All-Island Resource Adequacy Assessment 2025-2034

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.

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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 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. To plan the future of our energy security, continuing to map the island's electricity needs is an important part of our work.

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

Outputs from this assessment are also used to inform the Single Electricity Market (SEM) Capacity Auctions, a mechanism to ensure that the electricity supply in Ireland and Northern Ireland continues to meet demand into the future.

Stakeholder feedback

As part of the transition to the All-Island Resource Adequacy Assessment methodology, SONI and EirGrid undertook two public consultations: firstly on the methodology and secondly on the inputs and assumptions.

We would like to thank our stakeholders from across the energy industry who have engaged and interacted with us throughout the consultation processes as part of developing this new process.

The Assessment

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, data centres and other new technology load forecasts.

Generation: What can supply the demand?

Considering conventional generators, renewable energy, interconnectors, energy storage on the system today, 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, in addition to the variability of renewable generation and the availability of imports.

Adequacy: Is there a gap?

A detailed assessment of the supply-demand balance considering a wide range of possible outcomes with respect to the demand and generation factors outlined above.

Adequacy is measured against a standard called the Loss of Load Expectation (LOLE) Standard. The LOLE Standard is an accepted number of hours per year that there may be a shortage in electricity supply. The LOLE standard is 4.9 hours in Northern Ireland, meaning there could be 4.9 hours in a year when there is insufficient electricity supply to operate a secure power system, and the system could be operating with an increased level of risk.

The output from the assessment is a forecast of LOLE and an indication of whether or not the system requires additional capacity to operate securely.

To obtain the most relevant information, SONI engage 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 year's report was 30th April 2024 for the demand data and 8th May 2024 for the generation data.

Since the data freeze date, notable changes include the estimated energisation date of the new North-South Interconnector has been delayed to October 2031 and there has been an additional capacity market auction for which the results are not included in this assessment. Additionally, Storm Darragh caused significant and unforeseen damage at a power station in Northern Ireland, which resulted in the loss of a significant amount of conventional generation, the impact of this extended outage has not been captured in this assessment. Some of the units have returned to operations however they are impacted by the application of run hour limitations until they can run in closed-cycle mode.

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 2024[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 year, 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.

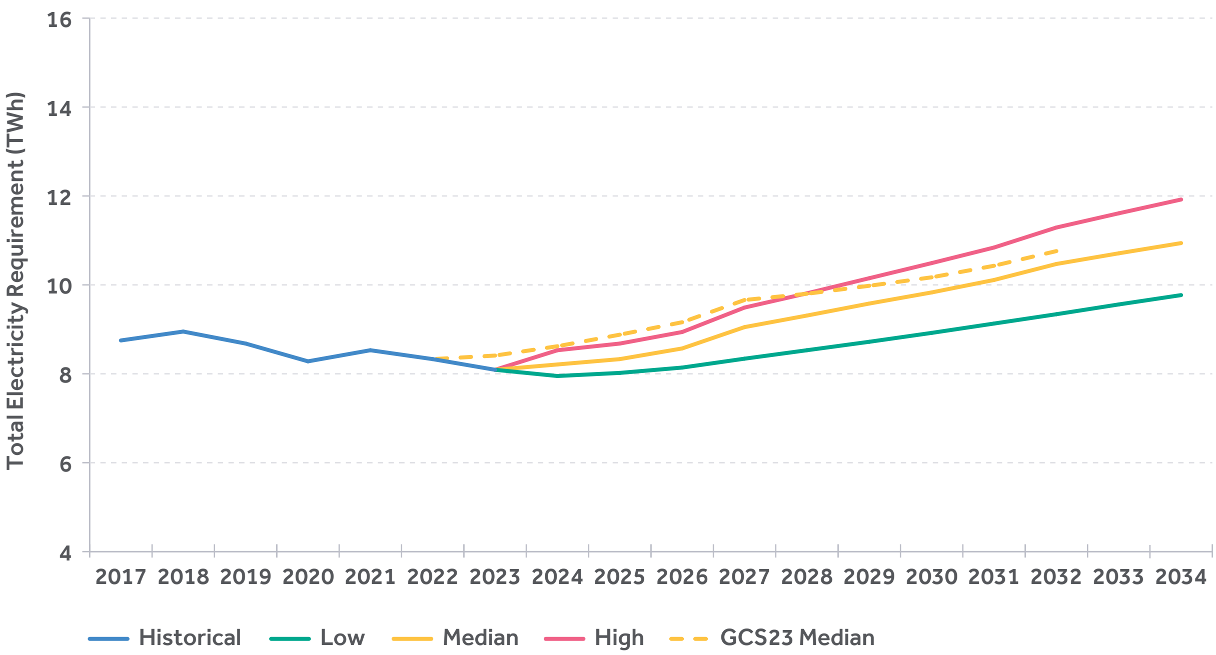
High demand: The high demand forecast is based on higher levels of new technology load growth, higher levels of electrification of heat and transport, potential additional data centre load that may connect to the system and a higher economic growth.

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 2024
4 https://www.legislation.gov.uk/nia/2022/31/enacted

Total Electricity Requirement Forecast

The Total Electricity Requirement (TER) is 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.

The latest Northern Ireland demand forecast below shows a reduction in the forecast demand for Northern Ireland relative to GCS 2023-2032. SONI continues to observe a reduction in electricity consumption due to the impact of lower economic growth and high fuel price effects observed in the later part of 2022 (due to global events) which continued into 2023. Including the latest economic trends in the demand forecasts results in a lower demand level, particularly out to 2026. From 2027 onwards, demand is forecast to increase based on an economic forecast, data centre and new technology load (NTL[5]) growth, and electrification of heat and transport.



Total electricity requirement for Northern Ireland

5 Large technology industrial demand customers primarily connected to the transmission system or new technologies required for the energy transition.

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 historic demand trends, correlated to temperature and 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 reduces peak demand by around 3% in the median demand scenario.

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 observed 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.

Capacity Delivery

In GCS 2023-2032 it was anticipated that new steam turbine capacity would be delivered in NI in 2027 which would remove the run hour restrictions associated with the new Open Cycle Gas Turbines at Kilroot.

The steam turbine capacity has since had its capacity market contract terminated at the request of the participant, and as a result is not included in SONI's adequacy assessment for Northern Ireland. The impact of this change is significant, as without the new steam turbine capacity, the run hour limits will remain in place on the new units at Kilroot which has a negative impact on the adequacy result.

This doesn't necessarily mean there will be supply shortages, but it does reflect a reduced level of resilience.

SONI continues to engage with the Department for the Economy and the Utility Regulator on the implications of run-hour restrictions on the Kilroot Gas Turbines.

Adequacy Forecast for Northern Ireland

Base and secure

Using the median demand forecast (our best estimate of what will happen in the future), we have developed two separate adequacy scenarios: base and secure.

The base scenario looks at the balance between generation and demand considering climate conditions, plant availability, renewable forecasts and the need to ensure there is sufficient capacity to cover system reserve requirements. This scenario is aligned with the European Resource Adequacy Assessment modelling framework.

The secure scenario looks at the balance between generation and demand under more challenging conditions such as low imports via interconnectors and run hour restrictions on new units. This is to further inform our planning so that we can be better prepared for a range of possible future scenarios.

This additional level of analysis has been made possible by this year's new methodology, which is more aligned with today's evolving power system, incorporating aspects such as interconnection and a greater level of renewables.

While this approach is used to factor in unique considerations for Northern Ireland, it is also consistent with the approach being taken by many other TSOs across Europe.

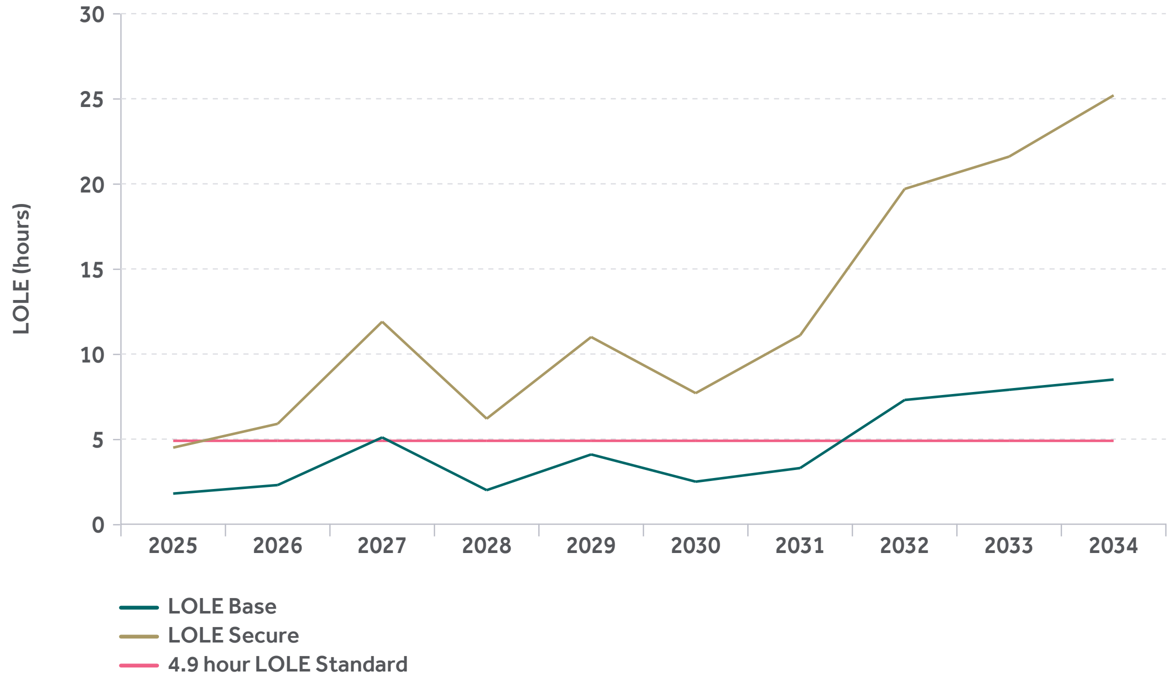
Please note that, while the base and secure scenarios use the median demand forecast, in the main report we have provided data for the high and low scenarios (6.5.5. Sensitivity Studies for Northern Ireland) to show the range of impacts under these conditions.

What do the results tell us?

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

- From 2025 to 2031, the base scenario shows the system is within standard meaning there is sufficient capacity to operate the system under normal conditions. From 2032, the base scenario results show the system is outside of standard and 30-50 MW of additional capacity is required.
- From 2026 onwards, the secure scenario shows the system is outside of standard meaning additional capacity is required to ensure we can continue to balance supply and demand under more challenging conditions. The results indicate, up to 100 MW of new capacity is required from 2026 to 2031 increasing to up to 200 MW by 2034.
- In both scenarios, 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.

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



Base and secure loss of load expectation results for Northern Ireland

power system. This scenario accounts for the impact of low imports, 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.

SONI acknowledges that capacity market auctions are still an option to procure new generation which could address the capacity shortfalls. Due to the freeze date for this report, results from the 2028/2029 T-4 capacity auction are not included in this adequacy assessment.

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 this period, 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.

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.
- Progress 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.

Over the ten-year period, there are iWhen 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 renewable energy target for 2030 while maintaining a secure supply of electricity for consumers.

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, 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 2025-2034

Disclaimer

SONI and EirGrid 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, SONI and EirGrid 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 for Northern Ireland and the Resource Adequacy Assessment Report for Ireland.

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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. EirGrid and SONI 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 2034, our electricity demand is set to increase as consumers use electricity in new ways to enable productivity, fuel transport and heat our homes. New government policies, such as the Climate Action Plan in Ireland and the Northern Ireland Energy Strategy 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. The new North-South Interconnector, alongside new interconnection to Great Britain and the new Celtic Interconnector to France, remain important for the medium- to long-term security of supply on the island of Ireland. The Single Electricity Market (SEM) will enable all consumers on the island of Ireland to realise the ambition of maximising the considerable efficiency benefits of the All-Island electricity system and market.

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 first edition of the All-Island Resource Adequacy Assessment framework – an evolution of the previous annual Generation Capacity Statement publication. The All-Island Resource Adequacy Assessment is required to reflect the modern and future power systems where the technology mix is becoming increasingly diverse and also enhance our alignment with the European Clean Energy Package.

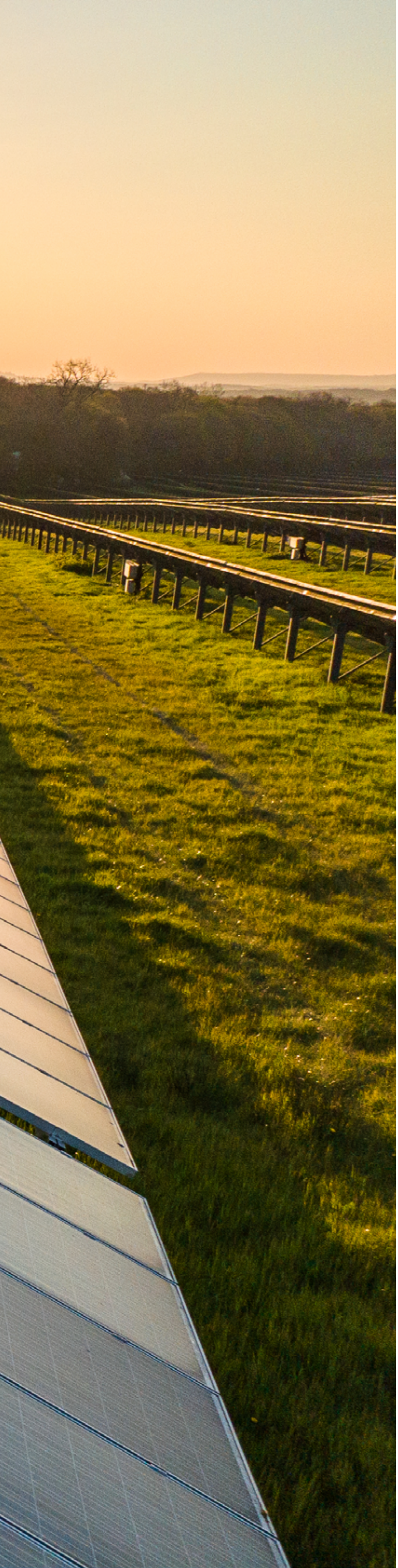
As part of the transition to this enhanced assessment framework, EirGrid and SONI have undertaken two public consultations on the Methodology and Inputs & Assumptions. We would like to thank our stakeholders from across the energy system who have actively engaged and interacted with us throughout the 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. 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.

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. We hope you find this All-Island Resource Adequacy Assessment both informative and useful in signalling the future needs of the grid.

Martin Corrigan
EirGrid Group
Chief Executive

Alan Campbell
SONI
Chief Executive



1. Document Structure

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

Six 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 first edition of the All-Island Resource Adequacy Assessment, meeting EirGrid's statutory and SONI's licence requirements in addition to relevant European regulatory requirements.

The All-Island Resource Adequacy Assessment is an evolution of the previous annual Generation Capacity Statement (GCS):

- Implementing an updated methodology and aims to reflect the modern and future power systems where the technology mix is becoming increasingly diverse.
- Aligning with the European modelling framework and regulatory requirements under the European Clean Energy Package.

Throughout 2023 and 2024, EirGrid and SONI have worked collaboratively with the Commission for Regulation of Utilities (CRU) and the Utility Regulator (UR) to develop the pathway for transitioning to the new process. The process development has included extensive engagement:

- In early 2023, EirGrid and SONI with support from an external partner developed a framework and an implementation plan for transitioning the traditional GCS process into this new All-Island Resource Adequacy Assessment process.
- In late 2023, EirGrid and SONI consulted on a new methodology for developing forecasts, including for demand, generation and adequacy assessments.
- In spring 2024, EirGrid and SONI carried out a public consultation on the range of inputs, data sources, and input assumptions to be used in the first iteration of the new process. An industry webinar was also held as part of this consultation process. Furthermore, EirGrid and SONI have engaged with industry experts, other TSOs and with academic experts on best practice for assessing resource adequacy for high renewable power systems.

The outcome of the extensive engagement process outlined above is this first edition of the All-Island Resource Adequacy Assessment. This report includes forecasts and analysis for both Ireland and Northern Ireland and has been produced on a joint basis by EirGrid and SONI.

In this assessment, a new approach has been taken in terms of assessing resource adequacy and two scenarios have been identified namely a Base and a Secure scenario. The Base scenario analyses the adequacy position in line with the European Resource Adequacy Assessment (ERAA), and the Secure scenario analyses the system considering Low Imports, Annual Run Hour Limits (ARHL) and other operational requirements.

EirGrid and SONI consider 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, noting that capacity market auctions remain an option to procure new generation which could address capacity shortfalls in the medium to long term.

This report examines the likely balance between electricity demand and supply across the 10-year period from 2025 to 2034 for Ireland and Northern Ireland against the relevant reliability standard. The reliability standard is called the Loss of Load Expectation (LOLE) standard and is an accepted number of hours per year that a country's electricity production cannot meet its demand. The LOLE standard for the SEM is 6.5 hours, as per the SEM Committee decision paper[1]. The jurisdictional LOLE standard is 3 hours for Ireland[2] as set by the Department of the Environment, Climate and Communications (DECC) working with the CRU and 4.9 hours for Northern Ireland as set by the Department for the Economy (DfE).

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. 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.

More detail on the key areas which have driven changes in the adequacy position since the GCS 2023-2032 for Ireland, Northern Ireland and All-Island forecasts are provided below.

2.1 Ireland

In last year's GCS 2023-2032, EirGrid forecasted significant deficits throughout the study horizon for all forecasted demand levels. The transition to the new resource adequacy assessment methodology is indicating lower LOLE results than in GCS 2023-2032; this is primarily a result of improved interconnection modelling which is now detailed multi-regional dynamic modelling replacing the previously assumed capacity credit approach.

The Base and Secure scenario results indicate adequacy challenges in 2025 and 2026 considering in-market measures only. The position improves in 2027 as Celtic is delivered and new gas capacity comes online. From 2028 the Base scenario indicates the system is operating within standard on average and therefore no additional capacity is required. The Secure scenario considers Low Imports, possible Annual Run Hour Limits on some new conventional units and Transmission Outage Planning indicating the system will be outside of standard and additional capacity is required across the study horizon.

In response to Ireland's challenging adequacy position, as identified in recent GCS publications, the CRU continues to update its "CRU Information Paper Security of Electricity Supply – Programme of Actions"[3], with the latest update published in April 2024. This recent update identifies three workstreams including system operations, demand initiatives and delivery. These workstreams include securing enduring capacity through market measures, improving demand side response, and in the short-term, keeping units open or delivering generation on a temporary basis over the next four to five years through the transition from older power plants to new capacity. This programme of work, directed by the CRU, will provide additional stability and resilience to the power system in Ireland.

The outputs and impact of the CRU's programme of actions are not reflected in the core scenario in this report, but the expected positive impact of the actions is captured by sensitivity studies illustrated in Section 6.4.6.

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
3 Electricity_Security_of_Supply_Programme_of_Work_Update_April_2024_.pdf

As part of these actions from the CRU-led Security of Supply programme, the CRU directed EirGrid to procure Temporary Emergency Generation to mitigate the security of supply risks identified. The Temporary Emergency Generation can only be used in emergency situations and therefore is 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 Temporary Emergency Generation 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.

EirGrid is actively engaging with the Department for the Environment, Climate and Communications, the CRU and other relevant stakeholders to resolve the capacity deficits over the coming decade.

A summary of the main drivers for change since GCS 2023-2032 is included below.

Demand

Ireland recorded several record peak electricity demand days leading to the 2023 transmission winter peak being modestly larger than 2022 demand winter peak (5543 MW in 2022 and 5567 MW in 2023), with growth being partially suppressed by mild winter effects. Overall demand continues to increase throughout the study horizon to 2034 by approximately 3% year-on-year. In 2023, the significant growth in data centre demand has been partially countered by the reduction in residential demand driven by high energy prices influencing consumer behaviour. The impact of last year's outturn demand, specifically the reduction in the residential sector, results in future electricity demand forecasts being lower in the short term compared to last year. However, by the end of the decade, assumptions for high growth from the electrification of heat and transport bring forecasted demand levels to a comparable position to last year's GCS 2023-2032.

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 2019-2023, replacing the 2018-2022 statistics used in GCS 2023-2032. Incorporating the updated plant performance statistics into the assessment, results in a marginally negative impact on the adequacy position across the study horizon.

New capacity through capacity auctions

Since the previous GCS report, the 2027/2028 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. The enhanced monitoring process is supported by expert independent analysis and considers projects successful in previous auctions from the 2023/2024 T-4 through to the 2027/2028 T-4 capacity auction. Note that due to the freeze date for this report, capacity auctions completed post April 2024 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 expected, if it is at risk of delay, or if it is not expected to deliver at all within the auction long stop dates.

The core scenario in this report includes a risk-assessed view of new capacity delivery, which, at the time of the data freeze, indicates that there is an improvement in the delivery of new capacity. The latest project information helps to improve Ireland's adequacy position across the horizon compared to the risk-adjusted view assumed in GCS 2023-2032. 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 deliver on time.

Renewable generation

Ireland has a renewable policy goal to deliver 80% renewable electricity by 2030. EirGrid has considered the Renewable Electricity Support Scheme (RESS) and Offshore RESS auction results, ESBN connection data and latest transmission connections processes data to develop a trajectory for deployment of new renewable capacity. Furthermore, EirGrid have engaged with the Sustainable Energy Authority of Ireland (SEAI) who have developed renewable generation forecasts based on judgments from a pool of expert stakeholders. These forecasts have been used in the core assessment in this report.

The impact of using this updated renewable trajectory is a lower installed capacity of each renewable category compared to GCS 2023-2032 which overall has a negative impact on the adequacy position. EirGrid has included a sensitivity study that analyses the impact of renewable energy deployment rates, examining the benefit of timely delivery of renewable targets and also the impact of delays to renewable delivery on the adequacy position.

2.2 Northern Ireland

The core scenario in GCS 2023-2032 indicated Northern Ireland would be in a capacity surplus from 2027 with the delivery of a new steam turbine at Kilroot that would form part of a combined cycle gas turbine arrangement with the new open cycle gas turbines (OCGTs). However, close to publication of GCS 2023-2032, the latest information suggested the new steam turbine capacity was at risk of non-delivery. To examine the possible impact of this new information, a sensitivity was carried out by SONI to assess the impact of non-delivery of the new steam turbine. This post-data freeze development indicated Northern Ireland could be in a capacity deficit across the horizon as the new open cycle gas turbines (OCGTs) would be subject to Annual Run Hour Limits (ARHLs) for the duration of the study horizon.

Across the majority of the study horizon, the Base scenario indicates the system is within standard on average for the majority of the Study Horizon. The Secure scenario considers Low Imports and indicates the system is outside of standard from 2026 across the Study horizon and additional capacity is required.

The overall position shows an improved outlook relative to the post-data freeze scenario in GCS 2023-2032, due to a combination of factors including the revised peak demand forecast being lower out to 2029 and improved modelling of run hour limits.

SONI is actively supporting the Department for the Economy, the Utility Regulator and other relevant stakeholders to address the capacity deficits over the coming years.

A summary of the main drivers for change since GCS 2023-2032 is included below.

Demand

The latest Northern Ireland demand forecast shows a reduction in the forecast demand for Northern Ireland relative to GCS 2023-2032. SONI continue to observe a reduction in electricity consumption; the impact of lower economic growth, and high fuel prices effects observed in the later part of 2022 (due to global events) and continuing into 2023. Including the latest economic trends into the demand forecasts result in a lower demand level particularly out to 2026. From 2027 onwards, demand is forecast to increase based on an economic forecast, data centre and new technology load (NTL[4]) growth, and electrification of heat and transport.

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 2019-2023, replacing the 2018-2022 statistics used in GCS 2023-2032. Incorporating the updated plant performance statistics into the assessment, results in a marginally negative impact on the adequacy position across the study horizon.

New capacity delivery

In GCS 2023-2032 the core scenario anticipated new steam turbine capacity would deliver in 2027 which would remove the Annual Run Hour Limits (ARHL) associated with the new KGT6 and KGT7 OCGTs. The steam turbine capacity has since had its capacity

4 Large high technology industrial demand customers primarily connected to the transmission system or new technologies required for the energy transition.

market contract terminated, and as a result is not included in SONI's assessment of resource adequacy for Northern Ireland.

EP Kilroot Limited's Capacity Market Termination Notice for their proposed Kilroot steam turbine (ST2) means ARHL will continue to apply to the new Open Cycle Gas Turbines (OCGT) at Kilroot across the full study horizon. The application of ARHL on the new 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. The results indicate significant adequacy benefit which could position Northern Ireland with a capacity surplus across the study horizon.

SONI continue to engage with DfE and the Utility Regulator on the implications of run-hour restrictions on Open Cycle Gas Turbines.

Renewable generation

Northern Ireland has a renewable policy goal to deliver 80% renewable electricity by 2030. As part of this resource adequacy assessment, SONI is assuming a pragmatic renewable deployment trajectory for the core scenario.

SONI has included a sensitivity study that analyses the impact of renewable energy deployment rates, examining the benefit of timely delivery of renewable targets and also 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, and EirGrid and SONI have provided an All-Island adequacy assessment starting from 2027. Until the delivery of the new North-South Interconnector, we need to limit the support between both jurisdictions to ensure system stability and security. Once the second North-South interconnector is online, the ability for support between the jurisdictions is increased. Our analysis shows the new interconnector will bring a benefit to the overall security of supply outlook across the island, along with other enduring market benefits such as renewable integration. However, the median scenario assessment for the All-Island system shows a capacity deficit across the study horizon, given the challenges regarding plant delivery coupled with retirement of existing plant and increasing demand.

Since 2016, EirGrid and SONI via the GCS have warned of an increasing tightness between supply and demand. There is no question that the current outlook, based on the best information available, 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, while challenging in its assessment, 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.

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 2025 to 2034.

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, EirGrid and SONI 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[5] and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations[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 also has responsibility for approving the annual implementation of the ERAA methodology conducted by ENTSO-E.

5 https://www.irishstatutebook.ie/eli/1999/act/23/section/38/enacted/en/html
6 https://www.irishstatutebook.ie/eli/2005/si/60/made/en/print#partx-article28
7 https://www.uregni.gov.uk/files/uregni/media-files/SONI TSO Consolidated Feb 2019.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 run studies that are relevant on a national level but may not be relevant at a pan-EU level.

The development of an implementation plan for this new resource adequacy assessment methodology has been a component of the Security of Supply Programme in Ireland, led by CRU; and the requirement for the framework to be applied in Northern Ireland has been acknowledged by UR. As part of the framework development, EirGrid and SONI have also received positive support for the projects through engagements with DECC in Ireland and the DfE in Northern Ireland.

Engagements on the implementation of this resource adequacy assessment framework have been ongoing with the Regulatory Authorities (RAs) from early 2023. Although the United Kingdom is no longer a member state of the EU, Northern Ireland is an integral part of the 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 lists 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 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 LOLE standard, which is now 3 hours in Ireland (previously 8 hours) and 4.9 hours in Northern Ireland. This means that EirGrid and SONI are planning the system with the standard 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.

This report has been produced on a joint basis by EirGrid and SONI to assess a 10-year Study Horizon from 2025-2034 for both Ireland and Northern Ireland. This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2023-2032, published in January 2024.

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]. EirGrid and SONI 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 30th April 2024 for the demand data and 8th May 2024 for the generation data used in this report. Future assessments using this methodology will include updates as new information and data for the period becomes available.

10 All-Island Resource Adequacy Assessment Methodology, https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034-Methodology.pdf

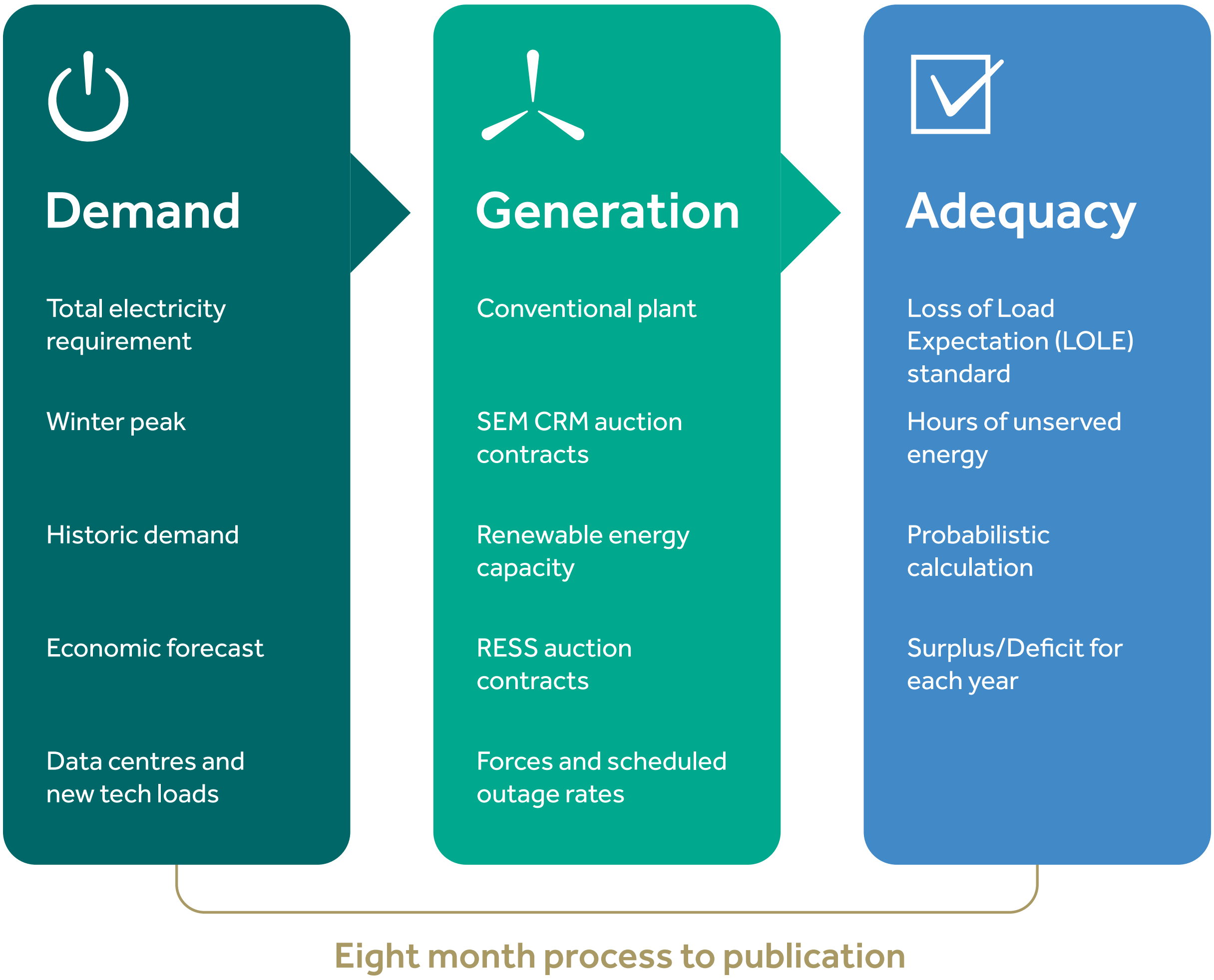


Figure 3.1 Adequacy Assessment Process

3.3 Capacity Market Interaction

Single Electricity Market (SEM) capacity auctions are completed 4 years ahead of time, known as a 'T-4' capacity auction. The last T-4 was run in 2023 to source capacity for the capacity year October 2027 to September 2028. 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 April 2024 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. The capacity auction processes use the demand and generation forecasts produced for this report assessment as inputs for the auctions that are run annually to procure capacity ahead of time to meet the future needs of the system. EirGrid and SONI are cognisant of the overarching role of the capacity market and have been careful to set out, clearly and transparently, the capacity requirements for the coming years.

