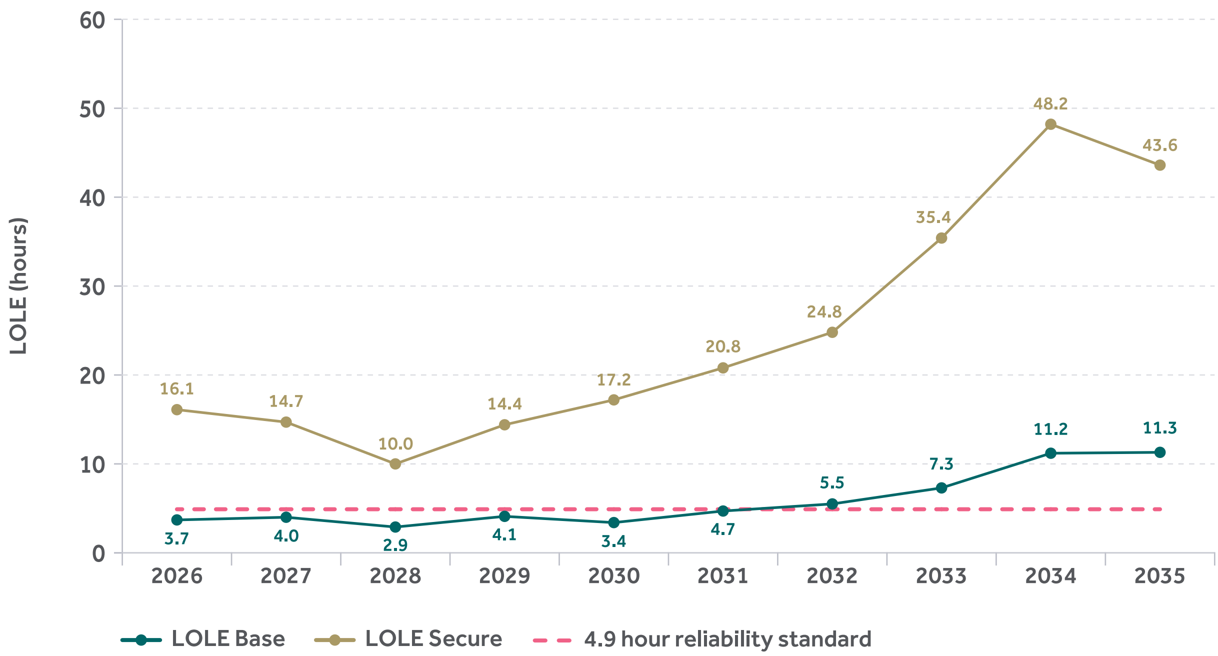
Please note that, while the base and secure scenarios use the median demand forecast, in the main report we have provided data for the high and low scenarios (6.5.5. Sensitivity Studies for Northern Ireland) to show the range of impacts under these conditions.

What do the results tell us?

The base and secure results for Northern Ireland are summarised below:

- **From 2026 to 2031,** the base assessment shows the system is within standard meaning there is sufficient capacity to operate the system under average conditions. From 2032, the base results show the system is outside of standard and up to 120 MW of additional capacity is required by 2035 to meet the reserve requirement.
- **From 2026** across the full study horizon, the secure assessment shows the system is outside of standard meaning additional capacity is required to ensure SONI can continue to balance supply and demand under more challenging conditions. The results indicate 100-200 MW of new capacity is required from 2026 to 2032, increasing to up to 320 MW by 2035.
- In both base and secure assessments, the key reason for the increasing loss of load expectation over time is a result of increasing demand not being met with new reliable capacity.
- Sensitivity analysis has been included, the key outcome of which shows that removal of the Annual Run Hour Limits on the KGT6 and KGT7 units has the largest positive impact on security of supply in Northern Ireland, resulting in both base and secure assessments being within the Reliability Standard.

SONI considers the secure scenario is most prudent and should be adopted for decisions relating to securing capacity for the continued secure and sustainable operation of the power system. This scenario accounts for the impact of a large unit outage, and the need to ensure there is sufficient capacity to cover operational requirements. Additional sensitivities are utilised to understand the impact of factors that have higher levels of uncertainty such as demand, renewable capacity, and storage forecasts.



Base and secure loss of load expectation results for Northern Ireland

Meeting the Challenges

Over the ten-year period, there are increased challenges relating to Northern Ireland's security of supply of electricity, with an increased potential for some limited disruption. During tight periods where demand can be elevated and renewable availability is low, there is a higher dependency on the availability of existing thermal generation. Given the small system size of Northern Ireland, the loss of a large unit or an interconnector will have a significant impact on power system reliability, particularly during periods of low wind and considering there are units restricted by Annual Run Hour Limitations.

SONI continues to work closely with the Department for the Economy, the Utility Regulator, NIE Networks, our counterparts in National Energy System Operator (NESO) in Great Britain, EirGrid the TSO for Ireland, the Gas TSOs and the energy industry to find solutions to the challenges facing Northern Ireland, as well as consideration of a range of mitigation measures.

These measures include:

- Maximising existing generation availability, including reconfiguration of the planned outage schedule.
- Utilising smaller, more responsive Open Cycle Gas Turbines.
- Utilising new technologies such as batteries.
- Incorporating advances in demand flexibility and Demand Side Unit (DSU) performance improvement
- Maximising the availability of imports from Great Britain and Ireland.
- Progressing future capacity auctions to procure additional capacity to improve the adequacy position. However, any delays to new units connecting to the system and entering the market, or discontinuation of projects, will significantly alter the outlook and prolong the period of capacity deficits.

When reading this report, it is important to consider the post data freeze date changes, including the potential impacts of prolonged outages due to recent storm damage, and the corresponding impact on the availability of run hour restricted plant.

Overall, a balanced portfolio of new electricity generation is required, and this includes the need for new cleaner dispatchable generation plant, especially at times when wind and solar generation is low. This balanced portfolio is also crucial to ensuring Northern Ireland meets its collective renewable energy target for 2030, while maintaining a secure supply of electricity for consumers.

All-Island Assessment

The new North-South Interconnector is expected to be completed by October 2031; therefore, we have provided an All-Island adequacy assessment within the AIRAA from 2032.

The All-Island adequacy assessment measures the adequacy position of the Single Electricity Market (SEM) which encompasses both Ireland and Northern Ireland. Adequacy for the SEM is measured against its own Reliability Standard of 6.5 hours LOLE set by the Single Electricity Market Committee.

The All-Island adequacy assessment shows the SEM is within the 6.5 hour Reliability Standard for both the Base and Secure assessments from 2032 to 2035. From our analysis, it is clear the new interconnector will support the overall security of supply outlook for both Ireland and Northern Ireland following its completion.

Conclusion

Over the next few years, the assessment indicates a potentially challenging outlook in Northern Ireland across the study horizon.

The electricity industry will have to find new ways to meet the increasing need for energy without relying primarily on burning fossil fuels. Looking out to 2030 and beyond, electricity demand is set to increase as consumers use electricity in new ways. New government policies are expected to help guide us away from fossil fuels toward alternative heating methods, such as electric heat pumps, and cleaner modes of transport, such as electric vehicles.

This changing demand and generation supply landscape will require coordinated management of both the volume and type of new capacity, alongside new ways of managing increasing demand to ensure security of supply.

SONI will continue to proactively engage with the Department for the Economy, the UR, industry and other relevant stakeholders to provide timely assessments, analysis, and options for operational mitigations.

Part B
All-Island Resource Adequacy Assessment 2026-2035


EirGrid

Disclaimer

EirGrid and SONI have followed accepted industry practice in the collection and analysis of data available. While all reasonable care has been taken in the preparation of this data, EirGrid and SONI are not responsible for any loss that may be attributed to the use of this information. Prior to taking business decisions, interested parties are advised to seek separate and independent opinion in relation to the matters covered by this report and should not rely solely upon data and information contained herein. Information in this document does not amount to a recommendation in respect of any possible investment. This document does not purport to contain all the information that a prospective investor or participant in the Single Electricity Market (SEM) may need.

This document incorporates the Resource Adequacy Assessment Report for Ireland and the Resource Adequacy Assessment for Northern Ireland.

For queries relating to this document or to request a copy contact: info@soni.ltd.uk or info@eirgrid.com.

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Preface

Introduction

As the transmission system operators (TSOs) for Ireland and Northern Ireland, EirGrid and SONI are responsible for the operation and planning of the electricity transmission systems.

As part of the transition to a more sustainable and low-carbon society, the grid is undergoing a process of modernisation and transformation. SONI and EirGrid are working to ensure that everyone has electricity when they need it while preparing the transmission grid to provide 80% of our power from renewable sources, in line with Government targets in both jurisdictions.

EirGrid's and SONI's analysis of our respective jurisdictions clearly shows that timely delivery of new reliable low-carbon solutions will be required to operate a secure and reliable power system as we transition to higher levels of renewable electricity over the coming years. Looking out to 2035, our electricity demand is set to increase as consumers use electricity in new ways to enable productivity and digitalisation, fuel transport and heat our homes. New Government policies, such as the Climate Action Plan in Ireland and the Energy Strategy in Northern Ireland are expected to help guide us away from fossil fuels and towards more efficient heating alternatives (such as electric heat pumps) and modes of transport (such as electric vehicles) as we aim to reduce our emissions and final energy consumption.

To ensure operation of a predominantly renewable power system, it is crucial that a balanced portfolio of new technologies is delivered, such as long duration energy storage, interconnection, demand-side flexibility and renewable-fuel-ready open cycle and combined cycle gas turbines. Delivery of the new North-South Interconnector and the new Celtic Interconnector to France, remain important for the medium- to long-term security of supply on the island of Ireland.

The changing demand and generation supply landscape across the island will require coordinated management of both the volume and type of new capacity connecting, alongside new ways of managing increasing demand to ensure security of supply over this unprecedented period of change.

About the All-Island Resource Adequacy Assessment

This document represents the second edition of the All-Island Resource Adequacy Assessment framework – an evolution of the previous annual Generation Capacity Statement publication. As part of the reporting process, SONI and EirGrid have undertaken a public consultation on the Methodology and Inputs and Assumptions. We would like to thank our stakeholders from across the energy sector who have actively engaged and interacted with us throughout the consultation processes.

This publication continues to outline the expected electricity demand and the level of generation capacity that will be required on the island of Ireland over the next ten years to maintain security of electricity supply and to support social and economic growth. Conducting this assessment is a key responsibility for EirGrid and SONI in relation to security of electricity supply, which supports the Commission for Regulation of Utilities (CRU) in Ireland, and the Department for the Economy (DfE) in Northern Ireland as the bodies with primary responsibility for security of supply. The design of the Single Electricity Market (SEM) is intended to support competition, allow increased renewables on the system, encourage new investment and support security of supply.

SONI and EirGrid are introducing the Economic Viability Assessment (EVA) for the first time in this report, as part of a phased pathway towards full incorporation into the central adequacy analysis. The development of an EVA has included a full public consultation, a public webinar, engagements with industry stakeholders, and workshops with other European TSOs. EirGrid and SONI look forward to continuing to work with stakeholders to build on the process in future iterations of this report.

Mapping the island's electricity needs is an important feature of our work as it helps our Governments, regulators and industry prepare for the future. The analysis contained within the report will be used to support Government and Regulatory Authorities in the development of energy policy and market design required to deliver a secure and reliable power system through the transition to a decarbonised power system. We hope you find this All-Island Resource Adequacy Assessment both informative and useful in signalling the future needs of the grid.

Alan Campbell
SONI
Chief Executive

Cathal Marley
EirGrid Group
Chief Executive

1. Document Structure

This document contains a Preface, an Executive Summary, four main sections and five appendices.

The structure of the document is as follows:

- The Executive Summary gives an overview of the main highlights of the document and presents the report in summary terms.
- The Introduction sets out statutory and legal obligations, also outlining the purpose and context of the report.
- The Demand section outlines the demand forecast presenting estimates of demand over the next ten years, along with analysis of the underlying trends.
- The Generation section describes the expected evolution of the generation portfolio over the next ten years for each technology class.
- The Adequacy section presents the results and analysis from the adequacy assessments.

Five appendices are included at the end of this report. They provide further detail on the data used in this study.

2. Executive Summary

This document represents the second edition of the All-Island Resource Adequacy Assessment (AIRAA), an evolution of the previous Generation Capacity Statement (GCS), meeting EirGrid's statutory and SONI's licence requirements in addition to relevant European regulatory requirements.

This report examines the likely balance between electricity demand and supply across the 10-year period from 2026 to 2035 for Ireland and Northern Ireland against the relevant Reliability Standard. The Reliability Standard is an accepted Loss of Load Expectation (LOLE), which is the number of hours per year that a country's electricity production is not expected to meet its demand. This LOLE measurement does not necessarily mean that electricity consumers will be without supply for any period. The Reliability Standard for the SEM is 6.5 hours, as per the SEM Committee decision paper[1]. The jurisdictional Reliability Standard is 3 hours for Ireland[2] as set by the Department of Climate, Energy and the Environment (DCEE) working with the Commission for Regulation of Utilities (CRU) and 4.9 hours for Northern Ireland as set by the Department for the Economy (DfE).

This report approaches modelling resource adequacy through two central assessments namely a Base and a Secure assessment. The Base assessment analyses the adequacy position broadly consistent with the European Resource Adequacy Assessment (ERAA) approach, and the Secure assessment analyses the system considering additional security analysis, and other operational requirements. SONI and EirGrid consider the Secure assessment is most prudent and should be considered as the central scenario for adequacy assessments, noting that capacity market auctions will procure new capacity if required to address capacity shortfalls in the medium to long term.

Since 2016, EirGrid and SONI via the GCS and the AIRAA have warned of an increasing tightness between supply and demand. There is no question that based on the best information available, the current outlook remains challenging. It is likely that in the coming years the system will experience a number of system alerts and the TSOs will need to work proactively to mitigate the risk of a more serious impact across Ireland and Northern Ireland. This report will allow the industry, Government, regulators and other stakeholders to support us in securing the transition to renewable energy and support social and economic growth into the future while proactively managing the supply demand balance.

In both jurisdictions, EirGrid and SONI continue to engage with their respective Government departments and regulatory authorities to provide timely assessments, analysis, and options for operational mitigations where required. These assessments support proactively planning the transition to a decarbonised and affordable power system driven predominantly by renewable energy whilst also ensuring security of supply of the future power system, meeting the evolving needs of economy and society.

1 SEM-23-072 Calculation of Single Value of Lost Load within the Single Electricity Market Information Paper | The Single Electricity Market Committee (semcommittee.com)

2 https://www.semcommittee.com/files/semcommittee/2024-07/SEM%20-%2024%20-%20051%202027-28%20T-4%20Volumes%20Information%20Note.pdf

Under EU Regulation 2019/943 Article 24, national resource adequacy assessments are required to include an Economic Viability Assessment (EVA). SONI and EirGrid are introducing an Economic Viability Assessment for the first time in this report, as part of a phased pathway towards full incorporation into the central adequacy assessment. The focus of this year is to introduce the new EVA process and to provide a basis for further engagement and consultation, such that the central adequacy assessment performed in future report iterations aligns with the requirements set out in Article 24 of EU Regulation 2019/943. The development of an EVA has included a full public consultation, a public webinar, engagements with industry stakeholders, and workshops with other European TSOs also conducting EVA analysis. SONI and EirGrid look forward to continuing to work with stakeholders to build on the process in future iterations of this report.

More detail on the key areas which have driven changes in the adequacy position since last year's AIRAA 2025-2034 forecasts for Ireland, Northern Ireland and All-Island systems are provided below, noting the data freeze for information and data used in this year's assessment was 30 June 2025.

2.1 Ireland

In last year's AIRAA 2025-2034, the Base and Secure assessment results indicated adequacy challenges in 2025 and 2026 considering in-market measures only. The position improved from 2027 as Celtic and new gas capacity were assumed to come online. From 2028 the Base assessment indicated the system was within standard on average. The Secure assessment considered the combined impact of Low Imports, possible Annual Run Hour Limits on some new conventional units and Transmission Outage Planning and indicated the system would be outside of standard across the full study horizon.

In this year's assessment, the Secure assessment considers the risk of a one-week period of low renewable availability, also known as a 'Dunkelflaute', replacing the previous low import consideration. This update is a result of improvements to the process for assessing risks, in which a range of credible risks are analysed in terms of impact and likelihood. Of the sensitivities analysed, the one week Dunkelflaute presented the highest overall risk when accounting for impact and likelihood and is therefore included in the Secure assessment. Since AIRAA 2025-2034, in the short term there are delays to the delivery of new capacity contracts awarded through the capacity market auctions. The recent exiting of older plant from the market, combined with delays to new capacity and a delay to the new Celtic interconnector coming online, result in increased stress in the initial years of the assessment from 2026 to 2028. For the median demand scenario, both the Base and Secure assessments show Ireland is outside of standard from 2026 to 2028, following which there is a continued improvement in the adequacy position as new capacity comes online, including Celtic from 2028. From 2029, the Base assessment results show a surplus across the remainder of the study horizon. The Secure assessment considers a one-week Dunkelflaute, alongside Annual Run Hour Limits on some new conventional units and Transmission Outage Planning. The Secure assessment indicates the system remains outside of standard with a deficit of around 200 MW increasing to over 400 MW in 2034.

The central adequacy assessments are built on median forecast assumptions, with further sensitivities utilised to analyse variations in assumptions. The sensitivity analysis highlights potential adequacy concerns arising from high demand, low renewable build out, low flexibility materialising and further delays of awarded capacity.

The CRU concluded its CRU Information Paper Security of Electricity Supply – Programme of Actions, in July 2025. As part of the actions from the CRU-led Security of Supply programme, the CRU directed EirGrid to procure Temporary Emergency Generation (TEG) and Retain Existing Units (REU) to proactively mitigate the risks of an electricity crisis as defined by Regulation (EU) 2019/941 and the Risk Preparedness Plan (RPP) for Ireland. The TEG and REU can only be used in emergency situations and therefore are not intended to be available to meet growing and enduring demand due to social or economic growth. Over the longer term, it remains crucial that the capacity market delivers new capacity in a timely fashion, and the type and volume of capacity needed to underpin the energy transition. The TEG and REU will, however, provide critical insurance and will be called upon in the event of a shortfall in market-based capacity and where alerts on the system are likely. Alerts occur where the buffer between electricity supply and demand is tighter than is required to operate a secure system.

The outputs and impact of the CRU's programme of actions are not reflected in the central adequacy assessment in this report, but the expected positive impact of the actions is captured in Section 6.4.6.

EirGrid is actively engaging with the Department of Climate, Energy and the Environment, the CRU and other relevant stakeholders in relation to planning a secure power system.

A summary of the main drivers for change since AIRAA 2025-2034 is included below.

Demand

Ireland observed a record electricity transmission peak demand of 6,024 MW on the 8 January 2024 exceeding the 6,000 MW mark for the first time ever. The particularly cold weather at the time of the peak was a key driver behind this record demand. Overall demand continues to increase throughout the study horizon and remains broadly in line with last year's projection reported in the AIRAA 2025-2034. The peak demand is forecasted to increase 19% by 2035 from 2024 levels. Looking forward across the study horizon, strong growth is observed, primarily driven by the growth in the data centre and new technology loads along with the electrification of heat and transport. The residential sector remains a key area of focus for electricity demand growth as the Irish Government plans towards housing targets noted in the National Planning Framework[3]. This year's electricity demand forecast accounts for these housing ambitions, as well as the associated reductions to be expected from the uptake of energy saving measures such as smart meters and efficiency gains.

Plant Performance

Plant performance is based on the previous 5-years of plant availability. This report includes plant performance statistics based on the 5-year period 2020-2024, replacing the 2019-2023 statistics used in AIRAA 2025-2034. Incorporating the updated plant performance statistics into the assessment, results in a marginally negative impact on the adequacy position across the study horizon.

3 https://cdn.npf.ie/wp-content/uploads/National-Planning-Framework-First-Revision-April-2025-1.pdf

New Capacity through Capacity Auctions

Since the AIRAA 2025-2034 assessment, the 2028/2029 T-4 capacity auction has run. As part of the Capacity Market's enhanced monitoring process, EirGrid, in collaboration with relevant state agencies, routinely engages with the project developers. The monitoring process assesses the latest updates to projects and any associated risks relating to the delivery of new capacity. Note that due to the freeze date for this report, capacity auctions completed post June 2025 are not included in this assessment.

The enhanced monitoring process uses the latest project information and assesses whether each project is expected to deliver earlier than the contracted capacity year, if it is at risk of delay, or if it is not expected to deliver at all within the auction long stop dates.

The central adequacy assessment in this report includes a forecast of new capacity delivery. At the time of the data freeze this forecast indicates continued new capacity delivery challenges in the short term which negatively impacts the adequacy position but an improvement in the delivery of new capacity in the medium to long term leading to a stronger adequacy position compared to AIRAA 2025-2034. It is noted that delivering new capacity remains a complex technical and logistical challenge, particularly in terms of timely commissioning.

EirGrid has included a sensitivity study that illustrates that the resource adequacy position could be significantly improved if all successful capacity market gas projects are delivered on time.

Renewable Generation

Ireland has a renewable policy goal to deliver 80% renewable electricity in line with Government targets. EirGrid has considered the Renewable Electricity Support Scheme (RESS) and Offshore RESS auction results, Electricity Supply Board Network (ESBN) connection data and latest transmission connections processes data to develop a trajectory for deployment of new renewable capacity. Furthermore, EirGrid has engaged with the Sustainable Energy Authority of Ireland (SEAI) who developed renewable generation forecasts based on judgments from a pool of expert stakeholders. These forecasts have been used in the central assessment in this report. This is the same renewable trajectory used in AIRAA 2025-2034 resulting in no change to the adequacy position. EirGrid has also analysed the impact of renewable energy deployment rates on the adequacy position, based on the high and low trajectories developed as part of the SEAI analysis.

2.2 Northern Ireland

In the AIRAA 2025-2034 assessment, the Base assessment indicated the Northern Ireland system would be within standard on average for the majority of the Study Horizon until 2031 and marginally outside of standard from 2032 to 2034, as a result of increasing demand not being met by equivalent delivery of new reliable capacity. The Secure assessment considered the impact of Low Imports and indicated the system would be outside of standard from 2026 across the remainder of the study horizon.

In this year's assessment, the Secure assessment considers the risk of a large unit outage, replacing the previous low import consideration. This is a result of improvements to the process for assessing risks, in which a range of credible risks are analysed in terms of impact and likelihood. Of the sensitivities analysed, the large unit outage sensitivity presented the highest overall risk when accounting for impact and likelihood and is therefore included in the Secure assessment. The Base assessment remains consistent with the AIRAA 2025-2034 indicating that Northern Ireland is within standard from 2026 to 2031 and outside of standard from 2032-2035, requiring up to 120 MW by 2035 to balance the forecast increase in demand. The Secure assessment, accounting for the impact of a large unit outage, indicates the system is outside of standard across the full horizon, requiring approximately 200 MW from 2026 to 2032, increasing up to 320 MW by 2035.

The central adequacy assessments are built on median forecast assumptions, with further sensitivities utilised to analyse variations in assumptions. The sensitivity analysis highlights adequacy concerns arising from high demand, low renewable build out, low flexibility and low run hour availability. The sensitivity analysis further indicates that removal of Annual Run Hour Restrictions on units in Northern Ireland has the largest benefit to the adequacy position, resulting in the Secure position being within standard across the full horizon.

SONI is actively supporting the Department for the Economy, the Utility Regulator and other relevant stakeholders to address issues related to security of supply over the coming years.

A summary of the key updates to the forecast since AIRAA 2025-2034 is included below.

Demand

The latest projections for Northern Ireland show a reduction in forecast demand relative to AIRAA 2025-2034. Between 2021 and 2023, SONI observed a reduction in electricity consumption year on year. This reduction was due to the impact of lower economic growth, and high fuel prices observed in the later part of 2022 (due to global events) which continued into 2023. A small rise in demand was then observed in 2024 as electricity consumption began to recover and fuel prices reduced. The forecasts for 2025 onwards indicate that Northern Ireland's demand will increase year on year, however, it will increase at a lower rate in comparison to the forecasts from AIRAA 2025-2034 due to revised projections for data centre and new technology load growth, the electrification of heat and transport and the latest economic trends.

Plant Performance

Plant performance is based on the previous 5-years of plant availability. This report includes plant performance statistics based on the 5-year period 2020-2024, replacing the 2019-2023 statistics used in AIRAA 2025-2034. Incorporating the updated plant performance statistics into the assessment, results in a marginally negative impact on the adequacy position across the study horizon.

Generation Capacity

The most significant change to the Northern Ireland portfolio in recent years has been the delivery of the Kilroot KGT6 and KGT7 units through the capacity market. Annual Run Hour Limits (ARHL) will continue to apply to the Open Cycle Gas Turbines (OCGT) across the full study horizon. The application of ARHL on the OCGTs at Kilroot, remains a significant risk to Northern Ireland's security of supply.

SONI has included a sensitivity of KGT6 and KGT7 OCGTs operating without run hour restrictions, alongside a new sensitivity to investigate the impact of reduced run hour availability. The results indicate significant adequacy benefit from the removal of ARHL, which could position Northern Ireland with a capacity surplus across the study horizon. The sensitivity removing ARHL does not refer to the possibility of removing ARHL, instead it provides analysis as to the impact of the ARHL on the system. The sensitivity investigating the impact of reduced run hour availability in a given year, indicates a negative impact on the adequacy position from managing units with reduced availability.

SONI continue to engage with DfE and the Utility Regulator on the implications of run-hour restrictions on OCGTs.

Renewable Generation

As part of this resource adequacy assessment, SONI is assuming a pragmatic renewable deployment trajectory for the central assessment. SONI has included two sensitivity studies analysing the impact of renewable energy deployment rates, examining the benefit of increased renewable delivery and the impact of delays to renewable delivery on the adequacy position.

2.3 All–Island

The new North-South Interconnector is expected to be constructed over the coming years, estimated for completion in October 2031. This is later than the assumed energisation date of 2027 assumed in AIRAA 2025-2034. EirGrid and SONI have conducted analysis of the resource adequacy benefits of the new North-South Interconnector on the All-Island adequacy assessment. Until the delivery of the new North-South Interconnector, power transfer between both jurisdictions to ensure system stability and security of each jurisdiction is highly constrained. Once the new North-South interconnector is online, the ability to transfer power between the jurisdictions will be increased. Our analysis shows the new interconnector will bring a benefit to the overall security of supply outlook across the island, with the Base assessment indicating a capacity surplus from 2032 and the Secure assessment indicating a capacity surplus in most years except 2034.

3. Introduction

This report seeks to inform market participants, regulatory authorities and policy makers of the generation capacity required to achieve an adequate supply and demand balance for electricity for the period from 2026 to 2035.

The development, planning and connection of new generation capacity to the transmission or distribution systems can involve long lead times and high capital investment. This report covers a ten-year study horizon to allow sufficient time for market participants, regulators and policy makers to plan and deliver necessary solutions required to support security of supply.

EirGrid and SONI, as the Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively, have a responsibility to operate the electricity transmission systems every minute of every day, whilst also planning the future of the transmission grid. To achieve this, SONI and EirGrid must balance supply and demand now and forecast how to do so in the future.

EirGrid, the TSO in Ireland, is required to publish forecast information about the power system, as set out in Section 38 of the Electricity Regulation Act 1999[4], Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations[5] and under S.I. No. 445 of 2000 European Communities (Internal Market in Electricity) Regulations as amended[6].

SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement (GCS), in accordance with Condition 35 of the Licence[7] to participate in the Transmission of Electricity granted to SONI by DfE.

3.1 European Regulatory Framework

The 'Clean Energy for all Europeans' package adopted in 2019 set out a new framework for the transition away from fossil fuels to cleaner sources of energy which included the Regulation on the internal market for electricity[8] (EU/2019/943) herein referred to as 'the Regulation'. Chapter IV (Articles 20-27) of the Regulation are focussed on resource adequacy.

Article 23 of the Regulation provides the mandate for the European Network for Transmission System Operators for Electricity (ENTSO-E) to conduct annual resource adequacy assessments based on projected supply and demand for electricity across the EU to identify resource adequacy concerns for Member States. ENTSO-E's obligations under Article 23 of the Regulation are fulfilled through the European Resource Adequacy Assessment[9] (ERAA) which was approved by the European Union Agency for Cooperation of Energy Regulators (ACER) on 2 October 2020. ACER has the responsibility for approving the annual implementation of the ERAA methodology conducted by ENTSO-E. A revision of the ERAA methodology is currently under ACER review and an updated methodology is expected to be adopted in 2026.

4 https://www.irishstatutebook.ie/eli/1999/act/23/section/38/enacted/en/html
5 https://www.irishstatutebook.ie/eli/2005/si/60/made/en/print#partx-article28
6 https://www.irishstatutebook.ie/eli/2022/si/227/made/en/print
7 https://www.uregni.gov.uk/files/uregni/documents/2025-08/2025-07-23%20SONI%20TSO%20Consolidated.pdf
8 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN
9 https://www.acer.europa.eu/Individual%20Decisions_annex/ACER%20Decision%2024-2020%20on%20ERAA%20-%20Annex%20I_1.pdf

Article 20(1) of the Regulation states that Member States may also carry out national adequacy assessments where necessary. Article 24 of the Regulation states that the national adequacy assessment should be based on the ERAA methodology, and capture market specific characteristics or risks that the European assessment may not capture in detail. Effectively, the national adequacy assessment provides the scope to consider market and system characteristics that are relevant on a national level but may not be relevant at a pan-EU level.

Although the United Kingdom is no longer a member state of the EU, Northern Ireland is an integral part of the Single Electricity Market (SEM) which operates on an All-Island basis. The Withdrawal Agreement has made provisions for the continued operation of the SEM. Article 9 and Annex 4 list the legislation that continues to apply in respect of Northern Ireland including EC 714/2009. Article 6 of the Withdrawal Agreement ensures that any legislation that updates this will continue to apply automatically to Northern Ireland. This means that Regulation 2019/943 applies with respect to electricity generation and transmission in Northern Ireland.

The national adequacy assessment enhances how TSOs can assess the balance of supply and demand in a weather-dependent power system. EirGrid and SONI continue to work closely with our respective Government Departments and Regulatory Authorities (RAs) to amend and adapt our local frameworks to align with Article 24 of the Regulation.

3.2 Resource Adequacy Assessment

Resource Adequacy is a measure of the ability of the electricity system to balance supply and demand for each hour across a calendar year. Adequacy is determined using the Reliability Standard, measured in hours of Loss of Load Expectation (LOLE) which is set as 3 hours in Ireland, 4.9 hours in Northern Ireland and 6.5 hours for the All-Island SEM. This means that SONI and EirGrid are planning the jurisdictions with the assumption that there will be insufficient generation to meet the system demand and operational requirements for 3 hours each year in Ireland and 4.9 hours each year in Northern Ireland.

Forecasting the electricity adequacy position is a multi-layered task for which EirGrid and SONI consider a number of factors including:

- **Demand** – *what is required* – including the total electricity requirement, the winter peak, historic demand, economic forecasts, Government targets, data centres and new technology loads forecasts.
- **Generation** – *what can supply the demand* – changes in resource portfolio, what is delivering through capacity auctions, buildout of renewable capacity, interconnection, the impact of climate conditions, and the impact of forced and scheduled outages on the availability of resources.
- **Adequacy** – *what is the gap* – Reliability Standards, hours of energy that is unserved, a probabilistic calculation of possible power system operating states.

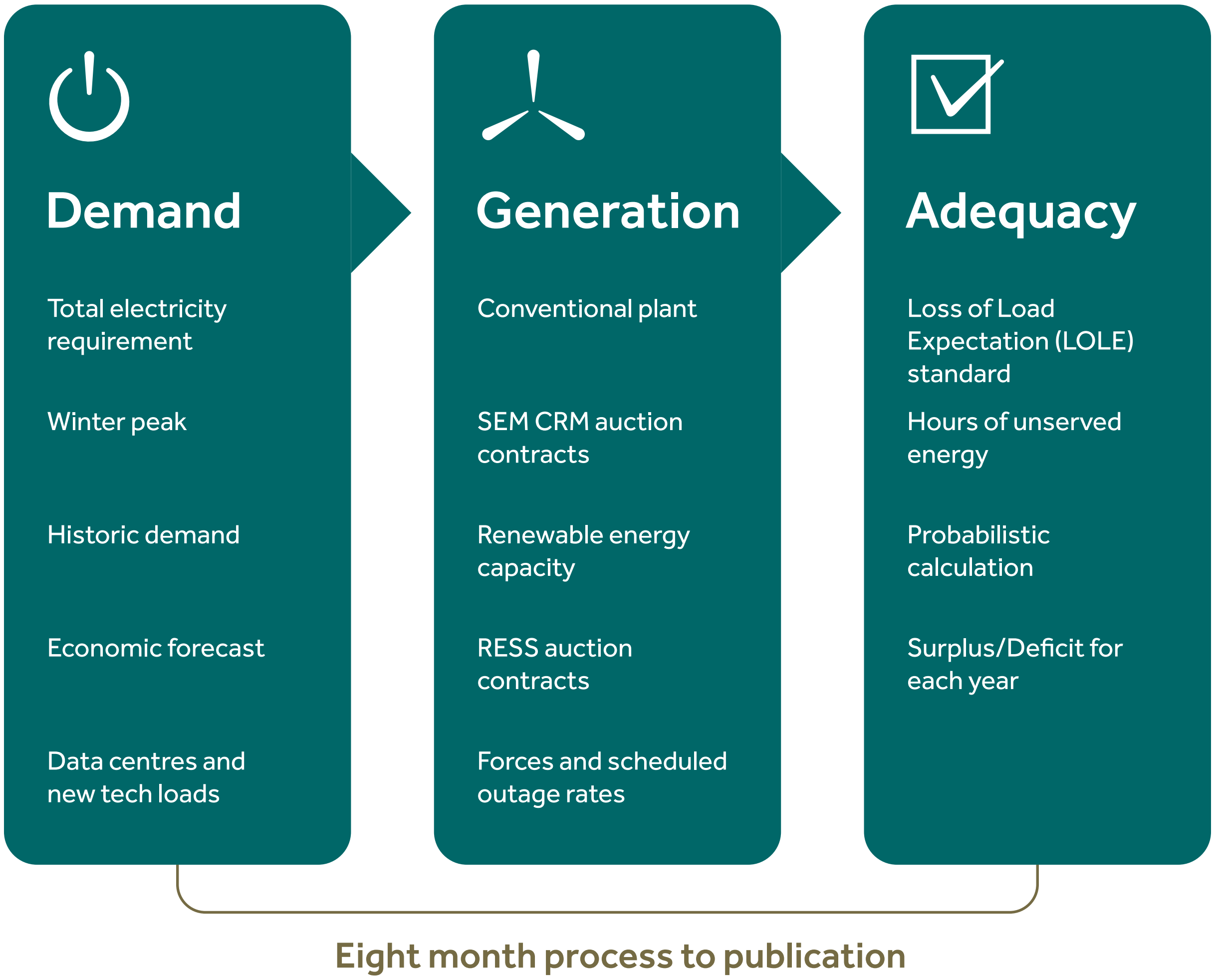


Figure 3.1 Adequacy Assessment Process

This report has been produced on a joint basis by EirGrid and SONI to assess a 10-year study horizon from 2026-2035 for both Ireland and Northern Ireland. This report supersedes the joint SONI and EirGrid All-Island Resource Adequacy Assessment 2025-2034, published in March 2025.

The assessment involves a detailed process completed over a period of approximately eight months. Steps in this process are outlined in Figure 3.1 and detail of the adequacy modelling methodology is described in the All-Island Resource Adequacy Assessment Methodology[10]. SONI and EirGrid continue to work with both RAs and other stakeholders to ensure that this document and the underlying methodologies remain relevant and useful.

When developing the forecasts in this report, the respective TSOs have endeavoured to use the most up-to-date information available at the time of the data freeze, which was the 30 June 2025. A post data freeze date information section has been included to acknowledge any significant changes on new information relating to input data or assumptions. Future assessments using this methodology will include updates as new information and data for the period becomes available.

3.3 Capacity Market Interaction

Longer-term SEM capacity auctions are run 4 years ahead of time and are known as a 'T-4' capacity auction. Prior to the data freeze date, the last T-4 was run in December 2024 to source capacity for the capacity year October 2028 to September 2029. T-1 auctions are a mechanism to procure capacity 1 year ahead of time if short term capacity needs are identified. Intermediate auctions such as T-2 and T-3 auctions are also a possibility if deemed necessary by the SEM Committee to support delivery of new capacity required for security of supply. Note that due to the freeze date for this report, capacity auctions completed post June 2025 are not included in this assessment.

The capacity auction de-rating and volume requirement processes are governed by a SEM Committee (SEMC) approved methodology which the TSOs implement. While the capacity market volume and de-rating processes are separate to the All-Island Resource Adequacy Assessment (AIRAA), they use the demand and generation forecasts as inputs for the auction requirements. The capacity auction processes take into account other factors beyond those included in this report's assessment, such as unit marginal contribution and least worst regrets analysis.

10 AIRAA 2026-2035 Methodology

4. Demand

4.1 Introduction

Predicting future electricity demand is a complex task. A ten-year demand forecast is developed for each jurisdiction, and these are then combined to create a total demand forecast for All-Island studies.

For each jurisdiction, the starting point is the historical demand data. The initial part of the demand forecasting process explores the effect of weather on demand, for example adjusting peak demand on a particularly cold or warm peak day to that of an average weather year. The peak demand that is transported on the transmission network is defined as the transmission peak and includes an estimate of transmission losses. On 8th January 2025, the all-island transmission peak electricity demand of 7,502 MW was recorded on the transmission system. This high level of demand was partly driven by a notable cold spell, with the national average temperature on the day estimated at -1.3°C. While January 2025 was notably cold overall—recording a monthly average temperature of 5.37°C, which is 0.45°C below the 29-year long-term average[11]—the conditions on 8th January were significantly colder than the monthly norm. Both Ireland and Northern Ireland recorded their transmission peak demands on this day, measuring 6,024 MW and 1,498 MW, respectively[12]. The timing of transmission peak varies across jurisdictions, which can result in misalignment between individual jurisdictional peaks and the all-island peak, as was observed in 2024.

The demand forecasting process considers the following factors that impact electricity demand: economic activity, electrification of heat and transport, and strong growth from sectors such as data centres and new technology loads[13]. Other factors that may decrease electricity peak demand are also examined such as the effect of 'smart' energy meters, smart charging of electric vehicles, and efficiency improvements driven by consumers, like buying new, more efficient, white goods or changing to more efficient lighting e.g. halogen to LEDs.

Another aspect of historical demand analysis is calculating the level of self-consumption, i.e. electricity that is self-generated and used on-site, without being transmitted to the grid or metered. Examples would be a Combined Heat and Power (CHP) unit providing electricity and heat to an industrial user, or a home fitted with roof-top solar PV panels.

The demand forecast outlined within this report is based on updated economic projections for both Ireland and Northern Ireland. Recent years have seen increased cost of living and high energy prices impacting demand. These factors are being closely monitored by EirGrid and SONI.

In response to an extensive consultation period (concluding in June 2025) [14], in which EirGrid engaged with multiple stakeholders, this year's Ireland demand forecast on the electrification of heat (heat pumps) and transport (electric vehicles) is informed by the Sustainability Energy Authority of Ireland's National Energy

11 [Climate Statement for January 2025 – Met Éireann – The Irish Meteorological Service]

12 Ireland's peak demand in 2024 was 5671 MW however "winter peak", which extends through to January of the following year, is used for modelling purposes. January 8th 2025 produced a 2024 winter peak of 6029 MW.

13 In this report, "new technology (or tech) load" refers to recent large scale, non-data centre growth in the technology sector that is considered separate from existing conventional (e.g. cement, pharma etc) industrial demand.

