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Ten-Year Generation Capacity Statement 2023–2032

January 2024

Document overview

This document contains two sections:

Part A

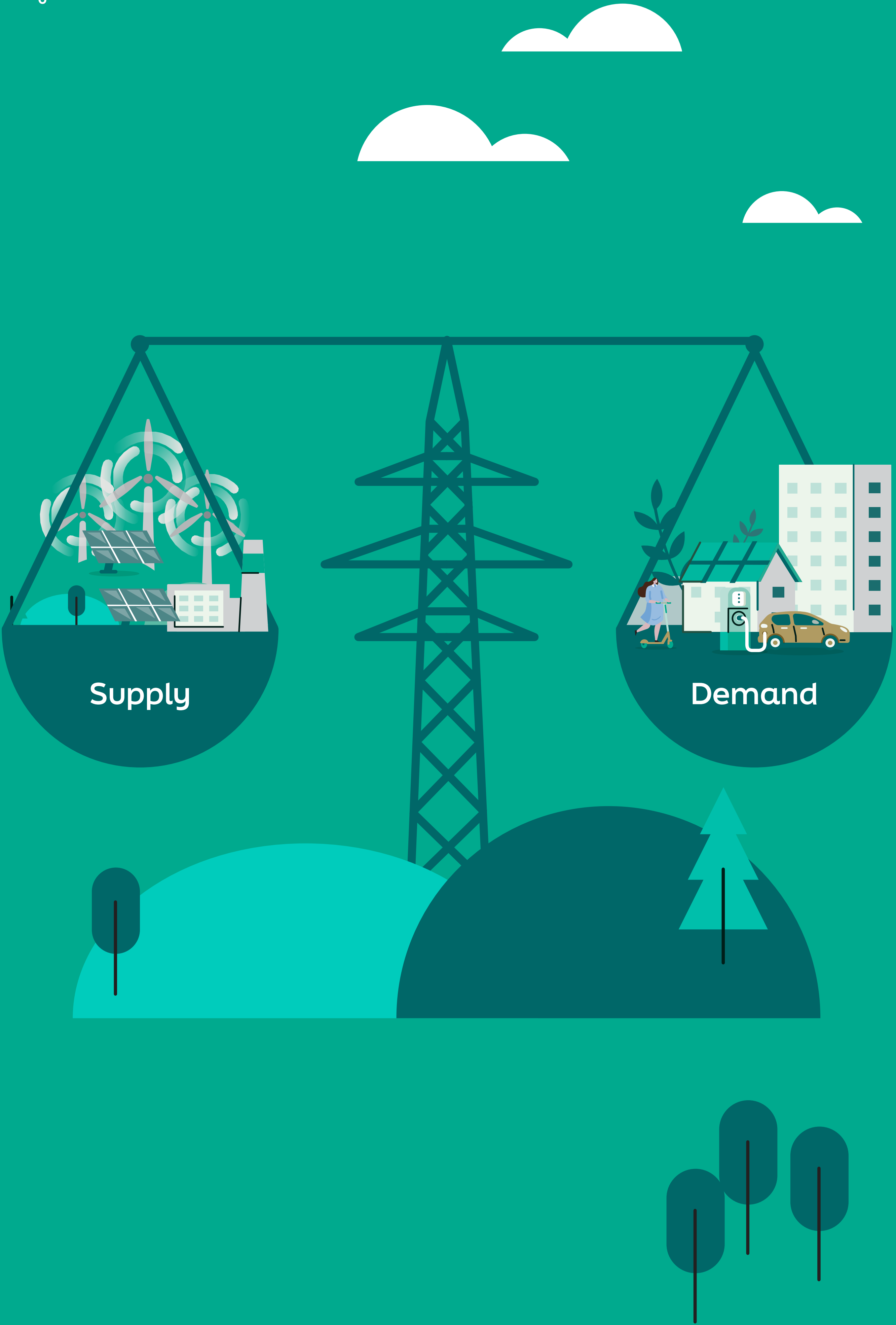
This is a plain English summary of the Generation Capacity Statement with a focus on Northern Ireland.

Part B

This is an all-island document and is a licence requirement for SONI and a regulatory requirement for EirGrid. This Generation Capacity Statement has been approved by the Utility Regulator in Northern Ireland, in accordance with the SONI licence requirement.

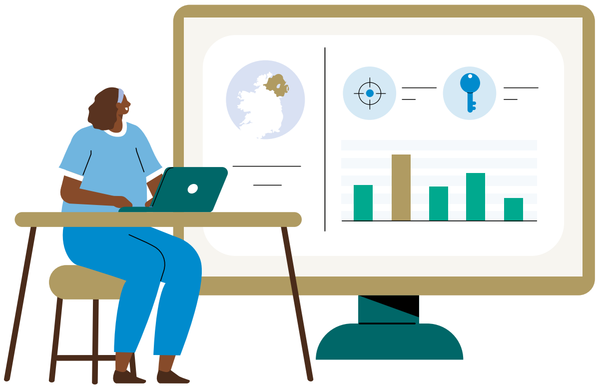
Contents

Part A
Ten-Year Generation Capacity Statement 2023–2032: A Summary Version


Supply
Demand

What is the GCS?

The Generation Capacity Statement (GCS) is an annual report from SONI, the electricity transmission system operator for Northern Ireland and EirGrid, our counterpart in Ireland. We are required by our license to publish this assessment each year once approved by the Utility Regulator.



Introduction

The GCS is our assessment of the balance between electricity demand and supply in Northern Ireland and Ireland over a ten-year period at a point in time. Our assessment looks at likely future consumer demand to understand how much electricity we will need.

The GCS is a means for SONI and EirGrid to signal future needs and requirements to the electricity market as well as to policy makers, regulators, and TSOs. The ten-year outlook reflects the time required by the wider energy eco-system to plan and build the necessary infrastructure that can address identified problems.

The GCS is a significant source of information for the all-island wholesale electricity market, which is called the Single Electricity Market (SEM). Within the SEM, Capacity Auctions are run annually to meet electricity capacity needs for a specified year. Auctions are run four years ahead with the option to run additional auctions from one to three years ahead. This assessment sends signals to the all-island market for electricity, where private sector companies bid to win contracts to build new generators and sell electricity onto the grid.

What is SONI's role?

SONI is the transmission system (the electricity grid) operator 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 grid to ensure that power can flow from where it is generated to where it is needed.

Our team of experts also forecast how much electricity we will need in the future to meet consumer demand to support the all-island electricity market. We do this through the Generation Capacity Statement.

How is the Generation Capacity Statement developed?

Our team of expert engineers and economists undertake detailed studies to understand how much consumer demand there is likely to be in the future. They look at trends in key economic activity such as transport, retail, office, and service sectors.

They also look at what new electricity generation is currently available and is due to be available in the future.

When researching for the GCS, SONI considers:

Demand: what are Northern Ireland's electricity needs?

This incorporates the total electricity and peak demand requirement including demand from homes, businesses, and industry, and growing levels from electric vehicles and heat pumps.

Generation: what energy can be supplied to meet the demand for electricity?

- This includes the energy coming from conventional (fossil fuelled) power stations, interconnection, capacity support from Ireland, battery energy storage, demand side participation and renewable sources.
- New energy generation expected to enter the power system through the all-island wholesale electricity market's capacity auctions.
- The impact of forced (unplanned) and scheduled (planned maintenance) outages of plant at conventional power stations.

Taking Demand and Generation together, the assessment then shows what's known as the 'adequacy position'. This includes the likely surplus or deficit for each year and whether Northern Ireland will have enough electricity to meet predicted demand and operational requirements to stay within the margin standards set by government, or whether more generation needs to be secured through the market. If a deficit is identified, the GCS provides a signal to industry that further capacity is needed in the future. The vehicle to source this further capacity is via the capacity auctions.

The measure of 'adequacy' for the GCS is known as Loss of Load Expectation (LOLE[1]). Loss of load Expectation is a mathematical expression used to assist in power system planning. This standard is based on a set number of hours per year that the system can expect to be operating with less electricity than is required to meet consumer demand. Any deficit or gap will result a breach of Northern Ireland's LOLE Standard.

Is the information in the GCS up-to-date when it is published?

To try and arrive at the most accurate adequacy assessment, the studies look at a number of different scenarios and assumptions and use statistical averages such as the 'median'. To allow time for the detailed studies to be undertaken, a 'data freeze' is used. For this year, the data freeze date for the demand forecast was March 2023 and the generation forecast was May 2023. Importantly, this means there are likely to be some changes to the overall assessment if there have been developments between the 'data freeze' dates and publication date of the GCS. For this reason, SONI has developed this summary to the GCS this year which incorporates such developments; this is intended to reflect a more up to date adequacy forecast at the date of publication. The data freeze date for the summary is October 2023.

Since the data freeze date, SONI has carried out a further sensitivity called the 'TSO adjusted scenario'; further information is in the Adequacy section of this summary document. SONI have engaged with the Utility Regulator and the Department for the Economy so that this scenario captures risks that are relevant to the longer-term adequacy position based on new information now available to the TSO. SONI are working with the Utility regulator and DfE on how these risks can be mitigated into the future including how short-term operational measures may minimise the loss of load risk to consumers.

1 The LOLE standard for Northern Ireland is set to 4.9 hours by the Department for the Economy and is factored into our calculations. This means that there should be enough capacity to meet demand so that the system does not exceed 4.9 hours of customer outages per year.

Global energy market context

Many countries across the world are also upgrading their energy systems to reduce the use of harmful fossil fuels. This transition aims to tackle climate change and help make energy markets more robust and resilient by incorporating more renewable energy and new technologies to facilitate a wider range of generation on the grid.

During this transition period, there may be some additional challenges, including balancing consumer demand with available electricity and managing timing of new generation coming onto the system against the retiring of old generation.

Northern Ireland also faces some of these challenges.

Northern Ireland is not an outlier here, National Grid ESO in GB, EirGrid in Ireland and electricity system operators globally are all experiencing similar challenges as we move through the transition from systems reliant on fossil fuels to cleaner systems based on renewable energy.

What is important is that SONI, along with other key stakeholders including the Department for the Economy and the Utility Regulator, works to identify and mitigate the challenges to our energy system. By sending the correct investment signals and working to develop the system efficiently and effectively, we work together to ensure a smooth energy transition.

In the following sections we highlight the key changes between GCS 2022–2031 and GCS 2023–2032 and any recent developments since this year's data freeze that could have an effect on the forecasts for adequacy in NI over the next ten years.

Demand

Changes since GCS 2022–2031

The median demand forecast is based on an average temperature year. It includes assumptions on data centre and new technology load in the connection process, electrification of heat and transport, along with the application of a central economic growth rate factor. This is our best estimate of what is required to support government policy of electrification of heat and transport and support economic growth.

Since the GCS 2022–2031 was published, out-turn Total Electricity Requirement (TER) for 2022 (the total amount of electricity used) was down compared to the initial forecast, particularly in the second half of the year, coinciding with high energy prices. Figure 1 illustrates the TER forecasts for GCS 2022–2031 median demand compared to the latest GCS 2023–2032 TER demand forecasts. The latest data has been factored into the GCS 2023–2032 TER demand forecasts and results in a lower TER demand level in the short term (2023 – 2026). Lowering the TER demand forecast improves the adequacy position for these years.

From 2027 onwards, the longer-term effect of high energy prices is expected to subside, and the demand forecast is comparable to what was estimated previously in GCS 2022–2031. The range difference between median and high demand is based on several factors including the effect of temperature, economics, growth in data centres and new technology loads, energy efficiency as well as electrification of heat and transport. The GCS 2023–2032 has used updated RP7 data provided by NIE Networks for electrification of heat and transport rather than using the TES NI 2020 data in the GCS 2022–2031. The growth in data centres and new technology loads is based on projects in the connection process. This update is to ensure consistency in planning across the transmission and distribution systems.

Figure 2 illustrates how the TER demand forecast is built up from the various demand components for the years 2025 and 2030. Growth in TER from 2025 is primarily driven by the electrification of heat and transport with government policies and incentives expected to drive growth. The growth in the Industrial component of TER includes new demand which are part of the connections process.

Post-data freeze developments

Since the data freeze date for the GCS 2023–2032, no further updates have been considered about expected demand.

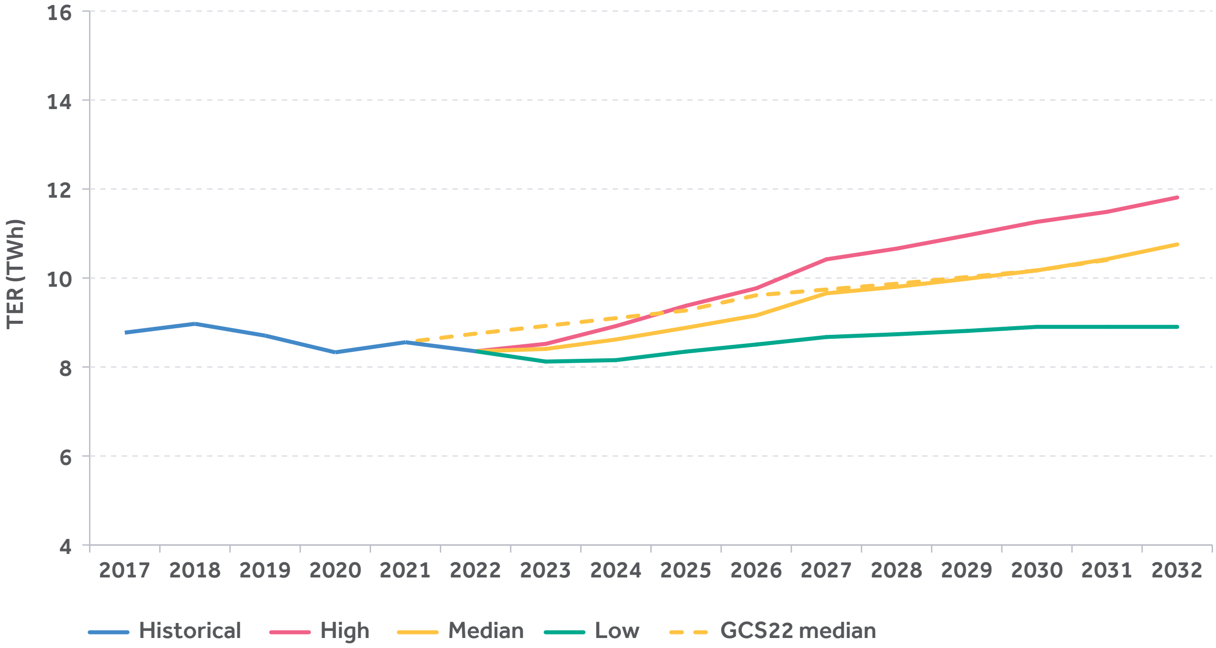


Figure 1: Northern Ireland TER forecast

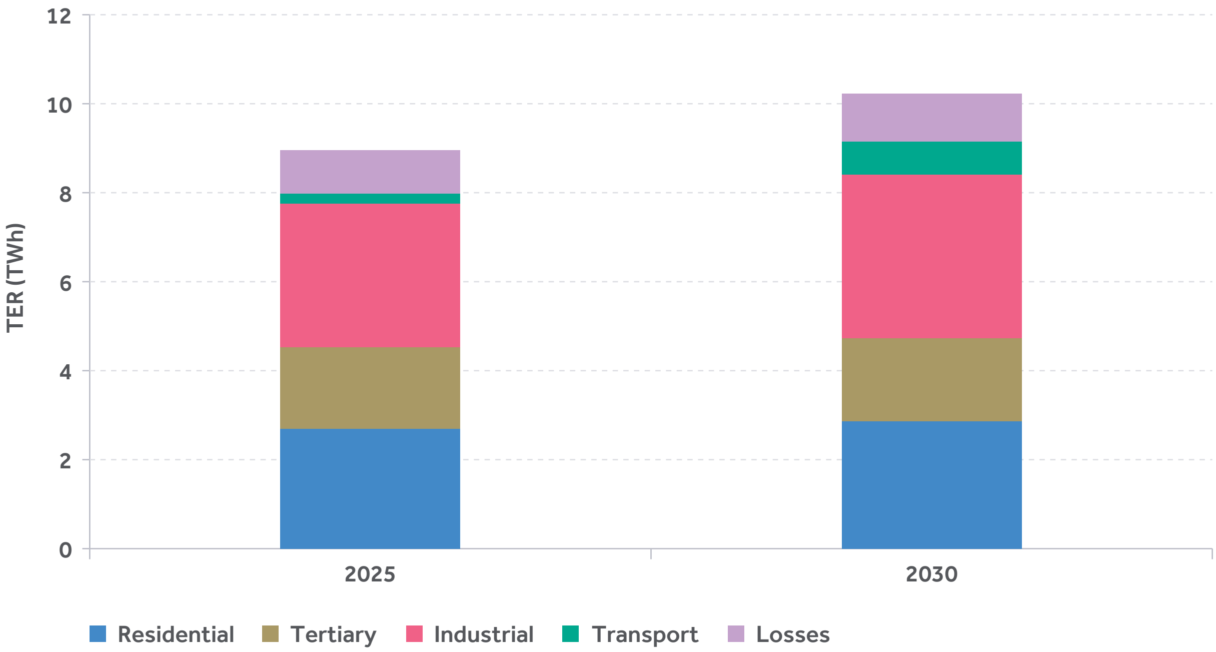


Figure 2: Northern Ireland sector breakdown with the Total Electricity Requirement forecast

Generation

Changes since GCS 2022–2031

The existing generation portfolio assumed for GCS 2023–2032 can be found in Appendix 4 of the main GCS paper.

Factors relating to generation which have had an impact on system adequacy forecasts for 2023–2032 include:

1. **Lower availability of existing generation in NI**
   As part of our annual process, SONI assess plant performance. We use past performance data of existing conventional plant generators across the island to assess their actual availability. Using real world data, we can understand trends in power plant availability. Future plant performance is based on a historic 5-year average for the all-island system. Including the latest plant performance data from 2022, the 5-year average is now below the 2019 outage statistics used in the GCS 2022–2031.
   The lower power plant availability worsens the adequacy position across the study timescales in the GCS 2023–2032.
   To maximise power plant availability SONI continues to engage with power plant owners and the regulator on maximising all available generation on the system and adapting the schedules for planned power plant and network maintenance. Furthermore, the SEMC published a decision in late 2022 to allow Demand Side Units to receive energy payments, which aims to incentivise improved availability and performance; SONI await the implementation of the SEMC decision, and we will continue assess DSU performance in future iterations of the GCS.

2. **Later than expected operation of new plant in Northern Ireland**
   The new gas units at Kilroot are modelled based on delivery by January 2024 rather than October 2023 thus worsening the adequacy position in 2023. In addition, the steam turbine at Kilroot is modelled to be delivered by 2027 rather than 2026, worsening the adequacy position in 2026.

Post-data freeze developments

Further, since the data-freeze date for GCS 2023–2032, other developments include:

1. Further indicated delay of gas units at Kilroot by the developer – at September 2023, the developer indicated that the plant would be operational by 24th March and 1st May rather than January 2024[2]. While this change was not included in the development of the GCS 2023–2032, it could have an impact on adequacy for 2024.

2. The T-1 23/24 capacity market auction has ran, this has negligible impact on the adequacy position for Northern Ireland.

3. The latest information available to SONI has identified an increased likelihood of the non-delivery of the steam turbine at the Kilroot site.

4. The T-4 27/28 capacity market auction has ran, this impact has not been accounted for.

2 https://umm.nordpoolgroup.com/#/messages?publicationDate=all&eventDate=nextweek&marketParticipants=A0020896N.IE

Adequacy

Changes since GCS 2022–2031

2023–2026

SONI's low, median and high demand scenarios at the data freeze date in the GCS 2023–2032 show that there are adequacy challenges over the next four years from 2023-2026. Using the median demand scenario, this equates to a LOLE position outside the standard of 4.9 hours outlined in Table 1. This can be explained by:

- 2023: later than expected delivery of new gas units at Kilroot until 2024.
- 2024: delivery of new gas units at Kilroot but they are run hour limited reducing expected available capacity.
- 2025: continued run hour limited plant in NI, plus planned outage of KGT1-4 at Kilroot.
- 2026: continued run hour limited plant in NI, with KGT1-4 returned to service.

2027–2032

Post-data freeze developments: The 'TSO adjusted scenario'

Since the freeze date SONI has carried out a further sensitivity to adjust for the non-delivery of the new steam turbine capacity; we have called this the 'TSO adjusted scenario', this is illustrated in Figure 3 – Sensitivity (2). The new steam turbine capacity at Kilroot was previously assumed to be available in 2027 in the GCS 2023–2032 core scenarios.

The TSO adjusted scenario includes prudent modelling of ARHLs applied to the new gas units at Kilroot for the entire study period due to the non-delivery of the steam turbine that would have established a Combined Cycle Gas Turbine at the site. Going forward the approach to modelling ARHLs will be evaluated within the new National Resource Adequacy Assessment which will form the basis for the next iteration of the adequacy forecast.

Figure 3 compares post freeze date TSO adjusted scenario (2) at the median demand with the GCS 2023–2032 core median scenario (1); the chart illustrates the expected impact on the surplus/deficit position moving from a surplus to deficit position due to the non-delivery of the steam turbine in 2027.

SONI has run a further sensitivity to evaluate the impact on system adequacy if ARHLs do not apply, or if additional capacity was made available through the market, this is illustrated in Figure 3 – Sensitivity (3).

When planning the power system for normal operation (which includes the 4.9 hours LOLE Standard), SONI include demand and operational reserves. When we consider Figure 3 a shortfall below zero does not necessarily mean consumers will experience loss of supply. During these shortfall periods, there is an expectation that the system may enter the Alert State at times, most likely at periods of high demand, low generation availability and low interconnector imports. In practice, when there is not enough supply to meet normal operation, the TSO has a range of operational measures available to minimise impact on consumers.

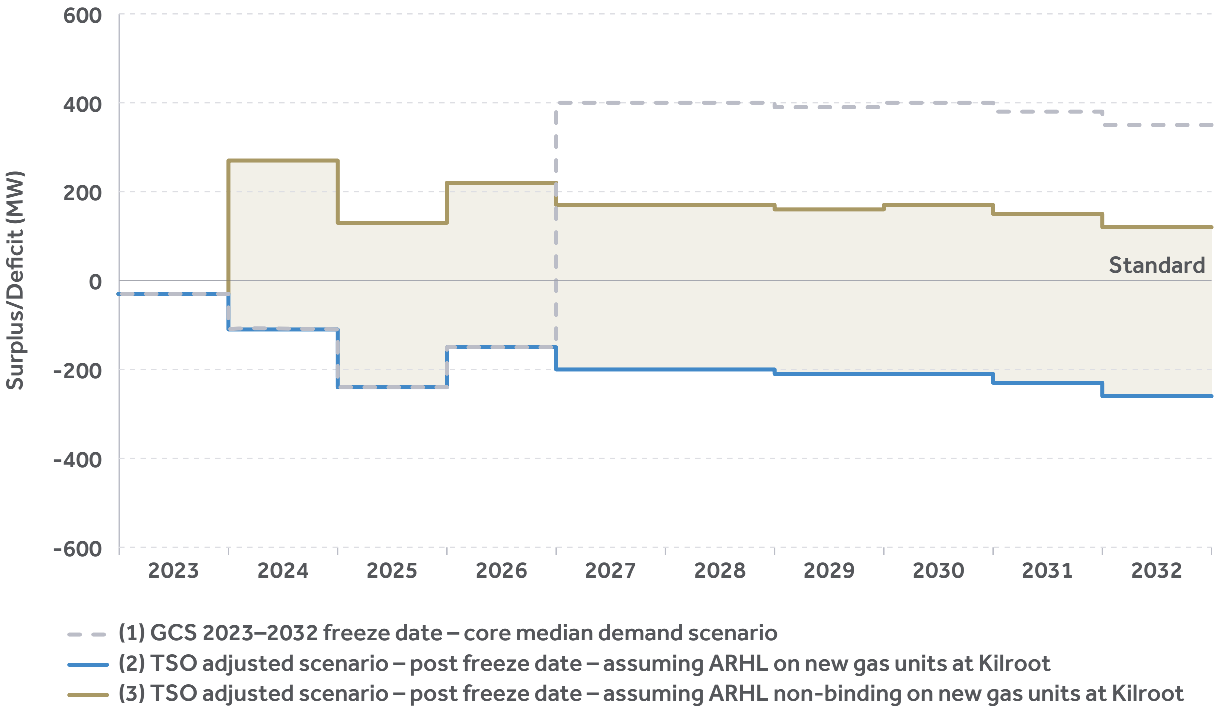


Figure 3: Post freeze date – adequacy assessment sensitivities on median demand – surplus/deficit position (MW)

How will we manage this challenging outlook?

This winter, we expect there will be sufficient generation available to meet consumer demand, recognising that there is an increased risk that the buffer margins for electricity generation may be tighter than normal. This means we may see more System Alerts being issued this Winter than in previous years. However, it is important to reassure consumers that the risk of any significant disruption is very small and our expert engineers have tried and tested plans in place to manage any challenges that arise.

SONI continues to work closely with the Department for the Economy, the Utility Regulator, the Northern Ireland Environment Agency, our counterparts in National Grid Electricity System Operator (ESO) in Great Britain, EirGrid the TSO for Ireland 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 OCGTs
- Utilising new technologies such as batteries.
- Maximising the availability of imports from Great Britain and Ireland.
- Continuing to work with partners and the developers of new generation to accelerate the delivery of the two new gas units at Kilroot.
- 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 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.

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 the 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.

All–Island Assessment

The new North-South Interconnector is expected to be completed over the coming years; therefore, we have provided an All-Island adequacy assessment within the GCS from 2026. Until this date we need to limit the support between both jurisdictions to ensure system stability and security. Once the new North-South interconnector is online, the ability for support is greatly increased. From our analysis it is clear the new interconnector will support the overall security of supply outlook, along with other enduring market measures.

Future resource adequacy assessments

Looking forward, SONI and EirGrid are working with the Utility Regulator and the CRU on replacing the currently used AdCal software package as specified in Appendix 5 of the Generation Capacity statement, to a new software tool that will be used within the soon to be consulted upon National Resource Adequacy Assessment. The new software tool is expected to enable SONI and EirGrid enhance their ability to assess the future power system challenges that are faced by an electricity system with high levels of variable renewable power sources in a transformation shift towards net-zero. The new tool will allow a broader range of scenarios and sensitivities to be assessed and will enhance our modelling capability for various technologies including, but not limited to renewable energy sources, renewable gas ready power plants, storage, demand side and interconnection. A methodology for the National Resource Adequacy Assessment will be published.

Part B
All-Island Ten Year Generation Capacity Statement 2023–2032

Disclaimer

SONI Ltd and EirGrid Plc 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 Generation Capacity Statement for Northern Ireland and the Generation Capacity Report for Ireland.

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Document structure

This document contains an Abbreviations and terms section, 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 statement in summary terms.

The **first main section** introduces our statutory and legal obligations. The purpose and context of the report is outlined.

The **second section** outlines the demand forecast methodology and presents estimates of demand over the next ten years.

The **third section** describes the assumptions in relation to electricity generation.

Adequacy assessments are presented in the **final section**.

Six **appendices** are included at the end of this report. They provide further detail on the data and methodology used in this study.

Abbreviations and 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.
ECP-1	Enduring Connection Policy	A process to provide connection offers to facilitate 2 GW of renewable generation in Ireland.
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.

Acronym/ abbreviation	Term	Explanation
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 = 1000000 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.
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 = 1000 kilowatts = 106 joules/second.

Acronym/ abbreviation	Term	Explanation
	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, e.g., hydrogen production.
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, Gas and water (UR).
	Reliability Options	The SEM CRM capacity auctions are a competitive process between qualified capacity providers to be awarded 'reliability options' for the provision of capacity to the all-island system.
RES	Renewable Energy Source	
RES-E		Renewable Electricity.
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 = 1000000000 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.

1. Preface

EirGrid Plc and SONI Ltd, are the Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively, it is our role to operate the electricity transmission system every minute of every day whilst also planning the future of the transmission grid for the island of Ireland.

EirGrid and SONI have completed adequacy analysis in their respective jurisdictions and have jointly prepared this All-Island Generation Capacity Statement (GCS) 2023–2032. This statement outlines 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 support social and economic growth. Whilst EirGrid and SONI are required to undertake this assessment, and have other responsibilities associated with security of electricity supply, it is ultimately the Commission for Regulation of Utilities (CRU) in Ireland, and the Department for the Economy (DfE) in Northern Ireland that are responsible for the security of supply. Primarily, it is the Single Electricity Market (SEM) that is used to ensure there is sufficient generation available to meet demand.

As part of the transition to a more sustainable and low carbon society, the grid is undergoing a process of modernisation, with greater needs for flexible generation to enable the transition while maintaining security of supply. We are working to ensure that everyone has electricity when they need it while preparing the transmission grid to provide up to 80% of our power from renewable sources by 2030, in line with Government targets in both jurisdictions. Whilst doing so, we aim to ensure consumers receive their power at the most economic price possible through our operational decisions and based on the prevailing market conditions.

In last year's GCS 2022–2031, we communicated that the adequacy of the power system would reduce and we would anticipate more system alerts. These alerts indicate to industry market participants that capacity margins are tight, and the loss of a generator could cause difficulty in meeting demand. During 2022/2023, at all times, our skilled and experienced workforce coupled with an improvement in generator reliability, lower demand than forecast, and favourable timing of renewable generation meant that supply was met without any customer disconnections. However, we still expect the number of system alerts to increase over the coming years, despite new capacity connecting, as existing capacity retires and demand increases.

EirGrid has statutory obligations to report security of supply risks to the CRU. EirGrid still forecasts capacity deficits in Ireland for the entire 10-year outlook of this statement. In comparison to last year's Generation Capacity Statement, the deficit in Ireland has increased in 2023, predominantly due to the forced loss of availability of a large existing generator, but the deficit has reduced across the rest of the study horizon. In the period 2024 until 2027, significant deficits are still observed, however mitigating options identified within the CRU led Security of Supply programme are able to manage the security of supply risk; these measures include delivery of temporary emergency generation and retention of existing units. Compared to the forecast in last year's GCS, beyond 2027, an improved adequacy position is forecast with the expected delivery of new capacity and the accelerated build out of renewables, which is offset by a downward trend in plant performance. In later years, delivery of new capacity is the main risk; without mitigation, alternative capacity is required. Over the long term, there are control measures that are outside the scope of this document. EirGrid continues to support the CRU and the Department of the Environment, Climate and Communications (DECC) on this, through the CRU's Security of Supply programme[1].

Since the publication of the GCS 2022–2031, in which adequacy challenges were highlighted, the adequacy outlook for Northern Ireland has deteriorated. Over the next four years SONI's adequacy forecast shows deficits, with the key risk to security of supply being the timely delivery of new capacity and annual run hour limitations on existing capacity and new capacity.

In the short-term, SONI continues to work with the Utility Regulator (UR), DfE and developers in closely monitoring and assessing the timely delivery of new plant. In the near term, the delivery of Open Cycle Gas Turbines is crucial to replace the retiring coal plant. In the medium-term, new generation has been successful in the T-4 25/26 capacity auction; this capacity is expected to convert the Open Cycle Gas Turbines, which have annual run hour limitations, to Combined Cycle Gas Turbines free from run hour restrictions. The removal of run hour restrictions is a key factor in forecasting that Northern Ireland will return to surplus from 2027 for the remainder of the study period. As the TSO, SONI is working with DfE and the UR to provide forecasting, analysis, and operational mitigations to ensure the security of the system.

EirGrid's and SONI's analysis of adequacy in their respective jurisdictions clearly shows that timely delivery of new capacity will be required to help serve us as we transition to high levels of renewable electricity over the coming decades. It is crucial that a balanced portfolio of new capacity is delivered, such as long duration storage, interconnection, demand side and renewable-ready open cycle and combined cycle gas turbines.

1 https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU202317_Electricity_Security_of_Supply_Programme_of_Work_Update_February_2023.pdf

The new North South Interconnector remains critical for security of supply in both jurisdictions as its introduction will reduce the overall capacity deficit. The North South Interconnector, as with existing and new interconnection to Great Britain and the new Celtic interconnector to France, remains crucial for the medium to long-term security of supply on the island of Ireland. Together with the Single Electricity Market (SEM) capacity auctions, this will enable all consumers on the island of Ireland to realise the ambition of maximising the considerable efficiency benefits of an all-island electricity system and market.

