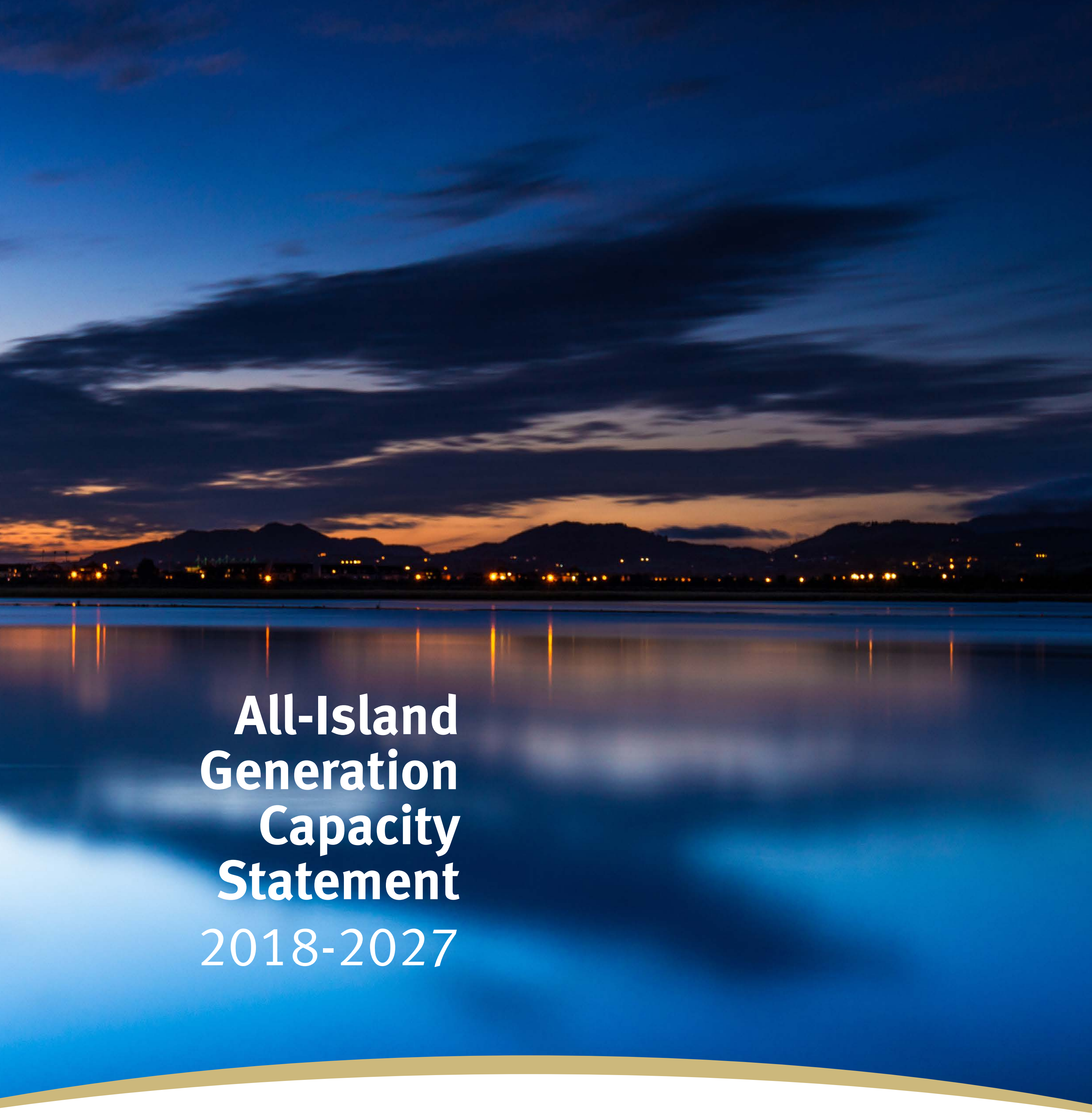

All-Island Generation Capacity Statement 2018-2027

EIRGRID GROUP

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This document incorporates the Generation Capacity Statement for Northern Ireland and the Generation Adequacy Report for Ireland.

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Table of Contents

Foreword

EirGrid and SONI, as transmission system operators for Ireland and Northern Ireland respectively, are pleased to present the All-Island Generation Capacity Statement 2018-2027.

In this statement we outline the expected electricity demand and the level of generation capacity that will be required on the island over the next ten years. We carried out generation adequacy studies to assess the balance between supply and demand for a number of realistic scenarios.

The electricity industry is undergoing a period of change due to the new Integrated-Single Electricity Market. This report is also evolving, in order to align better with the principles underlying the I-SEM Capacity Market.

Another challenge to the sector is the decommissioning of generation plant due to de-carbonisation targets. Both governments have ratified the Paris Agreement (COP 21), committing to global efforts to ensure that the global temperature increase stays well below 2°C (relative to pre-industrial temperatures).

Demand in Northern Ireland has been relatively stable and is expected to continue so. Demand in Ireland is increasing and is forecast to increase significantly, due to the expected expansion of many large energy users. With this increase in demand, it is expected that new generation will be required, and that this generation will need to be friendly to the environment.