14 https://consult.eirgrid.ie/en/consultation/all-island-resource-adequacy-assessment-2026-2035-methodology-and-inputs-assumptions-consultation

Projections report[15]. Additionally, there are multiple Irish Government policies that form key inputs into this year's modelling. These include but are not limited to: The National Planning Framework First Revision[16], the National Energy Demand Strategy[17], the Programme for Government 2025[18], Climate Action Plan 2024[19], and the EU Energy Efficiency Directive[20].

EirGrid is actively engaging with other stakeholders in the energy industry to discuss and align on modelling assumptions that will impact on demand forecasting over the next decade. Any updated information from these discussions will be incorporated in subsequent iterations of the AIRAA.

SONI looks at policy drivers and has considered the impact of the Northern Ireland Executive's Energy Strategy – The Path to Net Zero Energy[21] 2021, Path to Net Zero – Action Plan 2025[22] and the Climate Change Act (Northern Ireland) 2022[23]. Consistent with the approach taken for Ireland, the methodology for Northern Ireland's demand forecasting was consulted on as part of the All-Island Resource Adequacy Assessment 2026-2035 Methodology and Inputs and Assumptions Consultation[24].

In order to cover a range of possible future outcomes, the demand forecast is provided as three scenarios: low, median, and high demand. The range of demand scenarios provides the reader with an understanding should certain growth factors fail to materialise or if stronger growth is realised.

The forecasted demand time series is developed using ENTSO-E's Demand Forecast Tool (DFT). Adopting this tool in the calculation of hourly demand forecast aligns both EirGrid and SONI to the modelling process of the European Resource Adequacy Assessment (ERAA): the European modelling framework which aligns with the evolving power system. The DFT provides a wide range of results showing the impact of climate variability on forecasted demand values.

With the total electricity requirement (TER) and the peak demand forecast for the duration of the study, a forecast hourly demand profile is created for each jurisdiction separately and combined for the all-island studies as described in the All-Island resource Adequacy Assessment Methodology document[25].

The demand forecasts in this report are used as an input for the SEM Capacity Market auctions as part of the capacity requirement process for upcoming auctions.

4.2 Demand Forecast for Ireland

4.2.1 Methodology

The basis of the electricity forecast is a multiple year linear regression model factoring in economic growth. The effect of data centres and new technology loads, electrification of heat and transport, efficiency gains and demand flexibility are factored into the projected forecast as described in the following sections. More information relating to the way EirGrid has modelled future demand can be found within the

15 https://www.seai.ie/sites/default/files/publications/National-Energy-Projections-Report-2024.pdf
16 https://cdn.npf.ie/wp-content/uploads/National-Planning-Framework-First-Revision-April-2025-1.pdf
17 https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/NEDS_Decision_Paper_and_Annex.pdf
18 https://assets.gov.ie/static/documents/programme-for-Government-securing-irelands-future.pdf
19 https://assets.gov.ie/static/documents/climate-action-plan-2024-8ccbde73-e288-4241-8b26-6b4922389f25.pdf
20 https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en
21 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf
22 https://www.economy-ni.gov.uk/sites/default/files/2025-03/Energy%20Strategy%20-%20The%20Path%20to%20Net%20Zero%20Energy%20-%20Action%20Plan%202025%20Landscape%20-%20FINAL_0.pdf
23 https://www.legislation.gov.uk/nia/2022/31/enacted
24 All-Island Resource Adequacy Assessment 2026-2035 Methodology and Inputs & Assumptions Consultation | SONI Consultation Portal

accompanying All-Island Resource Adequacy Assessment Methodology document[25].

4.2.2 Economic Forecast

To forecast future electricity demand, an energy model requires forecasts on economic activity. EirGrid has sought the advice of the Economic and Social Research Institute (ESRI), which has expertise in modelling the Irish economy[26]. The key economic parameters used in this study are Real Modified Gross National Income (Real GNI*) and Personal Consumption.

Real Modified Gross National Income (Real GNI*)[27] is designed to exclude globalisation effects that disproportionally impact the measurement of the Irish economy's size. Predicted growth in GNI* influences the forecast of commercial and industrial electricity demand.

Personal Consumption measures consumer spending on goods and services, including items such as food, drink, cars, holidays, etc. Predicted growth in personal consumption influences the forecast of residential electricity demand.

These economic forecasts are provided by the ESRI[28] annually in support of EirGrid's long term adequacy studies. The shorter-term trends are based on their Quarterly Economic Commentary[29]. Longer-term trends arise out of the ESRI's Medium Term Review[30]. Steady economic growth is forecast to continue over the coming decade, however inflationary pressures and the uncertainty around geopolitical issues has driven a downward revision in this forecasted growth compared to last year's longer-term projections. ESRI's annual growth rates are detailed in Table 4.1 below. These were used for the three demand scenarios in the demand forecast. To account for economic uncertainty, the low and high demand forecasts assume a lower and higher growth respectively than ESRI's forecast[31].

In April 2025, the Irish Government published the National Planning Framework First Revision, which identified the need for 50,000 additional households per annum to 2040. To reflect this target, an adjustment was made to the macroeconomic model to account for the increased demand from the residential sector.

Table 4.1 Average annual growth rates for macroeconomic parameters, values used for Median demand as advised by the ESRI

	2024-2025			2026-2030			2031 - 2035		
	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)
Real GNI*[32]	2.4%	3.2%	3.5%	2.3%	3.0%	3.3%	1.9%	2.5%	2.8%
Personal Consumption	2.0%	2.6%	2.9%	1.9%	2.5%	2.8%	1.5%	2.0%	2.2%

25 AIRAA 2026-2035 Methodology
26 https://www.esri.ie/research-areas/macroeconomics
27 https://www.cso.ie/en/releasesandpublications/ep/p-nie/nie2019/mgni/
28 Economic Parameters obtained from ESRI on 4th March 2025.
29 https://www.esri.ie/publications/quarterly-economic-commentary-spring-2025
30 https://www.esri.ie/publications/medium-term-review-2013-2020
31 Previous AIRAAs used the same economic forecast for all demand levels.
32 Modified GNI or GNI* is a measure of Irish national income. It removes depreciation on intellectual property and leased aircraft, as well as net factor income of redomiciled PLCs

4.2.3 Data Centres and New Technology Loads

A key driver for electricity demand in Ireland for the next number of years is the connection of data centres and other new technology loads (NTLs).

In Ireland, there is approximately 2,100 MVA of demand capacity that is contracted to data centres and other new technology loads at the transmission level, and approximately a further 300 MVA contracted at the 110 kV distribution level. Small-scale data centres connected at lower voltage levels by ESBN are included as part of industrial demand growth. Based on EirGrid's annual review of data centres and new technology loads, demand is expected to continue to rise from current levels as these customers build out towards their contracted load. Almost all this extra load is contracted in the greater Dublin region and was contracted prior to the CRU direction that additional load relating to data centres will only be permitted if they meet the requirements set out in the CRU Direction CRU/21/124[33]. This means that *any new data centre projects which do not currently have connection agreements will be assessed on a number of criteria, including the "ability of the data centre applicant to bring onsite dispatchable generation (and/or storage) equivalent to or greater than their demand".* As of the freeze date for this study, there has only been one new data centre contracted as it had met the requirements of the CRU/21/124 direction for data centres. This study only considers data centres with an existing contract.

On 21 June 2023, the CRU published a call for evidence paper (CRU202357) to commence this review process, followed by the publication of a consultation paper (CRU2024001) on 15 January 2024. On 18 February 2025, the CRU published a proposed decision paper (CRU202504). The CRU has stated that "*The purpose of this proposed decision paper is to set out a pathway for connection applications to the electricity grid which addresses risks in relation to security of electricity supply and network constraints while minimising, where possible, potential impacts on national renewable energy targets and carbon emissions.*" The final decision paper will set out the Commission's decisions in relation to the Large Energy Users (LEUs) connection policy review.

At CRU's request EirGrid, alongside ESB Networks DSO and Gas Networks Ireland, have been conducting a Market Intelligence Exercise. As part of this, they published a stakeholder survey which closed on 1st August 2025. The output of the Market Intelligence Exercise may be used to inform future policy development, e.g. a potential State-led strategic approach to delivery of utility infrastructure for data centres in the medium term. Given this exercise occurred after the data freeze date, this has not been considered for this year's forecast but may be considered in future assessments.

33 CRU21124-CRU-Direction-to-the-System-Operators-related-to-Data-Centre-grid-connection-.pdf (divio-media.com)

The current demand forecast methodology is consistent with the All-Island Resource Adequacy Assessment 2025–2034. It considers 17 data centre projects at transmission level, and five at 110 kV distribution level, that are either connected or have a signed connection agreement. As part of the demand forecast process, EirGrid examines the status and historical demand growth rates of data centres and new technology loads. This informs the future demand growth expected from these customers. As part of the demand forecast, EirGrid accounts for a range of factors that will drive growth from each site: historical demand growth rates from existing sites, contracted positions from companies and their growth potential, financial close, planning permission, etc. This process creates three credible scenarios that drive demand across the low, median, and high forecast scenarios.

Consistent with the last All-Island Resource Adequacy Assessment 2025-2034, the latest median forecast shows there is very strong growth forecast in this sector out to 2031, with lower but continued growth out to the end of the study horizon. Note this growth is from projects with an existing contract increasing their demand, as these projects build out towards their contracted load. EirGrid notes that demand side flexibility of data centres is an area of ongoing development[34]. At this time, there is a small number of data centre sites with flexible demand that can be called on to reduce demand to prevent system alerts. Furthermore, under specific emergency situations, large energy users will be required to reduce their demand through a process known as mandatory demand curtailment. These measures are assumed to be operational measures during a system Emergency State rather than contributing to system adequacy. Consequently, this has not been factored into this study, though will continue to be monitored for future studies.

In forecasting future demand, EirGrid assumes data centres have a flat demand profile across the day, with a gradual ramp throughout the year to their forecasted demand. This has been observed in real time data. From the result of this process, Table 4.2 outlines the breakdown of data centre and new technology load demand forecasted by 2035. Figure 4.1 shows the forecasted scenarios for growth in this sector. The graph shows the number of projects that are currently under contract (maximum possible build-out of the current contracts) and the three demand scenarios (estimated build-out projections). It is worth noting that based on historical trends, EirGrid's high demand forecast assumes not all this future contracted demand is fully used, and some attrition will occur.

34 A recent Risk Preparedness Plan for Ireland, which outlines these measures, was published by CRU in May 2023. CRU_202346_Risk_Preparedness_Plan_May_2023.PDF (divio-media.com)

Table 4.2 Forecasted Data centre and New Technology Load Demand by 2035. 2024 Demand 959 MVA.		
Forecast Scenario	**Growth from 2024 to 2035 (MVA)**	**2035 Demand (MVA)**
Low	443	1402
Median	911	1870
High	1225	2183

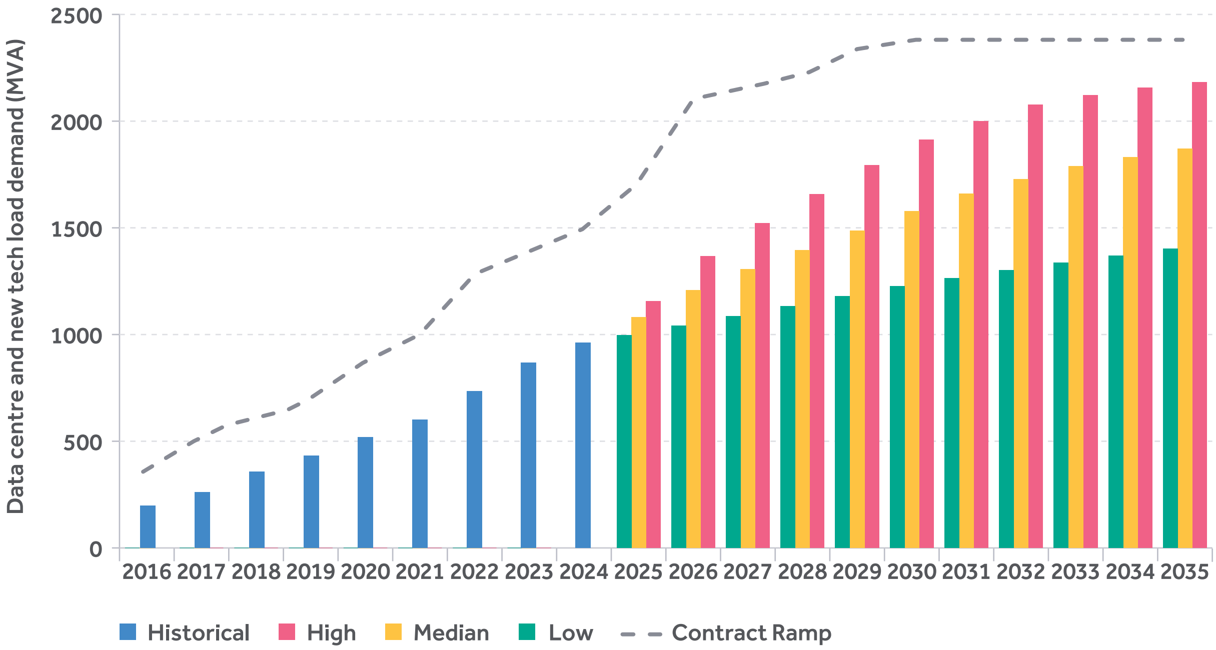


Figure 4.1 Ireland demand expected from assumed build out of data centres and new technology loads.

4.2.4 Electrification of Heat and Transport

This year's demand forecast uses the projected number of electric vehicles and heat pumps from SEAI's National Energy Projections WEM (With Existing Measures) and WAM (With Additional Measures) scenarios. In this year's forecast, the median scenario assumes there will be 768,000 electric vehicles and 675,000 heat pumps in Ireland in 2030, aligning to the WEM scenario. This is a change to last year's forecast in which the targets from Climate Action Plan 2024 were assumed. Table 4.3 compares these projections to the Climate Action Plan 2024 targets for 2030.

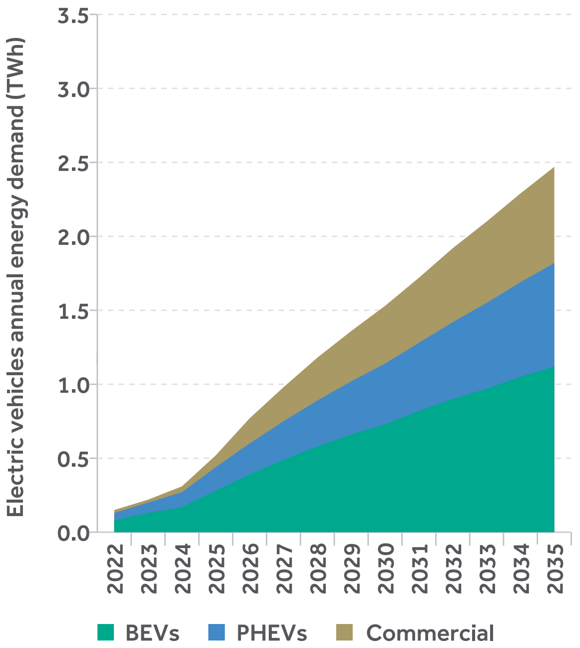
Table 4.4 details the split between retrofit and new build heat pumps as well as the projected number of electric vehicles by 2030. The total number of heat pumps assumes that each of the new houses built under the Government's National Planning Framework installs a new heat pump (300,000 by 2030) and that the full number of retrofit heat pumps within the WEM scenario is achieved. The low scenario adopts last year's modelling approach in assuming 75% of the median scenario's electric vehicles and retrofit heat pumps. The number of new build heat pumps within the low scenario matches the assumed growth in new housing stock- assuming 35,000 per annum. The high scenario follows a similar trend to the median in matching the number of new build heat pumps with new build houses, however a lower coefficient of performance (COP) for these units is assumed. The more ambitious WAM scenario forms the basis for the number of retrofit heat pumps as well as the projected number of units in the EV fleet.

Table 4.3 2030 EV & HP projections from SEAI's WEM Scenario in Median Scenario versus Climate Action Plan Targets 2024

Year: 2030		WEM (Median Scenario)	Climate Action Plan 2024
Electric Vehicles		768,000	927,000
Heat Pumps	Retrofit	240,000	400,000
	New Build	426,000	280,000
	Commercial	9,100	50,000

Table 4.4 Low, Median and High Total Electricity Requirement Key Assumption Differences by 2030

	Retrofit Heat Pumps	New Build Heat Pumps	Electric Vehicles
Low	75% SEAI WEM	Current Housing Trajectory c. 35k/year	75% SEAI WEM
Median	SEAI WEM (240k)	Gov Housing Targets (c. 50k/year) + Existing (126k)	SEAI WEM (768k)
High	SEAI WAM (362k)	Gov Housing Targets (c. 50k/year) + Lower COP	SEAI WAM (920k)



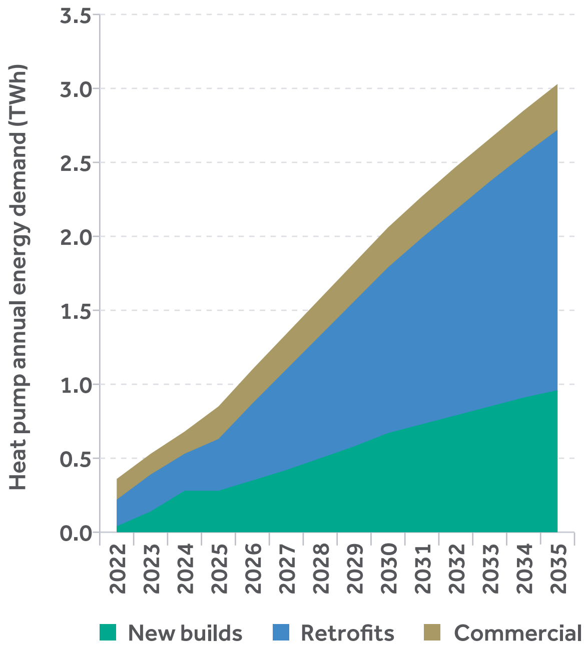


Figure 4.2 Electric Vehicle & Heat Pump electrical energy demand – median scenario

Electricity demand from electric vehicles is expected to grow significantly into the coming decade as people move away from conventional internal combustion engine vehicles in favour of electric vehicles. The majority share of this demand is forecast to come from passenger vehicles, specifically Battery Electric Vehicle (BEV)s. The increased uptake of EVs is driven by key Government policies such as the Climate Action Plan targets for Ireland.

Similarly, the residential sector is expected to account for the majority of electrified heating demand through the installation of heat pumps, as traditional methods of home heating such as gas and oil-fired boilers are replaced with modern electric heat pumps. This electrified residential heating demand will be achieved with the uptake of domestic heat pumps, split between new builds and retrofits as shown in Figure 4.2. Heat pumps are forecast to account for 7% of Ireland's total electricity requirement by 2035, up from 2% at present.

4.2.5 Temperature Correction

Temperature has a significant effect on electricity demand, particularly on the peak demand. Typically, every 1°C drop in temperature results in an electricity demand increase of approximately 40 MW[35]. This was particularly evident over the two severe winters of 2010 and 2011, when temperatures decreased dramatically, and demand increased to then record levels. Average Cold Spell (ACS) correction uses climate data from the past 25 years and has the effect of 'smoothing out' the historic peaks, removing the impact of temperature and enabling the underlying trends to be made apparent. Temperature correction is also applied to historic annual energy demand using the degree days methodology[36]. The 2024 winter peak of 6,024 MW is temperature corrected downwards to 5,912 MW as the temperature on peak day (8th January) was colder than the ACS temperature – see Figure 4.3 for the historical trend of temperature corrected peaks to date. The impact of temperature on annual energy demand is less pronounced compared to peak demand.

Whilst historical analysis aims to remove the impact of variable temperatures, it is important to account for this variable factor in forecasting future peak demand. ENTSO-E's Demand Forecasting Tool (DFT) incorporates 36 years of synthetic forecast climatic data for Ireland, each representing a distinct weather scenario characterised by variables such as wind speed, temperature, and solar irradiance. ENTSO-E's Forecasts are generated based on each forecast weather scenario, with the average of these taken as the median scenario. Both the high and low scenarios also take the climatic average results, however input parameters, such as economic growth, NTL demand, and the build out of HPs and EVs, are changed to reflect these scenarios.

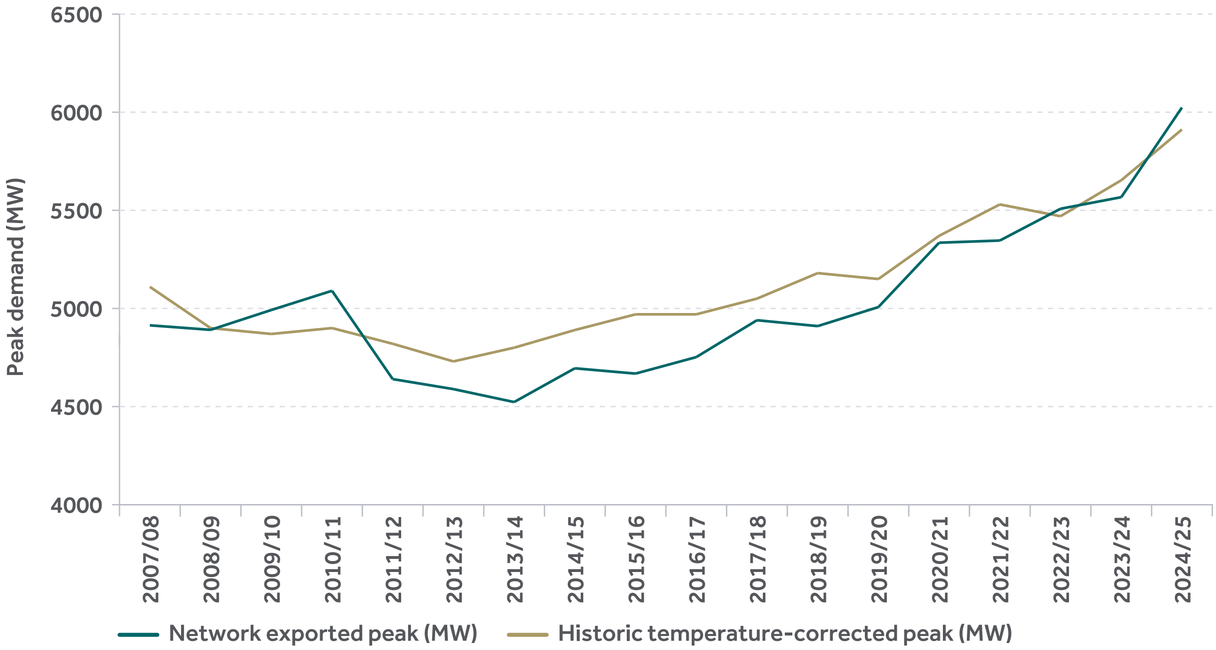


Figure 4.3 Historic Recorded and Temperature Corrected Peak Demand

35 https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-Winter-Outlook-2024-25.pdf
36 https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Heating_and_cooling_degree_days_-_statistics

4.2.6 Demand Flexibility

Demand side measures are a critical factor in understanding how electricity consumers will contribute to peak demand in the future. In July of 2024, the CRU published their National Energy Demand Strategy (NEDS) which identifies the appropriate steps to deliver the Climate Action Plan demand flexibility targets[37]. The forecasting process considers flexibility from electric vehicles and smart meters in the demand modelling, whilst storage and demand side units are flexibility options considered as supply side resources. Future policies will be monitored to understand the potential impact they could have to further demand flexibility potential, in particular how the sector evolves to meet the Irish Government's CAP 2024 target of achieving up to 30% flexible demand by 2030.

For this forecast, it is particularly important to account for the demand side flexibility services and incentives that could be delivered with smart meters, as this acts to temper future forecasts of peak electricity demand. EirGrid, based on NGESO data[38] used in CRU's NEDS publication, assumes by 2030 that smart meters can help reduce peak electricity demand by 12% for domestic users. This is linked to the uptake of Time of Use Tariffs, which is assumed to grow linearly as the rollout of smart meters continues under ESBN's National Smart Metering Programme[39]. This demand flexibility is included in the forecasts, and it is assumed that the appropriate incentives will be in place to ensure this materialises, otherwise additional capacity will be required.

In addition to altering existing behaviour in residential electricity demand, it is assumed that electric vehicle charging will also offer flexibility to avoid the peak demand periods over the full study time horizon. Vehicle charger technology has the potential to minimise the potential impact of electric vehicle demand on the electricity system, and on electricity markets. It is assumed that charger technology will evolve over time from simple chargers and patterns that are readily available today, to smart chargers with features such as programmable charge start times to smarter charging technology that optimises vehicle charging in line with dynamic electricity price signals. It is assumed that the appropriate policies and incentives are in place to ensure that smart vehicle charging technology is realised, otherwise additional capacity will be required.

Flexible demand sites, as mentioned in Section are identified as an emergency measure to prevent system alerts. These measures are assumed to be operational measures during a system Emergency State rather than contributing to system adequacy, and as such are not included in this study.

Figure 4.4 shows the average effect of demand flexibility services and incentives on residential demand and electric vehicle charging on the forecast peak day[40] in 2030 in the median scenario. Implementing demand flexibility services and incentives has the effect of reducing the peak demand by approximately 420 MW. This significant effect has been incorporated into the final peak demand calculations.

37 https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/NEDS_Decision_Paper_and_Annex.pdf
38 https://www.neso.energy/document/230236/download
39 https://www.esbnetworks.ie/services/manage-my-meter/about-smart-meters?https://www.esbnetworks.ie/services/manage-my-meter/about-smart-meters&gclsrc=aw.ds&gad_source=1&gad_campaignid=13801609574&gbraid=0AAAADg-OV6wboic1EZh-JSkeKqj5OLiy&gclid=CjwKCAjwwNbEBhBpEiwAFYLtGF_pdZn78fv9yJC5rpi74ZEEXFzTBi1Ad3Q7Xq7RvTB7VG__hY9UyxoCkr4QAvD_BwE
40 Forecast peak day is the day in which the annual maximum electricity demand is expected to occur. Peak days usually occur during periods of cold weather and reduced daylight as people consumer more energy to power heating and lighting i.e. winter time. Section 4.1 notes Ireland's 2024 peak day as January 8th.

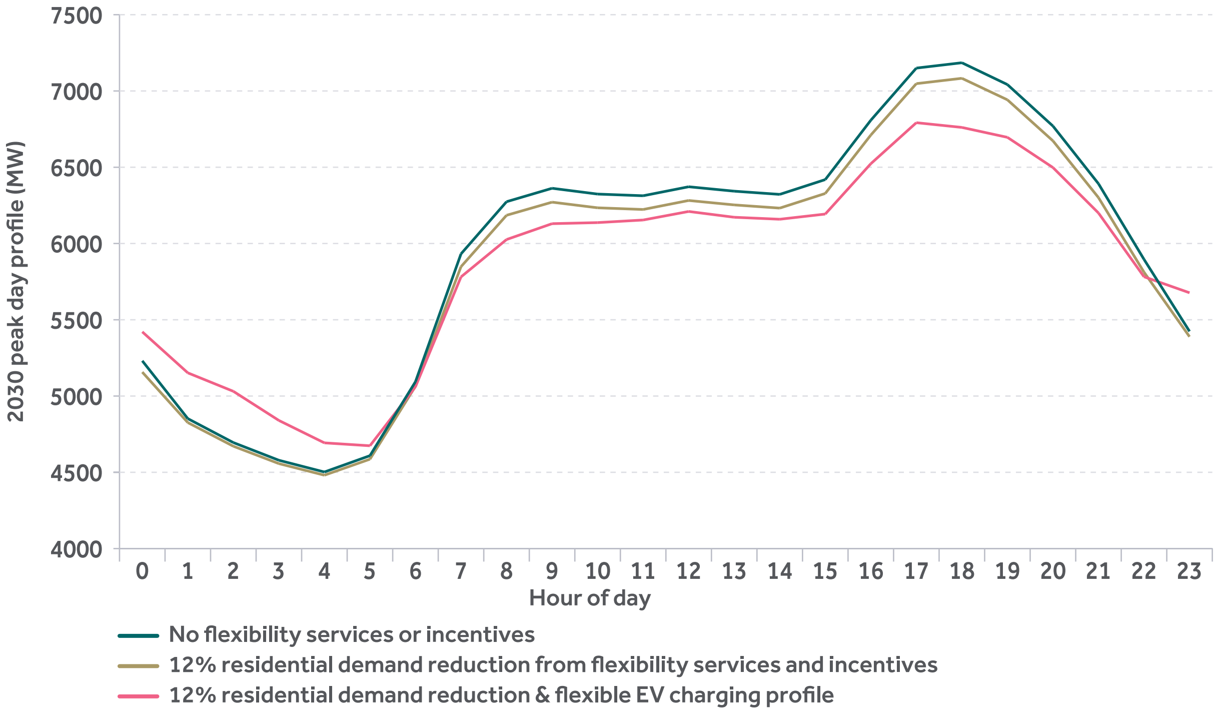


Figure 4.4 Impact of demand flexibility on 2030 peak day (median scenario)

Figure 4.5 shows the impact of demand flexibility services and incentives on the median scenario across the study period. The contribution of residential demand increases gradually out to 2030 as the services and incentives are incorporated to deliver the 12% peak demand reduction to customers utilising a time of use tariff. The contribution of flexible electric vehicle charging grows significantly through the study period as the number of electric vehicles increases, and the roll out of services and incentives to promote flexible charging are incorporated.

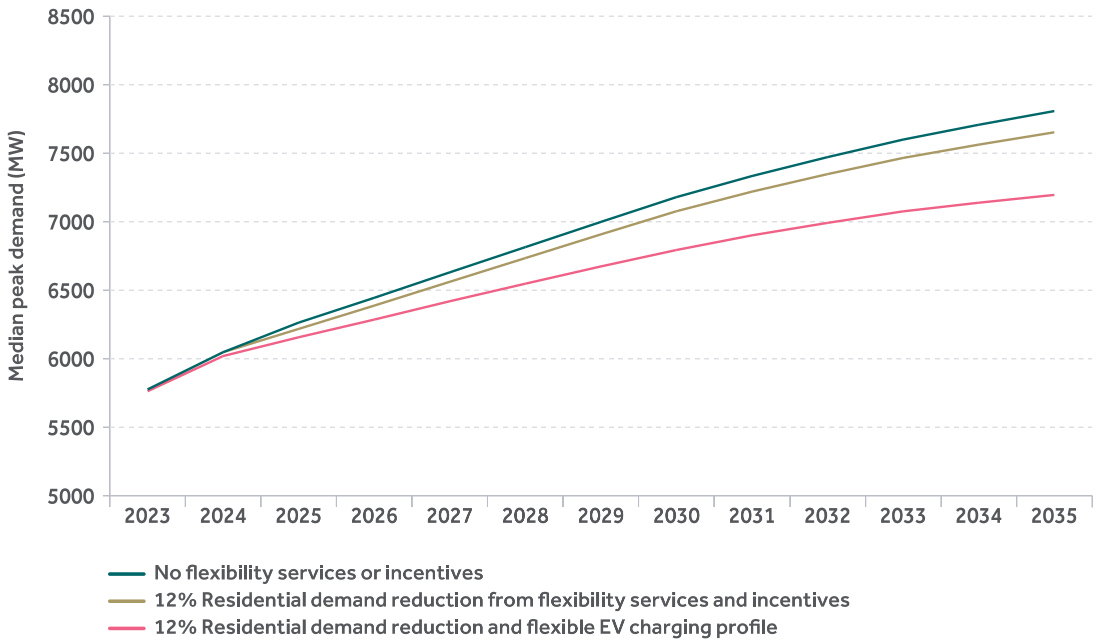


Figure 4.5 Impact of demand flexibility in median scenario across the study period

4.2.7 Annual Losses

Transporting electricity from the generator to the customer invariably leads to electrical grid losses. Based on the comparison of historical sales to exported energy over the period 2015 to 2024, it is estimated that, on average, approximately 7-8% of power produced is lost as it passes through the electricity transmission and distribution systems to homes and businesses.

4.2.8 Total Electricity Requirement (TER)

The Total Electricity Requirement (TER) includes the sum of electricity demand for the residential, tertiary, industrial and growing transport sectors. The tertiary sector comprises commercial activities such as retail, office and services. TER also includes self-consumption, which is defined as electricity demand met by behind the meter generation and including embedded generation.

The low, median, and high scenarios give an appropriate view of the range of possible demand growths facing Ireland. The results are shown in Figure 4.6 below. The median scenario, partly comprised of the details in Table 4.5, sees a minor reduction in forecast energy, out to 2030, compared to last year's AIRAA 2025-2034. This is primarily driven by delayed growth in the NTL sector, as detailed in Section , coupled with the downward revision of the number of projected EVs and HPs under the assumption of SEAI's WEM scenario. The projected increase in demand from the updated housing stock is partly reduced by efficiency improvements expected from the EU Energy Efficiency Directive[41]. Existing gains from energy-efficient lighting and appliances reduce the net impact of housing growth on residential electricity demand.

The median forecast from 2030 onwards increases in accordance with the growth in NTL demand as well as the continued electrification of heat and transport. Within the forecast there are energy reduction measures coming from expected efficiency gains and impacts of smart metering.

Additional to SEAI's EV and HP projections, this year's forecast also includes the National Energy Projections 2024[42] demand for Industrial Heat. Separate to commercial heat pump load, industrial heat captures the assumed electrification of industrial heat pumps, boilers, ovens, dryers, and kilns. The forecast is included in all three scenarios: low, median, and high.

The low scenario forecast is influenced by the same factors as detailed above for the median scenario. It has been revised upwards on last year's forecast due to an increase in the NTL low scenario. This increase is driven by the fact that the actual NTL demand for 2024 was higher than forecast in last year's AIRAA 2025-2034 NTL low scenario and has consequentially been increased for this year's study.

41 Energy Efficiency Directive
42 https://www.seai.ie/sites/default/files/publications/National-Energy-Projections-Report-2024.pdf

As is the case with the median scenarios, the high scenario demand is down on last year's projection for the first half of the forecast due to the decrease in the NTL high scenario forecast. As the study horizon progresses past 2030, this difference begins to reduce as the lower economic projections and improved efficiency gains begin to take effect.

Demand is forecasted to grow considerably, primarily driven by data centres and New Technology Loads in the short term (underpinning the digitisation of economies across the EU and in line with Government policy[43]), with electrification of heat and transport becoming a more significant factor towards the end of the decade. In the median scenario, by 2035 electricity demand is expected to increase by 40% relative to 2024 levels.

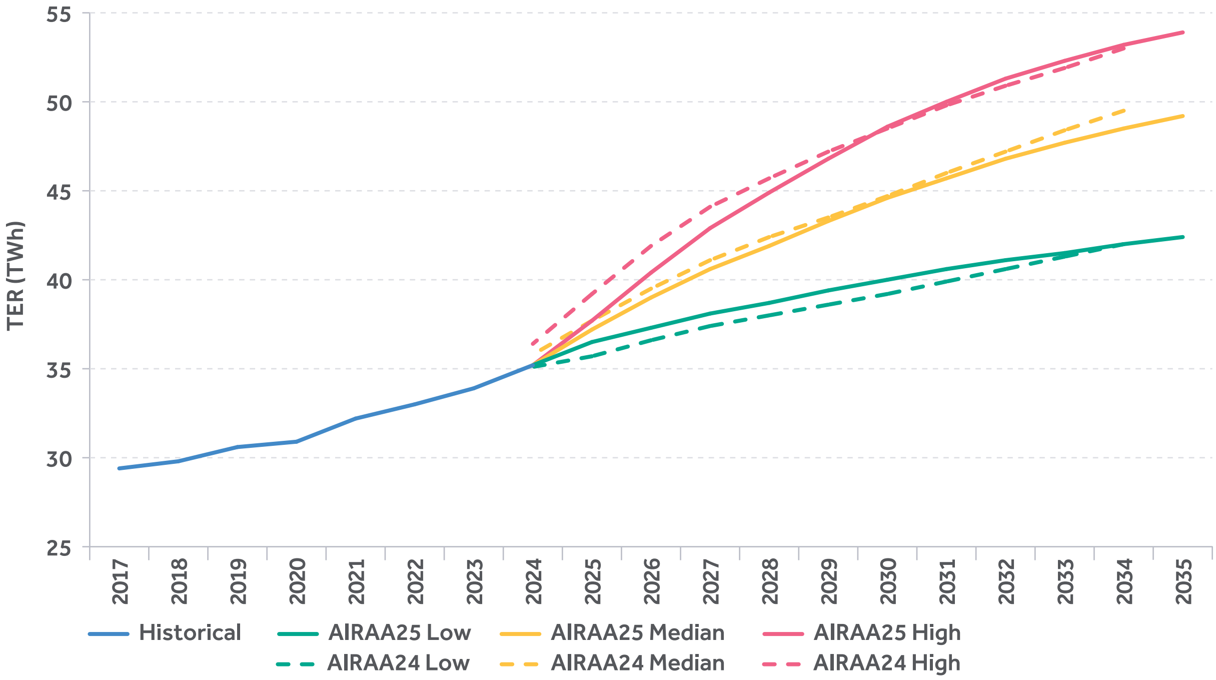


Figure 4.6 Total Electricity Requirement for Ireland

43 https://assets.gov.ie/static/documents/programme-for-Government-securing-irelands-future.pdf

Table 4.5 shows the key assumption differences between the low, median and high total electricity requirement in the forecast scenarios shown above.

Table 4.5 Low, Median and High Total Electricity Requirement Key Assumption Differences by 2030

		Low	Median	High
Housing		Based on Macro-Economic Projections from ESRI	Gov Housing Targets Achieved (c. 50k houses per annum)	Gov Housing Targets + Reduced Efficiency Gain
Heat Pumps	Retrofit	75% SEAI WEM	SEAI WEM (240k)	SEAI WAM (362k)
	New Builds	Current Housing Trajectory (c. 35k/year)	Gov Housing Targets (c. 50k/year) + Existing (126k)	Gov Housing Targets (c. 50k/year) + Lower COP
Electric Vehicles		75% SEAI WEM	SEAI WEM (768k)	SEAI WAM (920k)
Data centre & New Technology Loads		Low Ramp	Median Ramp	High Ramp
Economic Growth		75% ESRI Economic Projection	100% ESRI Economic Projection	110% ESRI Economic Projection
Industrial Heat		75% SEAI's National Energy Projections 2024 WEM Scenario	SEAI's National Energy Projections 2024 WEM Scenario	110% SEAI's National Energy Projections 2024 WEM Scenario

Figure 4.7 shows the breakdown of results across different sectors in the median scenario. The residential (excluding electric vehicles and head pumps) sector demand is expected to grow slowly across the study horizon as the increase in housing stock and growth in the economy is partly reduced by energy reduction measures such as smart meters and efficiency gains. The commercial and industrial (excluding data centres and new technology loads) sector, which captures industrial heating demand, remains relatively consistent across the decade.

The largest growth comes from data centres and new technology load as well as the increased uptake of electric vehicles and heat pumps, particularly later in the decade (32% of the growth forecast in 2030). Also notable is that by 2030, 32% of all electricity demand is expected to come from data centres and new technology loads.