In 2023, EirGrid and SONI jointly published an update to Shaping Our Electricity Future, which was first published in 2021. The original document outlined the network, market and operational changes required to deliver on a power system where 70% of our electricity was sourced from renewable resources by 2030. The updated Shaping Our Electricity Future v1.1 reflects the Climate Action Plan 2023 (Ireland) and Climate Change Act 2022 (Northern Ireland) which both target 80% of our electricity to come from renewable sources by 2030. In Ireland, carbon budgets were introduced in 2022. These set out, in five-year blocks of time, a limit for the total amount of carbon emissions that Ireland can emit. The electricity sector in Ireland is no longer solely aiming to achieve a 2030 target, but now must also do so without exceeding carbon emissions across five-year blocks.

In Northern Ireland, the Department of Agriculture, Environment and Rural Affairs (DAERA) is required under legislation to put in place a carbon budget for 2023 to 2027 by the end of 2023. Future iterations of Shaping Our Electricity Future will consider the Northern Ireland carbon budget.

The increased targets in Ireland and Northern Ireland have required a refreshed assessment of the type of capacity needed, the network required and the operational complexities of managing a power system with world leading levels of renewable generation. Achieving 80% renewable electricity will require a seismic shift in thinking, as the scale of the task is unprecedented and there are significant challenges in terms of deliverability, technical scarcities, and economic considerations. EirGrid and SONI, as the operators of the grid, will play a key role, but we cannot deliver on the renewable ambition on our own. This is a target that will require change across the electricity sector and beyond. There needs to be action from electricity generators and developers, from regulators, from government, from ESB Networks, from NIE Networks, and from large-scale energy users and members of every community in both jurisdictions. Timely planning decisions, availability of the road network for underground cables and public support are also all vital to enact change on this scale. All key players will need to work together, and there will be a need for flexibility and innovation from all.

It is clear the electricity industry must find new ways of meeting the increasing demand for electricity without relying on mainly burning fossil fuels. Looking out to 2032, our electricity demand is set to increase as consumers use electricity differently to enable productivity, new modes of transport and new ways to heat our homes. New Government policies are expected to help guide us away from fossil fuels and instead towards more efficient alternative heating methods (such as electric heat pumps) and modes of transport (such as electric vehicles) as we aim to reduce our emissions and final energy consumption.

This changing demand and generation supply landscape for 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. To prepare for this change, EirGrid and SONI must make the electricity grid stronger and more flexible. The transmission grids in Ireland and Northern Ireland will need to carry more power and most of this power will come from renewable generation that varies depending on the weather. EirGrid and SONI will use the existing grids to meet this goal where possible. However, given the scale of change, there is a significant need to plan for a great deal of new grid infrastructure – such as underground cables, pylons and substations.

EirGrid and SONI play a vitally important role in delivering a clean, affordable and secure supply of electricity for consumers in both jurisdictions. 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 the Generation Capacity Statement informative.

Mark Foley
EirGrid Group
Chief Executive

Alan Campbell
SONI
Managing Director

2. Executive summary

This Generation Capacity Statement (GCS) covers both Ireland and Northern Ireland. It is produced on a joint basis by EirGrid and SONI[1]. 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 system. The required forecasts and analysis act as signals for the regulators to incentivise the market to provide the right generation mix capable of meeting the expected demand.

1 Where 'we' is used, it refers to both companies, unless otherwise stated.

Introduction

In this GCS, we examine the likely balance between electricity demand and supply during the years 2023 to 2032. The adequacy position for each year is then compared to the adequacy standard for each jurisdiction. This standard is called the Loss of Load Expectation (LOLE) and is the expected number of hours per year that a country's electricity production cannot meet its demand. The LOLE is set to 8 hours for Ireland and 4.9 hours for Northern Ireland. The respective standards are set by the Commission for Regulation of Utilities (CRU) in Ireland and by the Department for the Economy (DfE) in Northern Ireland.

The GCS sets out the demand and generation inputs used to determine the power system's adequacy position; however, the purpose of this document is not to set out the measures necessary to resolve any deficits identified by the analysis. The GCS is a means for EirGrid and SONI to signal future needs and requirements to the energy market as well as to policy makers, regulators, and TSOs. It is published yearly to allow for changing demands and allows time for relevant stakeholders to respond. The ten-year outlook reflects the time required to provide the appropriate signals to support the build of new infrastructure needed to connect new generation.

The GCS is a significant input for the Single Electricity Market (SEM) Capacity Auctions which are run annually to meet capacity needs for the 'capacity year' in 4 years' time. This is known as a 'T-4'. The last T-4 was run in 2023 to source capacity for the capacity year October 2026 to September 2027. Intermediate auctions are also run, e.g., a T-3 auction was run in 2022 for the capacity year October 2024 to September 2025. Other intermediate auctions have been and are likely to be run to source new and enduring capacity to meet system needs. EirGrid and SONI are therefore cognisant of the overarching role of the capacity market and have been careful to set out, clearly and transparently, the generation requirements for the coming years. This will not include the other temporary measures required and implemented to manage the security of supply risks until such time as enduring market-based solutions are in place.

Over the next few years, the general outlook remains challenging for both jurisdictions, with capacity deficits identified across the whole study horizon for Ireland and the first four years in Northern Ireland. This is due to a combination of external factors that are presented through this document, with key factors highlighted for each jurisdiction below. EirGrid continues to engage with the Department for the Environment, Climate and Communications (DECC), the CRU and other relevant stakeholders in Ireland to provide timely assessments, analysis, and options for operational mitigations.

This includes supporting the security of supply programme that has clear actions up to 2025. SONI meanwhile is engaging with the DfE, the Utility Regulator (UR) and other relevant stakeholders in relation to the outlook for Northern Ireland, providing timely assessments, analysis and options for operational mitigations which can be implemented as necessary.

This executive summary outlines the key areas which have driven changes in the adequacy position since the GCS 2022–2031 for Ireland, Northern Ireland and all-island was published. The GCS 2024–2033 will be completed using the National Resource Adequacy Assessment (NRAA) methodology (Appendix 7) which will be consulted upon ahead of the GCS 2024–2033 publication.

2.1 Ireland

In response to continued challenges for Ireland's adequacy position, as identified in last year's GCS 2022–2031, the CRU has continued to update its published response "CRU Information Paper Security of Electricity Supply – Programme of Actions"[2], with the latest update in February 2023. This paper outlined a programme of work to address the forecasted increase in need for new generation capacity, through three overarching measures. These measures included 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 as we transition from older power plants to new capacity. This programme of work, directed by the CRU, will provide additional stability and resilience to the Irish electricity system.

The outputs and impact from the CRU's programme of actions are not reflected in the core GCS 2023–2032 scenarios, but the expected positive impact of the actions is captured by studies on the mitigating measures in Section 6.3.1.

2 https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU202317_Electricity_Security_of_Supply_Programme_of_Work_Update_February_2023.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 in a timely fashion, and that the type and volume of capacity needed to underpin the energy transition is procured. 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 prudent to maintain a secure system.

In last year's GCS 2022–2031, EirGrid forecasted significant deficits throughout the study horizon for all forecasted demand levels. In this year's assessment, EirGrid has updated to the latest, best available information at the time of the data freeze[3], and implemented new approaches to modelling, believed to improve the model accuracy. The updated adequacy forecast remains in deficit throughout the study period for the median and high demand projections, whilst the low demand forecast now meets the adequacy standard for 2028 to 2030. In comparison to last year's assessment, the adequacy position has degraded in 2023, but improved across the rest of the study horizon.

A summary of the main drivers for change are:

Demand

Global energy trends, policy measures and price impacted the out-turned electricity demand in 2022. Ireland recorded several record peak electricity demand days; however, the temperature corrected peak demand used in planning was slightly lower than in 2021. The suppressed peak demand was driven by lower demand from conventional residential, commercial, and industrial consumers, coinciding with high energy prices. However, the forecasted short-term predictions in the numbers of heat pumps, electric vehicles, and new demand from data centres and new tech loads still showed expected levels of growth. The impact of last year's demand results in future electricity lower 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 brings forecasted demand levels to a comparable position to last year's GCS 2022–2031.

3 Data Freeze for Demand Forecast: March 2023, Generation Forecast: May 2023.

Plant performance

The 2022 forced outages statistics are slightly improved over the 2021 performance, albeit these annual averages are the second worst on record. Incorporating the latest power plant outage statistics into the all-island 5-year capacity weighted average used in our forecasts, results in a lower projected long term availability of dispatchable generation compared to last year. Lower availability negatively impacts the adequacy position across the study horizon. In addition to this, the final remaining Tarbert unit (TB3) has been placed on a long-term outage until it is scheduled to close at the end of 2023, removing 243 MW of generation capacity that was previously assumed to be available in 2023.

New capacity through capacity auctions

Since the previous GCS report, the 2026/2027 T-4 capacity auction has run. The TSOs have risk assessed the delivery of this new capacity through the enhanced monitoring deliverability assessment; we also consider updated risk adjustment for capacity successful in previous auctions that are yet to deliver including the 2023/2024 T-4, 2024/2025 T-4, 2024/2025 T-3, 2025/2026 T-4. The regular enhanced monitoring process assesses the latest information available obtained through engagement with each project developer, along with collaboration across a range of relevant state agencies.

The process enables regular assessment of each project, providing updates on whether it is expected to be available earlier than expected, if they are at risk of delay, or if they are not expected to deliver at all within the auction long stop dates. The last TSO risk adjusted view of projects from previous auctions, as well as the successful new capacity, results in an improvement of Ireland's adequacy position across the horizon, but in particular post 2027. However, the system remains in deficit across the study horizon, and the adequacy position could be further improved if all successful projects manage to deliver on time. Future capacity auctions will aim to procure additional capacity to further improve the adequacy position.

Renewable generation

Increasing government ambition regarding the build out of renewable generation has been factored into this GCS. The increased level of assumed renewable capacities (capable of delivering 80% RES-E) improves the adequacy position.

As noted above, EirGrid is actively engaging with the DECC, the CRU and other relevant stakeholders to resolve the capacity deficits over the coming decade.

2.2 Northern Ireland

SONI's core median scenario shows there are adequacy challenges over the next four years, with later than expected delivery of plant and annual run hour limitations for open cycle gas turbine technology being a significant factor. However, the longer-term outlook for Northern Ireland's generation adequacy is positive, with a surplus of generation from 2027 until 2032.

Since the GCS 2022–2031, SONI has continued to evaluate the deliverability expectations of new plant as well as monitor the existing plant availability. These two key driving factors have degraded the adequacy position in the short term.

SONI is working closely with the DfE, the UR and other energy industry partners to put in place a range of robust, tried-and-tested mitigation measures to manage they challenges to security of supply should they arise.

A summary of the main drivers for change are:

New capacity delivery timing

New generation projects successful in the capacity auctions have been assessed as part of SONI's enhanced monitoring process whereby the latest best available data about the projects are assessed. At the time of the data freeze there are two key changes to these assumptions compared to last year's GCS. Firstly, the two new gas units that were expected to replace the Kilroot ST1 and ST2 coal units retiring in September 2023 are now expected to be delayed 3 months until January 2024. This leaves a capacity gap of 30 MW for winter 2023/24.

Secondly, on the basis of SONI's enhanced monitoring process, the successful capacity at the Kilroot site that cleared in the T-4 2025/2026 capacity auction is now expected to be available from 2027, one year later than previously assumed. The impact of this expected delay results in the KGT6 and KGT7 open cycle gas turbines being restricted by Annual Run Hour Limitations (ARHL) for an additional year. Subsequently, the adequacy position is forecast to remain in deficit for an additional year.

Demand

Out-turn demand for 2022 was lower than previously forecast, particularly in the second half of the year, coinciding with high energy prices. This data has been factored into future demand forecasts and results in a lower expected demand level in the short term (2023–2026). This lower demand forecast has had a positive impact on the adequacy position for these years. From 2027 onwards, the longer-term effect of high energy prices are expected to subside, and the demand forecast is comparable to what was estimated previously in GCS 2022–2031.

Plant performance

Future plant performance is now based on a historic 5-year average for the all-island system. Including the latest plant performance data from 2022, the 5-year average is now below the 2019 outage statistics used in the GCS 2022–2031. The lower power plant availability degrades the adequacy position across the study horizon.

As previously noted, SONI is actively working with the DfE, the UR, and other relevant stakeholders to address the forecasted capacity deficits over the coming years.

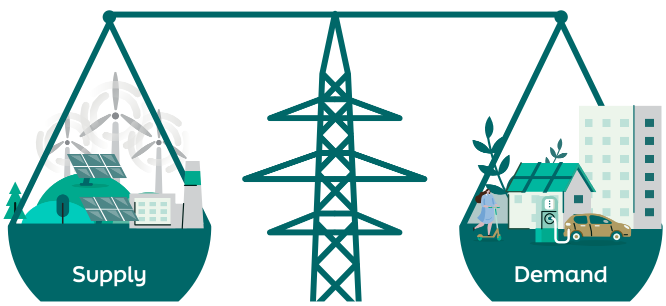
2.3 All-island

The new North-South Interconnector is expected to be completed over the coming years; therefore, we have provided an all-island adequacy assessment from 2026 and beyond. Until this date we need to limit the support between both jurisdictions to ensure system stability and security as described in section 5.5.1. Once the new North-South Interconnector is online, the ability for support is greatly increased. From our analysis, it is clear the new interconnector will support the longer-term security of supply outlook, indicating an all-island adequacy surplus from 2028 onwards in the Median scenario, along with other enduring market measures. An all-island deficit is still expected in 2026 and 2027, despite delivery of the North-South Interconnector due to significant deficits in both jurisdictions.

Since 2016, EirGrid and SONI via the GCS have warned of an increasing tightness between supply and demand. The analysis contained in this statement, based on the best information available, confirms a challenging outlook.

This does not necessarily mean that any disruption to the electricity supply will occur, rather it points to a number of additional challenges, an increased risk, and the likelihood of more system alerts in the coming years. This means that SONI and EirGrid may need to work proactively with partners to mitigate the risks of any more serious impacts across Ireland and Northern Ireland.

This GCS 2023–2032 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 likely generation capacity required to achieve an adequate supply and demand balance for electricity for the period up to 2032. It is a ten-year outlook to reflect the time required to allow market participants and generators to plan, develop and deliver the necessary infrastructure required to generate electricity.

Making a prediction of what the electricity adequacy position will be in the future is a multi-layered task for which EirGrid Plc and SONI Ltd consider a number of factors including:

Demand

What is required – including the total electricity requirement, the winter peak, historic demand, economic forecast (with the input of the ESRI and Oxford Economics), government targets, data centres and new technology loads forecasts.

Generation

What can meet the demand – changes in conventional plant, what is coming through capacity auctions, the capacity of renewable energy, and the impact of forced and scheduled outages.

Adequacy

What is the gap – standards of acceptable outages, hours of energy that is unserved, a probabilistic calculation.

Generation Adequacy is a measure of the capability of the electricity system to balance supply and demand for each hour across a calendar year. Adequacy is determined using the Loss of Load Expectation (LOLE) standard, which is 8 hours in Ireland 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 8 hours each year in Ireland and 4.9 hours each year in Northern Ireland. On the 31st of March 2023, the Single Electricity Market Committee (SEM-C) published an updated Net Cost of New Entry Decision[4]; subsequently, the departments and regulators in Ireland and Northern Ireland are reviewing the value of lost load and reliability standards. This will be monitored and included as appropriate in future GCS reports.

The development, planning and connection of new generation capacity to the transmission or distribution systems can involve long lead times and high capital investment. Consequently, this report provides information covering a ten-year timeframe to allow sufficient time for delivery of new generation.

EirGrid, the Transmission System Operator (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 and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations.

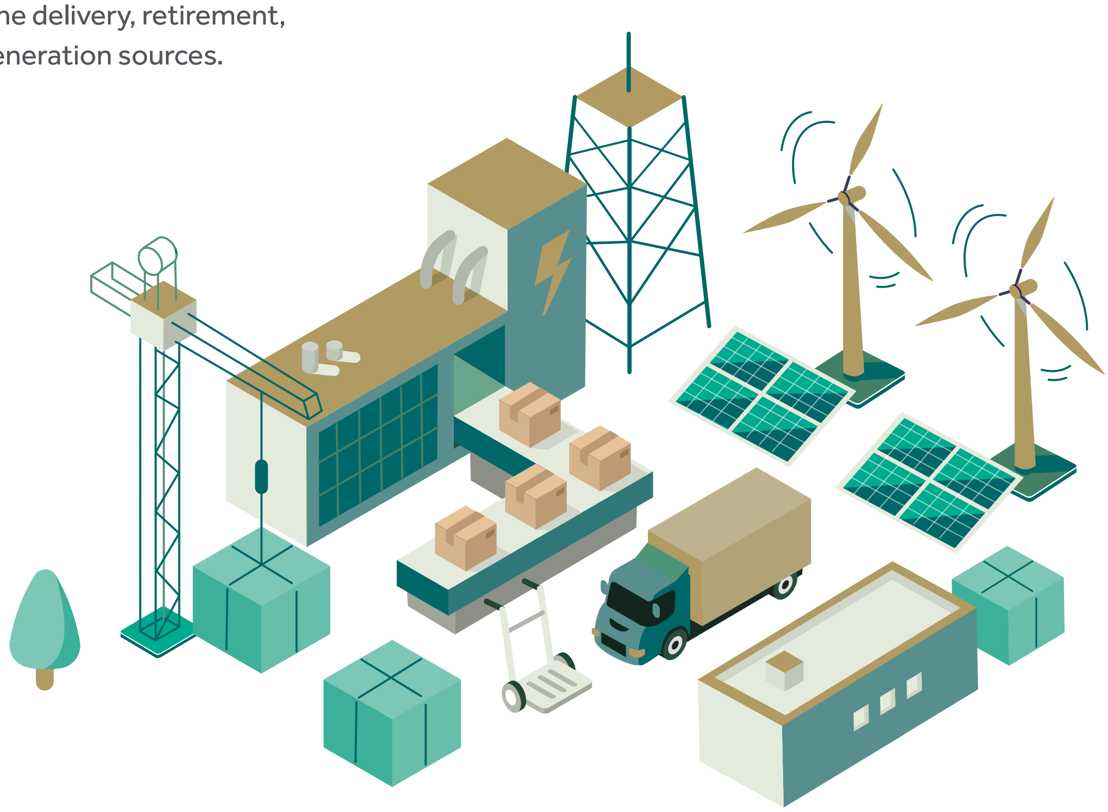
4 https://www.semcommittee.com/sites/semc/files/media-files/SEM-23-016%20BNE%20Decision%202023.pdf

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

This statement covers the years 2023–2032 for both Ireland and Northern Ireland, and is produced jointly between EirGrid Plc and SONI Ltd. Where 'we' is used, it refers to both companies, unless otherwise stated. This report supersedes the joint EirGrid and SONI all-island Generation Capacity Statement 2022–2031, published in October 2022. Input data and assumptions for both the demand and generation forecast have been reviewed and updated, including but not limited to economic forecasts, the impact of electricity prices, electrification policies, as well as the delivery, retirement, and availability of generation sources.

The GCS involves a detailed process completed over a period of approximately eight months. Steps in this process are outlined in Figure 1.1 and detail of the adequacy modelling methodology is described in Appendix 6. We will continue to work with the CRU in Ireland and the UR in Northern Ireland (jointly referred to as the Regulatory Authorities (RAs)), and other stakeholders to ensure that this document and the underlying methodologies remain relevant and useful.

In predicting the future of electricity generation supply in Ireland and Northern Ireland, we have endeavoured to use the most up-to-date information available at the time of the data freeze for this report (Demand Forecast: March 2023, Generation Forecast: May 2023).



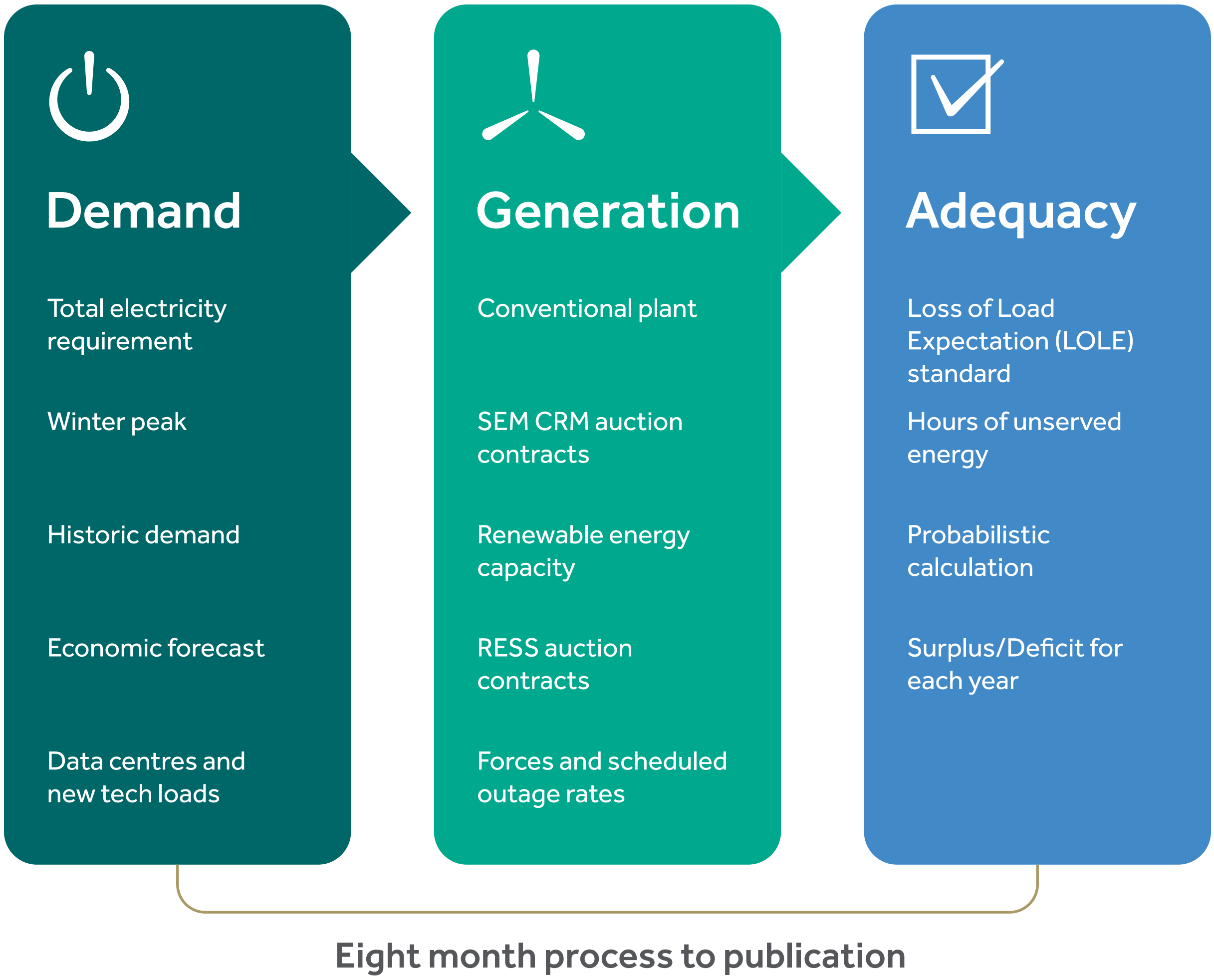


Figure 3.1 GCS development process

4. Demand

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.

4.1 Introduction

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.

Last year, on the 14th of December 2022, a record all-island winter peak demand figure of 7031 MW was measured on the transmission system. This high level of demand was partially driven by a particularly cold period of weather. Ireland had a record peak demand of 5544 MW on the 14th of December 2022. Northern Ireland had a peak demand of 1511 MW on the 12th of December 2022[5].

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

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. The long-term impact of the Russian invasion of Ukraine remains uncertain, however the contribution to the high cost of living and high energy prices impacting electricity demand is factored into the current forecasts and is being closely monitored by EirGrid and SONI.

5 These figures are based on the 1 minute averaged peak demand. Within the generation capacity statement the 30 minute averaged peak is predominantly used which would be slightly lower.

In developing demand forecasts in Ireland, EirGrid has taken into account the Climate Action Plan 2023[6] 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[7] 2021, Path to Net Zero – Action Plan 2023[8] and the Climate Change Act (Northern Ireland) 2022[9].

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

With the total electricity requirement and the peak demand forecast for the duration of the study, a forecast half-hourly demand profile is created for each jurisdiction separately and combined for the all-island studies as described in Appendix 2. As part of the SEM Capacity Market auction process, the GCS demand forecasts are used as an input for the capacity requirement of 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.

4.2.2 Historical data

Historical records of electricity generation and electricity sales are gathered from various sources including ESB Networks, SEAI (Sustainable Energy Authority of Ireland) and EirGrid. Information on the number of electric vehicles from SIMI (Society of the Irish Motor Industry) database[10], number of heat pumps from the BER database[11] and government publications[12,13,14], and demand from data centres and new technology loads enables trends to be identified for different sectors of demand.

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 2008 to 2020, it is estimated that, on average, approximately 8% of power produced is lost as it passes through the electricity transmission and distribution systems to homes and businesses.

6 https://www.gov.ie/en/publication/7bd8c-climate-action-plan-2023/
7 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf
8 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-Path-Net-Zero-Energy-2023-Action-Plan.pdf
9 https://www.legislation.gov.uk/nia/2022/31/enacted
10 https://www.simi.ie/en/motorstats
11 https://ndber.seai.ie/BERResearchTool/ber/search.aspx
12 https://assets.gov.ie/25419/c97cdecddf8c49ab976e773d4e11e515.pdf
13 https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/
14 https://www.gov.ie/en/publication/92514-annual-report-2021/

Historical weather data is obtained from Met Éireann, Ireland's National Meteorological Service. This data is used for the temperature correction as described in section 4.2.6 below.

4.2.3 Economic forecast

To predict 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[15]. The key economic parameters used in this study are Real Modified Gross National Income (Real GNI*) and Personal Consumption[16].

Real Modified Gross National Income (Real GNI*)[17] 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 such items 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[18] annually in support of the Generation Capacity Statement. The shorter-term trends are based on their Quarterly Economic Commentary[19]. Longer-term trends arise out of the ESRI's Medium Term Review[20]. Although there has been a period of economic turbulence over the past three years due to the effect of Covid, subsequent recovery, and the Russian invasion of Ukraine, the ESRI forecast suggests steady growth over the study period, however in the short term, the growth is lower than previously forecast. The figures listed in Table 4.1 were used for the three demand scenarios in GCS 2023–2032. 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[21], a change compared to the previous GCS which used the ESRI forecast for all demand levels.

15 https://www.esri.ie/research-areas/macroeconomics
16 Personal Consumption of Goods and Services (PCGS) measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.
17 https://www.cso.ie/en/releasesandpublications/ep/p-nie/nie2019/mgni/
18 Economic Parameters obtained from ESRI on 19th December 2022.
19 https://www.esri.ie/publications/quarterly-economic-commentary-winter-2022
20 https://www.esri.ie/publications/medium-term-review-2013-2020
21 Previous GCS used the same economic forecast for all demand levels.

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

	2022–2023			2024–2032		
	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)	Low (75% ESRI)	Median (ESRI)	High (110% ESRI)
Real GNI	0.15%	0.2%	0.22%	2.25%	3.0%	3.3%
Personal consumption	3.0%	4.0%	4.4%	1.88%	2.5%	2.75%

4.2.4 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.

In Ireland, there is presently 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. Demand from data centres and new technology loads is expected to continue to rise from their current demand level as these customers build out towards their contracted load. Almost all of 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[22].

GCS 2023–2032 considers sixteen projects for data centres that are either connected or have a signed connection agreement. As part of the demand forecast process, EirGrid examines the status of data centres and new technology loads. This informs the future demand growth expected from these customers. 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.

22 https://www.cru.ie/publications/27402/

In GCS 2023–2032, there is very strong growth forecast in this sector out to 2026, with continued growth towards the end of the decade. Note this growth is from previously contracted projects. As per the direction from CRU in November 2021, 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"[23]. EirGrid also notes that demand side flexibility of data centres is an area of ongoing development[24]. A small number of flexible demand sites have capacity that can be called on to prevent system alerts. For emergency situations, some sites will be required to curtail their demand requirements. 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 the GCS 2023–2032 study, though it 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 2032. 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 historic trends, EirGrid's high demand forecast assumes not all this future contracted demand is fully used, and some attrition will occur.

Table 4.2: Forecasted data centre and new technology load demand by 2032. 2022 demand 734 MVA

Forecast scenario	Growth from 2022–2032 (MVA)	2032 demand (MVA)
Low	304	1,038
Median	810	1,543
High	1,276	2,010

23 https://www.cru.ie/wp-content/uploads/2021/11/CRU21124-CRU-Direction-to-the-System-Operators-related-to-Data-Centre-grid-connection-processing.pdf
24 A recent Risk Preparedness Plan for Ireland, which outlines these measures, was published by CRU in May 2022. https://www.cru.ie/wp-content/uploads/2021/08/CRU202239-Risk-Preparedness-Plan-Ireland.pdf

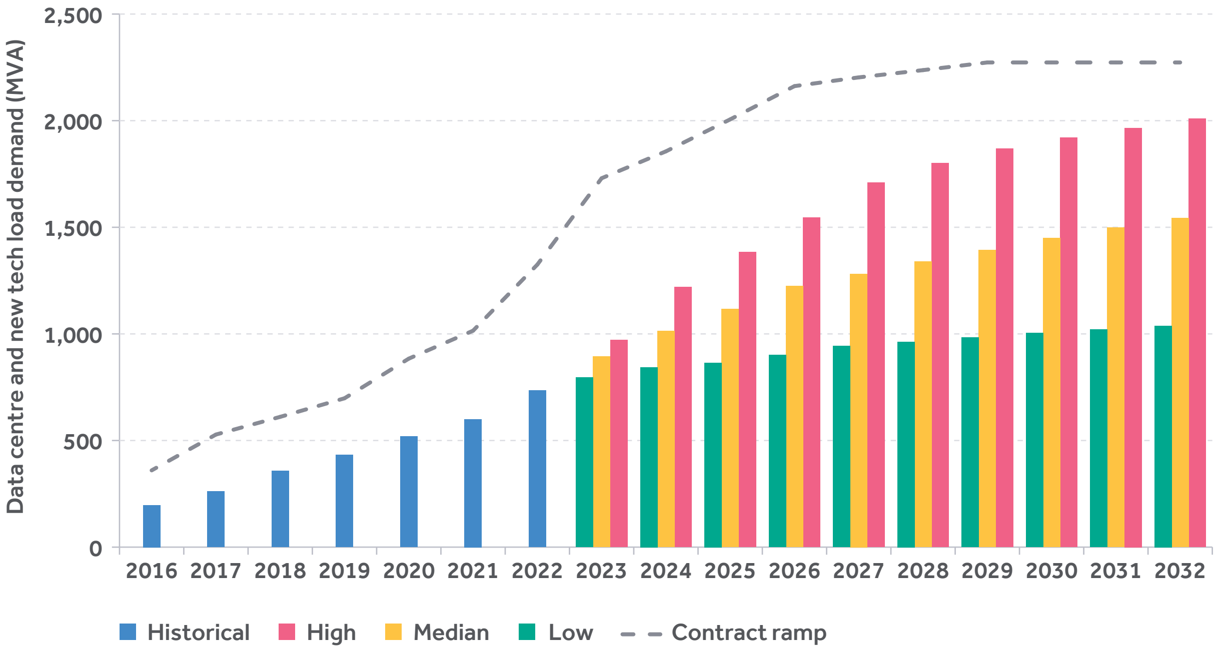


Figure 4.1: Ireland demand expected from assumed build out of data centres and new technology loads

4.2.5 Electrification of heat and transport

The GCS 2023–2032 takes account of the relevant electrification targets for heat and transport from the Irish Government's Climate Action Plan 2023[25] (CAP23). These are ambitious targets which are required to keep Ireland on track for halving emissions by 2030.

In this year's GCS 2023–2032, the median scenario assumes that by 2030, 100% of the CAP23 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. Beyond 2030 the trend is expected to continue.