We hope you find this document informative. This is your grid. We very much welcome feedback from you on how we can improve this document and make it more useful.

Mark Foley
Chief Executive,
EirGrid Group

Robin McCormick
Director, Operations, Planning & Innovation
and General Manager, SONI Ltd.

Document Structure

This document contains a Glossary of Terms section, an Executive Summary, four main sections and four appendices. The structure of the document is as follows:

The **Glossary of Terms** explains some technical terms used in the document.

The **Executive Summary** gives an overview of the main highlights of the document and presents the statement in summary terms.

Section 1 introduces our statutory and legal obligations. The purpose and context of the report is outlined.

Section 2 outlines the demand forecast methodology, and presents estimates of demand over the next ten years.

Section 3 describes the assumptions in relation to electricity generation.

Adequacy assessments are presented in **Section 4**.

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

Glossary of Terms

Acronym/ Abbreviation	Term	Explanation
AGU	Aggregated Generator Unit	A number of individual diesel 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=42,000 GWh, Peak = 7.3 GW (Median forecast for All-Island system in 2020) $$ALF = \frac{42,000/8760}{7.33} = 66\%$$ where 8760 = number of hours per year = 24*365
	Capacity Factor	$$\text{Capacity Factor} = \frac{\text{Energy Output}}{\text{Hours per year*Installed Capacity}}$$
CPM	Capacity Payments Mechanism	The Capacity Payments Mechanism was a Fixed Revenue system of payment for participants offering generation capacity in the SEM. The mechanism featured at its core, a fixed "pot" of money that was calculated on an annual basis by the Regulatory Authorities, with technical assistance from the System Operators. The CPM was replaced by the Capacity Market when I-SEM went live in October 2018.
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	Combined heat and power (CHP) is 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 transmission network connected generation stations to meet all customers' electricity requirements. This includes any losses (line or transformer).
DS3	Delivering a Secure Sustainable Electricity System	In response to binding National and European targets, EirGrid Group began a multi-year programme, "Delivering a Secure, Sustainable Electricity System" (DS3). The aim of the DS3 Programme is to meet the challenges of operating the electricity system in a secure manner while achieving these 2020 renewable electricity targets.
DSM	Demand Side Management	The modification of normal demand patterns usually through the use of financial incentives.

Acronym/ Abbreviation	Term	Explanation
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.
ENTSO-e		European Network of Transmission System Operators – Electricity
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.
FOP	Forced Outage Probability	This is the statistical probability that a generation unit will be unable to produce electricity for non-scheduled reasons due to the failure of either the generation plant or supporting systems. Periods when the unit is on scheduled outage are not included in the determination of forced outage probability.
	Generation Adequacy	The ability of all the generation units connected to the electrical power system to meet the total demand imposed on them at all times. The demand includes transmission and distribution losses in addition to customer demand.
GWh	Gigawatt Hour	Unit of energy 1 gigawatt hour = 1,000,000 kilowatt hours = 3.6 x 10^{12} joules
GDP	Gross Domestic Product	Value of the output of all goods and services produced within a nation's borders, normally given as a total for the year. It thus includes the production of foreign owned firms within the country, but excludes the income from domestically owned firms located abroad.
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.
	Interconnector	The electrical link, facilities and equipment that connect the transmission network of one country to another.
HVDC	High Voltage, Direct Current	A HVDC electric power transmission system uses direct current for the bulk transmission of electrical power.
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.

Acronym/ Abbreviation	Term	Explanation
I-SEM	Integrated-Single Electricity Market	The wholesale market on the island is changing considerably to take account of the requirements of the European Network Codes and the Target Model. It is anticipated that the I-SEM will bring benefits, including: • Increased access to cheaper sources of electricity • A more open and efficient pan-European electricity market delivering benefits to consumers • A basis for the development of intraday, forward, futures and derivative markets that enable investors and operators manage risk.
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.
	Mothball	To stop using a generation unit but keep it in good condition so that it can readily be used again.
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.
MVA	Mega Volt Ampere	Unit of apparent power. MVA ratings are often used for transformers, e.g. for customer connections.
MW	Megawatt	Unit of power 1 megawatt = 1,000 kilowatts = 10^6 joules / second
NIRO	Northern Ireland Renewables Obligation	NIRO is the main policy measure for supporting the development of renewable electricity in Northern Ireland.
REFIT 3	Renewable Energy Feed-in Tariff 3	REFIT 3 is a support scheme for renewable energy from the Department of Communications, Climate Action and Environment in Ireland. It is designed to incentivise the addition of 310 MW of renewable electricity capacity to the Irish grid. Of this, 185 MW will be High Efficiency CHP, using both Anaerobic Digestion and the thermo-chemical conversion of solid biomass, while 125 MW will be reserved for biomass combustion and biomass co-firing.[1]
RES	Renewable Energy Source	
SEAI		Sustainable Energy Authority of Ireland
SEM	Single Electricity Market	The Single Electricity Market (SEM) was the wholesale electricity market operating in Ireland and Northern Ireland from 2007 to 2018. It was a gross mandatory pool market operating with dual currencies.