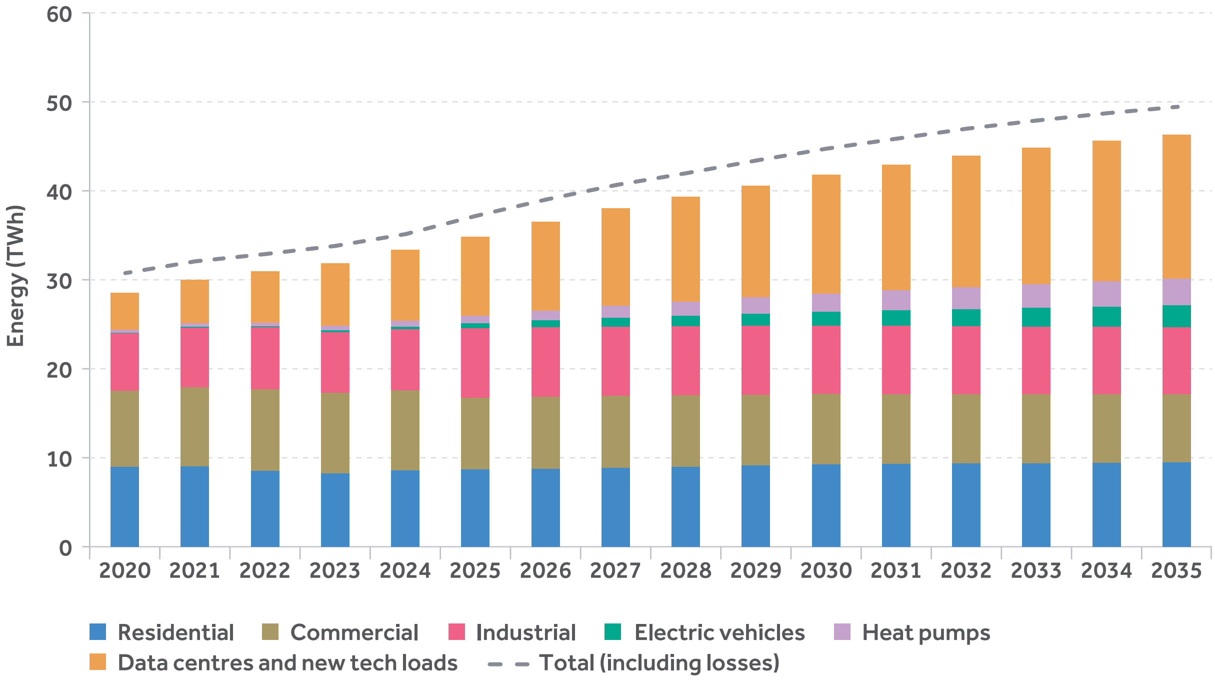


Figure 4.7 Ireland median demand Total Electricity Requirement sectoral breakdown

The proportion of median demand for each sector for 2026 and 2035 are estimated as follows:

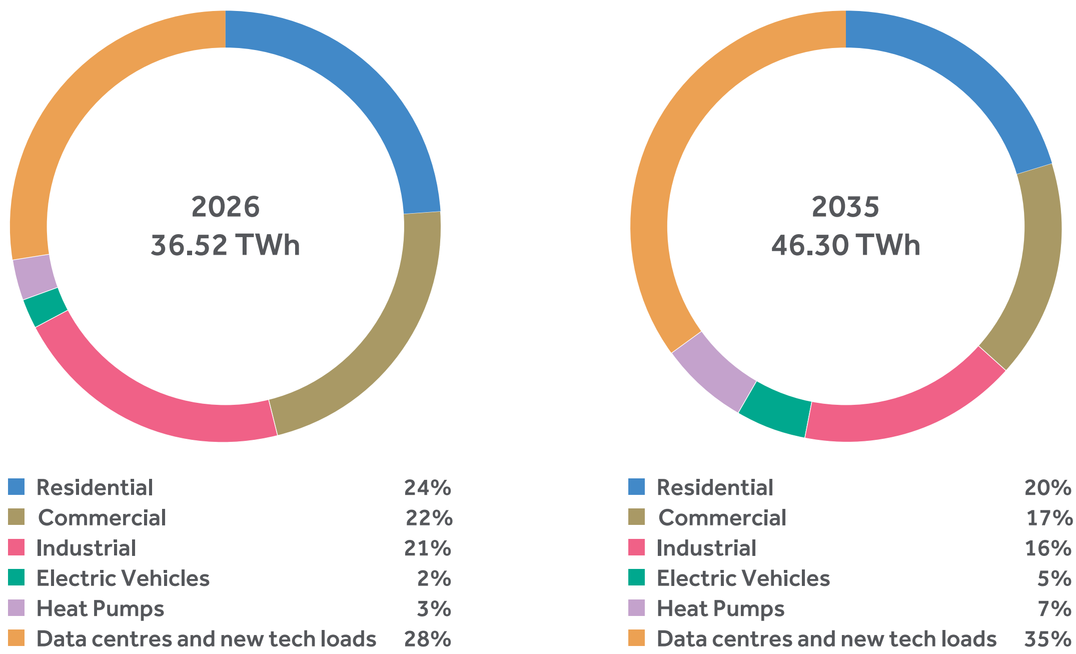
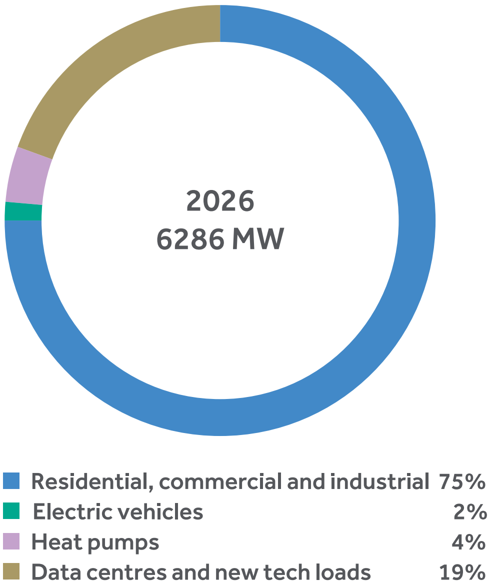


Figure 4.8 Sectoral contribution to Ireland's Median TER in 2026 & 2035

4.2.9 Peak Demand

The peak demand model separates sectors of demand to reflect the different behaviour of consumers. The outputs of this model form key inputs to the volumes set within the Capacity Remuneration Mechanism (CRM) each year. The conventional peak demand, made up of residential, commercial, and industrial consumption, utilises the historical relationship between annual electricity consumption and winter peak demand. Losses and self-consumption are accounted for within this forecast. New growth areas such as electrification of heat and transport, as well as data centres and new technology loads are forecast separately. Electric vehicle peak demand is based on the total energy required by electric vehicles, and the charging profile that electric vehicle owners are assumed to follow. The uptake of smart charging, modelled within the DFT, is a key factor in reducing the effect of electric vehicles on peak demand (Figure 4.12).

Heat pumps, in both residential and commercial settings, will contribute to a larger share of peak demand as Ireland progresses towards the end of our study horizon. Currently, the heat pump sector accounts for approximately 3% of peak demand, with this forecast to grow to 10% by 2035. Advancements in heat pump technology, including improved efficiency COP and smarter usage strategies, will lead to lower future demand compared to forecasts based on current usage patterns. Finally, as discussed in Section , data centre load is assumed to be consistent throughout the day with a gradual ramp throughout the year to their forecasted demand. Figure 4.9 details the percentage contributions of each sector towards overall peak demand in 2026 and 2035.



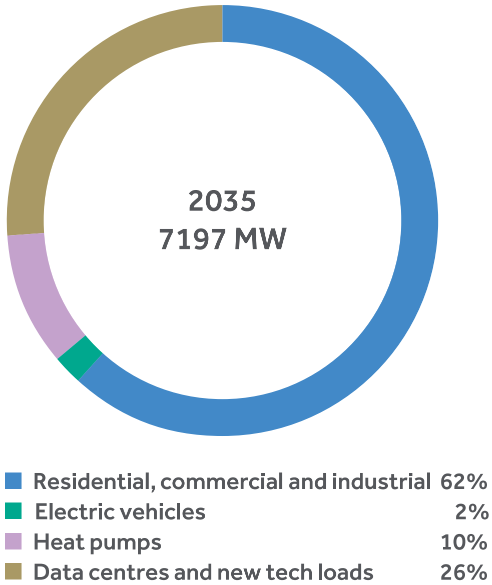


Figure 4.9 Sectoral contribution to Ireland's peak demand in 2026 & 2035

The overall peak forecast is shown in Figure 4.10. In the median scenario, the peak demand is forecasted to increase 19% by 2035 from 2024 levels. In recent years, there has been slower growth in the residential and commercial sectors, likely driven by energy prices and economic factors. As with the energy forecast, this has had an impact on the short-term peak forecast. Looking forward across the study horizon, strong growth is observed, primarily driven by the growth in the Data centre and New Technology Load[44] along with the electrification of heat and transport. The housing projections from the National Planning Framework and the efficiency gains from the Energy Efficiency Directive have also been incorporated into this year's forecast and do impact growth across the study horizon in all three scenarios.

The Low, Median, and High scenarios are primarily based on assumptions detailed in Table 4.5 above. Underlying trends such as domestic consumption, assumed efficiency targets, and the uptake of smart tariffs further contribute to the variation in each of the scenario forecasts shown in Figure 4.10.

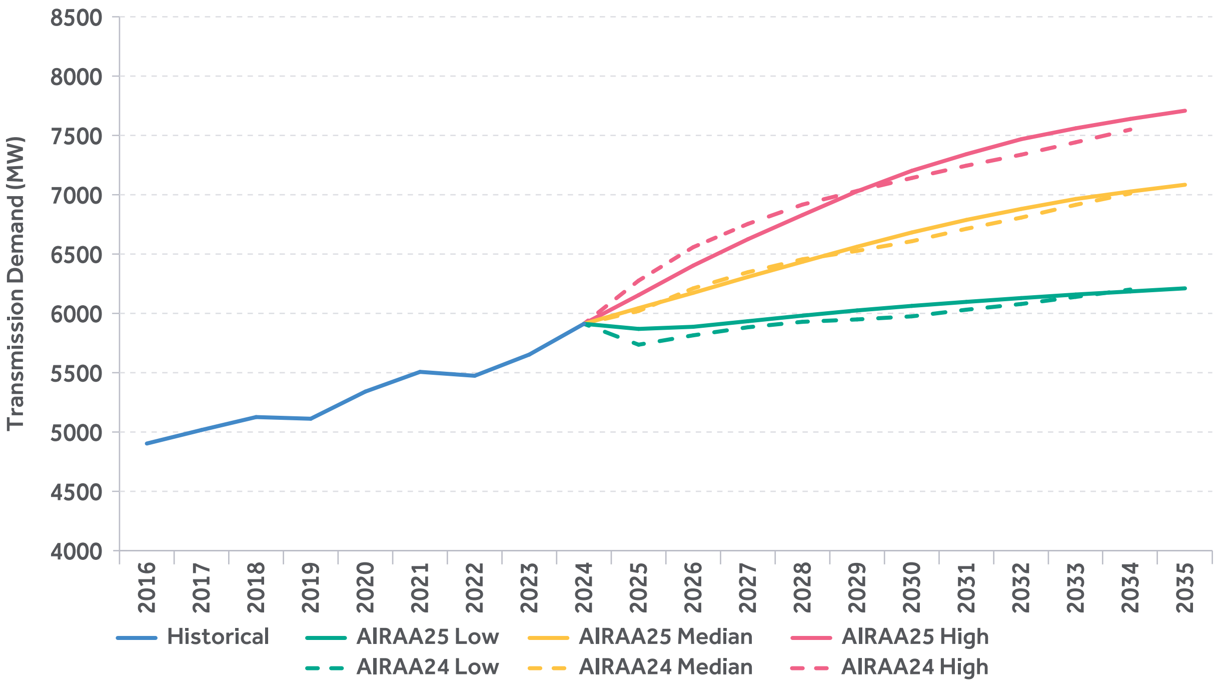


Figure 4.10 Transmission peak forecast for Ireland

44 As noted in section 4.2.3, any demand growth from Data centres and New Technology Loads is forecast on the basis of their contracted demand and from sites contracted prior to CRU direction CRU/21/124.

4.2.10 Demand Shape

Historically, the hourly load profile has been relatively consistent, and predictable throughout the year. As the energy sector evolves, new technologies, industries and consumer behaviour are changing how power is consumed. Of particular interest and influence is the continued adoption of electric vehicles and heat pumps. With large amounts of these new technologies, consumer behaviour will have a significant impact on the daily demand profile. ENTSOE's Demand Forecasting Tool (DFT) facilitates modelling of these new technology load profiles. Consumer behaviour will be an important consideration for modelling these new technologies as these sectors become more established.

The DFT produces a new forecast daily demand shape compared to what has previously been considered as the conventional shape. Where there has traditionally been a morning and evening load rise, circa 7-9am and 5-7pm respectively, the forecast profile begins to gradually increase demand in the early morning hours. This change in hourly demand is primarily driven by the projected numbers of EVs adopting ENTSOE's Ten Year Network Development Plan (TYNDP) 2022 charging profile[45] which favours night-time charging of EVs i.e. EV owners scheduling their vehicles to begin charging at traditionally "off-peak" hours. This transition to smarter charging is assumed for all four vehicle types: passenger plug-in hybrids, passenger battery electric, battery electric light commercial vehicle (BEV LCV), and battery electric busses, shown in Figure 4.12. The continued adoption of heat pumps, which sees peak usage occur during morning hours, also contributes to the gradual increase in demand during the earlier part of the day.

45 https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf

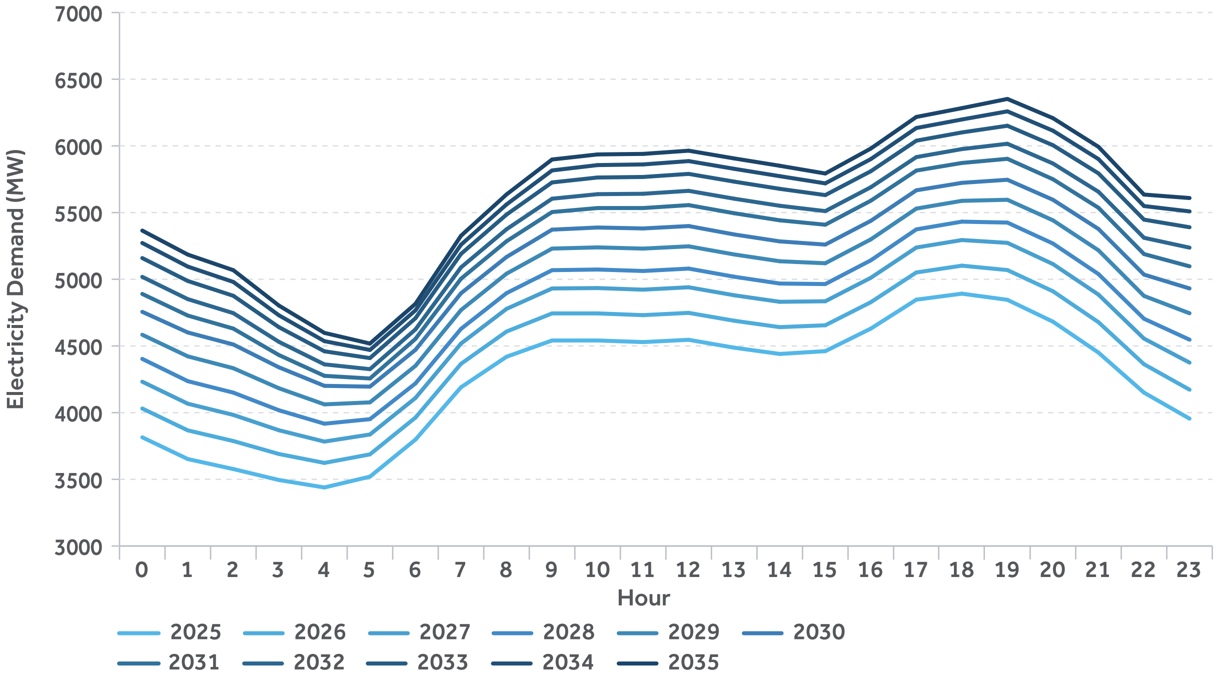


Figure 4.11 Forecast hourly demand shape in Ireland

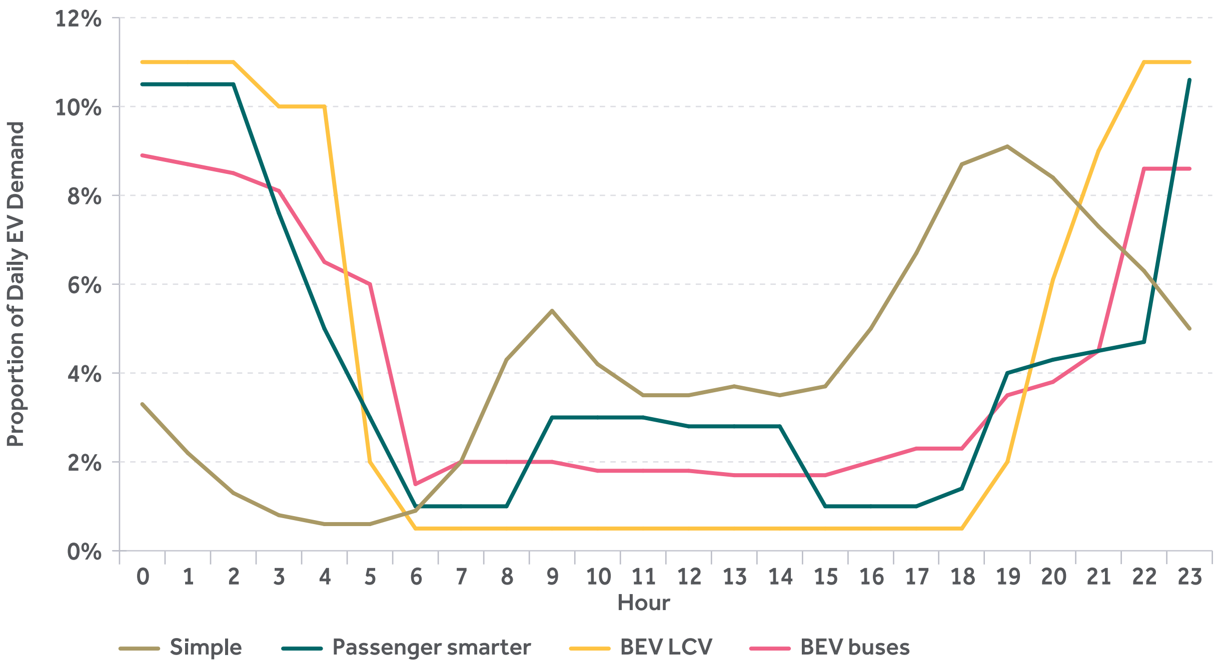


Figure 4.12 Electric vehicle charging profiles

4.3 Demand Forecast for Northern Ireland

4.3.1 Methodology

The electricity forecast model is a multiple year linear regression model which looks at current trends in areas such as energy sales and economic parameters to predict electricity demand into the future. Particular attention is paid to the effects of energy efficiency measures; new technology loads as well as the electrification of heat and transport. A spread of electricity forecasts is produced, covering the next ten years.

The Northern Ireland Executive's latest Energy Strategy – The Path to Net Zero Energy was published in December 2021. It outlines a roadmap to 2030 aiming to deliver a 56% reduction in energy-related emissions, on the pathway to deliver the 2050 vision of net zero carbon[46].

The Climate Change Act (Northern Ireland) 2022 was enacted in June 2022. Key aspects of this legislation include a target of at least 100% reduction in greenhouse gas (GHG) emissions by 2050, setting of carbon budgets, sectoral plans for emissions reduction targets and policies and procedures to drive targets and carbon budgets. The first three carbon budgets[47] and interim emissions reduction targets were agreed by the Northern Ireland Assembly in December 2024 and cover the years 2023 to 2037. The Department of Agriculture, Environment and Rural Affairs (DAERA) is expected to produce a series of interim and final reports setting out progress achieved against Northern Ireland's carbon budgets and emissions targets.

Following on from the new Energy Strategy, The Department for the Economy (DfE) published The Path to Net Zero – Action Plan 2022, 2023, 2024 and 2025. The Action Plan 2025[48] is an integral part of delivering the overall energy strategy. These actions will be taken forward during 2025 by Government and partners.

Through its technical expertise and data, SONI is supporting the Northern Ireland Executive's Energy Strategy. The Energy Strategy points to an increase in electricity demand from the heat and transport sectors as part of its key policies:

"We need new mechanisms to continue to deliver a secure electricity supply and ensure it is better matched with the higher and changing demands from the electrification of heat and transport."

SONI has developed three alternative scenarios to reflect the degree of uncertainty in the future when deriving an estimate of electricity demand. These scenarios combine a range of factors including economics, data centre and new technology load growth, energy efficiency, as well as electrification of heat and transport, to allow for the formulation of low, median, and high demand forecasts for Northern Ireland. These forecasts are then fed into an electricity forecast model called the Demand Forecasting Tool (DFT) produced by ENTSO-E.

46 The Path to Net Zero Energy Strategy
47 The Climate Change (Carbon Budgets 2023-2037) Regulations (Northern Ireland) 2024
48 The Path to Net Zero Energy Action Plan

The effects of climate variability are modelled using thirty-six weather scenarios that are incorporated into the DFT. Each weather scenario represents a distinct, synthetic forecast for climatic variables such as wind speed, temperature and solar irradiance. Northern Ireland's median demand input is fed into the DFT which produces an output forecast for each weather scenario. To produce a final result, SONI takes the average output across all thirty-six weather scenarios. This process is then repeated for the low and high demand inputs.

The median demand forecast includes assumptions on electrification of heat and transport, future energy efficiency in the electricity system, existing applications to the SONI Connections Team for new data centres, along with the application of a central economic growth rate factor. This is our best estimate of what might happen in the future.

The low demand forecast includes lower levels of electrification of heat and transport, higher levels of energy efficiency, an assumption of no new load for data centres across the forecast horizon and the pessimistic economic factor being applied. Conversely, the high demand forecast includes higher levels of electrification of heat and transport, lower levels of energy efficiency, additional load from data centres than what is expected in the median scenario and the more optimistic economic factor being applied.

4.3.2 Economic Forecast

The Total Electricity Requirement (TER) forecast is carried out with reference to economic parameters, primarily Gross Value Added (GVA). SONI has procured a ten-year economic forecast from Oxford Economics to provide data for the study.

4.3.3 Data centres and New Technology Loads

Currently there are no data centres or large energy users connected to the Northern Ireland transmission system; hence the low, median and high demand scenarios only consider existing applications to the SONI Connections Team when forecasting growth in the data centre and new technology load sector. However, following the publication of the UK Government's 'Compute Roadmap' targeting 'Developing Cutting-Edge AI Infrastructure: AI Growth Zones (AIGZs)'[49] we would anticipate growth in this area.

The Compute Roadmap was published in mid-July 2025. This was after the data freeze was implemented for this report in June 2025. As such its effects are not considered in this analysis but will be considered as appropriate for any future publications.

To capture the impact of applications from data centres seeking to connect in Northern Ireland, SONI has based the demand forecasts on different build-out scenarios. The low demand scenario assumes no data centre load. The median demand scenario includes a realistic estimate of new data centre load currently in the connection process. In addition to this, the high demand scenario contains potential additional load from data centres that are due to connect to the system within the ten-year study period. These three scenarios give an appropriate view of the range of possible demand growths and are based on applications for connection.

49 UK Compute Roadmap – GOV.UK

Figure 4.13 shows the total electricity requirement associated with data centres in Northern Ireland across the three demand scenarios. The low scenario assumes no additional data centres connect to the grid. As Northern Ireland's existing data centre demand is 0 TWh, that means this series is 0 TWh for all years. The median and high scenarios assume that data centre demand will not materialise until 2029.

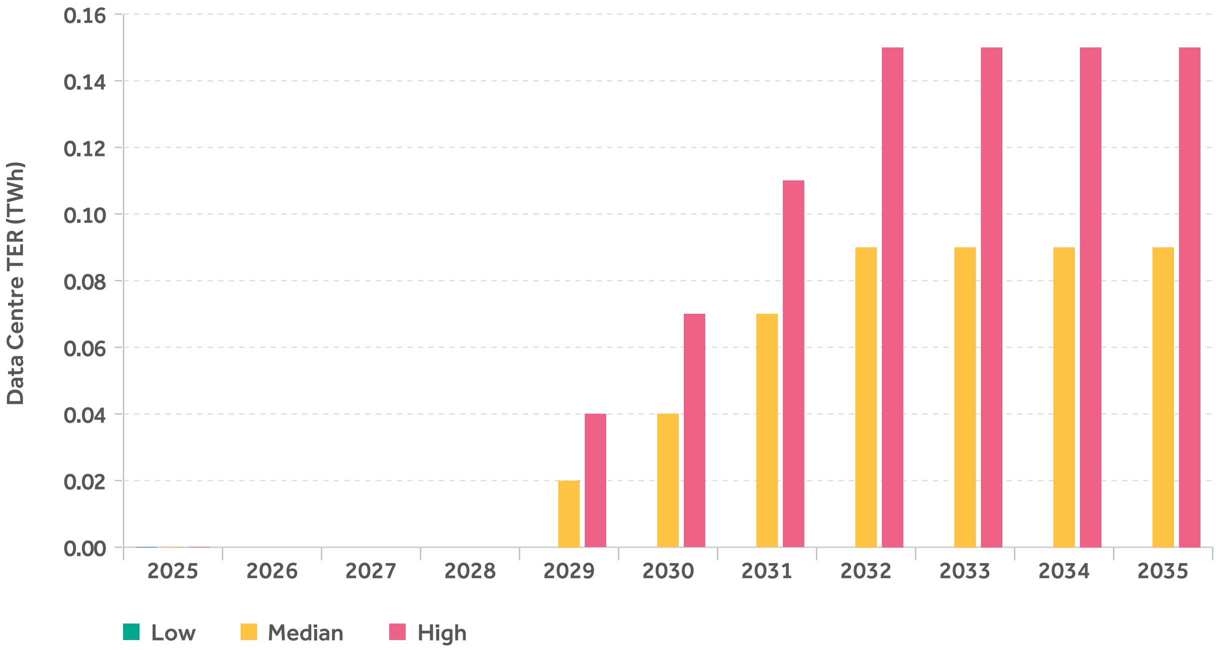


Figure 4.13 Northern Ireland TER expected from data centres across demand scenarios

4.3.4 Electrification of Heat and Transport

With the transition away from fossil fuel sources, an increasing proportion of energy demand will be met by electricity. The demand forecast reflects higher electrification in the heat and transport sectors.

The air source heat pump is a low carbon solution that can help decarbonise Northern Ireland's heating demand, particularly oil dependent households. Factors impacting the electricity demand of heat pumps include the number of installations, dwelling heat demand and coefficient of performance.

Electricity demand in the transport sector is expected to increase with the growth in new electric vehicle sales. The scale of this impact on electricity demand will depend on a wide range of factors such as the number and types of electric vehicle, vehicle usage and the charging patterns of vehicle owners. 'Off-Peak' vehicle charger technology has the ability to reduce the impact of electric vehicle demand on peak electricity demand and is included in this demand forecast. It is assumed that the appropriate policies and incentives will be in place to ensure that off-peak vehicle charging technology is realised otherwise additional capacity will be required.

The number of electric vehicle and heat pump installations included in the low, median and high demand forecast is detailed in Table 4.6. The data sources referenced to create the median scenario are described in the following paragraphs and summarised in Table 4.7. It should be noted that the low and high scenarios for the number of electric vehicles and heat pumps are determined by applying a multiplier of -20% and +20% respectively to the median scenario. This was deemed a reasonable estimate by SONI considering the absence of low and high scenarios in the data sources used for the median scenario.

The number of heat pump installations are based on Northern Ireland Electricity Networks (NIE Networks) most recent forecasts, specifically their Constrained Growth scenario, which they define as follows:

"This scenario reflects a continuation of the current low uptake of heat pumps in Northern Ireland out to the mid-2030s. After this, uptake ramps up in the later 2030s and 2040s in order for Northern Ireland to achieve net zero by 2050." [50]

The constrained growth scenario facilitates the slowest delivery to achieve net zero by 2050 across all NIE Networks heat pump uptake scenarios. The adoption of the most recent NIE Networks heat pump forecasts is consistent with the approach taken with AIRAA 2025-2034 to facilitate consistency in planning across the transmission and distribution systems.

The volumes of electric vehicles are based on figures from the Department for Infrastructure's (DfI) Transmission Emissions Model. The figures included in SONI's modelling were received from DfI before the data freeze in June 2025. The figures forecast the number of new electric vehicles to be sold across each horizon year.

Looking forward to future iterations of the AIRAA, SONI will seek to utilise the most up-to-date information available and seek updates to both NIE Networks' heat pump forecasts and DfI's electric vehicle forecasts.

Table 4.6 Number of electric vehicle and heat pump installations included in the low, median, and high demand forecast

	Low		Median		High	
	Electric Vehicles	Heat Pump Installations	Electric Vehicles	Heat Pump Installations	Electric Vehicles	Heat Pump Installations
2025	56,000	2,000	70,000	2,500	83,000	3,000
2030	194,000	34,400	242,000	43,000	291,000	51,500
2035	390,000	115,000	487,000	143,700	585,000	172,500

50 Distribution network planning scenarios

4.3.5 Total Electricity Requirement Forecast

The Total Electricity Requirement (TER) includes the sum of electricity demand for the residential, tertiary, industrial and growing transport sectors. The tertiary sector comprises commercial activities such as retail, office and services. TER also includes self-consumption, which is defined as electricity demand met by behind the meter generation and including embedded generation.

Power sector distribution and transmission system losses i.e. losses on energy transported across the grid (hereafter referred to as losses in this report) are also included in TER. Losses account for approximately 7-8% of TER as energy passes through the electricity transmission and distribution systems.

SONI has been working with NIE Networks and referencing the Renewable Obligation Certificate Register (ROC Register) to establish the amount of embedded generation that is currently connected on the system and to predict what amounts will be connecting in the future. An example of embedded generation is rooftop solar photovoltaic.

This has enabled SONI to make an informed estimate of the amount of energy contributing to the total demand by self-consumption, which is then added to the energy which must be exported by generators to meet all demand, resulting in the TER. This is because self-consumption has the effect of reducing demand on the transmission and distribution grids, and as such accounting for it is critical in ensuring the reliability of the power system. Self-consumption in Northern Ireland currently represents approximately 3% of TER.

Table 4.7 shows the key assumption differences between the low, median, and high TER in the forecast scenarios.

Table 4.7 Low, median and high Total Electricity Requirement key assumption differences for Northern Ireland

	Low	Median	High
Number of Electric Vehicles	DfI Transport Emissions Model Projections Less 20%	DfI Transport Emissions Model Projections	DfI Transport Emissions Model Projections Plus 20%
Number of Heat Pumps	NIE Networks Constrained Growth Scenario Projections Less 20%	NIE Networks Constrained Growth Scenario Projections	NIE Networks Constrained Growth Scenario Projections Plus 20%
Data centre and New Technology Loads	None	Median Ramp[51]	High Ramp
Economic Growth Projection	Oxford Economics Ten Year Forecast Less 1%	Oxford Economics Ten Year Forecast	Oxford Economics Ten Year Forecast Plus 1%

51 Median Ramp is based on projects currently in the connection process with a probability of connection applied. High Ramp is based on the same projects in the connection process with a higher probability of connection applied.

Figure 4.14 shows Northern Ireland's TER per historic year and the updated TER forecast per forecast horizon year. There is a reduction in the low, median, and high scenarios when compared to the forecast published in the AIRAA 2025-2034. Electricity consumption reduced in the later part of 2022 and continued into 2023 due to the impact of global events and the impact of high fuel prices. A small rise in Northern Ireland's TER was then observed in 2024 as electricity consumption began to recover and fuel prices have reduced. The TER forecasts from 2025 onwards observe an overall reduction in comparison to last year's forecasts due to revised projections for electric vehicle, heat pump and new technology loads. The difference between the median and high demand scenarios is based on several factors including economics, data centre and new technology load growth, energy efficiency as well as the electrification of heat and transport.

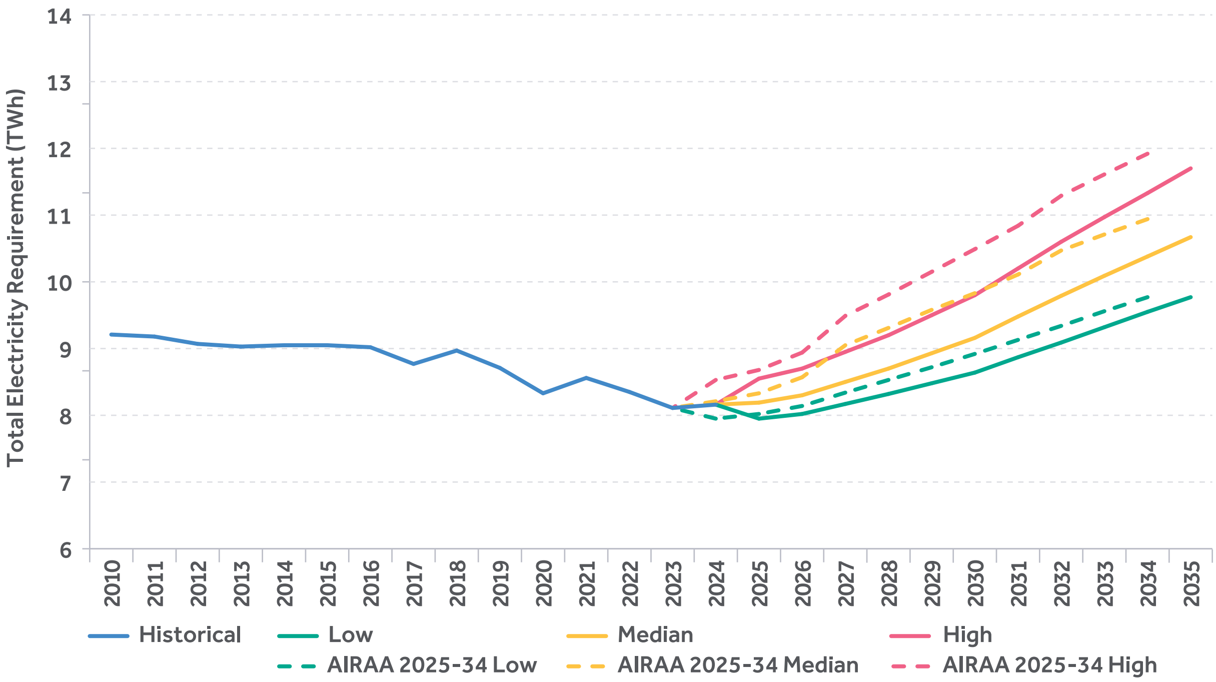


Figure 4.14 Northern Ireland total electricity requirement (TER) forecast

Figure 4.15 illustrates how the TER demand forecast is built up from the various components. Data points in the figure from 2020–2024 are based on historic data, whereas those from 2025–2035 represent the Median Forecast. Growth in TER is primarily driven by the electrification of heat and transport in line with Government strategy.

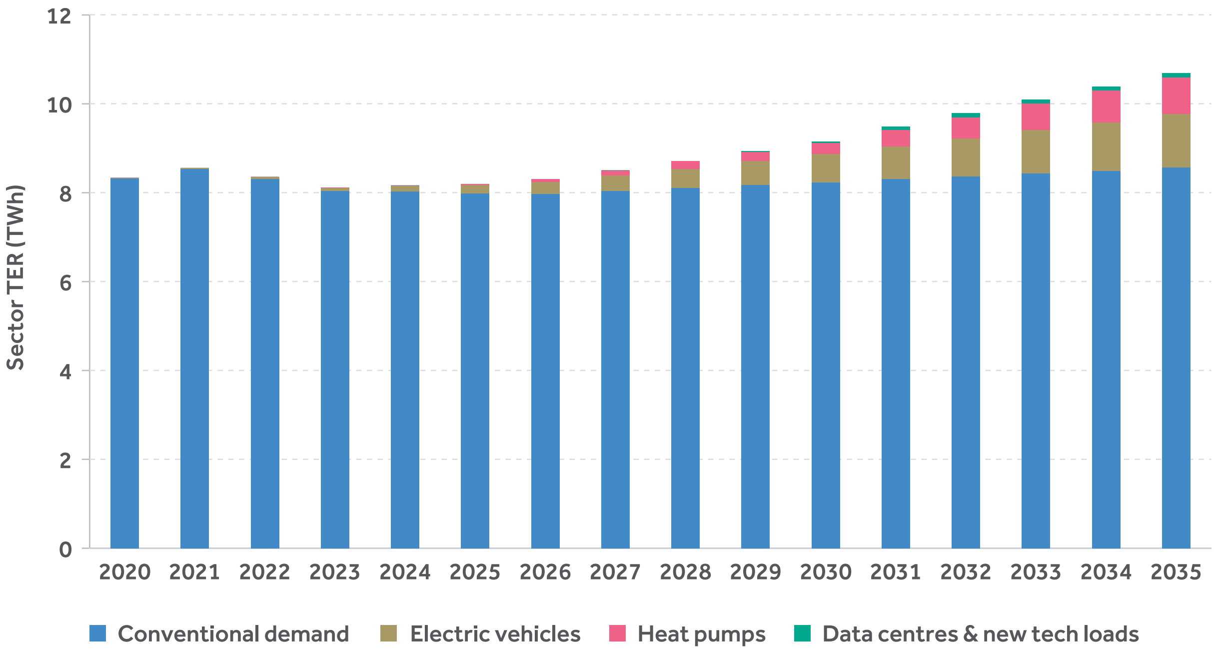


Figure 4.15 Northern Ireland median total electricity requirement (TER) forecast components

The proportion of demand coming from conventional demand versus new demand for the energy transition and sectorial shifts in 2026 and 2035 are forecasted as shown in Figure 4.16 below. New demand is represented in the figure by the Electric Vehicles sector, Heat Pumps sector and Data Centres & New Technology Loads sector. In 2026 new demand represents 4% of total demand, which rises to 20% by 2035.

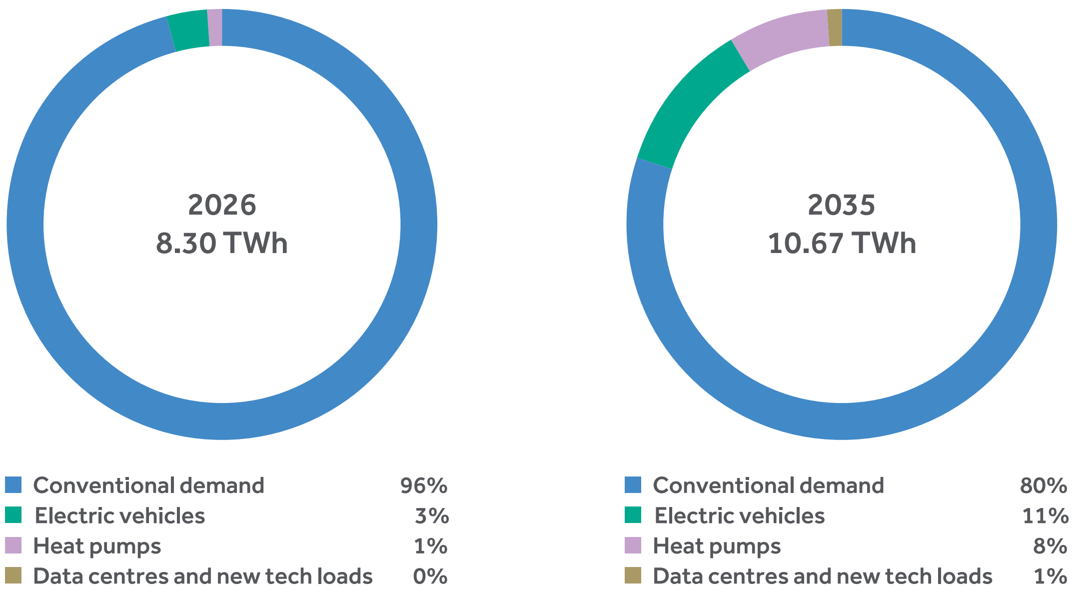


Figure 4.16 Northern Ireland's total electricity requirement (TER) breakdown in 2026 and 2035

4.3.6 Peak Demand Forecasting

SONI has aligned with the European Resource Adequacy Assessment (ERAA) modelling and utilised the ENTSO-E Demand Forecasting Toolbox to forecast the demand profile including peak demand. This tool utilises thirty-six weather scenarios alongside economic factors, forecasted heating profiles and EV charging profiles when calculating outputs.

One of the DFT's outputs is the TER peak demand. TER peak demand includes both losses and self-consumption i.e. demand that is masked by local generation. The contribution to TER peak demand from conventional demand versus new demand for the energy transition and sectorial shifts in 2026 and 2035 is forecasted as shown in Figure 4.17 below.