The core assessment is based on in-market adequacy measures. The impact of other temporary out-of-market measures required to manage the security of supply risks are assessed outside of the core assessment.

EirGrid and SONI work continuously to ensure the output from the All-Island Resource Adequacy Assessment report provides an appropriate signal to industry, regulators and policy makers regarding the capacity required to secure the future power system according to the specified jurisdictional reliability standard.

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 correcting peak demand on a particularly cold or warm peak day to that of an average weather year. On 16th of January 2023, an all-island peak demand figure of 6922 MW was measured on the transmission system. The high level of demand was partially driven by a particularly cold period of weather. Both Ireland and Northern Ireland recorded their peak demands one day later on the 17th of January, measuring 5424 MW and 1537 MW, respectively[11]. Each jurisdiction's peak does not necessarily occur at the same time, leading to different timings of each jurisdiction's peak and the all-island peak, as was the case in 2023. 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[12]. 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 a roof-top solar PV panel.

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 developing demand forecasts in Ireland, EirGrid has considered the Climate Action Plan 2023[13] targets, particularly on the electrification of the heat and transport sectors. 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[14] 2021, Path to Net Zero – Action Plan 2024[15] and the Climate Change Act (Northern Ireland) 2022[16].

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

11 Ireland's peak demand in 2023 was 5424 MW however "winter peak", which extends through to January of the following year, is used for modelling purposes. January 17th 2024 produced a 2023 winter peak of 5567 MW.
12 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.
13 https://www.gov.ie/en/publication/7bd8c-climate-action-plan-2023/
14 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf
15 Path to Net Zero – Action Plan 2024
16 https://www.legislation.gov.uk/nia/2022/31/enacted

provides the reader with an understanding should certain growth factors fail to materialise or if stronger growth is realised.

The forecast demand time series is developed using ENTSO-E's new Demand Forecast Tool (DFT). Adopting this tool in the calculation of hourly demand forecast aligns both EirGrid and SONI to the ERAA methodology, as outlined within the European Regulatory Framework (Clean Energy for all Europeans package[17]). The DFT provides a wider range of results than previously available from the GCS for both Total Energy Requirement (TER) (TWh) and Peak Demand (MW), showing the spread that climate has on forecasted values.

With the 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.

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 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 accompanying All-Island Resource Adequacy Assessment Methodology document[18].

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[19]. The key economic parameters used in this study are Real Modified Gross National Income (Real GNI*) and Personal Consumption[20].

Real Modified Gross National Income (Real GNI*)[21] 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[22] annually in support of EirGrid's long term adequacy studies. The shorter-term trends are based on their Quarterly

17 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN
18 All-Island Resource Adequacy Assessment Methodology, https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034-Methodology.pdf
19 https://www.esri.ie/research-areas/macroeconomics
20 Personal Consumption of Goods and Services (PCGS) measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.
21 https://www.cso.ie/en/releasesandpublications/ep/p-nie/nie2019/mgni/
22 Economic Parameters obtained from ESRI on 25th January 2024

Economic Commentary[23]. Longer-term trends arise out of the ESRI's Medium Term Review[24]. Both the global Covid pandemic and the Russian invasion of Ukraine have led to economic turbulence over the past four years. Ireland's subsequent recovery from these events has led to ESRI forecasting steady growth over the next decade, aligning to previous forecasts. The figures listed in Table 4.1 were used for the three demand scenarios in the demand forecast. To account for the uncertainty brought about from the high rate of inflation and the Russian invasion of Ukraine, the low and high demand forecasts assume a lower and higher growth respectively than ESRI's forecast[25].

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

	2023–2024			2025–2034		
	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)
Real GNI*	0.98%	1.30%	1.43%	2.25%	3.00%	3.30%
Personal Consumption	2.20%	2.90%	3.20%	1.88%	2.50%	2.75%

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 2000 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 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[26]. 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 have been no new data centres contracted that meet the CRU Direction. As such, this study only considers data centres with an existing contract.

23 https://www.esri.ie/publications/quarterly-economic-commentary-winter-2022
24 https://www.esri.ie/publications/medium-term-review-2013-2020
25 Previous GCS used the same economic forecast for all demand levels.
26 CRU21124-CRU-Direction-to-the-System-Operators-related-to-Data-Centre-grid-connection-.pdf (divio-media.com)

On 21 June 2023 the CRU published a Call for Evidence on Review of Large Energy Users Connection Policy (CRU/202357) and a subsequent consultation paper on Review of Large Energy Users connection policy (CRU/2024001). The CRU has stated that *"The aim of this review is to provide a pathway for new Large Energy User (LEU) connections to the electricity and gas systems which minimises the impact on national carbon emissions while taking into account capacity of the system in relation to supply of energy and grid infrastructure."*

The current demand forecast is consistent with the GCS 2023-2032 as it considers sixteen 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: these include 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 GCS 2023-2032, the latest median forecast shows there is very strong growth forecast in this sector out to 2026, 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[27]. 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 2034. 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.

27 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 2034. 2023 demand 867 MVA.

Forecast Scenario	Growth from 2023 – 2034 (MVA)	2034 Demand (MVA)
Low	422	1289
Median	813	1680
High	1200	2067

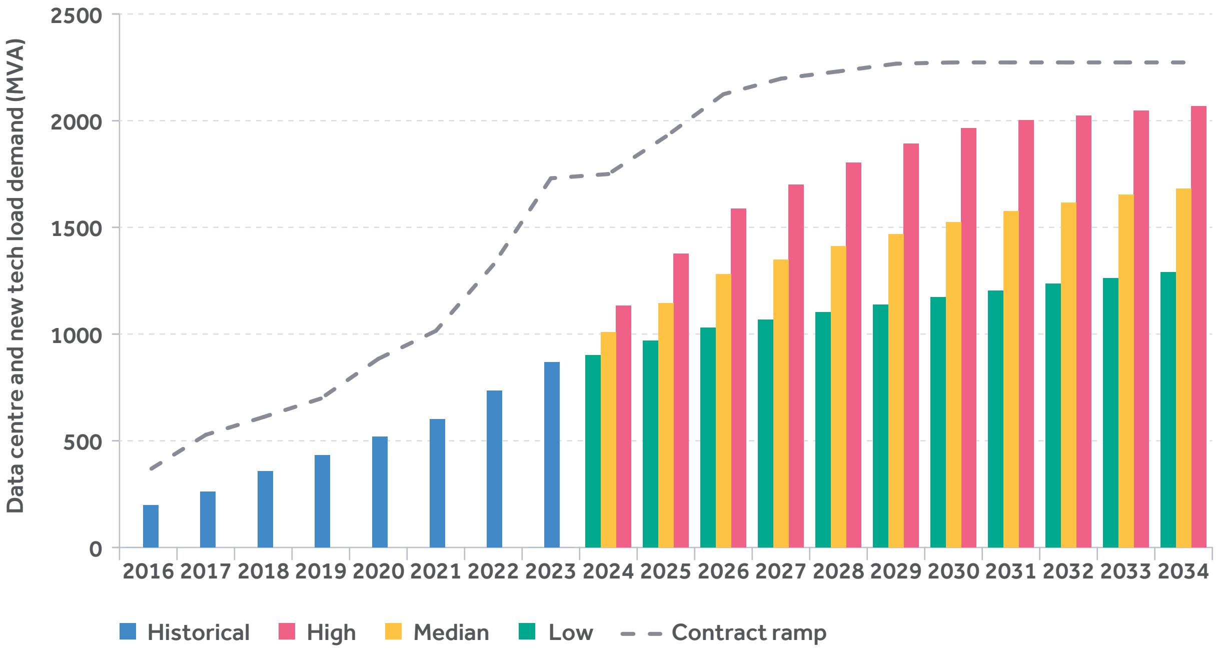


Figure 4.1 Ireland demand expected from assumed build out of data centres and new technology loads

4.2.4 Electrification of heat and transport

The forecast takes account of the relevant electrification targets for heat and transport from the Irish Government's Climate Action Plan 2024[28] (CAP 2024). These are ambitious targets which are required to keep Ireland on track for halving emissions by 2030. In this year's forecast, the median scenario assumes that by 2030, 100% of the CAP 2024 targets will be met. By 2030, the low scenario assumes 75% and the high scenario assumes 110%. For this study, a gradually increasing uptake is assumed for the interim years. For EVs, this trend continues beyond 2030 whilst accounting for older vehicles (older than 15 years) being taken off the road and limiting the sector's growth to 165,000 vehicles per year.

Table 4.3 Climate Action Plan 2024 targets for electric vehicles and heat pumps out to 2030

	Electric vehicles		Heat pumps		
	Passenger	Commercial	Residential – new builds	Residential – retrofits	Commercial
2025	175,000	10,300	170,000	45,000	25,000
2030	845,000	82,250	280,000	400,000	50,000

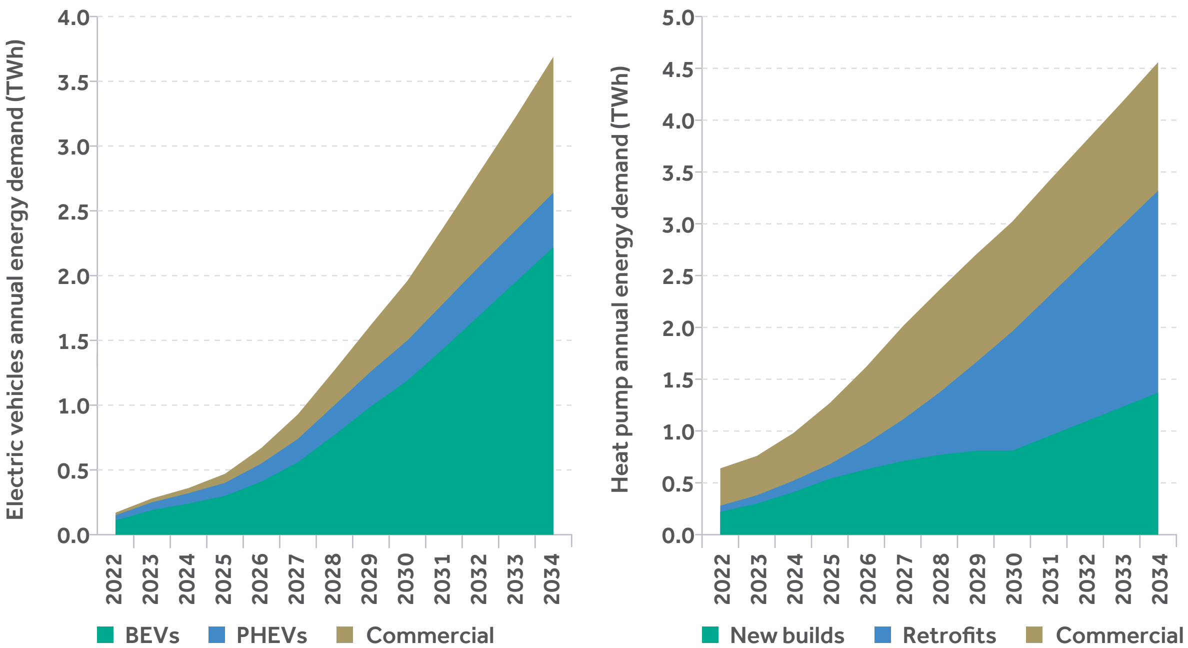


Figure 4.2 Electric vehicle & heat pump electrical energy demand - median scenario

28 https://www.gov.ie/en/publication/79659-climate-action-plan-2024/

Electricity demand from electric vehicles is expected to grow significantly between now and the end of the decade as Ireland progresses towards achieving government targets set out in the Climate Action Plan. The majority share of this demand is forecast to come from passenger vehicles, specifically BEVs.

Similarly, the residential sector is expected to account for the majority of electrified heating demand through the installation of heat pumps to the level targeted in the Climate Action Plan. This heat pump demand is forecasted to be via the uptake of domestic heat pumps, split between new builds and retrofits as shown in Figure 4.2. As assumed within CAP 2024, there will be approximately 730,000 electric heat pumps installed in Ireland by 2030. The adoption of electrified heat within homes and businesses will reduce the use of traditional fossil fuel type heating technologies, shifting the energy demand to the electricity sector (heat pumps are forecast to account for 7% of Ireland's Total Electricity Requirement by 2030, 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[29]. 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 (Figure 4.3). Temperature correction is also applied to historic annual energy demand using the degree days methodology[30]. The reason for the increase in temperature corrected peak demand in 2023 is captured in Section 4.2.9. 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. ENTSOE's Demand Forecasting Tool (DFT) uses 35 years of historic climatic data for Ireland to capture this variability. Forecasts are generated based on each historic climate year, with the average of these taken as the median core scenario. Both the high and low scenarios also take the climatic average results, however input parameters, such as economic growth and the build out of HPs and EVs, are changed to reflect these extreme scenarios i.e. 75% low, 110% high.

29 https://www.eirgridgroup.com/site-files/library/EirGrid/210963-EirGrid-Winter-Outlook-2022-2023.pdf
30 https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Heating_and_cooling_degree_days_-_statistics

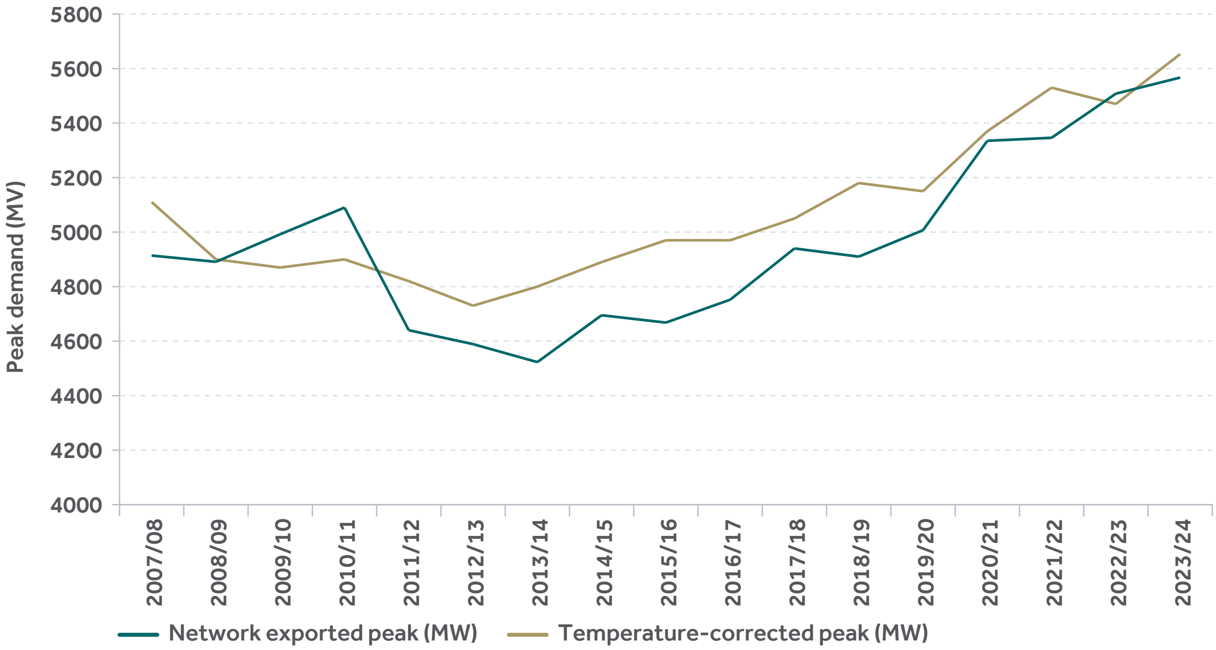


Figure 4.3 Historic recorded and temperature corrected peak demand

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[31]. 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 a study commissioned by CRU, assumes by 2030 that smart meters can help reduce peak electricity demand by 8.8% for domestic users[32]. There is assumed to be a linear increase in the effect of this demand flexibility from today until 2030. 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. Vehicle charger technology has the potential to minimise the potential impact of electric

31 https://www.cru.ie/about-us/news/national-energy-demand-strategy-consultation-paper/
32 https://www.ucd.ie/issda/data/commissionforenergyregulationcer/

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 4.2.3 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[33] in 2030 in the median scenario. Implementing demand flexibility services and incentives has the effect of reducing the peak demand by approximately 400 MW. This significant effect has been incorporated into the final peak demand calculations. Note, peak demand and TER presented in Section 4.2.8 and Section 4.2.9 respectively, are lower in this year's forecast for 2030 which has a consequent effect of reducing flexibility contribution relative to GCS 2023-2032.

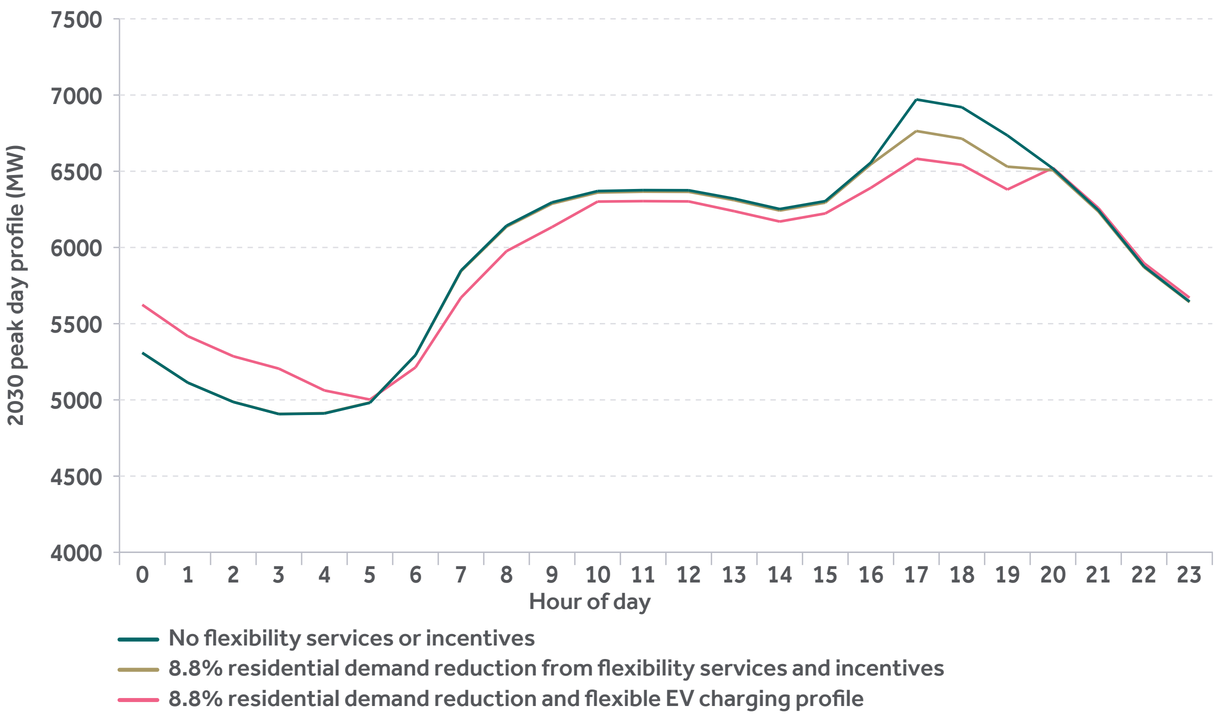


Figure 4.4 Impact of demand flexibility on 2030 peak day (median scenario)

33 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 2023 peak day as January 17th.

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 8.8% peak demand reduction. 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.

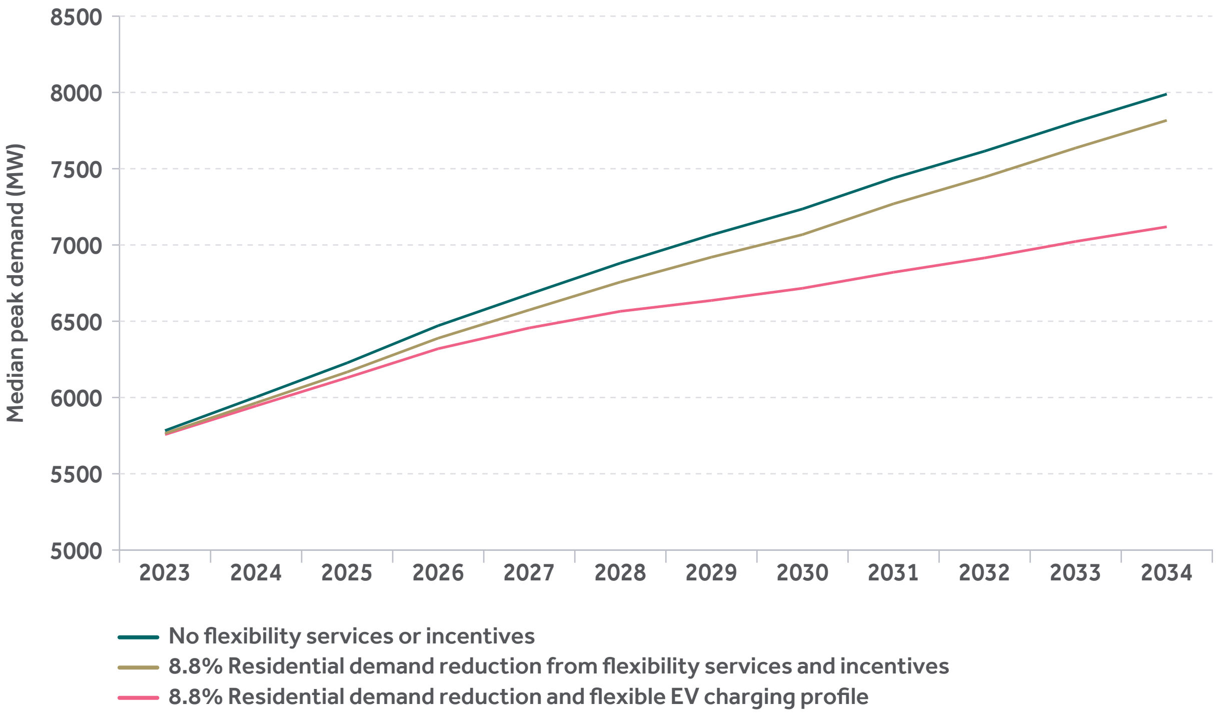


Figure 4.5 Impact of demand flexibility in median scenario across the study period

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 2010 to 2023, 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 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, representing 100% of CAP 2024 targets, sees a reduction in forecast energy, out to 2026, compared to last year's GCS 2023-2032. This is primarily driven by a reduction in domestic energy growth in the residential sector, which is assumed to

34 National-Energy-Projections-2023.pdf (seai.ie)

be driven by high energy costs, and lower forecast economic growth. From 2027 onwards, the median scenario shows strong growth due to the electrification of heat and transport as these sectors accelerate towards Climate Action Plan targets. This year's demand forecast also includes the impact of electrification of industrial heat demand. Data provided by SEAI's 2023 National Energy Projections[34], on the electrification of industrial heat pumps, boilers, ovens, dryers, and kilns has been added to all three scenarios within the demand forecast. The high forecast (red) is lower than GCS2023-2032 due to decreased demand in EVs post 2030, accounting for scrappage of vehicles older than 15 years, coupled with increased efficiency gains to align with the Energy Efficiency Directive.

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), with electrification of heat and transport becoming a more significant factor towards the end of the decade. In the median scenario, by 2034 electricity demand is expected to increase by 45% relative to 2023 levels.

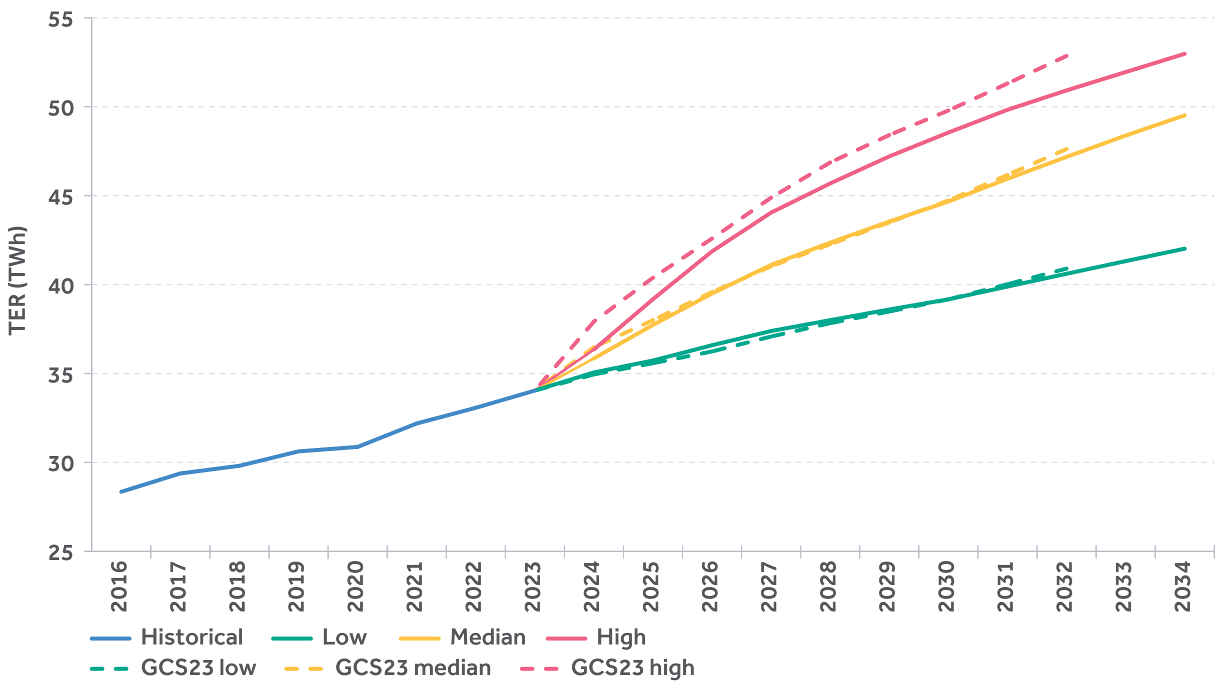


Figure 4.6 Total Electricity Requirement for Ireland

Table 4.4 shows the key assumption differences between the low, median and high total electricity requirement in the forecast scenarios shown above.

Table 4.4 Low, median and high Total Electricity Requirement key assumption differences

	Low	Median	High
Number of Electric Vehicles	75% Climate Action Plan Targets	100% Climate Action Plan Targets	110% Climate Action Plan Targets
Number of Domestic and Commercial Heat Pumps	75% Climate Action Plan Targets	100% Climate Action Plan Targets	110% Climate Action Plan Targets
Data Centre and New Technology Loads	Low Ramp	Median Ramp	High Ramp
Economic Growth Projection	75% ESRI Economic Projection	100% ESRI Economic Projection	110% ESRI Economic Projection

Figure 4.7 shows the breakdown of results across different sectors in the median scenario. The residential (excluding electric vehicles and head pumps), commercial and industrial (excluding data centres and new technology loads) sectors remain relatively consistent across the decade. The contribution of SEAI's industrial heating demand is included. The forecast also factors in enhanced efficiency savings from the targets set out in the updated EU Energy Efficiency Directive[35].

The largest growth comes from data centres and new technology load (68% of the growth forecast in 2025), and increased uptake of electric vehicles and heat pumps, particularly later in the decade (46% of the growth in 2030). Also notable is that by 2030, 29% of all electricity demand is expected to come from data centres and new technology loads.

35 https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en

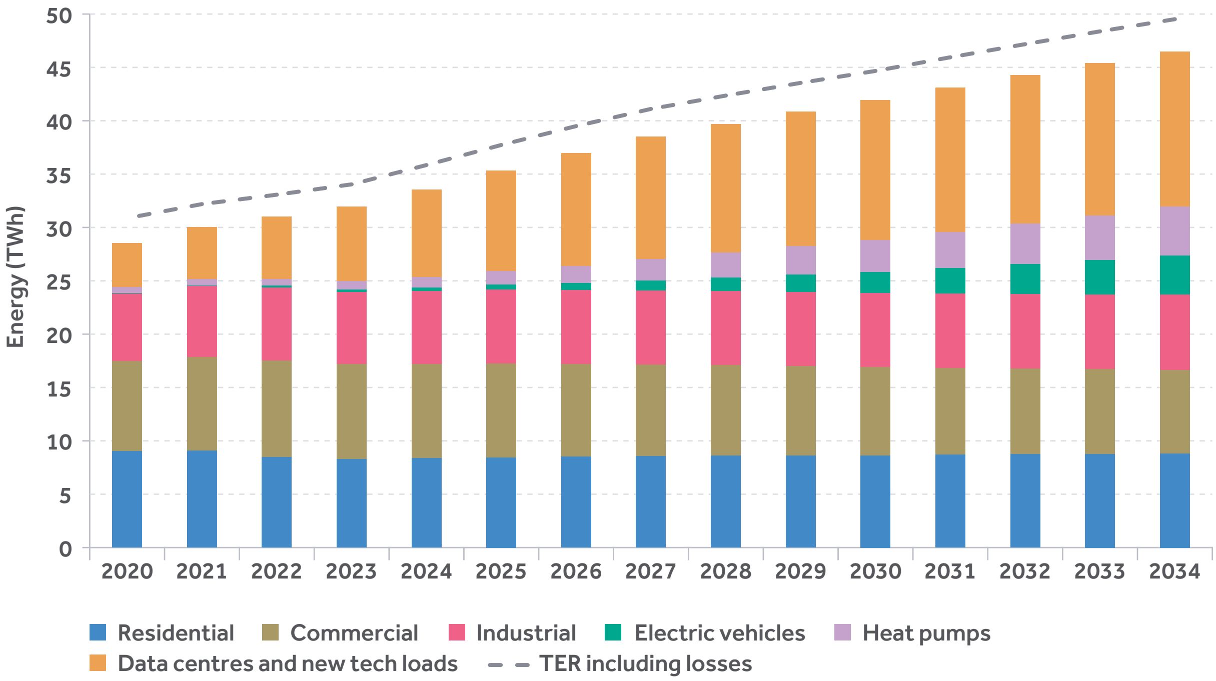


Figure 4.7 Ireland median demand Total Electricity Requirement sectoral breakdown

The proportion of demand for each sector for 2025 and 2034 are estimated as follows:

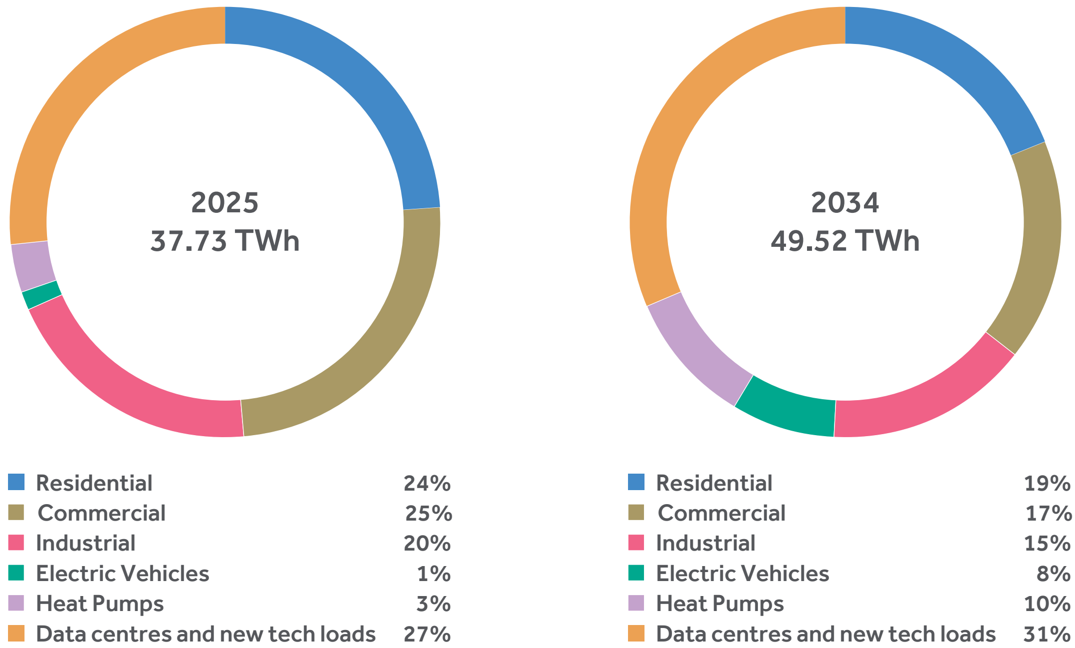


Figure 4.8 Sectoral contribution to Ireland's TER in 2025 & 2034

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. 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 4.10).