1 http://www.dccae.gov.ie/energy/en-ie/Renewable-Energy/Pages/Refit-3-landing-page.aspx

Acronym/ Abbreviation	Term	Explanation
SONI		System Operator Northern Ireland
TWh	Terawatt Hour	Unit of energy 1 terawatt hour = 1,000,000,000 kilowatt hours = 3.6 x 10^{15} joules
TER	Total Electricity Requirement	TER is the total amount of electricity required by a country. It includes all electricity exported by generating units, as well as that consumed on-site by self-consuming electricity producers, e.g. CHP.
	Transmission Losses	A small proportion of energy is lost as heat or light whilst transporting electricity on the transmission network. These losses are known as transmission losses.
	Transmission Peak	The peak demand that is transported on the transmission network. The transmission peak includes an estimate of transmission losses
TSO	Transmission System Operator	In the electrical power business, a transmission system operator is the licensed entity that is responsible for transmitting electrical power from generation plants to regional or local electricity distribution operators.

Executive Summary

Executive Summary

In this Generation Capacity Statement (GCS), we examine the likely balance between electricity demand and supply during the years 2018 to 2027. This GCS covers both Northern Ireland and Ireland, and is produced jointly between SONI and EirGrid[2].

SONI, the transmission system operator (TSO) in Northern Ireland, is required by licence to produce an annual Generation Capacity Statement. Similarly, EirGrid, the TSO in Ireland, has a regulatory requirement to publish forecast information about the power system, including an assessment of the balance between supply and demand.

To obtain the most relevant information, EirGrid and SONI consulted widely with industry participants and have used the most up-to-date information at the time of publication.

A range of scenarios was prepared to forecast electricity demand over the time horizon of the report.

In our adequacy assessment studies, we modelled the generation portfolio against the demand forecast, using the accepted standard risk. These studies were carried out separately for Ireland and Northern Ireland, and jointly on an all-island basis.

The findings, in terms of the overall demand and supply balance, should be useful to market participants, regulatory agencies and policy makers.

Key Messages

With the advent of the new I-SEM, the focus of this report is changing. Under the existing electricity market arrangements which ran until October 2018, all available generators benefited from capacity payments.

The I-SEM capacity market was designed to procure sufficient capacity to meet the adequacy standard. Generators that were not successful in the auction are included in our adequacy studies. However, this does not mean that the units will or will not continue to operate in the market.

We are working towards the delivery of the second North South interconnector in 2023. Planning permission for this interconnector has been granted in both Ireland and Northern Ireland. At the time of publication, the planning permissions are the subject of ongoing legal challenges in both jurisdictions.

EirGrid is progressing plans and development studies for the proposed Celtic Interconnector between Ireland and France. Elsewhere, we are working with Element Power on its Greenlink 500 MW interconnector linking the power markets in Ireland and Great Britain.

Much progress has been made towards meeting our targets for renewable energy, and this is set to continue. EirGrid and SONI are supporting the integration of more intermittent generation sources with initiatives that encourage flexibility such as DS3[3].

Brexit is an uncertainty for the future, but at this point, it is not clear what impact, if any, it will have on our adequacy studies. And so we have made no changes to our adequacy methodology for the all-island adequacy assessments. In the absence of the second North South interconnector, we have continued to include separate jurisdictional adequacy assessments.

2 Where 'we' is used, it refers to both companies, unless otherwise stated.
3 http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

The amount of generation required in the all-island Capacity Market is set by the capacity requirement, as calculated by EirGrid/SONI in accordance with an approved methodology and subsequently approved by the regulatory authorities. The demand forecast scenarios outlined in this report influence the calculation of the capacity requirement.

On a combined, all-island basis, the growth in energy demand for the next ten years varies between 15% in the low demand scenario, and 47% in the high scenario.

The all-island studies presented here are based on an 8 hour adequacy standard.

Northern Ireland

The electricity demand in Northern Ireland has been relatively flat in the last number of years. This is not currently forecasted to rise significantly in the near future, though there have been some enquiries and a connection application related to possible new Data Centre demand.

The major influence on generation adequacy is change to the plant portfolio. These changes could be due to emissions restrictions and/ or failure to obtain capacity payments.

There is a Locational Capacity Requirement for the Capacity Market that calculates the amount of generation required in constrained areas to ensure security of supply. For the purposes of setting the Locational Capacity Requirement (L1) for Northern Ireland, the SEM Committee decided to use a security of supply standard of 8 hours[4] per year.

The studies presented here are based on the 4.9 hour adequacy standard used in Northern Ireland.

For the purposes of our adequacy assessments, we have included all capacity unless they have notified us that they will be not available. Based on this, in the median demand scenario, Northern Ireland is within standard. However, if plant were to leave the market, then Northern Ireland could be in deficit.

Ireland

The demand forecast in Ireland is heavily influenced by the expected growth of large energy users, primarily Data Centres. These need a lot of power and can require the same amount of energy as a large town. Our analysis shows that demand from data centres could account for 31% of all demand by 2027 (in our median demand scenario).

For the purposes of our adequacy assessments, we have included all capacity unless they have notified us that they are not available. This does not mean that unsuccessful capacity will, or will not, continue to operate in the market.