Electric vehicle peak demand is based on the total energy required by electric vehicles, and the charging profile that electric vehicle owners are assumed to follow. The uptake of off-peak charging, modelled within the DFT, is a key factor in reducing the effect of electric vehicles on peak demand.

Heat pump peak demand is based on the forecasted number of installations; the annual heating demand heat pumps must supply and heat pump efficiency. Based on the assumptions for heat pump uptake in Northern Ireland, the electrification of heat will contribute to a larger share of peak demand as Northern Ireland progresses beyond 2030. Currently, the heat pump sector accounts for less than 1% of peak demand, with this forecast to grow to 14% by 2035.

Data centre load is expected to grow between the beginning and end of the forecast horizon, but not by a significant amount as the sector only contributes to 1% of TER by 2035.

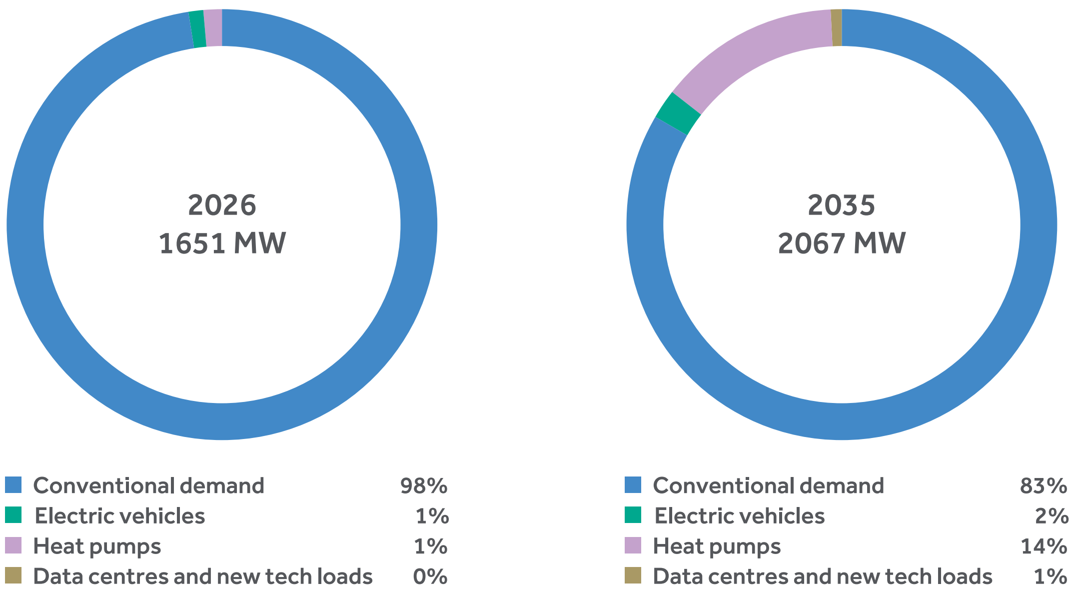


Figure 4.17 Northern Ireland's total electricity requirement (TER) peak demand breakdown in 2026 and 2035

Temperature has a significant effect on electricity demand, particularly on peak demand. This was particularly evident over the two severe winters of 2010 and 2011, when temperatures decreased dramatically, and demand increased to record levels. Average Cold Spell (ACS) correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences.

The ACS Transmission Peak is calculated based on actual metered sent out demand measured at generator export terminals. As such, sent out demand must travel through the transmission and distribution networks to supply consumers, incurring losses as it travels. From this, sent out demand is defined as the demand metered at generator export terminals that includes both exporting small scale generation and transmission and distribution (T&D) losses but does not include generation consumed 'behind the meter' such as rooftop solar panels.

Step one in the process is to apply ACS correction to actual sent out demand data. Step two is to exclude small scale exporting generation which results in the ACS transmission peak presented in Figure 4.18

The Northern Ireland 2024/25 recorded Sent Out Peak Demand of 1,520 MW occurred on Wednesday 8th January 2025 at 17:30. When the ACS process is applied the ACS Transmission Peak becomes 1,616 MW.

As with the annual electricity demand forecast outlined in Section , three peak forecast scenarios have been constructed.

Electricity demand in the heat and transport sector is expected to increase with the growth in heat pump and electric vehicle sales. A level of off-peak charging is assumed for electric vehicles within the forecast, the benefits of which are shown in Figure 4.19 and Figure 4.20. To realise these benefits, appropriate policies and incentives are required, otherwise additional generation capacity will be necessary.

SONI has utilised the ENTSO-E DFT to create the low, median and high peak demand forecasts. Climate variation is introduced to these forecasts through the use of thirty-six weather scenarios. SONI does not expect an extremely warm or extremely cold winter every year, and the range of conditions introduced in the weather scenarios is considered to be within the bounds of possibility.

The main difference between the forecasts of low, median, and high peaks is the amount of load assumed from data centres and electrification of heat and transport. This forecast employs a similar methodology as that used in the TER forecast and utilises the DFT modelling tool.

Figure 4.18 shows the ACS Transmission Peak forecast for Northern Ireland. The resulting forecast for 2025 has increased compared to the AIRAA 2025–2034 median scenario due to the vast majority of electric vehicles using a simple charging profile whereby their demand is not shifted away from peak times. The forecast between 2026 and 2035 has reduced compared to the AIRAA 2025-2034 median scenario. This is due to the reduction in electricity consumption observed at peak time from increased efficiency and the increasing implementation of off-peak charging for electric vehicles which shift their demand away from peak times. Beyond 2030, the growth in peak demand is expected to be driven primarily by the electrification of heat with smaller contributions from the electrification of transport and data centres.

The key assumption differences between the low, median and high peak electricity demand scenarios in the forecasts shown above are the same as those summarised in Table 4.7. Underlying trends such as residential consumption and assumed efficiency targets further contribute to the variation in each of the scenario forecasts shown in Figure 4.18.

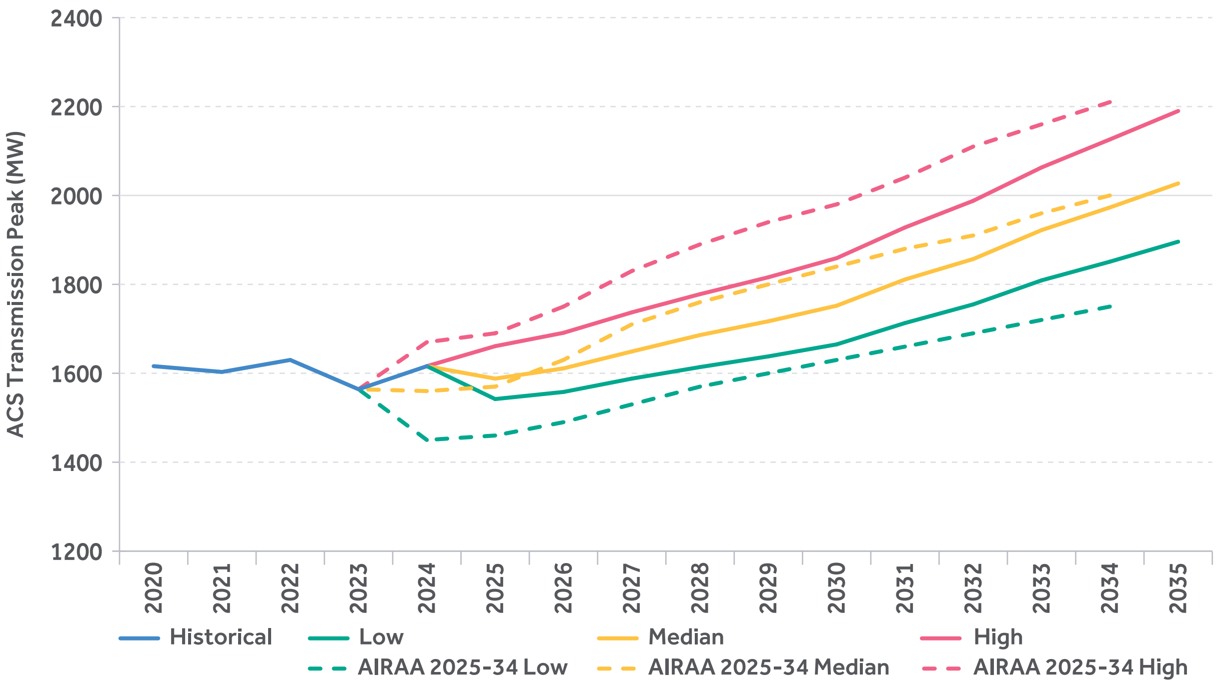


Figure 4.18 ACS Transmission Peak forecasts for Northern Ireland

4.3.7 Demand Flexibility: Impact of Off-Peak Charging

Demand flexibility has the capability to improve the adequacy of the electricity system by moving demand away from peak times. Figure 4.19 shows the effect of off-peak electric vehicle charging on the forecast peak day in 2030 that has been incorporated into the median demand forecast. Having off-peak electric vehicle charging reduces peak demand by around 4.3% in comparison to having no flexibility in electric vehicle charging.

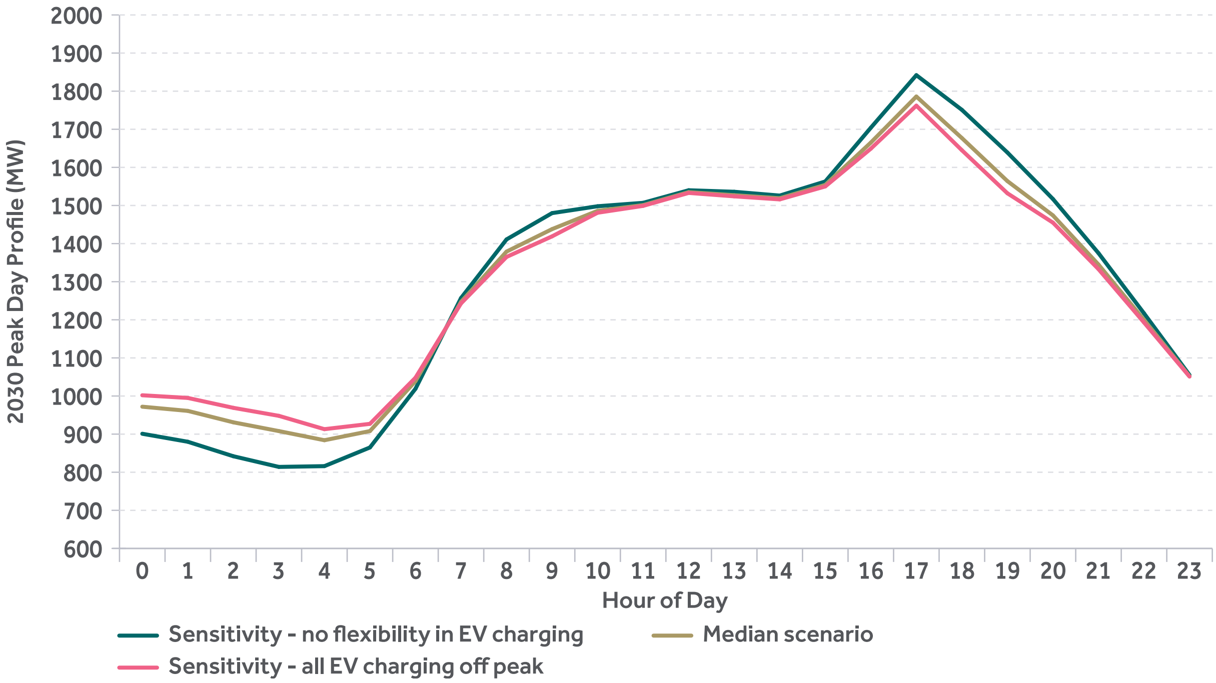


Figure 4.19 Impact of demand flexibility on 2030 peak day for Northern Ireland (median scenario)

Figure 4.20 shows the impact of demand flexibility services and incentives on the median scenario across the study period. The contribution of flexible electric vehicle charging grows through the study period as the number of electric vehicles increases, and the roll out of services and incentives to promote flexible charging are incorporated.

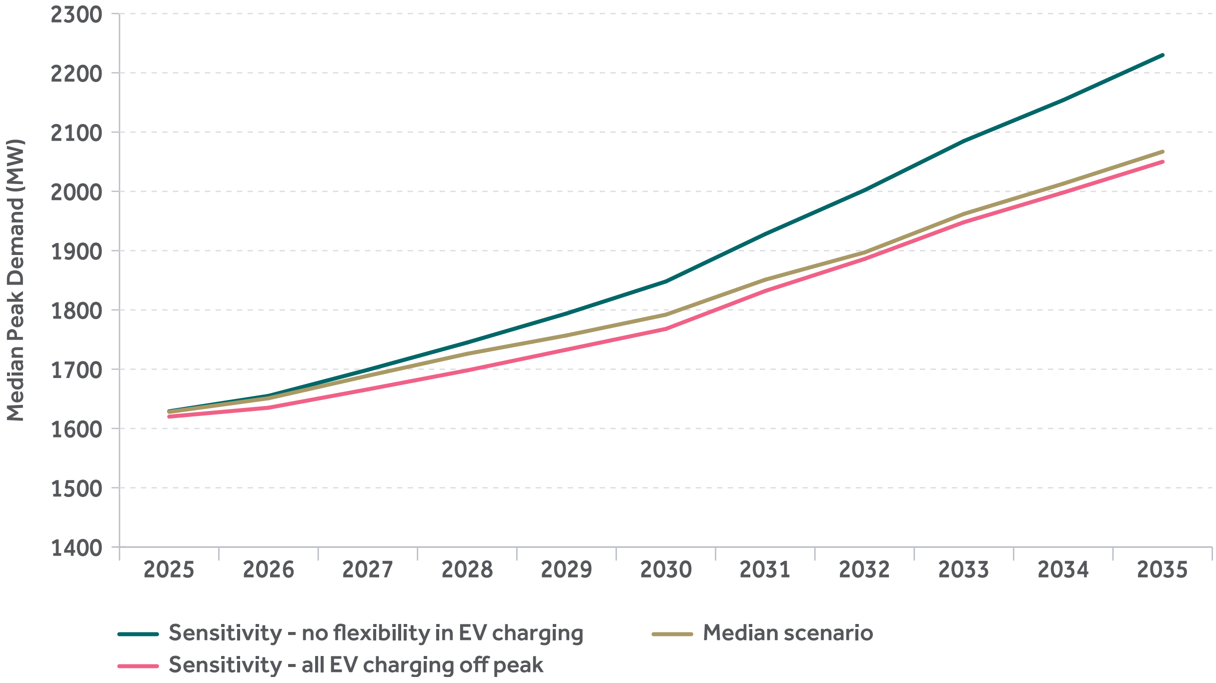


Figure 4.20 Impact of demand flexibility in median scenario across the study period for Northern Ireland

4.3.8 Shape of the Demand Profile

Historically, the shape of Northern Ireland's hourly demand profile was consistent and predictable throughout the year. However, the connection of new technologies to the grid such as electric vehicles and heat pumps, along with changing consumer behaviour in response to these new technologies is altering the profile's shape. As more heat pumps and electric vehicles connect to the grid, the effect of consumers changing how they use electricity will only increase, thereby further altering the shape of the demand profile.

ENTSO-E's DFT can model these new technology load profiles and thereby consider their effects when forecasting Northern Ireland's demand profile across the chosen horizon. As the electric vehicle, heat pump and other new technology sectors become more established, the modelling of how consumers use these technologies will increase in importance.

The DFT forecast produces a daily demand profile with a different shape compared to what has been observed as the historical demand profile, with the difference between the minimum and maximum demand seen on a daily basis decreasing as the forecasted years go on. The DFT's forecasted, daily demand per year over the forecast horizon of 2025–2035 can be seen in Figure 4.21 below. For illustrative purposes of presenting the shape of Northern Ireland's typical historical demand profile, a historical series has been added to Figure 4.21 showing the average sent out demand per hour during 2024.

For the historic demand profile, a peak typically occurs in the morning around 08:30 – 09:30 when consumers wake up, make breakfast and get ready to leave the house, followed by an evening peak typically around 17:30 – 18:30 when consumers return home and make dinner. However, it should be noted that the peaks do not always occur during these time frames and are subject to multiple factors including the season, weather and customer demand management.

With the DFT forecasted daily profile, the demand begins to gradually increase in the early morning hours due to the projected numbers of EVs adopting ENTSOE's Ten Year Network Development Plan (TYNDP) 2022 charging profile[52] which favours night-time charging of EVs i.e. EV owners scheduling their vehicles to begin charging at traditionally "off-peak" hours. As such, when comparing the historic demand profile to the DFT forecasted daily profile, the drop in overnight demand compared to the evening peak is higher.

The forecasted adoption of off-peak charging by Northern Ireland consumers is consistent with AIRAA 2025-2034 and assumes that consumers will seek to avoid high prices for EV charging, similar to the use of the Economy 7 tariff for heating. It is assumed that the appropriate policies and incentives will be in place to ensure that off-peak vehicle charging technology is realised otherwise additional capacity will be required and peak demand may increase.

52 https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf

The transition to consumers charging their vehicles "smartly" is assumed for all four vehicle types in the DFT: passenger battery electric, passenger plug-in hybrids, battery electric light commercial vehicles (BEV LCV), and battery electric busses. The continued adoption of heat pumps will also cause greater demand during morning hours and contributes to the increase in demand during the earlier part of the day.

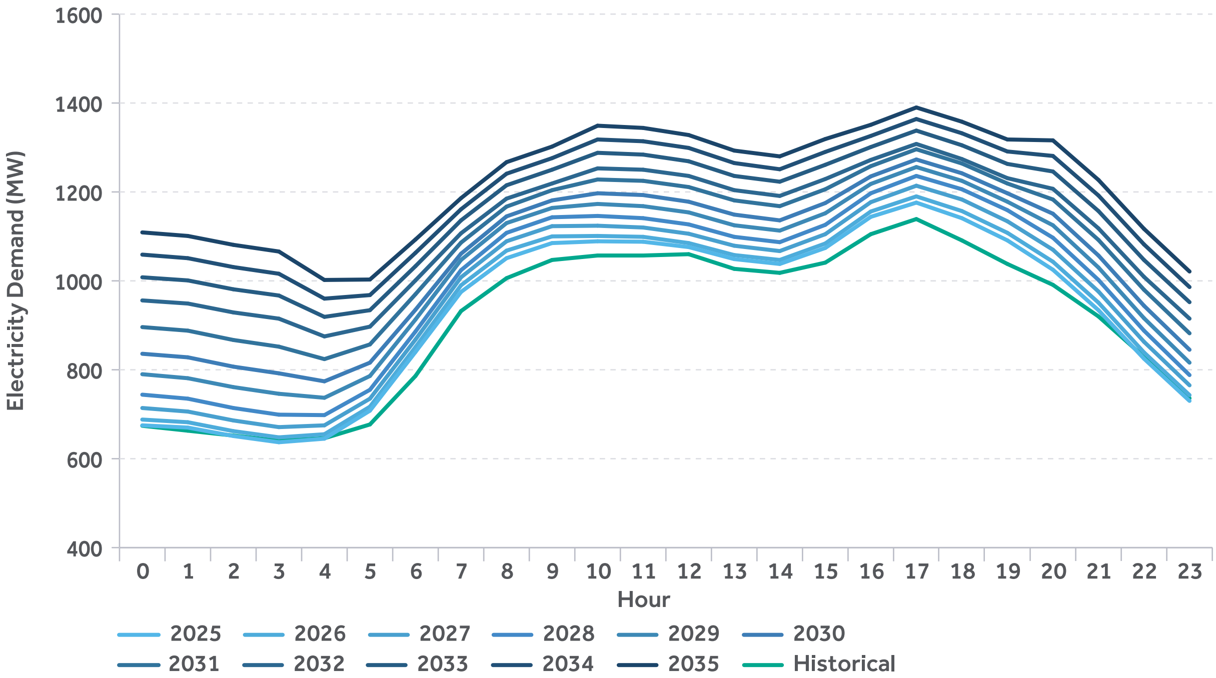


Figure 4.21 Historical and forecast hourly demand shape in Northern Ireland

4.4 Combined All-Island Demand Forecast

In order to carry out combined studies for the all-island system, the two jurisdictional forecasts are combined for the TER on an hourly basis to produce the new all-island TER and peak figures as shown in Figure 4.22 and Figure 4.23 below. As mentioned in Section 4.1, the All-Island peak may not necessarily occur at the same time for the individual jurisdictions Ireland and Northern Ireland. Therefore, the calculation of the forecasted All-Island peak is not a simple summation of the jurisdictional peaks.

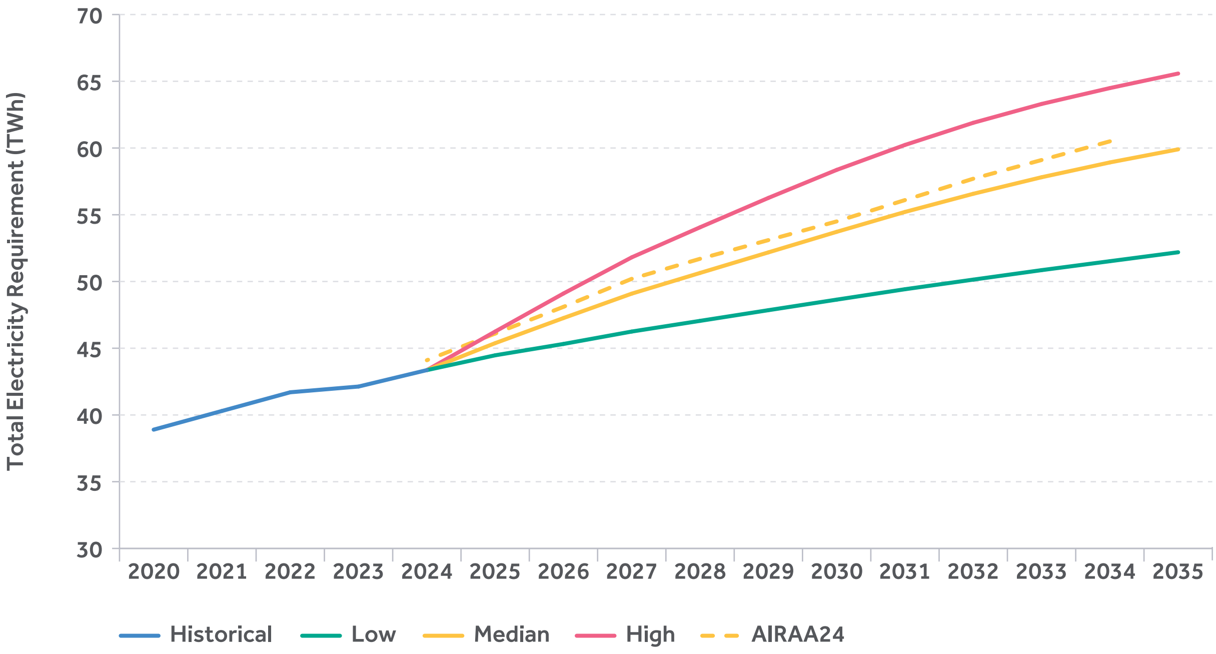


Figure 4.22 Combined TER forecast for all-island system

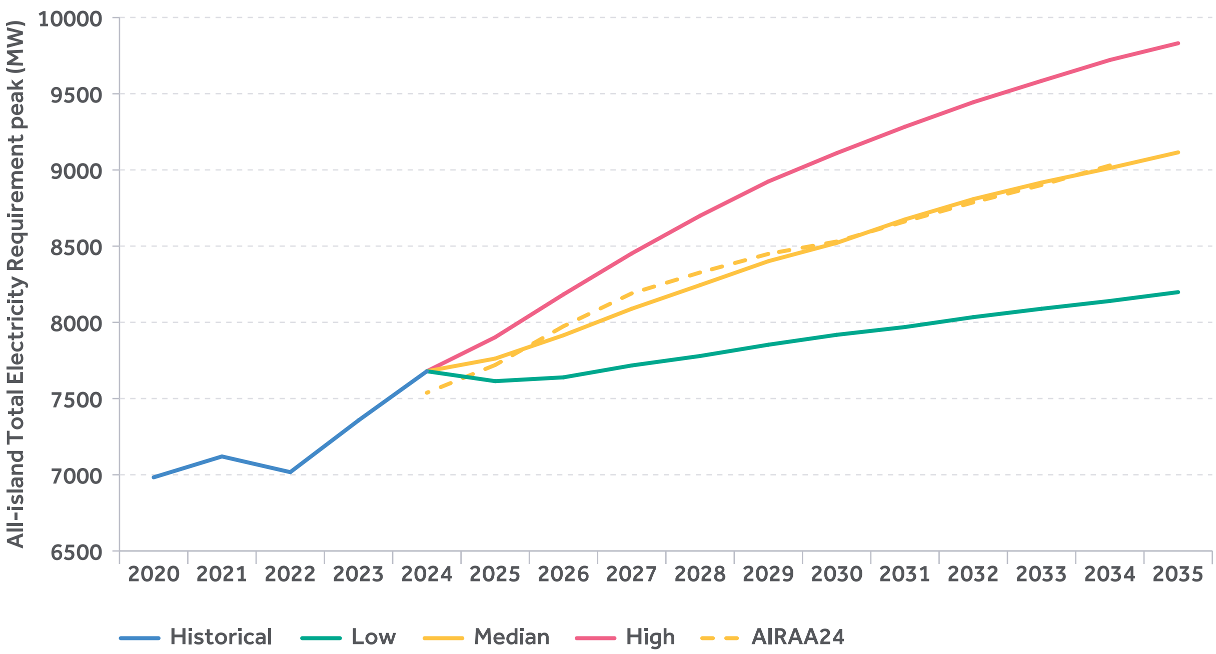


Figure 4.23 TER peak for the combined all-island forecast

5. Generation

5.1 Introduction

Figure 5.1 below illustrates the age of the dispatchable conventional and hydro generation resources in Ireland and Northern Ireland at the start of 2026. Note this does not include new capacity that may be commissioned during 2026. Based on the current portfolio trajectory, by the end of the study horizon in 2035 there will be approximately 3,200 MW of conventional capacity over 30 years of age, which could be at risk of exiting the market if it is no longer viable to keep ageing capacity operational in a power system predominantly powered by renewable energy. Furthermore, the declining performance and reliability of ageing plant has presented a challenge to the operation of the power system in recent years, and degrading performance of the existing portfolio could present similar risks in the future.

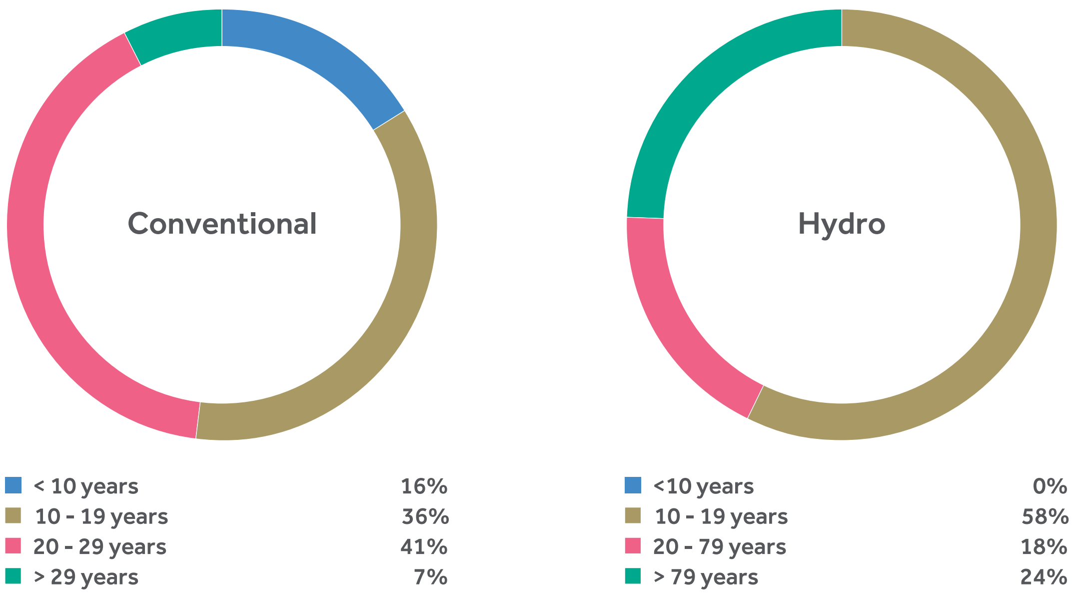


Figure 5.1 Age breakdown of dispatchable conventional and hydro generation resources for the All-Island system operational from the start of 2026

5.2 SEM Capacity Market

5.2.1 Overview

The Single Electricity Market (SEM), established in 2007, is the wholesale electricity market operating in Ireland and Northern Ireland. The market design was revised in October 2018 to enable free trade of electricity across borders without discrimination[53], encouraging the delivery of adequate supply to meet demand, to operate a power system securely.

Since 2018 the NI Executive and the Ireland Government have committed to the transition to net zero and set out a number of renewable targets. It is noted there are a number of projects underway[54] to deliver the market required to achieve renewable ambitions on the island of Ireland. The market-focussed projects include Strategic Markets Programme (SMP), SEMOpx projects, Future Arrangements for System Services (FASS), Scheduling and Dispatch Programme (SDP), with support from the Long Duration Energy Storage (LDES) and Energy Market Policy (EMP) workstreams.

The SEM is designed and regulated by the Single Electricity Market Committee (SEM Committee) which is made up of representatives from regulators in Northern Ireland (the Utility Regulator) and Ireland (the Commission for Regulation of Utilities) and two independent members. The SEM includes the energy market, capacity auctions and system services. SONI and EirGrid operate the SEM, under the contractual joint venture, the Single Electricity Market Operator (SEMO).

Under the SEM, only generating units that are successful in the capacity auctions will receive capacity payments. The aim of the capacity market is to procure the capacity required for the secure operation of the power system in both Northern Ireland and Ireland through competitive auctions therefore ensuring that consumers do not pay for more capacity than is needed. Since 2017, up to the data freeze date (30th June 2025) for this assessment there have been 16 capacity auctions aiming to secure capacity up to and including 2028/2029 capacity year. The results for each auction can be found on the SEMO[55] website.

53 https://www.sem-o.com/markets/developing-the-i-sem/index.xml
54 Future Power Markets Design Authority Newsletter – August 2025
55 SEMO Capacity Market

5.2.2 New Capacity Deliverability

The portfolio of new storage and synchronous generation capacity expected to connect to the system within the 10-year study horizon is based on results from the SEM capacity market auctions. Delivering new capacity is a complex and often challenging process therefore delivery of new capacity is monitored through the enhanced monitoring programme.

The enhanced monitoring programme analyses a range of factors including supply chain analysis, planning permission and grid (gas and electricity) connection timescales. The TSOs undertake a due diligence process at regular intervals with support Gas Networks Ireland, Mutual Energy and project developers to inform the forecast on expected delivery of new capacity. Technical deliverability assessments determine whether projects are on track for early delivery, if they are expected to be delayed or whether, based on the current information, they may not deliver at all. The outcome of this process is a forecast of expected delivery of new capacity, which is used in the central adequacy assessment.

In Ireland, the CRU concluded its CRU Information Paper Security of Electricity Supply – Programme of Actions, in July 2025. The deliverability of new capacity awarded in the capacity market will continue to be monitored by the Electricity Adequacy Reporting Group. Based on the latest deliverability assessment, not all awarded new capacity from previous auctions will be available on time for the start of the contracted capacity year. Additionally, it was the view of the final Security of Supply Pillar C programme (dated: 24th July 2025) that some projects had significant technical and/or planning challenges that could mean non-delivery.

In Northern Ireland, the Oversight Committee for New Awarded Capacity (OCNAC) oversees new developments which have secured capacity contracts and supports wider consideration of and decision making about security of supply in Northern Ireland. The OCNAC meetings provide senior stakeholders with visibility of the progress of new capacity delivery, provide a forum for relevant parties to identify any risks or obstacles to the delivery of that capacity within the contracted timelines, allow opportunity to query any changes to reporting of milestones and enable relevant parties the opportunity to offer support, solutions, or mitigations where feasible.

To promote timely delivery of new capacity, Early Delivery Incentives (EDIs) were introduced into the SEM capacity market in May 2024 as an option to accelerate delivery of new capacity[56]. These EDIs provide an opportunity for investors to receive payment for new capacity delivered ahead of the capacity year for which the capacity was awarded.

This report and security of supply studies continue to highlight the negative impact to system adequacy from new capacity not becoming available on time. In the short- to medium-term, failure to deliver new capacity for a given capacity year presents challenges to the adequacy position of the system. If new capacity fails to deliver on time for a given capacity year, mitigating measures may be required to ensure alternative capacity is made available. A sensitivity on the Ireland

56 SEM-24-037 Decision Paper – Early Delivery Incentives.pdf

adequacy analysis has been included to examine the impact on adequacy if all new capacity in Ireland was delivered for the start of each capacity year for which the capacity contract was awarded i.e. if all new projects are delivered on time.

5.2.3 Intermediate Length Contracts

In May 2024, Intermediate Length Contracts (ILCs) were introduced into the SEM capacity market as a mechanism to facilitate investment in capacity[57]. These ILCs provide an opportunity to reinvest and refurbish existing plant to increase capacity of the system, extend their lifetime, and facilitate decarbonisation measures. From the T-4 2028/2029 approximately 2 GW of rated capacity was awarded an ILC[58]. As such, a number of the units require maintenance outages to complete refurbishments resulting in scheduled outages from 2026 to 2028 as outlined in the Committed/ Provision Outage Program documents[59]. ILC outages are included in Appendix 3: Generation Plant Information.

5.2.4 Run Hour Restrictions

In 2017, the European Commission published a final decision on the Best Available Techniques[60] (BAT) for large combustion plants, which has applied new standards on emissions from August 2021. The latest BAT conclusions were published in February 2021[61]. For combustion plants, Emission Limit Values (ELVs) for Nitrous Oxide (NOx), Sulphur Dioxide (SO2) and particulate levels have been tightened and therefore new gas generating units could have Annual Run Hour Limitations (ARHL) of 500 or 1,500 hours depending on the units' technical characteristics (fuel source / efficiency).

There are a number of units that are subject to restrictions on the number of hours the units can operate in a given period of time; and a number of additional units that may be restricted as part of licensing arrangements. Annual constraints are often driven by emissions legislation, but daily or multi-day constraints could also arise due to planning restrictions or if fuel supply becomes an issue. A unit which is restricted to 500 or 1,500 hours of operational availability on an annual basis provides less value to reliable system operation than a unit which is available for 8,760 hours of operation (subject to outages).

Restrictions on power plants introduces additional complexity into operating a reliable system. Managing operational restrictions may require actions outside of the market. Operating restrictions on capacity will have implications for power system reliability, so it is prudent to include the effect as part of the reliability assessments. Within the planning timeframe, it is important that any impacts or issues are addressed through the relevant parties such as regulators, Government departments, and developers.

57 SEM-24-035 Intermediate Length Contract Decision Paper | The Single Electricity Market Committee
58 Capacity Market | Markets | SEMO
59 TSO Responsibilities | Publications | SEMO
60 https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1502972300769&uri=CELEX:32017D1442
61 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021D2326

5.3 Conventional Generation

The portfolio of conventional plant currently connected to the system can be categorised into gas turbine and steam turbine technologies. The gas turbine category includes distillate and gas oil fuelled power plant, along with combined and open cycle turbine plant configurations.

5.3.1 Ireland Portfolio

Existing Capacity

Table 5.1 below presents the expected changes to the existing conventional portfolio across the study horizon. It is worth noting that under the Grid Code[62,63], units are required to provide 24–36 months' notice, depending on the size of the unit, of intentions to close referred to as a "Closure Notice".

As such, there may be additional closures within the study horizon beyond those currently known at the data freeze date for this report publication. The 36-month notice period for larger units presents an ongoing risk for resource adequacy planning, where the opportunity to replace these units is at auctions which run 4 years ahead of time.

Some generators in Ireland have informed EirGrid of their intention to decommission, a common reason for plant decommissioning is increasing restrictions due to the Industrial Emissions Directive (IED) legislation. Directive 2010/75/EU[64] of the European Parliament and the Council on industrial emissions (the Industrial Emissions Directive or IED) is the main EU instrument regulating pollutant emissions from industrial installations.

Table 5.1 Assumptions for conventional plant changes in Ireland

Plant	Units	Capacity (MW)	Comment
Moneypoint	MP1	250	Following submission of a closure notice, these units exited the market at the end of June 2025. EirGrid notes that these units will be retained beyond this date to proactively mitigate the risks of an electricity crisis as defined by Regulation (EU) 2019/941 and the Risk Preparedness Plan (RPP) for Ireland[65]. However, this is considered a mitigating measure and not part of the central assessment.
	MP2	250	
	MP3	250	
Edenderry	ED3	58	Awarded capacity in the 2025/2026 T-4 capacity auction to switch fuel from Distillate Oil to Gas.
	ED5	58	
FlexGen	Ringsend	64	Newly operational as of Q4 2024.
	Poolbeg	64	
	Corduff	64	

62 EirGrid Grid Code Version 15
63 SONI Grid Code April 2024
64 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN
65 Security_of_Electricity_Supply_Retention_of_Moneypoint_Units_Information_Paper.pdf

New Capacity

In terms of the expected delivery of new capacity, Table 5.2 below presents the expected cumulative new capacity as of the data freeze date, relative to the total capacity that has been successful in the auctions.

Table 5.2 Ireland assumptions for new conventional plant capacities in adequacy studies (rated MW).

Cumulative (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Successful in Capacity Auctions less Operational Plant*	900	2,060	2,110	2,450	2,450	2,450	2,450	2,450	2,450	2,450
AIRAA 2025 Expected New Capacity Delivery**	610	910	1,500	1,900	1,900	1,900	1,900	1,900	1,900	1,900

* Capacity successful in capacity auctions that has not received a termination notice or is currently operational.
** Expected capacity is based on plant delivering early, delivering late, or not delivering. Note all values are rounded to the nearest 10 MW and capacity is presented as capacity commissioning during the calendar year.

Dublin Short Circuit Constraint

A short-circuit is a type of fault that can occur on the power system, resulting in a very large electrical flow, which can cause knock-on effects on the system including damaging technology. The power system must be operated to ensure that if a fault does happen, protective measures are in place.

The electricity system in Dublin has unique supply/demand considerations and challenges. Under certain operating scenarios in Dublin, high-short circuit levels can create challenges in the operation of the transmission system.

For Winter 2028, the management of short-circuit standards is more challenging due to the changing makeup of infrastructure and technology in the region that is planned, with the arrival of additional contracted generation and transmission network topology changes in Dublin. This has been outlined in EirGrid's Short Circuit Summary for Industry[66].

For the purposes of this year's adequacy assessment, a constraint is applied to the model to reflect these challenges. The model assumes that from Winter 2028 onwards, not all of the generation in Dublin can be dispatched at the same time without potentially breaching short-circuit standards.

As EirGrid has previously stated, with careful planning and investment, the risks associated with high short-circuit levels can be managed in the longer term which is outside the time horizon of this report, allowing for a more efficient and sustainable expansion of Ireland's electricity grid.

Solutions are currently being developed to address these challenges, including new 400 kV circuits in the Dublin area. Dublin does not currently have any circuits at this voltage level, but there are several 400 kV projects contained in the Network Delivery Portfolio (NDP) which will provide a basis to accommodate opportunities for new generation. This is an area of ongoing review for adequacy assessments.

66 Microsoft Word – Short Circuit Summary for Industry Reg Final rev 26032025

Run Hour Restrictions

In Ireland, a number of units have indicated that they will operate using non-conventional fuels as their primary fuel type for example Hydrogenated Vegetable Oil (HVO). The information relating to potential Annual Run Hour Limitations (ARHL) on units is evolving and uncertain. In addition, fuel supply challenges are possible which could restrict the operation of some units, e.g. ARHL or consecutive operating hour limit, resulting from fuel supply availability.