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 14% by 2034. Advancements in heat pump technology, including improved efficiency (COPs), and smarter usage strategies, will lead to lower future demand compared to forecasts based on current usage patterns. Finally, as discussed in section 4.2.3, data centre load is assumed to be consistent throughout the day with a gradual ramp throughout the year to their forecasted demand. Like Figure 4.8, Figure 4.9 depicts the percentage contributions of each sector towards overall peak demand in 2025 and 2034.

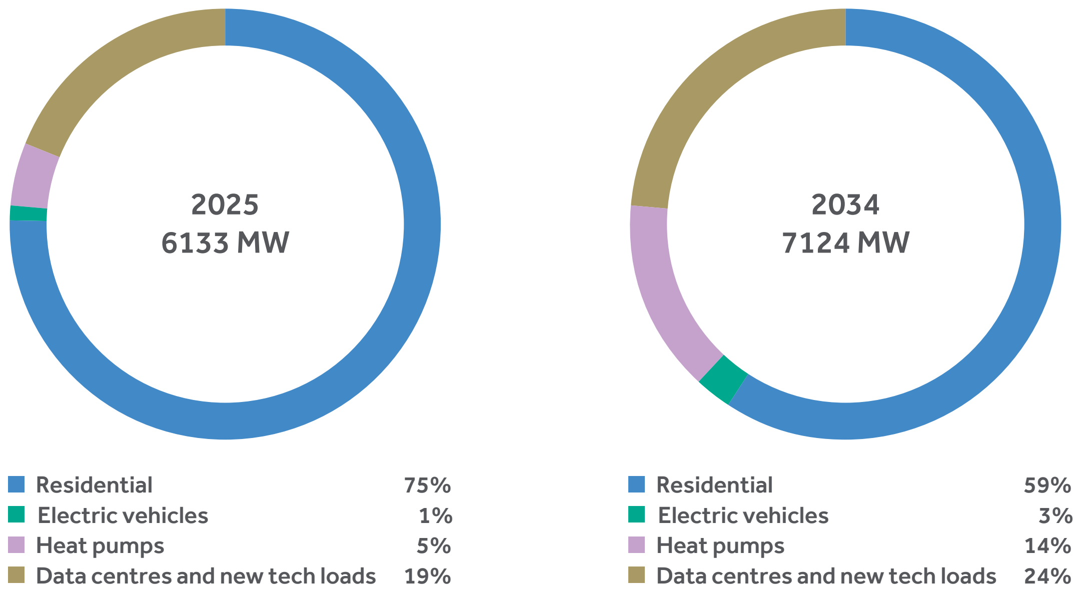


Figure 4.9 Sectoral contribution to Ireland's peak demand in 2025 & 2034

The overall peak forecast is shown in Figure 4.10. In the median scenario, the peak demand is forecasted to increase 24% by 2034 from 2023 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 tech load[36] along with the electrification of heat and transport. The increased ambition of the Energy Efficiency Directive has also been incorporated into this year's forecast and does impact growth across the study horizon in all three scenarios.

The low, median, and high scenarios have also been updated to reflect the latest inputs and assumptions for EVs, HPs, and NTLs, as described in sections 4.2.3 and 4.2.4.

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

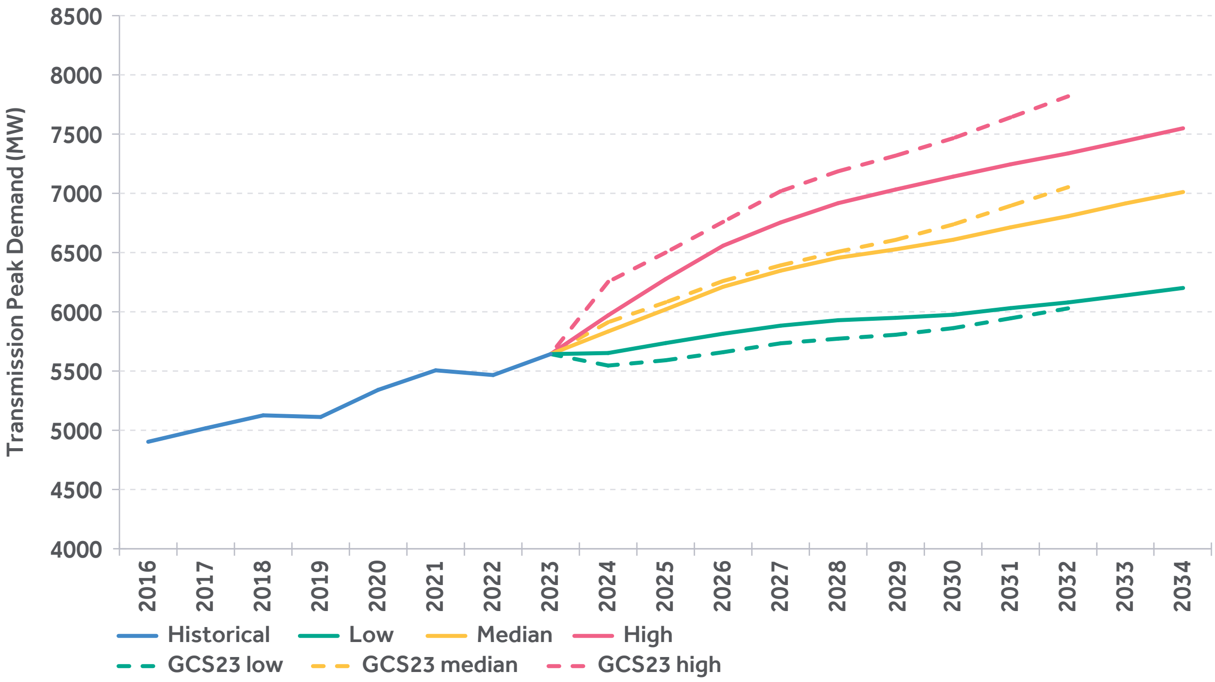


Figure 4.10 Transmission peak forecast for Ireland

36 As noted in section 4.2.3, any demand growth from data centres and new tech loads is forecast on the basis of their contracted demand and from sites contracted prior to CRU direction CRU/21/124.

This forecast incorporates 35 years of historical climate data within the DFT, enabling enhanced modelling of climatic impact on electricity demand. This significance is clearly shown by the spread of peak values in Figure 4.11. Results from the DFT median demand model show a spread of over 700 MW in 2034, which arises from the potential of extreme weather conditions in the future. Whilst the modelling of 35 climate years captures insights into the spread, resulting from climatic variations, the core modelling results reflect the average across the climate years.

Table 4.5 Low, median and high peak demand key assumption differences

	Low	Median	High
Number of Electric Vehicles	75% Climate Action Plan Targets	100% Climate Action Plan Targets	110% Climate Action Plan Targets
Number of Domestic and Commercial Heat Pumps	75% Climate Action Plan Targets	100% Climate Action Plan Targets	110% Climate Action Plan Targets
Data Centre and New Technology Loads	Low Ramp	Median Ramp	High Ramp
Economic Growth Projection	75% ESRI Economic Projection	100% ESRI Economic Projection	110% ESRI Economic Projection

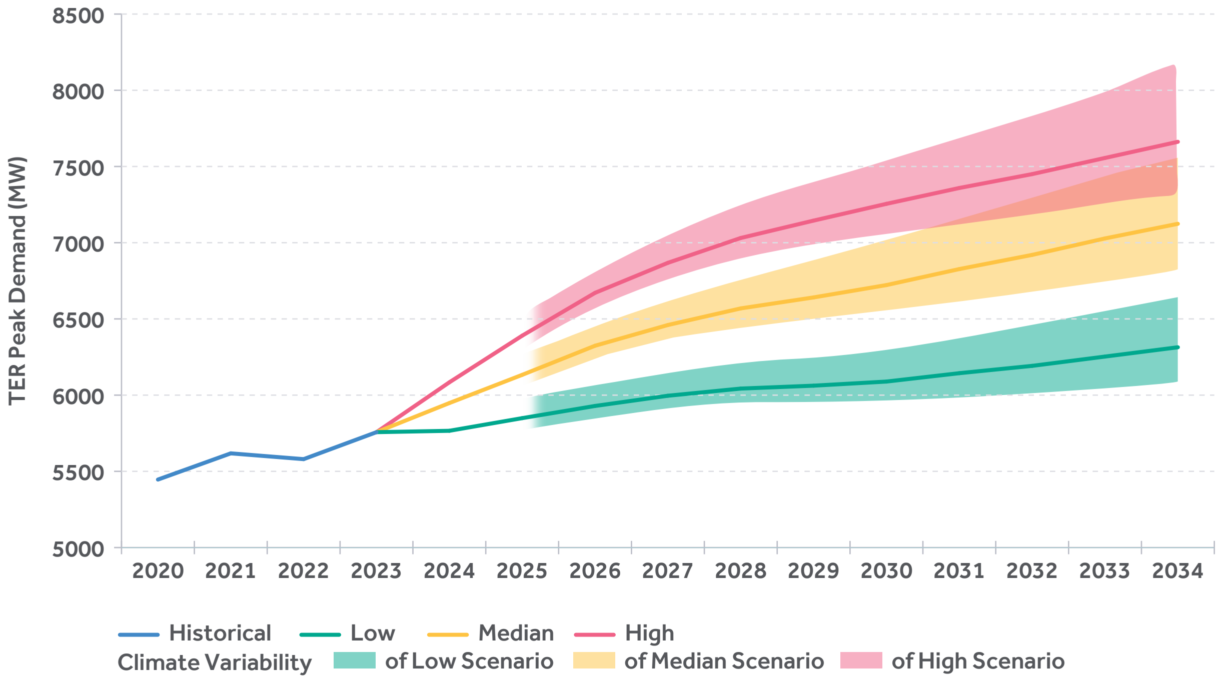


Figure 4.11 Impact of climate variability in Ireland on peak demand

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. The government has ambitious targets for EV and heat pumps which are required to meet climate objectives. With large amounts of these new technologies, consumer behaviour will have a significant impact on the daily demand profile. ENTSOE's Demand Forecasting Tool 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 peak, circa 7-9am and 5-7pm respectively, the forecast demand profile sees the addition of a peak in the early hours of the morning at approximately midnight shown in Figure 4.12. This newer spike in demand is primarily driven by the projected numbers of EVs adopting ENTSOE's Ten Year Network Development Plan (TYNDP) 2022 charging profile[37] which favours night-time charging of EVs i.e. EV owners scheduling their vehicles to begin charging at traditionally "off-peak" hours shown in Figure 4.13.

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

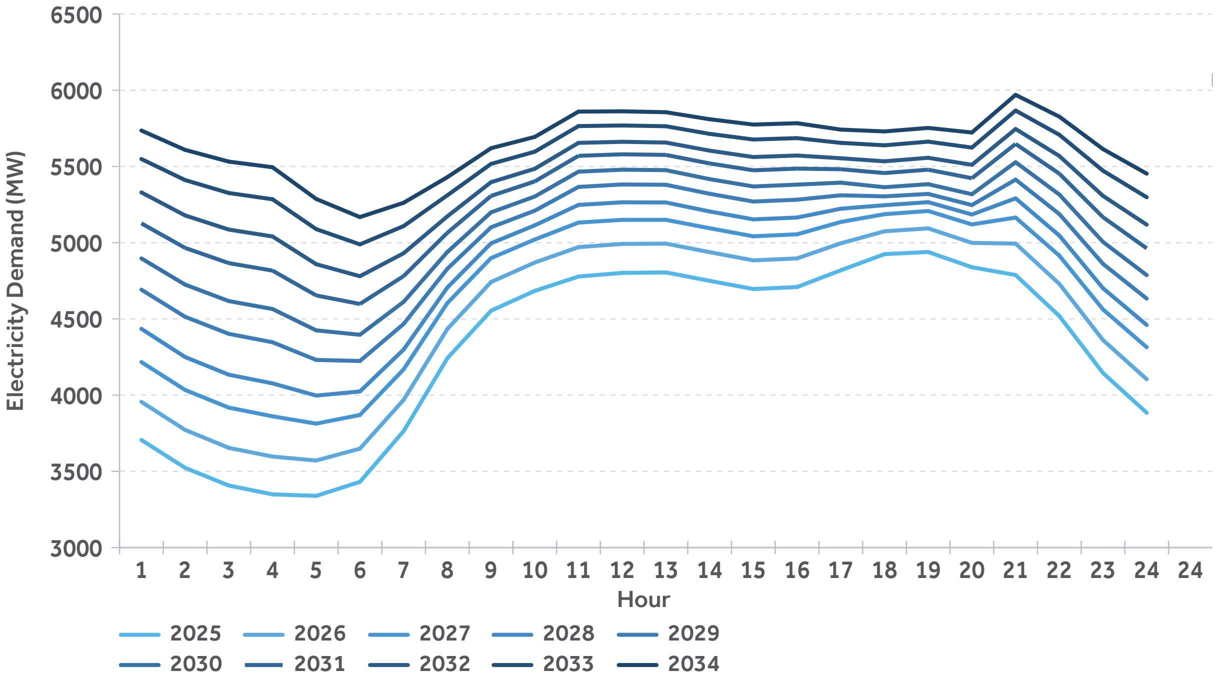


Figure 4.12 Forecast hourly demand shape in Ireland

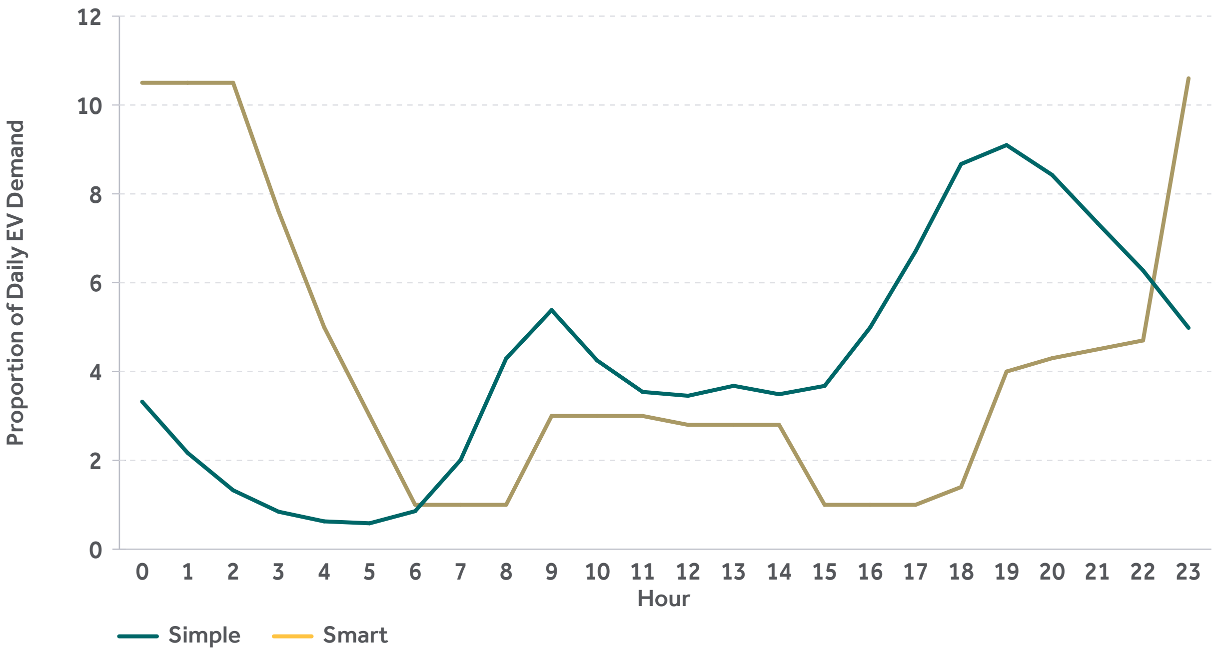


Figure 4.13 Electric vehicle charging profiles

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. SONI consulted on the demand forecasting methodology. Further details are available in the report 'Resource Adequacy Assessment Methodology for Ireland and Northern Ireland'[38].

The Northern Ireland Executive's new 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.

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 Department of Agriculture, Environment and Rural Affairs (DAERA) are 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, DfE published The Path to Net Zero – Action Plan 2022, 2023 and 2024. The Action Plan 2024 is an integral part of delivering the overall energy strategy. These actions will be taken forward during 2024 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.

Given the degree of uncertainty in the future, SONI is of the view that it is prudent to consider three alternative scenarios to derive an estimate of electricity demand. Combining a range of factors including temperature, economics, data centre and new technology load growth, energy efficiency, as well as electrification of heat and transport, allows for the formulation of low, median, and high demand forecasts.

The median demand forecast is based on an average temperature year based on a thirty-five year average. It includes assumptions on electrification of heat and transport, future energy efficiency in the electricity system, 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 is based on a relatively high temperature year, lower levels of electrification of heat and transport with higher levels of energy efficiency and the pessimistic economic factor being applied. Conversely, the high demand forecast is based on a relatively low temperature year, higher levels of electrification of heat and transport with lower levels of energy efficiency and the more optimistic economic factor being applied.

38 All-Island Resource Adequacy Assessment Methodology, https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034-Methodology.pdf

4.3.2 Economic forecast

The 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

There have been applications from data centres seeking to connect in Northern Ireland. In order to capture the impact, SONI has based the demand forecast scenarios on different build-out scenarios. The low demand scenario assumes no data centre load. The median demand scenario includes new data centre load in the connection process. In addition to this, the high demand scenario contains potential additional load that may 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.

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 from 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 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 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. 'Smart' 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 smart vehicle charging technology is realised otherwise additional capacity will be required.

The numbers of electric vehicles and heat pumps included in the low, median and high demand forecast are detailed in Table 4.6 with a linear uptake assumed in interim years. The number of electric vehicles and heat pumps are based on Northern Ireland Electricity Networks (NIE Networks) Regulatory Price Control 7 (RP7) figures[39]. This is consistent with GCS 2023-2032 to facilitate consistency in planning across the transmission and distribution systems. Looking forward to future iterations of the NRAA, SONI will seek to utilise the most up to date information available and will review the use of NIEN RP7 figures.

39 https://www.nienetworks.co.uk/rp7-business-plan

Table 4.6 Number of electric vehicles 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	73,000	15,000	100,000	22,000	101,000	25,000
2030	250,000	80,000	300,000	120,000	320,000	140,000

4.3.5 Total Electricity Requirement forecast

The Total Electricity Requirement (TER) is 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 power sector distribution and transmission system losses. Approximately 7-8% TER is lost as it passes through the electricity transmission and distribution systems.

SONI has been working with Northern Ireland Electricity Networks (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 photo voltaic.

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. Self-consumption in Northern Ireland currently represents approximately 3% of TER.

The updated TER forecast in Figure 4.14 shows reductions in the low, median, and high scenarios when compared to the forecast published in the Generation Capacity Statement 2023-2032. This is due to the reduction in electricity consumption that materialised in the later part of 2022 and continued into 2023 due to the impact of global events and the impact of high fuel prices. The difference between the median and high demand scenarios is based on several factors including the effect of temperature, economics, data centre and new technology load growth, energy efficiency as well as electrification of heat and transport.

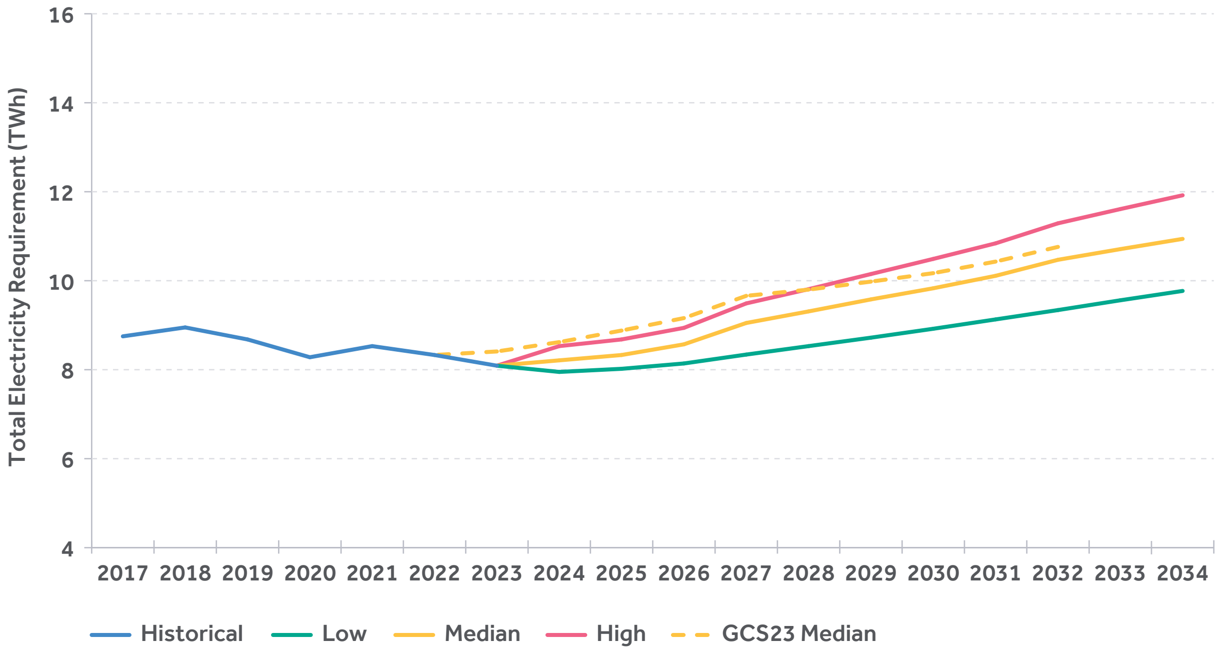


Figure 4.14 Northern Ireland TER forecast

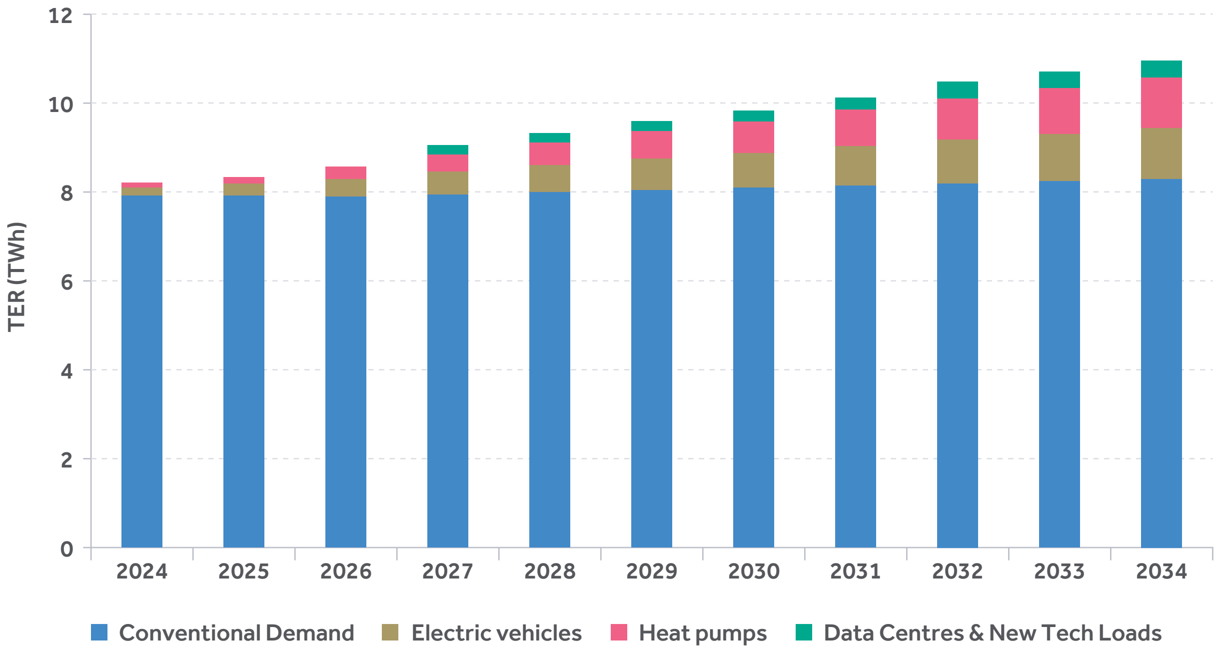


Figure 4.15 - Northern Ireland TER forecast components

Figure 4.15 illustrates how the TER demand forecast is built up from the various components for the years 2024 to 2034. Growth in TER is primarily driven by the electrification of heat and transport in line with government policies.

Table 4.7 shows the key assumption differences between the low, median, and high Total Electricity Requirement in the forecast scenarios shown above.

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

	Low	Median	High
Number of Electric Vehicles	NIE Networks RP7 Projections	NIE Networks RP7 Projections	NIE Networks RP7 Projections
Number of Heat Pumps	NIE Networks RP7 Projections	NIE Networks RP7 Projections	NIE Networks RP7 Projections
Data Centre and New Technology Loads	None	Median Ramp[40]	High Ramp
Economic Growth Projection	Oxford Economics Ten Year Forecast Less 1%	Oxford Economics Ten Year Forecast	Oxford Economics Ten Year Forecast Plus 1%

40 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.

4.3.6 Peak demand forecasting

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

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 Northern Ireland 2022/23 sent out peak of 1520 MW occurred on Wednesday 13 December 2022 at 17:30. When ACS temperature correction is applied the peak becomes 1514 MW.

As with the annual electricity demand forecast outlined in section 4.3.5, 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 smart charging is assumed for electric vehicles within the forecast, the benefits of which are shown in Figure 4.17 and Figure 4.18. To realise these benefits, appropriate policies and incentives are required, otherwise additional generation capacity will be necessary.

SONI has utilised the ENTSO-E Demand Forecasting Toolbox (DFT) to create the low, median and high peak demand forecasts. Similar to GCS 2023-2032, SONI has used temperature variation to give a plausible range between the low and high peak forecasts i.e. the low peak forecast is based on a mild winter (2007), and the high scenario is based on a very cold winter (2009). This has been based on historical records over the thirty-five climate years modelled in the DFT. While SONI does not expect an extremely warm or extremely cold winter every year, this range of scenarios is within the bounds of probability.

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 as well as the impact of climatic variability. This forecast employs a similar methodology as that used in the TER forecast and utilises the DFT modelling tool. Figure 4.16 shows the Transmission Peak forecast for Northern Ireland. The resulting forecast up to 2029 has reduced compared to the GCS 2023-2032 median scenario. This is due to the reduction in electricity consumption observed at peak time due to the impact of global events and the impact on fuel prices and increased efficiency. The expectation is for peak demand to continue to be suppressed due to high prices through to 2026. Beyond 2026 growth in peak demand is expected to be driven by data centre development as well electrification of heat and transport. From 2029 and until the end of the study horizon the demand forecast closely aligns with the GCS 2023-2032.

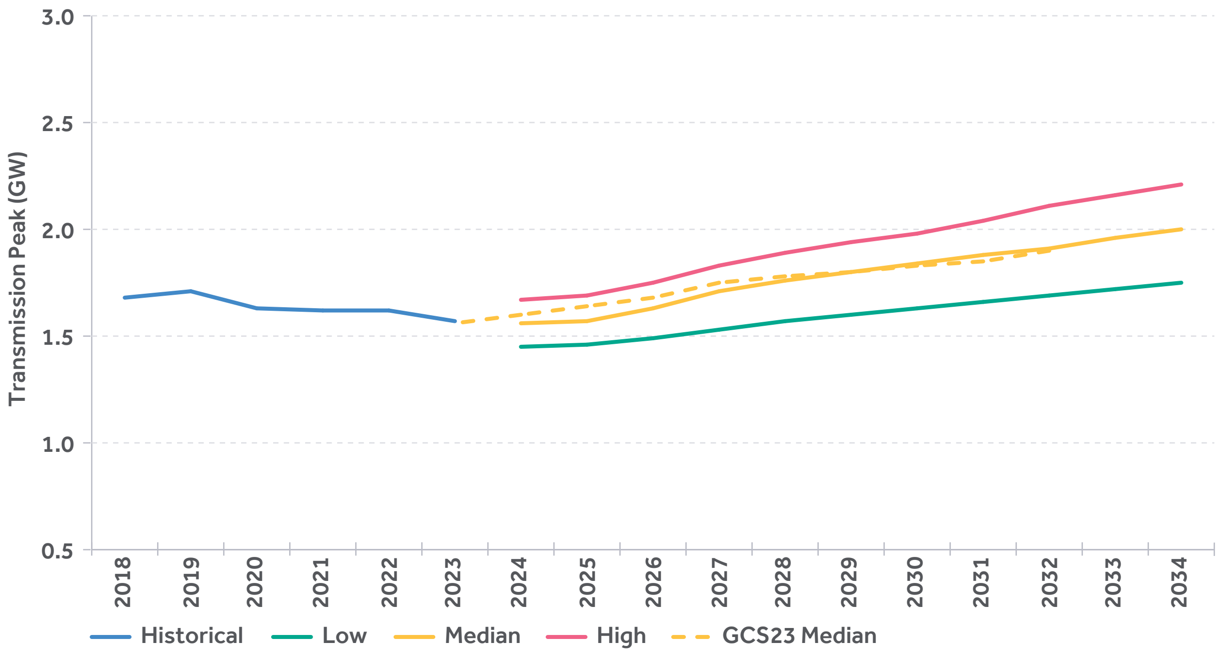


Figure 4.16 ACS transmission peak forecasts for Northern Ireland

Table 4.8 shows the key assumption differences between the low, median, and high peak electricity demand scenarios in the forecasts shown above.

Table 4.8 Low, median and high peak demand key assumption differences

	Low	Median	High
Number of Electric Vehicles	NIEN RP7 Projections	NIEN RP7 Projections	NIEN RP7 Projections
Number of Heat Pumps	NIEN RP7 Projections	NIEN RP7 Projections	NIEN RP7 Projections
Data Centre and New Technology Loads	None	Median Ramp	High Ramp
Economic Growth Projection	Oxford Economics Ten Year Forecast Less 1%	Oxford Economics Ten Year Forecast	Oxford Economics Ten Year Forecast Plus 1%
Temperature	One in 35 Year Mild	35 Year Average	One in 35 Year Cold

Appendix 1: Demand Scenarios lists the detailed energy and peak data out to 2034 including growth rates. Demand flexibility has the capability to improve the adequacy of the electricity system by moving demand away from peak times. Figure 4.17 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. Off-peak electric vehicle charging reduces peak demand by around 3% in this scenario.