Table 4.3: Climate Action Plan 2023 targets for electric vehicles and heat pumps

	Electric vehicles		Heat pumps		
	Passenger	Commercial	Residential – new builds	Residential – retrofits	Commercial
2025	175,000	20,000	100,000	100,000	N/A
2030	845,000	95,000	250,000	400,000	50,000

25 https://www.gov.ie/en/publication/7bd8c-climate-action-plan-2023/

The energy demand for electric vehicles accounts for the number of vehicles, vehicle efficiency, and average distance per vehicle. The main types of electric vehicles considered are Battery Electric Vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEVs) in the private sector, and the commercial sector assume the vehicles to be either BEVs or Low Emissions Vehicles (LEVs).

A significant factor in the impact of the electrification is when electric vehicle owners charge their vehicles. With no deliberate action, peak demand for electric vehicle charging is expected to coincide with the existing peak demand.

Encouraging owners to adapt the timing of their electric vehicle charging is a key factor in reducing the impact on the electricity system. This is covered in greater detail in the demand flexibility section (4.2.7).

The energy demand of heat pumps takes into consideration factors such as number of installations, the annual heat demand, and heat pump coefficient of performance. The impact of heat pumps on peak demand is based on analysis of historical heating demand across the year for a number of different climate years to estimate the heating demand on a winter's day. The hourly heat demand is assumed to be consistent throughout the day based on behavioural analysis of heat pump owners[26].

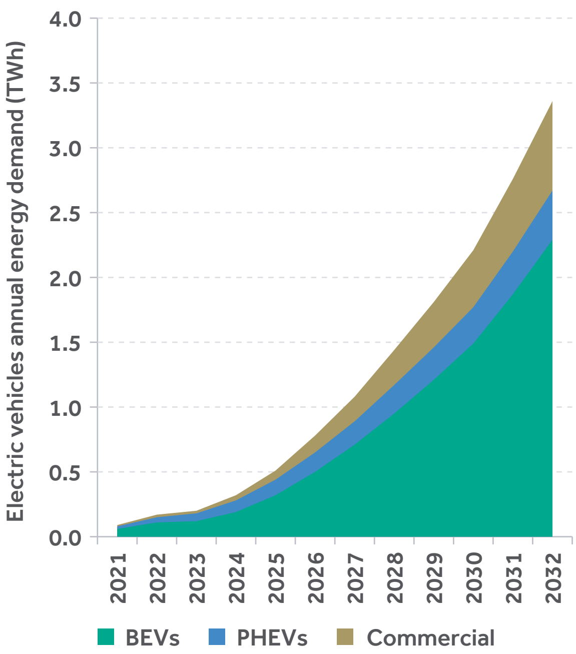


Figure 4.2: Electric vehicle electrical energy demand – median scenario

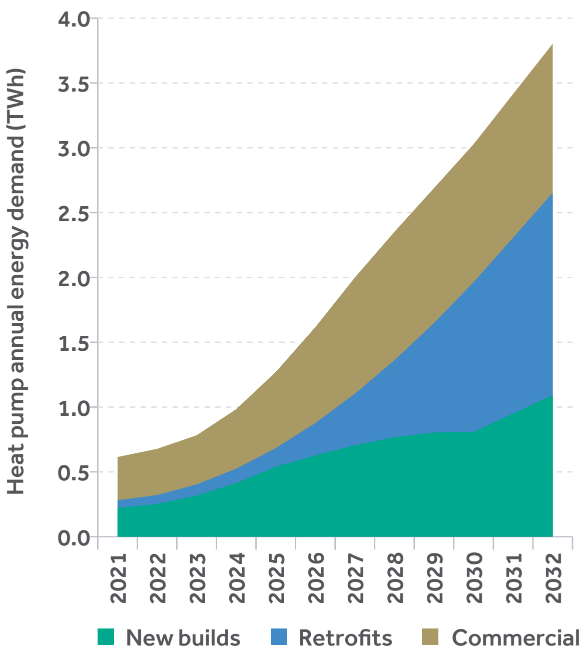


Figure 4.3: Heat pump electrical energy demand – median scenario

26 https://www.sciencedirect.com/science/article/pii/S037877882100061X

4.2.6 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[27]. 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 4.4). Temperature correction is also applied to historic annual energy demand using the degree days methodology[28]. The impact of temperature on annual energy demand is far less pronounced than on peak demand.

Whilst historic analysis aims to remove the impact of variable temperatures, it is important to account for this variable factor in forecasting future peak demand. Within the low demand scenario, the forecasted peak includes the assumption of a mild winter (2022), whilst the high scenario assumes a colder winter (2008). The chosen mild and cold climate years are chosen out of the latest 25 years of climate data, with both having roughly a one in seven probability of occurring based on historic analysis. For the purpose of this relatively short 10-year study, the future effects of climate change have not been forecast but will be considered for future publications. Details as to the reason for the drop in temperature corrected peak demand in 2022 are captured in section 4.2.11.

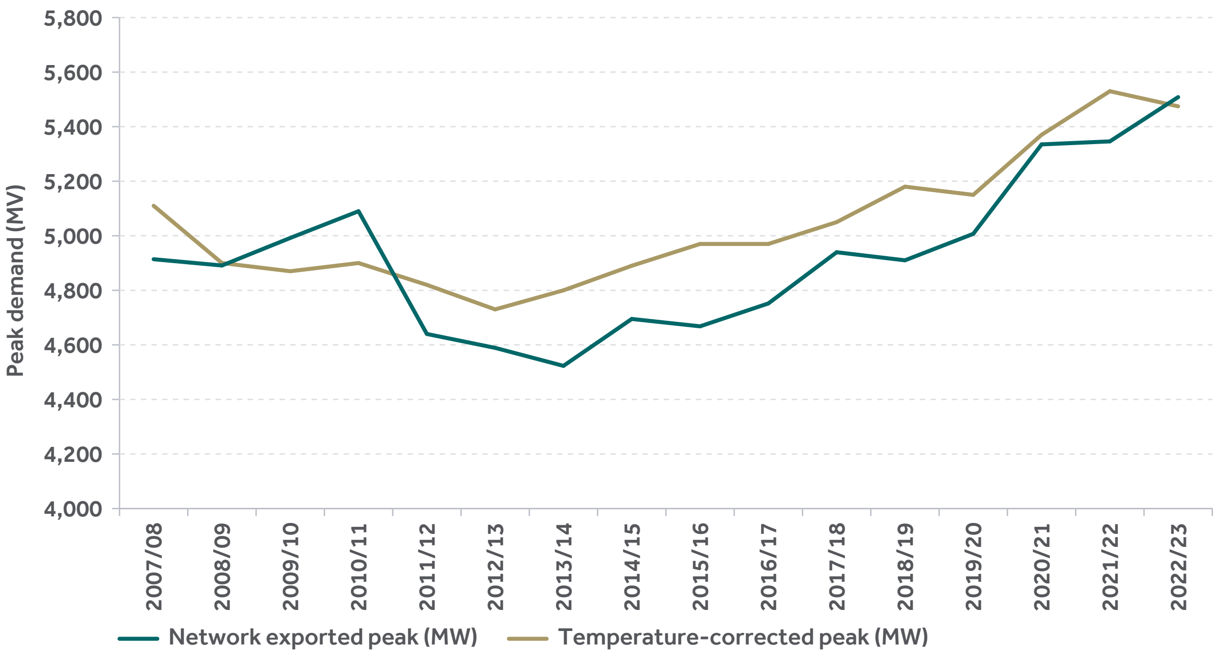


Figure 4.4: Historic recorded and temperature corrected peak demand

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

4.2.7 Demand flexibility

Demand side measures are a critical factor in understanding how electricity consumers will contribute to peak demand in the future. An energy demand strategy is under development by the CRU (targeting completion at the end of 2023), to identify the appropriate steps to deliver the Climate Action Plan demand flexibility targets. For this year's GCS, contributions from electric vehicles, smart meters and demand side units are modelled. Future policies will be monitored to understand the potential impact they could have to further demand flexibility potential.

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% for domestic users[29]. 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 also assumed that electric vehicle charging will offer flexibility to avoid the peak demand periods.

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

Within this study, it is assumed that most current electric vehicle owners use a 'simple' charging profile (as developed as part of Tomorrow's Energy Scenarios 2019[30]), that represents owners charging their vehicle when first plugging in. By 2030, it is assumed that through EV tariffs (which many electricity providers already offer), the roll out of smart meters and through education and behavioural changes, owners will move to a charging profile (similar to that developed by ENTSO-E[31]) that favours night-time charging, which reduces the demand occurring at peak to just 1% of the daily charging requirement.

Flexible demand sites, as mentioned in section 4.2.4 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.

29 https://www.cru.ie/wp-content/uploads/2011/07/cer11080ai.pdf
30 https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-Report.pdf
31 https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER_Decision_04-2023_ERAA_2022-AnnexI_Technical.pdf

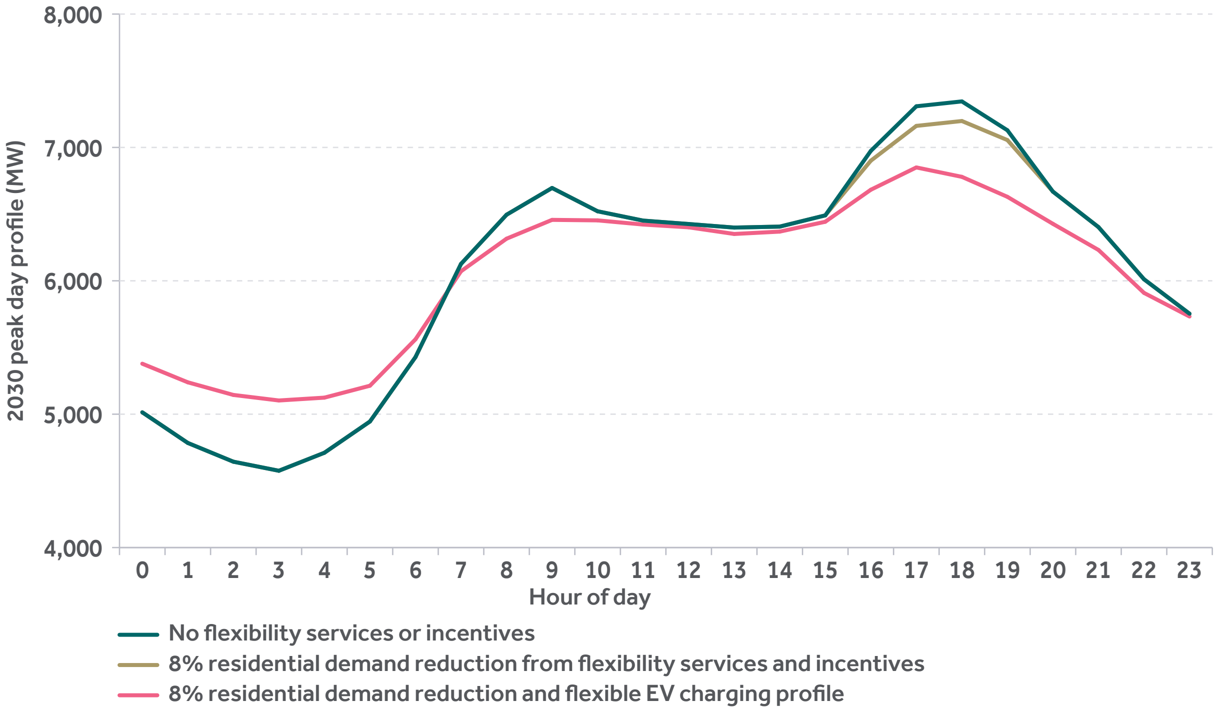


Figure 4.5: Impact of demand flexibility on 2030 peak day (median scenario)

Figure 4.5 shows the effect of demand flexibility services and incentives on residential demand and electric vehicle charging on the forecast peak day in 2030 in the median scenario (note this is based on the smoothed half hour demand profile used for these studies, the instantaneous demand will be less smooth). Implementing demand flexibility services and incentives has the effect of reducing the peak demand by approximately 600 MW. This significant effect has been incorporated into the final peak demand calculations.

Figure 4.6 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% 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.

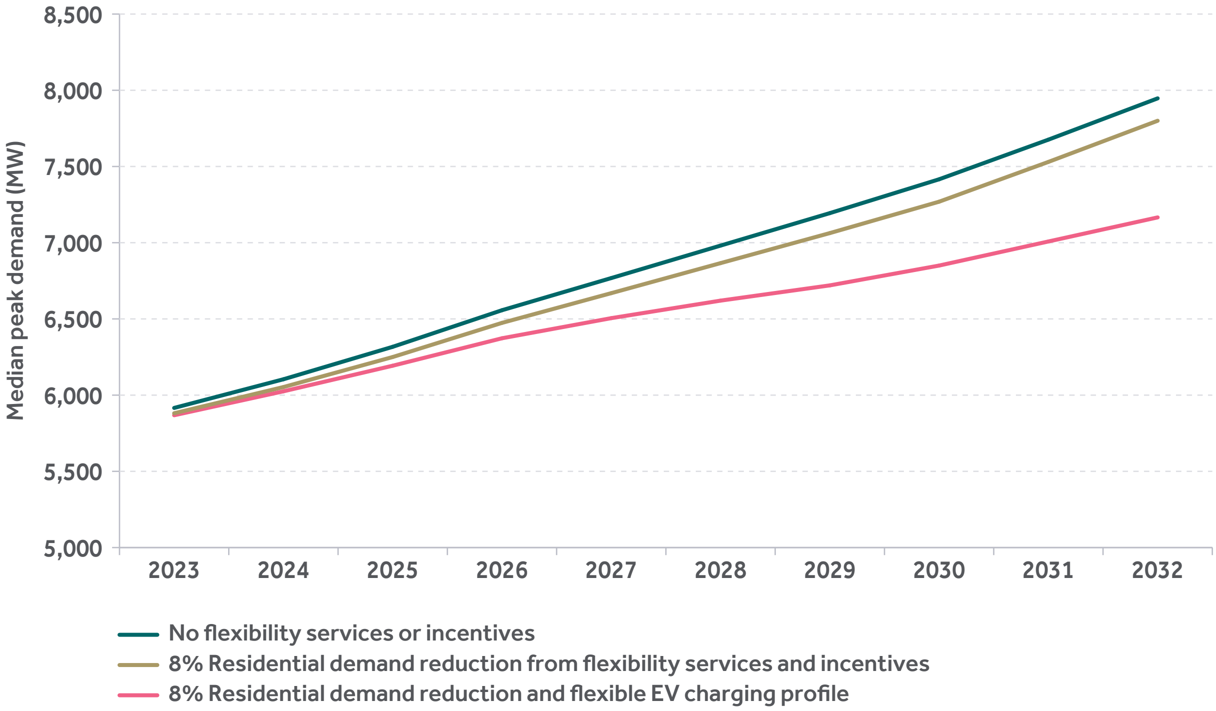


Figure 4.6: Impact of demand flexibility in median scenario across the study period

4.2.8 Efficiency improvements

Improvements in efficiencies are a critical element to consider when forecasting future electricity demand. The European Union has an energy efficiency directive (2018/2002[32]) which is to be further amended to deliver savings each year of 1.5% of final energy consumption from 2024–2030[33]. Whilst the directive is intended to drive a reduction in final energy consumption, the demand for electricity may increase due to government policies around carbon and the electrification of heat and transport.

Efficiency improvements are captured as part of the electrification of heat and transport, where technologies are assumed to become more efficient over time.

For heat pumps, this is based on the forecast from the Sustainable Energy Authority of Ireland's National Heat Study[34]. The efficiency gains reduce the total energy for heat pumps by 18% in 2030 versus the 2020 efficiencies. For electric vehicles, approximately 1% efficiency gain each year is assumed.

Within the residential, commercial and industrial demand, an element of efficiency improvements is already present in the historical trends (~0.7%) which is used to forecast the future demand. These trends are supplemented with additional reductions into the future to deliver 1.5% improvements, to reflect the enhanced ambition of the energy efficiency directive.

32 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0210.01.ENG
33 https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en#the-2012-energy-efficiency-directive
34 https://www.seai.ie/data-and-insights/national-heat-study/

4.2.9 Demand sources not included in forecast

Two potential areas of growth identified in the Climate Action Plan 2023 that have been omitted from this forecast are hydrogen production through electrolysis, and the electrification of heat in industry. Hydrogen production is not included in this forecast as the Climate Action Plan 2023 targets utilising surplus renewable electricity for Hydrogen production in 2030 and supporting the production via 2 GW of additional offshore wind beyond 2030. As such this will not affect the adequacy position. Electrification of heat in industry is an emerging sector of growth with the Climate Action Plan 2023 stating "investment in our electricity grid capacity and generation will further facilitate up to 3.5 TWh of new industrial heat pumps to provide for the decarbonising of manufacturing processes". There is still uncertainty as to how and when this demand will materialise, as such it has not been included for this study but will be monitored closely for future forecasts.

4.2.10 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 4.7 below. There is a slight decrease in the forecasted electricity requirement across the duration of the study relative to the previous forecast. This is predominantly present in the short term due to lower forecasted economic growth than was forecast last year, during the bounce back following Covid-19, and the effects of the Russian invasion of Ukraine. Despite this however, demand is still predicted to grow considerably, primarily driven by Data Centres and New Technology Loads in the short term (underpinning the digitisation of economies all across the EU), with electrification of heat and transport becoming a more significant factor towards the end of the decade. In the median scenario, the energy demand is forecasted to increase 43% by 2032, from 2022 levels[35].

35 Note 2022 data for Ireland consists of some assumed data as accurate figures not available at time of data freeze.

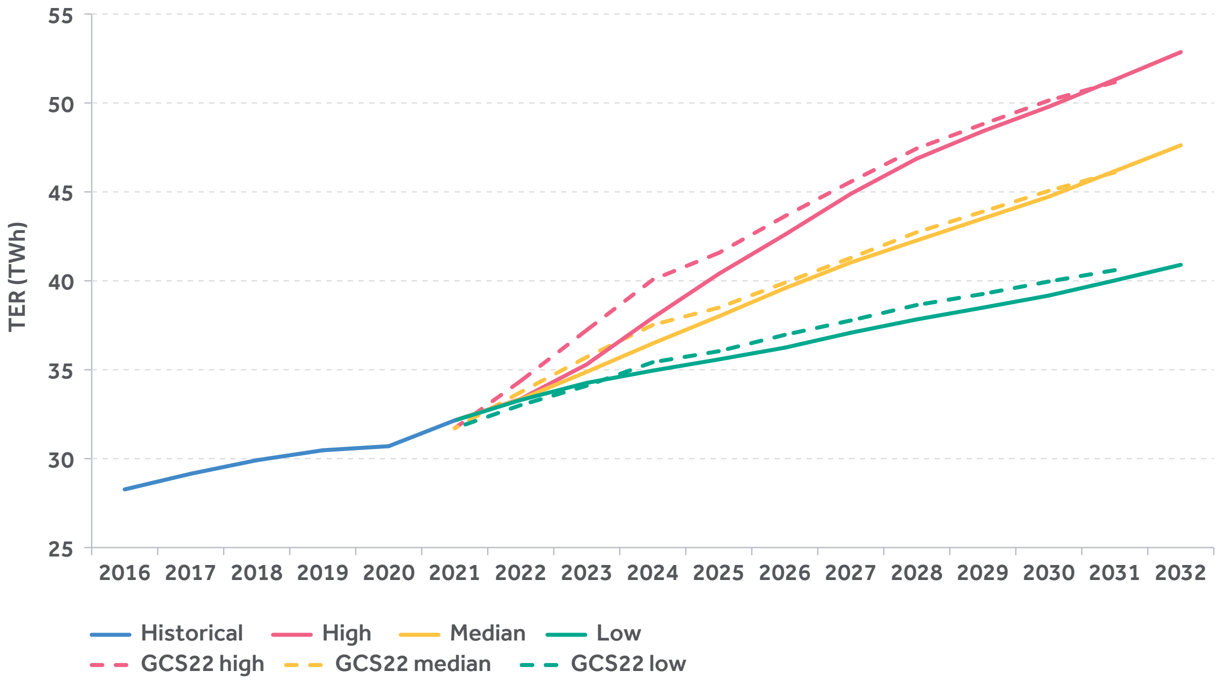


Figure 4.7: Total Electricity Requirement for Ireland

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 4.8 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 largest growth comes from data centres and new technology load (89% of the growth forecast in 2023), and increased uptake of electric vehicles and heat pumps, particularly later in the decade (64% of the growth in 2030). Also notable is that by 2030, 30% of all electricity demand is expected to come from data centres and new technology loads.

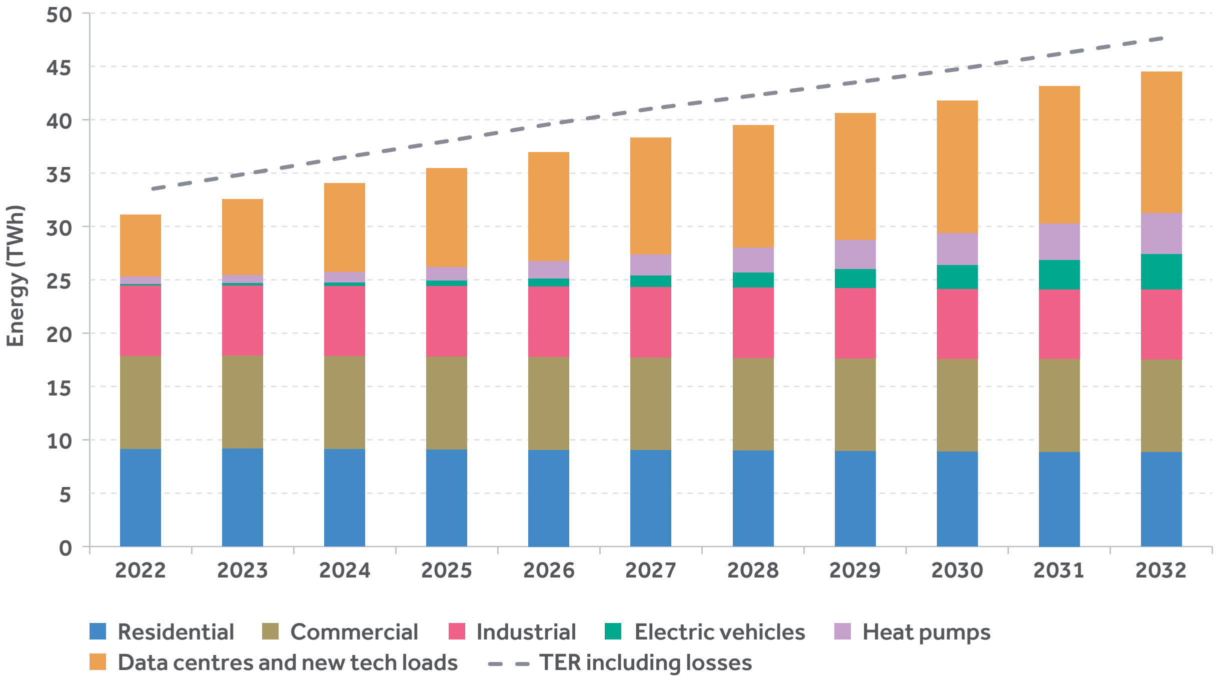


Figure 4.8: Ireland median demand Total Electricity Requirement sectoral breakdown

The proportion of demand for each sector for 2022 and 2032 are estimated as follows:

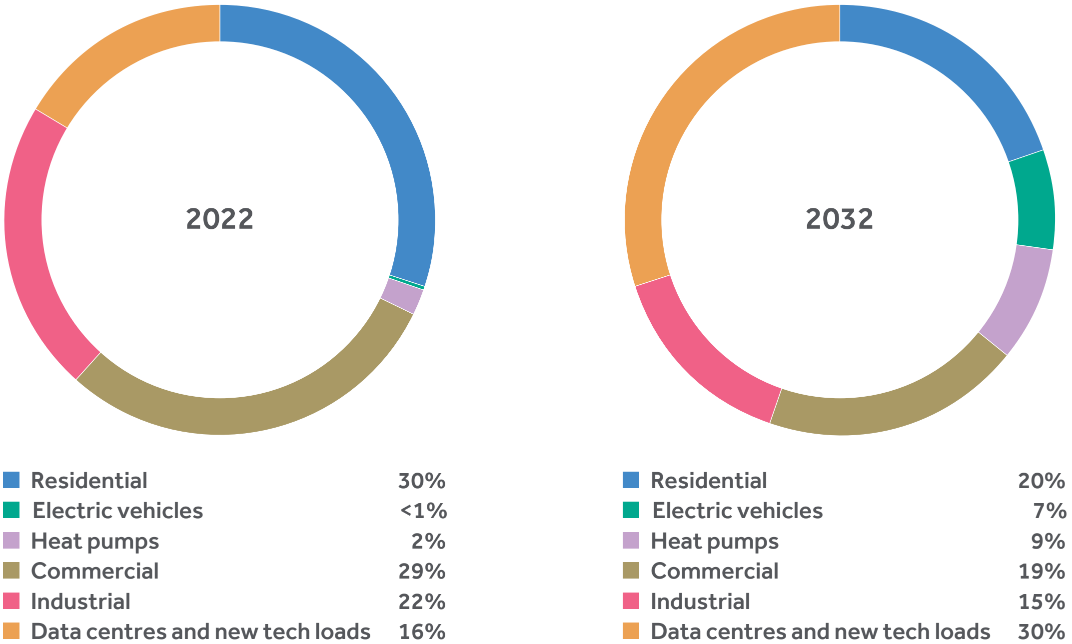
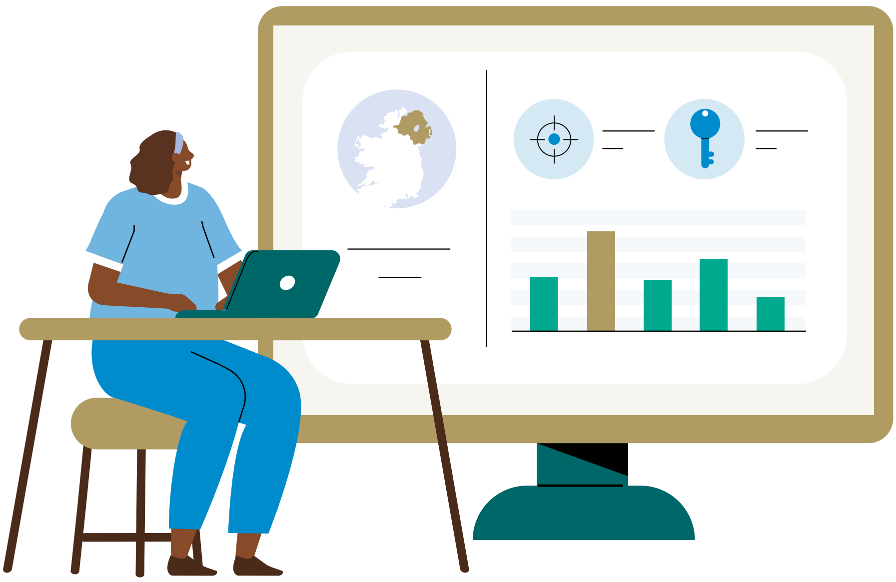


Figure 4.9: Ireland median demand sectoral proportion of energy requirement



4.2.11 Peak demand

The peak demand model separates sectors of demand to reflect the different behaviour of consumers. The conventional peak demand made up of residential, commercial, and industrial consumption utilises the historical relationship between annual electricity consumption and winter peak demand. This relationship is defined by the Annual Load Factor (ALF), which is calculated as the average load divided by the peak load. The historic trend of Annual Load Factor is used to project future peak demand, before adjusting this forecast to account for the effects of demand flexibility.

New growth areas such as Electrification of Heat and Transport, as well as Data Centres and New Technology Loads are forecast separately. As discussed in section 4.2.5, 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 expected increase of smarter charging (section 4.2.7) is a key factor in reducing the effect of electric vehicles on peak demand.

Heat pumps are assumed to have seasonal variation based on temperature, however the demand throughout a given day is expected to be relatively consistent. Finally, as discussed in section 4.2.4, data centre load is assumed to be consistent throughout the day with a gradual ramp throughout the year to their forecasted demand.

The overall peak demand forecast is shown in Figure 4.10. In the median scenario, the peak demand is forecasted to increase 29% by 2032 from 2022 levels. Again, there is a dip relative to last year's forecast in the short-term driven by lower economic growth and the impacts of the Russian invasion of Ukraine. However, as with the Total Electricity Requirement, demand towards the end of the decade is expected to be similar to the previous forecast, primarily driven by data centres and new technology loads, alongside the electrification of heat and transport.

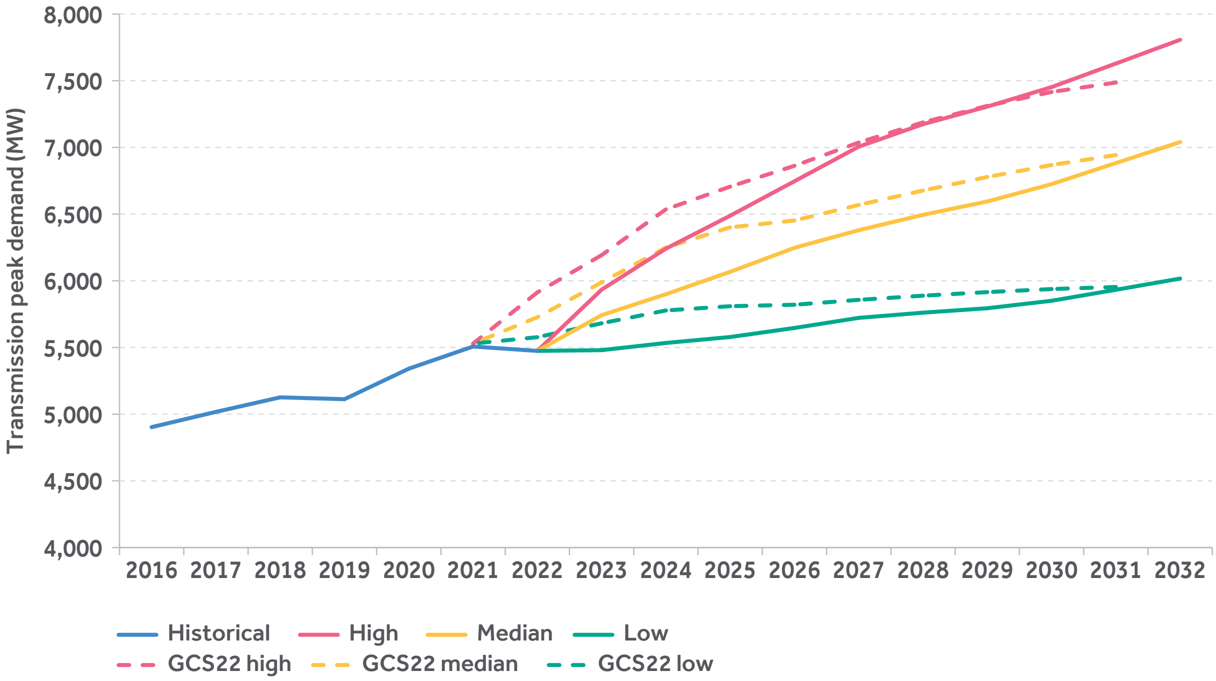


Figure 4.10: Transmission peak forecast for Ireland

Table 4.5 shows the key assumption differences between the low, median, and high peak electricity demand scenarios in the forecasts shown above.

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

Whilst the overall peak is expected to increase through the study period, the contributions to this peak of residential, commercial, and industrial demand are expected to drop as shown in Figure 4.11.

In 2022, the temperature corrected peak demand was lower than previously forecast (as shown in Figure 4.10), despite increases in the number of electric vehicles and heat pump installations and continued growth from Data Centres and New Technology loads. This drop in peak demand relative to the previous forecast is as a result of the reduced peak demand from the conventional residential, commercial, and industrial sectors (Figure 4.11).

This drop is predominantly theorised to be driven by high electricity prices. To account for this, in this year's forecast, the low demand forecast assumes this trend continues, the high demand forecast assumes the peak will bounce back to the previous level in 2021 as has been seen historically after significant drops (e.g. economic crash in 2009), whilst the median demand forecast predicts a smaller bounce back as the electricity prices stabilise, aligned to the longer-term historical trajectory. In all three of these scenarios, the long-term trend of a gradual reduction in conventional peak demand is expected to continue as a result of increased efficiencies and demand flexibility initiatives.