While there is a significant surplus of plant currently, this surplus is expected to be eroded by the growth in demand and some notified plant closures (e.g. due to emissions restrictions). By 2024, in the absence of the second North South Interconnector, this would result in the need for additional capacity. Should any other plant close (e.g. due to a failure to obtain capacity payments), then this could give rise to earlier deficits.

Demand Forecast

Due to the expected growth in demand from large energy users, the electricity demand in Ireland could grow by up to 57% in the next 10 years. To be prudent there is also a scenario where this growth is much lower, at 20%. This is largely in line with EirGrid's recently published 'Tomorrow's Energy Scenarios', whose scenarios see the TER (Total Electricity Requirement) increasing by between 22% and 53% to 2030[5].

4 https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-040%20CRM%20Locational%20Capacity%20Constraint%20Methodology%20Decision.pdf
5 http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf

The recent demand in Northern Ireland is relatively flat, and is expected to continue in this manner. The low demand scenario shows demand falling by 2% over the next 10 years, while in the high demand scenario, demand would rise by 15%.

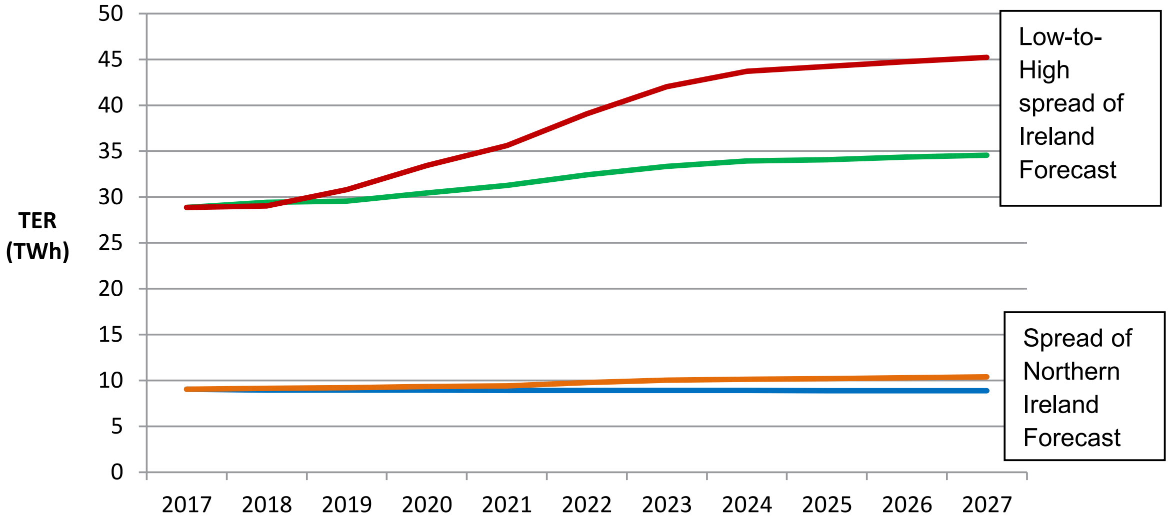


Figure 0-1 Demand forecasts for Ireland and Northern Ireland, showing the spread from low to high scenarios.

Dispatchable Generation and Interconnection

Figure 0-2 shows the dispatchable generation on the island at the start of 2018. This information was gathered from interested parties in the industry. Some generators have indicated that they will be unavailable in the latter half of the decade, reducing the total capacity by approximately 1.3 GW.

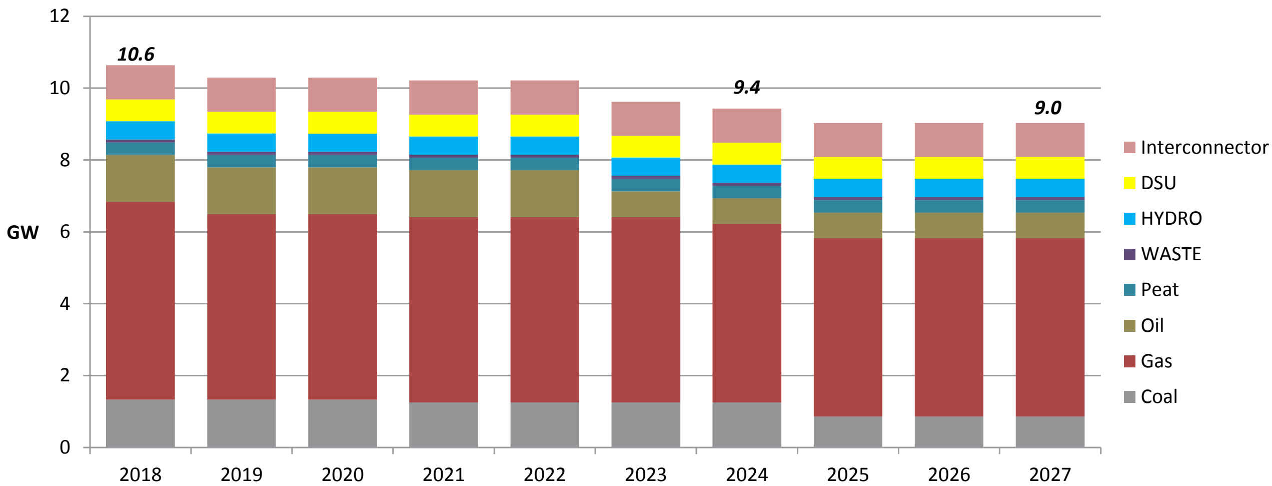


Figure 0-2 All-island portfolio of dispatchable generation and interconnection, as assumed in our reference scenario.