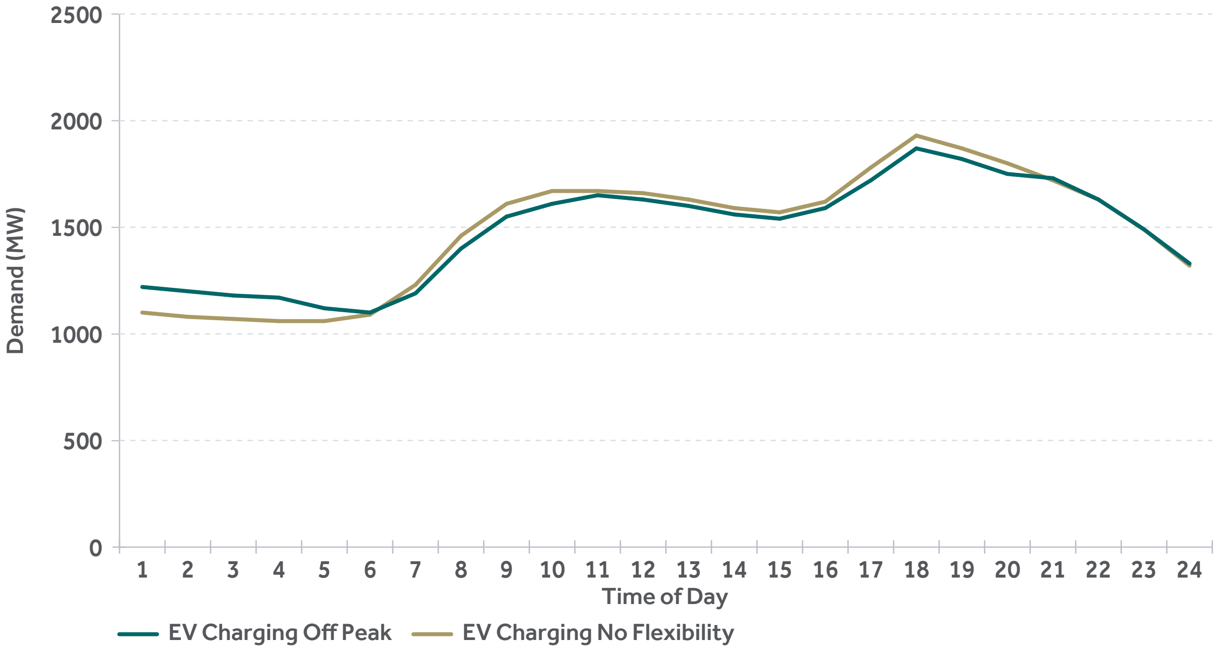


Figure 4.17 Impact of demand flexibility on 2030 peak day (median scenario)

Figure 4.18 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.

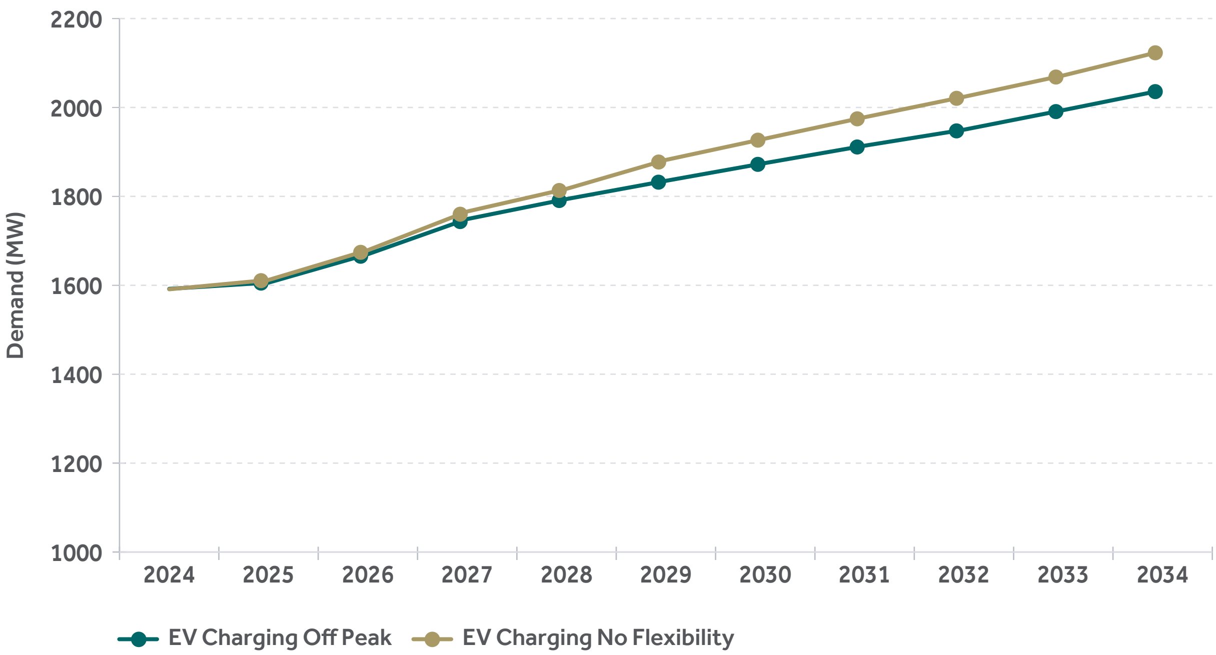


Figure 4.18 Impact of demand flexibility in median scenario across the study period

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 4.19 and Figure 4.20 below.

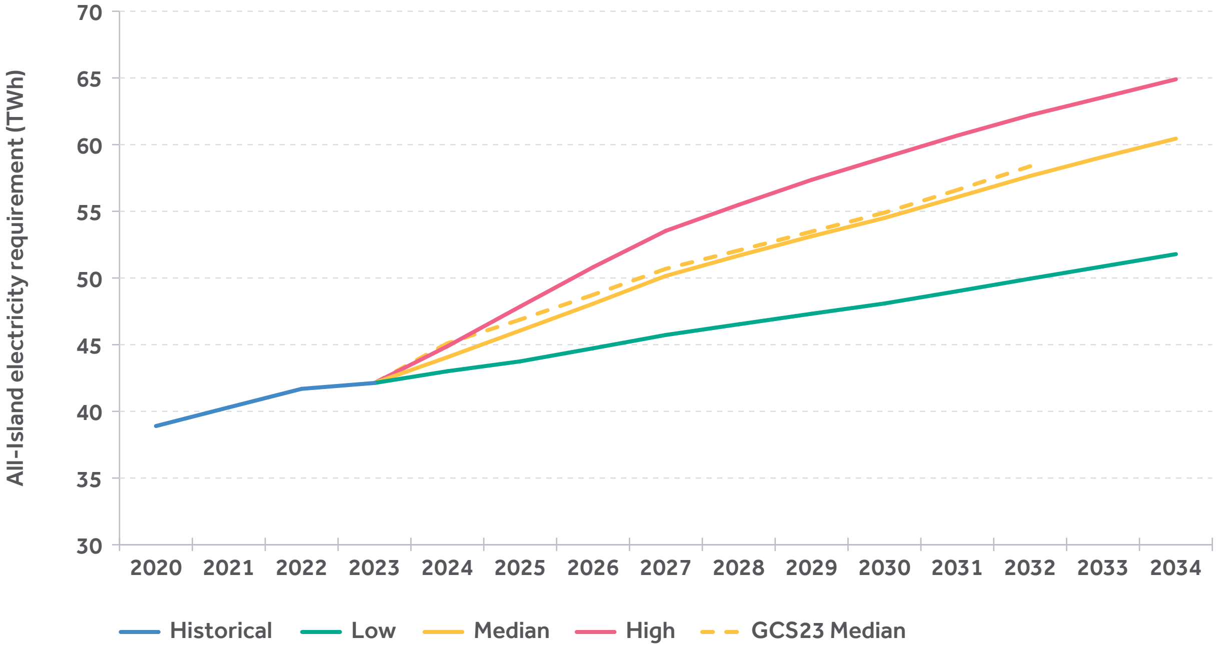


Figure 4.19 Combined TER forecast for all-island system

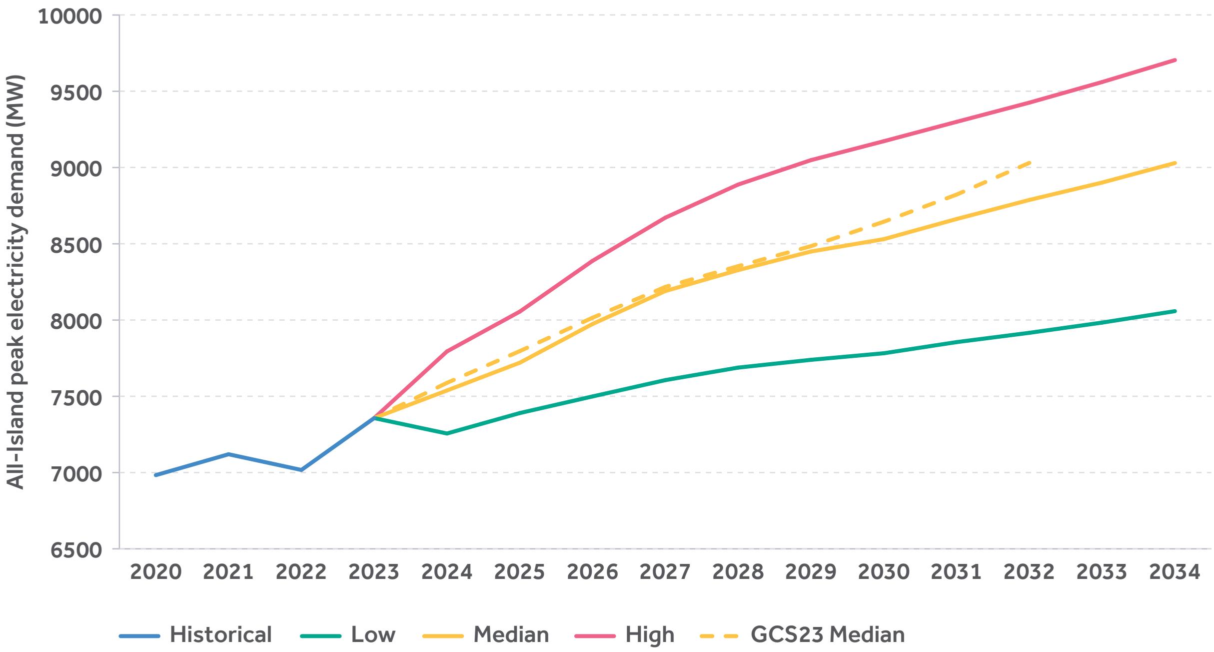


Figure 4.20 TER peak for the combined all-island forecast

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 in 2025. Note this does not include new capacity that may be commissioned during 2025. Based on the current portfolio trajectory, by the end of the study horizon in 2034 there will be approximately 1700 MW of conventional capacity over 30 years of age, which could be at risk of exiting the market if it is no longer economically viable to keep aging capacity operational in a power system predominantly powered by renewable energy. Furthermore, the declining performance and reliability of aging plant has presented a challenge to operation of the power system, and degrading performance of the existing portfolio could present similar risks in future.

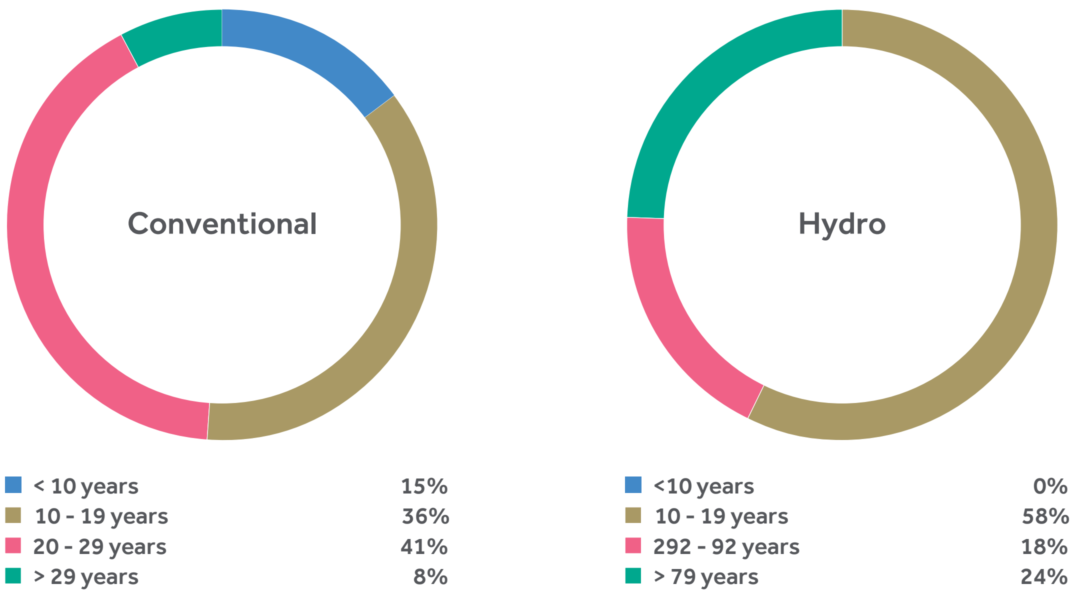


Figure 5.1 Age breakdown of dispatchable plant for the all-island system operational in 2025

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[41], encouraging the delivery of adequate supply to meet demand, excluding the non-energy services that are required to operate a power system securely.

Since 2018 the NI Executive and the Republic of 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[42] to deliver the market required to achieve renewable ambitions on the island of Ireland. The core market-focussed projects include Strategic Markets Programme (SMP), 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 for this assessment there have been 14 capacity auctions aiming to secure capacity up to and including 2027/2028 capacity year. The total volumes procured for each auction are presented in Appendix 2: Capacity Auction Results.

The forecast generation portfolio has been updated since the previous Generation Capacity Statement to include a risk adjusted view of the projects that were successful in capacity auctions up to and including the T-1 2024/2025, for which provisional results were published on the 8th May 2024.

41 https://www.sem-o.com/markets/developing-the-i-sem/index.xml
42 https://www.soni.ltd.uk/media/documents/Future-Power-Markets-Newsletter-Issue-10-July-2024.pdf

5.2.2 Deliverability risk assessment

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 and in respect of this, EirGrid and SONI are working with developers, regulatory authorities and other relevant agencies to monitor new capacity coming through the capacity auctions to monitor the deliverability of new projects and identify risks for the timely delivery of new capacity.

The enhanced monitoring programme of new capacity analyses a range of risk factors including supply chain analysis, risks to planning permission and grid (gas and electricity) connection timescales. The TSOs undertake a due diligence process at regular intervals with support from external partners with extensive experience in major power station projects, as well as Gas Networks Ireland, Mutual Energy and project developers to inform the TSO risk-adjusted view. Technical deliverability assessments determine whether projects are on track for early delivery, if they are expected to deliver late and whether, based on the current information, they are at a significant risk of not delivering. The outcome of this process is a risk-adjusted view of the delivery of new capacity, which EirGrid and SONI use in the core adequacy assessment.

In Ireland, the CRU continues to update its "CRU Information Paper Security of Electricity Supply – Programme of Actions", with the latest update published in April 2024. As part of this, Pillar C is focussed on the deliverability of new capacity.

It is EirGrid and SONI's view, based on the current deliverability assessment, that there is a risk that not all awarded new capacity from previous auctions will be available on the 1st of October of the target capacity year out to 2034. Additionally, it is our view that there are some projects which have significant technical and/or planning challenges that could mean non-delivery, and that additional capacity will be required to cover this risk.

The GCS 2023–2032 and ongoing security of supply studies highlighted the negative impact to system adequacy from the risk of new capacity not becoming available on time. In the short to medium term, failure to deliver new capacity for a given capacity year presents significant challenges to the adequacy position of the system. If new capacity fails to deliver on time for a given capacity year, mitigating measures are required to ensure alternative capacity is made available.

A sensitivity has been included to examine the impact on adequacy if all new capacity was delivered for the start of the capacity year for which the capacity contract was awarded i.e. if all new projects delivered on time.

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. The steam turbine category includes coal and heavy fuel oil (HFO).

5.3.1 Ireland portfolio

Figure 5.2 below shows the conventional portfolio in Ireland which is forecasted to be operational in the market in 2034, relative to the expected portfolio operational at the end of 2024. The differences in portfolio are driven by retirement of existing steam turbine units and introduction of new gas plant through the capacity market.

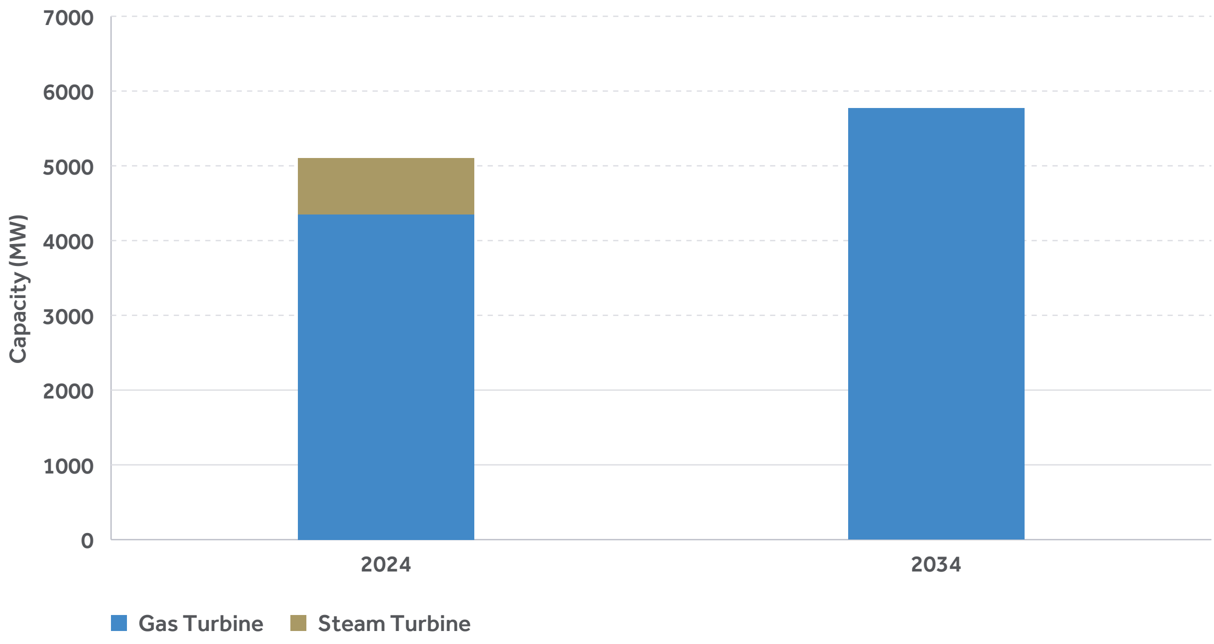


Figure 5.2 Conventional generation portfolio assumed in Ireland

In terms of the expected delivery of new capacity, Table 5.1 below presents the risk-adjusted view of capacity delivery at the data freeze date, relative to the total capacity that has been successful in the auctions.

Table 5.1 Ireland assumptions for new conventional plant capacities in adequacy studies (rated MW).

	2025	2026	2027	2028	Total
Total Successful in Capacity Auctions	980	120	1270	60	2430
Core Scenario Risk Adjusted View of New Capacity Delivery	530	290	760	60	1640

*This risk adjusted view is based on plant delivering early, delivering late, or not delivering. For reference, the capacity successful in capacity auctions that has not received a termination notice is also presented. Note all values are rounded to the nearest 10 MW and capacity is presented as capacity commissioning during the calendar year.

Table 5.2 below presents the expected changes to the existing conventional portfolio across the study horizon. It is worth noting that under Grid Code[43,44], 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 auctions which run at most 4 years ahead of time.

Some of the older generators in Ireland have informed EirGrid of their intention to decommission, as detailed below in Table 5.2. A common reason for plant decommissioning is increasing restrictions due to Industrial Emissions Directive (IED) legislation. 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.

Table 5.2 Assumptions for conventional plant changes in Ireland

Plant	Units	Export capacity (MW)	Expected Closure date	Comment
Aghada	AT1	90	-	Previously assumed to close at the end of 2023, however, is now assumed to be operational for the entire study period as the closure notice for the unit has been withdrawn.
Moneypoint	MP1 MP2 MP3	250 250 250	End of June 2025	Following submission of a closure notice and the outcome of the 2024/2025 T-1 Capacity Auction, these units are considered as in-market resources until the end of June 2025, at which point they will no longer be eligible for capacity payments due to CO2 limits. EirGrid notes that these units will be retained beyond this date for security of supply purposes. However, this is considered a mitigating measure and not part of the core scenario. MP2 is now running on Heavy Fuel Oil (HFO) with a capacity of 250 MW. The declared availability of MP1 and MP3 has declined recently and is now on average 250 MW.
Edenderry	ED3	58	N/A	Awarded capacity in the 2025/2026 T-4 capacity auction to switch fuel from Distillate Oil to Gas
	ED5	58	N/A	Awarded capacity in the 2025/2026 T-4 capacity auction to switch fuel from Distillate Oil to Gas

43 EirGrid Grid Code Version 14.144
44 SONI Grid Code April 2024
45 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN

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 ST1 and ST2 in September 2023. New capacity awarded through the capacity market auctions, in the form of the KGT6 and KGT7 units, has been developed and is assumed to be fully operational in-market from the start of the study horizon in 2025.

Kilroot units KGT1, KGT2, KGT3 and KGT4 were previously expected to have an extended planned outage in 2025 as they were not included in the 2024/2025 T-4 auction in January 2021. The units have since been awarded a capacity contract in the 2024/2025 T-1 auction and this is reflected in our modelling with these units being available in 2025 and for all other years of the studies.

In GCS 2023-2032, risks were identified regarding the new KGT6 and KGT7 units' delivery dates, concerns relating to annual run hour limitations on existing plant and new steam turbine capacity entering the market. The developer has informed SONI of annual run hour limitation on the new capacity awarded through several SEM T-4 auctions.

Annual run hour limitations are due to legal requirements in relation to the application of the Industrial Emissions Directive (IED) Best Available Techniques (BAT) conclusions which provide guidance on the best available techniques to ensure combustion technologies comply with emissions levels including Carbon Dioxide, Carbon Monoxide, NOx, SOx and particulate matter. The impact of constraints such as annual run hour limitations should be understood in the context of security of supply assessments. Where possible, technologies should be designed and operated to maximise its availability while minimising the impact on system wide emissions, otherwise there may be a negative impact on security of supply and the environment.

In GCS 2023-2032 the developer confirmed that the new capacity would be subject to Annual Run Hour Limitations (ARHL). Also at the time of GCS 2023-2032, an additional 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 new 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. Since the publication of GCS 2023-2032, this additional turbine has had its capacity market contract terminated[46] and as such SONI are assuming KGT6 and KGT7 will be subject to ARHL for the duration of the study horizon.

There are no changes forecast to the portfolio in Northern Ireland across the study horizon, shown in Figure 5.3.

46 https://www.sem-o.com/documents/general-publications/J.6.1.3-(f)-Capacity-Market_Capacity-Termination-Notice-GU_504020-110124.pdf

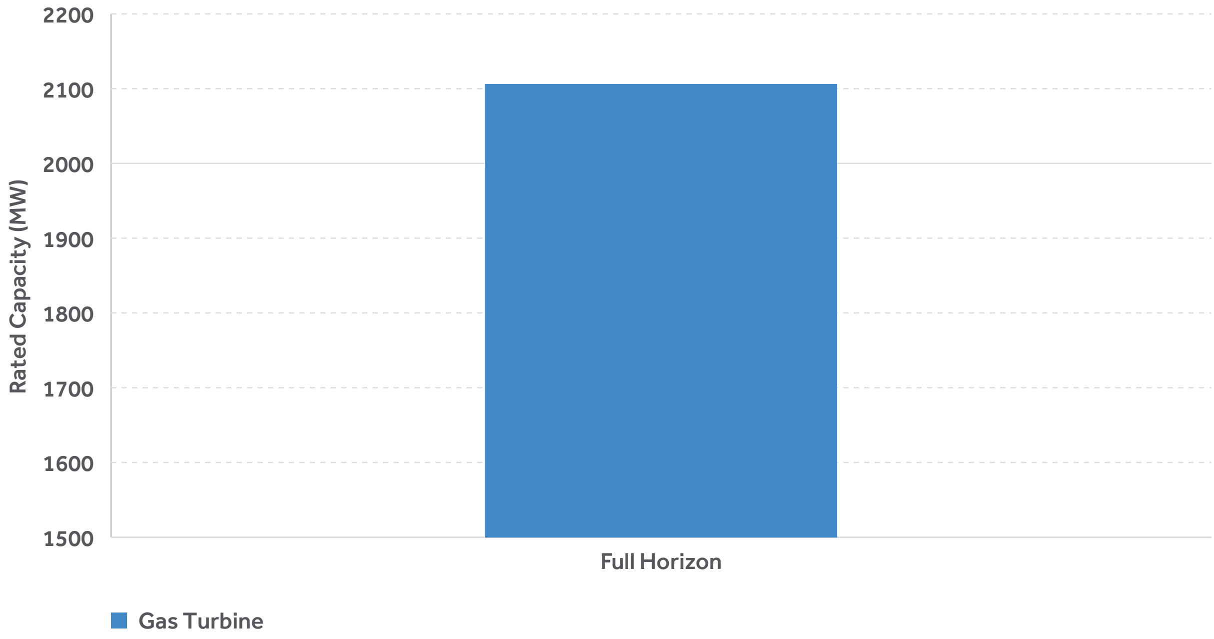
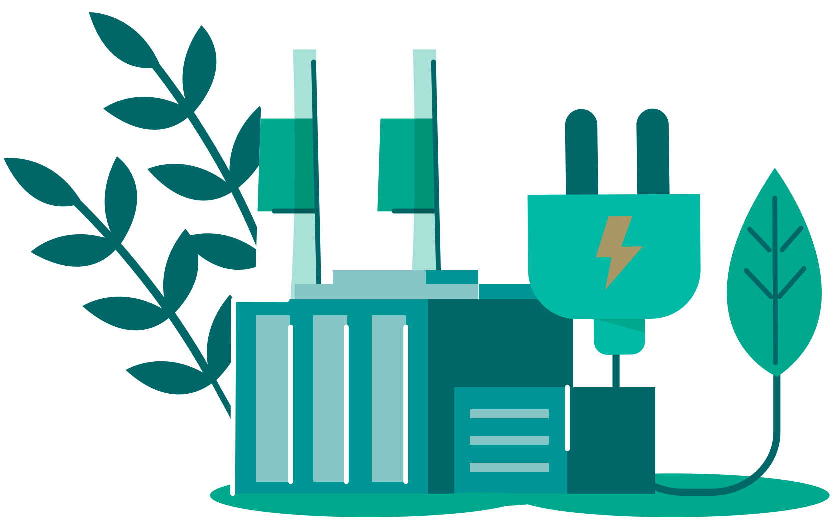


Figure 5.3 Conventional generation portfolio assumed in Northern Ireland



5.3.3 Operational restrictions

There are a number of new thermal 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 1500 hours of operational availability on an annual basis provides less value to reliable system operation than a unit which is available for 8760 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.

In 2017, the European Commission published a final decision on the Best Available Techniques[47] (BAT) for large combustion plants, which has applied new standards on emissions from August 2021. The latest BAT conclusions were published in February 2021[48]. 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 1500 hours depending on the units' technical characteristics (fuel source / efficiency).

48 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021D2326

In Ireland, there are a number of new units which have indicated that they will operate using non-conventional fuels as their as their primary fuel type for example Hydrogenated Vegetable Oil (HVO). The information relating to potential ARHL on units is evolving and it is uncertain whether there will be emissions legislation and possibly fuel supply challenges 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, DECC and project developers to understand operational restrictions that may be placed on units operating. Acknowledging the information is evolving, the Base scenario adequacy assessment assumes new capacity is not subject to run hour restrictions (unless ARHL has been confirmed by the relevant developer). To analyse the potential impact of such operating limits, the Secure assessment assumes some new units are restricted to a 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	2025	2026	2027	2028	2029	2030
500 hours*	270	390	840	840	730	730
1500 hours	210	210	210	210	210	210

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

Table 5.4 below indicates the cumulative capacity expected to be subject to run hour restrictions out to 2030 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	2025	2026	2027	2028	2029	2030
500 hours	310	310	310	310	310	310
1500 hours	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) and Moyle interconnectors provides a significant benefit to secure operation of the power systems in Ireland and Northern Ireland. It also allows balancing market opportunities for direct trading between the system operators, known as countertrading.

The existing North South Interconnector (between Louth and Tandragee), or the North South tie-line, plays a key role in system security and adequacy in both jurisdictions. Further transmission links between Ireland and Northern Ireland, including the second North South Interconnector would significantly enhance access to generation capacity in both jurisdictions.

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[49]. The All-Island Resource Adequacy Assessment includes the new North South Tie Line, whereas the jurisdictional core Resource Adequacy Assessments do not include the new North South Tie Line. These studies assume an NTC value lower than the actual physical rated capacity of the lines since operational rule and network N-1 contingencies are accounted for.

Table 5.5 below includes the assumption on the net transfer capacities for the tie line between Ireland and Northern Ireland, used in this assessment. The table also includes the additional increase in net transfer capacity once the second high-capacity transmission link between Ireland and Northern Ireland is assumed to be available by 2027. The total North South NTC from 2027 is therefore 1200 MW North to South direction and 1250 MW South to North direction.

Table 5.5 North south tie line 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 core adequacy assessments.
900	950	New North South Tie Line. Included from 2027 for the All-Island assessment.

49 TYNDP 2022 Project Collection (tyndp2022-project-platform.azurewebsites.net)

For the purposes of this report, an all-island generation adequacy assessment has been included, presenting results from 2027[50] onwards, in Section 6.6. Prior to the completion of this 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; therefore an all-island study has not been carried out.

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 500 MW, however this is assumed to increase to full 500 MW bi-directional utilisation from 2028 following delivery of the Moyle Interconnector Capacity Increase project[51].

For the purpose of the adequacy assessments undertaken in this report, the Greenlink interconnector connects the transmission systems of Ireland and Wales with a capacity of 500 MW in both directions and is assumed available from the start of 2025; and the Celtic interconnector connects the transmission systems of Ireland and France with a capacity of 700 MW in both directions and is assumed available from the start of 2027.

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

Table 5.6 HVDC net transfer capacity (MW) assumptions

	2025	2026	2027	2028	2029	2030
Moyle	450	450	450	500	500	500
EWIC	500	500	500	500	500	500
Greenlink	500	500	500	500	500	500
Celtic	0	0	700	700	700	700

50 Note this information was correct at the data freeze date. Updated post data freeze date information is referenced in section 6.3 estimated energisation in October 2031.
51 Draft Transmission Development Plan Northern Ireland 2023-2032

5.4.3 Further interconnection

There are further connection projects noted in ENTSO-E's most recent Ten-Year Network Development Plan 2022. In Northern Ireland there is potential for a new 700 MW interconnector to Scotland[52], with one potential operator (LirIC) receiving an interconnector licence from Ofgem. The Utility Regulator consulted[53] on the intended approach to the granting of a transmission license to Transmission Investment (TI) LirIC Limited in July 2024.

In Ireland, there is potential for a new 750 MW interconnector project (MARES Connect[54]) 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	2029	700
MARES Connect	Interconnector between Ireland and Wales	2029	750

52 LirIC - Transmission Investment (tinv.com)
53 Consultation on Proposed Electricity Transmission Licence for Transmission Investment LIRIC Limited
54 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 by 2030 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 four auctions conducted to date including three 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.

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.

The Sustainable Energy Authority of Ireland (SEAI) has developed forecasts[55] for variable generation capacity from surveys of expert stakeholders. The median forecast (EPO50) from this analysis has been selected for the core scenario 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.

55 SEAI Variable Generation Capacity Forecasts

The SEAI median forecast has been compared against EirGrid's internal developed trajectory discussed above, and the central estimate aligns with expectations for onshore wind and solar. In terms of offshore wind, both the expert elicitation and EirGrid's assessment of project timelines indicates timely delivery of the offshore project pipeline remains challenging. The core variable generation trajectory is shown in Figure 5.4 below.