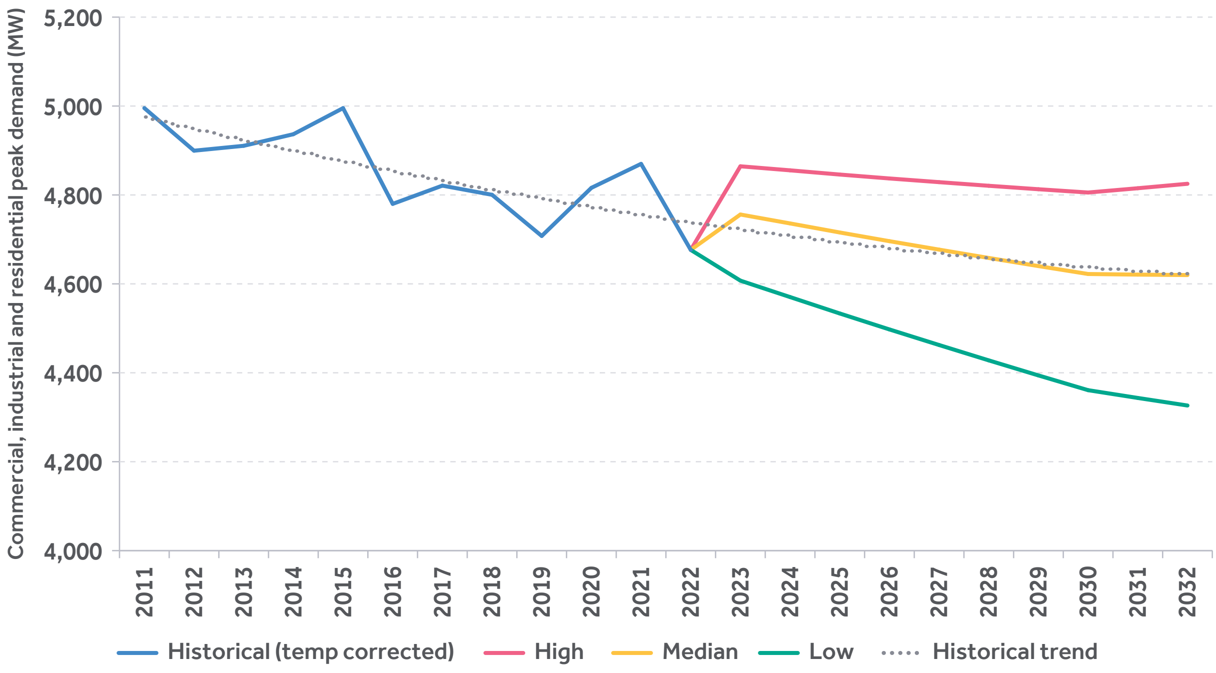


Figure 4.11: Residential, commercial and industrial peak demand (excluding electric vehicles, heat pumps, data centres and new technology loads

4.3 Demand forecast for Northern Ireland

4.3.1 Methodology

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

The TER forecast is carried out with reference to economic parameters, primarily Gross Value Added (GVA). The Northern Ireland economy was impacted significantly by Covid-19, reducing GVA in 2020 by approximately 10%[36]. The gradual removal of Covid-19 related restrictions led to GVA growth in 2021 of around 6% with continued strong economic growth in 2022 of approximately 4%. The Economy in Northern Ireland is forecast to contract slightly in 2023 with modest growth forecast for the years thereafter. Economic variables accounted for include, for example, unemployment, interest rate and inflation. Inflation has significantly impacted living costs including energy prices in 2022 and 2023.

The Northern Ireland Executive's new Energy Strategy – The Path to Net Zero Energy[37] 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[38] 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, setting of carbon budgets, sectoral plans for emissions reduction targets and policies and procedures to drive targets and carbon budgets. A series of interim and final reports setting out progress achieving carbon budgets and emissions targets will be prepared and published by DAERA.

Following on from the new Energy Strategy the Department for the Economy (DfE) published The Path to Net Zero – Action Plan 2022[39] and more recently The Path to Net Zero – Action Plan 2023[40]. The Action Plan 2023 is an integral part of delivering the overall energy strategy. These actions will be taken forward during 2023 by government and partners who will report in 2024 on the progress achieved against this 2023 Action Plan.

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.

36 Based on data averaged across multiple sources including Danske Bank & EY
37 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf
38 https://www.legislation.gov.uk/nia/2022/31/enacted
39 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf
40 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-Path-Net-Zero-Energy-2023-Action-Plan.pdf

4.3.2 Demand scenarios

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.

In order to compile these, SONI has taken a number of factors into consideration:

There have been applications from data centres and new technology loads 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 or new technology load. The median demand scenario includes a realistic estimate of data centre and new technology load in the connection process. In addition to this, the high demand scenario contains potential additional load from data centres and new technology loads that are due to connect to the system within the ten-year study period. These three scenarios give an appropriate view of the range of possible demand growths and are based on applications for connection.

With the transition from fossil fuel sources, it is estimated that going forward, a gradually increasing proportion of energy demand will be met from electricity. The demand forecasts across all scenarios reflect increasing 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. An objective of the Path to Net Zero Energy Action Plan 2023 will issue a consultation on a low carbon heat support scheme. Proposals will be developed for a support scheme for low carbon heating to assist the transition from fossil fuels to decarbonised forms of heating. Factors impacting electricity demand of heat pumps include number of installations, dwelling heat demand and coefficient of performance. The low, median and high demand forecast vary the forecast electricity demand from heat pumps on the basis of the number of installations, presented in Table 4.6.

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'[41] 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 are in place to ensure that smart vehicle charging technology is realised otherwise additional capacity will be required.

41 Charging profiles can be referenced in TESNI 2020. https://www.soni.ltd.uk/media/documents/TESNI-2020.pdf

The numbers of electric vehicles and heat pumps included in the low, median and high demand forecast are detailed below with a linear uptake assumed in interim years. Following on from last year's report the number of electric vehicles and heat pumps have been updated based on Northern Ireland Electricity Networks (NIE Networks) Regulatory Price Control 7 (RP7) figures. This update is to facilitate consistency in planning across the transmission and distribution systems.

The median demand forecast is based on an average temperature year based on a ten-year average. Based on the forecasts above, it includes assumptions on future electrification of heat and transport, future energy efficiency in the electricity system, along with the application of a central economic growth rate factor and the enduring impact of high energy prices out to 2027. 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 future electrification of heat and transport with higher levels of future energy efficiency and the pessimistic economic factor being applied alongside the enduring impact of high energy prices out to 2027. Conversely, the high demand forecast is based on a relatively low temperature year, higher levels of future electrification of heat and transport with lower levels of future energy efficiency and the more optimistic economic factor being applied alongside the enduring impact of high energy prices out to 2027.

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

4.3.3 Self-consumption

SONI has been working with Northern Ireland Electricity Networks (NIE Networks) and referencing the Renewable Obligation Certificate Register (ROC Register)[42] 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. Examples of embedded generation include 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.[43]

4.3.4 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[44].

The updated TER forecast (Figure 4.12) is reduced in the short term for median, high and low scenarios when compared to the forecast published in the Generation Capacity Statement 2022–2031. This is due to the reduction in electricity consumption we have seen in the later part of 2022 due to impact of global events and the impact of 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.

As shown in Figure 4.13, growth in TER from 2025 is primarily driven by the electrification of heat and transport with government policies and incentives expected to drive growth

Figure 4.13 Illustrates how the TER demand forecast is built up from the various demand components for the years 2025 and 2030.

42 https://www.renewablesandchp.ofgem.gov.uk/
43 Self-consumption in Northern Ireland currently represents approximately 3% of TER. This has grown over more than ten years with the installation of small-scale generation.
44 Losses describe the difference between the amount of energy entering a system and the amount of energy leaving it. For example, on the transmission grid, some energy provided by generators is lost, typically as heat and noise, as it travels across the grid to where it is needed.

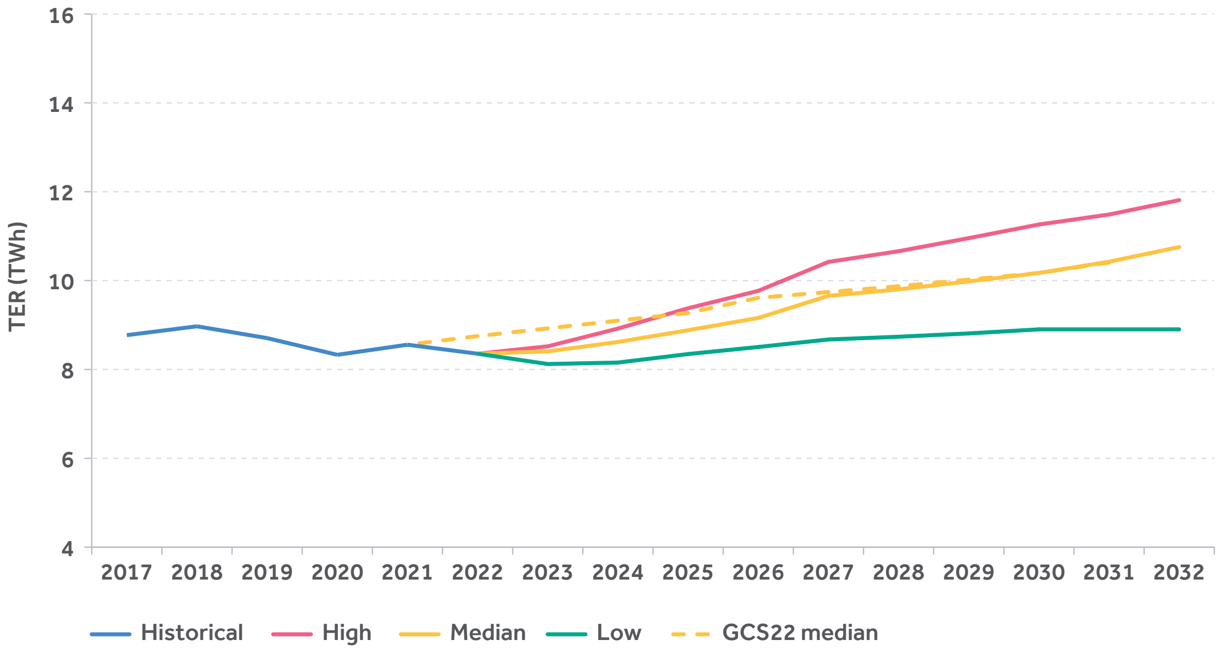


Figure 4.12: Northern Ireland TER forecast

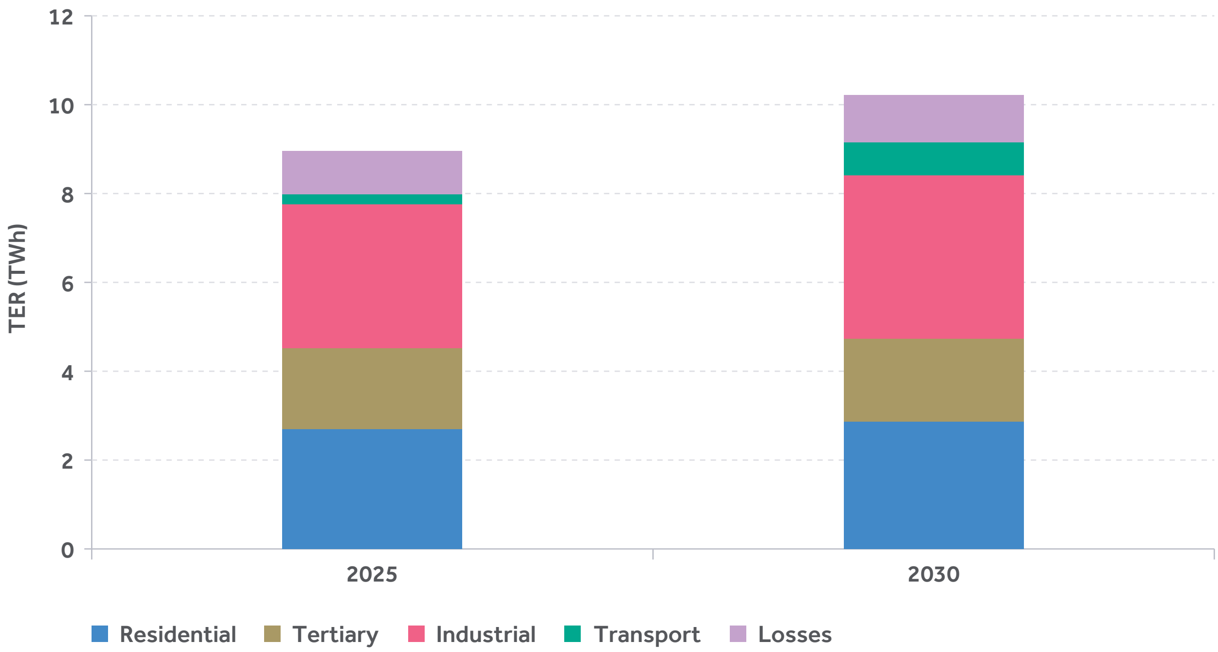


Figure 4.13: Demand breakdown

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[45]	High ramp
Economic growth projection	Oxford Economics ten year forecast less 1%	Oxford Economics ten year forecast	Oxford Economics Ten year forecast Plus 1%

4.3.5 Peak demand forecasting

The peak demand model is based on the historical relationship between the annual electricity consumption and winter peak demand. This relationship is defined by the Annual Load Factor (ALF), which is the average load divided by the peak load.

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 temperature-corrected peak curve is used in the ALF model, which can then be modelled for the future using the previously determined energy forecasts.

The Northern Ireland 2021/22 sent out[46] peak of 1568 MW occurred on Wednesday 8th December 2021 at 17:30. When ACS temperature correction is applied, the peak becomes 1620 MW.

As with the annual electricity demand forecast outlined in section 4.3.2, three peak forecast scenarios have been built.

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 metering is assumed within the forecast, the benefits of which are shown in Figure 4.16. To realise these benefits, appropriate policies and incentives are required, otherwise additional generation capacity will be necessary.

45 Based on projects currently in the connection process.
46 Sent Out generation is metered at the generator export point to the electricity system and includes both large scale and small scale generation.

In the early years of the ten-year peak demand forecast presented in this report, SONI 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 (2008), and the high scenario is based on a very cold winter (2010). This has been based on historical records over the last twenty-five years. While SONI does not expect an extremely warm or extremely cold winter every year, this range of scenarios is within the bounds of probability for the immediate years.

In later years of the ten-year peak demand forecast, variations caused by economic projections, data centre and new technology loads growth as well as electrification of heat and transport are more significant and are used instead.

The main difference between the forecasts of low, median, and high peaks is the amount of load assumed from electrification of heat and transport as well as data centres.

This forecast employs a similar methodology as that used in the TER forecast. Figure 4.14 shows the Transmission Peak forecast for Northern Ireland. The resulting forecast has reduced to 2026 compared to the GCS 2022–2031 median scenario. From 2027 and until the end of the study period demand forecast closely aligns with the GCS 2022–2031. This is due to the reduction in electricity consumption we have seen at peak time due to impact of global events and the impact on fuel prices. 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.

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

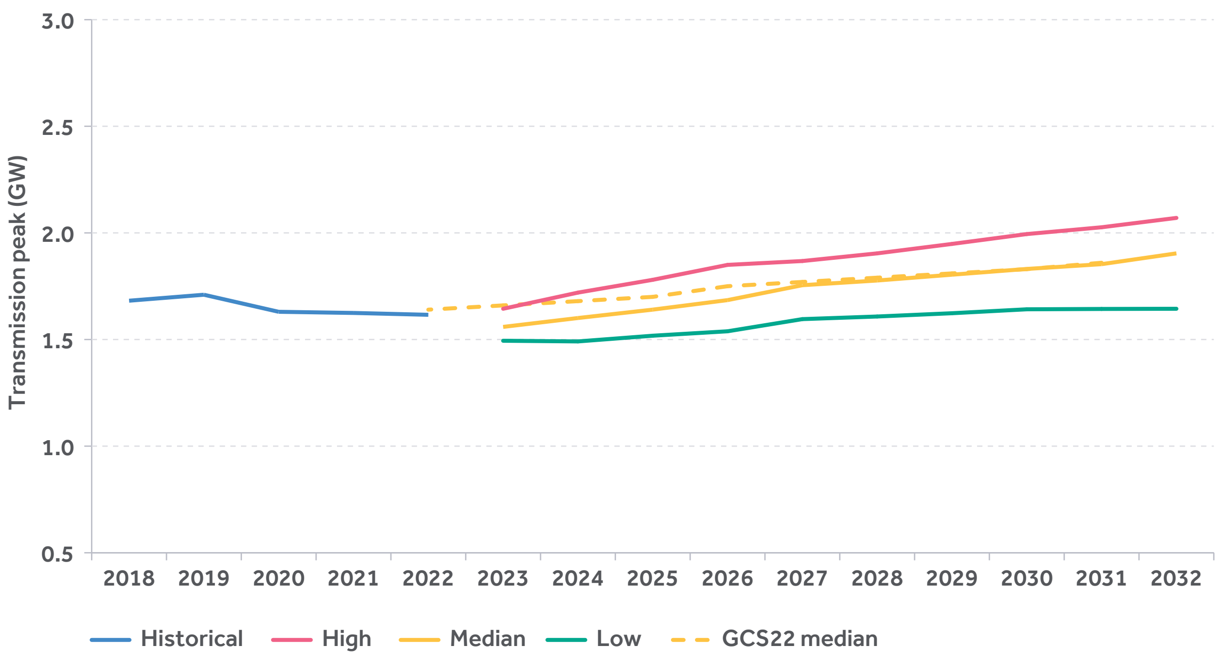


Figure 4.14: ACS transmission peak forecasts for Northern Ireland

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 25 year mild	Ten year average	One in 25 year cold

Appendix 1 lists the detailed energy and peak data out to 2032 including growth rates.

Demand flexibility has the capability to improve the adequacy of the electricity system by moving demand away from peak times. Figure 4.15 shows the effect that has been incorporated into the demand forecast of the demand flexibility services and incentives on residential demand and electric vehicle charging on the forecast peak day in 2030 in the median scenario.

Figure 4.16 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.

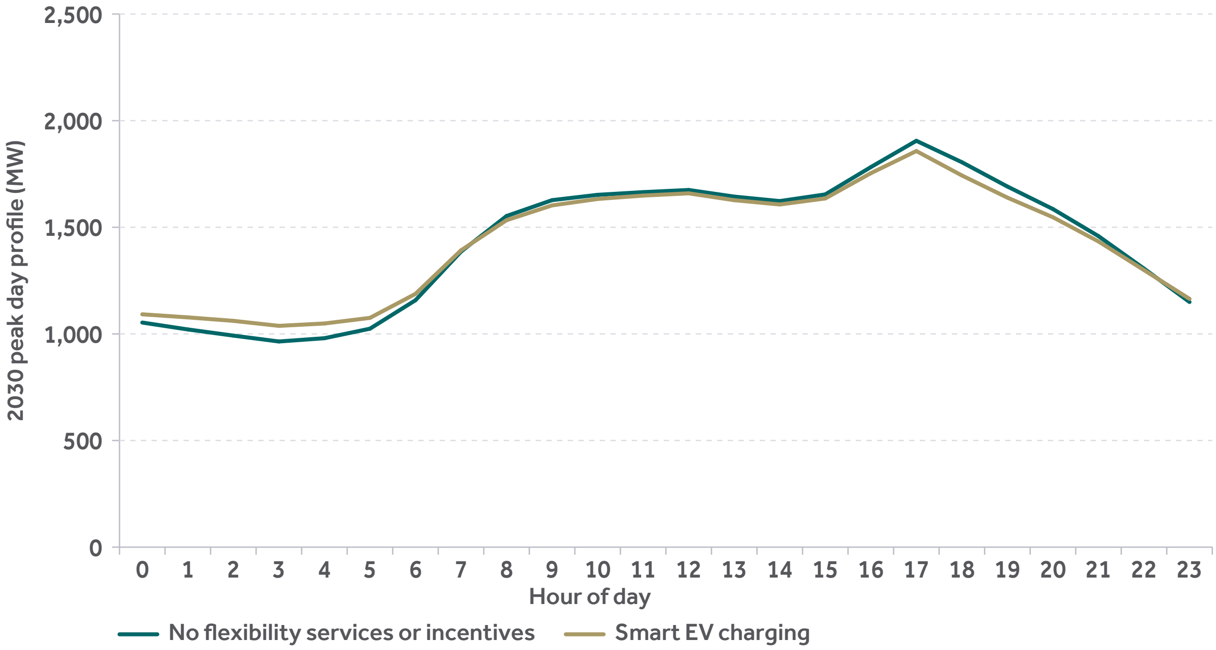


Figure 4.15: Impact of demand flexibility on 2030 peak day (median scenario)

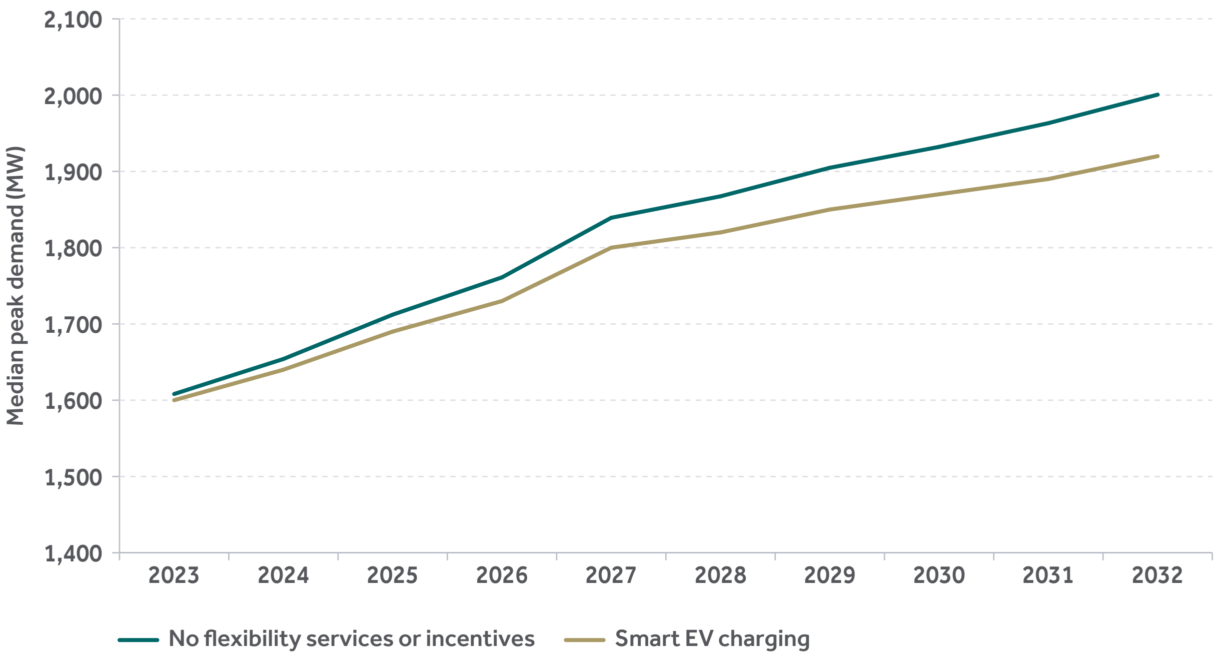


Figure 4.16: Impact of demand flexibility in median scenario across the study period

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 a half-hourly basis to produce the new all-island TER and peak figures as shown in Figure 4.17 and Figure 4.18 below.

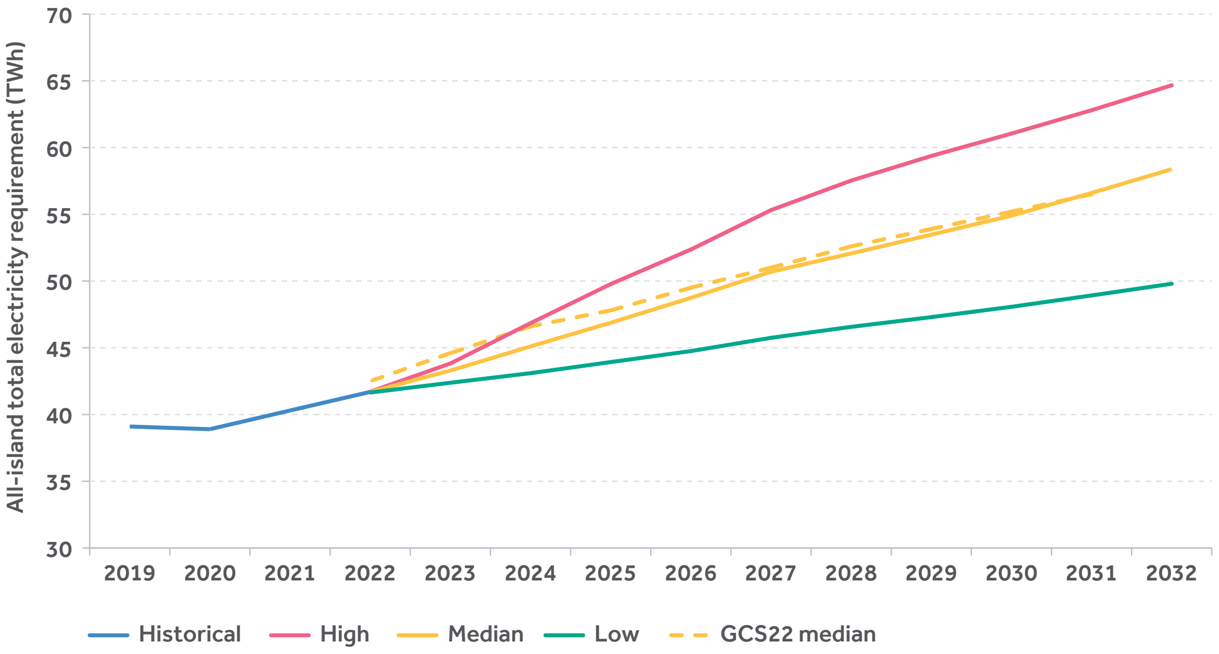


Figure 4.17: Combined TER forecast for the all-island system

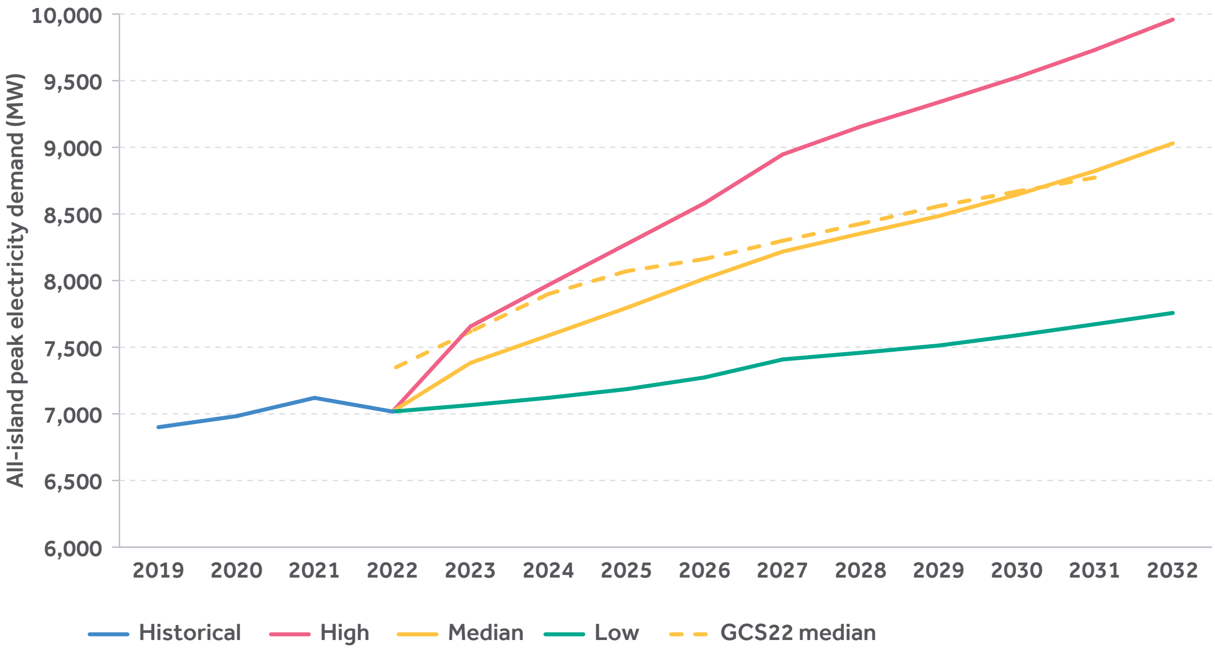


Figure 4.18: TER peak for the combined all-island forecast

5. Generation

This section describes all significant sources of electricity generation connected to the electricity system in Ireland and Northern Ireland.

5.1 Introduction

The portfolio changes over time due to factors such as existing plant retiring and new capacity obtained via the Capacity Market in the Single Electricity Market (SEM) and performance of plant. Furthermore, a plant that does not receive capacity payments may seek to exit the market. Any changes to the portfolio are particularly significant to the operation of the Ireland and Northern Ireland power systems which have a high proportion of variable renewable generation.

Figure 5.1 below illustrates the age of the dispatchable plant on the all-island system (excluding demand side units). Notably, almost 30% of the thermal capacity is over 30 years old as of 2023, with much of this aging plant expected to remain for the duration of this 10-year study. An ageing generation portfolio could result in declining availability.

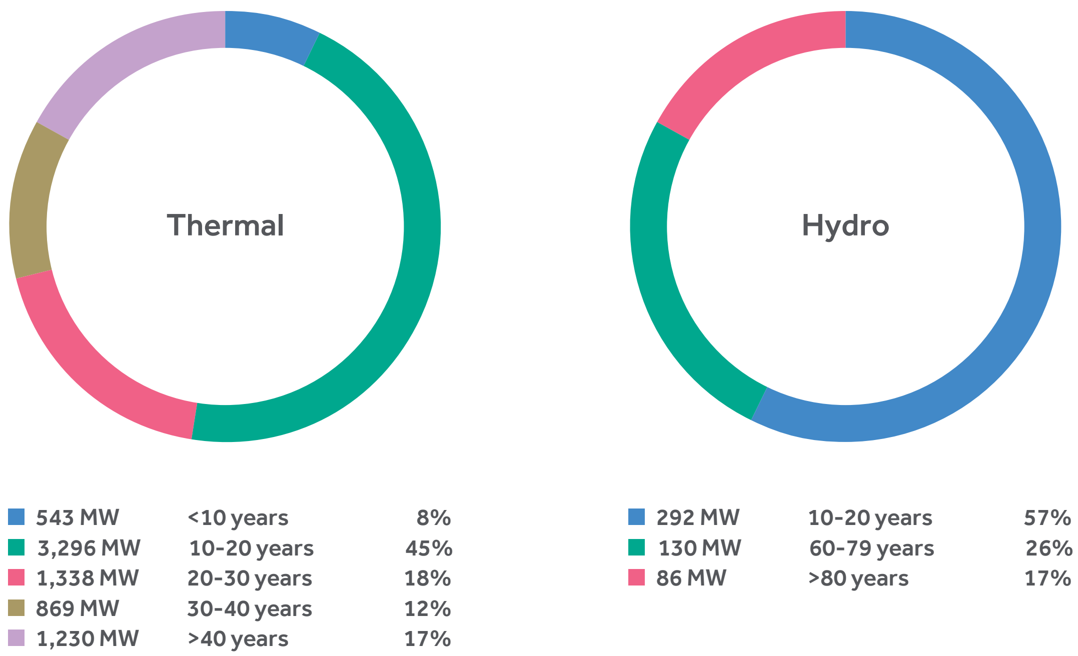


Figure 5.1: Age breakdown of dispatchable plant on the all-island system as of 2023

5.2 SEM capacity market auction results

The Single Electricity Market (SEM), established in 2007, is the wholesale electricity market operating in Ireland and Northern Ireland. It is designed to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand, excluding the non-energy services that are required to operate a power system securely. A revised market design went live in October 2018.

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). SONI and EirGrid, as TSOs, also have a number of obligations in the delivery of the capacity market auctions.