Renewable Energy Sources (RES)

Ireland

New wind farms commissioned in Ireland in 2017 brought the total wind capacity to over 3300 MW, contributing to the increase in overall RES percentage to 29%. Other sources of RES include biomass, hydro, solar PV and renewable waste. In the coming years, many new wind farms are due to connect, which are required in order to meet our 40% RES target in 2020.

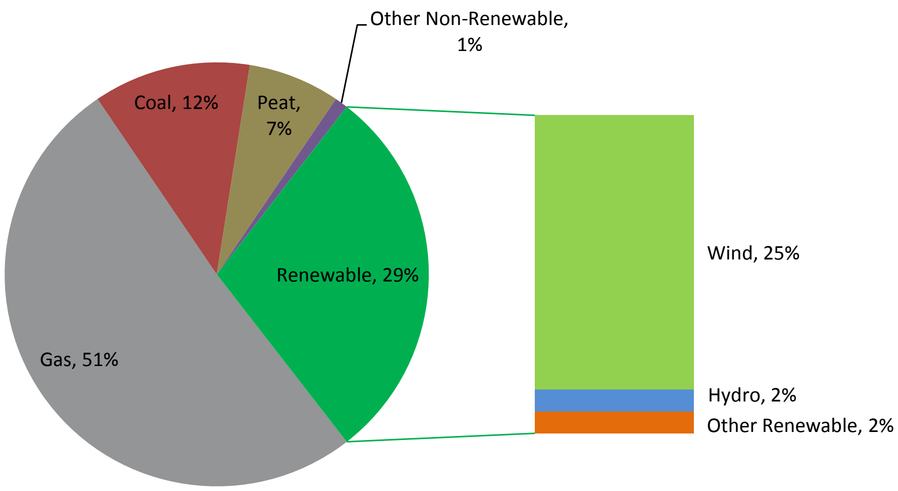


Figure 0-3 Fuel mix in Ireland in 2017.

Northern Ireland

There are over 1180 MW of wind currently installed in Northern Ireland, and this is set to grow to almost 1400 MW by 2020. This should be sufficient to meet the RES target of 40% by 2020. Solar Photovoltaic generation has seen rapid growth in Northern Ireland in recent years. A number of large-scale projects commissioned in 2017 bringing the total capacity to around 200 MW. SONI expects the total capacity in this sector to grow to 270 MW.

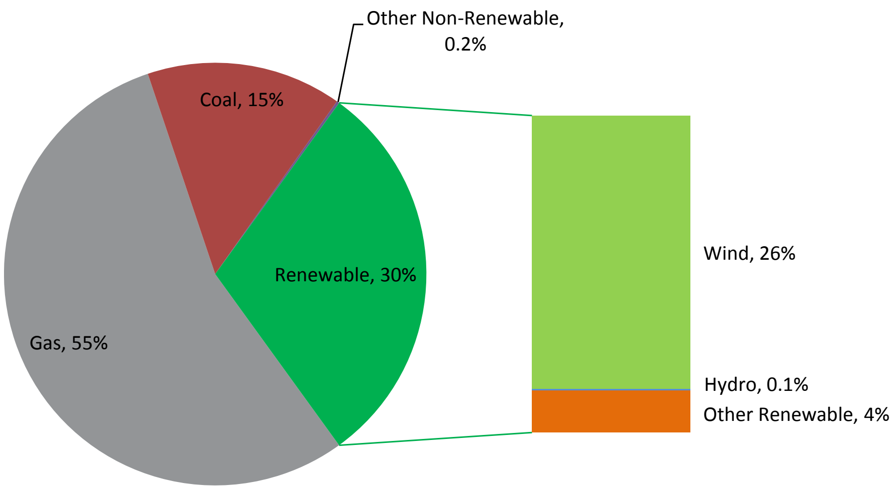


Figure 0-4 Fuel mix in Northern Ireland in 2017.

Adequacy Analysis

We can use the information gathered and the assumptions made in order to model the balance between supply and demand of electricity. Here we present a summary of our generation adequacy studies. Though we expect the second North South Interconnector to be available in 2023, we continue our single-jurisdictional studies beyond 2023, in the event that the second North South Interconnector is delayed.

Ireland, without the second North South Interconnector

In the absence of the second North South Interconnector, Ireland is assumed to continue to be able to rely on Northern Ireland for only 100 MW, across the current limited interconnection.