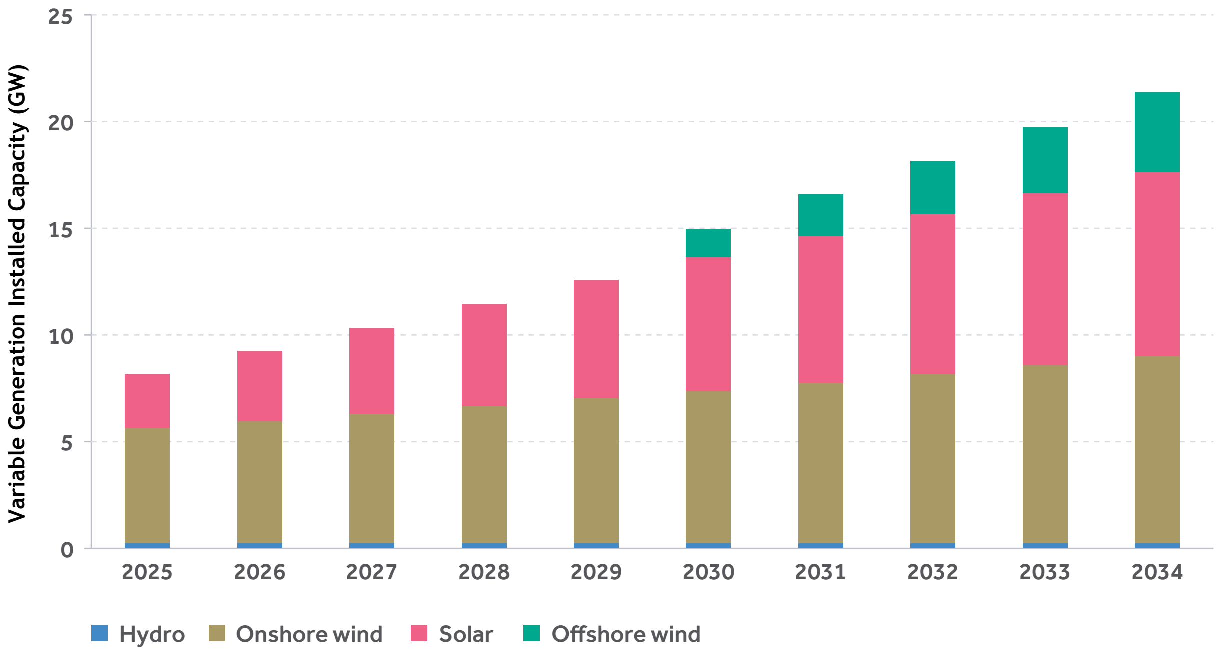


Figure 5.4 Assumed growth of variable generation capacity in Ireland

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 benefits that of full delivery of renewables to support the Climate Action Plan. The first sensitivity assumed the Shaping Our Electricity Future (SOEF) v1.1[56] low emissions renewable trajectory, which is aligned to the Climate Action Plan 2024. A second sensitivity also analyses the effect of a slower renewable buildout on system adequacy.

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[57] 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[58] was enacted in June 2022. Key aspects of this legislation include a target of at least 100% reduction in 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[59] and more recently The Path to Net Zero – Action Plan 2024[60]. The Action Plan 2024 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 2024. The strategy includes a target of 'at least 80% of electricity consumption from a diverse mix of renewable sources by 2030'. The renewable build out assumed for these studies is based on an 80% RES-E target.

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 intermittent 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 2024 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 place as detailed in the Northern Ireland Energy Strategy. The Department

56 cms.eirgrid.ie/sites/default/files/publications/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf
57 The Path to Net Zero Energy. Safe. Affordable. Clean. (economy-ni.gov.uk)
58 https://www.legislation.gov.uk/nia/2022/31/enacted
59 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf
60 Energy Strategy - Path to Net Zero Energy - 2024 Action Plan Report (economy-ni.gov.uk)

for the Economy consulted on the design considerations for a new scheme in February 2023, and a High-Level Design (HLD) has been published for a new Renewable Electricity Support Scheme (RESS) for Northern Ireland[61]. The HLD follows extensive stakeholder engagement and outlines the policy objectives of the scheme, features of the design and a roadmap of procurement under the scheme by 2030.

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.

The uncertainty regarding delivery of new renewable energy capacity is reflected in the assumed renewable trajectory shown in Figure 5.5. The core scenario assumes a lower trajectory than the renewable capacity required to achieve the 80% RES-E target as set out in Shaping Our Electricity Future v1.1 Roadmap, which is a prudent planning approach for resource adequacy assessments where the purpose is to identify risks to the balance between supply and demand.

A sensitivity is included to assess the future renewable capacity growth required to achieve an 80% renewable ambition aligned with the Shaping Our Electricity Future v1.1 Roadmap, and a further sensitivity analyses the impact of delays to renewable delivery on resource adequacy.

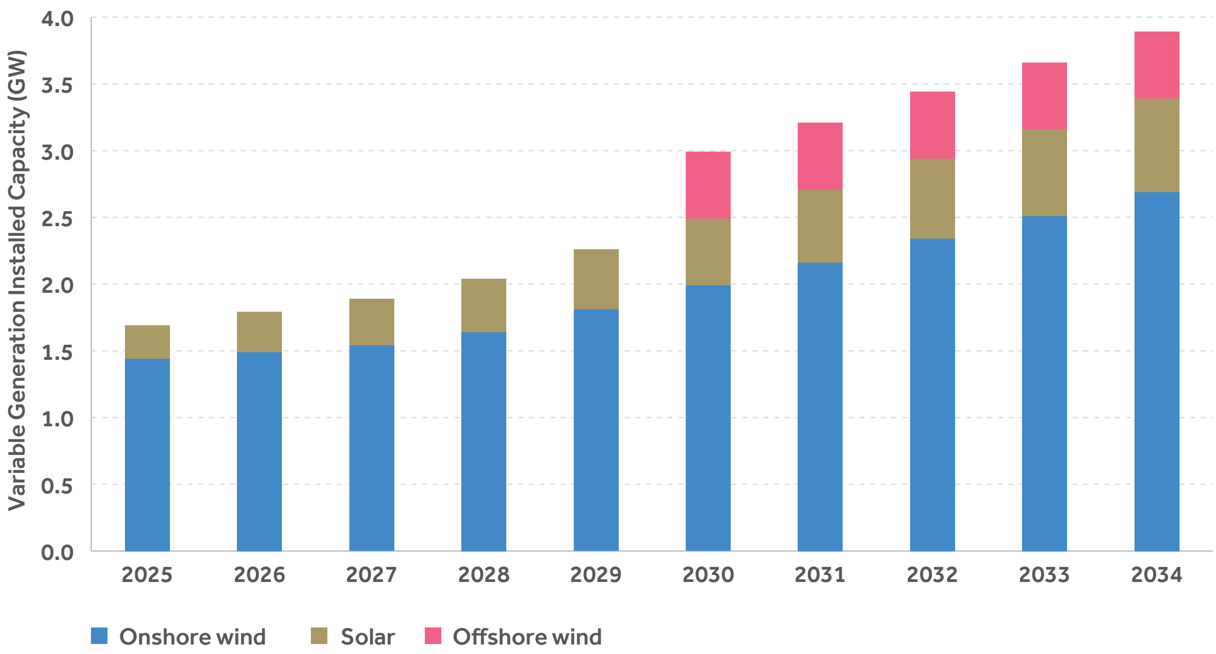


Figure 5.5 Assumed growth of renewable capacity in Northern Ireland

61 Renewable Electricity Support Scheme (economy-ni.gov.uk)

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 all-island 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[62] 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 pumped storage and batteries currently connected to the electricity system in each jurisdiction, and storage capacity that has been awarded contracts in the capacity auctions. As capacity auctions for the period 2029 onwards have yet to run, these studies use the 2028 value for the remainder of study horizon.

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 1.7 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.

62 https://cms.eirgrid.ie/sites/default/files/publications/Operational-Policy-Roadmap-2023-to-2030.pdf

Table 5.9 Ireland energy storage capacity (MW)						
Duration	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
<= 1 Hour	440	460	460	460	460	460
1-2 Hours	290	290	290	370	370	370
> 2 Hours	380	400	540	540	540	540
Total	1110	1150	1290	1370	1370	1370

Table 5.10 Ireland energy storage (MWh)						
Duration	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
<= 1 Hour	270	280	280	280	280	280
1-2 Hours	570	570	570	690	690	690
> 2 Hours	1780	1850	2360	2360	2360	2360
Total	2620	2700	3210	3330	3330	3330

In 2030, Ireland is assumed to have 1370 MW of generation capacity attributed to storage technologies, and 3330 MWh of storage capacity, this means storage can provide 1370 MW of power for almost 2.5 hours.

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.

Table 5.11 Northern Ireland energy storage capacity (MW)						
Duration	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
<= 1 Hour	200	200	200	200	200	200
1-2 Hours	0	0	0	0	0	0
> 2 Hours	0	0	0	0	0	0
Total	200	200	200	200	200	200

Table 5.12 Northern Ireland energy storage (MWh)						
Duration	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
<= 1 Hour	140	140	140	140	140	140
1-2 Hours	0	0	0	0	0	0
> 2 Hours	0	0	0	0	0	0
Total	140	140	140	140	140	140

Northern Ireland has 200 MW of generation capacity attributed to storage technologies, and 140 MWh of storage capacity, this means storage can provide 200 MW of power for over 40 minutes.

5.6.3 Long duration energy storage

The 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 the Environment, Climate and Communications (DECC) consulted[64] 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[63] which included grid flexibility options.

In November 2023, EirGrid and SONI published a Call for Evidence on the Market Procurement Options[65] 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. Given the uncertainty in terms of delivery of LDES projects, these have not been included in the core numbers 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 new sensitivity has been included to examine the value of LDES from a resource adequacy perspective.

63 Consultation on Developing an Electricity Storage Policy Framework for Ireland
64 Transitioning to a net zero energy system - Consultation on design considerations for a Northern Ireland Smart Systems and Flexibility Plan (economy-ni.gov.uk)
65 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 2028 are based on auction results. However, as auctions for the period 2029 onwards have yet to run, the studies use the 2028 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. Note, the capacities out to 2028 are based on auction results. However, as auctions for the period 2029 onwards have yet to run, the studies use the 2028 value for the remainder of the study horizon.

Table 5.13 Ireland DSU capacity (MW)

	2025	2026	2027	2028	2029	2030
Run Hour Limited	660	540	510	550	550	550
Non-Run Hour Limited	170	150	210	310	310	310

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

Table 5.14 Ireland DSU run hour restriction (hours)

	2025	2026	2027	2028	2029	2030
Daily Activation Limit	2	2	3	3	3	3

Industrial generation refers to generation usually powered by diesel or gas, located on industrial or commercial premises, which act as on-site supply during peak demand and emergency periods. The condition and mode of operation of this plant is uncertain, as some of these units fall outside the control of the TSOs. Industrial generation has been ascribed a capacity of 9 MW in Ireland for the purposes of this report.

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)

	2025	2026	2027	2028	2029	2030
Run Hour Limited	200	220	100	160	160	160
Non-Run Hour Limited	0	0	30	10	10	10

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)

	2025	2026	2027	2028	2029	2030
Daily Activation Limit	5	5	5	5	5	5

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)

	2025	2026	2027	2028	2029	2030
AGU	79	79	79	79	79	79

5.8. Other non-conventional generation

5.8.1 Small-scale CHP

Combined Heat and Power (CHP) uses 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 are approximately 160 MW of CHP units in Ireland, and these are included in the GCS 2023-2032 studies. These units are mostly gas-fired. For clarity, this small-scale CHP figure does not include 160 MW of centrally dispatched CHP plant operated by Aughinish Alumina. 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.

5.8.3 Small-scale Hydro

EirGrid estimates there is currently 26 MW[66] 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.

66 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[67] within the study horizon are excluded from the outage statistics calculation.

The resultant statistics for the 5-year period from 2019-2023 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	*	*	*	28.4
DSU Run Hour Limited	*	*	*	28.2
Gas Turbine	8.9	5.3	470	85.8
Hydro	10.9	5.4	470	83.7
Steam Turbine	11.3	9.4	820	79.3
Interconnector	4.5	3.8	340	91.7
Pumped Hydro Storage	2.7	7.4	650	89.9
System Wide	19.2	7.7	680	73.1

* DSUs do not declare unit level forced and scheduled outages in the same way a generator does. Therefore, in line with the monthly availability reporting, availability of DSUs considers a capacity-weighted availability instead of forced and scheduled outage statistics.

67 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. The figures presented in this section are intended to present overall trends of actual plant availability for all units on the system during the 10-year period, and do not factor into the model.

Based on five years of data from 2019 up to and including 2023, EirGrid and SONI have observed a further marginal downward trending of the All-Island system 5-year average availability of dispatchable generation compared with the GCS 2023-2032 from 78% to 77%. Whilst availability of dispatchable generation improved in 2023 relative to 2022, it was still lower than 2018, which was the year replaced in the sliding 5-year window.

As previously communicated in recent GCS publications, declining plant availability has been a significant challenge in recent years in terms of managing supply and demand. The availability decline observed in Figure 5.6 as largely been driven by the deteriorating performance of units which are in their final years of operation, in line with expectations due to the aging equipment and infrastructure becoming less reliable but also the expected reductions in investment to maintain the performance of the plant.

The historic 5-year average availability of dispatchable generation is approximately 77%. As noted above, the statistics used in the modelling are calculated removing units that have retired or are due to retire within the study horizon. The historic 5-year average availability of the dispatchable generation units with these units removed is approximately 84%, this is also illustrated in Figure 5.6.

Through excluding retired or retiring units, the calculation captures the trend from units which are expected to be on the system during the study horizon. As shown, this does capture a reduced availability compared to the 2018 5-year average, however, does not reflect the very low availability from units as they reach the end of operational life. This approach therefore does not capture possible 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.

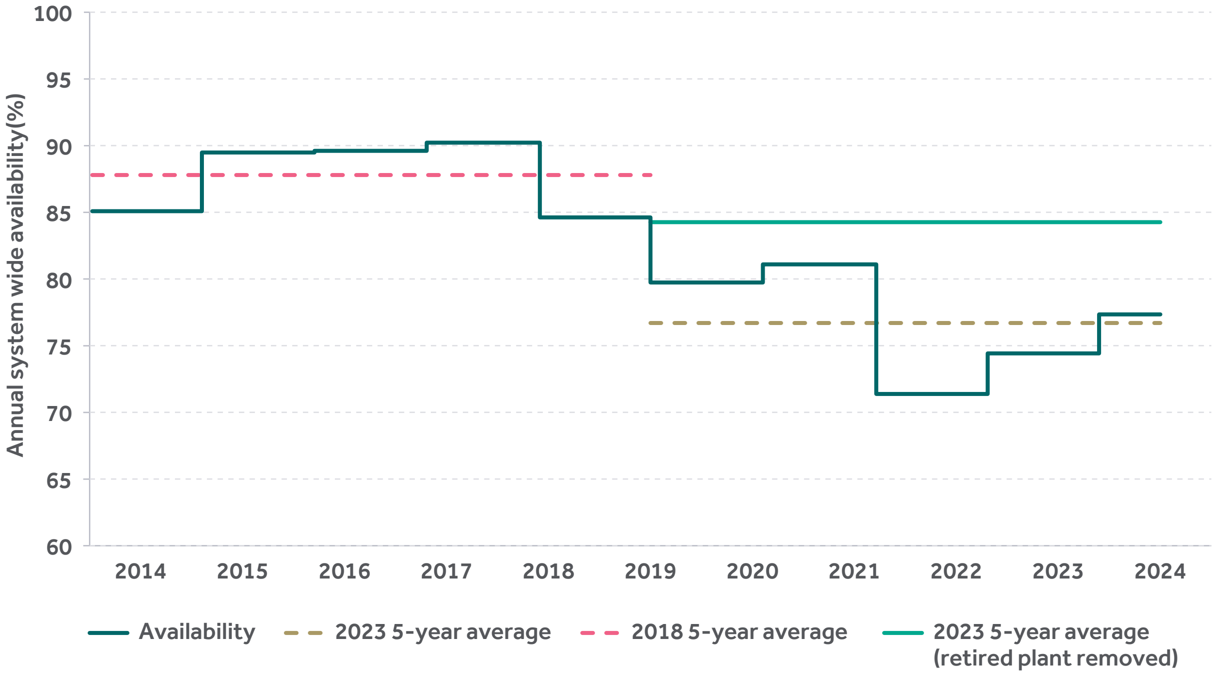


Figure 5.6 All-island average annual generation capacity availability for the past 10 years (excluding DSU)

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 5.7 below.

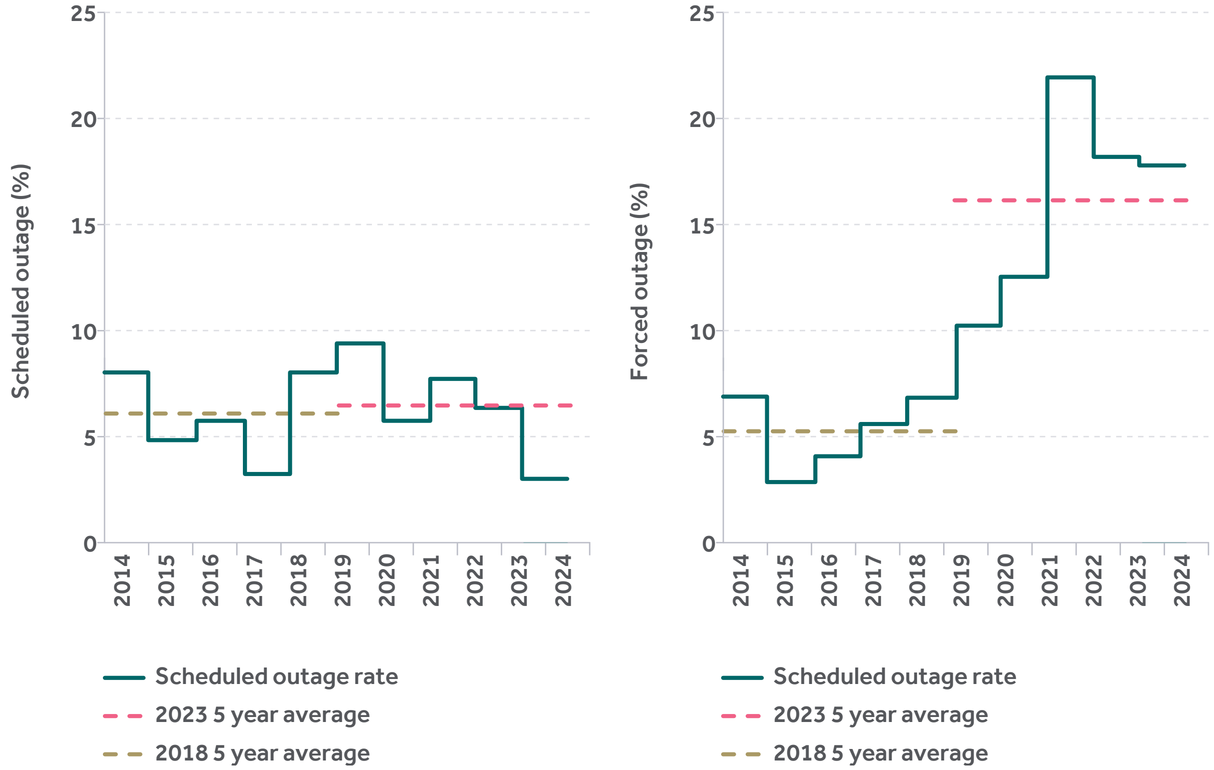


Figure 5.7 Average annual conventional generation capacity forced and scheduled outage rates in Ireland for the past 10 years

In Northern Ireland, the recent 5-year average indicates marginal increases in both forced and scheduled outage rates of generation, as shown in Figure 5.8 below.

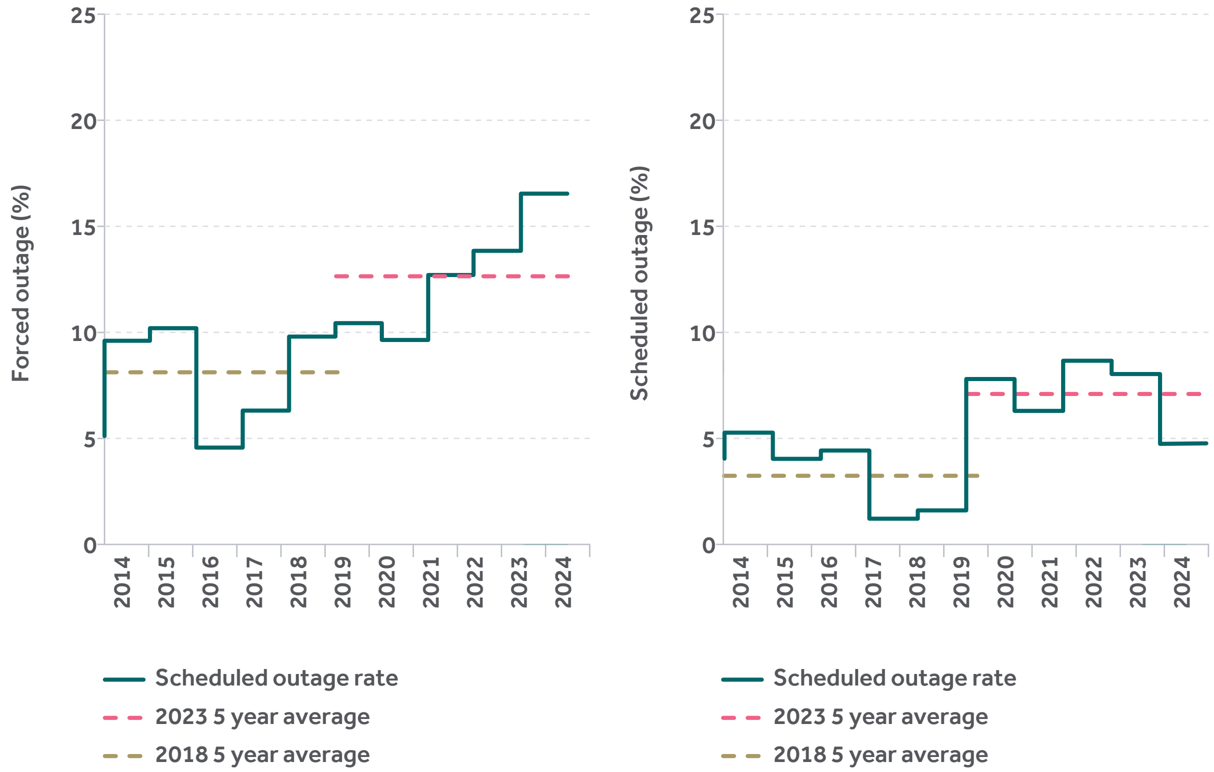


Figure 5.8 Average annual conventional generation capacity forced and scheduled outage rates in Northern Ireland for the past 10 years

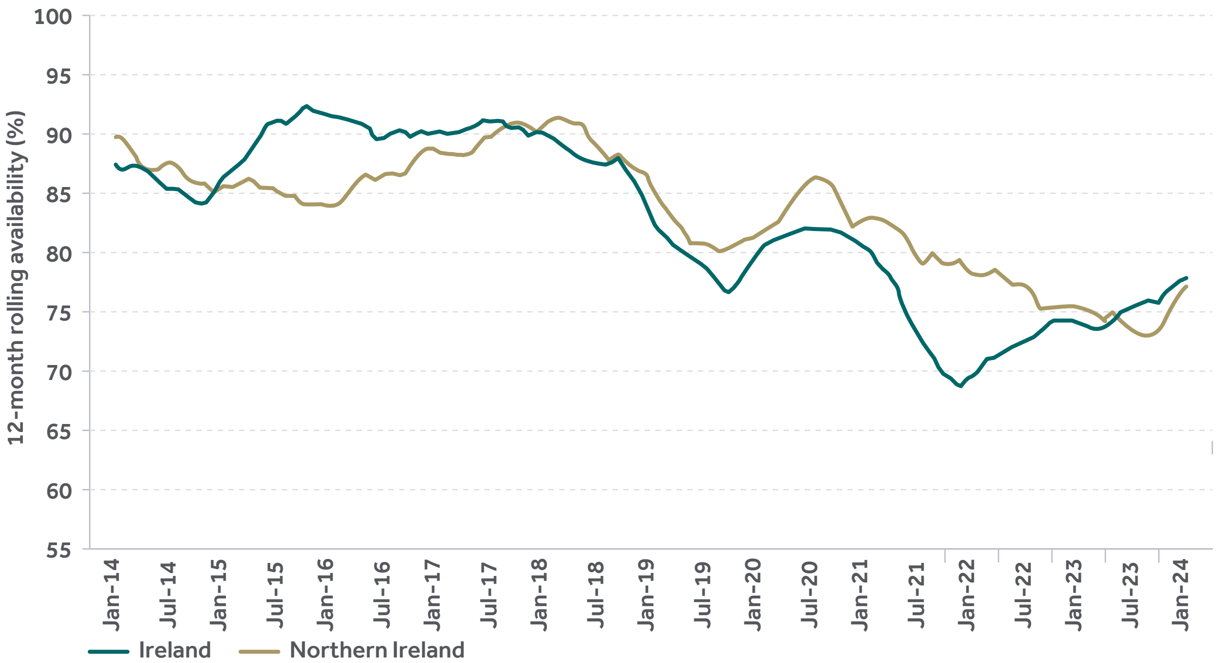


Figure 5.9 Ireland and Northern Ireland Conventional Generation Capacity Availability across the last 5 years

In both Ireland and Northern Ireland, there has been a gradual deterioration of unit availability over the last number of years. Whilst 2023 showed a slight improvement over 2022, the 5-year average availability has declined relative to GCS 2023-2032.

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 5.9 shows the availability trends across the last 5 years for Ireland and Northern Ireland. Figure 5.9 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.

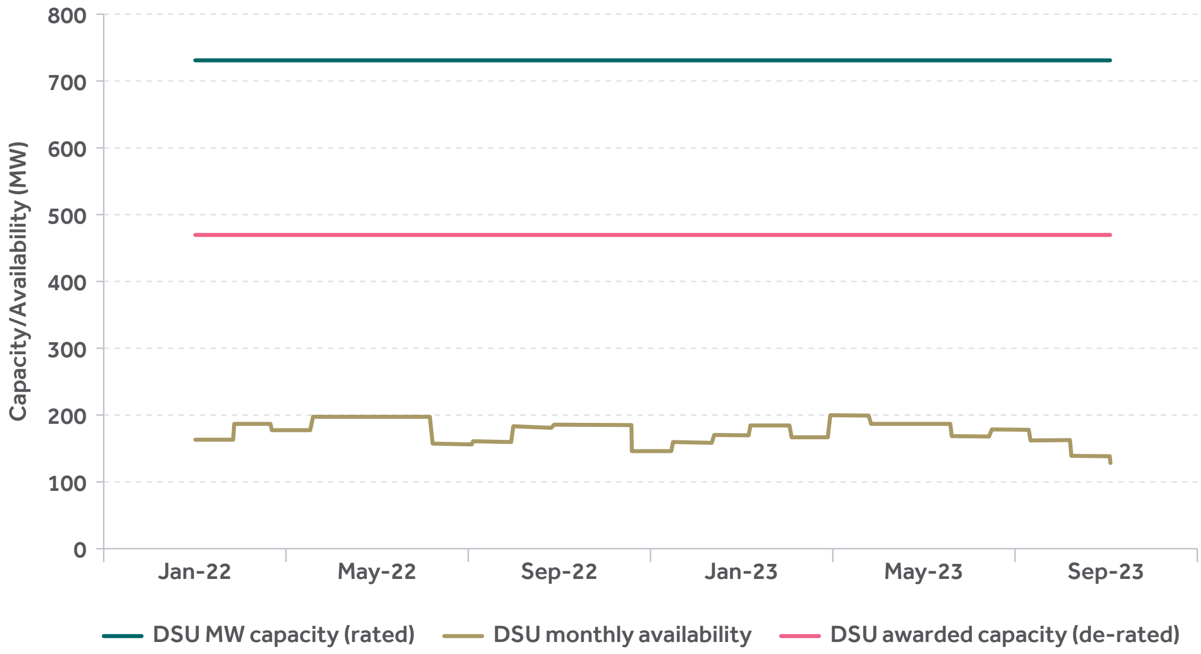


Figure 5.10 All-Island demand side unit monthly availability for 2022 and 2023 calendar years

EirGrid and SONI have both observed a consistently low availability of Demand Side Units on an All-Island basis, as shown in Figure 5.10 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. However, 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.

6. Adequacy

6.1 Introduction

Security of supply is a high priority for EU Member States, Policy Makers within DECC and DfE, Regulatory Authorities and TSOs.

Under current EU legislation[68] 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 is entitled to set and monitor the level of security of supply deemed appropriate for its own needs. In Ireland[69] and Northern Ireland[70], 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[71].

The security 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 standards

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

* Note this is a change from GCS 2023-2032 where the LOLE standard for the All-Island SEM and Ireland was 8 hours

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 transition to a new methodology for assessing resource adequacy provides significant opportunity for investigating resource adequacy in greater detail, such that the impact of individual factors can be appropriately dimensioned and represented. A stepwise approach has been adopted to provide clarity on the modelling process and results reporting.

Figure 6.1 below illustrates the enhanced process for modelling resource adequacy, which first constructs a "Base" scenario 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 scenario, 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

68 Directive 2019/944 and Regulation (EU) 2019/941
69 Statutory Instrument 60 of 2005
70 https://www.uregni.gov.uk/files/uregni/documents/2022-01/2022-01-17-soni-tso-consolidated.pdf
71 Part of the Withdrawal Agreement between the UK and the EU

challenging climate conditions. From the additional security analysis, a single sensitivity is selected to be used alongside other operational needs to derive a "Secure" scenario. Finally, further sensitivities have been investigated to analyse the relative impact of varying demand, renewable, storage and flexibility trajectories on the Base and Secure positions.

Step 1: Base Scenario Results

- Considers the median forecasts for demand and renewables
- Assessment of 35 Climate Years, with 20 different outage patterns for each climate year
- 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
- Analysis of challenging operational conditions such as low imports and low plant availability
- The outputs include MW impact assessments of adequacy sensitivities

Step 3: Secure Scenario Results

- Considers the Base scenario including a single sensitivity 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

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, and possibly alerts 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 LOLE 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).

6.2 Assumptions

The full range of inputs and assumptions are published separately[72] following consultation in Q1 2024, 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 2027, after Celtic in 2027 this increases the requirement 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[73] which establishes a guideline on electricity transmission system operation (System Operation Guideline – SOGL).

72 Inputs and Assumptions for Ireland and Northern Ireland, https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034 Input-Assumptions-Northern-Ireland.pdf
73 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation

6.3 Changes post data freeze date

This section includes significant developments between the data freeze date for this assessment (30th April 2024 for the demand data and 8th May 2024 for the generation data) and publication.

General

The 2028/2029 T-4 capacity auction took place on the 17th December 2024, in respect of capacity year 2028/2029, and 606 MW of new de-rated capacity was successfully awarded across the SEM (560 MW in Ireland and 46 MW in Northern Ireland). The results from this auction have been approved and the Final Capacity Auction Results Report[74] (FCAR) has been published. The results from this capacity auction have not been included in generation and adequacy forecasts for Ireland, Northern Ireland and the All-Island system. These results will be included in future forecasts, analysis and publications of this report.

On the 31st January 2025, EirGrid published the Network Delivery Portfolio (NDP) Publication Q4 2024[75]. The NDP provides a quarterly status update on projects being completed to reinforce the system and connect industry. In the Q4 2024 update, the Energisation date for the North South 400 kV Interconnector – RoI project is 06/10/2031, which provides updated information to the assumption outlined in Section 5.4 which outlined 2027 as the date from which the new North South would be available. This post data freeze date information does not change the jurisdictional study results for Ireland or Northern Ireland, which are modelled including the existing North South tie line only. The new information does however impact on the All-Island adequacy assessment, and therefore the All-Island results should be considered relevant from 2032 onwards.

Ireland

No developments are noted.

Northern Ireland

On the 7 December 2024, Storm Darragh caused significant and unforeseen damage at Ballylumford power station in Northern Ireland, which resulted in the loss of a significant amount of conventional generation. As a result of this damage, three of six large generators in Northern Ireland were forced into extended outage, necessary to assess and resolve damage caused by the storm. In January 2025, SONI published a revised assessment[76] for the remainder of the 2024/2025 winter period. The impact of this extended outage has not been captured in this publication.