Under the SEM, only generating units that are successful in the capacity auctions will receive capacity payments. The goal of the auction is to secure capacity required for the secure operation of the power system in both Northern Ireland and Ireland while ensuring that consumers do not pay for more capacity than is needed. Since 2017, there have been 11 auctions, the total volumes procured for each auction are presented in Appendix 3: Auction results.

The forecast generation portfolio has been updated since the previous Generation Capacity Statement to include a risk adjusted view of the new entrant generation units that were successful in the T-4 2026/2027 SEM CRM capacity auction, the results of which were published in April 2023[47].

To date, most renewable generation has not participated in the Capacity Auctions. In Ireland, renewable generation can receive support through the Renewable Electricity Support Scheme (RESS). In Northern Ireland, there are plans to launch the design of a renewable electricity support scheme. The Energy Strategy – Path to Net Zero Energy Action Plan 2023[48] proposes to publish the final design of renewable electricity support, along with a pathway and timeline for the support being in place.

Figure 5.2 displays the new de-rated capacity (i.e., a unit's effective capacity when its operational availability is taken into consideration) which was successful in the recent capacity auction[49].

47 https://www.sem-o.com/documents/general-publications/PCAR2627T-4-report.pdf
48 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-Path-Net-Zero-Energy-2023-Action-Plan.pdf
49 For assessing the adequacy position, a risk adjusted view based on the deliverability risk assessment is used.

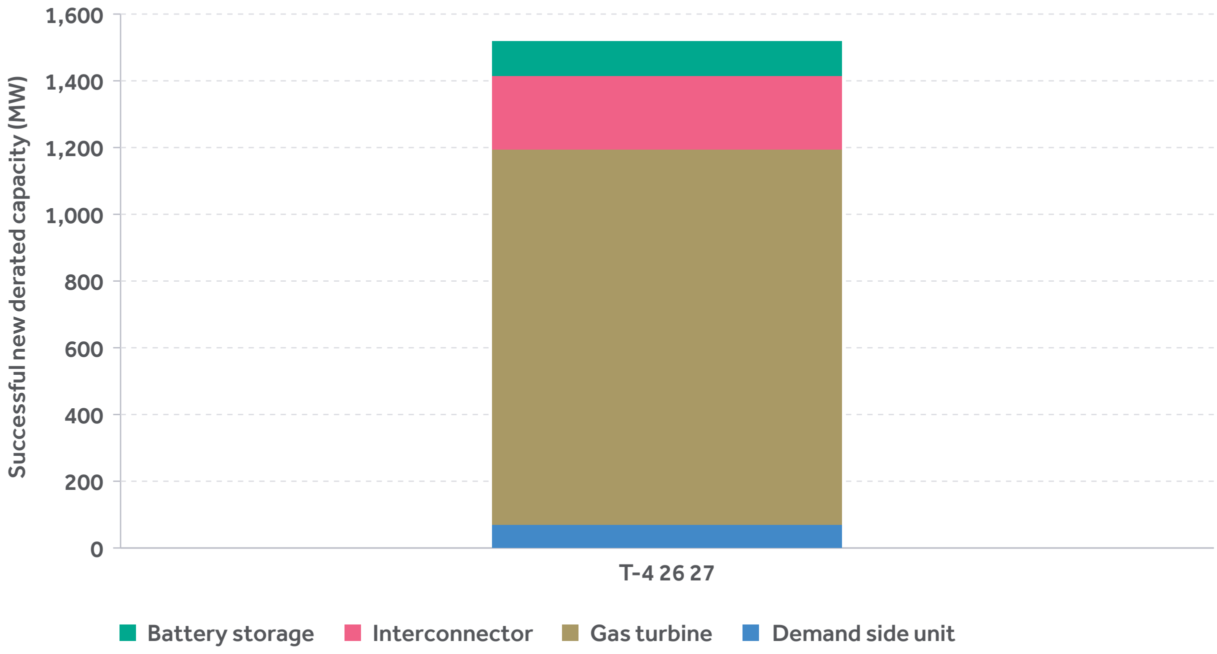


Figure 5.2: All-island derated successful new capacity in the T-4 2026-2027 capacity auction (non-risk adjusted)

5.2.1 EirGrid and SONI deliverability risk assessment

Delivering new capacity of the volume required is a complex task for the developers and delays can take place due to issues relating to planning permission, environmental consenting and the supply chain. Since 2018, less than 30 MW of new gas capacity has been delivered with 410 MW of new gas capacity terminating their contracts. Approximately 750 MW of new capacity units that were due to connect to the system and be available during this study period (2023–2032) have subsequently terminated their contracts (see Appendix 3: Auction Results for a list of these units) with over 70% of this capacity having had 10-year contracts in place.

The Capacity Market Code makes provision for an 18-month long stop date, which is built into 10-year capacity contracts. This means developers may connect up to 18 months after the 1st of October of their first capacity contract year without being subject to termination charges, giving greater opportunity for these projects to deliver.

Delivering new capacity is a constantly evolving process. To this end, both EirGrid and SONI have implemented enhanced monitoring of new capacity coming through the capacity auctions. Through this enhanced monitoring we are able to gain insights into the deliverability risks associated with the new projects as they progress through their implementation plans.

It is EirGrid's 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 2032. 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.

In 2017, the European Commission published a final decision on the Best Available Techniques[50] (BAT) for large combustion plants, which has applied new standards on emissions from August 2021. The latest BAT conclusions were published in February 2021[51]. For combustion plants, Emission Limit Values (ELVs) for Nitrous Oxide (NOx), Sulphur Dioxide (SO_2) and particulate levels have been tightened. As such, at this time, EirGrid and SONI continue to have concerns that some new gas generating units that were awarded contracts prior to the requirement for declaring annual run hour limitations (ARHL) will have ARHL applied based on information from developers. The GCS 2022–2031 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.

The EirGrid and SONI post-auction risk adjusted views of new capacity which has been successful in the Capacity Auction is outlined in Table 5.1 for Ireland and Table 5.2 for Northern Ireland. 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 and project developers to inform the TSOs' risk adjusted view. We include a technical deliverability assessment on whether projects schedules for delivering can be earlier, if they are expected to deliver late and whether based on the current information, they are a significant risk of not delivering within the auction long stop dates.

Based on the current information available to SONI, there are two new gas units in Northern Ireland that are expected to be subject to ARHLs when they become available in 2024[52]. There is an additional steam unit planned at this site; based on SONI's risk adjusted view, it is expected to be available from 2027 instead of in 2026 and is expected to remove any ARHLs as the plant will have the ability to operate as a combined cycle gas turbine (CCGT). A sensitivity has been included in Section 6.4 demonstrating the impact of the steam turbine delivering on time, and another sensitivity demonstrating the impact annual run hour restrictions not being applied.

50 31 http://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1502972300769&uri=CELEX:32017D1442
51 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021D2326
52 Based on information provided by the generator through the survey process.

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

Ireland		2024	2025	2026	2027	2028
Gas turbine	GCS2023 risk adjusted capacity	330	200	290	0	570
	Total successful in capacity auctions	230	1,280	120	1,270	N/A

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

Northern Ireland		2024	2025	2026	2027	2028
Gas turbine	GCS2023 risk adjusted capacity	720[53]	0	0	0[54]	0
	Total successful in capacity auctions	720	0	0	0	0
Steam turbine	GCS2023 risk adjusted capacity	0	0	0	310	0
	Total successful in capacity auctions	0	0	310	0	0

This risk adjusted view is based on plant delivering early, delivering late, or not delivering. For reference, the capacity successful in capacity auctions is also presented. Values are rounded to the nearest 10 MW.

53 Subject to Annual Run Hour Limitations (ARHL).
54 ARHL removed as station converts to CCGT. This will increase the overall contribution to system adequacy.

5.3 Changes to conventional generation in Ireland

This section describes changes in fully dispatchable-plant capacities in Ireland. Information on known plant additions and closures are documented.

Some of the older generators in Ireland have informed EirGrid of their intention to decommission, as detailed below in Table 5.3.

A common reason for plant decommissioning is increasing restrictions due to Industrial Emissions Directive (IED) legislation.

Directive 2010/75/EU[55] 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 5.3 Assumptions for conventional plant changes in Ireland

Plant	Units	Export capacity (MW)	Modelled as closing by the end of:	Comment
Aghada	AT1	90	2023	IED limited life-time derogation. ESB has provided a closure notice for these units.[56]
Tarbert	TB1	54	2021	SSE has previously provided a closure notice for this unit to close by the end of 2023. TB1 has since been placed on outage until Dec 2023 so will be excluded from studies.
	TB2	54	2021	SSE has previously provided a closure notice for this unit to close by the end of 2023. TB2 has since been placed on outage until Dec 2023 so will be excluded from studies.
	TB3	241	2022	SSE has previously provided a closure notice for this unit to close by the end of 2023. TB2 has since been placed on outage until Dec 2023 so will be excluded from studies.
	TB4	243	2021	SSE has previously provided a closure notice for this unit to close by the end of 2023. TB4 has since been placed on outage until Dec 2023 so will be excluded from studies.

55 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN
56 New information post freeze date regarding this is captured in Section 6.2.

Table 5.3 Assumptions for conventional plant changes in Ireland

Plant	Units	Export capacity (MW)	Modelled as closing by the end of:	Comment
Moneypoint	MP1 MP2 MP3	250 250 250	2024	ESB have issued a closure notice for these units to close in October 2024. EirGrid notes that these units may be retained beyond this date for security of supply purposes. However, this is considered a mitigating measure and not part of the GCS 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	ED1	118	2030	The Bord na Móna plant ED1 was due to close at the end of 2023. Planning permission was recently awarded to keep this unit operating until 2030, running on 100% biomass from 2024.
	ED3	58	N/A	Switching fuel by 2026 from distillate oil to gas.
	ED5	58	N/A	Switching fuel by 2026 from distillate oil to gas.

5.4 Changes to conventional generation in Northern Ireland

This section describes changes in fully dispatchable plant capacities in Northern Ireland. Information on known plant unavailability, additions and closures are documented in Table 5.4 and Table 5.5.

The forecast generation portfolio has been updated in this year's GCS to include the new entrant generation units that were successful in the SEM CRM T-4 2026/2027 capacity auctions.

The studies include cleared existing capacity and the new capacity awarded are either one or ten-year contracts.

Kilroot units KGT1, KGT2, KGT3 and KGT4 have an extended planned outage in 2025. They were not included in the T-4 2024/25 auction in January 2021, and this is reflected in our modelling with these units being unavailable in 2025 but available for all other years of the studies. This capacity is outlined in Table 5.4.

Table 5.4: Assumptions for Kilroot GT plant capacity

Plant	Export capacity (MW)	Modelling assumption:	Comment
KGT1	29	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction.
KGT2	29	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction.
KGT3	42	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction.
KGT4	42	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction.

Kilroot ST1 and ST2 did not qualify for inclusion in the T-4 2023/24 auction in April 2020 and the developer subsequently issued a Closure Notice for ST1 and ST2 confirming its intention to close both units on 30th September 2023. This capacity is outlined in Table 3.5. The units each have HFO rating of 238 MW, however the station has been declared unavailable for HFO operation for significant periods during 2021 and 2022.

SONI obtained clarification from the plant operator on the running of existing near end of life coal plant. At present, the plant operates at a reduced generation capacity following the expiration of the COVID-19 Regulatory Position Statement to manage and comply with their most recent environmental permit.

Following engagement with the Department for the Economy (DfE) and Northern Ireland Environment Agency (NIEA), SONI is aware that a Direction under the Pollution Prevention Control (Industrial Emissions) Regulations (PPC(IE)) was issued by the Department of Agriculture and Rural Development (DAERA) to the Chief Inspector (the PPC(IE) Regulator) in April 2022[57]. The Direction instructs the PPC(IE) regulator not to enforce against exceedances on air emission limits where there is significant and imminent risk to the security of NI's electricity supply, as determined by the Department for Economy.

Following receipt of the Direction issued by DAERA, the coal station operator has been written to by the Northern Ireland Environment Agency (NIEA), confirming that the PPC(IE) regulator has received the above Direction. The coal station's operator's current position is to run at reduced generation capacity and not invoke the use of the DAERA Direction. However, from an operational perspective, the units have been available to the TSO to be run at full output on coal for four hours per day and stay within their emissions limit.

Table 5.5: Assumptions for plant changes in Northern Ireland

Plant	Export capacity (MW)	Modelled as closing by the end of:	Comment
Kilroot ST1	130	End of September 2023	EPUKI, the owner of Kilroot, has provided a closure notice for this unit. Operation ceases 30th September 2023. The 238 MW is based on the HFO rating; however, the station has been declared unavailable for HFO operation for significant periods during 2021 and 2022. Due to Environmental Permit Compliance Restrictions, the unit is assumed to be 130 MW for modelling purposes.
Kilroot ST2	130	End of September 2023	EPUKI has provided a closure notice for this unit. Operation ceases 30th September 2023. The 238 MW is based on the HFO rating; however, the station has been declared unavailable for HFO operation for significant periods during 2021 and 2022. Due to Environmental Permit Compliance Restrictions, the unit is assumed to be 130 MW for modelling purposes.

57 https://public-registers.daera-ni.gov.uk/pollution-prevention-control

The operator has informed SONI that each of these units are limited to a maximum of 175 MW when running on coal. Furthermore, to comply with their latest Environmental Permit the coal units are not operated as fully available at 175 MW, but at this output they are restricted by the operator to a limited number of periods across a typical day[58]. Currently the average availability throughout the day whilst maintaining emissions compliance is 130 MW. This limitation is reflected in our modelling.

There are some uncertainties in Northern Ireland around new capacity becoming available for a given capacity year and risks around annual run hour limitations on both existing plant and new capacity entering the market. EPUKI has informed SONI of annual run hour limitations on some new open cycle gas turbine capacity awarded through two SEM capacity market auctions.

Furthermore, SONI has identified operational risks if annual run hour limitations (as discussed in Section 5.2.1) are applied to capacity connected to the system and operating in the market.

The latest capacity offered at the Kilroot site which cleared in the recent T-4 2025/2026 was classified as part of a Combined Cycle Gas Turbine (CCGT) arrangement with no annual run hour limitations; it is expected to be available from 2027. This arrangement would utilise waste heat from the new KGT6 and KGT7 Open Cycle Gas Turbines. Therefore, the impact of ARHL is included in the core scenarios only from 2024 up until 2027.

58 https://umm.nordpoolgroup.com/#/messages/b70bb29a-5544-401b-a0e0-960d430d80c0/2

5.5 Interconnection and tie lines

Interconnection allows the transport of electrical power between two markets. Interconnection with Great Britain over the East-West and Moyle interconnectors provides a significant capacity benefit. 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 operating a reliable power system 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.

Within the all-island market, the tie-line between Ireland and Northern Ireland is an element of the transmission system, rather than an interconnector to facilitate cross-border market trading. For this reason, as an essential element of AC grid, it is treated differently to how the East-West (EWIC) and Moyle HVDC interconnectors are considered. These interconnectors are subject to cross-border trading obligations, eligible for participation in the Capacity Market and are therefore given capacity market de-rating factors.

5.5.1 North South Interconnector (tie line)

The second high-capacity transmission link between Ireland and Northern Ireland is anticipated to be completed by 2026. It is assumed that all-island generation adequacy assessments can be carried out from 2026 onwards, these results are presented in Section 6.5. This all-island assessment shows an improvement in the security of supply for both jurisdictions, as the demand and generation portfolios for Northern Ireland and Ireland are aggregated to meet the combined demand.

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, as such an all-island study is not carried out.

Generation adequacy assessments for each region are carried out for the full study duration with an assumed degree of capacity interdependence from the other region. This is due to the system outages and the region demand peak for each region occurring at different times. Therefore, some allowance for inter-regional supply can be estimated to balance supply across the island.

The capacity reliance values used for the whole adequacy studies are shown in Table 5.6. This capacity reliance figure assumes that there is sufficient capacity from either jurisdiction to facilitate an exchange of power.

Table 5.6: Capacity reliance at present on the existing North South Interconnector

	North to South	South to North
Capacity reliance	100 MW	200 MW

SONI and EirGrid define the capacity reliance as the effective capacity adequacy benefit across a typical year. During real time operations, physical flows may be above or below the stated capacity reliance[59]. A sensitivity is modelled for both Ireland and Northern Ireland, where the available capacity from the other jurisdiction is zero.

5.5.2 Interconnection between the all-island system and Great Britain

When assessing the contribution of an interconnector to generation adequacy, it is necessary to consider the availability of generation in the neighbouring region, as well as the availability of the interconnector itself.

The East-West interconnector connects the transmission systems of Ireland and Wales with a capacity of 500 MW in either direction. In Northern Ireland, the Moyle Interconnector is a dual monopole HVDC link with two coaxial undersea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The import capacity of the Moyle Interconnector is currently 450 MW, however a trial of increasing this import capacity to 500 MW is taking place and will be monitored for inclusion in future studies.

It is difficult to predict whether the maximum import capacity will be available at all times. For the purposes of this adequacy study EirGrid and SONI assumes two existing HVDC interconnectors between the all-island system and Great Britain. We model this with one 500 MWrated and one 450 MWrated interconnectors, we apply a 60% External Market de-rating and use the relevant 5-year average outage statistics for each interconnector as indicated in Table 5.8.

59 Dynamic modelling of this tie line is planned for future modelling development as described in Appendix 7.

5.5.3 Further interconnection

There are several proposed new interconnector projects seeking to connect to the Ireland and Northern Ireland transmission systems. Table 5.7 summarises the projects that are assessed as part of the current European Ten-Year Network Development Plan[60]. For the purpose of the adequacy assessment, the Celtic Interconnector is assumed available from 2027, and it is assigned the external market de-rating factor of 60%[61] and 5-year average availability statistics[62]. While new interconnection will facilitate the integration of renewables, for the purposes of this adequacy assessment, it is assumed there is a shared adequacy benefit between EWIC, Moyle and Greenlink. This benefit is equivalent to one 500 MWrated and one 450 MWrated interconnector between SEM and GB. Furthermore, it is noted that the external SEM to GB market de-rating factors need to be re-evaluated as new interconnection comes online and as such, EirGrid and SONI will engage with the regulatory authorities on this.

There are further connection projects noted in ENTSOE's most recent Ten-Year Network Development Plan 2022. In Northern Ireland there is potential for new interconnection (LirIC) to Scotland, with one potential operator receiving an interconnector licence from Ofgem. In Ireland, there is a further interconnector project (MARES Connect) from Ireland to GB. Furthermore, over the long term the TSOs continue to evaluate the potential for further interconnection between the SEM and other external markets. Based on the early development status of the MARES and LirIC projects they are not included within any studies in this report.

Table 5.7 Future interconnection projects

Project	Description	Project promoters target commissioning year
Celtic Interconnector	Interconnector between Ireland and France (with PCI status[63])	2026
Greenlink Interconnector	Project providing interconnection between Ireland and Wales	2024
LirIC	Interconnector between Northern Ireland and Scotland	2028
MARES Connect	Interconnector between Ireland and Wales	2027

60 TYNDP 2020 is produced by the European Network of Transmission System Operators – Electricity (ENTSO-e), see https://eepublicdownloads.azureedge.net/tyndp-documents/TYNDP_2020_Joint_Scenario_Report_ENTSOG_ENTSOE_200629_Final.pdf
61 Although this interconnector is from SEM to France, we assume the 60% based on current Capacity Auction interconnector de-ratings for SEM to GB market.
62 Dynamic modelling of interconnection is planned as a future modelling development as described in Appendix 7.
63 EC Project of Common Interest, see: fifth_pci_list_19_november_2021_annex.pdf (europa.eu)

5.6 Renewable targets

5.6.1 Wind power in Ireland

In Ireland, the Irish Government launched an initiative that provides support to renewable electricity projects called the Renewable Electricity Support Scheme (RESS), and an offshore specific initiative called the Offshore Renewable Electricity Support Scheme (ORESS). Based on the Climate Action Plan 2023, it can be assumed that Ireland's renewable targets will be achieved largely through the deployment of additional wind and solar powered generation. 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[64], while ESB Networks publishes that which is distribution connected[65].

The Irish Government's updated Climate Action Plan 2023[66] has set an ambitious target to achieve 80% RES-E by 2030 and substantial emissions reductions. This will require significant escalation in growth rates of renewables in the electricity sector. The current plan in Ireland includes delivering 5 GW of offshore wind by 2030. Within the Shaping Our Electricity Future (SOEF) v1.1 emissions study, three renewable trajectories are assessed.

For GCS 2023–2032, EirGrid have taken a prudent approach and assumed renewable rollout is based on the capacities installed today, the projects coming through the RESS auction for the next few years, and the SOEF v1.1 central emissions renewables trajectory as shown in Figure 5.3, however a sensitivity has been included to capture the impact on adequacy if the highly ambitious low emissions renewables portfolio presented in SOEF v1.1 is achieved.

Installed capacity of wind generation has increased from 135 MW at the end of 2002 to 4.5 GW at the end of 2022. This value is expected to increase to 7 GW of onshore wind and at least 5 GW of offshore capacity by 2030. There is an increase in the onshore capacity assumed compared to the previous GCS as a result of the increased 80% renewable targets in 2030.

Figure 5.4 shows the total wind generation, along with the capacity factor and normalised wind generation. To calculate the normalised wind generation, as per RES Directive (2009/28/EC)[67], the average capacity factor from the last five years is applied to the installed capacity. This normalised annual energy has grown from 4,484 GWh in 2013 to 10,953 GWh in 2022 accounting for constraints and curtailment.

64 http://www.EirGridgroup.com/customer-and-industry/general-customer-information/connected-and-contracted-generators/
65 https://www.esbnetworks.ie/new-connections/generator-connections/generator-connection-statistics
66 https://www.gov.ie/en/publication/7bd8c-climate-action-plan-2023/
67 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0028&from=EN

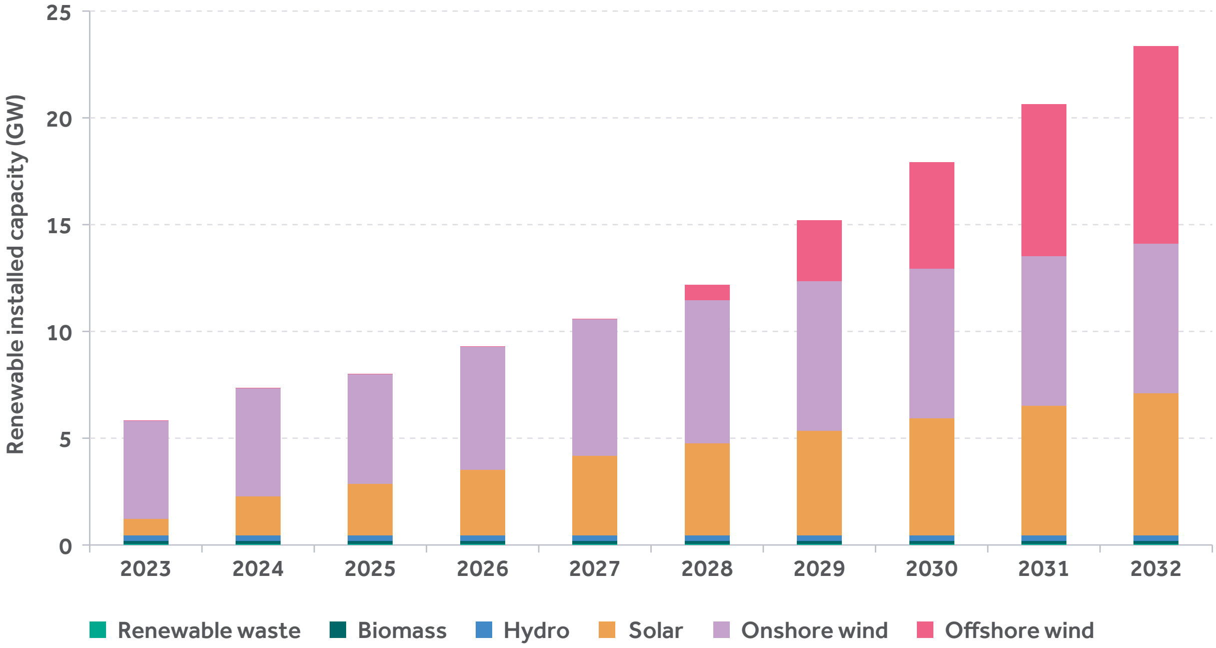


Figure 5.3: Assumed growth of renewable capacity in Ireland

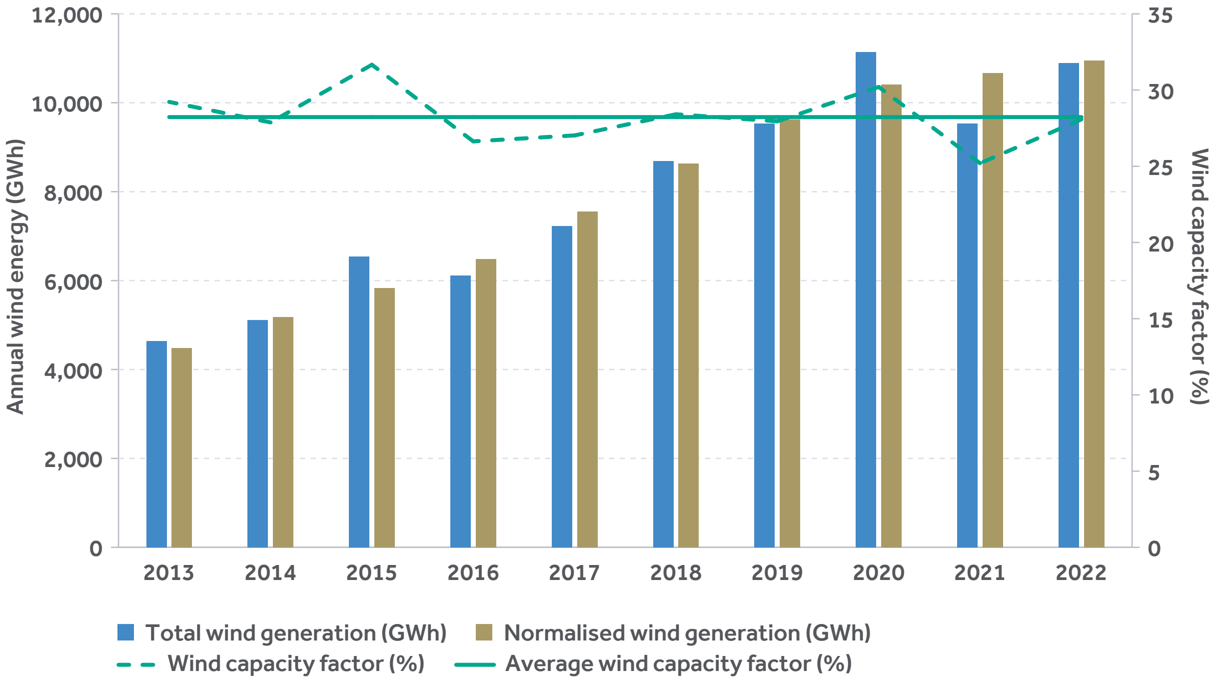


Figure 5.4 – The actual and normalised energy produced from wind power in Ireland over the last ten years

5.6.2 Wind Power in Northern Ireland

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[68] 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[69] 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[70] and more recently The Path to Net Zero – Action Plan 2023[71]. This Action Plan 2023 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 2023. The strategy includes a target of '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% target.

It is clear that significant investment will be required to deliver higher levels of new renewable and low carbon technologies. Whilst the SEM provides revenue streams for power generators irrespective of technology, 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 in Northern Ireland to encourage investment and reduce risk for investors. Both GB 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 2023 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 for the Economy consulted on the design considerations for a new scheme between February – April 2023[72].

In the medium term, onshore wind and solar PV are expected to be the most readily deployed technologies for Northern Ireland. Offshore renewables offer a significant opportunity to develop additional large-scale renewable capacity. This is included in the NI Strategy Action Plan for 2023.

68 The Path to Net Zero Energy. Safe. Affordable. Clean. (economy-ni.gov.uk)
69 https://www.legislation.gov.uk/nia/2022/31/enacted
70 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf
71 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-Path-Net-Zero-Energy-2023-Action-Plan.pdf
72 https://www.economy-ni.gov.uk/consultations/design-considerations-renewable-electricity-support-scheme-northern-ireland

In 2022, 43.5% of the total electricity requirement (TER) was met by renewable sources (based on sent out metering) in Northern Ireland, most of which was from wind power. Total and normalised wind generation for Northern Ireland is detailed in Figure 5.5. This normalised annual energy has grown from 1,259 GWh in 2013 to 2,781 GWh in 2022, accounting for constraints and curtailment.

SONI' projection of future renewable capacity growth is based on what would be required to achieve an 80% renewable ambition aligned to the DfE Energy strategy and ratcheting of the electricity target by the Northern Ireland Climate Change Act 2021; as published in the SOEF v1.1 report. The Northern Ireland Climate Action Plan due for publication in 2024 will set out a cumulative carbon budget for intervening years to at least 2030. Our projections do not consider the impact of any new carbon budgets. These assumptions are detailed in Figure 5.6.

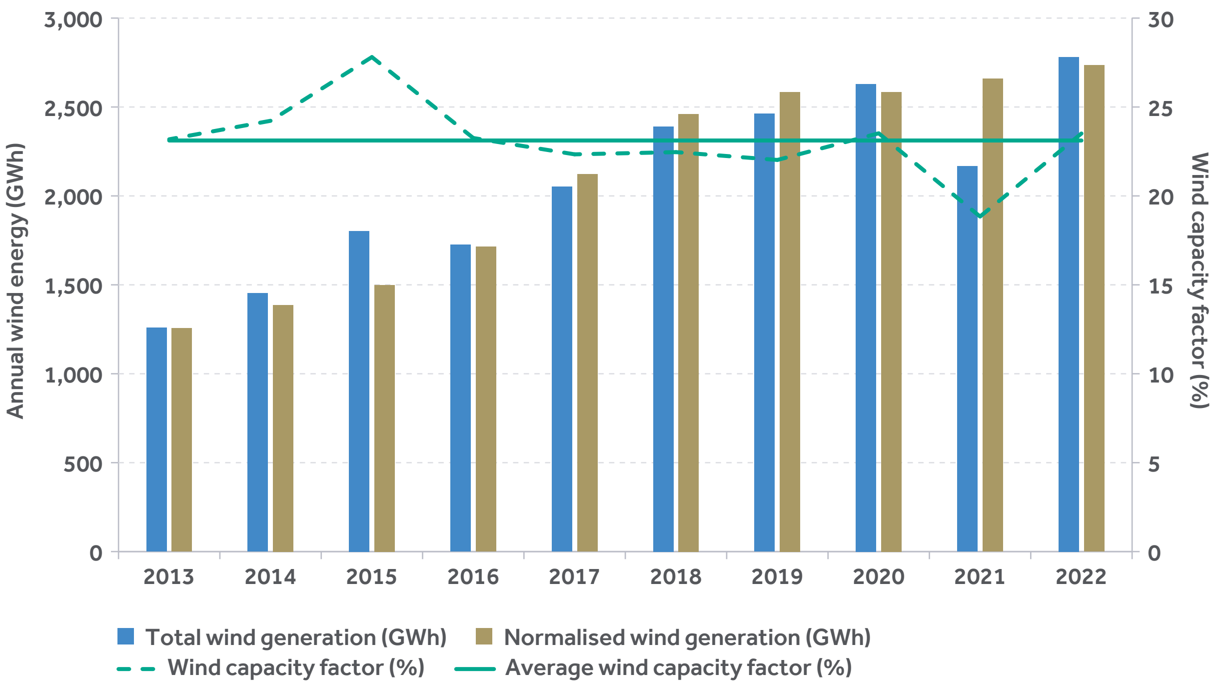


Figure 5.5: The actual and normalised energy produced from wind power in Northern Ireland over the last ten years

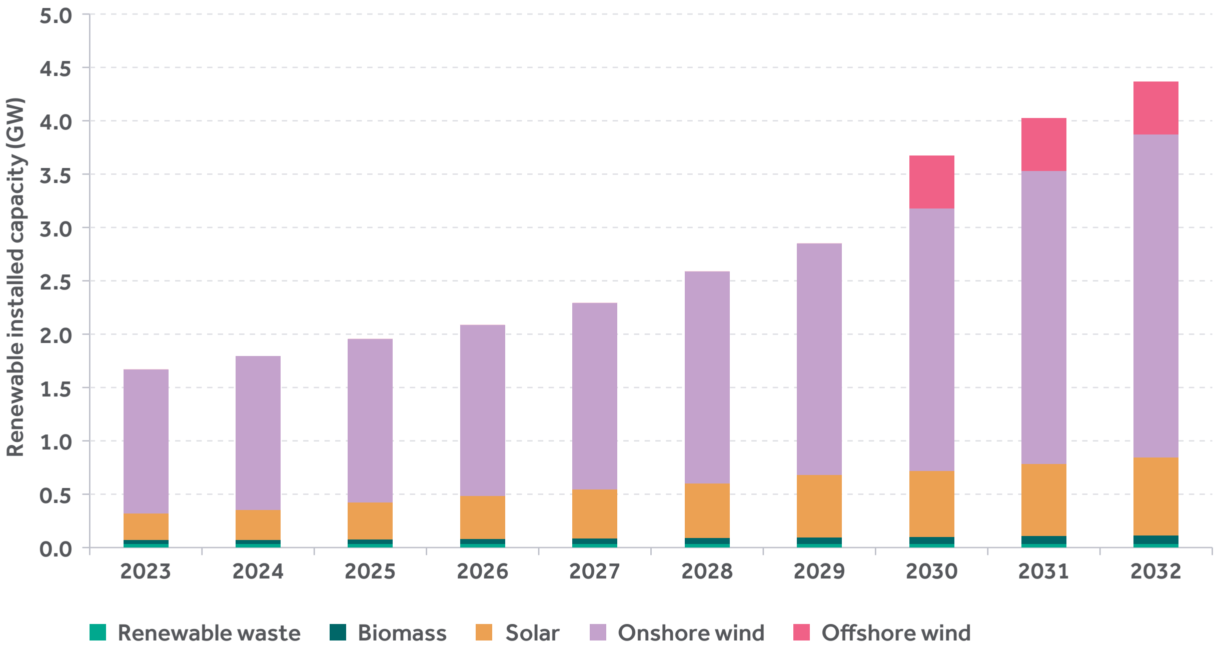


Figure 5.6: Assumed growth of renewable capacity in Northern Ireland

5.6.3 Solar PV

In Ireland, EirGrid has assumed the amount of solar PV will grow from approximately 1.1 GW today to 6.7 GW in 2032. The portfolio in Ireland contains significantly more solar than was assumed in last year's GCS 2022–2031 (1.7 GW in 2031) to deliver the 80% renewable generation targets. This aligns to the same central emissions SOEF v1.1 renewables portfolio as discussed in Section 5.6.1, and delivers 80% RES-E. There is an additional sensitivity included in the adequacy analysis (Section 6.3) where the ambitious CAP23 renewable targets including 8 GW of solar capacity by 2030 is achieved. This ambitious increase in the levels of solar generation is delivered both through grid scale solar projects coming through the RESS auctions and micro/mini solar generators being installed on domestic and commercial properties.