In the Capacity Requirement calculations for the Capacity Market, 10 different demand levels were examined, equally spaced from Low to High demand. Then, a Least Worst Regrets analysis was carried out to choose the optimal case. This has resulted in the Capacity Requirement being chosen for demand level 8, i.e. between the Median and the High demands. Our reference scenario for Ireland assumes the 8th level demand forecast. Ireland starts in a position of significant generation surplus in 2018. Thereafter, some generation plant is assumed to shut down because of emissions restrictions. By 2024, a deficit of capacity is forecasted and, in the absence of the second North South Interconnector, additional capacity would be needed.

With a low availability scenario (worst year in 5 years) and median demand, there would be a deficit of plant by 2024.

If base-load high-carbon plant were unavailable from 2026 (e.g. Moneypoint coal units), they would need to be replaced.

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Demand Level 8	1780	1620	1470	1260	930	170	-140	-200	-250	-290
Median Demand	1800	1680	1540	1360	1090	370	100	40	-10	-50
Low availability, Median Demand	1480	1370	1210	1030	760	50	-220	-270	-320	-350
Low Carbon, Median Demand									-680	-720

Table 0-1 Results of adequacy studies for Ireland, given in MW of surplus plant (+) or deficit (-).

Northern Ireland, without the second North South Interconnector

When Northern Ireland is assessed on its own, we assume a continued ability to rely on 200 MW from Ireland.

In the median demand scenario, there is surplus capacity. This surplus reduces to modest levels by 2025 due to the assumed unavailability of Kilroot coal plant. There is also a surplus in the low and high demand scenarios.

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Median Demand	570	570	570	520	500	490	480	160	160	150
Low Demand	600	610	620	570	580	580	580	270	270	270
High Demand	530	520	530	470	430	400	390	50	50	30

Table 0-2 Results of adequacy studies for Northern Ireland, given in MW of surplus plant (+) or deficit (-).

All-Island, with the second North South Interconnector

The second North South Interconnector is planned to be commissioned in 2023. Thereafter, we can consider the all-island system to be capable of operating electrically as one, i.e. with all the generation capacity from both jurisdictions to meet the combined load.

One of the advantages of considering an all-island system is a capacity benefit, i.e. in general, you need less capacity for the combined all-island system than for the sum of two single-jurisdiction studies.

In the median demand scenario, the All-Island system has sufficient capacity assuming all existing capacity remains available, with the exception of capacity that has notified us that it will be not available.

If low availability were to transpire in any year from 2026, then there would be significant deficits. The Low Carbon scenario shows a deficit of over 300 MW from 2026.

Scenario	2024	2025	2026	2027
Demand Level 8	570	160	90	40
Median Demand	850	450	390	350
Low availability, Median Demand	450	30	-30	-70
Low Carbon, Median Demand			-310	-350

Table 0-3 Results of adequacy studies for the All-Island system.

1 Introduction

1. Introduction

This report seeks to inform market participants, regulatory agencies and policy makers of the likely generation capacity required to achieve an adequate supply and demand balance for electricity for the period up to 2027[6].

Generation adequacy is a measure of the capability of the electricity supply to meet the electricity demand on the system. 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.

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.

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

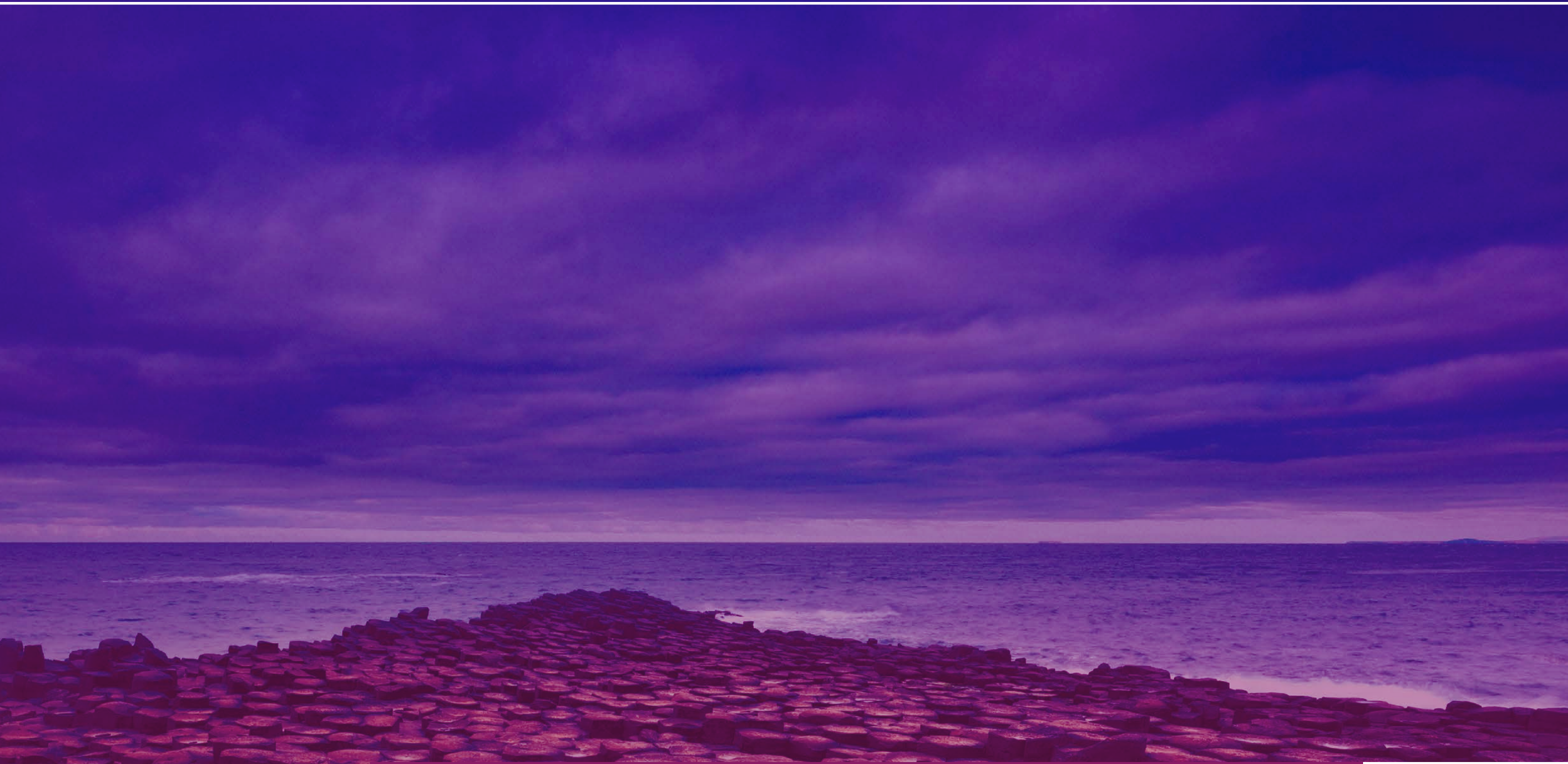
This Generation Capacity Statement covers the years 2018-2027 for both Northern Ireland and Ireland, and is produced jointly between SONI and EirGrid. Where 'we' is used, it refers to both companies, unless otherwise stated.