The utilisation of Kilroot KGT6 and KGT7 units, which are subject to ARHL, has increased due to the damage to the power station, and the need to securely operate the system in line with operational policy. The impact of a reduced number of available run hours across the study horizon on these units has not been captured in this publication.

This is an exceptional event which has not been included in the Northern Ireland adequacy modelling, but which should be considered alongside the adequacy results, particularly in 2025. SONI will continue to work

74 Final Capacity Auction Results Report 2028/2029 T-4
75 Network Delivery Portfolio Publication Q4 2024
76 SONI Addendum to the Winter Outlook 2024

closely with the Department for the Economy (DfE), the Utility Regulator (UR), NIE Networks, Mutual Energy and private industry to ensure the full conventional generation portfolio is restored as soon as possible and security of supply is maintained in Northern Ireland.

6.4 Ireland adequacy analysis

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

6.4.1 Summary

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

- From 2025 to 2027, both scenarios 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.
- From 2027 to 2028, the delivery of the new Celtic interconnector, along with new gas capacity improves the outlook, reducing the LOLE in both scenarios.
- From 2028 to 2032, the base scenario is within standard, meaning there is sufficient capacity to operate the system under normal conditions. The secure scenario, however, remains outside of standard meaning an additional 600-800 MW is required to ensure we can continue to balance supply and demand under more challenging conditions. The additional MW capacity is required in the secure scenario to provide system reserve requirements (for when the demand for electricity is high) as well as facilitate network outages (which are needed when we connect new generation and infrastructure to the grid).
- From 2033 to 2034 both scenarios show the system is outside of standard meaning additional capacity is required in the range of 100-1000 MW.

EirGrid 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 low imports, annual run hour limits 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, storage and flexibility forecasts.

EirGrid acknowledges that capacity market auctions are still an option to procure new generation which could address the capacity shortfalls. Due to the freeze date for this report, results from the 2028/2029 T-4 capacity auction , in which 560 MW of new de-rated capacity was successfully awarded in Ireland, are not included in this adequacy assessment.

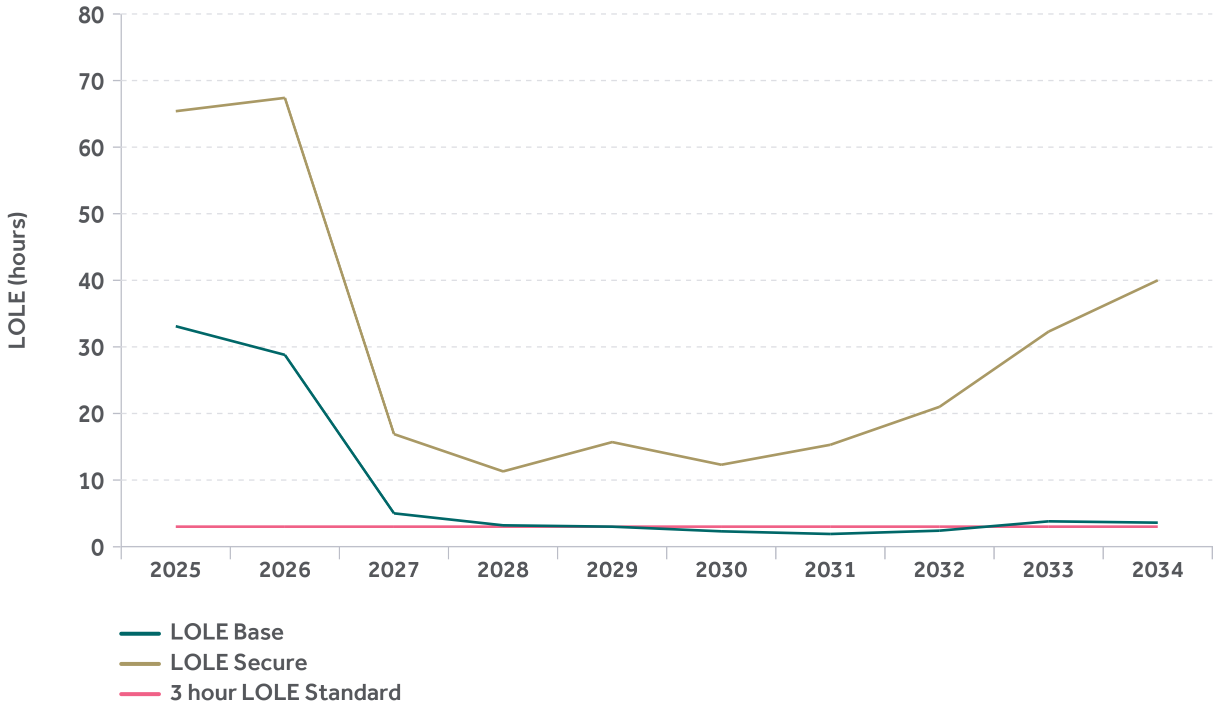


Figure 6.2 Base and Secure loss of load expectation results for Ireland

6.4.2 Base scenario results

The LOLE Base results are presented in Figure 6.3 and Table 6.2 below, these results can be considered for comparison against the reference scenario ERAA results[77]. 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 results presented in Figure 6.3 show the spread of the 35 Climate Years, where the individual Climate Year LOLE result is an average of 20 outage patterns. The LOLE Base is the average of the 35 climate years therefore considering a total of 700 possible Monte Carlo Years for each Study Year (20 outage patterns for 35 Climate Years). From Figure 6.3 it can be observed that approximately 1/3rd of the climate year results are above the LOLE Base.

The final LOLE Base result in Table 6.2 indicates the number of hours a year in which there could be a risk of insufficient supply to meet demand and reserve requirements under average climate and plant availability conditions. Further impact analysis of the more challenging Climate Years, along with low import and low plant availability is completed in the following sections.

In addition to the results discussed above, Table 6.3 indicates the number of hours for the Base scenario in which dynamic reserves have been reduced to the minimum operating level.

77 ENTSO-E – ERAA 2023

The LOLE Base results indicate Ireland exceeds the LOLE Standard in 2025 and 2026 as existing generators exit the market, noting this part of the assessment does not include out of market measures. In 2027 Ireland is close to standard as new capacity is delivered through the capacity market and Celtic comes online. 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 5.2.2, 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. Beyond 2027 Ireland is within the LOLE Standard until 2033 at which point demand increases are forecast to outpace the delivery of new reliable capacity. Capacity auctions are still an option to procure additional conventional, storage and DSU capacity across the horizon.

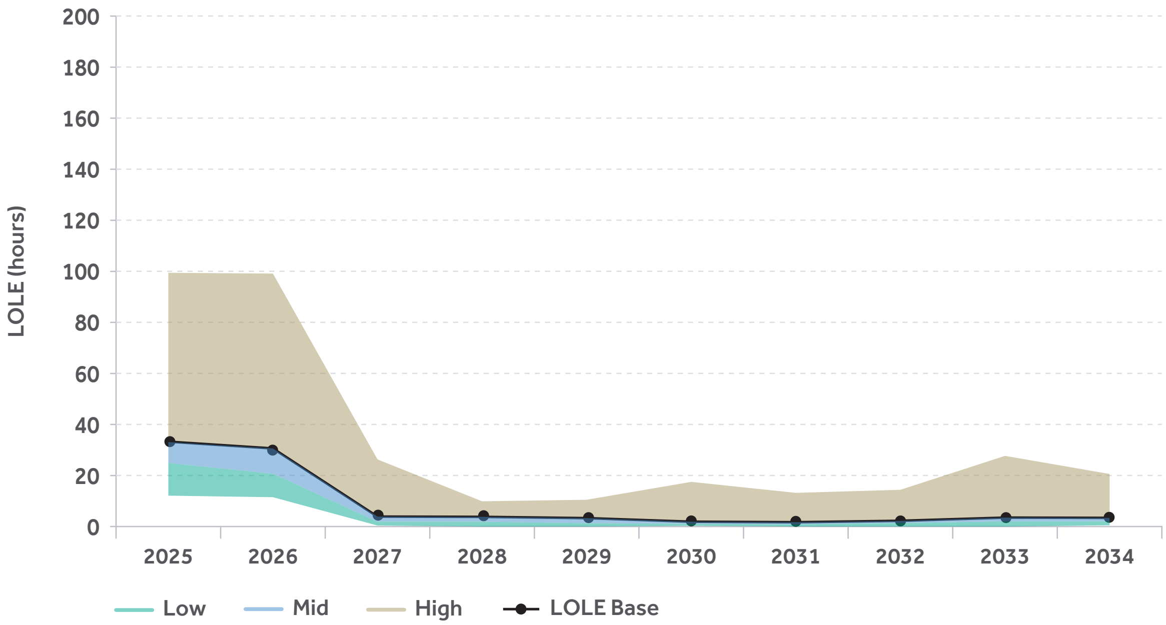


Figure 6.3 Distribution of LOLE Base results for the Ireland median demand scenario where each low/mid/high band represents 1/3rd of the 35 climate year results (includes reserves)

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

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Base (hours)	33.1	28.8	5.0	3.2	3.0	2.3	1.9	2.4	3.8	3.6
EENS Base (GWh)	10.5	9.8	2.0	1.0	1.1	0.9	0.6	0.8	1.4	1.0

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

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Base Demand Only (hours)	12.9	11.7	1.7	0.7	0.9	0.7	0.4	0.5	1.0	0.8
EENS Base Demand Only (GWh)	3.4	3.6	0.5	0.2	0.3	0.2	0.1	0.2	0.4	0.2

The All-Island Resource Adequacy Assessment Methodology[78] prescribes the process for calculating the MW surplus/deficit. The process is an iterative process using a subset of Climate Years to represent the LOLE Base scenario results in Table 6.2 and adding incremental values of perfect plant or demand to reach the LOLE Standard. Selecting a subset of Climate Years is required to reduce the complexity and computational effort required for the calculation. This assessment has selected 3 Climate Years which when averaged represent the LOLE Base results. The Climate years selected include 2006, 2007 and 2016, the resultant average LOLE of these 3 years is shown in Table 6.4 below.

Table 6.4 Average LOLE of the 3 climate years used in the surplus/deficit calculation for ireland (includes reserves)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
3 Climate Year LOLE	25.1	30.5	7.8	3.0	2.6	2.2	2.1	2.5	4.4	3.6

For each of the 3 Climate Years, the Surplus/Deficit MW value is calculated and averaged to find the MW Base value presented in Figure 6.4 and Table 6.5 below. Components on the negative y-axis represent a capacity need relative to the 3 hour LOLE Standard (deficit) and components on the positive y-axis represent a capacity margin relative to the 3 hour LOLE Standard (surplus). It is observed that additional capacity is required to mitigate risk to demand in 2025 and 2026, and capacity is required to meet the required system reserve requirements in 2025-2027 and 2033-2034.

78 All-Island Resource Adequacy Assessment Methodology, https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034-Methodology.pdf

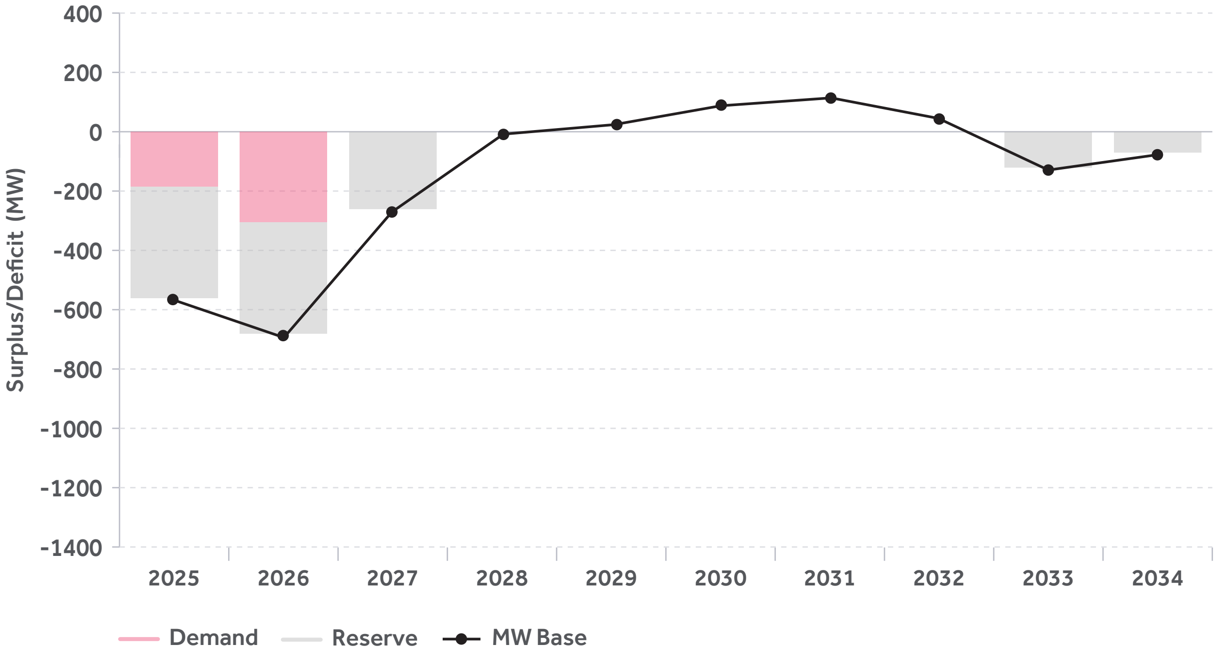


Figure 6.4 MW Base results for Ireland in terms of surplus (+) and deficit (-) of perfect plant

Table 6.5 MW Base results for Ireland in terms of surplus (+) and deficit (-) of perfect plant

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MW Base	-560	-680	-260	10	50	110	140	70	-120	-70

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[79], 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 sensitivities:

- **Low French Nuclear –** Assessing the impact of removing 2 or 4 medium sized Nuclear units in France. The sensitivity of removing 2 French Nuclear Units shows an average impact of 170 MW, increasing to 340 MW with removing 4 French Nuclear Units.
- **Climate Variability –** The range of LOLE results (averaged across 20 outage patterns) can vary between the climate years simulated. Figure 6.3 above illustrates the different Climate years simulated indicate a wide variance of LOLE results, with approximately 1/3rd of

79 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

climate year LOLE results exceeding the Base LOLE. Considering the High band of LOLE results, 2001 was selected as representative of a 1-in-10 climate year for this analysis. It should be noted 2001 is not the worst Climate Year, instead it is a mid-point in the High band of results. This sensitivity shows an average impact of 290 MW.

- **Low Plant Availability –** The range of LOLE results for a single climate year vary across 30 different outage patterns simulated analysing the impact of a 1-in-10 outage pattern. This sensitivity shows an average impact of 210 MW.
- **Low Imports –** Assessing the impact of Low Imports, which has been implemented through limiting HVDC interconnector imports to 70% of their Maximum Import Capacity (MIC). 70% could be considered as a Low Import scenario resulting from a variety of circumstances such as the extended loss of 1 interconnector to the SEM e.g. in 2025 the loss of Greenlink would leave 950 MW of import capacity available to the SEM from of a maximum 1450 MW, this is ~70%. This sensitivity shows an average impact of 210 MW.

It is important to note the above sensitivities do not represent the worst-case scenarios, and instead analyse events within the range of credible operating scenarios.

Figure 6.5 below shows the outcome from the uncertainty sensitivity analysis. From the analysis, it is observed that climate and import sensitivities have an increasing effect across the study horizon. Based on the results below, the Low Imports sensitivity has been selected for use in the Secure analysis in the next section, as it is reflective of the average trend and impact of the five sensitivities across the study horizon.

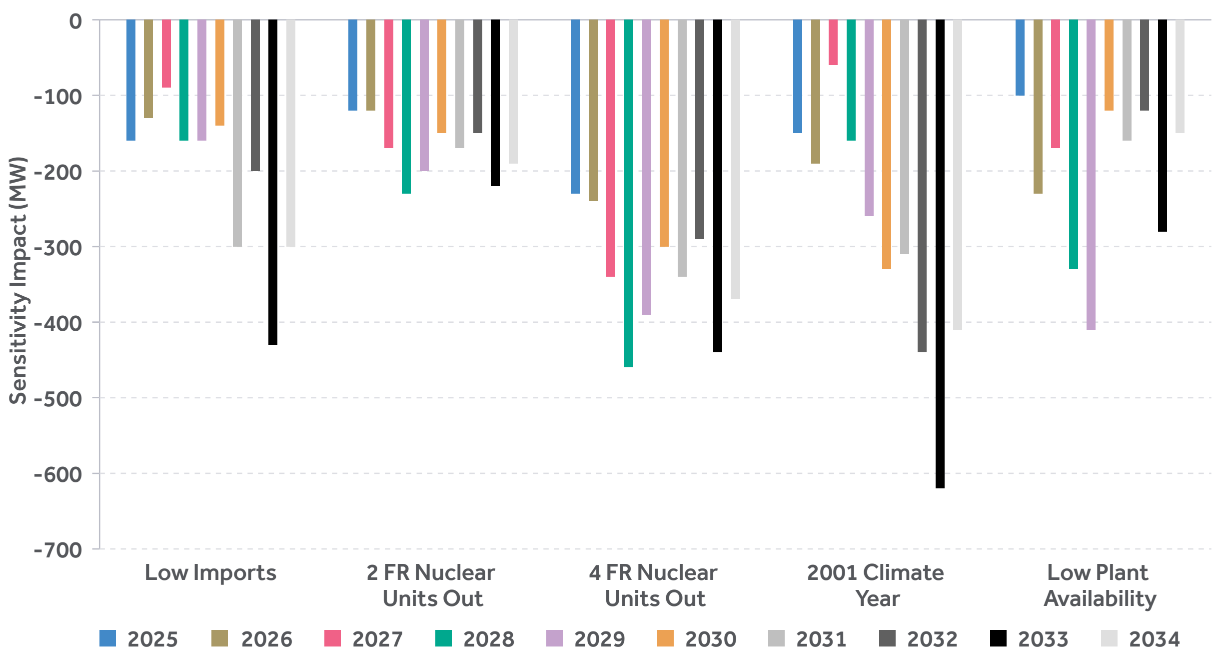


Figure 6.5 Sensitivity analysis for Ireland in terms of deficit (-) of perfect plant impact

6.4.4 Secure scenario results

The Secure scenario accounts for the impact of Low Imports, implemented as described in section 6.4.3. The scenario also considers the impact of Annual Run Hour Limits (ARHL) on some new conventional units as described in section 5.3.3. The Secure scenario results are presented in Figure 6.6 and Table 6.6 below. The Secure results indicate under stressed conditions the system could exceed the 3 hour LOLE Standard across the full study horizon.

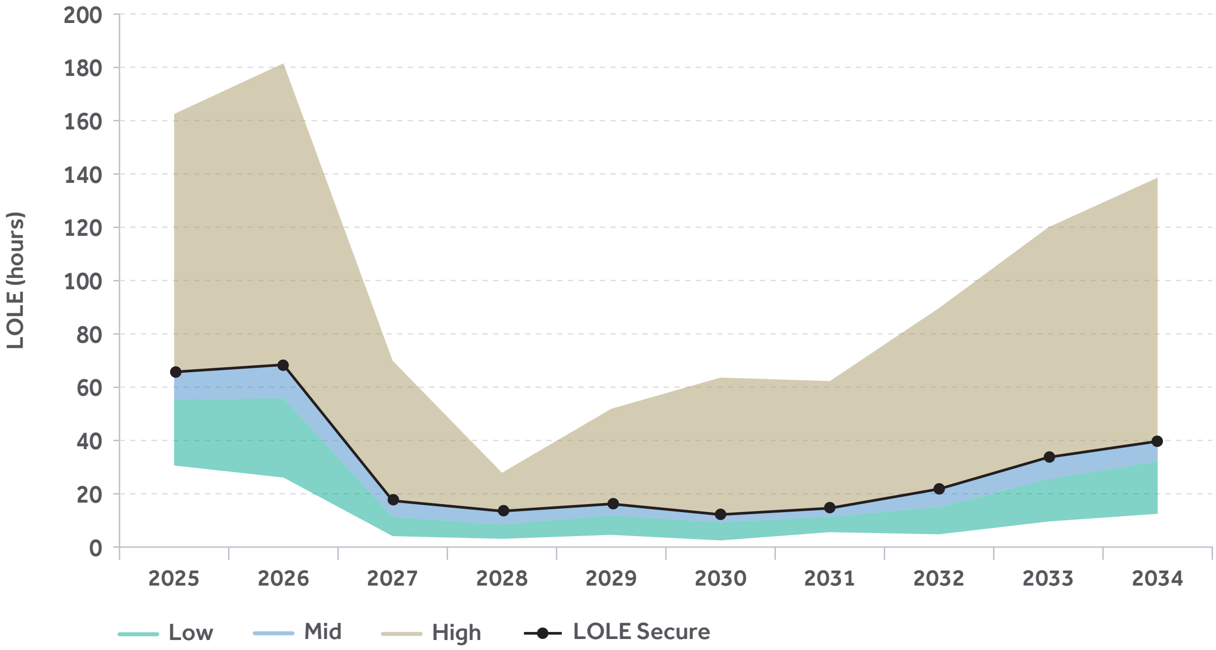


Figure 6.6 Distribution of LOLE Secure results for the Ireland median demand scenario where each low/mid/high band represents 1/3rd of the 35 climate year results (includes reserves)

Table 6.6 LOLE and EENS Secure results for Ireland (includes reserves)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Secure (hours)	65.4	67.4	16.9	11.3	15.7	12.3	15.3	21.0	32.3	40.0
EENS Secure (GWh)	20.5	21.7	5.7	3.5	4.9	4.0	4.3	6.4	10.4	12.7

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 Climate Years are used for the MW Secure analysis as the MW Base analysis. Figure 6.7 and Table 6.7 below show the detailed breakdown of the MW Secure results indicating the total capacity required to operate securely, resilient to the impact of Low Imports and ARHL on new units whilst supporting the power system through the transition towards climate action targets.

The results show the combined impact of Low Imports and ARHL could increase the risk to consumers in 2025-2026 and 2033-2034, and in other years (2027-2032) increase the additional capacity required to cover the system reserve needs. The full capacity to cover TOPs is required in each year of the study horizon, which whilst this 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.

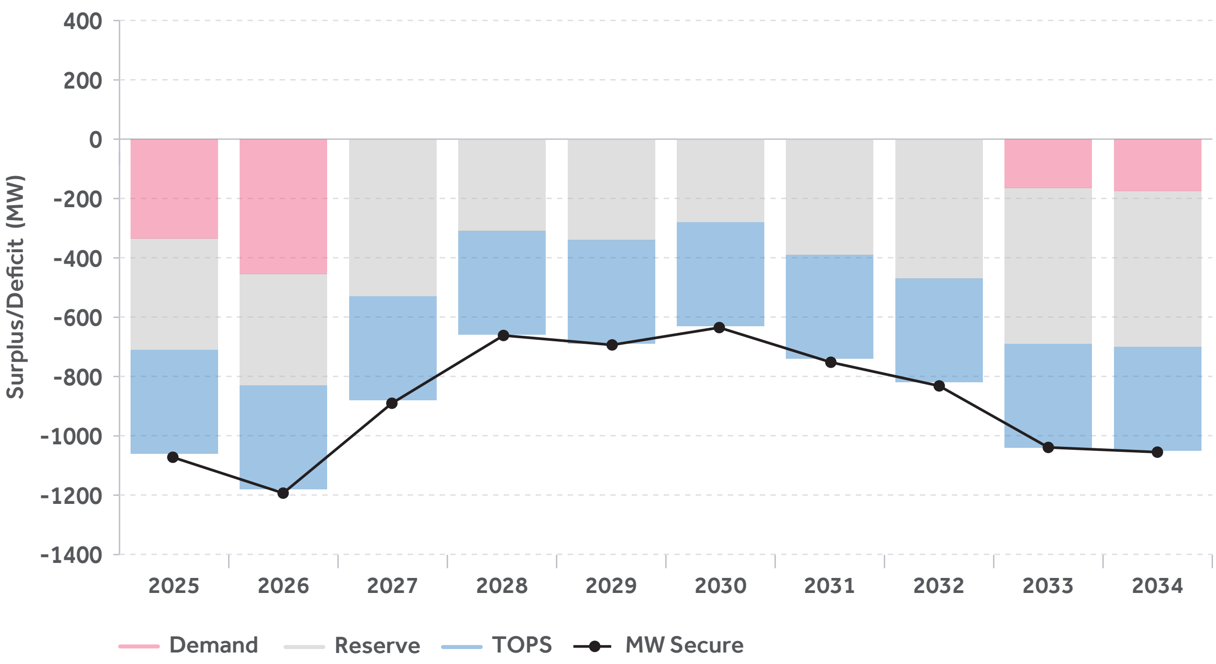


Figure 6.7 Secure surplus/deficit results for Ireland in terms of surplus (+) and deficit (-) of perfect plant

Table 6.7 Secure surplus/deficit results for ireland in terms of surplus (+) and deficit (-) of perfect plant

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MW Secure	-1060	-1180	-880	-660	-690	-630	-740	-820	-1040	-1050

6.4.5 Sensitivity studies

The Base and Secure scenarios 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, and the results are shown in Figure 6.8. These sensitivities go beyond what has been included in previous GCS publications, illustrating the enhanced modelling capability of the new resource adequacy assessment methodology. 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 Secure positions described above.

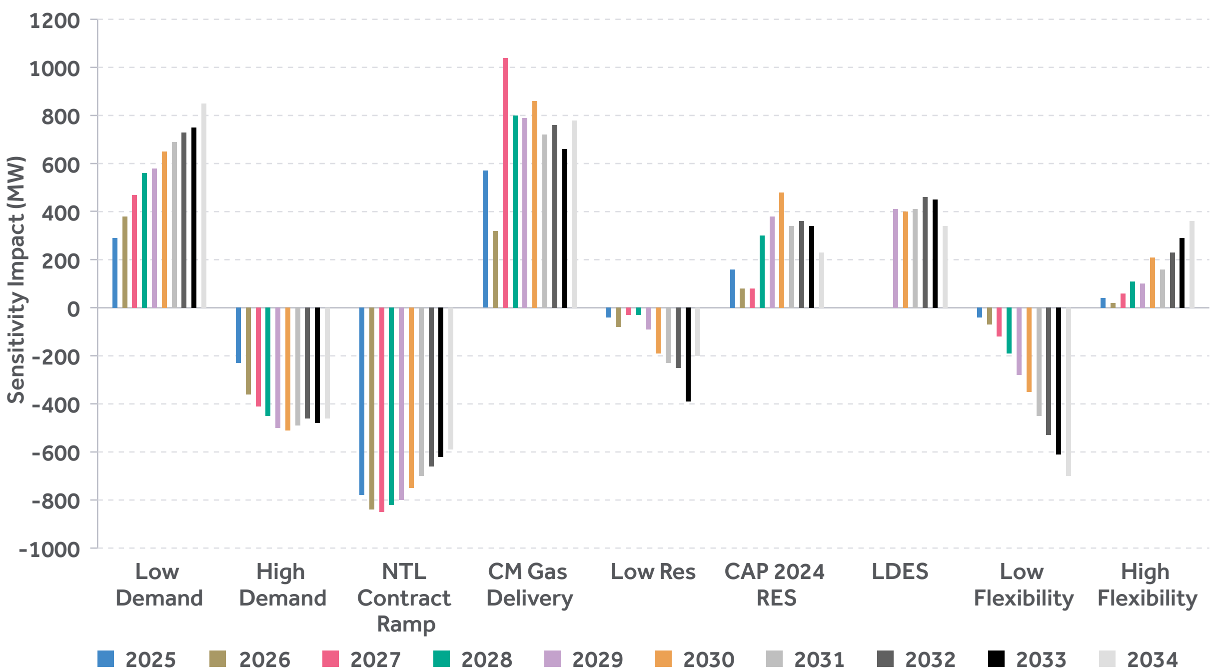


Figure 6.8 Sensitivity analysis for Ireland

The details behind each sensitivity shown in Figure 6.8 are outlined in greater detail below.

Demand

Three sensitivities have been included, analysing the Low and High Demand forecasts as presented in Section 4.2 and the impact of the New technology Load (NTL) forecast reaching the contract ramp, details of which are included in Section 4.2.3. Low Demand is shown to have an adequacy benefit, increasing linearly across the study horizon from 300-800 MW. The High Demand has the inverse effect, indicating a negative adequacy impact of 200-400 in the early years, increasing to 500 MW from 2029 onwards. The new tech load forecast reaching the contracted ramp has a negative impact on adequacy of approximately 600-800 MW.

Capacity market delivery

This sensitivity assesses the impact of all 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. The impact of this sensitivity is a 700-800 MW adequacy benefit. It is worth noting this sensitivity assumes new plant operating on HVO is not subject to run hour limits.

Low RES

This 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[80]. The renewable trajectory used in this sensitivity is shown in Table 6.8. The impact of a low renewable build out is most significant post 2030, with an average negative impact of 270 MW.

Table 6.8 Low renewable deployment scenario (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Offshore Wind	25	25	25	25	25	25	25	400	850	1000
Onshore Wind	5150	5400	5600	5800	6000	6200	6500	6800	7100	7350
Solar	1800	2200	2600	3050	3450	3850	4200	4600	5000	5350

80 SEAI Variable Generation Capacity Forecasts

High RES

This sensitivity assesses the impact of full delivery of the Climate Action Plan 2024 targets, using the SOEF v1.1 low emissions renewable capacity trajectory required to achieve the sectoral emissions budget for the power sector. The renewable trajectory used in this sensitivity is show in Table 6.9. This sensitivity shows an average benefit across the study horizon of 280 MW.

Table 6.9 SOEF v1.1 low emissions trajectory (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Offshore Wind	25	25	25	1200	2865	5000	7135	9270	9270	9270
Onshore Wind	6004	7000	8200	9000	9000	9000	9000	9000	9000	9000
Solar	4800	4800	5600	6500	7250	8000	8750	9500	9500	9500

Energy storage

This sensitivity assesses the contribution of 8-hour storage to system adequacy. It is worth noting again the assessment only considers storage with capacity contracts and does not assume a further buildout beyond the latest T-4 auction. However, it is recognised that longer duration 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, 400 MW of 8-hour battery storage has been included from 2029, as capacity auctions completed at the data freeze date consider up to the year 2028. The average contribution to the adequacy position is 410 MW, illustrating the value longer duration storage can contribute. Note the quantity of storage included in this sensitivity is not indicative of the quantity required in the future, and therefore the actual contribution from LDES will depend on the specific evolution of the portfolio.

High flexibility

This sensitivity considers the value of future power system flexibility through 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 2025-2029 average benefit of 70 MW increasing in 2030-2034 to an average benefit of 250 MW. Note EirGrid acknowledges this is an area for future development. 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.

Low flexibility

This sensitivity illustrates the estimated 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 4.2.6. The negative impact of Low Flex could be 350 MW in 2030 increasing to 700 MW in 2034.

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 Information Paper Security of Electricity Supply – Programme of Actions"[81], the latest publication from April 2024 captures the proactive response.

As part of these actions, the CRU has directed EirGrid to procure Temporary Emergency Generation to help mitigate the clear risks presented by the current security of supply challenges. This non-market based generation can only be activated by the System Operator (considered in system margin calculations) 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 outlined in the Risk Preparedness Plan for Ireland (RPP)[82], published by the CRU on 31 May 2023[83]. 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 6.9, 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.