Northern Ireland has experienced a rapid growth in the capacity of solar PV. SONI currently estimates solar PV capacity at approximately 300 MW. For the purpose of this statement SONI has assumed capacity will grow to approximately 730 MW by 2032. SONI has based the future growth of renewable capacity on government targets as reported in SOEF v1.1, which targeted 80% RES-E.

Similar to the treatment of wind power, solar PV capacity is modelled in our adequacy assessments using a net demand methodology, as discussed in Section 5.7.

5.7 Modelling of non-conventional generation in adequacy studies

In this GCS 2023–2032, both wind and solar generation has been modelled using a 'net demand' methodology, whereby historic climatic and renewable generation data is used to create a half-hourly profile of available wind and solar energy in both Ireland and Northern Ireland. These half-hourly availabilities are scaled by the assumed installed capacities of each technology to create a time varying generation profile across the year for a given forecast year. Compared to the capacity credit approach used previously[73], this approach is deemed to better represent the residual demand that must be met by dispatchable power plants.

Whilst using the net demand approach does not have a significant impact on the adequacy surplus/deficit position, it does have an impact on the LOLE (Loss of Load Expectation) results presented in Section 6. Typically a lower LOLE value results as all of the variable renewable energy is available to serve the demand in the model. The figures below show the significant variability of these renewables using 2030 as an example. Figure 5.7 and Figure 5.8 show the varying contribution of solar (grid connected and small scale) on a summer's day compared to a winter's day. During winter, the contribution from solar is significantly less, and it will not contribute directly to adequacy at the time of peak demand (around 6pm). This trend has been noted in a number of other jurisdictions which have higher solar penetration values than Ireland, e.g., Germany.

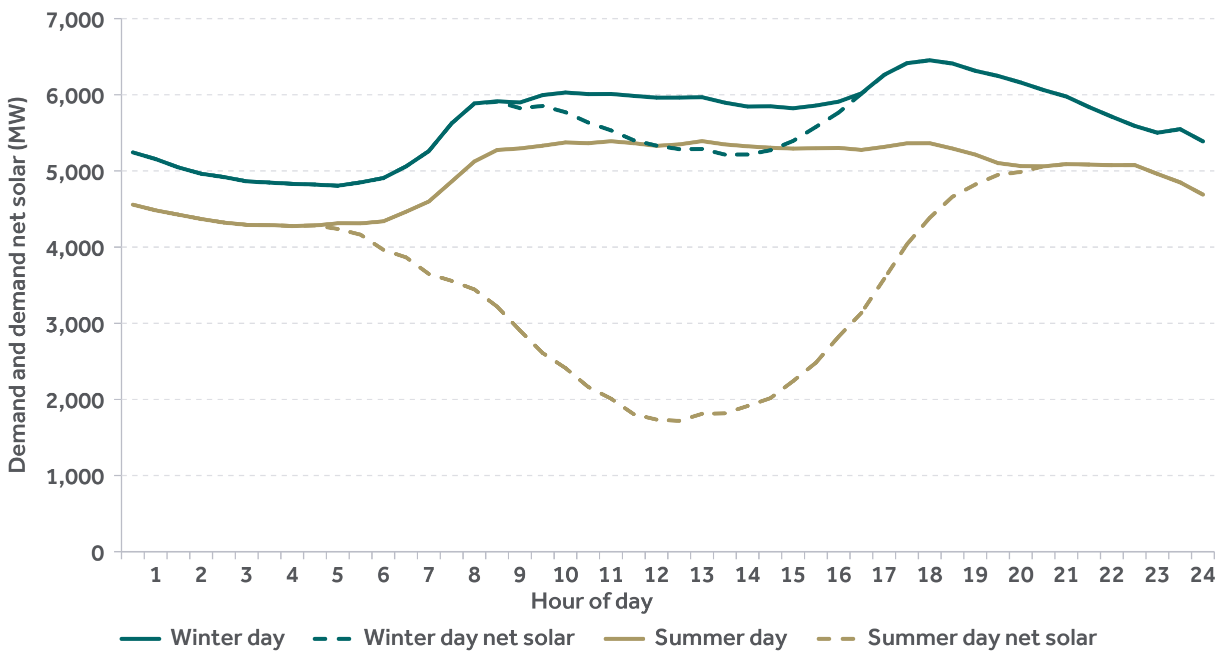


Figure 5.7: Impact of solar using net demand methodology in Ireland in 2030

73 The capacity credits were calculated based on profiles as the average capacity adequacy value for a range of installed renewable capacities.

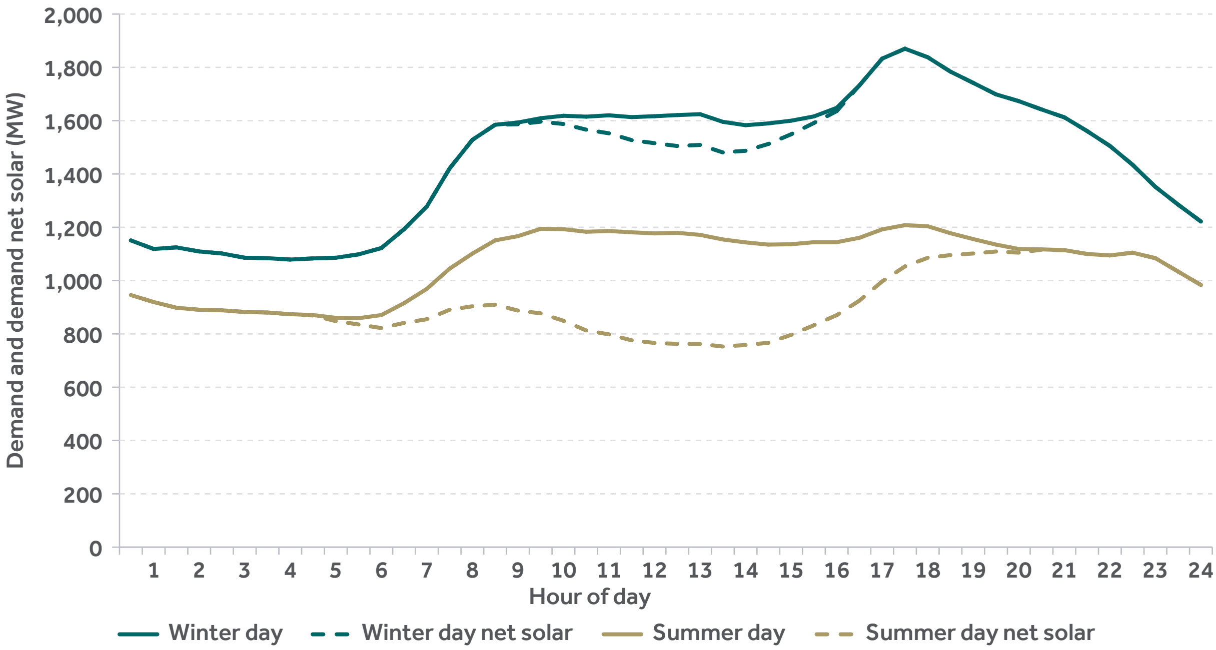


Figure 5.8: Impact of solar using net demand methodology in Northern Ireland in 2030

Figure 5.9 and Figure 5.10 show the impact of a day with very high wind output (a windy day with lots of renewable power), and relatively low wind output (a calm day with close to no wind power available).

On a day with very high wind output, the gold trend line shows that for the majority of the day, more wind is generated than the demand, and as such is limited by the System Non-Synchronous Penetration (SNSP) operational limits which are targeted to increase to 95% by 2030.

On an example day with lower wind output, there are time periods when wind provides very little power to change the shape of the net demand profile, on these days wind has less contribution to system adequacy. Figure 5.10 shows an example where the lowest wind period coincides with the highest demand in Northern Ireland.

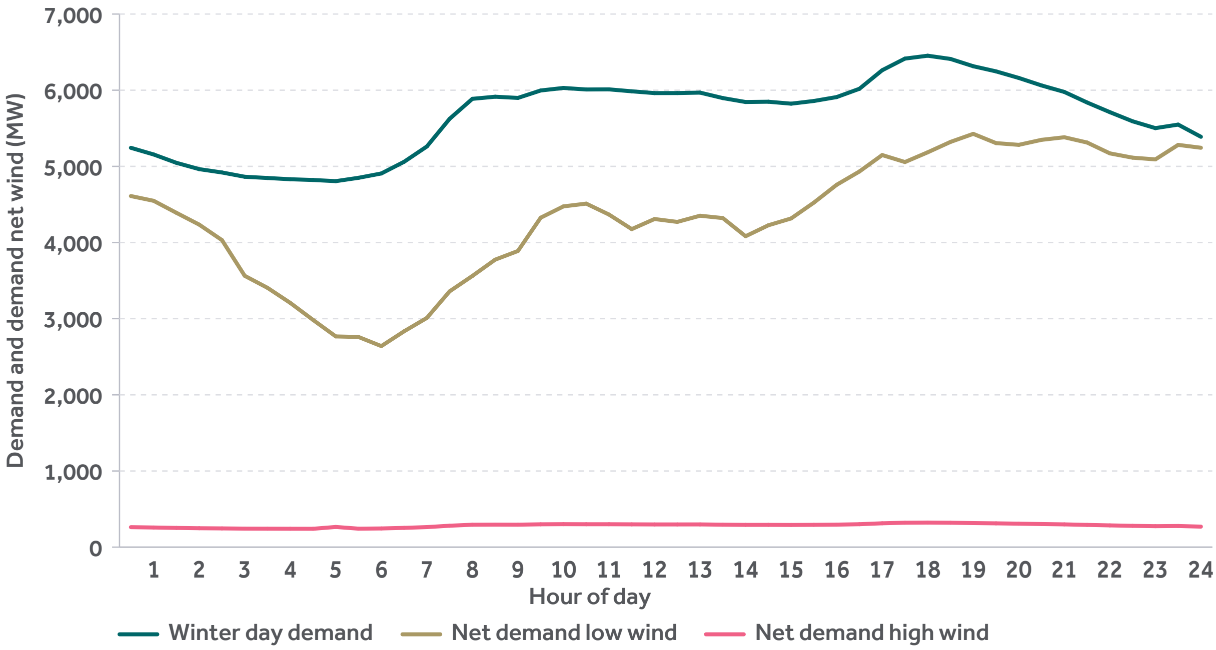


Figure 5.9: Impact of wind using net demand methodology in Ireland in 2030

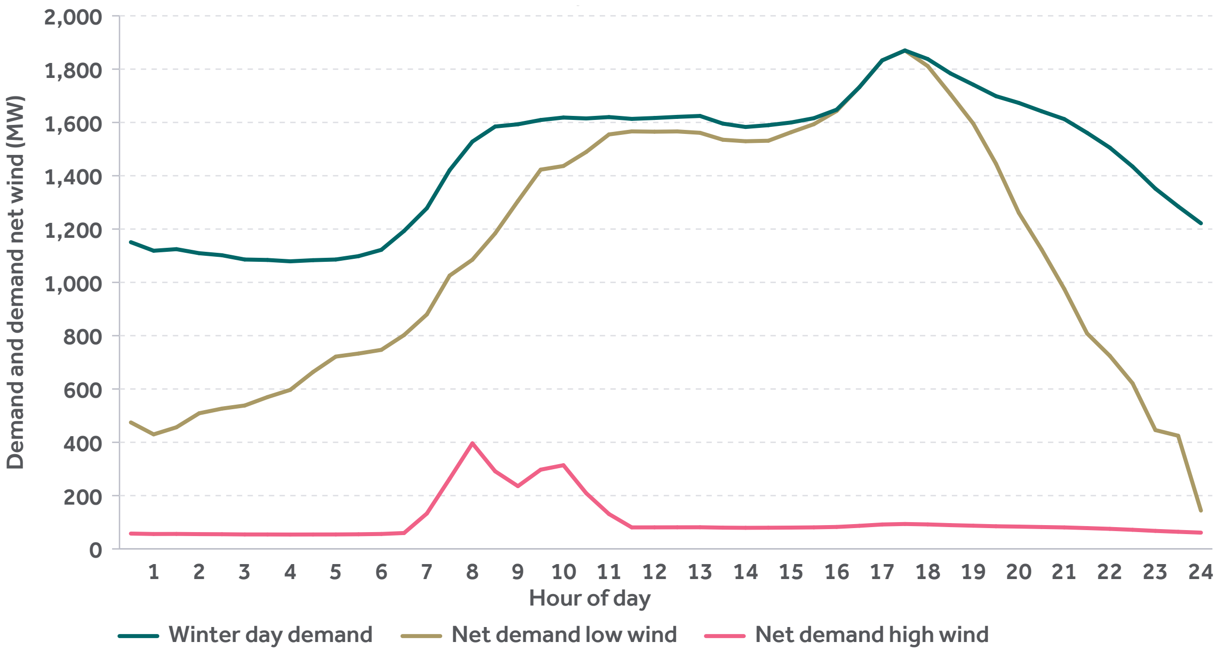


Figure 5.10: Impact of wind using net demand methodology in Northern Ireland in 2030

Interconnector modelling is based on a simplified methodology using de-rated capacity credits. In this adequacy study, EirGrid and SONI assume a 60% External Market de-rating (EMDF) aligned to the value used in the capacity market and outage statistics as indicated in Table 5.8. The de-rating values used in this study for interconnectors are as follows:

Table 5.8: Derating values used in AdCal studies

Technology	De-rating value across 2023–2032
Interconnectors	SEM <-> GB: 950 MWrated * 60% EMDF = 570 MW SEM <-> France: 700 MWrated * 60 %EMDF = 420 MW All Interconnectors are modelled with outage statistics as documented in Section 5.9

*Incorporates a 60% External Market De-Rating Factor (EMDF).

5.8 Other non-conventional generation

The assumed build-out of non-conventional generators is summarised in Appendix 4.

5.8.1 Demand Side Units (DSUs)

A DSU consists of one or more individual demand sites that can provide demand side flexibility that is able to be dispatched as if it were a generator. An individual demand site is typically a medium to large industrial premises. A DSU Aggregator can contract with a number of individual demand sites and aggregate them together to operate as a single DSU.

In the Capacity Market, DSUs typically are awarded 1-year contracts therefore the DSU capacity varies each year. Table 5.9 shows the DSU rated capacities assumed for the study horizon in Ireland and Northern Ireland. Note, the capacities from 2023 to 2027 are based on auction results. However, as auctions for the period 2028 onwards have yet to run, the studies use the 2027 value for the remainder of study horizon.

Table 5.9: Ireland and Northern Ireland DSU capacity (MW Rated)										
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Ireland	639	589	727	662	745	745	745	745	745	745
Northern Ireland	136	165	225	234	237	237	237	237	237	237
Total	**775**	**754**	**952**	**896**	**982**	**982**	**982**	**982**	**982**	**982**

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 (rated) in Ireland for the purposes of this report.

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 Northern Ireland, the total AGU capacity is 79 MW.

DSUs now form an increasing portion of the generation portfolio, therefore EirGrid and SONI will continue to engage with these capacity units to realise their full potential for contributing to system adequacy.

5.8.2 Energy storage

There are two key revenue mechanisms by which battery projects are incentivised to connect to the SEM: SEM Capacity Auctions and DS3 System Services. These routes to market offer different but essential services to the power system on the island of Ireland.

The aim of DS3 System Services is to incentivise investments in all forms of generation that can provide all-island services that ensure the power system can operate securely with higher levels of non-synchronous renewable generation (up to 75% instantaneous penetration today with 95% targeted in 2030).

Table 5.10 and Table 5.11 provide a summary of the total assumed generation and storage capacity of energy storage technology. They include pumped storage, batteries connected to the electricity system currently, and those that has been awarded contracts in the capacity auctions. Projects in the capacity market are offered either one or ten-year contracts, the table below takes this into consideration. As auctions for the period 2028 onwards have yet to run, these studies use the 2027 value for the remainder of study horizon.

The figures in Table 5.10 reflect the rated generation capacity of the storage technologies, whilst the figures in Table 5.11 reflect how much energy can be stored in each jurisdiction. In 2030, Ireland has 1300 MW of generation capacity attributed to storage technologies, and 3280 MWh of storage capacity, this means 1300 MW of generation can occur for just over two and a half hours. Across the study horizon, Northern Ireland has 200 MW of generation capacity attributable to storage technologies, and 140 MWh of storage capacity, this means 200 MW of generation can occur for 0.7 hours.

To enable storage to mitigate periods of low wind and solar output in the future, increasing the storage capacity (MWh), and therefore the duration of which the storage technologies can provide power to the grid is of significant importance.

Table 5.10: Total storage generation capacity (MW rated) assumed in studies for Ireland and Northern Ireland

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Ireland	870	1,020	1,100	1,140	1,300	1,300	1,300	1,300	1,300	1,300
Northern Ireland	200	200	200	200	200	200	200	200	200	200
Total	**1,070**	**1,220**	**1,300**	**1,340**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**

Table 5.11: Total energy storage capacity (MWh) assumed in studies for Ireland and Northern Ireland

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Ireland	2,090	2,390	2,630	2,720	3,280	3,280	3,280	3,280	3,280	3,280
Northern Ireland	140	140	140	140	140	140	140	140	140	140
Total	**2,230**	**2,530**	**2,770**	**2,860**	**3,420**	**3,420**	**3,420**	**3,420**	**3,420**	**3,420**

5.8.3 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 CO_2 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 statement, 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). For the purpose of this statement, SONI assumes the current assumption on small-scale CHP capacity does not change over the next 10 years.

5.8.4 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 2030. This unit was awarded planning permission to operate as a 100% biomass unit from 2024. This unit is currently operating on a mix of peat and biomass. EirGrid assumes the unit uses a biomass percentage of 65% in 2023, and 100% thereafter.

In the T-4 2026/2027 capacity auction, two units that are planning to initially run on Hydrogenated Vegetable Oil have been successful with a total derated capacity of 400 MW for a 10-year contract. These units are targeting delivery for the 2026/2027 capacity year.

Currently in Northern Ireland, SONI estimates there is 46 MW of small-scale generation powered by biofuels, including biomass, biogas and landfill gas. We have not been made aware 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.

5.8.5 Large and small-scale hydro

EirGrid estimates there is currently 26 MW[74] 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. A large-scale hydro project, with capacity 360 MW in Silvermines in County Tipperary, has been deemed a PCI project by the European Union[75]. This project has not been included in adequacy assessments as it is in the early stages of development however the project will be followed and included when appropriate.

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.

5.8.6 Waste-to-energy

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

- Dublin Waste to Energy plant – 61 MW.
- Indaver Waste to Energy plant – 17 MW.

The GCS 2023–2032 assumes a 50% renewable content, thus contributing to RES targets.

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.

5.8.7 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.

74 https://www.seai.ie/publications/2020-Renewable-Energy-in-Ireland-Report.pdf
75 https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.29.pdf

5.9 Plant availability

Outage statistics for this study align to the SEM Capacity Market Auction Requirements methodology[76]. They are determined at a technology class level using 5-year capacity weighted averages of forced and scheduled outage rates for all technology classes shown in Table 5.12.

Table 5.12: Summary of availability parameters used in the study

Technology category	Mean forced outage probability (%)	Mean scheduled outage rate (weeks)
DSU[77]	35.6%	14
Gas turbine	9.1%	3
Hydro	8.3%	3
Steam turbine	9.1%	4
Pumped storage	3.6%	3
System wide	9.1%	3
Interconnector	4.5%	2

Based on the data available since 2018 up to and including 2022, EirGrid and SONI have observed a continued decline of the all-island system 5-year average availability of thermal plant compared with the GCS 2022–2031, where declining plant availability was highlighted as a risk to system security.

DSU availability has continued to be low, and for this study, the TSOs have used historical availability statistics thereby ensuring the adequacy assessment uses data that is more representative of actual DSU performance. The higher outage statistics for DSUs are aligned to the updated and approved SEMC outage statistic methodology used for the capacity requirement process as part of the capacity market.

In last year's GCS 2022–2031, the 2019 outage statistics were applied to forecast availability of existing plants and a 5-year technology class average applied to new plants. This year, a 5-year average has been used for all generation to better align to the capacity market methodology. Historically, the adequacy calculation for the generation capacity statement has relied on 5-year run hour weighted technology class outage rates used in the most recent completed capacity auction. An update to the capacity market methodology has moved to utilising 5-year capacity weighted technology class outage rates. This updated approach provides a better valuation of capacity availability during periods of system stress.

76 https://www.semcommittee.com/sites/semc/files/media-files/ISAC2_SO_Con_paper.pdf
77 DSU Outage statistics utilise the self-reported outages published as part of the monthly generator availability reports. Recently the generator availability reports have moved to representing DSUs on the basis of availability rather than forced and scheduled outages as shown in Figure 5.14.

The outage statistics used in the GCS 2023–2032 adequacy studies are based on the capacity weighted 5-year average technology class outage rates from 2018 to 2022.

The historical data shows that retiring units tend to degrade the system average availability, so including the statistics of retiring plants in future years will negatively impact the assumed outage rates for other plant for a given class.

To account for this, units that are forecast to retire within the study period (2023–2032) are not included in the calculation of the 5-year average outage statistics shown in Table 5.12. These retiring units use a 5-year average based on unit level outage statistics.

Figure 5.11 shows system-wide availability for dispatchable generation capacity in Ireland and Northern Ireland which has been decreasing for the past number of years, reducing the generation fleet's ability to contribute to the operation of the power system.

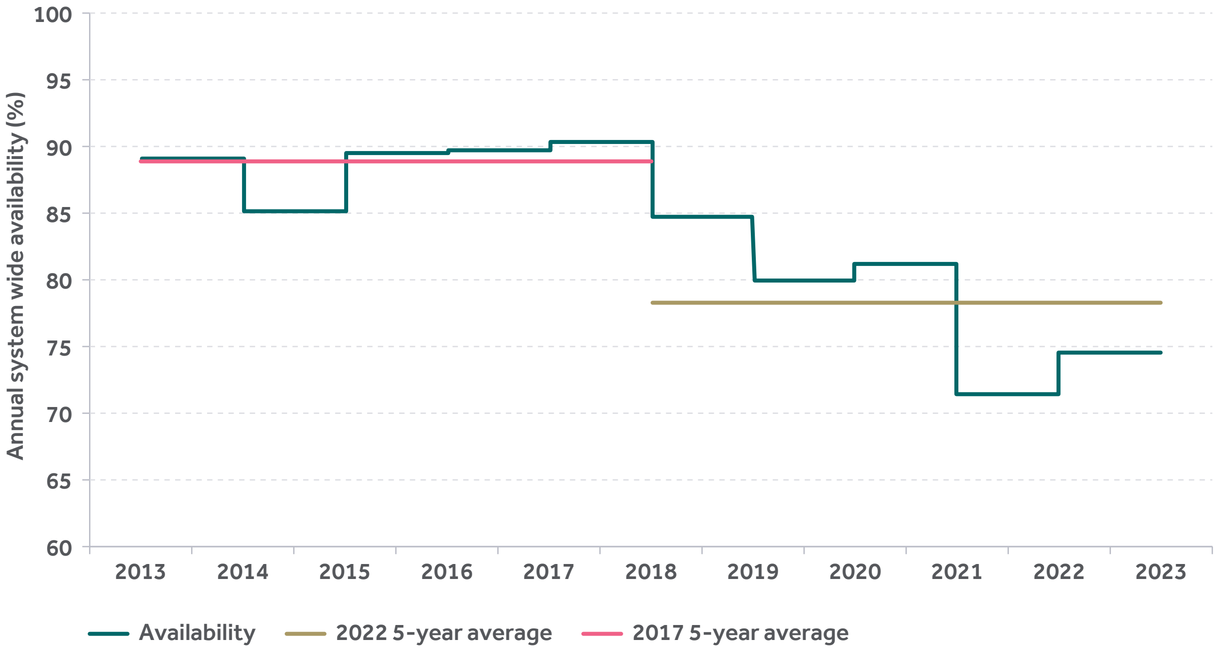


Figure 5.11: All-island average annual conventional generation capacity availability for the past 10 years (excluding DSU)

Forced Outage Rates have generally been increasing over the past number of years, contributing to the falling power plant availability. 2021 was a particularly poor year for plant performance in Ireland with two large units on forced outage for the majority of the year. These trends are displayed in Figure 5.12.

For comparison, the conventional generation capacity Forced Outage Rates for Northern Ireland are also increasing as shown in Figure 5.13. This increase is expected in line with the increasing age of the dispatchable generation portfolio in Northern Ireland.

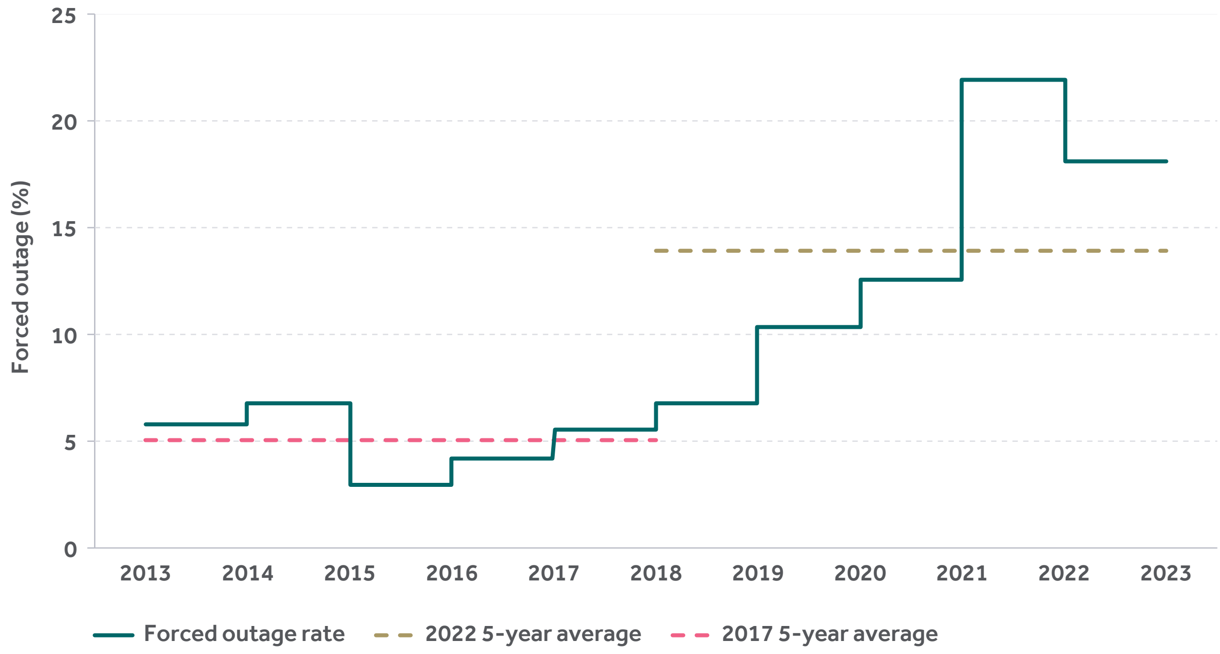


Figure 5.12: Average annual conventional generation capacity Forced Outage Rates in Ireland for the past 10 years (excluding DSU)

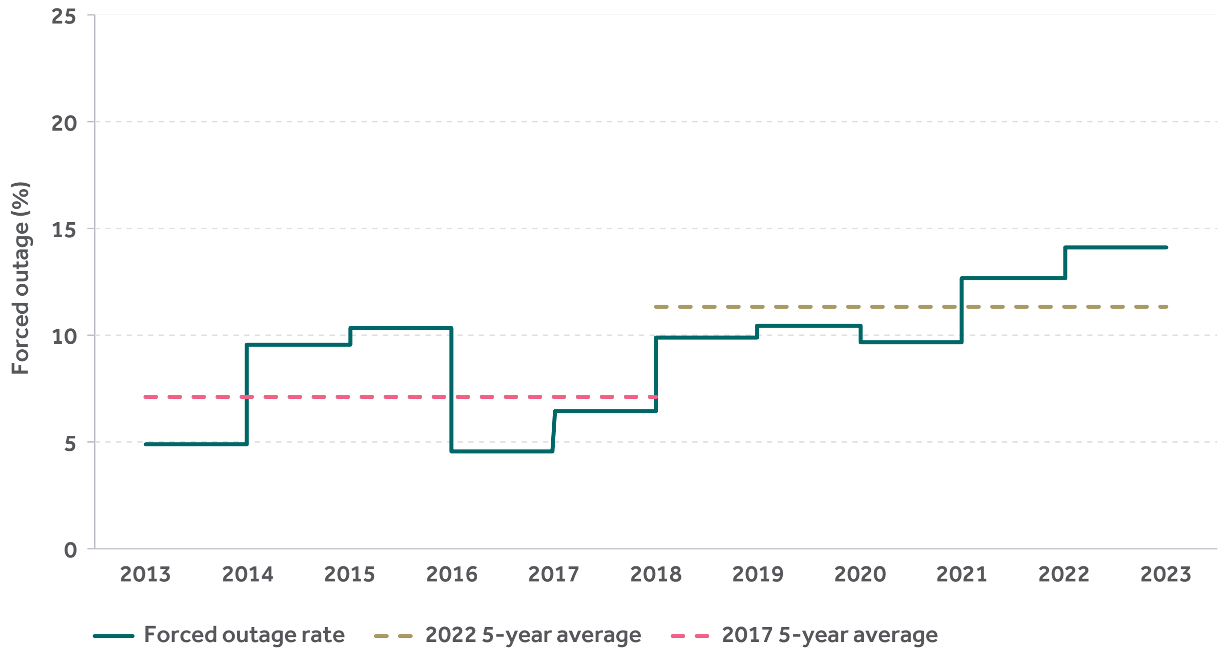


Figure 5.13: Average annual conventional generation capacity Forced Outage Rates in Northern Ireland for the past 10 years (excluding DSU)

In Ireland and Northern Ireland, on average, there has been a deterioration of unit availability over the last number of years. Whilst 2022 showed a slight improvement over 2021, the 5-year average availability for the GCS 2023–2032 is degraded compared to last year's position.