This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2017-2026, published in April 2017.

Input data assumptions have been reviewed and updated.

The Generation Capacity Statement is evolving to support the I-SEM Capacity Market and other requirements of a changing electricity system. These changes will also be reflected across a longer horizon by the energy scenarios being produced by SONI and EirGrid. We will continue to work with Regulators and other stakeholders to ensure that both the document and the underlying methodologies remain relevant and useful.

6 EirGrid and SONI also publish a Winter Outlook Report which is focused on the following winter period, thus concentrating on the known, short-term plant position rather than the long-term outlook presented in the Generation Capacity Statement. http://www.eirgridgroup.com/site-files/library/EirGrid/Winter-Outlook-2017-18.pdf



2 Demand Forecast

2. Demand Forecast

2.1. Introduction

Making a prediction of what the electricity demand will be in the future is a multi-layered task. The demand forecast is developed for each jurisdiction separately, then added together for all-island studies.

For each jurisdiction, we initially analyse the historical demand data to provide a suitable starting point. Part of this process involves the exploration of weather effects on demand, e.g. the correction of a high peak demand on a particularly cold day to what it would have been had the weather been average.

Another aspect of the historical analysis is the calculation of the amount of self-consumption, i.e. energy that is created and used on-site, without being transmitted to the grid or metered. Examples would be a self-consuming CHP unit or a domestic solar PV panel. As this sector is growing, it is necessary to track it and the influence that it has on the total metered demand.

We also examine other factors affecting demand, such as economic activity and any particular sectors that are experiencing strong growth. When forecasting demand, we need to take into account the expected growth in these areas.

This GCS demand forecast is used in the calculation of the Capacity Requirement in the I-SEM Capacity Market auction. In order to cover a range of possible futures, the GCS demand forecast is provided as a number of plausible scenarios, from low to high demand.

2.2. Demand Forecast for Ireland

2.2.1. Methodology

The electricity forecast model for Ireland is a multiple linear regression model which predicts electricity demand based on changes in economic parameters. Particular attention is paid to the effects of energy efficiency measures and large, new industrial users. A spread of electricity forecasts is produced, covering the next ten years.

EirGrid has sought the advice of the Economic and Social Research Institute (ESRI) which has expertise in modelling the Irish economy[7]. They advised us to focus on the economic parameters of Personal Consumption[8] and adjusted GNP[9].

The demand forecast incorporates some reduction due to energy efficiency measures, in line with Ireland's National Energy Efficiency Action Plan[10]. This includes the effect of the installation of smart meters, which could reduce peak demand from domestic users by up to 8%.

7 http://www.esri.ie/irish-economy/
8 Personal Consumption of Goods and Services (PCGS) measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.
9 Gross National Product is the total value of goods and services produced in a country, discounting the net amount of incomes sent to or received from abroad. It is modified for the effect of re-domiciled companies, i.e. foreign companies which hold substantial investments overseas but have established a legal presence in Ireland.
10 http://www.dccae.gov.ie/energy/en-ie/Energy-Efficiency/Pages/National-Energy-Efficiency-Action-Plan-(NEEAP).aspx

2.2.2. Historical Data

Historical records of electricity generated and electricity sales are gathered from various sources such as the ESB Networks, SEAI (Sustainable Energy Authority of Ireland) and EirGrid. Transporting electricity from the generator to the customer invariably leads to losses. Based on the comparison of historical sales to exported energy, we have estimated that between 7 and 8% of power produced is lost as it passes through the electricity transmission and distribution systems.