EirGrid will continue to engage with the EPA, the CRU, DCEE and project developers to understand operational restrictions that may be placed on units operating. Acknowledging the information is evolving, the Base adequacy assessment assumes new capacity is not subject to run hour restrictions (unless ARHL has been confirmed through relevant sources). To analyse the potential impact of such operating limits, the Secure adequacy assessment assumes some new units are restricted to 1,500 hours ARHL. This operating hour restriction is implemented by limiting operation of relevant units to typical peak demand periods.

Table 5.3 below indicates the cumulative capacity expected to be subject to run hour restrictions out to 2030 in Ireland. Note the table below includes existing and new capacity and assumes there is no change post 2030.

Table 5.3 Capacity (MW) assumed to be subject to run hour limits in Ireland

Run Hour Restriction	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
500 hours	270	270	270	270	270	270	270	270	270	270
1500 hours*	210	210	510	510	510	510	510	510	510	510

* Includes new capacity that is assumed to be subject to run hour limits in the Secure adequacy assessment

5.3.2 Northern Ireland Portfolio

In Northern Ireland, the most significant portfolio evolution in recent years has been the retirement of the two Kilroot coal units K1 and K2 in September 2023. Capacity awarded through the capacity market auctions, in the form of the Kilroot KGT6 and KGT7 units, has been developed and is now operational.

The KGT6 and KGT7 units are subject to Annual Run Hour Limitations (ARHL). In 2023 an additional steam turbine was expected to develop at the site to construct a Combined Cycle Gas Turbine (CCGT) arrangement. This arrangement was intending to utilise waste heat from the KGT6 and KGT7 Open Cycle Gas Turbines using Heat Recovery Steam Generators, improving the operating efficiency of the arrangement, and therefore removing the ARHL restriction. In January 2024 the additional turbine had its capacity market contract terminated[67] and as such SONI assumes KGT6 and KGT7 will be subject to ARHL for the duration of the study horizon.

The ARHL restricts KGT6 and KGT7 to operating 1,500 hours per year over a five-year rolling average (peak of 2,250 hours allowed in a single year) to limit emissions. Following Storm Darragh in December 2024, Ballylumford C Station was forced off resulting in increased running of the KGT6 and KGT7 units. In 2025, both KGT6 and KGT7 have accumulated in excess of 2,000 hours despite the implementation of emergency measures by SONI to manage run hours, for example managing operational constraints.

The published Operational Constraints Document[68] outlines the requirements to maintain system stability in Northern Ireland. There are only three thermal generation locations in Northern Ireland: Ballylumford Power Station, Coolkeeragh Power Station and Kilroot Power Station. To satisfy the stability constraints, all of the generation in Northern Ireland cannot rely on any one location. When Coolkeeragh C30 takes an outage, KGT6 or KGT7 must run, increasing the run hour utilisation on the units.

67 J.6.1.3-(f)-Capacity-Market_Capacity-Termination-Notice-GU_504020-110124.pdf
68 Weekly Operational Constraints Update

The current need to manage run hours within the maximum annual run hour limit of 2,250 hours presents a significant challenge which is expected to impact on future years, in terms of managing the run hours on the units within the annual 1,500 rolling average over a five-year period. Increased utilisation of run hours on the units in the early years (>2000 hours) means limited hours will be available in future years (<1,000 hours). The central analysis in this assessment assumes the run hours can be managed over the coming years; however two sensitivities are included to evaluate the impact of reduced run hour availability and the impact of removing the run hour restriction completely. Section 6.3 includes further post data freeze date information in relation the ARHL on units for 2025.

Table 5.4 below indicates the cumulative capacity expected to be subject to run hour restrictions out to 2035 in Northern Ireland. Note the table below includes existing and new capacity and assumes there is no change post 2030.

Table 5.4 Capacity (MW) assumed to be subject to run hour limits in Northern Ireland

Run Hour Restriction	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
500 hours	310	310	310	310	310	310	310	310	310	310
1,500 hours	700	700	700	700	700	700	700	700	700	700

5.4 Interconnection & Tie Lines

Interconnection allows the transport of electrical power between two markets. Interconnection with Great Britain over the East-West (EWIC), Moyle and Greenlink interconnectors provides a significant benefit to secure operation of the power systems in Ireland and Northern Ireland.

The existing North South tie line (between Louth and Tandragee), plays a key role in system security and adequacy in both jurisdictions. Increasing interconnection between the two jurisdictions on the island, in the form of the second North South Interconnector, will significantly enhance access to generation capacity in both jurisdictions contributing positively to security of supply in the SEM.

The Celtic interconnector, currently under development, will connect Ireland to France. Upon completion, this interconnector will be Ireland's first direct link to continental Europe and will bring adequacy benefits through access to more diversified markets.

5.4.1 North South Tie Line

This All-Island Resource Adequacy Assessment will be based on an economic unit dispatch model allowing dynamic modelling of power flows between Ireland and Northern Ireland.

Generation adequacy assessments for each region are carried out based on the Net Transfer Capacity (NTC) between the jurisdictions which has been derived through grid transfer capacity studies as part of the TYNDP process[69]. The All-Island adequacy assessment includes the new North South Interconnector, whereas the jurisdictional adequacy assessments do not include the new North South Interconnector. These studies assume an NTC value lower than the actual physical rated capacity of the lines since operational rules and network N-1 contingencies are accounted for in the NTC value.

Table 5.5 below includes the assumption on the net transfer capacities for the transmission between Ireland and Northern Ireland, used in this assessment. The table also includes the additional increase in NTC once the second high-capacity transmission link between Ireland and Northern Ireland is assumed to be available by 2032[70]. The total North South NTC from 2032 is therefore 1,200 MW North to South direction and 1,250 MW South to North direction.

For the purposes of this report, the jurisdictional assessments consider the existing North South tie line only, with the value of the new North South Interconnector being assessed as part of the All-Island assessment.

Table 5.5 North South Net Transfer Capacity

N > S Capacity (MW)	S > N Capacity (MW)	Description
300	300	Existing North South tie line. Included in all years of the study horizon for the jurisdictional central adequacy assessments.
900	950	New North South Interconnector. Included from 2032 for the All-Island assessment.

69 TYNDP 2022 Project Collection (tyndp2022-project-platform.azurewebsites.net)
70 EirGrid's Network Delivery Portfolio Publication Q1 2025

5.4.2 HVDC Interconnection from the all-island system to Great Britain and France

When assessing the contribution of an interconnector to generation adequacy, consideration of the availability of generation at the other side is needed, as well as the availability of the interconnector itself.

The East-West Interconnector (EWIC) connects the transmission systems of Ireland and Wales with a capacity of 500 MW in both directions. In Northern Ireland, the Moyle Interconnector is a dual monopole HVDC link with two coaxial undersea cables from Northern Ireland to Scotland. The import capacity of the Moyle Interconnector is currently 450 MW and the export capacity restricted to 400 MW; however, this is assumed to increase to the full 500 MW bi-directional utilisation from 2028 following delivery of the Moyle Interconnector Capacity Increase project[71].

The Greenlink interconnector connects the transmission systems of Ireland and Wales with a capacity of 500 MW in both directions. The Greenlink interconnector was energised in April 2025.

The Celtic interconnector will connect the transmission systems of Ireland and France with a capacity of 700 MW in both directions. The Celtic interconnector was originally intended to energise in 2027 but following cable manufacturing delays it is now assumed available from April 2028[72].

Table 5.6 summarises the interconnection portfolio, including existing interconnectors and projects that are anticipated to deliver by 2030.

Table 5.6 HVDC Net Transfer Capacity (MW) assumptions for Northern Ireland / Ireland connection. Loss factors derived from Transmission Loss Adjustment Factors (TLAFs) for 2024-202573. The loss factor for Celtic is an anticipated loss factor based on engineering judgement of the EirGrid Interconnection team

Line	Import (MW)	Loss Factor	Comment
Moyle	450	2.4%	Increases to +/-500 MW from 2028
EWIC	500	4.7%	
Greenlink	500	2.3%	
Celtic	700	4.2%	Assumed available from the start of Q2 2028

71 Draft Transmission Development Plan Northern Ireland 2023-2032
72 Celtic Interconnector | Projects | EirGrid
73 2024-25 Approved TLAFs v1.1.xlsx

5.4.3 Further Interconnection

There are further projects noted in ENTSO-E's most recent Ten-Year Network Development Plan 2024[74]. In Northern Ireland there is potential for a new 700 MW interconnector to Scotland[75], with one potential operator (LirIC) receiving an interconnector licence from Ofgem. The Utility Regulator granted a transmission license to Transmission Investment (TI) LirIC Limited in December 2024[76]. In Ireland, there is potential for a new 750 MW interconnector project (MARES Connect[77]) between Ireland and Wales.

The LirIC and Mares Connect projects are at relatively early stages of development, with grid connections, land and regulatory terms still being processed. As such, these projects are not included within any studies in this report.

Table 5.7 Further interconnection projects

Project	Description	Project Promoters' Target Commissioning Year	Assumed Net Transfer Capacity (MW)
LirIC	Interconnector between Northern Ireland and Scotland	2032	700
MARES Connect	Interconnector between Ireland and Wales	2029	750

74 TYNDP 2024
75 LirIC – Transmission Investment (tinv.com)
76 Grant of Electricity Transmission Licence to TI LirIC Limited | Utility Regulator
77 Non-Technical Summary | MaresConnect Interconnector

5.5 Variable Generation

5.5.1 Ireland Portfolio

The Irish Government's Climate Action Plan 2024 has set an ambitious target to achieve 80% RES-E and substantial emissions reductions. The plan sets clear targets for the required quantity of new renewable technologies including offshore wind, onshore wind, large-scale solar and rooftop solar as summarised in Table 5.8.

Table 5.8 Climate Action Plan renewable targets in Ireland

Technology	2025 Target	2030 Target
Onshore Wind	6 GW	9 GW
Offshore Wind	-	At least 5 GW
Solar	Up to 5 GW	8 GW

To incentivise new renewable projects and deliver the required capacity to achieve these targets, the Irish Government introduced competitive auctions for renewable energy projects. In total, there have been five auctions conducted to date including four Renewable Electricity Support Scheme (RESS) auctions targeting onshore projects (wind/solar/hybrid) and one Offshore Renewable Electricity Support Scheme (ORESS) specifically targeting offshore wind projects. Two additional auctions, RESS 5 and ORESS Tonn Nua, are expected to conclude by the end of 2025[78].

In addition to the renewable support schemes, to streamline the connections processes there have been a number of grid access schemes to develop connection of renewable generation: Gate 3, Non-GPA and ECP, the latest of which is ECP-2. EirGrid publishes a list of all transmission connected wind generation in Ireland, while ESB Networks publishes that which is distribution connected. EirGrid has considered the RESS and ORESS auction results, ESBN data and latest connections offer processes data to develop a trajectory for deployment of new renewable capacity.

78 RESS | Customer information | EirGrid

The Sustainable Energy Authority of Ireland (SEAI) has developed forecasts[79] for variable generation capacity from surveys of expert stakeholders in the Decarbonised Electricity System Study (DESS) – Forecasts of plausible rates of generation technology deployment 2024 –2040. The median forecast (EPO50) from this analysis has been selected for the central adequacy assessment in this report. The forecast represents a plausible 'best guess' deployment forecast for each variable renewable technology, as judged by a pool of expert stakeholders in Q1 2024. More information on the SEAI forecasts can be obtained in the SEAI Forecasts of plausible rates of generation technology deployment 2024 –2040. The median variable generation trajectory is shown in Figure 5.2 below.

Overall, the trajectory assumes a delay in achieving the Climate Action Plan targets for 2030; however, it is appropriate to be prudent in the assumptions regarding renewable delivery for the purpose of an adequacy assessment where the intention is to ensure there is sufficient firm capacity to balance supply and demand; particularly as Ireland transitions to a highly renewable power system.

To indicate the value of renewable resources to reliable system operation, two sensitivities have been identified to highlight the contribution of renewables to resource adequacy. The first sensitivity assumes the SEAI high forecast (EP010), and a second sensitivity analyses the effect of the slower renewable buildout using the SEAI low forecast (EP090).

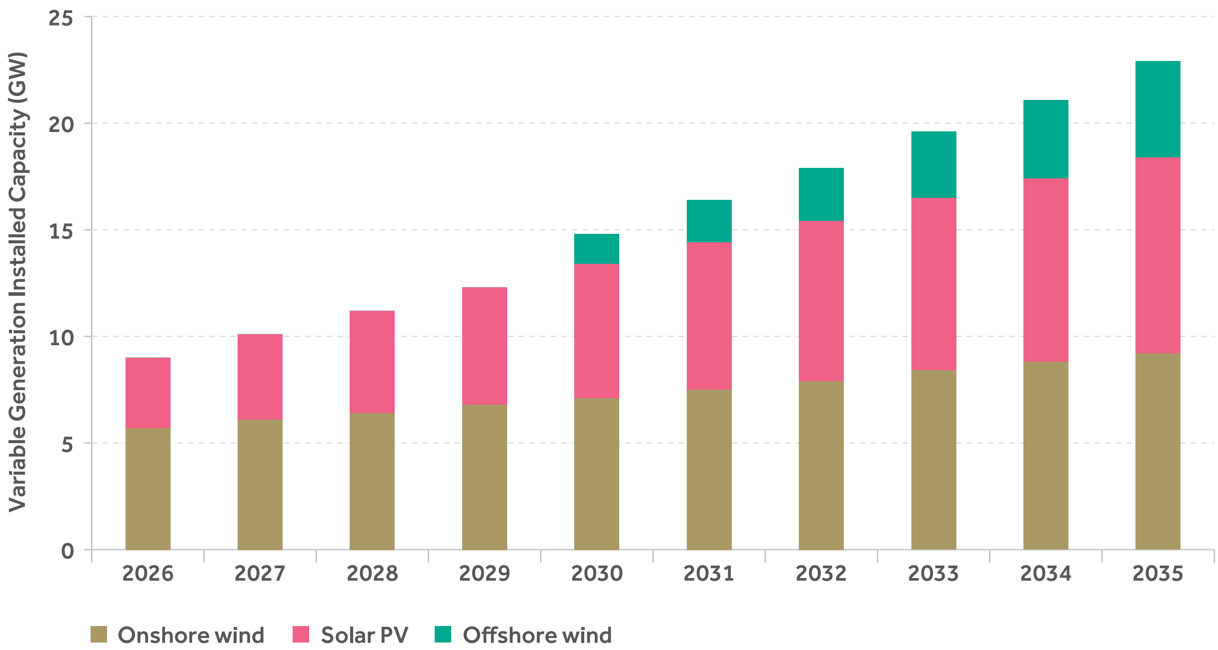


Figure 5.2 Assumed growth of variable generation capacity in Ireland

79 SEAI Variable Generation Capacity Forecasts

5.5.2 Northern Ireland Portfolio

In June 2019, the UK became the first major economy to commit to a 100% reduction in greenhouse gas emissions by 2050. This 'net zero' target represents a significant step-change in the commitment to addressing the climate crisis. The Northern Ireland Executive's new Energy Strategy – The Path to Net Zero Energy[80] was published in December 2021. It outlines a roadmap to 2030 that aims to deliver a 56% reduction in energy-related emissions, on the pathway to deliver the 2050 vision of net zero carbon. The Climate Change Act (Northern Ireland) 2022[81] was enacted in June 2022. Key aspects of this legislation include a target of at least 100% reduction to net zero greenhouse gas (GHG) emissions by 2050.

Following on from the new Energy Strategy, the Department for the Economy (DfE) published The Path to Net Zero – Action Plan 2022[82] and more recently The Path to Net Zero – Action Plan 2025[83]. The Action Plan 2025 is an integral part of delivering the overall energy strategy. The plan lays out a range of actions that the Government expects to take forward with other partners during 2025. The strategy includes a target of 'at least 80% of electricity consumption from a diverse mix of renewable sources by 2030'.

It is clear that significant investment will be required to deliver higher levels of new renewable and low carbon technologies. However, the closure of the Northern Ireland Renewables Obligation (NIRO) in 2017 means that no support scheme designed to meet the specific needs of variable generation is available to encourage renewable energy investment in Northern Ireland. Both Great Britain and Ireland have auction-style mechanisms in Contracts for Difference (CfD) and the Renewable Electricity Support Scheme (RESS).

The Path to Net Zero – Action Plan 2025 highlights an action on the Department for Economy to launch the final design of a renewable electricity support scheme along with a pathway and timeline for the support scheme to be in place as detailed in the Northern Ireland Energy Strategy. The Department for the Economy consulted on the design considerations for a new scheme in February 2023, then in April 2024, the Department published the High-Level Design (HLD)[84] for a Renewable Electricity Support Scheme for Northern Ireland. The purpose of the publication was to outline the broader policy objectives of the new scheme, highlight the design features, and present an auction roadmap of renewable generation to be procured under the scheme by 2030. In September 2025 the Department published the Final Scheme Design for a renewable electricity support scheme[85], namely the Renewable Electricity Price Guarantee (REPG).

80 The Path to Net Zero Energy. Safe. Affordable. Clean. (economy-ni.gov.uk)
81 https://www.legislation.gov.uk/nia/2022/31/enacted
82 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf
83 The Path to Net Zero – Action Plan 2025
84 Renewable Electricity Support Scheme (economy-ni.gov.uk)
85 Final Scheme Design for a renewable electricity support scheme for Northern Ireland

The first auction is anticipated to take place in Q1 of 2027, and contracts awarded the same year. Until such time as contracts are awarded through the REPG, renewable forecasts are constructed using a bottom-up approach assessing connections pipelines and extrapolating across the study horizon assuming a consistent rollout of renewable technologies, as shown in Figure 5.3.

In the short to medium term, onshore wind and solar PV are expected to be the most readily deployed technologies for Northern Ireland. In the medium to long term, offshore renewable energy offers a significant opportunity to develop additional large-scale renewable capacity.

A sensitivity assesses the impact of accelerated renewable capacity growth, and a further sensitivity analyses the impact of delays to renewable delivery on resource adequacy.

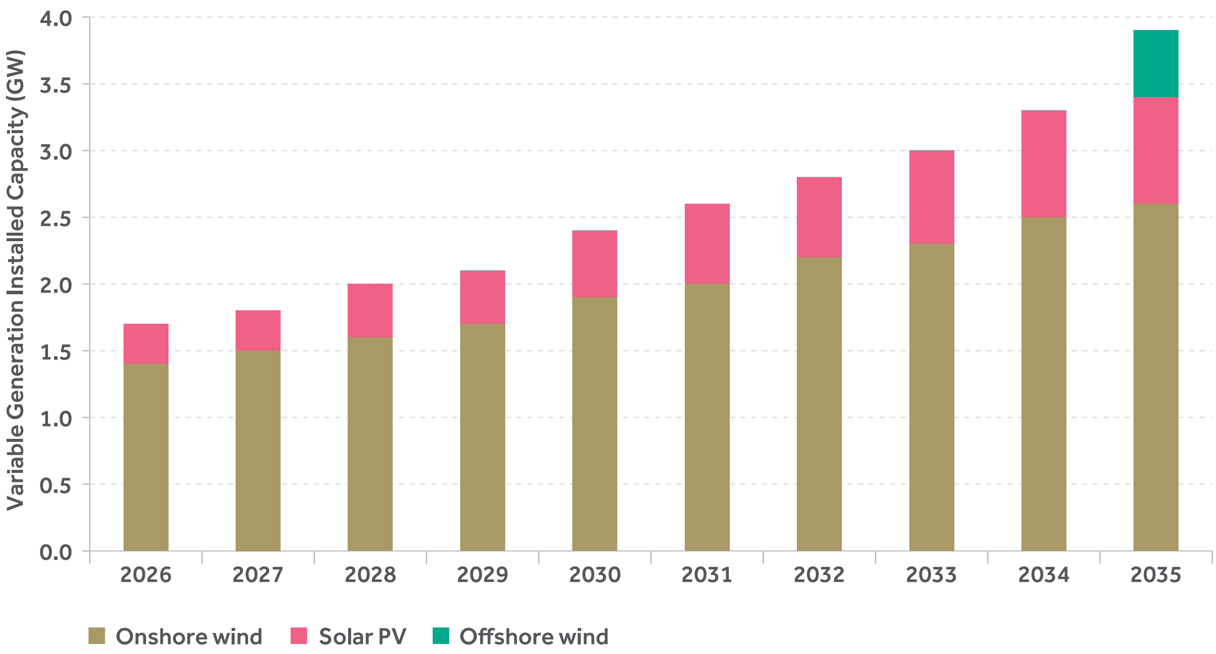


Figure 5.3 Assumed growth of renewable capacity in Northern Ireland

5.6 Energy Storage

The energy storage portfolio in Ireland and Northern Ireland has evolved in recent years with increasing battery storage being introduced into the portfolio. Battery storage technologies can avail of a range of market revenue streams including the wholesale market, capacity payments and DS3 System Services. The aim of DS3 System Services is to incentivise resources that can provide services to ensure the power system can operate securely with higher levels of System Non-Synchronous Penetration (SNSP). The system can currently operate up to 75% SNSP, and the operational policy roadmap[86] to deliver on renewable energy ambitions is targeting 95% SNSP by 2030.

The construct of the DS3 system service contracts was such that revenue streams applicable to batteries were primarily fast acting frequency response services including fast frequency response and operating reserves. As such, a large portion of the current battery portfolio are short duration storage, typically providing less than one hour of energy response. However, in 2023 the first multi-hour battery was commissioned in Ireland, having been successful in the T-4 auction timeframe. There are also several other prospective multi-hour duration units at various stages of development in both Ireland and Northern Ireland.

The tables presented in this section include existing pumped storage and batteries currently connected to the electricity system in each jurisdiction, and new storage capacity that has been awarded contracts in the capacity auctions. As capacity auctions for the period 2030 onwards have yet to run, these studies use the 2029 value for the remainder of study horizon.

86 Operational Policy Roadmap 2025-2035

5.6.1 Ireland Portfolio

Multi-hour Pumped Hydro Storage (PHS) is a form of hydroelectric energy infrastructure that involves storing energy by using electricity to pump water from a lower reservoir to an upper reservoir. Electricity is produced by allowing the water to flow down to a lower reservoir which spins a turbine connected to a generator. Afterwards, generally when electricity prices are cheap, the water is pumped back up, and the reservoir is replenished. At present Turlough Hill in Co. Wicklow, which comprises four turbines with a rated power of 292 MW, and storage station with a capacity of 1.6 GWh, is the only PHS facility in the country.

Table 5.9 and Table 5.10 provide a summary of the total installed generation and energy storage capacity in Ireland, including battery and pumped storage, considering 3 categories of storage duration.

In 2030, Ireland is assumed to have 1,800 MW of generation capacity attributed to storage technologies, and 4,760 MWh of storage capacity, this means storage can provide 1,800 MW of power for over 2.5 hours.

Table 5.9 Ireland Energy Storage Capacity (MW) rounded to the nearest 10 MW

Duration	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<= 1 Hour	460	460	460	480	480	480	480	480	480	480
1-4 Hours	390	530	620	920	920	920	920	920	920	920
> 4 Hours	0	0	0	110	110	110	110	110	110	110
Pump Storage	290	290	290	290	290	290	290	290	290	290
Total	1,140	1,280	1,370	1,800	1,800	1,800	1,800	1,800	1,800	1,800

Table 5.10 Ireland Energy Storage (MWh) rounded to the nearest 10 MWh

Duration	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<= 1 Hour	290	290	290	290	290	290	290	290	290	290
1-4 Hours	880	1,390	1,510	2,220	2,220	2,220	2,220	2,220	2,220	2,220
> 4 Hours	0	0	0	650	650	650	650	650	650	650
Pump Storage	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Total	2,770	3,280	3,400	4,760	4,760	4,760	4,760	4,760	4,760	4,760

5.6.2 Northern Ireland Portfolio

Table 5.11 and Table 5.12 provide a summary of the total installed generation and energy storage capacity of batteries in Northern Ireland. All batteries assumed to be connected to the system in Northern Ireland are less than 1 hour duration, based on the latest capacity auction results. Unlike Ireland, Northern Ireland does not currently have any Multi-hour Pumped Hydro Storage (PHS) facilities.

In 2030, Northern Ireland is assumed to have 240 MW of generation capacity attributed to storage technologies, and 220 MWh of storage capacity, this means storage can provide 240 MW of power for approximately 1 hour.

Table 5.11 Northern Ireland Energy Storage Capacity (MW) rounded to the nearest 10 MW

Duration	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<= 1 Hour	200	200	200	200	200	200	200	200	200	200
1-4 Hours	10	10	20	40	40	40	40	40	40	40
Total	210	210	220	240	240	240	240	240	240	240

Table 5.12 Northern Ireland Energy Storage (MWh) rounded to the nearest 10 MWh

Duration	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<= 1 Hour	140	140	140	140	140	140	140	140	140	140
1-4 Hours	20	20	50	80	80	80	80	80	80	80
Total	160	160	190	220	220	220	220	220	220	220

5.6.3 Long Duration Energy Storage

The Shaping Our Electricity Future (SOEF) v1.1 roadmap identified the need for significant amounts of Long Duration Energy Storage (LDES) in both Ireland and Northern Ireland to increase renewable energy utilisation / decrease renewable energy dispatch down and provide an alternative to fossil fuel generation during periods of low renewable output.

In Ireland, the Department of Climate, Energy and the Environment (DCEE) consulted[87] on the role of energy storage in Ireland, in addition to the challenges and opportunities presented. In Northern Ireland, the Department for Economy consulted on design considerations for a smart systems and flexibility plan[88] which included grid flexibility options.

In November 2023, EirGrid and SONI published a Call for Evidence on the Market Procurement Options[89] for Long Duration Energy Storage (LDES), which detailed the growing system need for Long Duration Energy Storage and potential procurement methods to provide a financial incentive for its connection. There will be a forthcoming EirGrid consultation on the initial procurement process for LDES assets, the outcomes of which will inform the final recommendation paper and detailed procurement design through 2026/2027.

Given the uncertainty in terms of delivery of LDES projects, prospective LDES projects have not been included in the tables above, however as this work progresses projects which begin to materialise will be considered for future adequacy assessments. Whilst this work progresses, a sensitivity has been included to examine the value of additional storage from a resource adequacy perspective for both Ireland and Northern Ireland.

87 Electricity Storage Policy Framework
88 Transitioning to a net zero energy system – Consultation on design considerations for a Northern Ireland Smart Systems and Flexibility Plan (economy-ni.gov.uk)
89 A Call for Evidence on the Market Procurement Options for Long Duration Energy Storage (LDES) | EirGrid Consultation Portal

5.7 Demand Side Units

A DSU consists of one or more individual demand sites that are aggregated into a single unit that is capable of being dispatched as if it were a generator. An individual demand site is one which can either reduce on site energy consumption or use an onsite generator to provide a reduction in net energy consumption.

In the Capacity Market, DSUs typically are awarded 1-year contracts therefore the DSU capacity varies each year. The capacities out to 2029 are based on auction results, noting as auctions for the period 2030 onwards have yet to run, the studies use the 2029 value for the remainder of the study horizon.

5.7.1 Ireland Portfolio

Table 5.13 shows the DSU rated capacities assumed for the study horizon in Ireland.

Table 5.13 Ireland DSU capacity (MW), round to nearest 10 MW

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Run Hour Limited	570	520	570	750	750	750	750	750	750	750
Non-Run Hour Limited	190	230	290	480	480	480	480	480	480	480

Table 5.14 below includes the daily run hour limitation applied to Run Hour Limited DSU, based on an average of run hour limited DSU contracts awarded through the capacity market auctions.

Table 5.14 Ireland DSU run hour restriction (hours)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Daily Activation Limit	2	2	2	2	2	2	2	2	2	2

5.7.2 Northern Ireland Portfolio

Table 5.15 shows the DSU rated capacities assumed for the study horizon in Northern Ireland.

Table 5.15 Northern Ireland DSU capacity (MW), round to nearest 10 MW

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Run Hour Limited	140	80	120	130	130	130	130	130	130	130
Non-Run Hour Limited	50	50	60	110	110	110	110	110	110	110

Table 5.16 below includes the daily run hour limitation applied to Run Hour Limited DSU, based on contracts awarded through the capacity market auctions.

Table 5.16 Northern Ireland DSU run hour restriction (hours)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Daily Activation Limit	3	1	2	2	2	2	2	2	2	2

Dispatchable Aggregated Generating Units (AGU) operate in Northern Ireland, which consist of grouping together several individual diesel generators and gas engines to make their combined capacity available to the market. In addition to the DSU capacity in the tables above, the assumed AGU capacity in Northern Ireland is shown in Table 5.17.

Table 5.17 Northern Ireland AGU capacity (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
AGU	79	79	79	79	79	79	79	79	79	79

5.8 Other Non-Conventional Generation

5.8.1 Small-scale CHP

Combined Heat and Power (CHP) use generation plant to simultaneously create both electricity and useful heat. The overall efficiency of CHP plants is relatively high — often in excess of 80% — and its operation provides benefits in terms of reducing fossil fuel consumption and minimising CO2 emissions, since exhaust heat is used in place of additional boilers to provide heating.

There is approximately 160 MW of small-scale CHP units in Ireland included in the study. An additional 160 MW of centrally dispatched CHP plant operated by Aughinish Alumina is accounted for separately. For the purpose of this assessment, EirGrid assumes the current assumption on small-scale CHP capacity does not change over the next 10 years.

In Northern Ireland, there is currently an estimated 9 MW of small-scale CHP connected to the distribution system (3 MW of which is renewable and 6 MW non-renewable). SONI has not been informed of new capacity coming forward, therefore, for the purpose of this statement, it is assumed that the current capacity of small-scale CHP does not change over the next 10 years.

5.8.2 Biofuel

There are several different types of biofuel-powered generation plant on the island.

In Ireland, EirGrid currently estimates there is 24 MW of generation capacity powered by biofuel, biogas or landfill gas as their primary source of fuel, with an additional 30 MW of biofuel units that are registered under DSU operators.

Bord Na Mona's Edenderry 118 MW unit is assumed to continue operation until the end of the study horizon. This unit was awarded planning permission to operate as a 100% biomass unit from 2024 and is currently operating on 100% biomass.

Currently in Northern Ireland, SONI estimates there is 46 MW of small-scale generation powered by biofuels, including biomass, biogas and landfill gas. There has been no notification of new capacity, therefore, for the purpose of this report, it is assumed this capacity will not change over the next 10 years.

In 2015, Lisahally Waste Project became operational in Northern Ireland. It is a wood-fuelled energy-from-waste/ biomass combined heat and power plant with a capacity of approximately 18 MW. The plant is dispatchable and has been granted priority dispatch.

A number of units which have been successful in recent capacity auctions have indicated that they are planning to operate on Hydrogenated Vegetable Oil, as explained further in Section .

5.8.3 Small-scale Hydro

EirGrid estimates there is currently 26 MW[90] of small-scale hydro capacity installed in rivers and streams across Ireland. This is a mature technology, however as there is the lack of suitable new locations, this factor limits future growth from hydro technologies. EirGrid assumes there are no further increases in small hydro capacity over the 10 years of the study horizon.

In Northern Ireland, small-scale hydro capacity is around 6 MW. Northern Ireland's hydro capacity is generally derived from many small run-of-the-river projects. For the purpose of this report, SONI assumes this small-scale hydro capacity will not change across the 10 years.

5.8.4 Waste-to-energy

In Ireland, there are currently two waste-to-energy plants:

- Dublin Waste to Energy plant – 62 MW
- Indaver Waste to Energy plant – 17 MW

In Northern Ireland, there is currently one waste-to-energy plant:

- Full Circle Generation Waste to Energy plant at Bombardier – 15 MW

No additional capacity is forecast for the next 10 years in either jurisdiction.

5.8.5 Marine Energy

In Ireland, there is a high degree of uncertainty associated with this new emerging technology. EirGrid has taken the conservative approach and assumed there are no commercial marine developments within the study horizon of this statement.

In Northern Ireland, the Crown Estate awarded development rights for sites off the North Coast close to Torr Head and Fair Head. At present, there are no connection offers in place for tidal projects. Therefore, for this report, SONI has not included any marine capacity within our adequacy studies. SONI will continue to monitor its status with a view to incorporating it into future studies.

90 https://www.seai.ie/publications/2020-Renewable-Energy-in-Ireland-Report.pdf

5.9 Plant Availability

The availability of non-renewable resources in adequacy modelling is required to reflect the possibility of generators being on forced or scheduled outage. Forced outages may be the result of unit trips, outage overruns or urgent repairs, whilst scheduled outages are those with prior approval from the EirGrid or SONI Generation Outage Planning Teams.

The statistics are derived on an all-island basis and calculated at a technology class level using 5-year capacity weighted averages of forced and scheduled outage rates for separate technology classes. Units that have retired or are forecast to retire[91] within the study horizon are excluded from the outage statistics calculation. In line with the monthly availability reporting, availability of DSUs considers a capacity-weighted availability instead of forced and scheduled outage statistics and therefore only receives an annual availability rating. Scheduled outages at battery storage units have been observed to be near 0% and therefore batteries have been excluded from scheduled outage reporting in this assessment.

The resultant statistics for the 5-year period from 2020-2024 are shown in Table 5.18 below.

Table 5.18 Summary of technology class availability statistics

Technology Category	Mean Forced Outage Probability (%)	Mean Scheduled Outage Rate (%)	Mean Scheduled Outage Duration (hours)	Annual Availability (%)
DSU	*	*	*	26.2
DSU Run Hour Limited	*	*	*	23.4
Gas Turbine	11.1	4.8	420	84.1
Hydro	13.4	5.9	520	80.7
Steam Turbine	15.9	7.6	660	76.5
Interconnector	4.5	3.8	340	91.7
Pumped Hydro Storage	2.7	5.2	450	92.1
Other Storage***	5.1	**	**	94.9
System Wide	21.1	6.1	540	72.7

* In line with the monthly availability reporting, availability of DSUs considers a capacity-weighted availability instead of forced and scheduled outage statistics.

** Scheduled outages for battery storage units were observed to be close to 0% and therefore have not been included as part of this assessment.

*** Other Storage statistics are based on one year of availability data, which will be expanded on over the coming years as more data becomes available.

91 Including Steam Turbine (B4-5,K1-2,LR4,MP1-3,TB1-4) and Gas Turbine (MRC,NW5)

5.9.1 Historic Plant Availability

This subsection provides an overview of the observed plant performance over the previous 10-year period. Based on five years of data from 2020 up to and including 2024, SONI and EirGrid have observed a further marginal downward trending of the All-Island system 5-year average availability of dispatchable generation compared with the AIRAA 2025-2034 from 77% to 76%. Whilst availability of dispatchable generation improved in 2024 relative to 2023, it was still lower than 2019, which was the year replaced in the sliding 5-year window.

As previously communicated in recent publications, plant availability has been a significant challenge in recent years in terms of managing supply and demand. From 2018 a decline in plant availability was observed, largely driven by the deteriorating performance of units which are in their final years of operation. This is in line with expectations due to aging equipment and infrastructure becoming less reliable.

The historic 5-year average availability of dispatchable generation is approximately 76%. Note the statistics used in the modelling are calculated removing units that have retired, therefore capturing the units which are expected to be operational during the study period. The approach assumes no deterioration of plant performance as the portfolio ages across the study horizon and as older units reach the end of their operational life.

The figures presented below include data pertaining to dispatchable generation including gas turbines, steam turbines, hydro and pumped storage. DSU availability is captured in a standalone figure at the end of the section.

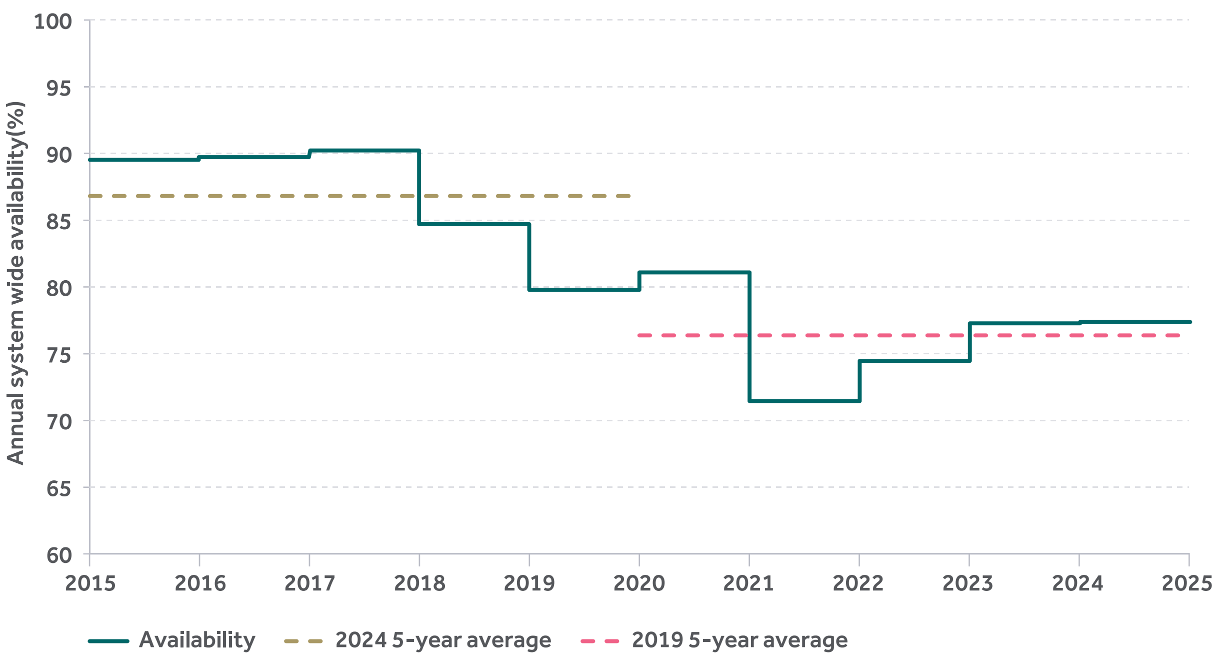


Figure 5.4 All-island average annual generation capacity availability for the past 10 years (excluding DSU)

In Ireland, the declining availability of generation is primarily driven by increased forced outage rates, whilst scheduled outage rates have remained broadly consistent as shown in Figure 5.5 below.

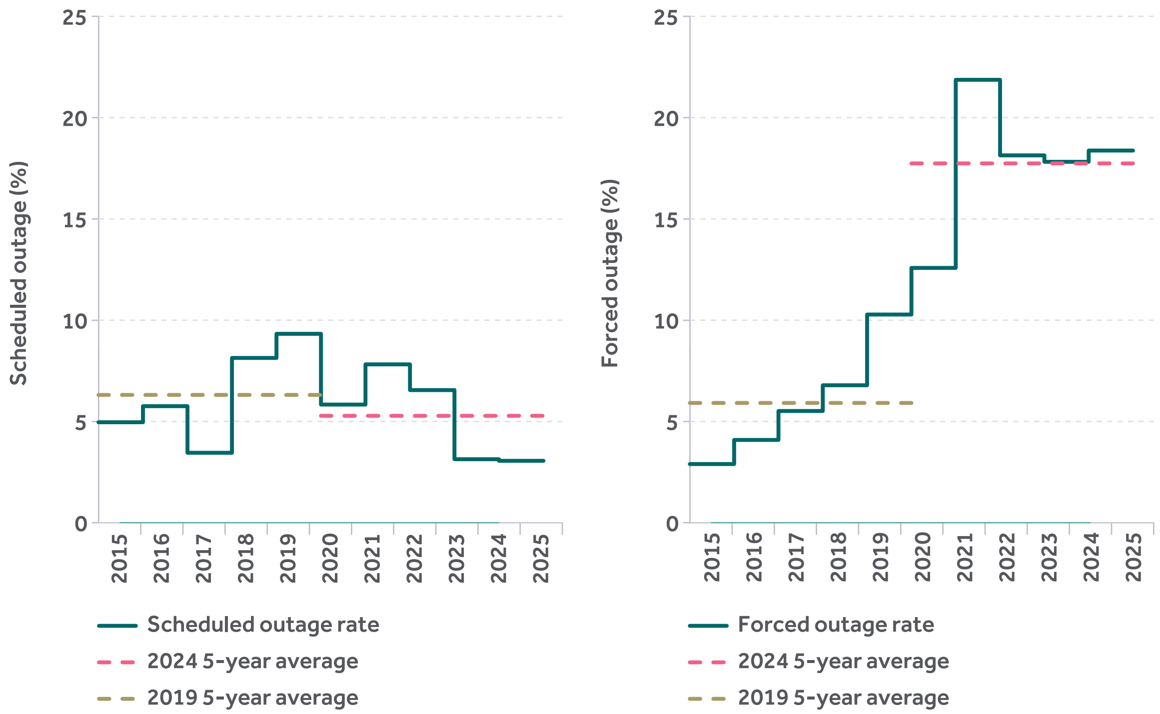


Figure 5.5 Average annual conventional generation capacity Forced and Scheduled Outage Rates in Ireland for the past 10 years

In Northern Ireland, the recent 5-year average indicates marginal increases in both forced and scheduled outage rates of generation, as shown in Figure 5.6 below.