EirGrid and SONI have both observed a continued deterioration of conventional plant unit availability and this was particularly acute in Ireland across 2021, when two large units were forced offline for extended periods of time. Figure 5.14 shows the deteriorating availability trends across the last 5 years for Ireland and Northern Ireland.

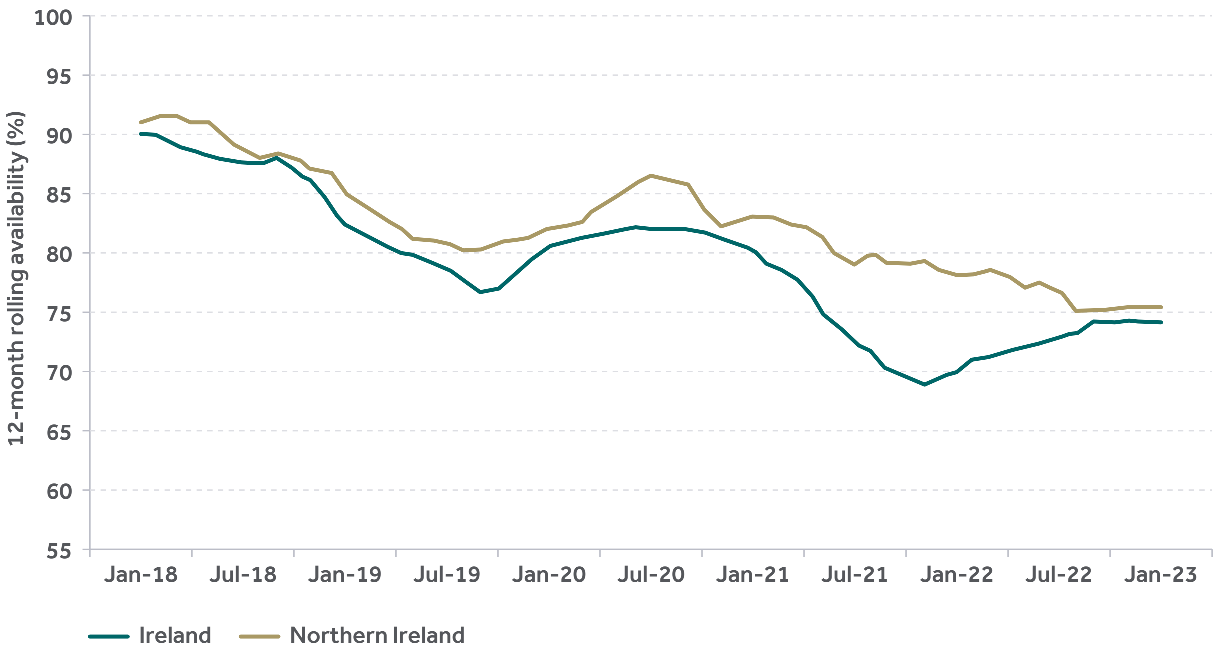


Figure 5.14: Ireland and Northern Ireland conventional generation capacity availability for the last 5 years (excluding DSU)

EirGrid and SONI have both observed a consistently low availability of Demand Side Units on an all-island basis, as shown in Figure 5.15. Demand Side Units are a significant portion of the dispatchable capacity in both Ireland and Northern Ireland, able to provide a net reduction in demand 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 availability of DSUs rather than the forced and scheduled outages is currently considered a more representative measure of their contribution to system adequacy. The monthly generator availability reports have moved to represent DSUs on this basis. This approach will be investigated for future studies as an alternative method of modelling once more data is available demonstrating the representative availability.

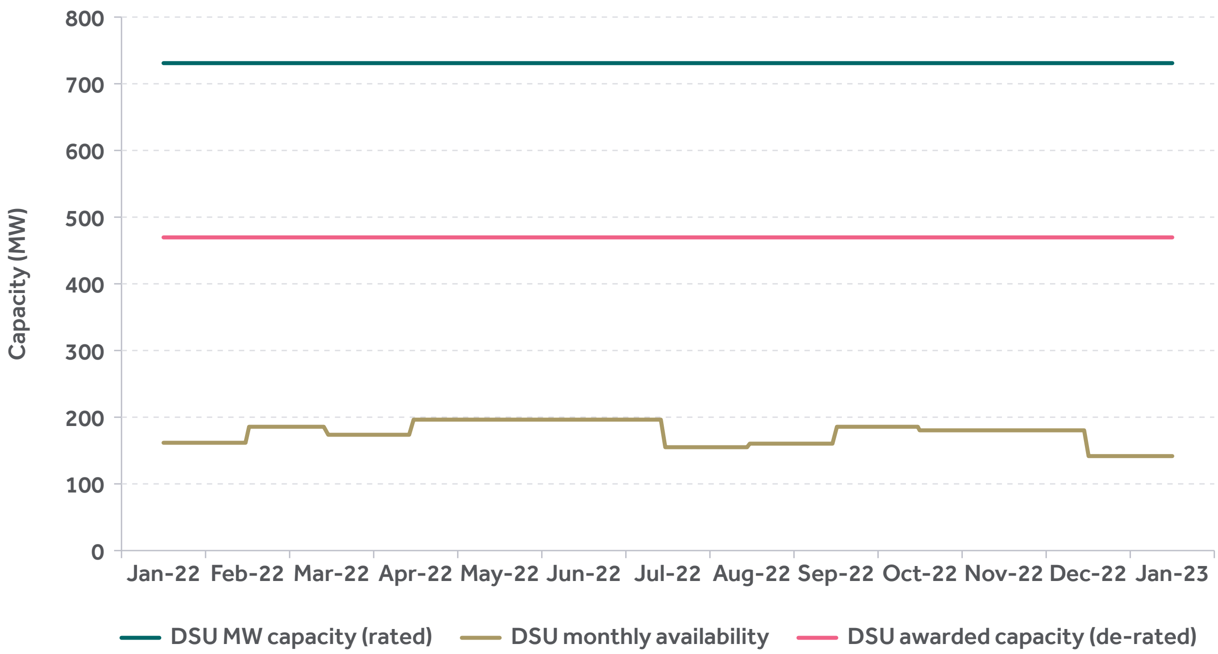


Figure 5.15: All-island demand side unit monthly availability for 2022 calendar year

6. Adequacy

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

6.1 Introduction

Under current EU legislation[78] 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. EU Member states have the responsibility to comply with the requirements of the EU Target Model, which is designed around forward, intra-day and balancing markets. In Ireland[79] and Northern Ireland[80], 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 and review this report. In Northern Ireland, the report is reviewed and approved by the Utility Regulator. 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[81].

The security standard is set as a number of hours of Loss of Load Expectation (LOLE) which 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 SEM as a whole, as well as separately for Ireland and Northern Ireland, using the following security standards:

- SEM: 8 hours LOLE.
- Ireland: 8 hours LOLE.
- Northern Ireland: 4.9 hours LOLE.

We study generation adequacy in order to assess the balance of supply and demand in the future. The assumptions made in the last two chapters for supply and demand are now brought together in our adequacy assessments. Detail on the methodology we employ is given in Appendix 6.

Studies are carried out in three different ways:

- For Ireland alone;
- For Northern Ireland alone; and
- For both jurisdictions combined, i.e., on an all-island basis.

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

In this section, we describe the setup of each scenario and present the results of the adequacy studies in graphical format. It is important to acknowledge the shifting nature of adequacy year-on-year. As a result, this document is updated annually.

The core scenarios of this year's GCS 2023–2032 take a pragmatic view and considers factors such as power plant availability, deliverability risks of new capacity becoming available on time, the impact of ARHL and need to ensure there is sufficient capacity to cover operational requirements. Sensitivities are utilised to understand the impact of factors that have higher levels of uncertainty.

6.2 Assumptions

In our adequacy studies, we assume the following:

- The adequacy standard is set at 8 hours LOLE per year for Ireland and in the all-island case. Ireland only study assumes a 100 MW capacity reliance on Northern Ireland.
- For Northern Ireland, the standard is 4.9 hours LOLE and assumes a 200 MW capacity reliance from Ireland.
- Interconnector modelling is based on a methodology using the same 60% external market derating factor for GB>SEM and France>IE, as approved by the SEM Committee[82] and forced and scheduled outages.
- The portfolio excludes generation capacity that has notified us that they will not be available.
- The portfolio excludes generation capacity that has a high likelihood of retirement based on an economic assessment of failing to qualify for a capacity auction.
- This study assessed capacity adequacy and does not model network related issues.
- DSU and battery modelling uses AdCal's energy limited modelling functionality, which models the effect of peak shaving from these technology types.
- Annual run hour limitations (ARHLs) are modelled on applicable[83] new plants that are expected to run in the market. Otherwise, ARHLs are not modelled on Open Cycle Gas Turbines which are normally used for replacement reserve to the system.

82 https://www.semcommittee.com/sites/semc/files/media-files/SEM-18-030a%20Appendix%20A%20TSO%20Capacity%20Requirement%20and%20De-rating%20Factors%20Methodology%20June%202018.pdf
83 Kilroot KGT6 and KTG7 Open Cycle Gas Turbines limited to 1500 hours as advised by the developer.

- Reserves are included as an operational requirement across all study years.
- For Ireland, 75% of the largest single infeed sets the reserve requirement. This amounts to 375 MW of reserve across all years, from 2025 EirGrid include an additional 350 MW transmission outage planning requirement; to facilitate outages needed to connect new generation and infrastructure to deliver on government 2030 renewable targets. In 2027, we assume the Celtic Interconnector becomes the largest single infeed resulting in a change to the reserve requirement increasing by 150 MW to 525 MW.
- In Northern Ireland, SONI assumes an operational requirement of 200 MW across all years.
- The adequacy results are given in MW as a surplus (+) or deficit (-) of perfect plant (plant that is 100% available).

6.2.1 Key assumption updates for GCS 2023–2032:

- The risk adjusted view of new plant deliverability has been updated to include the latest information as described in Section 5.2.1. Whilst the methodology of assessing deliverability is the same, latest data means some projects are now assumed to deliver earlier, some later, and some projects are no longer assumed to deliver.
- Generation from wind and solar is modelled utilising a net-demand methodology as outlined in Section 5.7. Previously a consistent capacity credit across the year was applied.
- Projected installed capacity of wind and solar generation is based on current installed capacities (inc. rooftop solar) with the initial build out based on projects in the RESS auctions. The build out beyond the RESS auction timing is based on an 80% RES-E portfolio in 2030. Previously, this was based on a 70% RES-E portfolio.
- Battery capacities installed on the system accounts for both projects that are currently connected, and projects that are expected to connect on the basis of the capacity market. Previously units that had not come through the capacity market were not included.
- The availability statistics for thermal generation units, demand side units, storage and interconnectors that are not retiring are based on 5-year capacity weighted technology class average. Previously, forecast statistics were calculated at a unit level on the basis of the 2019 performance, with only new plant having the 5-year average applied, and demand side units having a system wide average applied.
- Availability statistics for retiring plant do not contribute to the 5-year average for other plant on the system. For the retiring plant, their individual unit 5-year average availability is utilised. Previously the availability of retiring plant was included in the calculation of 5-year averages to be applied to future plant.

Changes post data freeze date

Ireland

As part of EirGrid's role in managing security of supply, EirGrid is continuously monitoring deliverability and progress of generation as well as trends in the latest demand data. Since the data freeze, a number of items have changed including:

- The closure notice for AT1 (due to close end of 2023) has been withdrawn.
- A Capacity Market Code modification is being evaluated to allow extension of the Interim Secondary Trading Arrangements (ISTA) to cover capacity that cannot operate for the whole Capacity Year but could still make an important contribution to security of supply. Capacity that had been awarded but can no longer operate in the CRM will be expected to enter into an appropriate Interim Secondary Trade.
- Seven projects have submitted termination notices totalling 47 MW. Two of these projects (22 MW) had 10-year contracts.
- The T-1 2023/2024 capacity market auction has run with provisional results indicating 345 MW of successful new capacity across Ireland and Northern Ireland.
- Latest Data from ESB showing the total energy sales to distribution connected customers have been provided. This data shows a slightly less growth than was estimated in this study, however the trends are similar.

These impacts were not captured in the GCS 2023–2032; however they are being monitored as part of the ongoing security of supply work with the Commission for Regulation of Utilities (CRU) and the Department for the Environment, Climate and Communications.

Northern Ireland

As part of SONI's role in managing security of supply, SONI is continuously monitoring deliverability and progress of generation as well as trends in the latest demand data. Since the data freeze, an increased level of risk regarding the delivery of the steam turbine at the Kilroot site by the long stop date has been identified. The sensitivity below reflects the position if this capacity fails to deliver.

In addition, since the data freeze date, the T-1 2023/2024 capacity market auction has run with provisional results indicating 345 MW of successful new capacity across Ireland and Northern Ireland.

Sensitivity of surplus/deficit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SEM CRM Generation T-4 2025/2026 Auction Kilroot not delivered	-30	-110	-240	-150	-200	-200	-210	-210	-230	-260

6.3 Adequacy results for Ireland

The adequacy assessment of Ireland system shows an initial deficit position in all of the core scenarios with the median and high scenario remains in deficit over the study horizon (this is prior to the security of supply mitigating measures such as temporary emergency generation as described in Section 6.3.1).

The median demand scenario is a central scenario that EirGrid use to plan the future electricity system needs. Taking this scenario as a reference we observe the most significant capacity deficits in 2025 and 2026. These shortfalls are driven by insufficient capacity being delivered which is needed to replace existing generation plant leaving the system and to supply the expected strong growth in demand. Across all scenarios, 2025 shows the greatest deficit.

From 2026 to 2028, a decrease in the deficit is forecast as new capacity units are expected to connect to the system, but the deficit remains significant. The benefit of this new capacity is somewhat tempered by the increasing demand (average of 130 MW/year in the median scenario between 2026–2032). It should be noted that a future T-4 capacity auction will run in September 2023[84] and will aim to procure generation capacity for October 2027. Further new capacity will be procured as part of this auction, which would further reduce the deficit towards the end of the decade.

In 2027, the energisation of the Celtic Interconnector reduces the deficit further. Beyond 2028, the deficits increase each year due to the increasing demand. The results are provided in Table 6.1. The core scenario trends can be seen in Figure 6.1.

As with the previous GCS study, for GCS 2023–2032, as part of the reliability assessment, EirGrid has factored in the realities in the operation of the transmission system to cater for operational requirements such as reserve. For Ireland this reserve requirement is 375 MW until the end of 2026, then increasing to 525 MW. A transmission outage planning requirement of 350 MW is included from 2025 across the remainder of the study period. For Ireland the total operational requirement by 2032 is 875 MW. As noted earlier, the median scenario provides a view of what is required to support Ireland's transition to low carbon economy and low emissions power sector, and therefore includes an adjustment for transmission outage planning. To this end, EirGrid has carried out a number of sensitivity studies on the median demand scenario.

The first sensitivity shows the impact of assuming no capacity support from Northern Ireland. Typically, this is assumed to be 100 MW in all scenarios. As the margins in both jurisdictions are becoming tighter, there is a possibility that this support through the existing North-South Interconnector may not be available.

The second sensitivity assesses the impact of delivering the highly ambitious CAP23 renewable targets, with a renewable rollout trajectory aligned to the low emissions scenario in SOEF v1.1. This reduces the deficit across the study horizon with a benefit of between 20 MW and 140 MW depending on the year. However, the system remains in significant deficit for the duration of the study.

84 https://www.sem-o.com/documents/general-publications/CAT2728T-4-2027-2028-T-4-Capacity-Auction-Timetable.pdf

A further sensitivity shows the impact of all new capacity that has been successful in the auction being delivered on time. It is worth stating that 10-year capacity contracts have an 18-month long stop which means that delivery can be up to 18 months after commencement of the capacity year. In this scenario it can be observed that deficits start to reduce a year earlier in 2025; the deficit is reduced by 1700 MW in 2027 resulting in a surplus capacity for the remainder of the study. These sensitivities indicate either late delivery of capacity or the application of ARHL will require additional measures to reduce deficits. These measures are outside the scope of this report.

As the system is in adequacy deficit, there is a greater loss of load expectation (LOLE) than the reliability standard of 8 hours. The LOLE for the median scenario is presented in Table 6.2.

Note the results here do not give a sense of the scale or duration of the LOLE as this is calculated cumulatively across each hour of the year. A full description of the LOLE methodology is outlined in Appendix 5. An improvement to the modelling methodology regarding renewable generation as described in Section 5.7 has had a substantial impact on the forecast LOLE in this year's GCS, which is notably lower than the previous publication.

In Table 6.2, the LOLE results with and without the operational requirements are presented. Including the operational requirements represents the time at which the system is running at risk and is therefore not considered reliable. The LOLE results without the operational requirements indicate the number of hours that a loss of load is expected to occur.

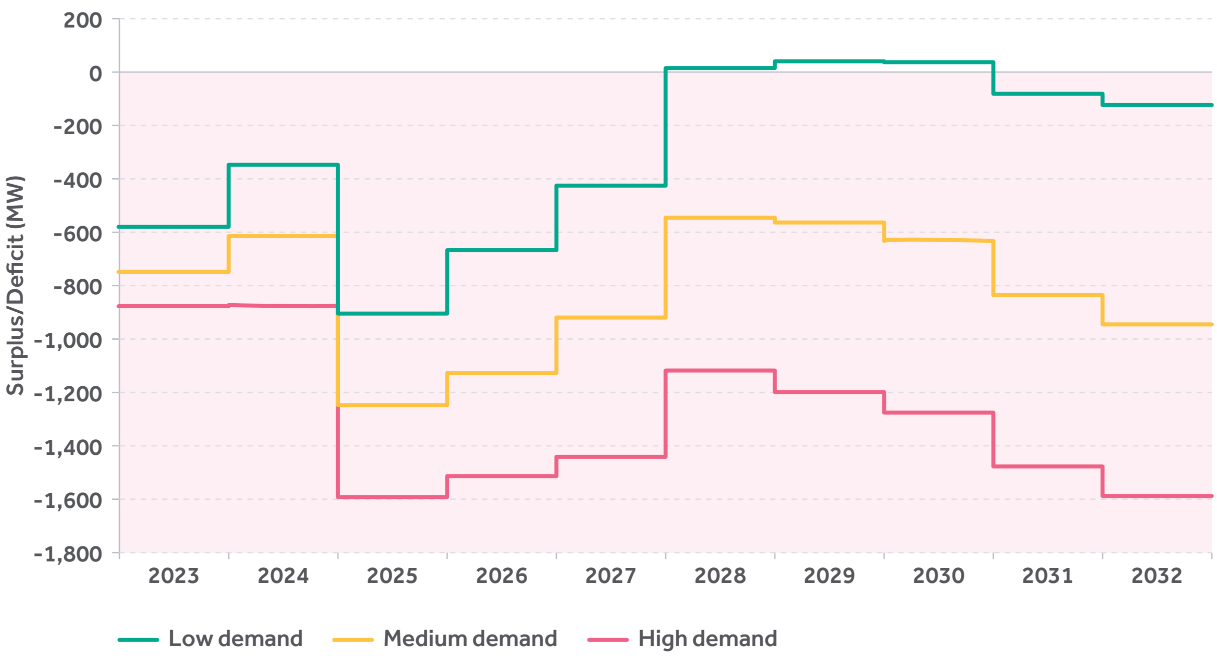


Figure 6.1: Core scenario adequacy analysis for Ireland in terms of surplus (+) and deficit (-) of plant

Table 6.1: Results of adequacy studies for Ireland given in MW of surplus plant (+) or deficit (-)

Core scenarios	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low demand	-580	-350	-900	-670	-430	10	40	40	-80	-120
Median demand	-750	-610	-1,250	-1,130	-920	-550	-560	-630	-840	-950
High demand	-880	-870	-1,590	-1,510	-1,440	-1,120	-1,200	-1,280	-1,480	-1,590
Sensitivities on median demand										
No NS availability	-850	-710	-1,350	-1,230	-1,020	-650	-660	-730	-940	-1,050
SOEF v1.1 low emissions scenario RES trajectory	-730	-560	-1,130	-1,030	-800	-410	-460	-530	-740	-860
All new units delivering on time	-750	-690	-460	-430	780	710	670	600	410	310

Table 6.2: Loss of Load Expectation (LOLE) in hours for Ireland in the median scenario

Hours	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LOLE including demand and operational requirements (hours)	174	102	728	474	252	70	70	83	140	175
LOLE demand only (hours)	52	29	303	188	52	11	12	15	32	46

Previous reported LOLE included operational requirements.

6.3.1 Mitigating measures

EirGrid notes that the results presented above do not include any of the mitigating measures identified as part of the CRU Security of Supply Programme; this includes delivery of temporary generation, additional demand side response or retention of existing units. The CRU Information Paper Security of Electricity Supply – Programme of Actions[85] latest publication from February 2023 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), published by the CRU on 31 May 2023[86].

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 6.2, some of the measures are temporary in nature and are not included in the central analysis, as otherwise it would not send a clear signal to the energy ecosystem that permanent capacity is needed.

85 https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU202317_Electricity_Security_of_Supply_Programme_of_Work_Update_February_2023.pdf
86 https://www.cru.ie/publications/27519/

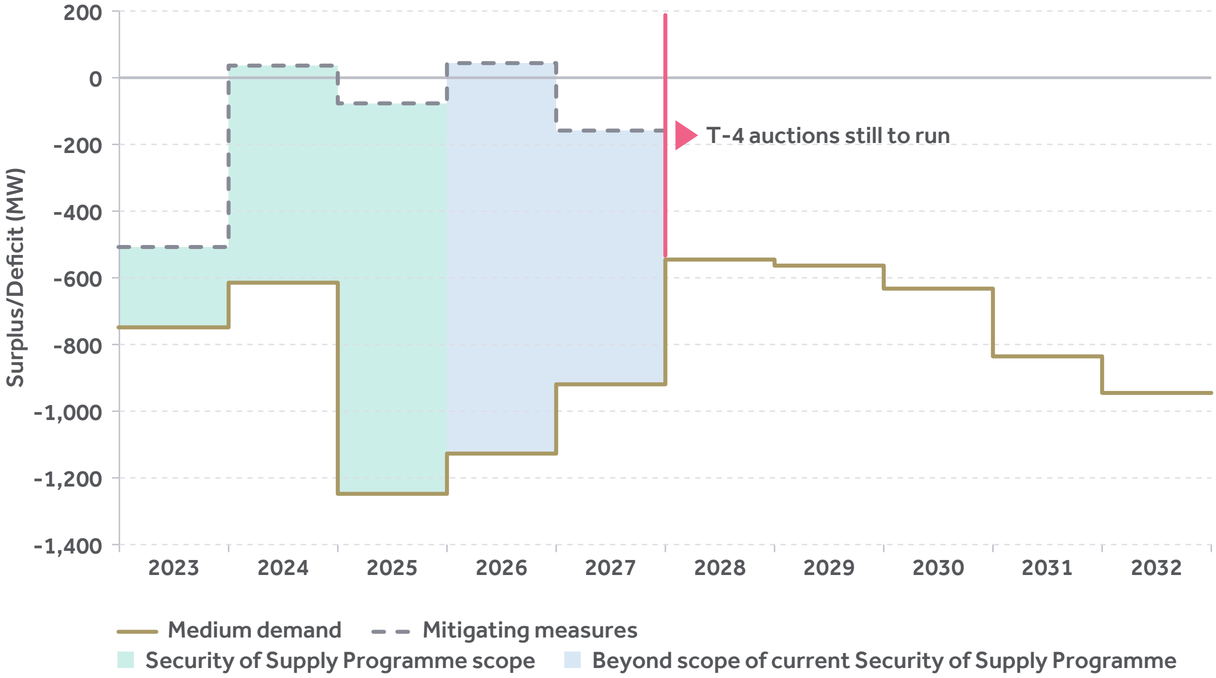


Figure 6.2: Ireland adequacy position with mitigating measures

6.4 Adequacy results for Northern Ireland

The adequacy assessment of the Northern Ireland system shows a deficit in the median scenario from 2023 until the end of 2026. From 2027, all the core scenarios are in surplus for the remainder of the study horizon. Figure 6.3 shows a graphical representation of the adequacy studies' results for Northern Ireland over the ten years of the study.

The median demand scenario inclusive of operational requirements is shown to be in deficit in 2023 against the 4.9-hour LOLE standard. This is a reduction compared to the GCS 2022–2031 due to deteriorating plant performance and the modelling of the delivery of the new KGT6 and KGT7 Open Cycle Gas Turbines which are assumed to be available from the beginning of 2024 with the existing coal/oil fired capacity expected to close by the end of September 2023.

The LOLE increases and the capacity outlook drops further into deficit in 2024, 2025 and 2026 with the closure of coal/oil fired generation, the planned outages of KGT1-4, and the new OCGTs with ARHL of 1,500 hours on average per annum.

In 2027, the outlook returns to a surplus of approximately 400 MW for the remaining years of the study. This is because in the T-4 2025/2026 capacity auction a steam turbine was successful. Based on discussions with the developer this will be utilised as part of a CCGT arrangement whereby it would utilise waste heat from the new KGT6 and KGT7 Open Cycle Gas Turbines. The developer is currently working through the design of the system, however, since the capacity was cleared as part of a CCGT arrangement, SONI has assumed the new capacity will remove all ARHL associated with KGT6 and KGT7.

It is expected that the generation that was successful in the T-4 2025/2026 capacity auction will become available from the start of 2027. This is based on the best available information to the TSO at the time of the data freeze. Any delays to this new capacity will significantly impact negatively on capacity adequacy in Northern Ireland.

There are existing operational measures in place to manage the transmission system when the balance of demand and generation is not adequate. SONI are working closely with DFE and UR to review these operational measures for a range of potential scenarios in the future.

Furthermore, we assume once the CCGT is in place from 2027 that all run hour restrictions are removed. This is based on information from the developer. For GCS 2023–2032, as part of the reliability assessment, SONI has factored in the realities in the operation of the transmission system to cater for operational requirements such as reserve. For Northern Ireland this reserve requirement is 200 MW.

SONI has completed a range of adequacy scenarios studies to assess the risk to security of supply in Northern Ireland. The studies presented provide an indication of Northern Ireland's adequacy position based on a range of credible scenarios:

1. Loss of tie-line support from Ireland. In this scenario the assumed contribution of 200 MW from Ireland is removed.
2. A scenario assuming loss of tie-line support from Ireland with the average annual 1500 running hour restriction on the new Kilroot capacity not removed in 2027.
3. A scenario assuming new generation from the SEM CRM auctions is delivered on time in the median demand scenario.
4. A scenario assuming that annual run hour limitations are not applied to KGT6 or KGT7.

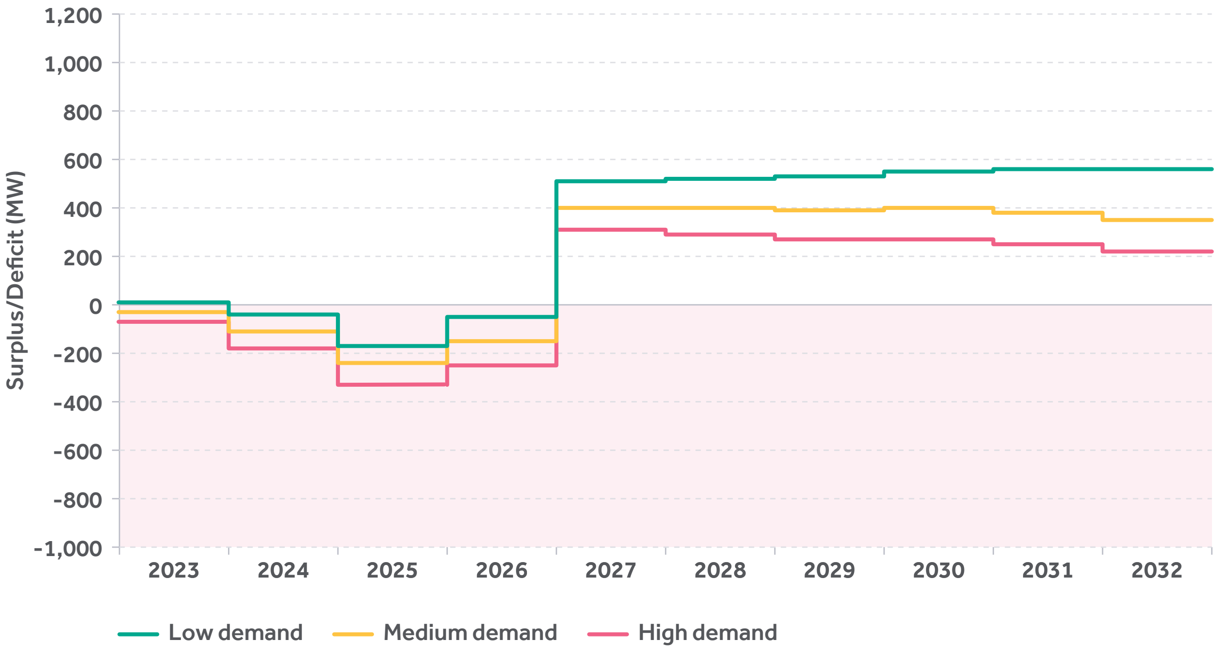


Figure 6.3: Adequacy results for Northern Ireland, in terms of surplus (+) or deficit (-) of plant (MW)

In Table 6.4, the LOLE results with and without the operational requirements are presented. The results with the operational requirements included can be compared to the reliability standard set for the TSO to adhere to. Including the operational requirements represents the time at which the system is running at risk and is therefore not considered reliable. The LOLE results for demand only indicate the number of hours that a loss of load is expected to occur.

6.4.1 Mitigating measures

SONI is working closely with the Department for the Economy, the Utility Regulator and other energy industry partners to put in place a range of robust, tried-and-tested mitigation measures to manage they challenges to security of supply should they arise. These plans include maximising existing generation availability, including the use of smaller, more responsive, open-cycle gas turbines, utilising new technologies such as batteries and maximising the availability of imports from Great Britain and the Republic of Ireland. We will continue to work with partners and the generator to accelerate the delivery of the two new turbines at Kilroot.

Table 6.3: Results of adequacy studies for Northern Ireland, given in ME of surplus plant (+) or deficit (-)

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low demand	10	-40	-170	-50	510	520	530	550	560	560
Median demand	-30	-110	-240	-150	400	400	390	400	380	350
High demand	-70	-180	-330	-250	310	290	270	270	250	220
Sensitivities on median demand										
1. No NS reliance	-230	-310	-440	-350	200	200	190	200	180	150
2. No NS reliance & ARHL from 2027	-230	-310	-440	-350	-360	-360	-370	-360	-380	-420
3. ST delivery from 2026	-30	-110	-240	440	400	400	390	400	380	350
4. No ARHL	-30	270	130	220	400	400	390	400	380	350

Table 6.4: Results of adequacy studies for Northern Ireland, given in hours of LOLE

LOLE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LOLE including demand and operational requirements (hours)[87]	6.5	15.7	50.4	21.5	0.2	0.2	0.2	0.2	0.2	0.3
LOLE demand only (hours)	1.2	3.2	12.8	4.8	0	0	0	0	0	0
Previous reported LOLE included operational requirements.										

87 From 2027, the system is in surplus to the 4.9 hour LOLE standard, however there remains a small amount of LOLE

6.5 Adequacy results for the All-island system

Adequacy studies are carried out on an all-island basis, which assumes that the second North-South Interconnector is commissioned by end of 2025 and become fully operational by 2026.

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. Figure 6.4 and Table 6.5 show the all-island adequacy results for the core scenarios. The benefit from the Celtic Interconnector is seen from 2027. From 2028 onwards, the changes in adequacy position are driven primarily by the demand changes. Table 6.6 shows the LOLE for the study horizon.