81 Electricity_Security_of_Supply_Programme_of_Work_Update_April_2024_.pdf
82 CRU_202346_Risk_Preparedness_Plan_May_2023.PDF (divio-media.com)
83 https://www.cru.ie/publications/27519/

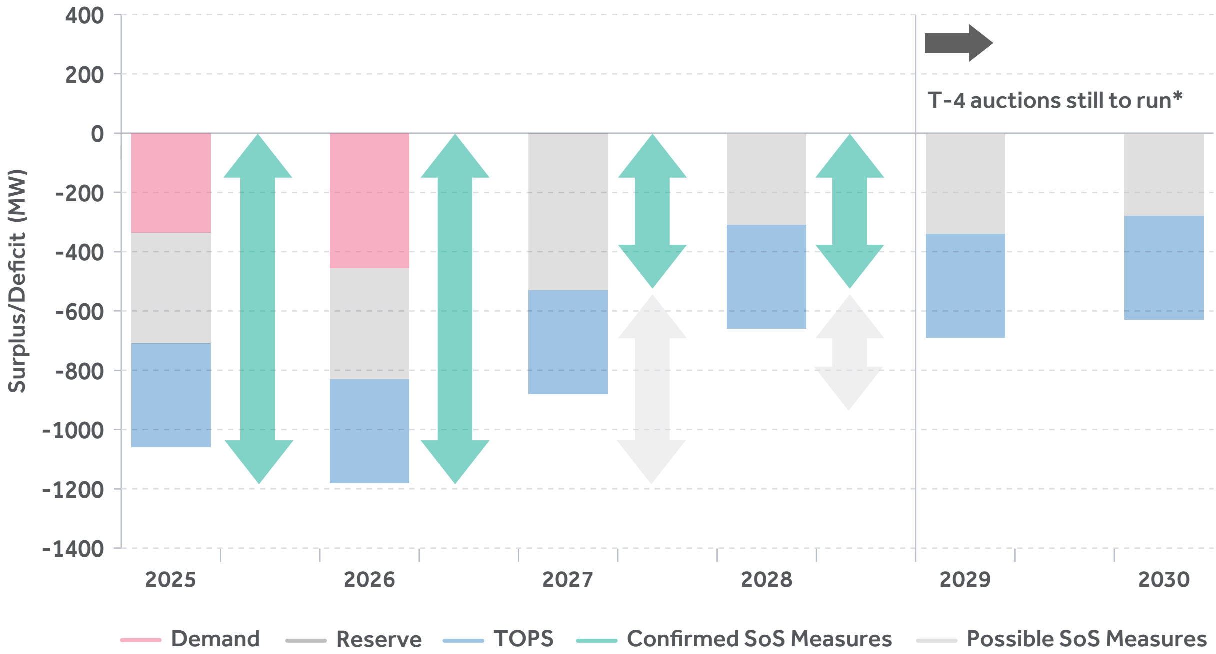


Figure 6.9 Ireland adequacy position with mitigating measures
** Note that due to freeze date for this report, capacity auctions completed post April 2024 are not included in this assessment.*

6.5 Northern Ireland adequacy analysis

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

6.5.1 Summary

The Base and Secure scenario results are shown in Figure 6.10 and summarised below:

- From 2025 to 2031, the base scenario shows the system is within standard meaning there is sufficient capacity to operate the system under normal conditions. From 2032, the Base results show the system is outside of standard and 30-50 MW of additional capacity is required.
- From 2026 onwards, the Secure scenario shows the system is outside of standard meaning additional capacity is required to ensure we can continue to balance supply and demand under more challenging conditions. The results indicate, up to 100 MW of new capacity is required from 2026 to 2031 increasing to up to 200 MW by 2034.

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 low imports, 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.

SONI acknowledges that capacity market auctions are still an option to procure new generation which could address the capacity shortfalls. Due to the freeze date for this report, in which 46 MW of new de-rated capacity was successfully awarded in Northern Ireland, results from the 2028/2029 T-4 capacity auction are not included in this adequacy assessment.

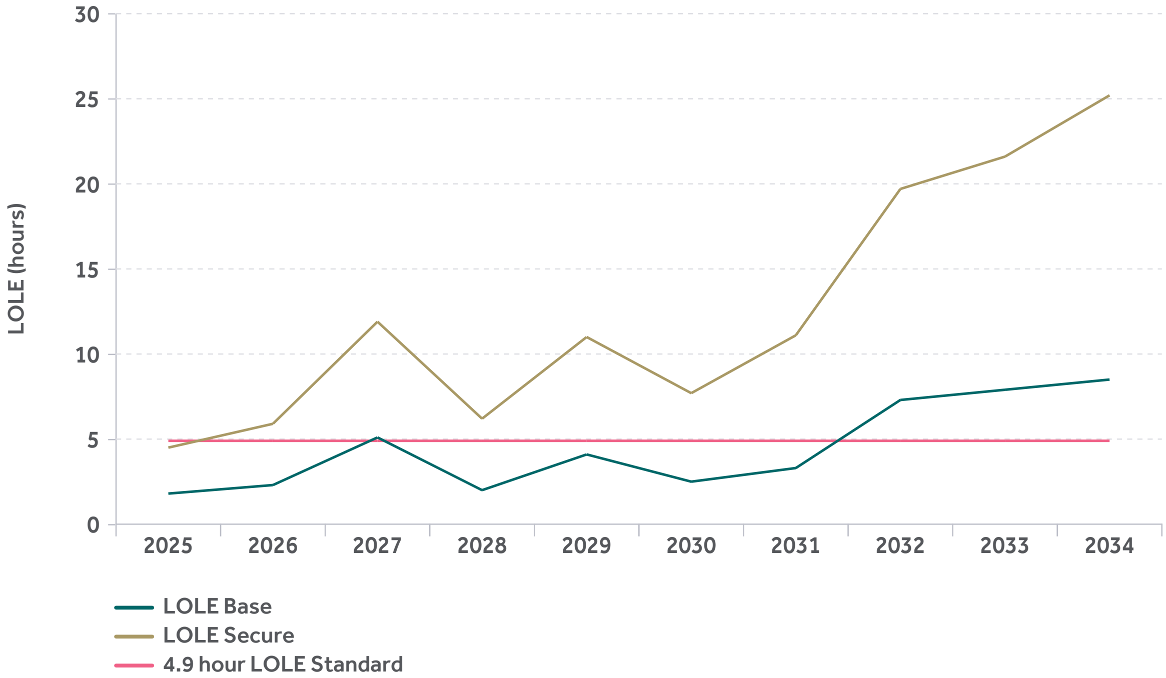


Figure 6.10 Base and Secure loss of load expectation results for Northern Ireland

6.5.2 Base Scenario Results

The LOLE Base results are presented in Figure 6.11 and Table 6.10 below, these results can be considered for comparison against the reference scenario ERAA results[84]. 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 results presented in Figure 6.11 show the spread of the 35 Climate Years, where the individual climate year LOLE result is an average of 20 outage patterns. The LOLE Base is the average of the 35 Climate Years therefore considering a total of 700 possible Monte Carlo Years for each Study Year (20 outage patterns for 35 Climate Years). From Figure 6.11 it is observed that approximately 1/3rd of the climate year results are above the LOLE Base.

The final LOLE Base result in Table 6.10 indicates the number of hours a year in which there could be a risk of insufficient supply to meet demand and reserve requirements under average climate and plant availability conditions. Further impact analysis of the more challenging Climate Years, along with low import and low plant availability is completed in the following sections.

In addition to the results discussed above, Table 6.11 indicates the number of hours for the Base scenario in which dynamic 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 (discussed in Section 5.4) and in 2030 when 500 MW of offshore is assumed to be available.

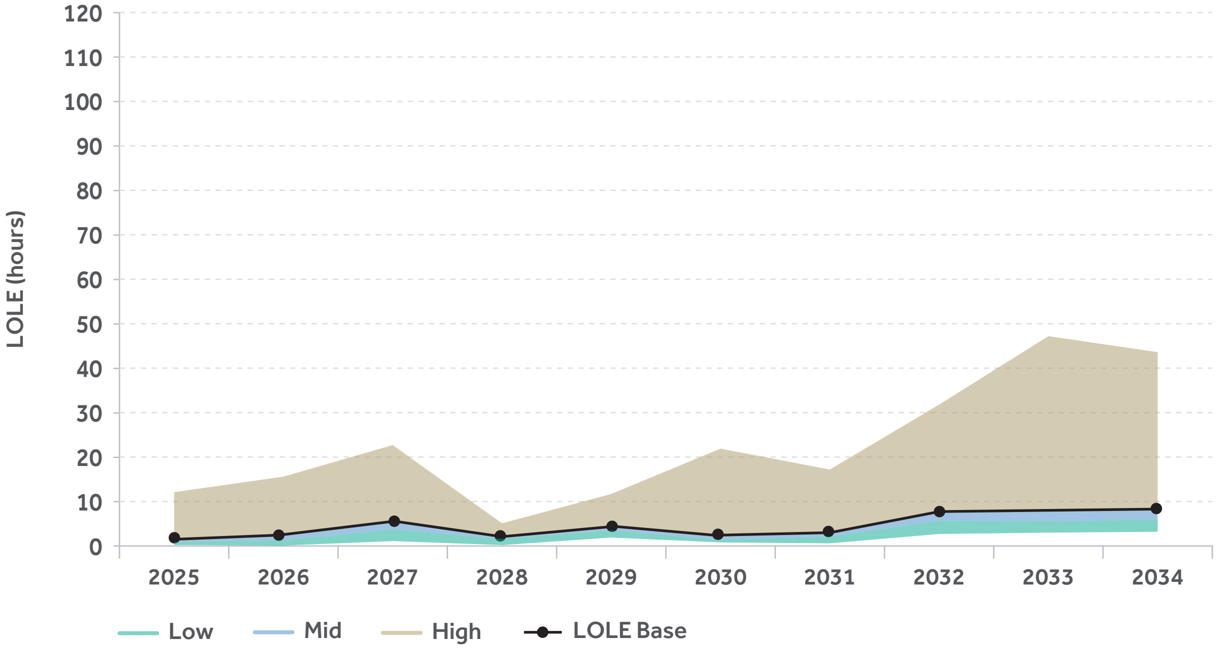


Figure 6.11 Distribution of LOLE Base results for the Northern Ireland median demand scenario where each low/mid/high band represents 1/3rd of the 35 climate year results (includes reserves)

Table 6.10 LOLE and EENS Base results for Northern Ireland (includes reserves)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Base (hours)	1.8	2.3	5.1	2.0	4.1	2.5	3.3	7.3	7.9	8.5
EENS Base (GWh)	0.2	0.3	0.6	0.2	0.5	0.3	0.4	0.9	1.1	1.1

Table 6.11 LOLE and EENS Base demand only results for Northern Ireland (excludes reserves)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Base Demand Only (hours)	0.8	1.1	1.4	0.6	1.3	0.8	0.9	2.1	2.6	2.8
EENS Base Demand Only (GWh)	0.09	0.15	0.20	0.07	0.15	0.13	0.12	0.25	0.37	0.33

The All-Island Resource Adequacy Assessment Methodology[85] prescribes the process for calculating the MW Surplus/ Deficit. The process is an iterative process using a subset of Climate Years to represent the LOLE Base scenario results in Table 6.10 and adding incremental values of perfect plant or demand to reach the LOLE Standard. Selecting a subset of Climate Years is required to reduce the complexity and computational effort required for the calculation. This assessment has selected 3 Climate Years which when averaged represent the LOLE Base results. The Climate years selected include 1985, 1990 and 2016, the resultant average LOLE of these 3 years is shown in Table 6.12 below.

Table 6.12 Average LOLE of the 3 climate years used in the surplus/deficit calculation for Northern Ireland (includes reserves)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
3 Climate Year LOLE	1.4	3.0	4.6	3.9	3.8	2.4	4.5	6.3	6.1	7.5

85 All-Island Resource Adequacy Assessment Methodology, https://cms.soni.ltd.uk/sites/default/files/publications/AIRAA-2025-2034-Methodology.pdf

For each of the 3 Climate Years, the Surplus/Deficit MW value is calculated and averaged to find the MW Base value presented in Figure 6.12 and Table 6.13 below. Components on the negative y-axis represents a capacity need relative to the 4.9 hour LOLE Standard (deficit) and components on the positive y-axis represent a capacity margin relative to the 4.9 hour LOLE Standard (surplus). The Base results position the system with a minor surplus from 2025-2031 at which point minor additional capacity is required to meet the required system reserve needs from 2032-2034.

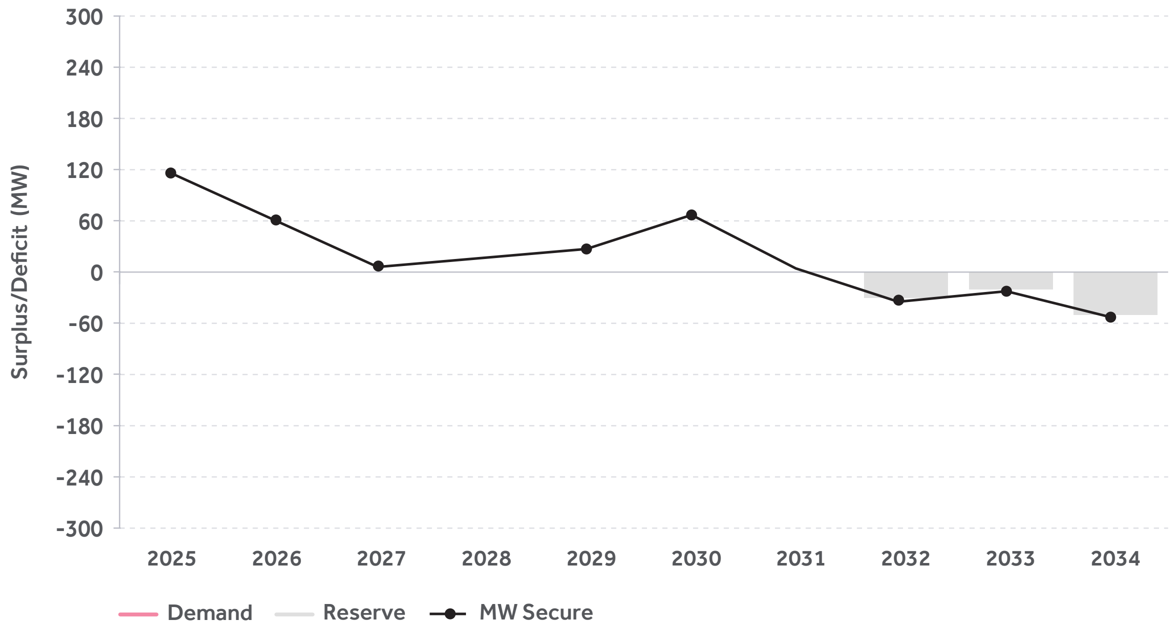


Figure 6.12 MW Base results for Northern Ireland in terms of surplus (+) and deficit (-) of perfect plant

Table 6.13 MW Base results for Northern Ireland in terms of surplus (+) and deficit (-) of perfect plant

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MW Base	120	60	10	20	30	70	10	-30	-20	-50

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[86], 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 sensitivities:
- **Low French Nuclear –** Assessing the impact of removing 2 or 4 medium sized Nuclear units in France. The sensitivity of removing 2 French Nuclear Units shows an average impact of 80 MW, increasing to 150 MW with removing 4 French Nuclear Units.
- **Climate Variability –** The range of LOLE results (averaged across 20 samples) can vary between the climate years simulated. Figure 6.11 above illustrates the different climate years simulated indicate a wide variance of LOLE results, with approximately 1/3rd of climate year LOLE results exceeding the Base LOLE. Considering the High band of LOLE results, 2001 was selected as representative of a 1-in-10 climate year for this analysis. It should be noted 2001 is not the worst climate year, instead it is a mid-point in the High band of results. This sensitivity shows an average impact 100 MW.
- **Low Plant Availability –** The range of LOLE results for a single climate year vary across 30 different outage patterns simulated analysing the impact of a 1-in-10 outage pattern. This sensitivity shows an average impact 80 MW.
- **Low Imports –** Assessing the impact of Low Imports, which has been implemented through limiting HVDC interconnector imports to 70% of their Maximum Import Capacity (MIC). 70% has been selected as it is approximately equivalent to of the extended loss of 1 interconnector to the SEM e.g. in 2025 the loss of Greenlink would leave 950 MW of import capacity available to the SEM out of 1450 which is ~70%. This sensitivity shows an average impact 130 MW.

It is important to note the above sensitivities do not represent the worst-case scenarios, and instead analyse events within the range of credible operating scenarios.

Figure 6.13 below shows the outcome from the uncertainty sensitivity analysis. From the analysis, it is observed that climate and import sensitivities have an increasing effect across the study horizon. The Low Imports sensitivity was selected for the Secure analysis in the next section, as it is reflective of the average trend and impact of the five sensitivities across the study horizon.

86 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

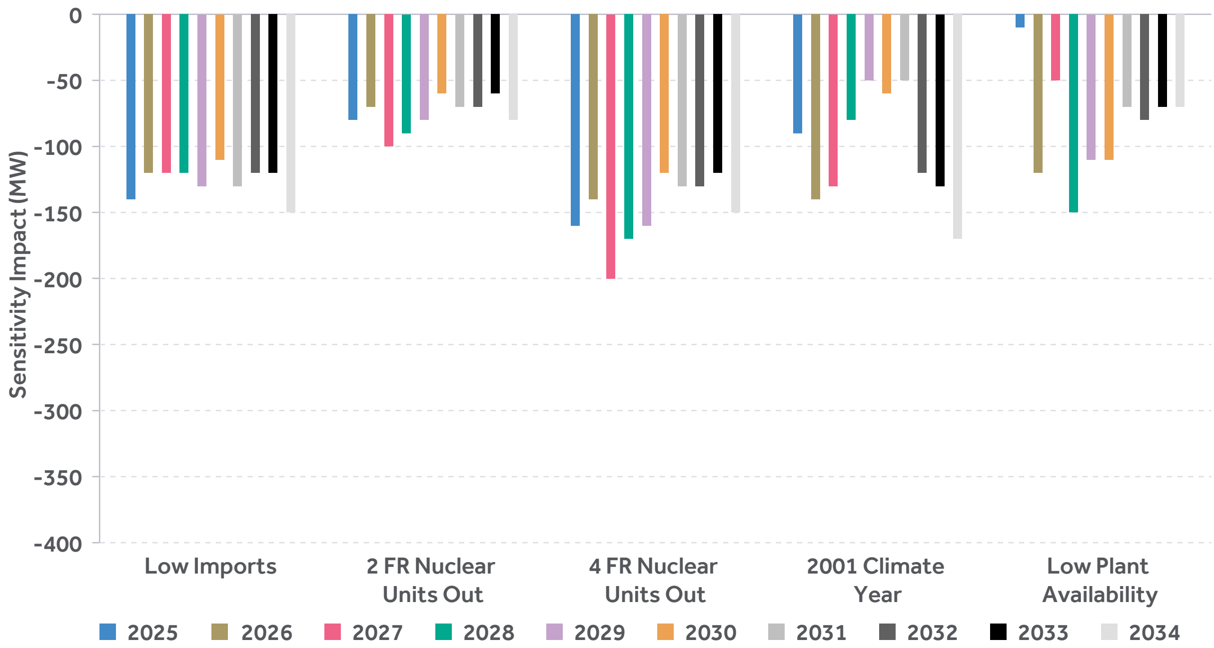


Figure 6.13 Sensitivity analysis for Northern Ireland in terms of deficit (-) of perfect plant impact

6.5.4 Secure scenario results

The Secure analysis for Northern Ireland accounts for the impact of Low Imports, and the results are presented in Figure 6.14 and Table 6.14 below. The Secure results indicate under stressed conditions the system could exceed the 4.9 hour LOLE Standard from 2026 onwards.

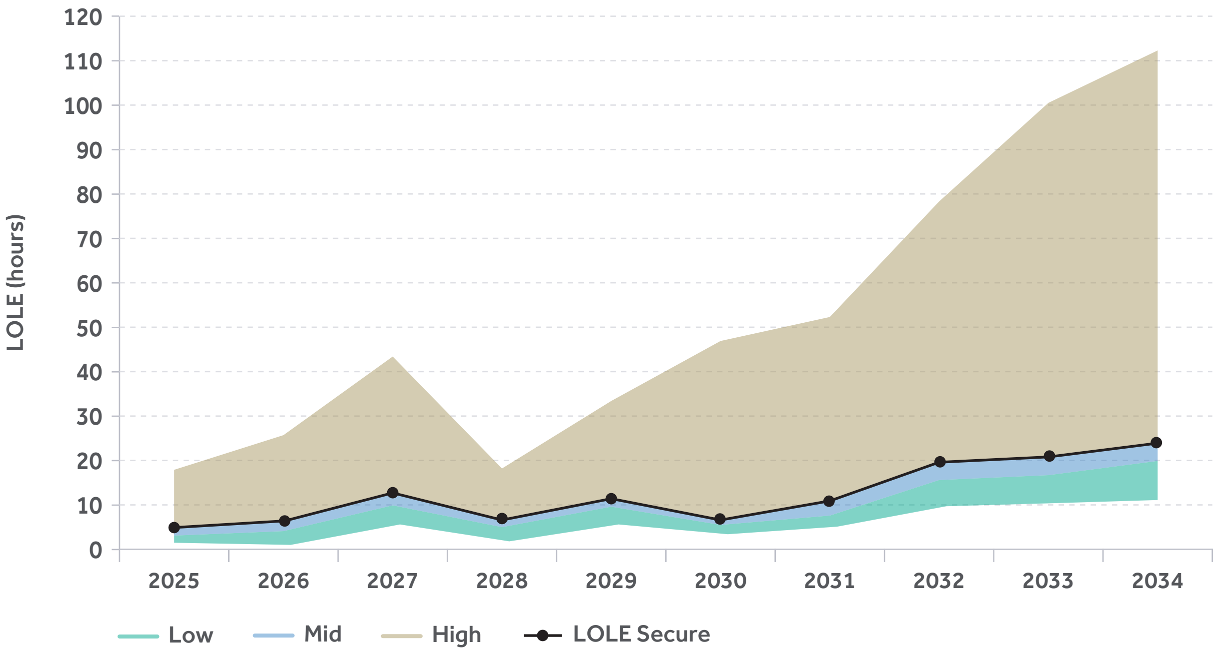


Figure 6.14 Distribution of LOLE Secure results for the Northern Ireland median demand scenario where each low/mid/high band represents 1/3rd of the 35 climate year results (includes reserves)

Table 6.14 LOLE and EENS Secure results for Northern Ireland (includes reserves)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Secure (hours)	4.5	5.9	11.9	6.2	11.0	7.7	11.1	19.7	21.6	25.2
EENS Secure (GWh)	0.5	0.7	1.6	0.7	1.4	1.0	1.4	2.8	3.3	3.7

To ensure consistency throughout the surplus/deficit calculation the same 3 Climate Years are used for the MW Secure analysis as the MW Base analysis. Figure 6.15 and Table 6.15 below show the detailed breakdown of the MW Secure results indicating the total capacity required to operate securely, resilient to the impact of Low Imports and support the power system through the transition towards climate targets. The results show the impact of Low Imports means additional capacity is required to cover the system reserve needs from 2026-2033, and there is a minor need for additional capacity to cover demand in 2034.

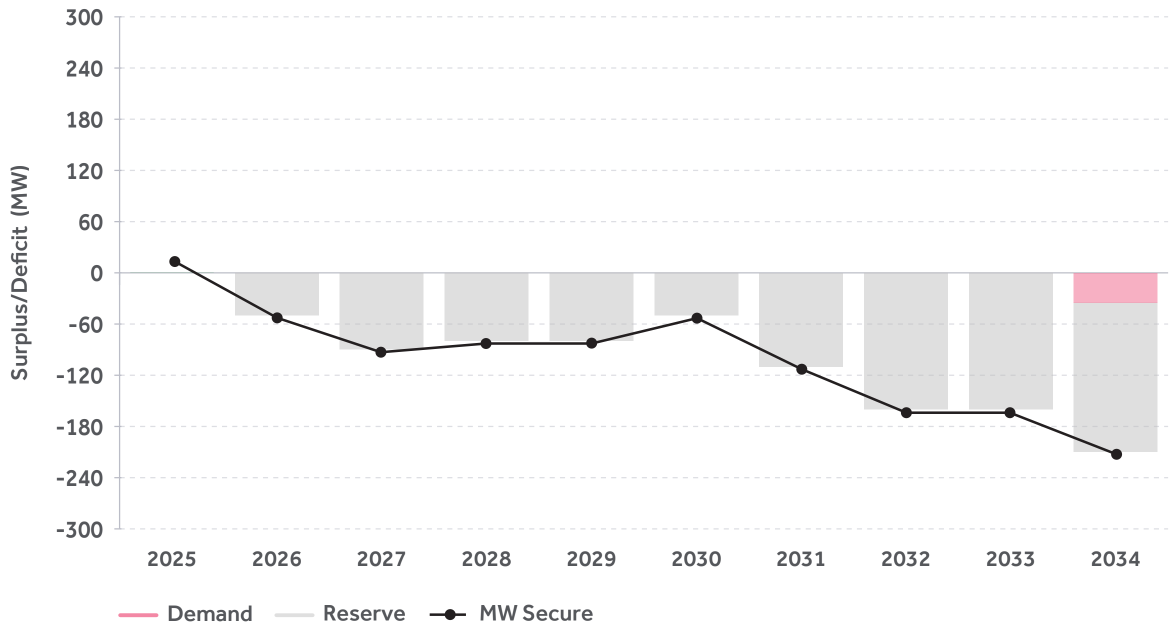


Figure 6.15 MW Secure results for Northern Ireland in terms of surplus (+) and deficit (-) of perfect plant

Table 6.15 MW secure results for Northern Ireland in terms of Surplus (+) and Deficit (-) of perfect plant										
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MW Secure	20	-50	-90	-80	-80	-50	-110	-160	-160	-210

6.5.5 Sensitivity studies

The Base and Secure scenarios 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 have carried out several sensitivity studies on the Base scenario, and the results are shown in Figure 6.16. These sensitivities go beyond what has been included in previous GCS publications, illustrating the enhanced modelling capability of the new resource adequacy assessment methodology. 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.

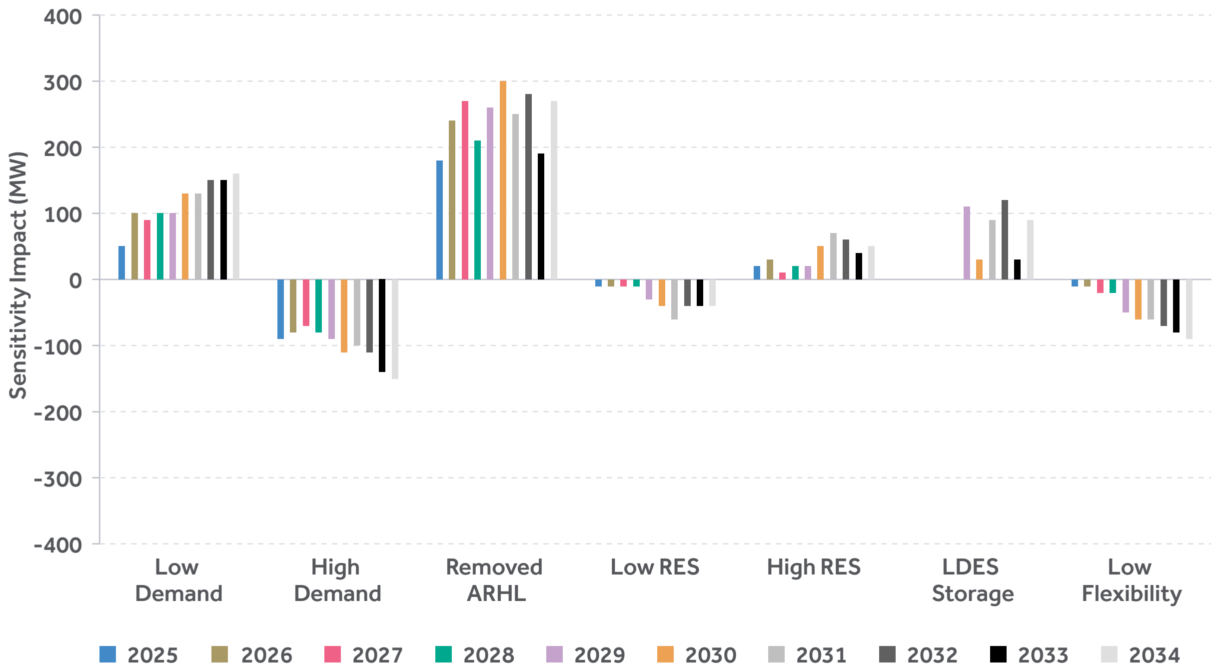


Figure 6.16 Sensitivity analysis for Northern Ireland

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 4.3. Low Demand is shown to have an adequacy benefit, increasing linearly across the study horizon from 50-150 MW. The High Demand has the inverse effect, indicating a negative adequacy impact of 90 MW in the early years, increasing to 150 MW towards the end of the Study Horizon.

No Annual Run Hour Limits (ARHL)

This sensitivity assesses the impact of no run hour limits on the new KGT6 and KGT7 units. The resulting impact is a benefit of approximately 200-300 MW across the study horizon, which would result in Northern Ireland operating within the LOLE Standard in the Secure scenario.

Low RES

This sensitivity assesses the impact of a low renewable buildout. The impact is most significant post 2030, showing a deficit increase of approximately 50 MW. The sensitivity of the adequacy results to the renewable trajectory has increasing significance across the study horizon as the power system becomes more dependent on renewables as the primary source of electricity supply. The renewable trajectory used in this sensitivity is shown in Table 6.16.

Table 6.16 Northern Ireland low renewable trajectory (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Offshore Wind	0	0	0	0	0	0	0	500	500	500
Onshore Wind	1410	1435	1460	1510	1598	1685	1773	1860	1948	2035
Solar	250	280	310	340	370	400	430	460	490	520

High RES

This sensitivity assesses the impact of full delivery of the Shaping Our Electricity Future v1.1 portfolio required to achieve 80% RES-E target in Northern Ireland. Note this trajectory also assumes delivery of 1 GW of offshore wind from 2030, aligned to DfE's ambition for offshore wind. The significant increase in renewable energy from the start of the study horizon provides a deficit reduction benefit of 50-100 MW. The renewable trajectory used in this sensitivity is shown in Table 6.17.

Table 6.17 Northern Ireland high renewable trajectory (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Offshore Wind	0	0	0	0	0	1000	1000	1000	1000	1000
Onshore Wind	1540	1610	1750	1990	2170	2460	2740	3030	3030	3030
Solar	300	350	400	450	525	600	675	750	825	900

Energy storage

This sensitivity assesses the contribution of 8-hour storage to system adequacy. It is worth noting again the core scenario only considers storage with capacity contracts and does not assume a further buildout beyond the latest T-4 auction. However, it is recognised that longer duration 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, 100 MW of 8-hour battery storage has been included from 2029, as capacity auctions completed at the data freeze date consider up to the year 2028. The average contribution to the adequacy position is 80 MW, illustrating the value longer duration storage can contribute. Note the quantity of storage included in this sensitivity is not indicative of the quantity required in future, and therefore the actual contribution from LDES will depend on the specific evolution of the portfolio.

Low Flex

This sensitivity illustrates the estimated 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 4.3.6.

6.6 All-Island adequacy analysis

All-Island Adequacy studies are completed assuming the second North-South Interconnector is operational from 2027. The analysis includes two scenarios, first using the Base scenario configuration and then using the Secure scenario configuration from the jurisdictional studies for Ireland and Northern Ireland, with the result being an All-Island position relative the 6.5 hour LOLE Standard for the SEM. Contrary to the jurisdictional assessments, the All-Island results are analysed on a single climate year which for the purposes of this assessment is 2016. The post data freeze date updated information regarding North South, presented in Section 6.3 indicating energisation in October 2031 should be considered when reading this section.

The All-Island assessment shows an improvement in security of supply for both jurisdictions, 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. This capacity benefit demonstrates some of the advantages of the second North South Interconnector.

The Base scenario results are shown in Table 6.18 and Figure 6.17. The LOLE Base results indicate the All-Island system is operating within the LOLE Standard from 2027 across the Study Horizon.