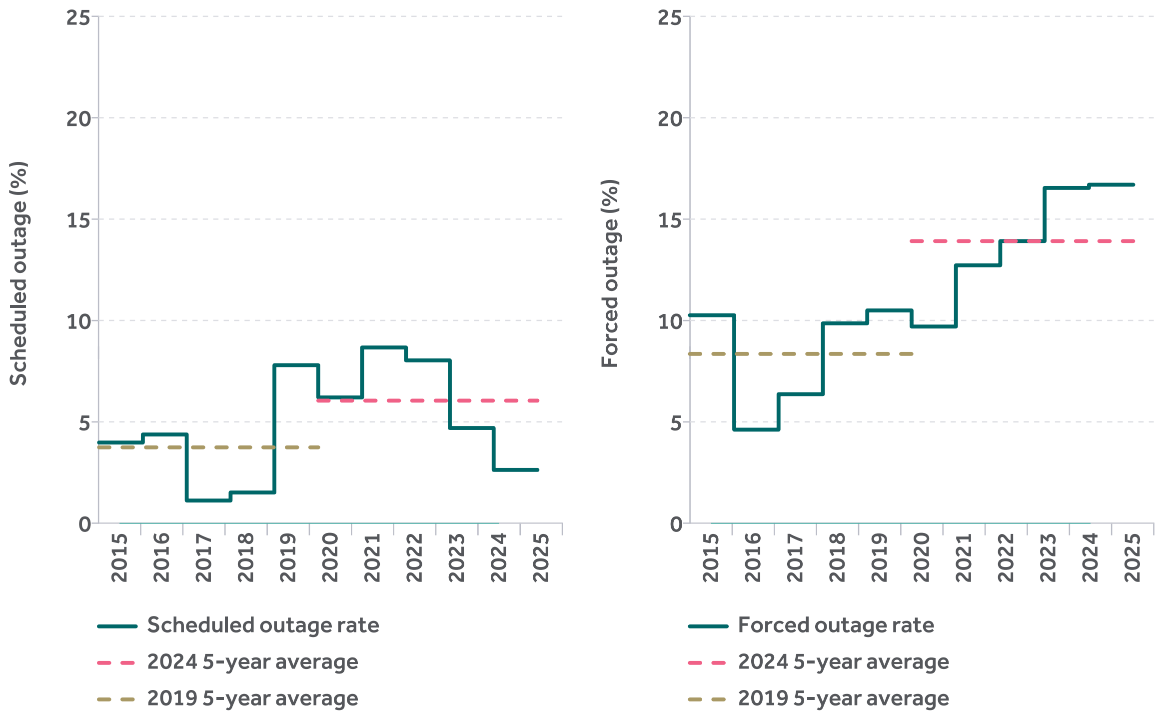


Figure 5.6 Average annual conventional generation capacity Forced and Scheduled Outage Rates in Northern Ireland for the past 10 years

The deterioration of conventional plant availability was particularly acute in Ireland during 2021, where several large units were forced offline for extended periods of time. Figure 5.7 shows the availability trends across the last 10 years for Ireland and Northern Ireland. Figure 5.7 also captures the very low availability of Ireland's thermal units in 2021, the availability was adversely impacted due to several long duration outages from several large thermal units.

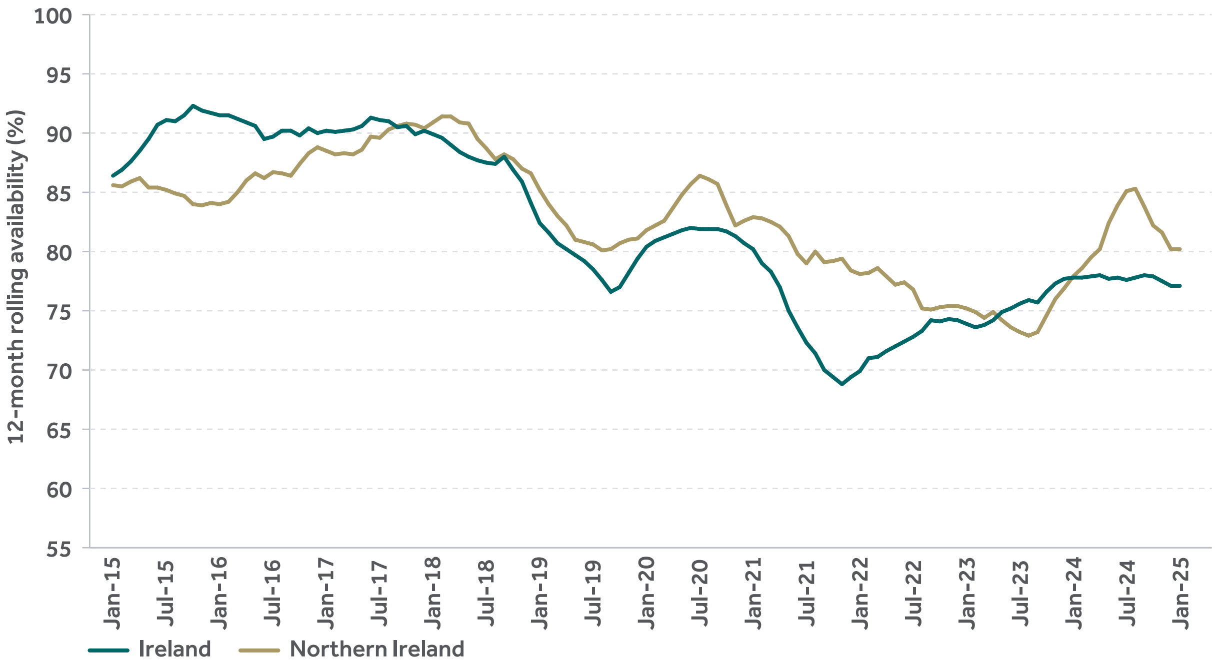


Figure 5.7 Ireland and Northern Ireland Conventional Generation Capacity Availability across the last 10 years

EirGrid and SONI have both observed a consistently low average availability of Demand Side Units on an All-Island basis, as shown in Figure 5.8 below. Demand Side Units are a significant portion of the resource portfolio in both Ireland and Northern Ireland, able to provide a net demand reduction to support system reliability. Average availability from these units has remained below expectations according to capacity contracts awarded through the capacity market auctions. Assessing the overall operational outturn availability of DSUs rather than the forced and scheduled outages is currently considered a more representative measure of their contribution to system adequacy.

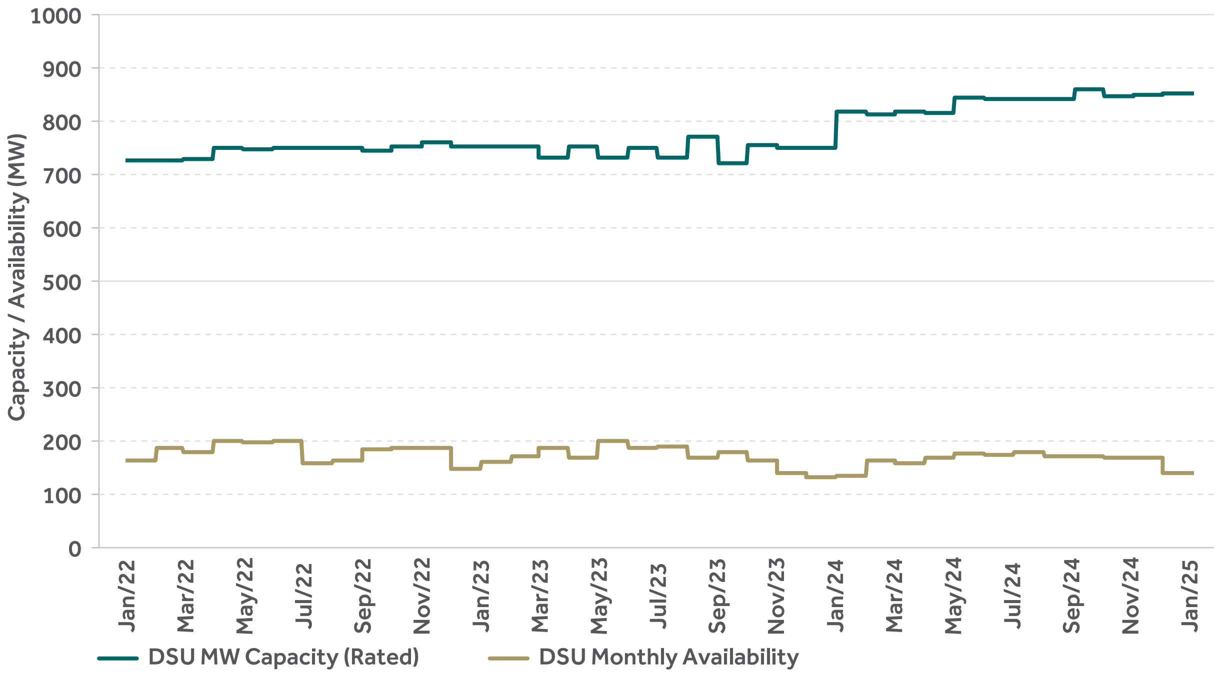


Figure 5.8 All-Island Demand Side Unit monthly availability for 2022 to 2025 calendar years

6. Adequacy

6.1 Introduction

Security of supply is a high priority for EU Member States, policy makers within DCEE and DfE, Regulatory Authorities and TSOs.

Under current EU legislation[92] there is an obligation on each Member State to monitor the security of electricity supply within their territory over the medium to long-term and each member state sets and monitors the appropriate level of security of supply for its own needs. In Ireland[93] and Northern Ireland[94], the TSOs are required to report and advise on security of supply in electricity through adequate planning and operation of transmission capacity. In Ireland, the Commission for Regulation of Utilities (CRU) is responsible for security of supply, which includes review of the methodology and this report. In Northern Ireland, the Utility Regulator (UR) will review and approve both the methodology and this report. The legislation continues to apply in Northern Ireland following the UK's departure from the European Union, as specified in Annex 4 of the Northern Ireland Protocol[95].

Generation adequacy is studied to assess the balance of supply and demand in the future. The supply and demand projections from the previous chapters are now brought together in our adequacy assessments. The AIRAA implements a National Resource Adequacy Assessment (NRAA) methodology in accordance with the requirements set out in Article 24 of European Regulation 2019/943 (Regulation on the internal market for electricity[96]), following the principles of the broader European Resource Adequacy Assessment (ERAA) as set out in Article 23.

The Reliability Standard is set as a number of hours of Loss of Load Expectation (LOLE). This is the mathematical expectation of the number of hours in the year during which the available generation plant will be inadequate to meet the instantaneous demand. At present, the generation security standard is evaluated for the All-Island SEM, as well as separately for Ireland and Northern Ireland, using the security standards in Table 6.1.

Table 6.1 LOLE Reliability Standards

Area	LOLE Reliability Standard (hours)
All-Island SEM	6.5
Ireland	3
Northern Ireland	4.9

Figure 6.1 below illustrates the process for modelling resource adequacy. The process first constructs a "Base" assessment considering factors such as power plant availability, expected delivery of new capacity, the impact of confirmed ARHL, renewable forecasts and the need to ensure there is sufficient capacity to cover system reserve requirements.

Building on the Base assessment, the additional security analysis assesses the impact of credible sensitivities that could impact the reliable operation of the power system, such as low interconnector imports, low generator availability and more challenging

92 Directive 2019/944 and Regulation (EU) 2019/941
93 Statutory Instrument 60 of 2005
94 https://www.uregni.gov.uk/files/uregni/documents/2025-08/2025-07-23%20SONI%20TSO%20Consolidated.pdf
95 Part of the Withdrawal Agreement between the UK and the EU
96 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

climate conditions. The AIRAA 2026-2035 has built on the foundations of the first AIRAA 2025-2034 additional security analysis implementation, taking account of feedback from stakeholders to improve the robustness of the process. The additional security analysis uses ACER's methodology for identifying regional electricity crisis scenarios[97] as the basis for the assessment, combining an impact and likelihood assessment to determine an overall risk rating for the various sensitivities where:

- First, the impact of each sensitivity is assessed through modelling each sensitivity to analyse a counterfactual LOLE and EENS impact relative to the Base assessment. To classify the impact of a sensitivity, the following five-step classification scale is used in evaluating the LOLE and EENS impact: Insignificant < Minor < Major < Critical < Disastrous.
- Next, the likelihood of the sensitivity is assessed where possible using historical data where available to perform a quantitative assessment, where data is not available an estimate of the likelihood may be based on qualitative assessments using expert judgment. To classify the likelihood of a sensitivity, the following six-step classification scale is used: Extremely Unlikely < Very Unlikely < Unlikely < Possible < Likely < Very Likely.
- Finally, the impact and likelihood assessment for each sensitivity are combined using a likelihood – impact matrix to derive an overall risk rating. The risk rating ranges from Low < Medium < High < Very High < Extremely High.

Information on the specific classification scale ranges and likelihood – impact matrix is available in Appendix 1 of the ACER methodology[98]. From the additional security analysis, a single sensitivity with the highest risk rating is selected to be used alongside other operational needs to derive a "Secure" assessment. Finally, further sensitivities are investigated to analyse the relative impact of varying demand, renewable, storage and flexibility trajectories on the Base and Secure positions.

The results presented include:

- LOLE / EENS – These figures include reserves and indicate the number of hours and energy for which the system may experience tight margins, possibly alerts and loss of load with results presented in hours and Gigawatt hours respectively.
- LOLE Demand Only / EENS Demand Only – These figures exclude reserves from the calculation therefore indicating the number of hours and energy for which loss of load could be at risk of occurring, with results presented in hours and Gigawatt hours respectively.
- Surplus / Deficit – These figures include reserves and indicates the capacity position relative to the Reliability Standard, where a negative value indicates additional capacity is required to achieve the standard (deficit), and a positive value indicates there is a capacity margin relative to the standard (surplus).

97 Annex I to ACER Decision 02/2024 Regional Electricity Crisis Scenarios Methodology Amendment
98 Annex I to ACER Decision 02/2024 Regional Electricity Crisis Scenarios Methodology Amendment

Step 1: Base Assessment Results

- Considers the median forecasts for demand and renewables
- Assessment of 36 weather scenarios, with 30 different outage patterns for each weather scenario
- The outputs include Base LOLE & EENS results which are aligned to ERAA results

Step 2: Additional Security Analysis

- Starting with the Base results, considers feedback received through consultation processes regarding factors which may impact on the ability to operate a reliable power system
- Sensitivity analysis of challenging operational conditions such as harsh climate conditions, levels of import and plant availability
- Each sensitivity is assessed on its LOLE and EENS impact and the likelihood of the event happening. These two variables are combined into an overall risk rating

Step 3: Secure Assessment Results

- Considers the Base assessment including a single sensitivity with the highest risk rating from Step 2 along with other operational requirements of the system that are not considered in the Base Results
- The outputs include Secure LOLE and EENS results accounting for credible adequacy challenges

Step 4: Sensitivity Studies

- Assess the influence of forecast ranges above and/or below the median forecast e.g. high and low demand forecasts
- Indicates capacity adequacy value from individual elements within the portfolio e.g. the impact of higher or lower renewable deployment rates
- The outputs indicate a MW impact which can be considered relative to the Base and Secure results

Figure 6.1 Adequacy Modelling Process Overview

6.2 Assumptions

The full range of inputs and assumptions are published separately[99] following consultation in June 2025, however for clarity the key assumptions are also identified below.

- The portfolio includes capacity which is expected to be operational in-market for each year of the study horizon. Generation capacity that has notified us that they will not be available for a given year is excluded. Additionally, the assessment includes new capacity delivery assumptions and excludes any out of market adequacy measures (the impact of out of market measures is captured in a standalone section where applicable).
- Reserves are included as an operational requirement across all study years based on the assumed Largest Single Infeed (LSI) for the synchronous area. The LSI is then considered as satisfied by Ireland and Northern Ireland using a 75%/25% requirement split. Therefore, the requirement for Ireland and Northern Ireland is 375/125 MW respectively prior to Celtic becoming the LSI in April 2028 at which point the requirement increases to 525/175 MW respectively. The Replacement Reserve requirement is the same as the Operating Reserve (OR) requirement aligned with the Commission Regulation (EU) 2017/1485[100] which establishes a guideline on electricity transmission system operation (System Operation Guideline – SOGL).
- The AIRAA 2026-2035 has transitioned to using weather scenarios aligned with the Pan-European Climate database (PECDv4.1) used in the ERAA 2024 assessment. The main difference is the previous PECD used in AIRAA 2025-2034 was based on historic climate years from 1982-2016 whereas the weather scenarios are intended to account for the effects of climate change. More information on the PECD is available in the ERAA 2024 methodology[101].

99 AIRAA 2026-2035 Inputs and Assumptions for Northern Ireland
100 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation
101 ERAA 2024 methodology

6.3 Changes Post Data Freeze Date

This section includes significant developments between the data freeze date for this assessment (30th June 2025 for the demand and generation data) and publication.

6.3.1 General

At the time of the data freeze, the 2025/2026 T-1 auction results[102] were not published and therefore have not been included in this assessment. Through this capacity auction additional contracts, approximately 38 de-rated MW of Demand Side Units and battery storage, were awarded which could have a positive contribution to adequacy in 2026. However as the quantities were relatively small these changes would not be expected to materially impact the adequacy position in either Ireland or Northern Ireland.

Northern Ireland

2025 has been a challenging year operationally due to prolonged outages of conventional generation. These outages have meant that SONI has had to rely more heavily on generation subject to Annual Run-Hour Limits (ARHL). In balancing competing security of supply concerns, there were periods when SONI were required to operate the system outside of operational constraints and several System Alert (Amber) notifications were issued to update Market Participants with respect to Northern Ireland system status.

Considering increasing Security of Supply challenges, SONI conducted analysis on the need for ARHL generation to operate in excess of permitted hours to support Security of Supply in Northern Ireland. To provide an update to Market Participants, SONI issued a Market Message[103] detailing this analysis in September 2025, which was also published by SEMO and supported by publication of a Technical addendum to SONI's Market Message[104].

In September 2025, Pollution Prevention and Control (PPC) variation notices[105] were issued increasing the ARHL on two OCGT's at Kilroot. In November 2025 subsequent variation notices[106] were issued enabling utilisation of run hours in excess of the 2,250 maximum hours, permitting a maximum hours of operation per unit in 2025 of 4,110 hours and a combined maximum operation across both units of 6,961 hours in the calendar year 2025. In calculating the five-year rolling average, the variation notice disregards any hours of operation in exceedance of 2,250 hours, up to a maximum of 1,860 hours.

Throughout 2025, SONI continued to work closely with the Department for the Economy and Utility Regulator to provide timely analysis and expertise to ensure security of supply could be maintained in Northern Ireland.

102 https://www.sem-o.com/sites/semo/files/2025-07/FCAR2526T-1.pdf
103 SONI Market Message
104 Technical addendum to SONI's Market Message
105 Variation Notice V6 23.09.2025 and Variation Notice V7 30.09.2025
106 Variation Notice V8 06.11.2025 and Variation Notice V9 12.11.2025

6.4 Ireland Adequacy Analysis

This section presents the adequacy modelling results for Ireland, including Base and Secure assessment results, sensitivity analysis and driving factors for the underlying results across the 10-year study horizon.

6.4.1 Summary

The Base and Secure assessment results are shown in Figure 6.2 and summarised below:

- From 2026 to 2028, both assessments show the system is outside of standard meaning additional capacity is required. This additional capacity will be provided by the CRU Security of Supply Programme Measures which are detailed in the section below. Throughout this period, the delivery of the new Celtic interconnector, along with new gas plant capacity improves the outlook, reducing the LOLE in both assessments.
- From 2029, the Base assessment is within standard, meaning there is sufficient capacity to operate the system under normal conditions. The Secure assessment, however, remains outside of standard indicating around 200 MW is required increasing to over 400 MW in 2034 to ensure we can continue to balance supply and demand under more challenging conditions. This additional capacity is required to provide system reserve requirements as well as facilitate network outages which are needed when we connect new generation and infrastructure to the grid.

EirGrid consider the Secure assessment is most prudent and should be considered as the central scenario for adequacy assessments, noting that capacity auctions remain the mechanism for determining specific auction requirements in the medium to long term. This assessment accounts for the impact of prolonged low renewable availability, annual run hour limits and the need to ensure there is sufficient capacity to cover operational requirements.

The central adequacy assessments are built on median forecast assumptions, with further sensitivities utilised to analyse variations in assumptions. The sensitivity analysis highlights potential adequacy concerns arising from high demand, low renewable build out, low flexibility materialising and further delays of awarded capacity.

Figure 6.2 Base and Secure Loss Of Load Expectation results for Ireland

6.4.2 Base Assessment Results

The LOLE Base results are presented in Table 6.2 below, these results can be considered for comparison against the reference scenario ERAA results[107]. When comparing against ERAA results it is also important to consider country comments which highlight any reasons for differences between results at European and national level, such as alignment of data freeze dates, which may result in different data inputs.

The LOLE Base is the average of the 36 weather scenarios with 30 outage patterns for each weather scenario therefore considering a total of 1,080 possible Monte Carlo Years for each study year. The results in Table 6.2 indicate the average number of hours per year in which there could be a risk of insufficient supply to meet demand and reserve requirements. Table 6.3 indicates the number of hours for the Base assessment in which there could be a risk of insufficient supply to meet demand after reducing reserves to the minimum operating level.

107 ERAA 2024

The LOLE Base results show Ireland is outside of the Reliability Standard from 2026 to 2028. Delays to new capacity entering the market to replace recent exit of capacity from the market and a delay to energisation of the Celtic Interconnector contribute to the tight reliability position. Note the new capacity delivery inputs are based on the enhanced monitoring programme delivery assumptions at the time of the data freeze as discussed in Section , and therefore does not consider all capacity with awarded capacity contracts being delivered on time. The impact of capacity market delivery is further considered as a sensitivity in Section 6.4.5. The adequacy position improves year on year as new capacity comes online, and Celtic becomes available in April 2028. From 2029, Ireland is within the adequacy standard for the remainder of the study horizon out to 2035.

Table 6.2 LOLE and EENS Base results for Ireland (includes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LOLE Base (hours)	71.6	43.6	7.9	1.5	0.4	0.3	0.4	0.7	0.9	1.6
EENS Base (GWh)	23.9	14.1	2.5	0.5	0.1	0.1	0.1	0.2	0.2	0.4

Table 6.3 LOLE and EENS Base Demand only results for Ireland (excludes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LOLE Base Demand Only (hours)	28.3	16.9	2.1	0.3	0.0	0.1	0.1	0.1	0.1	0.3
EENS Base Demand Only (GWh)	8.6	4.9	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.1

The All-Island Resource Adequacy Assessment Methodology[108] prescribes the process for calculating the MW Surplus/Deficit. The process is an iterative process using a subset of weather scenarios to represent the LOLE Base assessment results in Table 6.2 and adding incremental values of perfect plant or demand to reach the Reliability Standard. Selecting a subset of weather scenarios is required to reduce the complexity and computational effort required for the calculation. This assessment has selected 3 weather scenarios which, when averaged, represent the LOLE Base results. The weather scenarios selected to represent the LOLE Base results are WS04, WS28 and WS34, the resultant average LOLE of these 3 years is shown in Table 6.4 below.

108 AIRAA 2026-2035 Methodology

Table 6.4 Average LOLE of the 3 weather scenarios used in the Surplus/Deficit calculation for Ireland (includes reserves)										
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
3 weather scenario LOLE	77.0	45.6	6.7	1.6	0.4	0.4	0.5	0.6	0.8	2.0

For each of the 3 weather scenarios, the Surplus/Deficit MW value is calculated and averaged to find the MW Base value presented in Figure 6.3 below. Components on the negative y-axis represent a capacity need relative to the 3 hour Reliability Standard (deficit) and components on the positive y-axis represent a capacity margin relative to the 3 hour Reliability Standard (surplus).

Figure 6.3 indicates capacity is required to cover reserves across the years 2026 to 2028, with further capacity needed to meet demand from 2026 to 2027. The short-term options to address the deficits are presented in section 6.4.6. From 2029, the system indicates a position of capacity surplus for the Base assessment.

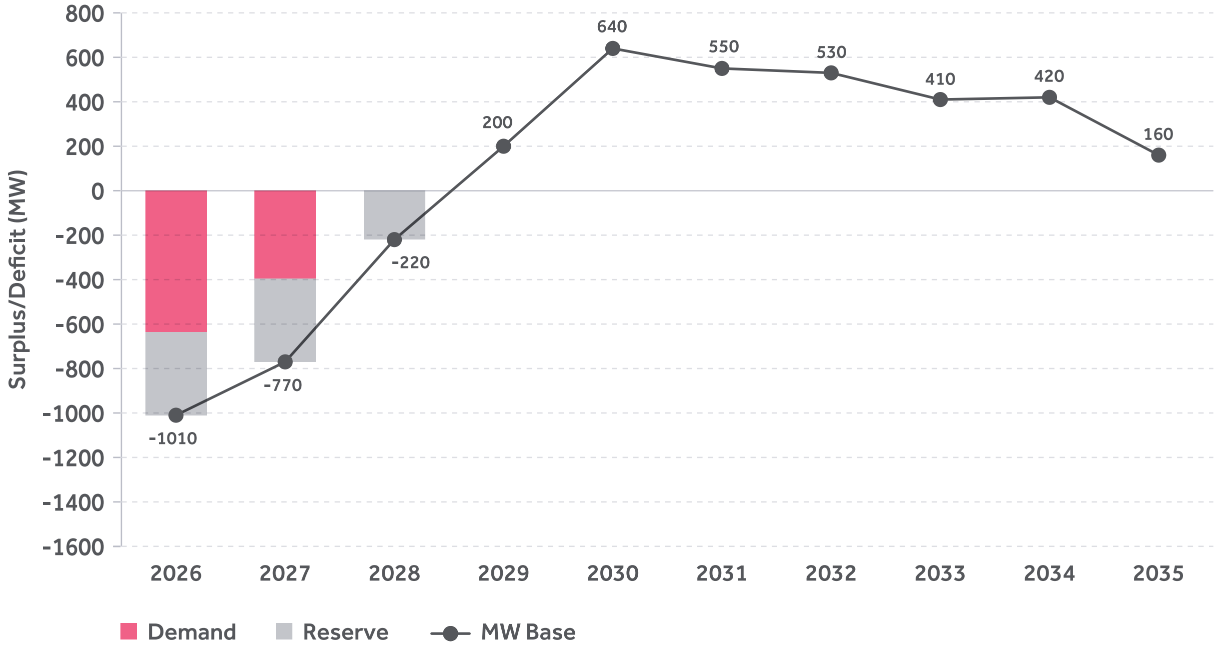


Figure 6.3 MW Base results for Ireland in terms of surplus (+) and deficit (-) of perfect plant

6.4.3 Additional Security Analysis

Through the consultation process, extensive feedback was received on the need to consider plausible events beyond average operating conditions that could materialise and their consequent impact on power system reliability. Under Article 24 of the Regulation[109], national assessments may complement the European assessment taking into account additional sensitivities.

This section seeks to address the feedback from industry and investigates the following additional security analysis sensitivities using the methodology described in Section :

- **Low French Nuclear –** Assessing the impact of removing 2 or 4 medium sized nuclear units in France. The assessment indicated a Medium risk for Ireland in the 2-unit sensitivity and a Low risk in the 4-unit sensitivity.
- **Dunkelflaute –** Assessing the impact of a 1 or 2 weeklong Dunkelflaute, implemented through assuming low wind availability across Ireland, Northern Ireland and Great Britain in December, meaning solar availability is naturally also low during the period. The assessment indicated a Medium risk for Ireland from the 1-week Dunkelflaute and a Low risk from the 2-week Dunkelflaute.
- **Low Plant Availability –** Assessing the impact of low plant availability, implemented through fixing unit level outage statistics to the highest years forced outage rates from the last 5 years. The assessment indicated a Low risk for Ireland from increased forced outage rates.
- **Interconnector Outage –** Assessing the impact of a 6-month interconnector outage, implemented through taking out a 500 MW interconnector between SEM and GB for 6 months during the winter period. The assessment indicated a Low risk for Ireland from an extended interconnector outage.

It is important to note the above sensitivities do not represent the worst-case events and instead analyse credible events in isolation. Of the sensitivities analysed, the one week Dunkelflaute presented the highest overall risk when accounting for impact and likelihood and is therefore included in the Secure assessment for Ireland.

The outcome from this analysis represents a change from AIRAA 2025-2034 which considered the risk of low imports, and this is a result of completing a more detailed analysis using the Risk Preparedness Plan[110] methodology as guidance. This analysis continues to illustrate the evolution of the new AIRAA process and will continue to be enhanced for future years to encompass feedback from stakeholders regarding the process and potential risks facing the future power system in Ireland.

109 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN
110 Annex I to ACER Decision 02/2024 Regional Electricity Crisis Scenarios Methodology Amendment

6.4.4 Secure Assessment Results

The Secure assessment accounts for the impact of a 1-week Dunkelflaute event, implemented as described in section . The Secure assessment also considers the impact of Annual Run Hour Limits (ARHL) on some new conventional units as described in section . The Secure assessment results are presented in Table 6.5 below. The Secure results follow a similar trend to the Base results where the system exceeds the Reliability Standard in the early years (2026-2030) but improves year on year as new capacity is delivered to the system. The Secure results show the system is briefly within the Reliability Standard for 2031 and 2032 but then rises above the Reliability Standard from 2032 onward as demand continues to grow.

Table 6.5 LOLE and EENS Secure results for Ireland (includes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LOLE Secure (hours)	88.5	57.0	14.6	4.1	3.1	2.8	3.0	4.1	7.1	5.4
EENS Secure (GWh)	32.1	19.5	5.6	1.3	1.0	0.9	0.9	1.2	2.6	1.8

EirGrid have dimensioned a 350 MW Transmission Outage Planning (TOP) requirement to facilitate network upgrades and reinforcements to deliver on climate ambitions in Ireland. TOPs is not included in the LOLE assessment above; however, it is included in the MW Secure calculation to reflect the overall capacity needs of the system.

To ensure consistency throughout the Surplus/Deficit calculation, the same three weather scenarios are used for the Secure assessment as the Base assessment. Figure 6.4 below shows the detailed breakdown of the MW Secure results indicating the total capacity required to operate securely, resilient to the impact of a Dunkelflaute event and ARHL on new units whilst supporting the power system through the transition towards climate action targets.

The results show the combined impact of Dunkelflaute and ARHL could increase the risk to meeting demand requirements in 2026-2027, and in other years additional capacity could be required to cover the system reserve needs and to cover TOPs. It should be noted that whilst insufficient capacity to provide TOPs may not increase adequacy risks to consumers, it may impact on the potential to facilitate network outages required to deliver on renewables and decarbonisation targets.

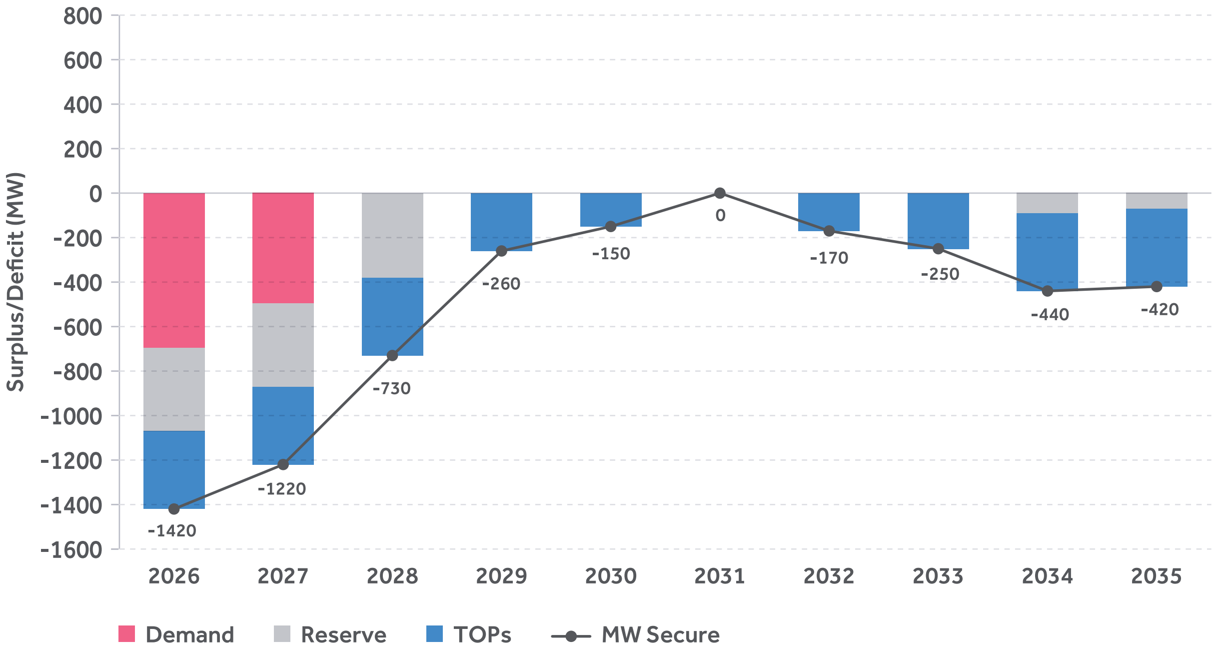


Figure 6.4 Secure Surplus/Deficit results for Ireland in terms of surplus (+) and deficit (-) of perfect plant

6.4.5 Sensitivity Studies

The Base and Secure assessments provide a view of what could be required to support Ireland's transition to a low carbon economy and a low emissions power sector; at the same time recognising there are a variety of factors which may affect the adequacy position. To this end, EirGrid has carried out several sensitivity studies on the Base assessment, and the results are shown in Figure 6.5. In constructing the specific sensitivities, feedback received through the consultation process has been used to inform the sensitivity selection.

It is important to note the sensitivities are not a final Surplus/Deficit position, but instead isolated impact assessments which should be considered relative to the MW Base and MW Secure positions described above.

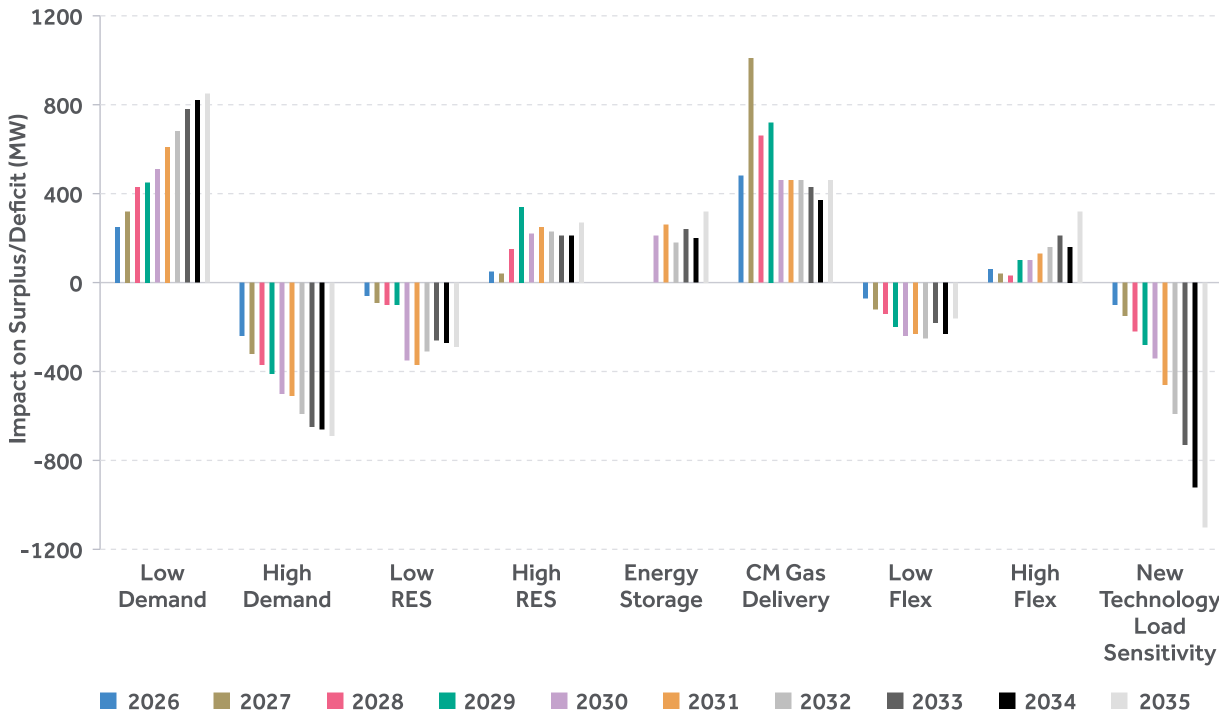


Figure 6.5 Sensitivity analysis for Ireland

The details behind each sensitivity shown in Figure 6.5 are outlined in greater detail below.

Demand

Two sensitivities have been included, analysing the Low and High Demand forecasts as presented in Section . The Low Demand sensitivity is shown to have an adequacy benefit, increasing linearly across the study horizon from 250-850 MW. The High Demand sensitivity has the inverse effect, indicating a negative adequacy impact of 240-690 MW. It is observed through this sensitivity there is a strong correlation between the forecasted low/high demand peak relative to the median peak and the adequacy position.

Capacity Market Gas Plant Delivery

This sensitivity assesses the impact of all gas capacity which has been awarded a capacity contract that has not yet been terminated, delivering on time for the year in which its contract was due to commence. For clarity, the on-time delivery date is as per the initial T-4 auction in which a capacity contract was awarded. This sensitivity reflects a larger positive impact on adequacy in the earlier part of the study horizon as capacity projects deliver earlier than in the Base assessment with an average impact of 670 MW in 2026-2030, declining to an average positive impact of 440 MW in 2031-2035.

Renewable trajectory

The Low RES sensitivity assesses the impact of a slower renewable buildout, using the low renewable deployment scenario based on the SEAI expert elicitation study. More information on the SEAI forecasts can be obtained in the SEAI Forecasts of plausible rates of generation technology deployment 2024–2040[111]. The renewable trajectory used in this sensitivity is shown in Table 6.6. The impact of a low renewable build out is most significant post 2030, with an average negative impact of around 310 MW.

Table 6.6 Low RES renewable trajectory (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Offshore Wind	30	30	30	30	30	30	400	830	980	1,010
Onshore Wind	5,390	5,600	5,810	6,020	6,200	6,490	6,790	7,100	7,360	7,610
Solar	2,220	2,620	3,030	3,430	3,840	4,220	4,600	4,980	5,370	5,440

The High RES sensitivity assesses the impact of a faster renewable buildout, using the high renewable deployment scenario based on the SEAI expert elicitation study. More information on the SEAI forecasts can be obtained in the SEAI Forecasts of plausible rates of generation technology deployment 2024 –2040[112]. The renewable trajectory used in this sensitivity is shown in Table 6.7 The impact of a high renewable build out is most significant post 2030, with an average positive impact of around 230 MW.