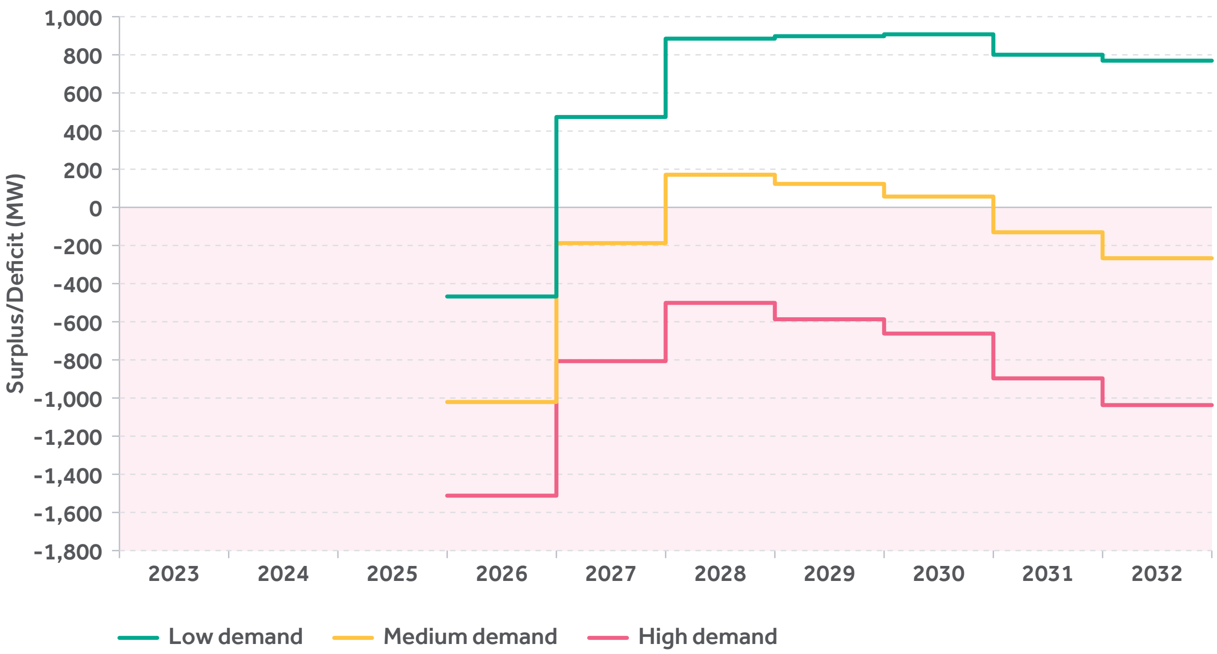


Figure 6.4: Adequacy results for the all-island system

Table 6.5: Results of adequacy studies for the all-island system (MW)

Scenario	2026	2027	2028	2029	2030	2031	2032
Low demand	-470	470	890	900	900	800	770
Median demand	-1,020	-190	170	120	60	-130	-270
High demand	-1,510	-780	-430	-510	-590	-820	-960

Table 6.6: Loss of Load Expectation (LOLE) for all-island system (hours)

LOLE	2026	2027	2028	2029	2030	2031	2032
LOLE including demand and operational requirements (hours)	285	12	3	3	5	10	15
LOLE demand only (hours)	17	0	0	0	0	0	0

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

Median	Calendar year TER (TWh)[88]						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						
2022	33.3		8.35		41.7		5.60	1.65	7.02	5.47	1.62	6.86
2023	34.9	4.8%	8.41	1.1%	43.3	3.8%	5.87	1.59	7.38	5.74	1.56	7.21
2024	36.5	4.6%	8.62	2.5%	45.1	4.2%	6.03	1.64	7.59	5.90	1.60	7.43
2025	38.0	4.1%	8.88	3.0%	46.9	4.0%	6.19	1.68	7.8	6.07	1.64	7.64
2026	39.6	4.2%	9.16	3.2%	48.8	4.1%	6.37	1.72	8.02	6.25	1.68	7.87
2027	41.0	3.5%	9.66	5.5%	50.7	3.9%	6.51	1.79	8.22	6.38	1.75	8.06
2028	42.3	3.2%	9.80	1.4%	52.1	2.8%	6.62	1.81	8.35	6.49	1.78	8.19
2029	43.5	2.8%	9.98	1.8%	53.5	2.7%	6.72	1.84	8.48	6.59	1.80	8.31
2030	44.7	2.8%	10.17	1.9%	54.9	2.6%	6.85	1.87	8.64	6.72	1.83	8.47
2031	46.2	3.4%	10.43	2.6%	56.6	3.1%	7.01	1.89	8.82	6.88	1.85	8.65
2032	47.6	3.0%	10.76	3.2%	58.4	3.2%	7.17	1.94	9.03	7.04	1.9	8.87

88 Note 2022 data for Ireland, and subsequently all-island consists of some assumed data as accurate figures were not available at time of data freeze.

Table A1-2

Low	Calendar year TER (TWh)[89]						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						
2022	33.3		8.35		41.7		5.60	1.65	7.02	5.47	1.62	6.86
2023	34.3	3.0%	8.12	-2.8%	42.4	1.7%	5.61	1.53	7.07	5.48	1.49	6.90
2024	34.9	1.7%	8.15	0.4%	43.1	1.7%	5.66	1.53	7.12	5.53	1.49	6.96
2025	35.6	2.0%	8.35	2.5%	44.0	2.1%	5.70	1.55	7.19	5.58	1.52	7.03
2026	36.2	1.7%	8.51	1.9%	44.7	1.6%	5.77	1.57	7.27	5.65	1.54	7.12
2027	37.1	2.5%	8.67	1.9%	45.8	2.5%	5.85	1.63	7.41	5.72	1.60	7.25
2028	37.8	1.9%	8.74	0.8%	46.5	1.5%	5.89	1.64	7.46	5.76	1.61	7.30
2029	38.5	1.9%	8.81	0.8%	47.3	1.7%	5.92	1.66	7.51	5.79	1.62	7.34
2030	39.2	1.8%	8.90	1.0%	48.1	1.7%	5.98	1.68	7.59	5.85	1.64	7.42
2031	40.0	2.0%	8.90	0.0%	48.9	1.7%	6.06	1.68	7.67	5.93	1.64	7.50
2032	40.9	2.3%	8.90	0.0%	49.8	1.8%	6.14	1.68	7.76	6.02	1.64	7.60

89 Note 2022 data for Ireland, and subsequently all-island consists of some assumed data as accurate figures were not available at time of data freeze.

Table A1-3													
High	**Calendar year TER (TWh)[90]**						**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**						
2022	33.4		8.35		41.8		5.6	1.65	7.02	5.47	1.62	6.86
2023	35.3	5.7%	8.52	2.0%	43.8	4.8%	6.06	1.68	7.66	5.93	1.64	7.49
2024	37.9	7.4%	8.92	4.7%	46.8	6.8%	6.37	1.76	7.97	6.24	1.72	7.81
2025	40.4	6.6%	9.38	5.2%	49.8	6.4%	6.61	1.82	8.27	6.49	1.78	8.11
2026	42.6	5.4%	9.77	4.2%	52.4	5.2%	6.87	1.89	8.58	6.75	1.85	8.43
2027	44.9	5.4%	10.42	6.7%	55.3	5.5%	7.13	1.9	8.95	7.01	1.87	8.79
2028	46.9	4.5%	10.66	2.3%	57.6	4.2%	7.3	1.94	9.16	7.17	1.9	9
2029	48.4	3.2%	10.96	2.8%	59.4	3.1%	7.43	1.99	9.34	7.31	1.95	9.17
2030	49.8	2.9%	11.26	2.7%	61.1	2.9%	7.58	2.03	9.52	7.45	1.99	9.35
2031	51.3	3.0%	11.49	2.0%	62.8	2.8%	7.75	2.06	9.73	7.63	2.03	9.56
2032	52.9	3.1%	11.81	2.8%	64.7	3.0%	7.93	2.11	9.96	7.81	2.07	9.8

90 Note 2022 data for Ireland, and subsequently all-island consists of some assumed data as accurate figures were not available at time of data freeze.

Appendix 2: Demand profile methodology

To create future demand profiles for the adequacy studies, it is necessary to use an appropriate base year profile which provides a representative demand profile of both jurisdictions.

This profile is then progressively scaled up using forecasts of energy peak and demand. Similar to the methodology employed in the Capacity Market auction calculations, we have used a number of base year profiles, carried out a number of adequacy studies separately, and then taken an average of the results. The profile year that gave the closest result to this average was then used for subsequent adequacy studies. This avoids any bias that might ensue if only one atypical year were used.

To reflect different segments of demand, additional forecast industrial and data-centre type demand is grown separately using a profile appropriate to its expected usage, i.e., flat demand profile. Remaining additional demand is grown proportionally using historical demand profiles.

The choice for load profiling is a matter for continual review.

Electricity usage generally follows some predictable patterns. For example, the peak demand typically occurs during winter weekday evenings while minimum usage typically occurs during summer weekend night-time hours. Peak demand during summer months occurs much earlier in the day than it does in the winter period.

Figure A2-1 shows typical daily demand profiles for a winter weekday. Many factors impact on this electricity usage pattern throughout the year. Examples include weather, sporting or social events, holidays, and customer demand management.

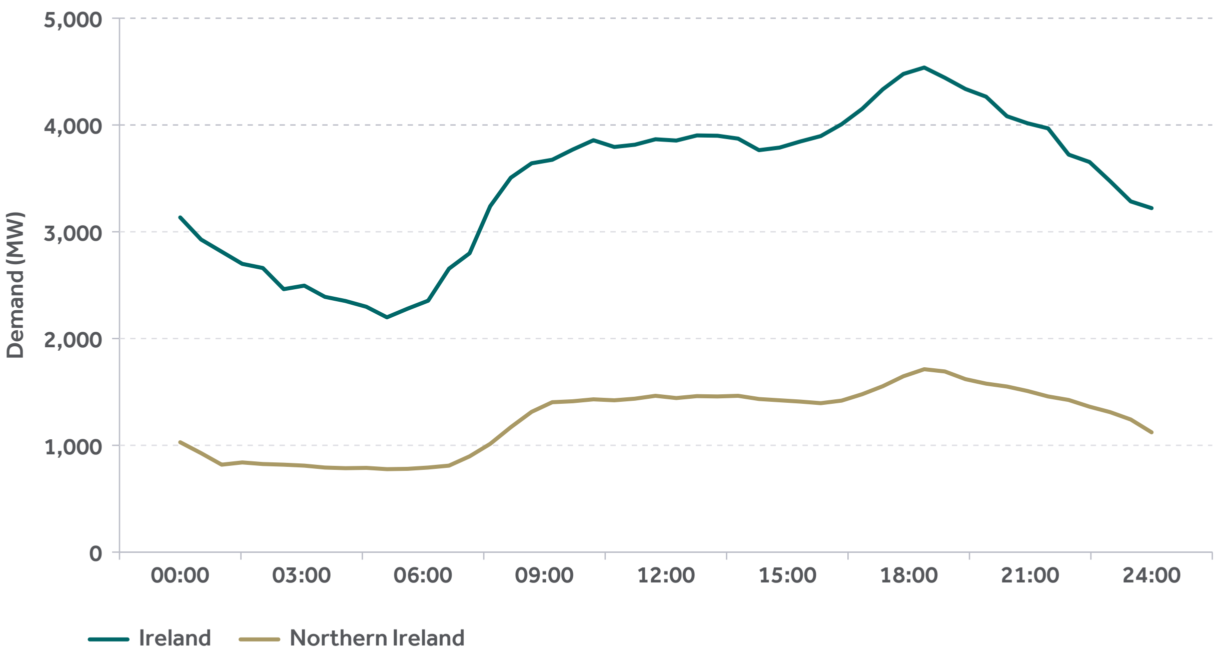


Figure A2.1: Typical daily demand profile – winter weekday

Appendix 3: Auction results

Table A3-1

Auction	Date	Awarded capacity (MW de-rated)
2018/2019 T-1	15/12/2017	7,774[91]
2019/2020 T-1	13/12/2018	8,266[92]
2022/2023 T-4	28/03/2019	7,412[93]
2020/2021 T-1	26/11/2019	7,606[94]
2021/2022 T-2	05/12/2019	7,512[95]
2023/2024 T-4	27/04/2020	7,322[96]
2024/2025 T-4	21/01/2021	6,168[97]
2022/2023 T-1	21/10/2021	1,121[98]
2024/2025 T-3	20/01/2022	1,471[99]
2025/2026 T-4	24/03/2022	6,484[100]
2026/2027 T-4*	23/03/2023	7,204[101]

All results are rounded to the nearest MW.
*Provisional results.

91 https://www.sem-o.com/documents/general-publications/Capacity-Market-Final-Capacity-Auction-Results-Report_FCAR1819T-1.pdf
92 https://www.sem-o.com/documents/general-publications/T-1-2019-2020-Final-Capacity-Auction-Results-Report.pdf
93 https://www.sem-o.com/documents/general-publications/T-4-2022–2023-Final-Capacity-Auction-Results-Report.pdf
94 https://www.sem-o.com/documents/general-publications/T-1-2020-2021-Final-Capacity-Auction-Results-Report.pdf
95 https://www.sem-o.com/documents/general-publications/T-2-2021-2022-Final-Capacity-Auction-Results-Report.pdf
96 https://www.sem-o.com/documents/general-publications/T-4-2023-2024-Final-Capacity-Auction-Results-Report.pdf
97 https://www.sem-o.com/documents/general-publications/T-4-2024-2025-Final-Capacity-Auction-Results-Report.pdf
98 https://www.sem-o.com/documents/general-publications/T-1-2022–2023-Final-Capacity-Auction-Results-Report.pdf
99 https://www.sem-o.com/documents/general-publications/T-3-2024-2025-Final-Capacity-Auction-Results-Report.pdf
100 https://www.sem-o.com/documents/general-publications/T-4-2025-26-Final-Capacity-Auction-Results-Report.pdf
101 https://www.sem-o.com/documents/general-publications/PCAR2627T-4-report.pdf

Auction termination notices

Table A3-2					
Plant	**Technology type**	**Auction**	**Contract length**	**Awarded new capacity terminated (MW)**	**Termination effective date**
EnerNOC	DSU	2022/2023 T-4	1	60.696	08/05/2021[102]
ESB	Gas Turbine	2022/2023 T-4	10	192.36	08/05/2021[103]
ESB	Gas Turbine	2022/2023 T-4	10	215.46	11/01/2021[104]
Statkraft	Wind	2022/2023 T-4	1	44.5	01/05/2021[105]
Data and Power Hub	Gas Turbine	2023/2024 T-4	10	105.328	04/08/2022[106]
Energia	Other Storage	2023/2024 T-4	10	17.64	07/12/2021[107]
ESB	Gas Turbine	2023/2024 T-4	1	11.49	19/04/2021[108]
EnerNOC	DSU	2023/2024 T-4	1	12.147	07/12/2021[109]
ESB	Gas Turbine	2024/2025 T-4	1	10.14	19/04/2021[110]
Statkraft	Gas Turbine	2024/2025 T-4	10	45.1	18/08/2021[111]
Rhode Energy Storage	Other Storage	2024/2025 T-3	1	14.25	28/04/2022[112]

Table A3-2captures termination notices for capacity that has terminated contracts that would have provided capacity for the study period (2023–2032).

102 https://www.sem-o.com/documents/general-publications/2223T-4-Capacity-Market_Capacity-Termination-Notice_PY_000088-EnerNoc.pdf
103 https://www.sem-o.com/documents/general-publications/2223T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB-(2).pdf
104 https://www.sem-o.com/documents/general-publications/2223T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB.pdf
105 https://www.sem-o.com/documents/general-publications/2223T-4-Capacity-Market_Capacity-Termination-Notice_PY_034058-Statkraft-Ireland.pdf
106 https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_034087-Data-and-Power-Hub.pdf
107 https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_000044.pdf
108 https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB.pdf
109 https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_000088.pdf
110 https://www.sem-o.com/documents/general-publications/2425T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB.pdf
111 https://www.sem-o.com/documents/general-publications/2425T-4-Capacity-Market_Capacity-Termination-Notice_PY_034058-Statkraft-Ireland.pdf
112 https://www.sem-o.com/documents/general-publications/2425T-3-Capacity-Market-Termination-Notice-PY_034111-Rhode-Energy-Storage.pdf

Appendix 4: Generation plant information

Table A4-1: Registered capacity of dispatchable generation and interconnectors in Ireland in 2023 (MW)

	ID	Fuel type	Technology category	2023	Comment
Aghada	AT1	Gas/DO	Gas turbine	90	To close before end of 2023.
	AT2	Gas/DO	Gas turbine	90	
	AT4	Gas/DO	Gas turbine	90	
	AD2	Gas/DO	Gas turbine	449	
All DSU	DSU	DSU	DSU	639	
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	Planning Permission was granted to extend operation to 2030. Will run exclusively on biomass from Jan 2024.
	ED3	DO/Gas	Gas turbine	58	Operating on gas from Oct 2026.
	ED5	DO/Gas	Gas turbine	58	Operating on gas from Oct 2026.
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 October 2024.
	MP2	HFO	Steam turbine	250	Modelled as not available from October 2024.
	MP3	Coal/HFO	Steam turbine	250	Modelled as not available from October 2024.
Poolbeg CC	PBA	Gas/DO	Gas turbine	234	
	PBB		Gas turbine	234	
Rhode	RP1	DO	Gas turbine	52	
	RP2	DO	Gas turbine	52	

Table A4-1: Registered capacity of dispatchable generation and interconnectors in Ireland in 2023 (MW)

	ID	Fuel type	Technology category	2023	Comment
Sealrock	SK3	Gas/DO	Gas turbine	81	
	SK4	Gas/DO	Gas turbine	81	
Tarbert	TB1	HFO	Steam turbine	54	Unit has been placed on outage until Dec 2023. Scheduled to close thereafter.
	TB2	HFO	Steam turbine	54	
	TB3	HFO	Steam turbine	241	
	TB4	HFO	Steam turbine	243	
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 dispatchable including DSU				**7,321**	

DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil.

Table A4-2: Partially/Non-dispatchable plant in Ireland (MW)

At year end:	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Wind onshore	4,595	5,060	5,110	5,755	6,400	6,700	7,000	7,000	7,000	7,000
Wind offshore	25	25	25	25	25	725	2,865	5,000	7,135	9,270
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
Solar PV	786	1,838	2,436	3,089	3,741	4,327	4,914	5,500	6,086	6,672
Total	**5,624**	**7,141**	**7,789**	**9,087**	**10,384**	**11,970**	**14,997**	**17,718**	**20,439**	**23,160**

Table A4-3: All renewable energy sources in Ireland (MW).										
At year end:	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
All wind	4,620	5,085	5,135	5,780	6,425	7,425	9,865	12,000	14,135	16,270
All hydro	242	242	242	242	242	242	242	242	242	242
Biomass/LFG (including those units registered in the capacity market and biomass CHP)	24	24	24	24	24	24	24	24	24	24
Waste (assume 50% renewable)	39	39	39	39	39	39	39	39	39	39
Peat stations on biomass	77	118	118	118	118	118	118	118	0	0
Solar	786	1,838	2,436	3,089	3,741	4,327	4,914	5,500	6,086	6,672
Total RES	**5,788**	**7,346**	**7,994**	**9,292**	**10,589**	**12,175**	**15,202**	**17,923**	**20,526**	**23,247**
We have assumed that the peat plant at Edenderry will be approximately 60% powered by biomass in 2023, and 100% from 2024.										

Table A4-4: Registered capacity of dispatchable generation and interconnectors in Northern Ireland in 2023 (MW)

	ID	Fuel type	Technology category	2022	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	ST1	Heavy fuel oil/coal	Steam turbine	130	Ceases operation in 2023.
	ST2	Heavy fuel oil/coal	Steam turbine	130	Ceases operation in 2023.
	KGT1	Distillate oil	Gas turbine	29	
	KGT2	Distillate oil	Gas turbine	29	
	KGT3	Distillate oil	Gas turbine	42	
	KGT4	Distillate oil	Gas turbine	42	
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	136	
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	
Total dispatchable plant:				**2,267**	

Table A4-5: Partially/Non-dispatchable plant in Northern Ireland (MW)										
At year end:	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Large scale wind	1,169	1,263	1,356	1,427	1,571	1,809	1,993	2,778	3,063	3,348
Small scale wind	180	180	180	180	180	180	180	180	180	180
Solar PV	250	280	345	401	457	509	582	617	677	731
Small scale biogas	24	24	24	24	24	24	24	24	24	24
Landfill gas	16	16	16	16	16	16	16	16	16	16
Small scale biomass	6	6	6	6	6	6	6	6	6	6
Renewable CHP	3	3	3	3	3	3	3	3	3	3
Other CHP	6	6	6	6	6	6	6	6	6	6
Small scale hydro	6	6	6	6	6	6	6	6	6	6
Waste-to-energy	15	15	15	15	15	15	15	15	15	15
Total	**1,675**	**1,799**	**1,957**	**2,084**	**2,284**	**2,574**	**2,831**	**3,651**	**3,996**	**4,335**

Table A4-6: All renewable energy sources in Northern Ireland (MW)										
At year end:	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
All wind	1,349	1,443	1,536	1,607	1,751	1,989	2,173	2,958	3,243	3,528
Solar PV	250	280	345	401	457	509	582	617	677	731
All biomass/ biogas/LFGas/ WTE	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
Total RES	**1,687**	**1,811**	**1,969**	**2,096**	**2,296**	**2,586**	**2,843**	**3,663**	**4,008**	**4,347**

Appendix 5: Adequacy methodology

Generation adequacy is assessed by determining the likelihood of there being sufficient generation to meet customer demand.

Generation adequacy standard

For these purposes customers include Distribution System Operators such as ESB and NIEN and some large users, such as data centres who connect directly to the grid. It does not necessarily take into account any limitations imposed by the transmission system, reserve requirements or the energy markets though often these considerations can be incorporated into adequacy calculations by making modifications to the input datasets.

In practice, when there is not enough supply to meet load, the load must be reduced. This is achieved by cutting off electricity from customers. In adequacy calculations, if there is predicted to be a supply shortage at any time, there is a LOLE for that period. In reality, load shedding due to generation shortages is a very rare event.

LOLE can be used to set an adequacy standard. In Ireland the adequacy standard is 8 hours LOLE per annum and Northern Ireland it is 4.9 hours LOLE per annum. If this is exceeded in either jurisdiction, it indicates the system has a higher than acceptable level of risk. The adequacy standard used for all-island calculations is 8 hours.

With any generator, there is always a risk that it may suddenly and unexpectedly be unable to generate electricity (due to equipment failure, for example). Such events are called forced outages, and the proportion of time a generator is out of action due to such an event gives its forced outage rate (FOR).

Forced outages mean that the available generation in a system at any future period is never certain. At any particular time, several units may fail simultaneously or there may be no such failures at all. There is therefore a probabilistic aspect to supply and to the LOLE.

The model used for these studies works out the probability of load loss for each half-hour period – it is these that are then summed to get the yearly LOLE, which is then compared to the adequacy standard. It is assumed that forced outages of generators are independent events and that one generator failing does not influence the failure of another.

As well as outages, adequacy calculations should consider other characteristics that restrict the ability of a generator to generate electricity when needed. This is the case for wind and solar generation whose ability to generate is determined by climatic conditions. Generators that are limited in the amount of time they can generate such as storage generators also need to be considered.

Loss of Load Expectation

AdCal software is used to calculate LOLE. The probability of supply not meeting demand is calculated for each hour of each study year. The annual LOLE is the sum of the contributions from each hour.

Consider now the simplest case of a single-system study, with a deterministic load model (that is, with only one value used for each load), and no scheduled maintenance, so that there is one generation availability distribution for the entire year.

If:

$L_{h,d}$ = load at hour h on day d

G = generation plant available

H = number loads/day to be examined (i.e., 1, 24 or 48)

D = total number of days in year to be examined

Then the annual LOLE is given by:

$$\text{LOLE} = \sum_{d=1,D} \sum_{h=1,H} \text{Prob.}(G < L_{h,d})$$

This equation is used in the following practical example.

Simplified example of LOLE calculation

Consider a system consisting of just three generation units, as in Table A5-1.

Table A5-1: System for LOLE example

	Capacity (MW)	Forced outage probability	Probability of being available
Unit A	10	0.05	0.95
Unit B	20	0.08	0.92
Unit C	50	0.10	0.90
Total	**80**		

If the load to be served in a particular hour is 55 MW, what is the probability of this load being met in this hour? To calculate this, the following steps are followed, see Table A5-2:

1. How many different states can the system be in, i.e., if all units are available, if one is forced out, if two are forced out, or all three?
2. How many megawatts are in service for each of these states?
3. What is the probability of each of these states occurring?
4. Add up the probabilities for the states where the load cannot be met.
5. Calculate expectation.

Only states 1, 2 and 3 are providing enough generation to meet the demand of 55 MW. The probabilities for the other five failing states are added up to give a total probability of 0.1036. So, in this particular hour, there is a chance of approximately 10% that there will not be enough generation to meet the load.

It can be said that this hour is contributing about 6 minutes (10% of 1 hour) to the total LOLE for the year. This is then summed for each hour of the year.

Table A5-2: Probability table

State	Units in service	Capacity in service (MW)	Probability for (A*B*C)	Probability	Ability to meet 55 MW demand	Expectation of failure (LOLE)
1	A, B, C	80	0.95*0.92*0.90 =	0.7866	Pass	0
2	B, C	70	0.05*0.92*0.90 =	0.0414	Pass	0
3	A, C	60	0.95*0.08*0.90 =	0.0684	Pass	0
4	C	50	0.05*0.08*0.90 =	0.0036	Fail	0.0036
5	A, B	30	0.95*0.92*0.10 =	0.0874	Fail	0.0874
6	B	20	0.05*0.92*0.10 =	0.0046	Fail	0.0046
7	A	10	0.95*0.08*0.10 =	0.0076	Fail	0.0076
8	none	0	0.05*0.08*0.10 =	0.0004	Fail	0.0004
Total				**1.0000**		**0.1036**

Interpretation of results

While the use of LOLE allows a sophisticated, repeatable and technically accurate assessment of generation adequacy to be undertaken, understanding and interpreting the results may not be completely intuitive. If, for example, in a sample year, the analysis shows that there is a loss of load expectation of 16 hours, this does not mean that all customers will be without supply for 16 hours or that, if there is a supply shortage, it will last for 16 consecutive hours.

It does mean that if the sample year could be replayed many times and each unique outcome averaged, that demand could be expected to exceed supply for an annual average duration of 16 hours. If such circumstances arose, typically only a small number of customers would be affected for a short period. Normal practice would be to maintain supply to industry, and to use a rolling process to ensure that any burden is spread.

In addition, results expressed in LOLE terms do not give an intuitive feel for the scale of the plant shortage or surplus. This effect is accentuated by the fact that the relationship between LOLE and plant shortage/surplus is highly non-linear. In other words, it does not take twice as much plant to return a system to the 8-hour standard from 24 hours LOLE as it would from 16 hours.

The adequacy calculation assumes that forced outages are independent, and that if one generator trips it does not affect the likelihood of another generator tripping. In some situations, it is possible that a generator tripping can cause a system voltage disturbance that in turn could cause another generator to trip. Any such occurrences are a matter for system security, and therefore are outside the scope of these system adequacy studies.

As for common-mode failures, it is possible that more than one generating unit is affected at the same time by, for example, a computer virus or by extreme weather, etc. However, it could be considered the responsibility of each generator to put in place measures to militate against such known risks for their own units.

Surplus and deficit

In order to assist understanding and interpretation of results, a further calculation is made which indicates the amount of plant required to return the system to standard. This effectively translates the gap between the LOLE projected for a given year and the standard into an equivalent plant capacity (in MW). If the system is in surplus, this value indicates how much plant can be removed from the system without breaching the LOLE standard. Conversely, if the system is in breach of the LOLE standard, the calculation indicates how much plant should be added to the system to maintain security.

The exact amount of plant that could be added or removed would depend on the particular size and availability of any new plant to be added. The amount of surplus or deficit plant is therefore given in terms of Perfect Plant. Perfect Plant may be thought of as a conventional generator with no outages. In reality, no plant is perfect, and the amount of real plant in surplus or deficit will always be higher.

It should be noted that actual loss of load as a result of a supply shortage does not represent a catastrophic failure of the power system[113]. In all probability such shortages, or loss of load, would not result in widespread interruptions to customers. Rather, it would likely take the form of supply outages to a small number of customers for a period in the order of an hour or two. This would be done in a controlled fashion, to ensure that impact on critical services is minimised.

Value of Lost Load

The Value of Lost Load is becoming more and more important in current TSOs 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 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 industrials 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 revised Electricity Regulation, a part of the Clean Energy Package would require ENTSO-E, pursuant to Article 19.5 and Article 10, to develop a common VoLL methodology. ENTSO-E is working on developing a common VoLL methodology for member TSOs.[114]

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.

113 In line with international practice, some risks of such supply shortages are accepted to avoid the unreasonably high cost associated with reducing this risk to a negligible level.
114 https://www.acer.europa.eu/Events/Workshop-on-the-estimation-of-the-cost-of-disruption-of-gas-supply-CoDG-and-the-value-of-lost-load-in-power-supply-systems-VoLL-in-Europe/Documents/CEPAPresentation_VoLLWorkshop.pdf

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 8hr 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. [115] 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

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

Figure A5-1 shows the point at which this balance point is found – marked by X between both graphs.

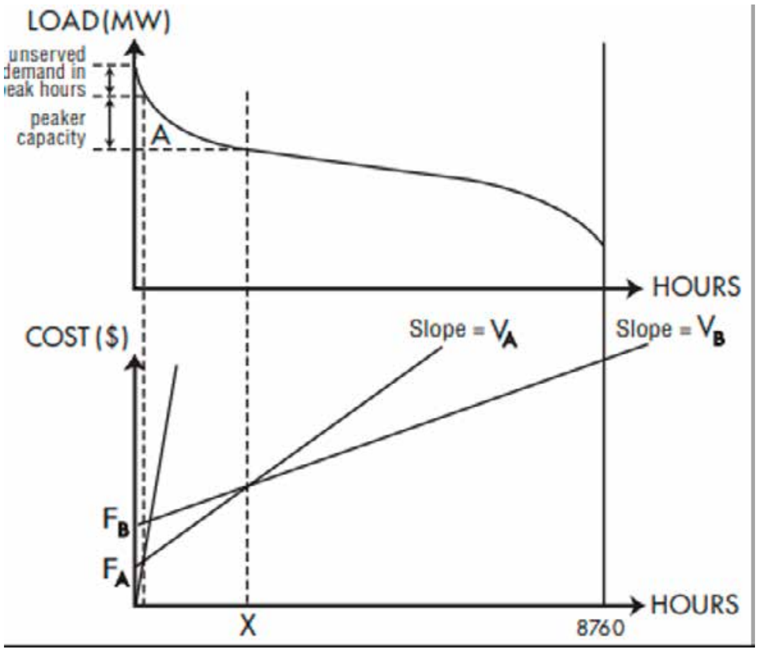


Figure A5-1 Balance point between the Costs of a New Entrant (CONE) to meet demand versus the cost impact of not meeting demand (VoLL) for a certain LOLE[116]

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

Appendix 6: National resource adequacy assessment

From next year, the Generation Capacity Statement will transition away from using a Convolution based tool as described in Appendix 5, to using a Monte-Carlo simulation-based tool. This tool is expected to enable EirGrid and SONI to better reflect the future challenges facing the electricity system with more dynamic modelling of renewable energy, storage and interconnection. Within this change in methodology, the approach and report will also aim to comply with Article 24 of Regulation (EU) 2019/943[117].

The convolution-based tool used for current generation capacity statements assesses on average the generation availability, and therefore, on average what the risk of LOLE would be in each hour of the year. Monte-Carlo simulations model random outage patterns and repeat the simulation multiple times to evaluate an average position.

Whilst on average the results of convolution and Monte-Carlo simulation will be similar, the latter will reflect the more extreme conditions that can contribute to both high and low risk periods. Monte-Carlo simulation also allows better representation of the risk of low renewable energy periods and times of low interconnector support.

As part of the process of transitioning to a new modelling approach compliant with Article 24, consultations will be held to gather expert opinions on the methodology and assumptions being proposed.

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

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