Table 6.18 Base results for the All-Island system

	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Base (hours)	4.1	2.6	3.4	2.0	3.5	2.4	3.7	2.5
EENS Base (GWh)	2.3	1.0	1.4	0.5	1.2	0.8	1.9	0.6
MW Base	240	280	260	380	320	250	130	140

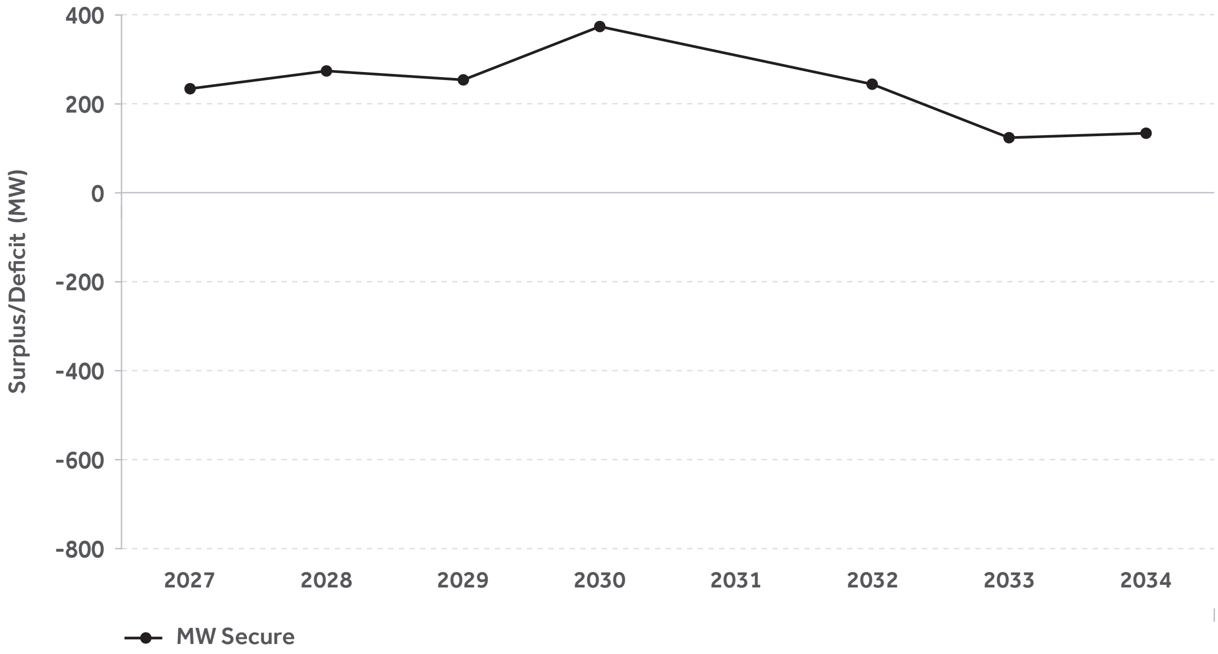


Figure 6.17 Base scenario adequacy analysis for the All-Island system in terms of surplus (+) and deficit (-) of perfect plant

The Secure scenario results are shown in Table 6 19 and Figure 6 18. The results indicate the system is outside of the LOLE Standard when considering low imports to the SEM, along with ARHL on some new conventional units and TOPs in Ireland.

Table 6.19 Secure results for the All-Island system

	2027	2028	2029	2030	2031	2032	2033	2034
LOLE Secure (hours)	9.6	7.9	8.7	7.1	9.2	14.7	23.9	28.9
EENS Secure (GWh)	4.1	2.4	2.7	2.0	3.4	3.9	8.6	9.2
MW Secure	-350	-360	-270	-330	-330	-460	-570	-630

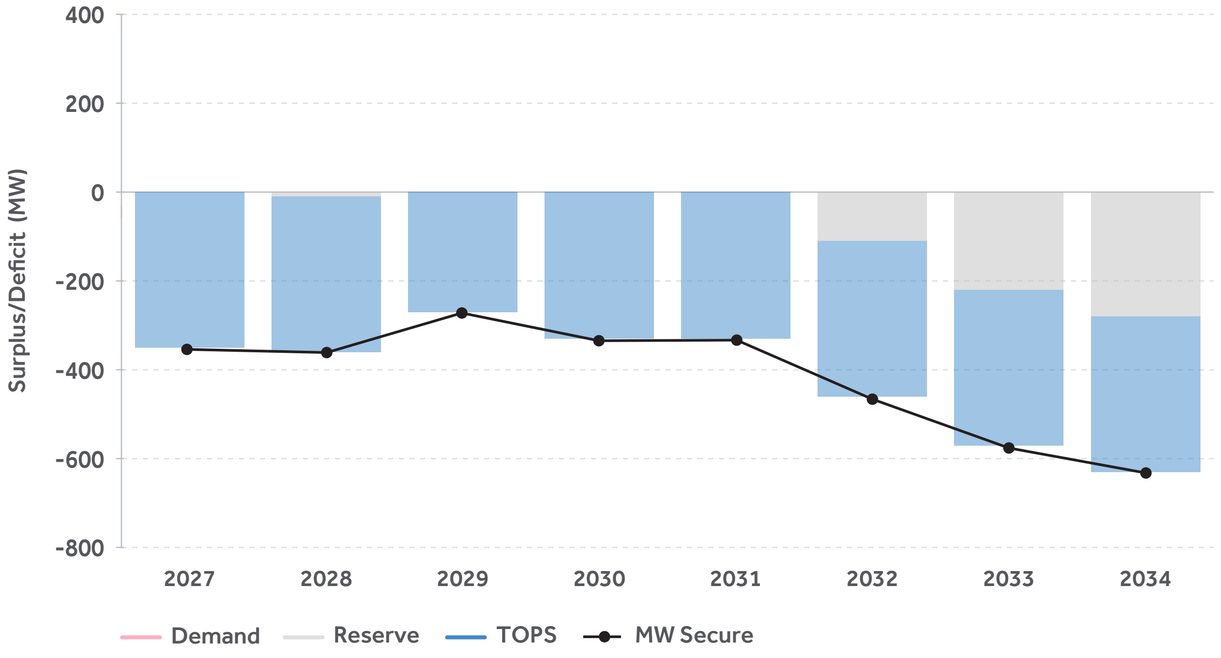


Figure 6.18 Secure scenario adequacy analysis for the All-Island system in terms of surplus (+) and deficit (-) of perfect plant

7. Appendix 1: Demand Scenarios

The Demand Forecast, given in Calendar year format (including a correction to 366 days in each Leap year), 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.

Table A1.1 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						
2023	34.0		8.09		42.1		5.76	1.6	7.36	5.64	1.57	7.21
2024	35.8	5.3%	8.21	1.6%	44.1	4.6%	5.95	1.59	7.54	5.83	1.56	7.39
2025	37.7	5.2%	8.33	1.4%	46.1	4.5%	6.13	1.61	7.72	6.02	1.57	7.57
2026	39.5	4.7%	8.57	2.8%	48.1	4.4%	6.32	1.67	7.97	6.21	1.63	7.82
2027	41.1	4.1%	9.05	5.7%	50.2	4.4%	6.46	1.75	8.19	6.35	1.71	8.04
2028	42.4	3.1%	9.31	2.9%	51.7	3.0%	6.57	1.79	8.33	6.46	1.76	8.18
2029	43.5	2.8%	9.58	2.9%	53.1	2.8%	6.64	1.84	8.45	6.53	1.80	8.30
2030	44.7	2.6%	9.83	2.5%	54.5	2.6%	6.72	1.87	8.53	6.61	1.84	8.39
2031	46.0	2.9%	10.11	2.9%	56.1	2.9%	6.83	1.91	8.66	6.71	1.88	8.52
2032	47.2	2.7%	10.47	3.5%	57.7	2.8%	6.92	1.95	8.79	6.81	1.91	8.63
2033	48.4	2.5%	10.71	2.3%	59.1	2.5%	7.03	1.99	8.90	6.91	1.96	8.76
2034	49.5	2.4%	10.94	2.2%	60.5	2.3%	7.12	2.04	9.03	7.01	2.00	8.88

Table A1.2 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						
2023	34.0		8.09		42.1		5.75	1.6	7.35	5.64	1.57	7.21
2024	35.1	3.0%	7.95	-1.7%	43.0	2.1%	5.77	1.49	7.26	5.65	1.45	7.11
2025	35.7	1.9%	8.02	0.8%	43.7	1.7%	5.85	1.49	7.39	5.74	1.46	7.24
2026	36.6	2.4%	8.14	1.5%	44.7	2.3%	5.93	1.53	7.50	5.82	1.49	7.35
2027	37.4	2.2%	8.34	2.4%	45.7	2.2%	6.00	1.57	7.61	5.88	1.53	7.45
2028	38.0	1.6%	8.53	2.3%	46.5	1.8%	6.04	1.61	7.69	5.93	1.57	7.54
2029	38.6	1.6%	8.72	2.3%	47.3	1.7%	6.06	1.64	7.74	5.95	1.60	7.59
2030	39.2	1.5%	8.92	2.2%	48.1	1.6%	6.09	1.66	7.78	5.98	1.63	7.64
2031	39.9	1.8%	9.13	2.3%	49.0	1.9%	6.14	1.70	7.85	6.03	1.66	7.71
2032	40.6	1.8%	9.34	2.3%	49.9	1.9%	6.19	1.73	7.92	6.08	1.69	7.76
2033	41.3	1.7%	9.56	2.3%	50.9	1.9%	6.25	1.76	7.98	6.14	1.72	7.84
2034	42.0	1.7%	9.77	2.3%	51.8	1.8%	6.31	1.79	8.06	6.20	1.75	7.90

Table A1.3 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						
2023	34.0		8.10		42.1		5.76	1.60	7.36	5.64	1.57	7.21
2024	36.4	6.8%	8.53	5.2%	44.9	6.5%	6.08	1.71	7.79	5.97	1.67	7.65
2025	39.2	7.8%	8.68	1.8%	47.9	6.6%	6.39	1.73	8.06	6.28	1.69	7.90
2026	41.9	6.9%	8.94	3.0%	50.8	6.2%	6.67	1.78	8.39	6.56	1.75	8.23
2027	44.1	5.2%	9.49	6.2%	53.5	5.4%	6.87	1.87	8.67	6.75	1.83	8.52
2028	45.7	3.7%	9.81	3.3%	55.5	3.6%	7.03	1.92	8.89	6.92	1.89	8.74
2029	47.2	3.3%	10.15	3.5%	57.4	3.4%	7.15	1.98	9.05	7.03	1.94	8.89
2030	48.5	2.8%	10.49	3.3%	59.0	2.9%	7.25	2.02	9.17	7.14	1.98	9.03
2031	49.8	2.6%	10.84	3.4%	60.7	2.8%	7.36	2.08	9.30	7.25	2.04	9.16
2032	50.9	2.2%	11.29	4.1%	62.2	2.5%	7.45	2.14	9.43	7.34	2.11	9.27
2033	51.9	2.0%	11.61	2.8%	63.6	2.2%	7.56	2.19	9.56	7.44	2.16	9.42
2034	53.0	2.0%	11.92	2.7%	64.9	2.1%	7.66	2.24	9.70	7.55	2.21	9.55

8. Appendix 2: Capacity Auction Results

Table A2.1 Capacity auction results		
Auction	**Date**	**Awarded Capacity (MW De-Rated)**
2018/2019 T-1	15/12/2017	7,774[87]
2019/2020 T-1	13/12/2018	8,266[88]
2020/2021 T-1	26/11/2019	7,606[89]
2021/2022 T-2	05/12/2019	7,512[90]
2022/2023 T-4	28/03/2019	7,412[91]
2022/2023 T-1	27/04/2020	1,121[92]
2023/2024 T-4	21/01/2021	7,322[93]
2023/2024 T-4	07/09/2023	639[94]
2024/2025 T-4	21/10/2021	6,168[95]
2024/2025 T-3	20/01/2022	1,471[96]
2025/2026 T-4	24/03/2022	6,484[97]
2026/2027 T-4	04/05/2023	7,204[98]
2027/2028 T-4	05/12/2023	5,470[99]
2024/2025 T-1*	08/05/2024	785[100]

*Provisional results at the time of the data freeze date

8.1 Terminated awarded new capacity

Table A2.2 Terminated awarded new capacity	
Technology Class	**Terminated Awarded New Capacity (MW)**
Demand Side Unit	154.903
Gas Turbine	1145.005
Other Storage	119.640
Wind	48.251

87 https://www.sem-o.com/documents/general-publications/Capacity-Market-Final-Capacity-Auction-Results-Report_FCAR1819T-1.pdf
88 https://www.sem-o.com/documents/general-publications/T-1-2019-2020-Final-Capacity-Auction-Results-Report.pdf
89 https://www.sem-o.com/documents/general-publications/T-1-2020-2021-Final-Capacity-Auction-Results-Report.pdf
90 https://www.sem-o.com/documents/general-publications/T-2-2021-2022-Final-Capacity-Auction-Results-Report.pdf
91 https://www.sem-o.com/documents/general-publications/T-4-2022-2023-Final-Capacity-Auction-Results-Report.pdf
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93 https://www.sem-o.com/documents/general-publications/T-4-2023-2024-Final-Capacity-Auction-Results-Report.pdf
94 https://www.sem-o.com/documents/general-publications/FCAR2324T-1-report.pdf
95 https://www.sem-o.com/documents/general-publications/T-4-2024-2025-Final-Capacity-Auction-Results-Report.pdf
96 https://www.sem-o.com/documents/general-publications/T-3-2024-2025-Final-Capacity-Auction-Results-Report.pdf
97 https://www.sem-o.com/documents/general-publications/T-4-2025-26-Final-Capacity-Auction-Results-Report.pdf
98 https://www.sem-o.com/documents/general-publications/FCAR2627T-4-report.pdf
99 https://www.sem-o.com/documents/general-publications/FCAR2728T-4-report-v1.0.pdf
100 https://www.sem-o.com/documents/general-publications/2425T-1-Provisional-Capacity-Auction-Results-Report.pdf

9. Appendix 3: Generation Plant Information

9.1 Ireland

Table A3.1 Registered capacity of dispatchable generation and interconnectors in Ireland in 2025 (MW)

	ID	Fuel type	Technology category	2023	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	830	
Ardnacrusha	AA1-4	Hydro	Hydro	86	
Dublin Bay	DB1	Gas/DO	Gas Turbine	415	
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	
Great Island CCGT	GI4	Gas/DO	Gas Turbine	464	
Huntstown	HNC	Gas/DO	Gas Turbine	337	
	HN2	Gas/DO	Gas Turbine	408	
Indaver Waste	IW1	Waste	Steam Turbine	17	
Lee	LE1-4	Hydro	Hydro	27	
Liffey	LI1-4	Hydro	Hydro	38	
Moneypoint	MP1	Coal/HFO	Steam Turbine	250	Modelled as not available from the start of July 2025
	MP2	HFO	Steam Turbine	250	Modelled as not available from the start of July 2025
	MP3	Coal/HFO	Steam Turbine	250	Modelled as not available from the start of July 2025
Poolbeg CC	PBA	Gas/DO	Gas Turbine	234	
	PBB		Gas Turbine	234	
Rhode	RP1	DO	Gas Turbine	52	
	RP2	DO	Gas Turbine	52	

Table A3.1 Registered capacity of dispatchable generation and interconnectors in Ireland in 2025 (MW)

	ID	Fuel type	Technology category	2023	Comment
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	Pumped storage	Storage	292	
Tynagh	TYC	Gas/DO	Gas Turbine	389	
Whitegate	WG1	Gas/DO	Gas Turbine	450	
Total:				**6920**	

Table A3.2 All renewable energy sources in Ireland (MW)

At year end:	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Wind Onshore	5400	5750	6050	6450	6800	7150	7550	7950	8350	8750
Wind Offshore	25	25	25	25	25	1350	1950	2500	3100	3750
Solar PV	2500	3250	4000	4750	5500	6300	6900	7500	8050	8650
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	129	129	129	129	129	129	129	129	129	129
Total	**8143**	**9243**	**10293**	**11443**	**12543**	**15018**	**16618**	**18168**	**19718**	**21368**

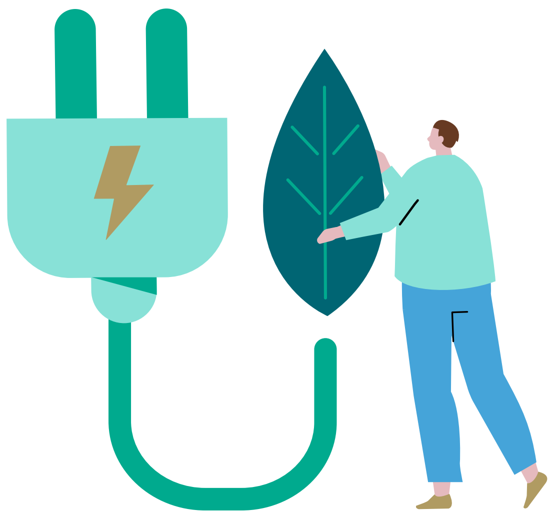
9.2 Northern Ireland

Table A3.3 Registered capacity of dispatchable generation and interconnectors in Northern Ireland in 2025 (MW)

	ID	Fuel Type	Technology Category	2025	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	
DSU	DSU	Various	DSU	200	
Lisahally		Biomass		18	Not in Capacity Market, but assumed available for capacity requirement
Contour Global	CGA / CGC	Gas	Gas Turbine	12	
Moyle		DC Interconnector		450	Assumed to increase to 500 MW in 2028
Total:				**2771**	

Table A3.4 Partially/non-dispatchable plant in Northern Ireland (MW)										
At year end:	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Large Scale Wind	1255	1305	1355	1455	1630	2305	2480	2655	2830	3005
Small Scale Wind	180	180	180	180	180	180	180	180	180	180
Solar PV	250	300	350	400	450	500	550	600	650	700
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	**1761**	**1861**	**1961**	**2111**	**2336**	**3061**	**3286**	**3511**	**3736**	**3961**

Table A3.5 All renewable energy sources in Northern Ireland (MW)										
At year end:	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
All Wind	1435	1485	1535	1635	1810	2485	2660	2835	3010	3185
Solar PV	250	300	350	400	450	500	550	600	650	700
All Biomass/ Biogas/LFGas/ WTE	250	300	350	400	450	500	550	600	650	700
	79	79	79	79	79	79	79	79	79	79
Renewable CHP	3	3	3	3	3	3	3	3	3	3
Hydro	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**



10. Appendix 4: Alignment of Plexos and AdCal

Plexos is the modelling application used to implement the Monte Carlo adequacy assessment methodology for this All-Island Resource Adequacy Assessment 2025-34. This is an update from previous adequacy assessments which used a tool called AdCal. Since this is the first time that Plexos is being used for the All-Island Resource Adequacy Assessments, at request from industry and other stakeholders EirGrid and SONI have conducted additional parallel studies in AdCal and Plexos to align the results using each methodology.

10.1 Modelling applications

AdCal was an application used by EirGrid and SONI to conduct adequacy assessments up to and including GCS 2023-2032. It is a convolution-based model that builds a generation probability distribution to calculate LOLE and the MW surplus/deficit. AdCal is a suitable tool for power systems that mainly consist of conventional power units complimented by a small number of simple storages, like Turlough Hill, and where the largest risk to resource, adequacy is the loss of a conventional plant. It has limited functionality in terms of modelling energy limited technologies such as DSUs and battery storage, and also limited capability to model interconnection and renewable resources.

Plexos is an energy market simulation software developed by Energy Exemplar, used to build detailed multi-regional models required to represent the evolving power systems in Ireland and Northern Ireland which have high renewable penetrations and interconnection to other markets. Plexos economically dispatches resources to meet demand including renewables, energy storage, conventional plant as interconnectors, therefore better representing actual power system operational scenarios compared to AdCal.

10.2 Modelling results

This section presents a comparison of the Secure scenario results presented in Section 6.4.4 (Figure 6.7) for Ireland and Section 6.5.4 (Figure 6.15) for Northern Ireland with the equivalent results for each jurisdiction if they were completed using AdCal. The comparison has been presented in terms of the Surplus/ Deficit results with individual assessments for the Ireland and Northern Ireland power systems. The inputs to each model have been aligned for the Plexos and AdCal runs including demand, renewable capacities, generation portfolios, energy storage limits and reserve requirements.

Ireland

The adequacy assessment for the Ireland system using Plexos and AdCal is shown in Figure A4.1 and Table A4.1. Overall, the results are reasonably consistent across the study horizon between the two different methodologies, with the average absolute delta between the two being 140 MW across 2025-32. Across the period the results are aligned until additional benefit from offshore wind is realised in Plexos from 2030 onwards

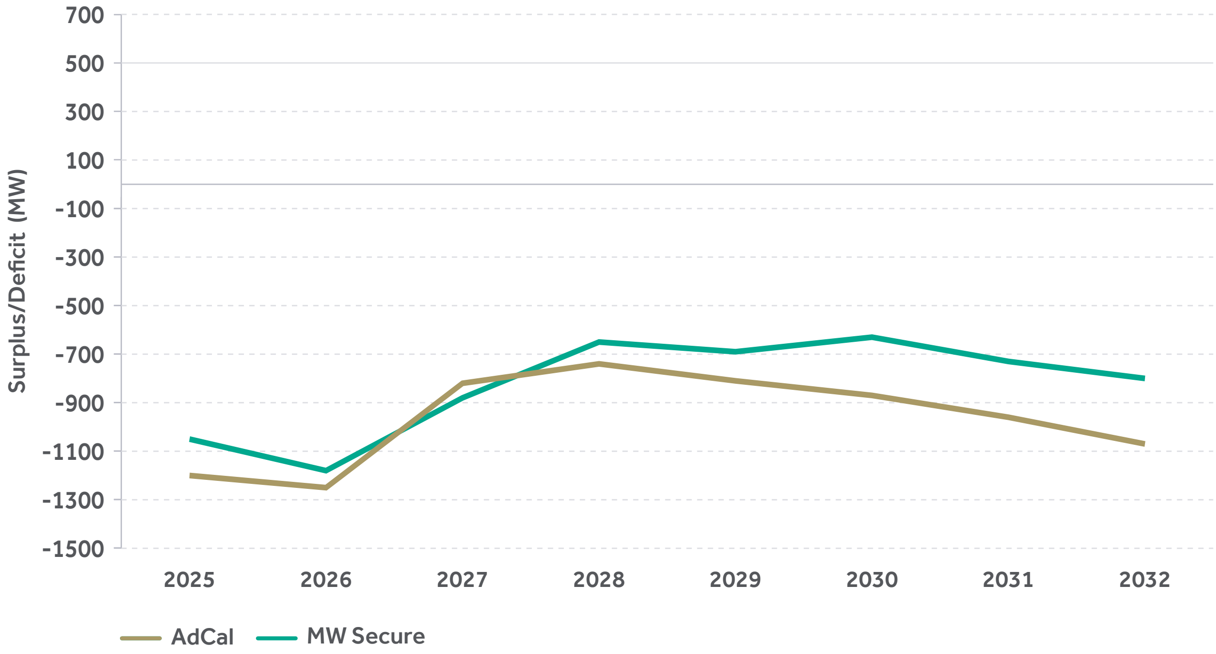


Figure A4.1 Results of adequacy alignment for Ireland given in MW in terms of surplus (+) and deficit (-) of perfect plant

Table A4.1 Results of adequacy alignment for Ireland given in MW in terms of surplus (+) and deficit (-) of perfect plant

	2025	2026	2027	2028	2029	2030	2031	2032
AdCal	-1200	-1250	-820	-740	-810	-870	-960	-1070
MW Secure	-1050	-1180	-880	-650	-690	-630	-730	-800

Northern Ireland

The adequacy assessment for the Northern Ireland system, under the core median demand scenario using Plexos and AdCal, is shown in Figure A4.2 and A4.2. Overall, the trend is similar across the study horizon however there is a clear delta between the two methodologies with the average difference between the two being 170 MW across 2025-32. The deficit in Northern Ireland calculated using Plexos is significantly less across the modelled period. The difference is driven by improved optimisation of Run Hour Limited plants, resulting in a positive impact on the adequacy position in Plexos compared to AdCal.

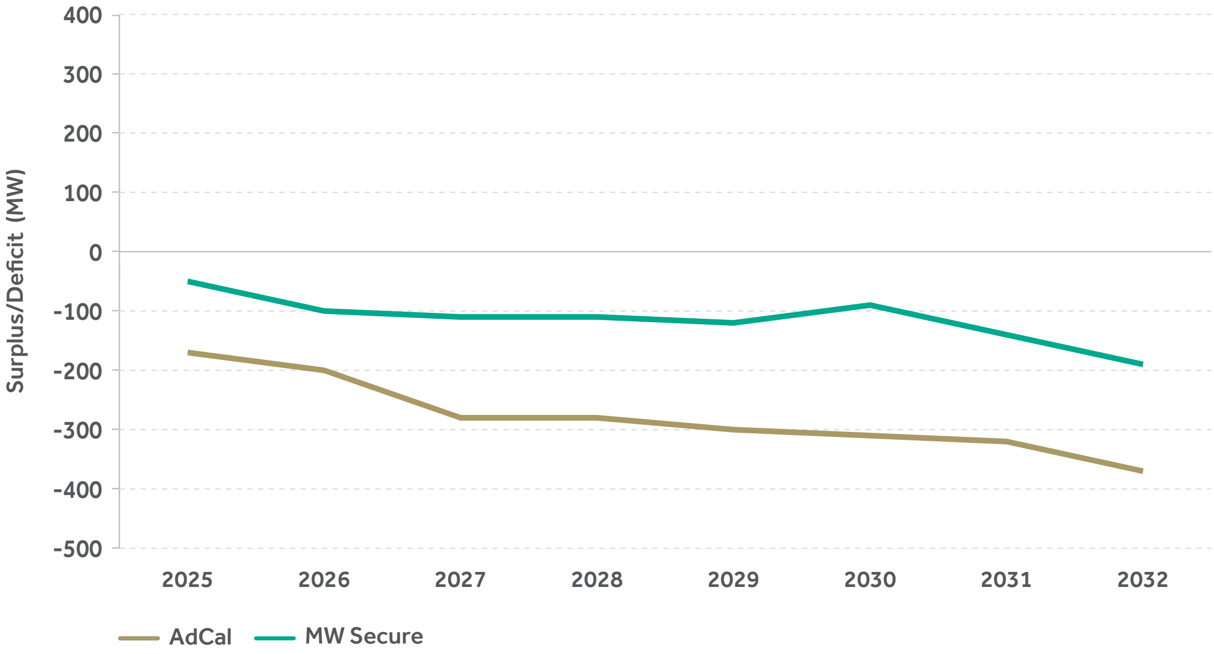


Figure A4.2 Results of adequacy alignment for Northern Ireland given in MW in terms of surplus (+) and deficit (-) of perfect plant

Table A4.2 Results of adequacy alignment for Northern Ireland given in MW in terms of surplus (+) and deficit (-) of perfect plant

	2025	2026	2027	2028	2029	2030	2031	2032
AdCal	-170	-200	-280	-280	-300	-310	-320	-370
MW Secure	-50	-100	-110	-110	-120	-90	-140	-190

10.3 Results alignment

Due to the difference in modelling applications and probabilistic assessment methodologies, quantifying the specific drivers for differences between the results is a challenge. However, the stepwise process of building the models to complete the alignment process and produce the results below has provided some insights into the key drivers for deviations, more information on which are provided below.

- **Maintenance Scheduling:** AdCal typically produces the most optimal scheduled outage pattern whereas Plexos produces a range of possible outage patterns which on average reflect the actual observed historic scheduled outages of generators. The result is a negative impact on the adequacy position in Plexos compared to AdCal.
- **New Capacity Delivery:** In AdCal, new units are considered either in or out for a given year whereas in Plexos specific dates can be input for units. To provide an example, where units would have been assumed to be available from October 2026, in AdCal they will be included from the start of 2027, whereas in Plexos these units can be available from October 2026. In this example Plexos would have additional benefit from the unit as it would be available for an additional 3 months during winter 2026.
- **Annual Run Hour Limits:** Plexos provides better modelling capabilities for modelling ARHL, as units can be used over peak times of the day when they are likely to be needed most, whereas modelling ARHL in AdCal restricts operation to weeks of the year where they may be needed the most. The increased granularity of modelling in Plexos is observed to provide a positive impact on the adequacy position.
- **Renewable Interaction with Storage:** AdCal models limited interaction between storage and renewable energy whereas in Plexos storage can be better optimised across multiple days to complement renewable availability. The renewable interaction with storage technologies has a positive impact on the adequacy position in Plexos compared to AdCal.
- **Offshore Wind Availability:** Offshore wind in AdCal uses the same availability profile as onshore wind, whereas in Plexos specific offshore profiles are used based on the Pan-European Climate Database (PECD) data. This is reflective of the higher capacity factors expected from offshore wind relative to onshore wind technologies. Accounting for the higher availability of offshore wind has a positive impact on the adequacy position in Plexos compared to AdCal.

11. Appendix 5: Value of Lost Load

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

The Value of Lost Load (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 LOLE Standard is 3hr and in Northern Ireland the LOLE 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 LOLE standard.

The most efficient number of hours of outage to allow (LOLE 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[101]. Put algebraically, outage makes sense as long as

VoLL * LOLE standard < CoNE

For example:

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

101 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.

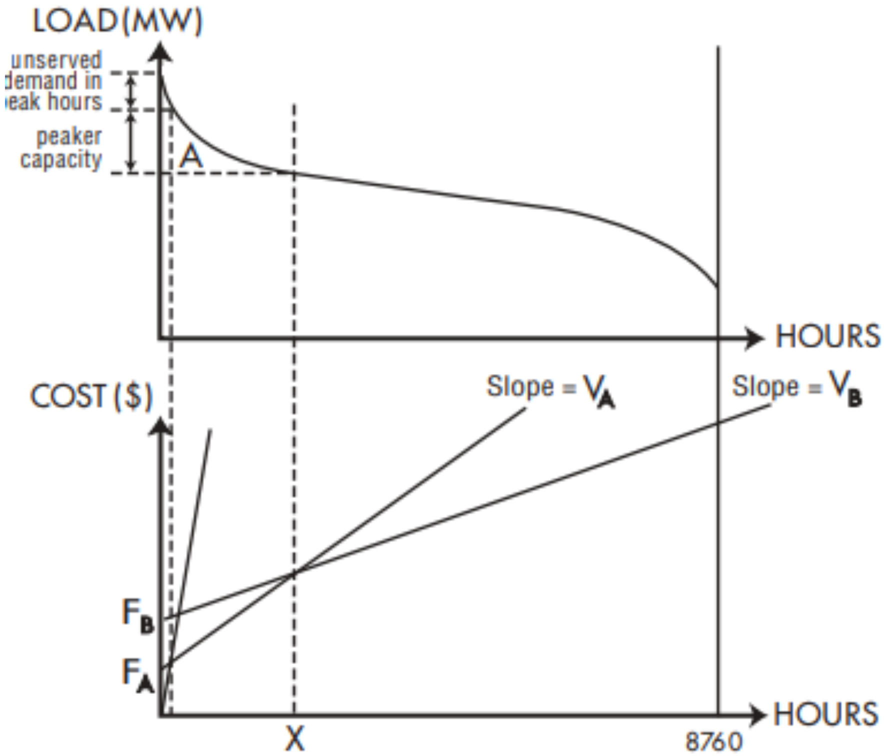


Figure A5.1 Balance point between the costs of a new entrant (CoNE) to meet demand versus the cost impact of not meeting demand (VoLL) for a certain LOLE[102]

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

12. Appendix 6: 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., TER = 54900 GWh, Peak = 8.64 GW (Median forecast for all-island system in 2030). $$ALF = \frac{54900/8760}{8.64} = 73\%$$ 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 CO_2 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 2GW 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	A subsidiary within ESB Group, ESB Networks is the licensed operator of the electricity distribution system in the Republic of Ireland and owner of all transmission and distribution network infrastructure.
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.
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 x 1012 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	

Acronym/ Abbreviation	Term	Explanation
RES-E		Renewable Electricity.
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 x 1015 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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