Table 6.7 High RES renewable trajectory (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Offshore Wind	30	30	410	1,340	3,650	4,430	5,200	6,020	6,870	7,730
Onshore Wind	6,400	6,940	7,470	8,010	8,460	9,020	9,580	10,130	10,680	11,220
Solar	4,120	5,160	6,200	7,230	8,270	9,010	9,830	10,670	11,580	12,490

111 SEAI Variable Generation Capacity Forecasts
112 SEAI Variable Generation Capacity Forecasts

Energy Storage

This sensitivity assesses the contribution of additional storage to system adequacy. It is worth noting the central adequacy assessments consider storage with capacity contracts and do not assume a further buildout beyond the latest T-4 auction. It is recognised that storage will likely play a significant role in the future resource portfolio, and this sensitivity analyses the possible benefit from an adequacy perspective. For the purpose of this sensitivity, additional battery storage represents the 3- or 4-hour duration projects. The additional storage included in this sensitivity is shown in Table 6.8 below. The average contribution to the adequacy position is 240 MW from 2030, illustrating the value additional storage can contribute.

Table 6.8 Ireland high storage additional capacity

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Capacity (MW)	0	0	0	0	650	800	800	800	800	800
Storage (MWh)	0	0	0	0	2,450	2,900	2,900	2,900	2,900	2,900

Flexibility

The Low Flex sensitivity illustrates the impact on the adequacy position if flexibility measures assumed in the demand forecasting process do not materialise. Further details on the implementation of flexibility are presented in Section . Low Flex has a negative impact on the adequacy position of 220 MW on average from 2030.

This High Flex sensitivity considers the value of dynamic power system flexibility assessing the impact of price responsive demand. This is modelled through enabling a portion of the Electric Vehicle fleet to charge at times when prices are low. This sensitivity shows increasing value from flexibility across the study horizon from a 2026-2030 average positive impact of 70 MW increasing in 2031-2035 to an average of 200 MW. At this time the sensitivity is modelled in a simple unconstrained way; it does not consider real world behavioural or system operational constraints. The sensitivity provides an early look at the potential value of more flexible within day demand shifting for electric vehicles.

New Technology Load Sensitivity

An additional demand sensitivity has been included to reflect potential growth in new data centres beyond 2030 and also investment in new energy intensive sectors. The outcome reflects the impact from the demand growth without inclusion of additional generation.
In April 2025, the CRU published a proposed decision for an LEU Connection Policy, which set out the potential requirement for new data centres connecting to the electricity network to provide dispatchable onsite generation linked to their demand growth. This is expected to address any adequacy concerns from the LEU sector.

6.4.6 Mitigating Measures

EirGrid notes that the results presented in the above scenarios do not include the mitigating measures identified as part of the CRU Security of Supply Programme; this includes delivery of temporary generation, additional demand side response and retention of existing units. The CRU published its "Electricity Security of Supply Programme of Work Update[113]" in May 2025.

As part of the programme of actions, the CRU directed EirGrid to procure Temporary Emergency Generation and Retain Existing Units (Moneypoint Units MP1, MP2 and MP3) to proactively mitigate the risks of an electricity crisis as defined by Regulation (EU) 2019/941 and the Risk Preparedness Plan (RPP) for Ireland.

As outlined in the Risk Preparedness Plan[114], published by the CRU on 31 May 2023[115], non-market based generation can only be activated by the System Operator in response to system margin concerns, when the system would otherwise be in System Alert or Emergency state, and dispatched where it is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation. As a temporary measure to prevent and mitigate an Electricity Crisis under the RPP, it is not intended to be available to meet growing and enduring demand due to social or economic growth. It will, however, provide critical insurance and will be called upon in the event of a shortfall in market-based capacity and where alerts on the system are likely. Alerts occur where the buffer between electricity supply and demand is tighter than is prudent to maintain a secure system.

Whilst these measures improve the adequacy position as shown in Figure 6.6, the measures are temporary in nature and are therefore not included in the central analysis, as otherwise it would not send a clear signal to the energy ecosystem that permanent capacity is needed. Figure 6.6 indicates the confirmed measures are sufficient to cover the shortage to Demand and Reserves, but extensions could be required to ensure operational requirements are provided in 2027 as a result of delays to delivery of new capacity.

113 Electricity_Security_of_Supply_Programme_of_Work_Update_Information_Note.pdf
114 CRU_202346_Risk_Preparedness_Plan_May_2023.PDF
115 Risk Preparedness Regulation | CRU.ie

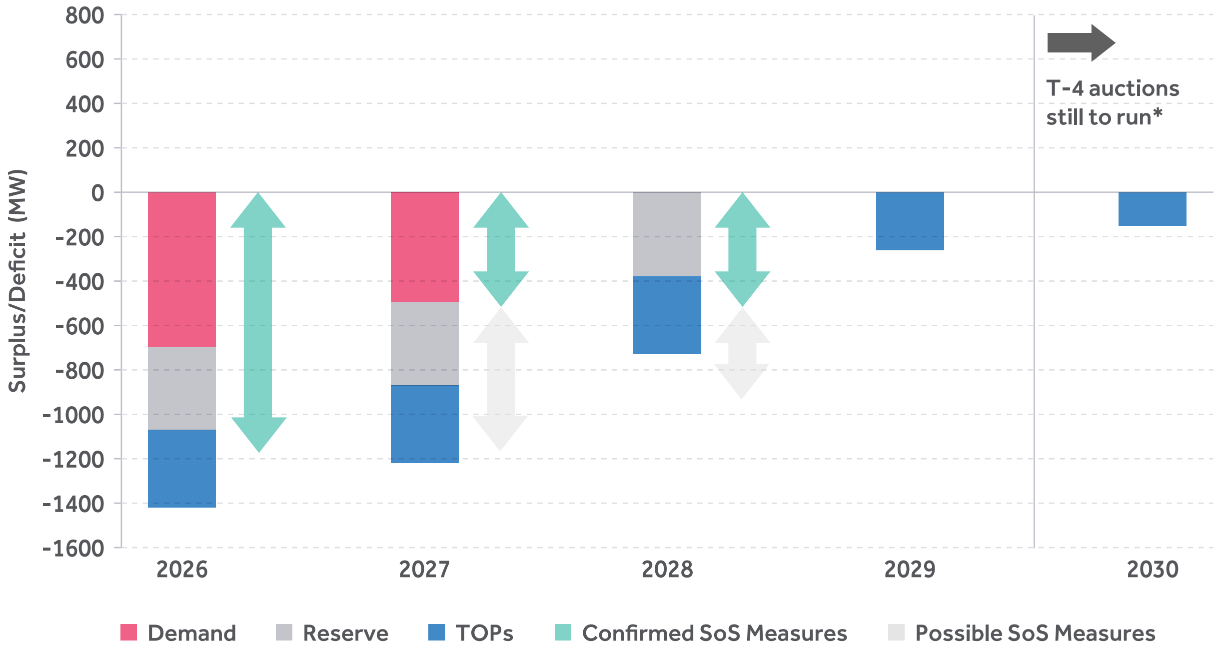


Figure 6.6 Ireland adequacy position with mitigating measures

* Note that due to freeze date for this report, capacity auctions completed post June 2025 are not included in this assessment.

6.5 Northern Ireland Adequacy Analysis

This section presents the adequacy modelling results for Northern Ireland, including Base and Secure assessment results, sensitivity analysis and driving factors for the underlying results across the 10-year study horizon.

6.5.1 Summary

The Base and Secure assessment results are shown in Figure 6.7 and summarised below:

- From 2026 to 2031, the Base assessment shows the system is within standard meaning there is sufficient capacity to operate the system under average conditions. From 2032, the Base results show the system is outside of standard and 30-120 MW of additional capacity is required to meet the reserve requirement.
- From 2026 across the full study horizon, the Secure assessment shows the system is outside of standard meaning additional capacity is required to ensure SONI can continue to balance supply and demand under more challenging conditions. The results indicate, 100-200 MW of new capacity is required from 2026 to 2032 increasing to up to 320 MW by 2035.
- In both assessments, the key reason for the increasing loss of load expectation over time is a result of increasing demand not being met with new reliable capacity.
- Sensitivity analysis has been included, the key outcome of which shows that removal of the Annual Run Hour Limits on the KGT6 and KGT7 units has the largest positive impact on security of supply in Northern Ireland, resulting in both Base and Secure assessments being within the Reliability Standard.

SONI considers the Secure assessment is most prudent and should be considered as the central scenario for adequacy assessments, noting that capacity auctions remain the mechanism for determining specific auction requirements. The Secure assessment accounts for a large unit outage, and the need to ensure there is sufficient capacity to cover operational requirements.

The central adequacy assessments are built on median forecast assumptions, with further sensitivities utilised to analyse variations in assumptions. The sensitivity analysis highlights adequacy concerns arising from high demand, low renewable build out, low flexibility and low run hour availability

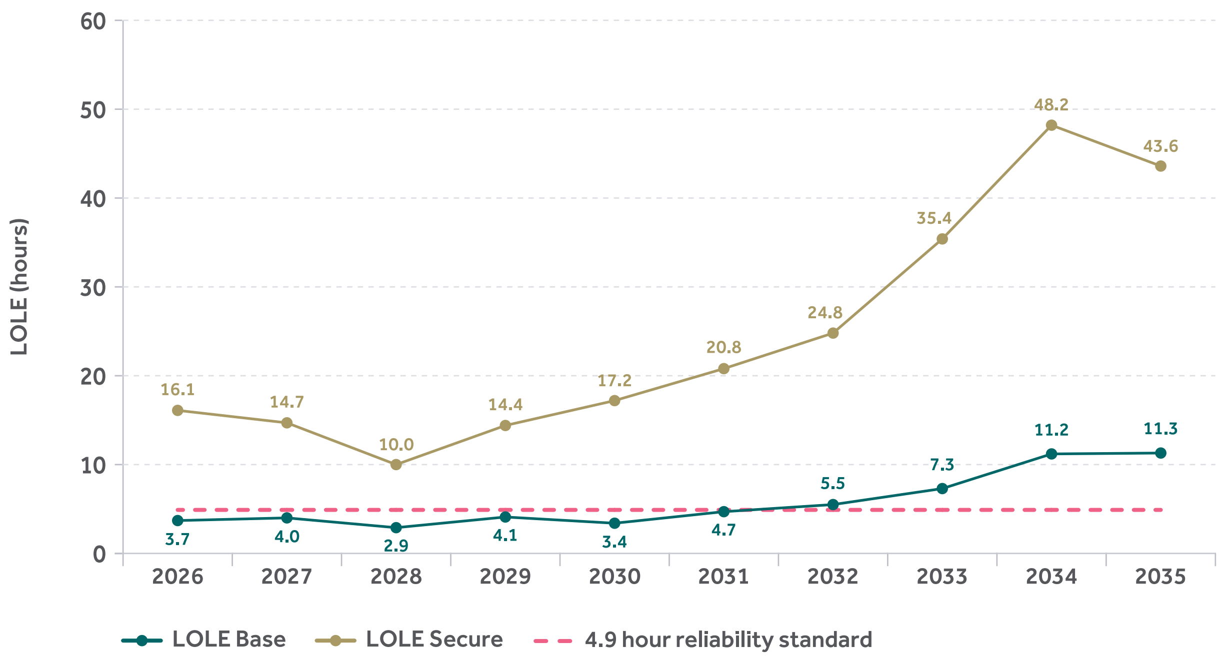


Figure 6.7 Base and Secure Loss Of Load Expectation results for Northern Ireland

6.5.2 Base Assessment Results

The LOLE Base results are presented in Table 6.9 below, these results can be considered for comparison against the reference scenario ERAA results[116]. When comparing against ERAA results it is also important to consider country comments which highlight any reasons for differences between results at European and national level, such as alignment of data freeze dates which may result in different data inputs.

The LOLE Base is the average of the 36 weather scenarios with 30 outage patterns simulated for each weather scenario therefore considering a total of 1,080 possible Monte Carlo years for each study year. The results in Table 6.9 indicate the average number of hours in which there could be a risk of insufficient supply to meet demand and reserve requirements. Table 6.10 indicates the number of hours for the Base assessment in which reserves have been reduced to the minimum operating level.

In general, the LOLE results for Northern Ireland increase across the study horizon, due to demand increasing with the electrification of heat and transport. However, there are notable reductions in 2028 when the full import capacity is assumed to be available on Moyle and Celtic arrives in Ireland (discussed in Section) and in 2030 when Ireland is observed to transition into a position of capacity surplus. The slower renewable capacity trajectory relative to AIRAA 2025-2034 means LOLE in the later years increases at a steeper rate. In 2035 the LOLE increase is tempered as 500 MW of offshore capacity becomes available.

Table 6.9 LOLE and EENS Base results for Northern Ireland (includes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LOLE Base (hours)	3.7	4.0	2.9	4.1	3.4	4.7	5.5	7.3	11.2	11.3
EENS Base (GWh)	0.5	0.5	0.3	0.5	0.4	0.5	0.6	1.0	1.4	1.6

Table 6.10 LOLE and EENS Base Demand Only results for Northern Ireland (excludes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LOLE Base Demand Only (hours)	1.5	1.7	0.8	1.2	0.9	1.3	1.4	2.2	3.5	4.0
EENS Base Demand Only (GWh)	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.5

116 ENTSO-E ERAA 2024

The All-Island Resource Adequacy Assessment Methodology[117] prescribes the process for calculating the MW Surplus/Deficit. The process is an iterative process using a subset of weather scenarios to represent the LOLE Base assessment results in Table 6.9 and adding incremental values of perfect plant or demand to reach the Reliability Standard. Selecting a subset of weather scenarios is required to reduce the complexity and computational effort required for the calculation. This assessment has selected 3 weather scenarios which when averaged represent the LOLE Base results. The weather scenarios selected to represent the LOLE Base results are WS04, WS28 and WS34, the resultant average LOLE of these 3 years is shown in Table 6.11 below.

Table 6.11 Average LOLE of the 3 weather scenarios used in the Surplus/Deficit calculation for Northern Ireland (includes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
3 weather scenario LOLE	4.2	4.9	2.6	4.0	3.9	4.6	6.4	8.7	13.1	12.7

For each of the 3 weather scenarios, the Surplus/Deficit MW value is calculated and averaged to find the MW Base value presented in Figure 6.8 below. Components on the negative y-axis represents a capacity need relative to the 4.9 hour Reliability Standard (deficit) and components on the positive y-axis represent a capacity margin relative to the 4.9 hour Reliability Standard (surplus).

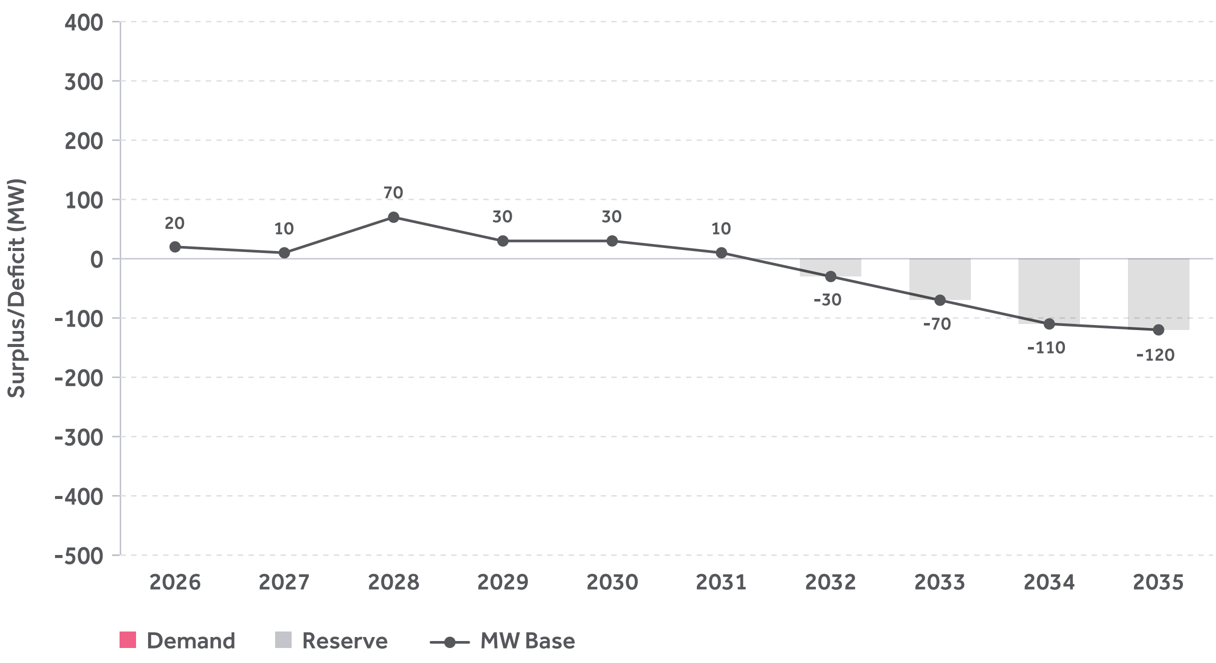


Figure 6.8 MW Base results for Northern Ireland in terms of surplus (+) and deficit (-) of perfect plant

117 AIRAA 2026-2035 Methodology

6.5.3 Additional Security Analysis

Through the consultation process, extensive feedback was received on the need to consider plausible events beyond average operating conditions that could materialise and their consequent impact on power system reliability. Under Article 24 of the Regulation[118], national assessments may compliment the European assessment taking into account additional sensitivities.

This section seeks to address the feedback from industry and investigates the following additional security analysis sensitivities using the methodology described in Section :

- **Low French Nuclear –** Assessing the impact of removing 2 or 4 medium sized nuclear units in France. The assessment indicated a Medium risk for Northern Ireland in the 2-unit sensitivity and a Low risk in the 4-unit sensitivity.
- **Dunkelflaute –** Assessing the impact of a 1 or 2 weeklong Dunkelflaute, implemented through assuming low wind availability across Ireland, Northern Ireland and Great Britain. The assessment indicated a Low risk for Northern Ireland for both durations of Dunkelflaute considered.
- **Large Unit Outage –** Assessing the impact of a prolonged outage of the largest generator in Northern Ireland (C30), where the outage period occurs over winter from December through to February. The assessment indicated a High risk for Northern Ireland.
- **Interconnector Outage –** Assessing the impact of a 6-month interconnector outage, implemented through taking out an interconnector between Ireland and GB for 6 months during the winter period. The assessment indicated a Low risk for Northern Ireland.

It is important to note the above sensitivities do not represent the worst-case events and instead analyse credible events in isolation. Of the sensitivities analysed, the Large Unit Outage sensitivity presented the highest overall risk when accounting for impact and likelihood and is therefore included in the Secure assessment for Northern Ireland.

The outcome from this analysis represents a change from AIRAA 2025-2034 which considered the risk of low imports, and this is a result of completing a more detailed analysis using the Risk Preparedness Plan[119] methodology as guidance. This analysis continues to illustrate the evolution of the new AIRAA process and will continue to be enhanced for future years to encompass feedback from stakeholders regarding the process and potential risks facing the future power system in Northern Ireland.

118 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN
119 Annex I to ACER Decision 02/2024 Regional Electricity Crisis Scenarios Methodology Amendment

6.5.4 Secure assessment Results

The Secure assessment for Northern Ireland accounts for the impact of a prolonged outage of a large unit, and the results are presented in Table 6.12 below. The Secure results indicate under these conditions the system could exceed the 4.9 hour Reliability Standard from 2026 onwards.

Table 6.12 LOLE and EENS Secure results for Northern Ireland (includes reserves)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LOLE Secure (hours)	16.1	14.7	10	14.4	17.2	20.8	24.8	35.4	48.2	43.6
EENS Secure (GWh)	2.2	2.0	1.3	1.8	2.2	2.6	3.2	5.0	7.2	6.5

To ensure consistency throughout the Surplus/Deficit calculation the same 3 weather scenarios are used for the MW Secure analysis as the MW Base analysis. Figure 6.9 below shows the detailed breakdown of the MW Secure results indicating the total capacity required to operate the system securely, to manage the impact of a large unit outage and be able to support the power system through the transition towards climate targets. The results show the impact of a large unit outage means additional capacity is required to cover the system reserve needs across the study horizon and in some years a risk to meeting demand requirements.

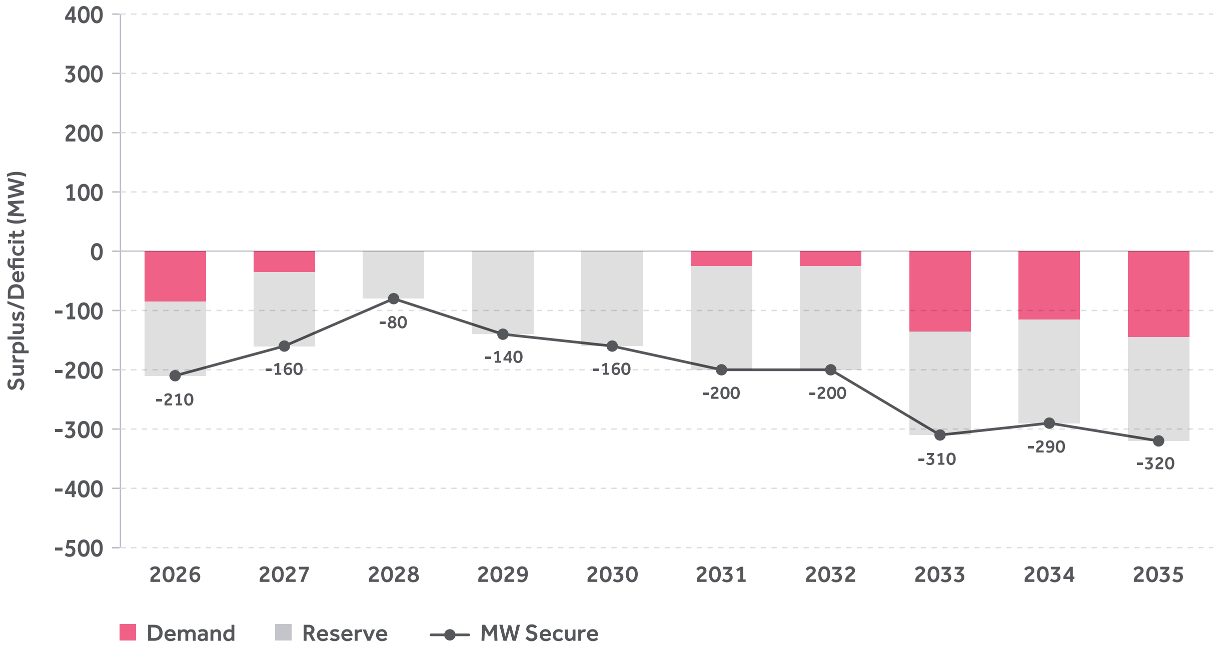


Figure 6.9 MW Secure results for Northern Ireland in terms of surplus (+) and deficit (-) of perfect plant

6.5.5 Sensitivity Studies

The Base and Secure assessments provide a view of how the dynamics of the energy system are likely to evolve over the coming decade, as Northern Ireland transitions to more low carbon technologies and increasing penetration from renewable resources. To this end, SONI has carried out several sensitivity studies on the Base assessment, and the results are shown in Figure 6.10. In constructing the specific sensitivities, SONI has incorporated stakeholder feedback received through the consultation process for this project.

It is important to note the sensitivities are not a final Surplus/Deficit position, but instead isolated impact assessments which should be considered relative to the MW Base and Secure positions described above.

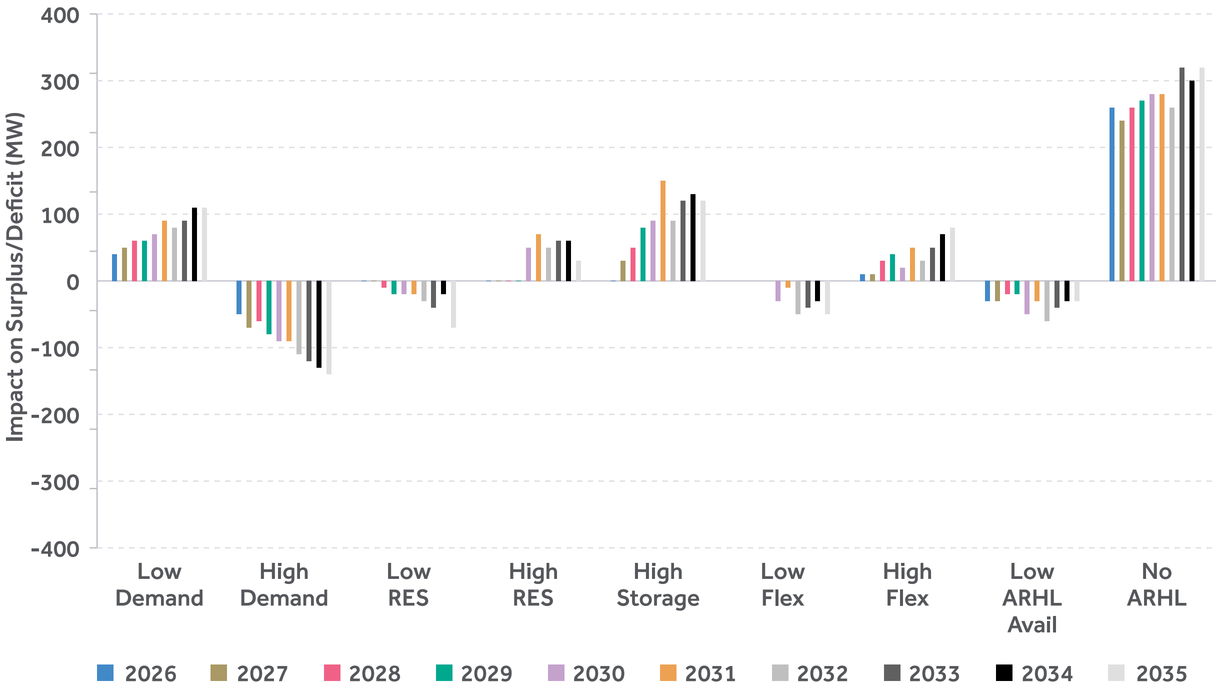


Figure 6.10 Sensitivity analysis for Northern Ireland

The specific details behind each sensitivity are outlined in greater detail below.

Demand

Two sensitivities have been included, analysing the Low and High Demand forecasts as presented in Section . The Low Demand sensitivity is shown to have a positive impact on adequacy across the study horizon, increasing linearly across the study horizon from 40MW in 2026 up to 110 MW in 2035. The High Demand sensitivity has the inverse effect, indicating an increasingly negative impact on adequacy across the study horizon ranging from 50 MW in 2026 up to 140 MW in 2035. It is observed through this sensitivity there is a strong correlation between the forecasted low/high demand peak relative to the median peak and the adequacy position.

Annual Run Hour Limits (ARHL)

Two sensitivities have been included, one analysing the positive impact of no run hour limits on the KGT6 and KGT7 units and a second sensitivity analysing the impact of limited available run hours. The No ARHL sensitivity has a large positive impact on adequacy of approximately 250-300 MW across the study horizon, which would result in Northern Ireland operating within the Reliability Standard in both Base the Secure assessment.

The AIRAA methodology permits two Operating Hour Limit categories, 1,500 and 500 hours. The central assessments model units based on a 1,500 Operating Hour Limit, and the Low ARHL Avail sensitivity assumes the 500 Operating Hour Limit. The Low ARHL Avail indicates a negative impact on adequacy of approximately 50 MW on average across the study horizon, resulting in the Base assessment being outside of the Reliability Standard across all years except 2028 and 2029 and the Secure assessment moving further outside of the Reliability Standard across the full horizon. Note the purpose of the Low ARHL Avail sensitivity is to illustrate the impact of reduced availability of ARHL plant in any given year and does not consider actual used or remaining run hours on specific units.

Renewable trajectory

Two sensitivities have been included, analysing the impact of a higher and lower renewable capacity trajectory relative to the median trajectory. The low renewable trajectory used in this sensitivity is shown in Table 6.13. The impact of a low renewable buildout is most significant post 2030, showing a negative impact on adequacy of approximately 40 MW.

Table 6.13 Northern Ireland low renewable trajectory (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Offshore Wind	0	0	0	0	0	0	0	0	0	0
Onshore Wind	1,395	1,425	1,465	1,540	1,615	1,690	1,765	1,840	1,915	1,990
Solar	260	275	300	330	365	400	435	470	505	540

The high renewable buildout assumes delivery of 1 GW of offshore wind from 2030, aligned to DfE's ambition for offshore wind as per the Northern Ireland Energy Strategy along with increased onshore capacity. The renewable trajectory used in this sensitivity is shown in Table 6.14. The increase in renewable energy has a positive impact on adequacy from 2030 (when the offshore comes in) of approximately 50 MW.

Table 6.14 Northern Ireland high renewable trajectory (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Offshore Wind	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000
Onshore Wind	1,420	1,490	1,590	1,780	1,970	2,160	2,340	2,530	2,720	2,910
Solar	280	310	380	450	540	630	710	800	890	980

Energy Storage

This sensitivity assesses the contribution of additional storage to system adequacy. It is worth noting the central adequacy assessments consider storage with capacity contracts and do not assume a further buildout beyond the latest T-4 auction. It is recognised that storage will likely play a significant role in the future resource portfolio, and this sensitivity analyses the possible benefit from an adequacy perspective. For the purpose of this sensitivity, additional projects have been included which have entered SONI's connection process (some have accepted offers and some are still at application stage). The additional storage included in this sensitivity is shown in Table 6.15 below. The average contribution to the adequacy position is 60 MW up to 2030 and 120 MW after 2030, illustrating the value additional storage can contribute.

Table 6.15 Northern Ireland high storage additional capacity

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Capacity (MW)	0	100	150	280	530	720	720	720	720	720
Storage (MWh)	0	200	250	500	950	1,420	1,420	1,420	1,420	1,420

Flexibility

The Low Flex sensitivity illustrates the impact on the adequacy position if flexibility measures assumed in the demand forecasting process do not materialise. Further details on the implementation of flexibility are presented in Section . Low Flex has a negative impact on the adequacy position of 40 MW on average from 2030.

The High Flex sensitivity considers the value of dynamic power system flexibility assessing the impact of price responsive demand. This is modelled through enabling a portion of the Electric Vehicle fleet to charge at times when prices are low. This sensitivity shows increasing value from flexibility across the study horizon from a 2026-2030 average positive impact of 20 MW, increasing in 2031-2035 to an average of 60 MW. At this time the sensitivity is modelled in a simple unconstrained way; it does not consider real world behavioural or system operational constraints. The sensitivity provides an early look at the potential value of more flexible within day demand shifting for electric vehicles.

6.6 All-Island Adequacy Analysis

All-Island Adequacy studies are completed assuming the second North-South Interconnector is operational from October 2031. The analysis includes two scenarios, first using the Base assessment configuration and then using the Secure assessment which includes the impact of a 1-week Dunkelflaute event. The additional security analysis process from the jurisdictional assessments above identified a one-week Dunkelflaute as a risk for Ireland and a large unit outage as a risk for Northern Ireland. The analysis was not completed specifically for the purpose of the All-Island assessment, as such the one-week Dunkelflaute was selected for the Secure assessment as it is modelled as low wind across the SEM and therefore most relevant to the island as a whole. Note, future iterations may extend the additional security analysis approach to incorporate All-Island specific security analysis.

The result for the All-Island position is relative to the 6.5 hour Reliability Standard for the SEM. The All-Island assessment shows an improvement in security of supply for both jurisdictions, relative to individual jurisdictional results, as the physical restriction on power transfer is relaxed. Prior to the completion of the second North-South Interconnector project, the existing tie line between the two regions creates a physical constraint affecting the level of support that can be provided between jurisdictions.

In the All-Island case, the surplus for any particular year is greater than the sum of the two separate jurisdictional studies as each jurisdiction is better able to support the other during times of system stress. Additionally, the SEM Reliability Standard is more relaxed than jurisdictional Reliability Standards for Ireland and Northern Ireland which also results in an improved position.

The Base assessment results are shown in Table 6.16 indicating the SEM is within the 6.5 hour Reliability Standard for all years.

Table 6.16 Base results for the All-Island system				
	2032	2033	2034	2035
LOLE Base (hours)	0.2	0.1	0.3	0.4
EENS Base (GWh)	0.0	0.0	0.1	0.1
MW Base	1,010	1,020	1,020	8,30

The Secure assessment includes the impact of a 1-week Dunkelflaute event, and the results are shown in Table 6.17. Both assessments indicate the SEM is within the 6.5 hour Reliability Standard for all years. Note TOPs is not included in the LOLE Secure calculation; however, it is included in the MW Secure calculation to reflect the overall capacity needs of the system as described in Section . The inclusion of TOPs results in MW Secure calculation means that while the LOLE results are within standard there is a in a small deficit in 2034.

Table 6.17 Secure results for the All-Island system				
	2032	2033	2034	2035
LOLE Secure (hours)	1.2	1.4	4.0	2.6
EENS Secure (GWh)	0.0	0.2	1.1	0.3
MW Secure	360	340	-30	80

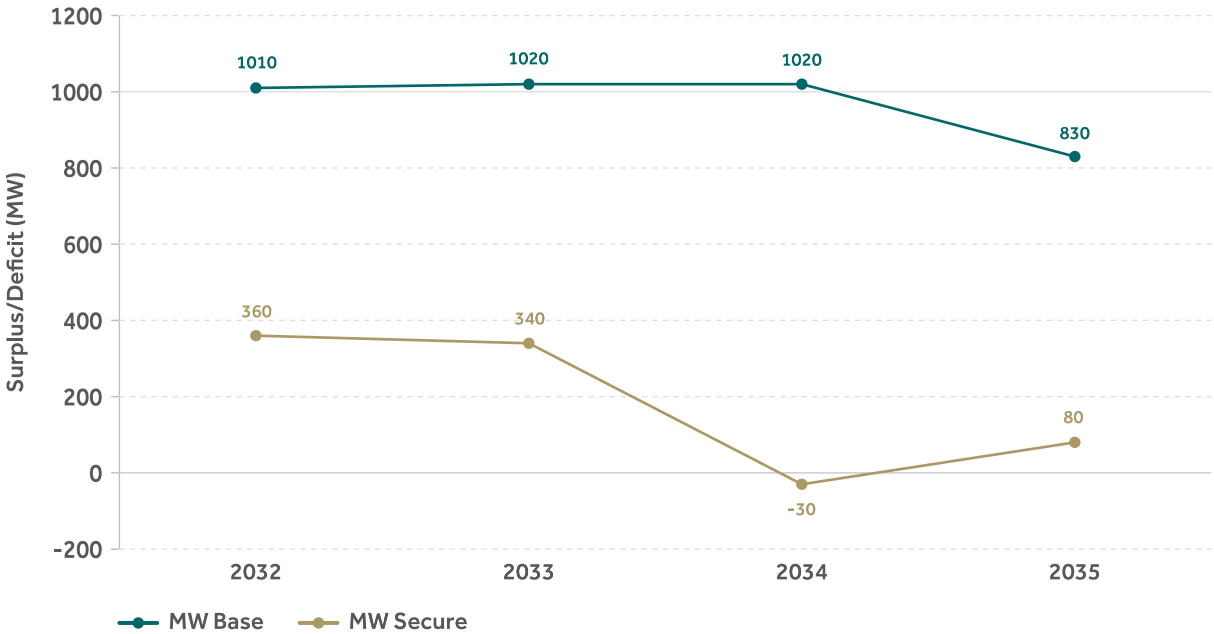
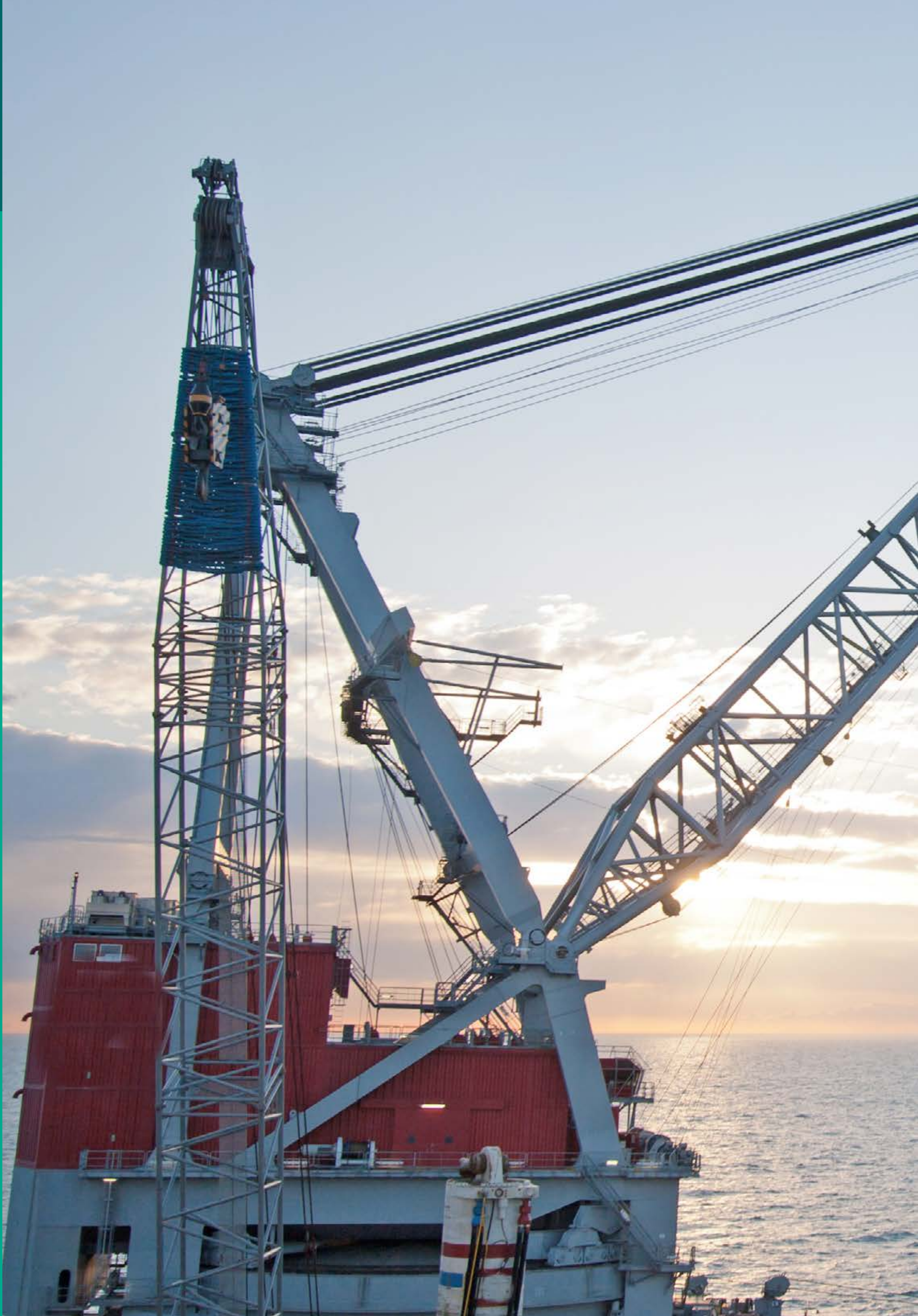


Figure 6.11 MW results for the All-Island in terms of surplus (+) and deficit (-) of perfect plant



Appendix 1: Economic Viability Assessment

An Economic Viability Assessment (EVA) is used to assess the viability of capacity resources in the energy-only electricity market, providing analysis as to whether units may be economically viable or whether they may observe missing money[120], and as such could signal a need for additional revenue streams such as through capacity mechanisms. Under Article 24 of EU Regulation 2019/943[121], an assessment of the economic viability of capacity resources is required as part of a National Resource Adequacy Assessment.

It is important to note the EVA is not a forecast of market outcomes or investor decisions, and therefore the process outputs should be interpreted with caution. It is acknowledged that the factors included in this EVA represent a simplification, and do not capture the range of uncertainties which would be assessed by prospective market entrants. The process is a standalone piece of analysis looking at specific scenarios and has no influence or implications with respect to the SEM capacity auction processes.

SONI and EirGrid are introducing this EVA for the first time in this report, as part of a phased pathway towards full incorporation into the central adequacy assessment for AIRAA 2027-2036. The focus of this year's initial EVA is to introduce the new EVA process and demonstrate the working of the process under a range of scenarios. The inaugural EVA is intended to provide a basis for further engagement and consultation such that the central adequacy assessment performed in the AIRAA 2027-2036 report aligns with the requirements set out in Article 24 of EU Regulation 2019/943.

The development of an EVA has included a full public consultation, a public webinar, engagements with industry stakeholders, and workshops with other European TSOs also conducting EVA analysis.

120 Missing money occurs when a resource's revenues from the (energy-only) electricity market is not sufficient to cover the resource's costs.
121 EU Regulation 2019/943

A1.1 Process

The EVA process implements an iterative revenue-based methodology by simulating the electricity market revenues through an economic dispatch model and comparing against costs to assess whether a unit is economically viable. The process for the revenue-based EVA process is shown below in Figure A1.1 and summarised below:

1. Starting scenario: The starting scenario for the EVA is the Base assessment from the adequacy study with median demand, renewable trajectories and capacity forecasts. The starting scenario aims to approximate day-ahead market and therefore excludes reserves and North South flow constraints.

2. Economic dispatch for the EVA: An economic dispatch is modelled for all study years for one representative weather scenario[122] which for this year's assessment is weather scenario 34. During this stage, units which are Annual Run Hour Limited will be tracked to ensure they do not operate above the limit.

3. Assess economic viability of units: The economic viability is assessed by comparing the cashflows of revenues (inframarginal rent and ancillary service revenue) against costs (capital and fixed expenditure). The process assesses the viability of existing units and potential viability of new units such as new OCGTs, CCGTs, and BESS. Note, units are only assessed for years in which they do not have a capacity market contract, units which hold a contract are assumed to be viable. At the time of the data freeze the latest auction was the 2028/2029 T-4, as such the viability of units in the absence of capacity revenue has commenced from 2030.

4. Adjust capacities based on economic viability: Units have three potential statuses: online, offline, or mothballed — the economic viability of all units will be calculated for all statuses. The economic viability of units is assessed through calculating the Net Present Value (NPV) of the cashflows for all potential statuses. Units are assessed in each iteration, and their status is updated to the most economically viable status[123]. For example, if the NPV of a unit is more economically viable when the candidate is mothballed for 2 years rather than online or offline, the candidate is mothballed for 2 years.

5. Iterate until convergence: The process is repeated until convergence is achieved such that all units reach their most economically viable status i.e. there are no units online which are unviable and vice versa.

6. Final EVA portfolio: Once convergence is reached, this is the final post-EVA portfolio.

122 One representative weather scenario is deemed appropriate for the first year of implementing the EVA, in future the implementation may extend to using more weather scenarios to capture the impact of climate variability on revenues. The representative weather scenario was selected as the one with LOLE values closest to the 36 weather scenario average, future EVA iterations may expand selection to analyse revenues also.

123 Units with the highest difference in NPV between two statuses is adjusted first.

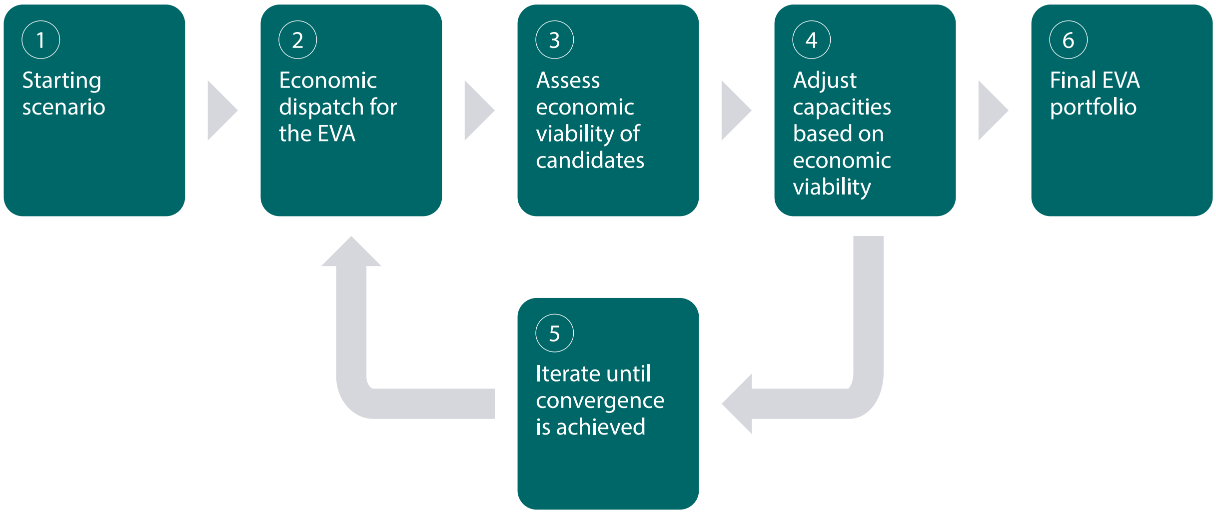
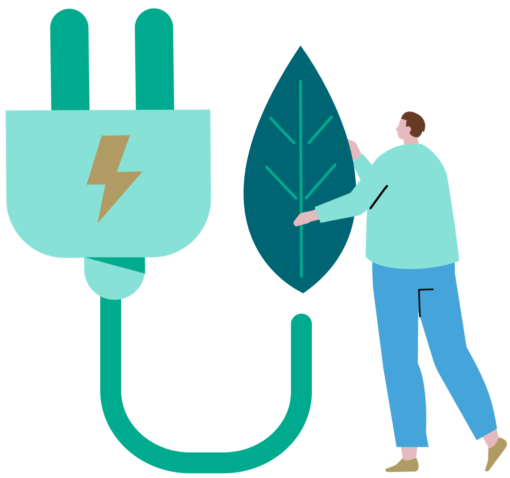


Figure A1.1 Revenue-based EVA process



A1.2 Considerations

It has already been outlined in previous sections that the EVA represents a simplified view of economic viability, and Table A1.1 below has been included to outline a number of key points for consideration when interpreting the EVA scenarios and results. Specific data and assumptions applicable to the assessment are available in the published Inputs and Assumptions[124] document.

Table A1.1 EVA considerations

Number	Comment
1	The EVA does not model system operational or transmission constraints (e.g. inertia, must-run, SNSP, transmission), which may misrepresent actual revenue potential for some units.
2	The EVA adopts a simplified view of costs and revenues which do not take into account all considerations taken as part of a financial assessment for a project. Therefore, the EVA outputs simplify "viability" and do not aim to predict how investors would make decisions.
3	The model is limited to a 10-year horizon and therefore modelling of costs and revenues beyond 2035 has not been conducted, instead values from the last modelled year are retained for the remainder of the unit's lifetime.
4	The EVA outcome relies heavily on inputs which are uncertain, including fuel prices, technology costs, renewable trajectory, demand trajectory and changes in neighbouring regions (e.g. Great Britain and France).
5	The EVA does not model future capacity market auctions. This assumption is to provide a perspective on viability without capacity market support and is not a comment on the likelihood of future capacity auctions or capacity requirements.
6	Renewable capacities are not included in the EVA as they are assumed to be driven by policy support schemes.
7	The entry and exit of Demand Side Units (DSU) has not been considered due to lack of data regarding costs and other inputs.
8	A single weather scenario (WS) has been selected as a representative WS; in reality, the outturn climate conditions could have a material effect on the viability of units for a given study year.
9	The source used for the cost assumptions is the SEMC BNE study, which may be outdated and may underestimate actual costs. Additionally, the categories used are for CCGTs and OCGTs and these are not broken down by the age of the unit or specific types of CCGTs and OCGTs.

124 AIRAA 2026-2035 Inputs and Assumptions for Northern Ireland

A1.3 Scenarios

Five scenarios have been explored to illustrate the impact of various revenue and cost inputs and assumptions in the economic viability assessment. The five scenarios summarised in Table A1.2 below have been developed as a result of the consultation process and stakeholder engagement. Scenarios 1, 2, 3, and 5 provide alternative assessments of revenues and scenario 4 analyses a reduction in the costs of BESS.

Table A1.2 Economic Viability Assessment (EVA) summary of scenarios

Scenario	Implementation	Rationale
S1 - With scarcity pricing	The price cap in the economic dispatch has been fixed to the values used in ERAA 2024.	Assessment price cap assumption aligned with ERAA 2024.
S2 - Without scarcity pricing	Prices in the economic dispatch are capped at 500 €/MWh.	Consultation feedback that historic SEM prices have rarely exceed 500 €/MWh, otherwise aligned with Scenario 1.
S3 – Energy only revenue	Only energy revenues are included as part of the assessment.	Consultation feedback that there is uncertainty regarding future ancillary service revenue, otherwise aligned with Scenario 1.
S4 - Low battery costs	Battery capex and opex is 30% lower, with the economic lifetime of batteries increased from 10 to 20 years.	Assess impact of lower storage costs and test ability of EVA process to commission new resources, otherwise aligned with Scenario 1.
S5 – Without scarcity pricing & energy only revenue	Revenues from the economic dispatch are capped at 500 €/MWh, only energy revenues are included, and the highest revenue monte carlo sample from each weather scenario is excluded.	A look at "stacking" multiple aspects of consultation feedback including S2, S3.

A1.4 Results

The EVA process indicates across all scenarios there is a significant volume of units which are unviable in the absence of capacity market revenues i.e. units have a negative NPV. Units which are unviable are excluded from the portfolio for the adequacy assessment and therefore the adequacy assessment indicates a worsening of the overall adequacy position as there is less capacity in the overall portfolio.

It is important to note the multi-scenario analysis does not seek to reflect the likelihood of any of the scenarios becoming reality and instead provides an assessment of resource viability in the absence of capacity revenues for a varying set of input assumptions to demonstrate the process.

Economic Viability Results

The model indicates that across all scenarios, there is an amount of capacity which is unviable and is therefore classed as offline. The units which are deemed to be offline first is usually determined by their position in the merit order. The analysis indicates units which are towards the end of the merit order, such as peaking units, are the first to experience negative NPV followed by some OCGTs, as these units have lower run hours and are less able to obtain sufficient inframarginal rent in the day ahead market. There are limited new units brought online across the scenarios, with no gas turbines brought online and only one scenario (S4 – where battery costs are assumed to decrease) indicates a possibility of new entry of battery capacity resources.

The magnitude of the capacity changes can be seen in Figure A1.2. The capacity values in the chart are in a rated capacity basis with the capacity differences compared to the pre-EVA starting portfolio. Values above zero represent new units coming online and values below zero represent capacity changes from online to offline.

Adequacy Results

A range of scenarios are presented in Section , to illustrate the impact on portfolio changes for a range of inputs. This year the assessment has focussed primarily on establishing the viability assessment process; in future assessments the analysis will be further expanded to incorporate a post-EVA adequacy assessment. As a general observation, if the capacity deemed unviable from the scenarios explored in this assessment was not made available to the generation portfolio in the SEM, this would have a significant impact on adequacy results.

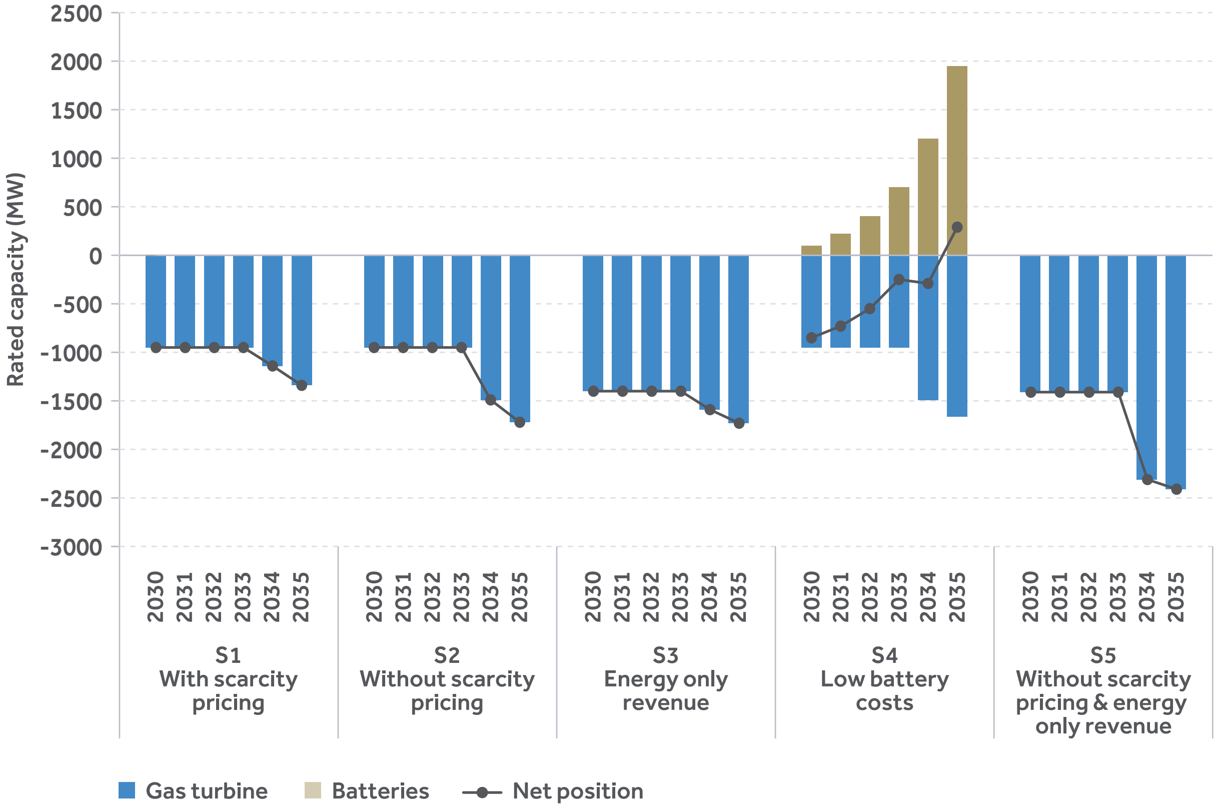


Figure A1.2 Economic Viability Assessment (EVA) rated capacity changes compared to the central adequacy scenario

A1.5 Conclusion

The Economic Viability Assessment presented in this section is a significant step in terms of establishing a new process. Wide ranging feedback was received through extensive consultation with industry, regulators and other Transmission System Operators and whilst the process incorporates some of the key feedback, the process will be developed going into AIRAA 2027-2036 at which point the output from the EVA will be accounted for in the central adequacy assessment.

EirGrid and SONI would therefore welcome further proactive engagement from all stakeholders to refine the process and gather appropriate inputs to inform future assessments, ensuring the unique characteristics of the SEM are represented accordingly.

Appendix 2: Demand Scenarios

The Demand Forecast, given in Calendar year format for Total Electricity Requirement (TER). TER is the total electricity required by the region, i.e., it includes all electricity produced by large-scale, dispatchable generators, all small-scale exporting generators, and an estimate of electricity produced by self-consuming generators. Historic values are corrected for temperature.

Table A2.1 Demand forecast for the Median scenario in calendar year format for Ireland and Northern Ireland

Median	Calendar Year TER (TWh)						TER peak (GW)			Transmission peak (GW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
	TER	% growth	TER	% growth	TER	% growth						
2024	35.2	3.8%	8.2	0.6%	43.4	3.2%	6.02	1.66	7.63	5.91	1.61	7.48
2025	37.2	5.7%	8.2	0.4%	45.4	4.7%	6.16	1.63	7.76	6.04	1.59	7.61
2026	39.0	4.8%	8.3	1.3%	47.3	4.1%	6.29	1.65	7.92	6.17	1.61	7.76
2027	40.6	4.2%	8.5	2.4%	49.1	3.9%	6.42	1.69	8.09	6.31	1.65	7.94
2028	41.9	3.3%	8.7	2.4%	50.6	3.2%	6.55	1.73	8.24	6.43	1.69	8.09
2029	43.3	3.1%	8.9	2.6%	52.2	3.1%	6.67	1.76	8.40	6.56	1.72	8.25
2030	44.6	3.0%	9.2	2.6%	53.7	2.9%	6.79	1.79	8.52	6.68	1.75	8.37
2031	45.7	2.6%	9.5	3.5%	55.2	2.8%	6.90	1.85	8.68	6.79	1.81	8.53
2032	46.8	2.3%	9.8	3.3%	56.6	2.5%	6.99	1.90	8.81	6.88	1.86	8.66
2033	47.7	2.0%	10.1	3.1%	57.8	2.2%	7.07	1.96	8.92	6.96	1.92	8.77
2034	48.5	1.7%	10.4	2.9%	58.9	1.9%	7.14	2.01	9.01	7.03	1.97	8.86
2035	49.2	1.4%	10.7	2.8%	59.9	1.7%	7.19	2.07	9.12	7.08	2.03	8.97

Table A2.2 Demand forecast for the Low scenario in calendar year format for Ireland and Northern Ireland

Low	Calendar Year TER (TWh)						TER peak (GW)			Transmission peak (GW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
	TER	% growth	TER	% growth	TER	% growth						
2024	35.2	3.8%	8.2	0.6%	43.4	3.2%	6.02	1.66	7.63	5.91	1.61	7.48
2025	36.5	3.8%	8.0	-2.6%	44.5	2.6%	5.98	1.58	7.61	5.87	1.54	7.46
2026	37.3	2.2%	8.0	0.9%	45.3	1.9%	6.00	1.60	7.64	5.89	1.56	7.49
2027	38.1	2.1%	8.2	1.9%	46.2	2.0%	6.05	1.63	7.72	5.93	1.59	7.56
2028	38.7	1.7%	8.3	1.9%	47.0	1.7%	6.09	1.65	7.78	5.98	1.61	7.63
2029	39.4	1.6%	8.5	1.9%	47.8	1.7%	6.14	1.68	7.85	6.03	1.64	7.70
2030	40.0	1.6%	8.6	1.9%	48.6	1.7%	6.17	1.71	7.92	6.06	1.67	7.77
2031	40.6	1.4%	8.9	2.7%	49.4	1.6%	6.21	1.75	7.97	6.10	1.71	7.82
2032	41.1	1.2%	9.1	2.5%	50.1	1.5%	6.24	1.80	8.03	6.13	1.76	7.88
2033	41.5	1.2%	9.3	2.5%	50.8	1.4%	6.27	1.85	8.09	6.16	1.81	7.94
2034	42.0	1.1%	9.6	2.5%	51.5	1.3%	6.30	1.89	8.14	6.19	1.85	7.99
2035	42.4	1.0%	9.8	2.3%	52.2	1.3%	6.32	1.94	8.20	6.21	1.90	8.05

Table A2.3 Demand forecast for the High scenario in calendar year format for Ireland and Northern Ireland

High	Calendar Year TER (TWh)						TER peak (GW)			Transmission peak (GW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
	TER	% growth	TER	% growth	TER	% growth						
2024	35.2	3.8%	8.2	0.6%	43.4	3.2%	6.02	1.66	7.63	5.91	1.61	7.48
2025	37.7	7.1%	8.6	4.8%	46.3	6.7%	6.27	1.70	7.90	6.15	1.66	7.75
2026	40.4	7.2%	8.7	1.8%	49.1	6.2%	6.51	1.73	8.18	6.40	1.69	8.03
2027	42.9	6.1%	9.0	2.9%	51.8	5.5%	6.74	1.78	8.45	6.62	1.74	8.30
2028	44.9	4.7%	9.2	2.8%	54.1	4.3%	6.94	1.82	8.70	6.83	1.78	8.55
2029	46.8	4.3%	9.5	3.3%	56.3	4.1%	7.14	1.86	8.92	7.03	1.82	8.77
2030	48.6	3.8%	9.8	3.2%	58.4	3.7%	7.31	1.90	9.11	7.20	1.86	8.96
2031	50.0	3.0%	10.2	4.1%	60.2	3.2%	7.45	1.97	9.28	7.34	1.93	9.13
2032	51.3	2.5%	10.6	3.9%	61.9	2.8%	7.58	2.03	9.44	7.47	1.99	9.30
2033	52.3	2.0%	11.0	3.5%	63.3	2.3%	7.67	2.10	9.58	7.56	2.06	9.44
2034	53.2	1.6%	11.3	3.3%	64.5	1.9%	7.75	2.17	9.72	7.64	2.13	9.57
2035	53.9	1.4%	11.7	3.3%	65.6	1.7%	7.82	2.23	9.83	7.71	2.19	9.68

Appendix 3: Generation Plant Information

Ireland

Table A3.1 Registered capacity of dispatchable generation and interconnectors in Ireland in 2026 (MW)

	ID	Fuel Type	Technology Category	2026	Comment
Aghada	AT1	Gas/DO	Gas Turbine	90	
	AT2	Gas/DO	Gas Turbine	90	
	AT4	Gas/DO	Gas Turbine	90	
	AD2	Gas/DO	Gas Turbine	449	
All DSU	DSU	DSU	DSU	760	
Ardnacrusha	AA1-4	Hydro	Hydro	86	
Battery	Battery	Battery	Other Storage	850	
Dublin Bay	DB1	Gas/DO	Gas Turbine	415	ILC refurbishment Jun to Oct 2026
Dublin Waste	DW1	Waste	Steam Turbine	61	
Edenderry	ED1	Milled peat/ Biomass	Steam Turbine	118	
	ED3	DO/Gas	Gas Turbine	58	
	ED5	DO/Gas	Gas Turbine	58	
Erne	ER1-4	Hydro	Hydro	65	
EWIC	EW1		DC Interconnector	500	
FlexGen	Ringsend	Gas/Multi Fuel	Gas Turbine	64	Newly operational as of Q4 2024
	Poolbeg	Gas/Multi Fuel	Gas Turbine	64	Newly operational as of Q4 2024
	Coruff	Gas/Multi Fuel	Gas Turbine	64	Newly operational as of Q4 2024
Great Island CCGT	GI4	Gas/DO	Gas Turbine	464	
Greenlink	GLK		DC Interconnector	500	
Huntstown	HNC	Gas/DO	Gas Turbine	337	ILC refurbishment Mar to Jul 2028
	HN2	Gas/DO	Gas Turbine	408	ILC refurbishment Jul to Oct 2028
Indaver Waste	IW1	Waste	Steam Turbine	17	
Lee	LE1-4	Hydro	Hydro	27	

Table A3.1 Registered capacity of dispatchable generation and interconnectors in Ireland in 2026 (MW)					
	ID	**Fuel Type**	**Technology Category**	**2026**	**Comment**
Liffey	LI1-4	Hydro	Hydro	38	
Poolbeg CC	PBA	Gas/DO	Gas Turbine	234	
	PBB		Gas Turbine	234	
Rhode	RP1	DO	Gas Turbine	52	
	RP2	DO	Gas Turbine	52	
Sealrock	SK3	Gas/DO	Gas Turbine	81	
	SK4	Gas/DO	Gas Turbine	81	
Tawnaghmore	TP1	DO	Gas Turbine	52	
	TP3	DO	Gas Turbine	52	
Turlough Hill	TH1/2	Pumped storage	Storage	292	ILC refurbishment Feb to Oct 2027
Tynagh	TYC	Gas/DO	Gas Turbine	389	ILC refurbishment May to Jul 2027
Whitegate	WG1	Gas/DO	Gas Turbine	450	ILC refurbishment Mar to May 2027
Total:				**7,642**	

Table A3.2 Partially/non-dispatchable plant in Ireland (MW)										
At year end:	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Wind Onshore	5,740	6,070	6,440	6,810	7,130	7,530	7,940	8,350	8,770	9,180
Wind Offshore	30	30	30	30	1,350	1,950	2,520	3,120	3,730	4,480
Solar PV	3,260	4,010	4,770	5,520	6,280	6,880	7,480	8,060	8,640	9,220
Small Scale Hydro	26	26	26	26	26	26	26	26	26	26
Biomass and Biogas	24	24	24	24	24	24	24	24	24	24
Biomass CHP	30	30	30	30	30	30	30	30	30	30
Industrial	9	9	9	9	9	9	9	9	9	9
Conventional CHP	130	130	130	130	130	130	130	130	130	130
Total	**9,249**	**10,329**	**11,459**	**12,579**	**14,979**	**16,579**	**18,159**	**19,749**	**21,359**	**23,099**

Northern Ireland

Table A3.3 Registered capacity of dispatchable generation and interconnectors in Northern Ireland in 2026 (MW)					
	ID	**Fuel Type**	**Technology Category**	**2026**	**Comment**
Ballylumford	B31	Gas/Heavy Fuel Oil	Gas Turbine	246	
	B32	Gas/Heavy Fuel Oil	Gas Turbine	246	
	B10	Gas/Heavy Fuel Oil	Gas Turbine	101	
	GT7(GT1)	Distillate Oil	Gas Turbine	58	
	GT8(GT2)	Distillate Oil	Gas Turbine	58	
Kilroot	KGT1	Distillate Oil	Gas Turbine	29	
	KGT2	Distillate Oil	Gas Turbine	29	
	KGT3	Distillate Oil	Gas Turbine	42	
	KGT4	Distillate Oil	Gas Turbine	42	
	KGT6	Gas	Gas Turbine	350	
	KGT7	Gas	Gas Turbine	350	
Coolkeeragh	GT8	Distillate Oil	Gas Turbine	53	
	C30	Gas/Distillate Oil	Gas Turbine	408	
AGU	AGU	Distillate Oil	Gas Turbine	79	
CMN	CMN	Distillate Oil	Gas Turbine	20	
DSU	DSU	Various	DSU	189	
Battery	Battery	Battery	Other Storage	212	
Lisahally		Biomass		18	Not in Capacity Market, but assumed available for capacity requirement
Moyle		DC Interconnector		450	Assumed to increase to 500 MW in 2028
Total:				**2,980**	

Table A3.4 Partially/non-dispatchable plant in Northern Ireland (MW)										
At year end:	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Onshore Wind	1,230	1,290	1,370	1,520	1,670	1,820	1,970	2,120	2,270	2,420
Offshore Wind	0	0	0	0	0	0	0	0	0	500
Small Scale Wind	180	180	180	180	180	180	180	180	180	180
Solar PV	270	300	350	410	480	550	620	690	760	830
Small Scale Biogas	24	24	24	24	24	24	24	24	24	24
Landfill Gas	16	16	16	16	16	16	16	16	16	16
Small Scale Biomass	6	6	6	6	6	6	6	6	6	6
Renewable CHP	3	3	3	3	3	3	3	3	3	3
Other CHP	6	6	6	6	6	6	6	6	6	6
Small Scale Hydro	6	6	6	6	6	6	6	6	6	6
Waste-to-Energy	15	15	15	15	15	15	15	15	15	15
Total	**1,756**	**1,846**	**1,976**	**2,186**	**2,406**	**2,626**	**2,846**	**3,066**	**3,286**	**4,006**

Table A3.5 All renewable energy sources in Northern Ireland (MW)										
At year end:	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
All Wind	1,410	1,470	1,550	1,700	1,850	2,000	2,150	2,300	2,450	3,100
Solar PV	270	300	350	410	480	550	620	690	760	830
All Biomass/Biogas/ LFGas/WTE	46	46	46	46	46	46	46	46	46	46
Renewable CHP	3	3	3	3	3	3	3	3	3	3
Hydro	6	6	6	6	6	6	6	6	6	6
Total RES	**1,735**	**1,825**	**1,955**	**2,165**	**2,385**	**2,605**	**2,825**	**3,045**	**3,265**	**3,985**

Appendix 4: Value of Lost Load

The Value of Lost Load (VoLL) is becoming more and more important in current TSO's activities, especially regarding the generation adequacy issue. The VoLL can be used within capacity mechanisms and the cost-benefit analysis of system investments.

The VoLL is the monetary damage arising from the non-supply of a given amount of energy (in MWh for instance) due to a power outage. Costs can be significant as they imply the interruption of productive processes for industry and businesses or the reduction of leisure activities. VoLL can vary per country depending on how much each country values the factors which affect the cost of lost load.

The time of lost load is also significant. A power interruption during the night for 5 minutes does not have the same consequences as if it occurs during the peak hours for one hour. There is not a unique VoLL which can be applied for all types of outages. The VoLL should be fine-tuned to precisely consider interruptions characteristics and then real costs caused by an outage.

For defining generation adequacy standard, the VoLL should be assessed during peak hours only and should consider a several-hours pre-notification time.

The existing Reliability Standard is for an average LOLE. Two parameters feed into this Reliability Standard – the Net Cost of New Entry (CoNE) and the Value of Lost Load (VoLL). In Ireland the Reliability Standard is 3hr and in Northern Ireland the Reliability Standard is 4.9 hours.

In the SEM market, the VoLL and Net CoNE are set for each SEM Capacity Market which is used to calculate the value of contracts awarded to winning generators in each auction.

In essence, VoLL estimates the cost of not having enough supply to serve the load, while CoNE evaluates the cost of having over-supply. In order to find the optimal balance between supply and demand, we can use VoLL and CoNE to define the most appropriate Reliability Standard.

The most efficient number of hours of outage to allow (Reliability Standard) is a function of the Value of Lost Load (VoLL) and the fixed and variable costs of a peaker (Cost of New Entry (CoNE)).

The answer to the question "How many hours of lost load should I allow?" is derived from a straightforward cost analysis: In theory, load should be unserved in hours when the cost of serving it would exceed VoLL[125]. Put algebraically, outage makes sense as long as

VoLL * Reliability Standard < CoNE

For example:

VoLL ~ [Cost of CoNE] / [Reliability Standard] = [€80,000/MW year] / [8 hours / year] = €10,000 /MWh

125 http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Hunt_Making_Competition_Work.pdf

Figure A4.1 shows the point at which this balance point is found – marked by X between both graphs.

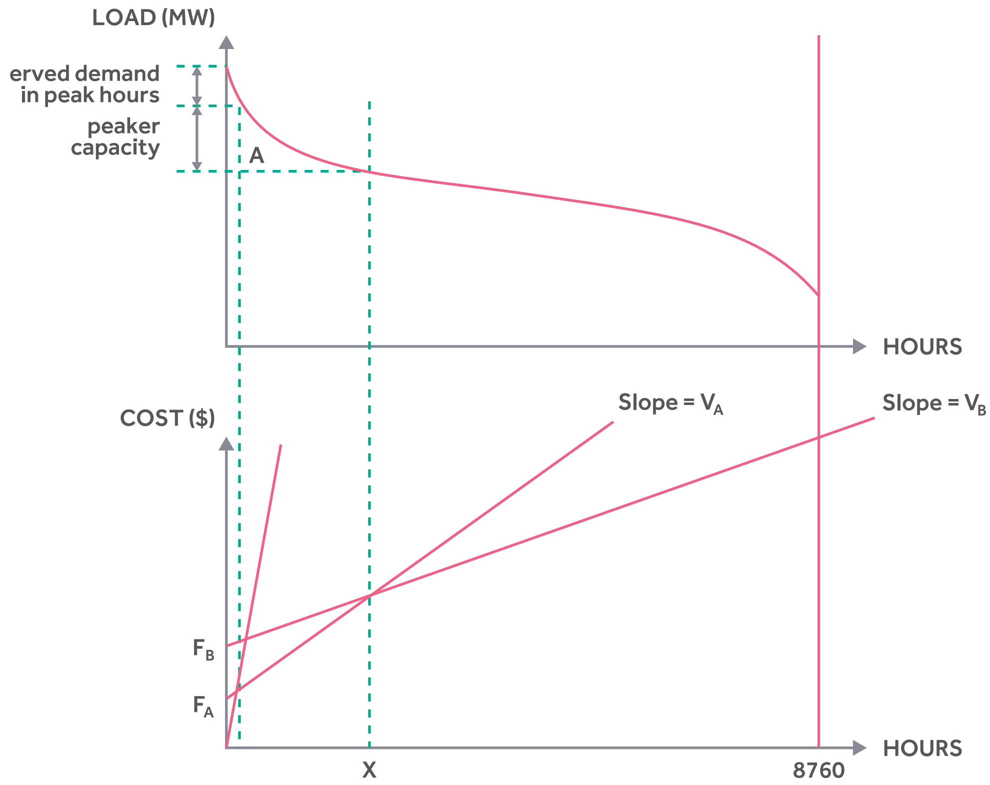


Figure A4.1 – Balance point between the costs of a new entrant (CoNE) to meet demand versus the cost impact of not meeting demand (VoLL) for a certain LOLE[126]

126 http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Hunt_Making_Competition_Work.pdf

Appendix 5: Glossary of Terms

Acronym/ Abbreviation	Term	Explanation
ACS	Average Cold Spell	Average Cold Spell (ACS) correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences.
AGU	Aggregated Generator Unit	A number of individual generators grouping together to make available their combined capacity.
ALF	Annual Load Factor	The ALF is the average load divided by the peak load. E.g. if TER=54900 GWh, Peak = 8.64 GW $ALF=\frac{54900/8760}{8.64}=73\%$ where 8760 = number of hours per year = 24*365.
CF	Capacity Factor	$\text{Capacity Factor} = \frac{\text{Energy Output}}{\text{Hours per year * Installed Capacity}}$
CEP	Clean Energy Package	EU Commission package of measures to facilitate the clean energy transition. The EU has committed to cut CO2 emissions by at least 40% by 2030 while modernising the EU's economy.
CCGT	Combined Cycle Gas Turbine	A type of thermal generator that typically uses natural gas as a fuel source. It is a collection of gas turbines and steam units; where waste heat from the gas turbines(s) is passed through a heat recovery boiler to generate steam for the steam turbines.
CHP	Combined Heat and Power	A highly efficient process that captures and utilises the heat that is a by-product of the electricity generation process.
	Demand	The amount of electrical power that is consumed by a customer and is measured in megawatts (MW). In a general sense, the amount of power that must be transported from generation stations to meet all customers' electricity requirements. This includes any losses (line or transformer).
DSU	Demand Side Unit	A Demand Side Unit (DSU) consists of one or more Individual Demand Sites that can be dispatched by the Transmission System Operator (TSO) as if it was a generator.
	Dispatchable Generation	Sources of electricity that can be used on demand and dispatched at the request of power grid operators, according to market needs. Does not include wind and solar generation which are non-dispatchable generation.
	EU-SysFlex	Aiming to achieve a pan-European system with an efficient coordinated use of flexibilities for the integration of a large share of renewable energy sources. EU-SysFlex will come up with new types of services that will meet the needs of the system with more than 50% of renewable energy sources.

Acronym/ Abbreviation	Term	Explanation
ECP	Enduring Connection Policy	A process to provide connection offers to facilitate 2 GW of renewable generation in Ireland.
EMDF	External Market De-Rating Factor	De-rating applied to interconnectors to external markets.
ENTSO-E	European Network of Transmission System Operators – Electricity	ENTSO-E, the European Network of Transmission System Operators, represents 43 electricity transmission system operators from 36 countries across Europe.
ESB Networks	Electricity Supply Board: Networks	ESB Networks is a business unit within ESB Group which carries out ESB Networks DAC's functions as Distribution System Operation in addition to the functions of ESB as the licensed Transmission Asset Owner (TAO) and Distribution Asset Owner (DAO) for Ireland
ESRI	Economic and Social Research Institute	The role of the Economic and Social Research Institute is to advance evidence-based policymaking that supports economic sustainability and social progress in Ireland.
EVA	Economic Viability Assessment	An assessment used to assess the viability of capacity resources in the energy-only electricity market.
EVs		Electric Vehicles.
FOP	Forced Outage Probability	This is the statistical probability that a generation unit will be unable to produce electricity for non-scheduled reasons due to the failure of either the generation plant or supporting systems. Periods when the unit is on scheduled outage are not included in the determination of forced outage probability.
	Generation Adequacy	The ability of all the generation units connected to the electrical power system to meet the total demand imposed on them at all times. The demand includes transmission and distribution losses in addition to customer demand.
GWh	Gigawatt Hour	Unit of energy. 1 gigawatt hour = 1,000,000 kilowatt hours = 3.6×10^{12} joules.
GNP	Gross National Product	The total value of goods produced, and services provided by a country during one year, equal to the gross domestic product plus the net income from foreign investments.
GVA	Gross Value Added	In economics, GVA is the measure of the value of goods and services produced in an area, industry or sector of an economy. In national accounts GVA is output minus intermediate consumption; it is a balancing item of the national accounts' production account.

Acronym/ Abbreviation	Term	Explanation
HVDC	High Voltage, Direct Current	A HVDC electric power transmission system uses direct current for the bulk transmission of electrical power.
IC	Interconnector	The electrical link, facilities and equipment that connect the transmission network of one country to another.
IED	Industrial Emissions Directive	Directive 2010/75/EU of the European Parliament and the Council on industrial emissions (the Industrial Emissions Directive or IED) is the main EU instrument regulating pollutant emissions from industrial installations.
LOLE	Loss of Load Expectation	The LOLE is the mathematical expectation of the number of hours in the year during which the available generation plant will be inadequate to meet the instantaneous demand.
MEC	Maximum Export Capacity	The maximum export value (MW) provided in accordance with a generator's connection agreement. The MEC is a contract value which the generator chooses as its maximum output and is used in the design of the Transmission System.
MVA	Mega Volt Ampere	Unit of apparent power. MVA ratings are often used for transformers, e.g., for customer connections.
MW	Megawatt	Unit of power. 1 megawatt = 1,000 kilowatts = 106 joules / second.
	Non-GPA	Non-Group Processing Approach.
NTL	New Technology Loads	Large high technology industrial demand customers primarily connected to the transmission system or new technologies required for the energy transition.
NIE Networks	Northern Ireland Electricity Networks	NIE Networks owns the electricity transmission and distribution network and operates the electricity distribution network which transports electricity to customers in Northern Ireland.
RAs	Regulatory Authorities	Refers to both: Ireland: Commission for Regulation of Utilities (CRU). Northern Ireland: Utility Regulator for Electricity and Gas for Northern Ireland.
	Reliability Options	The SEM CRM Capacity Auctions are a competitive process between qualified capacity providers to be awarded "reliability options" for the provision of capacity to the All-Island system.
RES	Renewable Energy Source	
RES-E		Renewable Electricity.

Acronym/ Abbreviation	Term	Explanation
RESS	Renewable Energy Support Scheme	Scheme will provide for a renewable electricity (RES-E) ambition of up to 70% by 2030 in Ireland, initially announced via the Government Climate Action Plan 2019. Subject to determining the cost-effective level which will be set out in the National Energy and Climate Plan (NECP).
Annual Run Hour Limitations		Restrictions on availability of plant due to external factors for example environmental.
SEAI		Sustainable Energy Authority of Ireland.
SEM	Single Electricity Market	This is the wholesale market for the island of Ireland.
ENTSO-E TYNDP		European Network of Transmission System Operators – Electricity Ten Year National Development Plan.
TWh	Terawatt Hour	Unit of energy 1 terawatt hour = 1,000,000,000 kilowatt hours = 3.6×10^{15} joules.
TER	Total Electricity Requirement	TER is the total amount of electricity required by a country. It includes all electricity exported by generating units, as well as that consumed on-site by self-consuming electricity producers, e.g., CHP.
	Transmission Losses	A small proportion of energy is lost as heat or light whilst transporting electricity on the transmission network. These losses are known as transmission losses.
	Transmission Peak	The peak demand that is transported on the transmission network. The transmission peak includes an estimate of transmission losses.
TSO	Transmission System Operator	In the electrical power business, a transmission system operator is the licensed entity that is responsible for transmitting electrical power from generation plants to regional or local electricity distribution operators.
TYNDP	Ten Year Network Development Plan	ENTSO-E's 10-year network development plan (TYNDP) is the pan-European electricity infrastructure development plan. It looks at the future power system in its entirety and at how power links and storage can be used to make the energy transition happen in a cost-effective and secure way.

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