Past economic data is sourced from the most recent Quarterly National Accounts of the Central Statistics Office. We analyse the data to capture the most recent trends relating the economic parameters to demand patterns.

Historical weather data is obtained from Met Éireann, Ireland's National Meteorological Service.

2.2.3. Forecasting Causal Inputs

In order for the trained energy model to make future predictions, we require forecasts of GNP and Personal Consumption. These forecasts are provided by the ESRI in their Quarterly Economic Commentary. Longer-term trends arise from the ESRI's Medium Term Review.

As a cross-check, the ESRI forecasts were compared with predictions from other institutions such as the Department of Finance and the Central Bank of Ireland.

	2017-2020	2021-2027
GNP	4.0%	3.5%
Personal Consumption	2.8%	2.7%

Table 2-1 Average annual growths for macroeconomic parameters, as provided by the ESRI.

2.2.4. Large Energy Users in Ireland

A key driver for electricity demand in Ireland for the next number of years is the connection of new large energy users, such as data centres. Large industrial connections normally do not dominate a country's energy demand forecast, but this is the case for Ireland at the moment. A significant proportion of this extra load will materialise in the Dublin region.

In Ireland, there is presently over 400 MVA of demand capacity that is contracted to data centres. These customers are connected to the transmission system or to the distribution system. The typical load drawn by these customers is approximately 50% of their contracted Maximum Input Capacity. This is expected to rise as these customers build out to their full potential.

Furthermore, there are many data centre projects in the connection process, or that have made material enquiries. We have examined the status of these proposed projects, and have made assumptions concerning the demand from these data centres in the future. This has formed the differences between our low, median and high scenarios.

- From those projects that have connection offers in place (or in the connection process), we assume 1400 MVA of demand.
- For those projects that have made material enquiries, we assume an additional 370 MVA.

In forecasting future demand, we also need to appreciate that data centres normally have a flat demand profile.

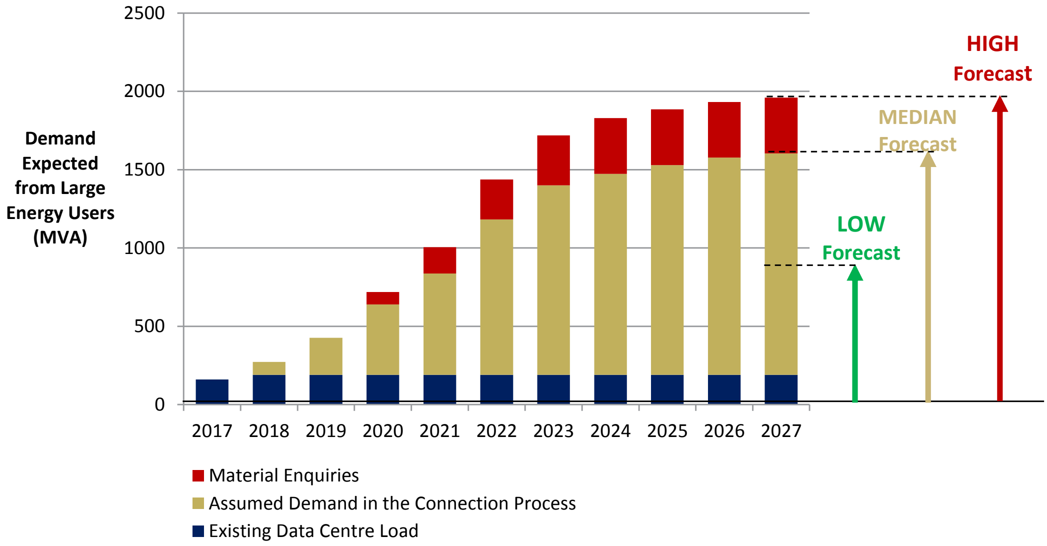


Figure 2-1 Demand expected from assumed build-out of large energy users, divided into 3 different categories. Also illustrated is how we assume to divide out this demand into the Low, Median and High Demand forecast scenarios for 2027.

2.2.5. Forecast Scenarios and Large Energy Users

In order to capture the impact of data centres and other large energy users, we have based the different demand forecast scenarios for Ireland on different build-out scenarios. All scenarios have the same assumptions for the data centres already built.

The demand forecast low scenario starts with the recent demand growth and the economic inputs as discussed above. This low scenario is based on the assumption that approximately half of the potential demand in the connection process will connect (700 MVA).

The median scenario accounts for the connection of all 1400 MVA of potential demand in the connection process. The high scenario, in addition to the demand in the median scenario, also assumes that 370 MVA of the demand projects with material enquiries will connect.

These three scenarios give an appropriate view of the range of possible demand growths facing Ireland. The Median demand is now higher than for last year's forecast for high demand, indicating the progression of many of the Data Centre projects.

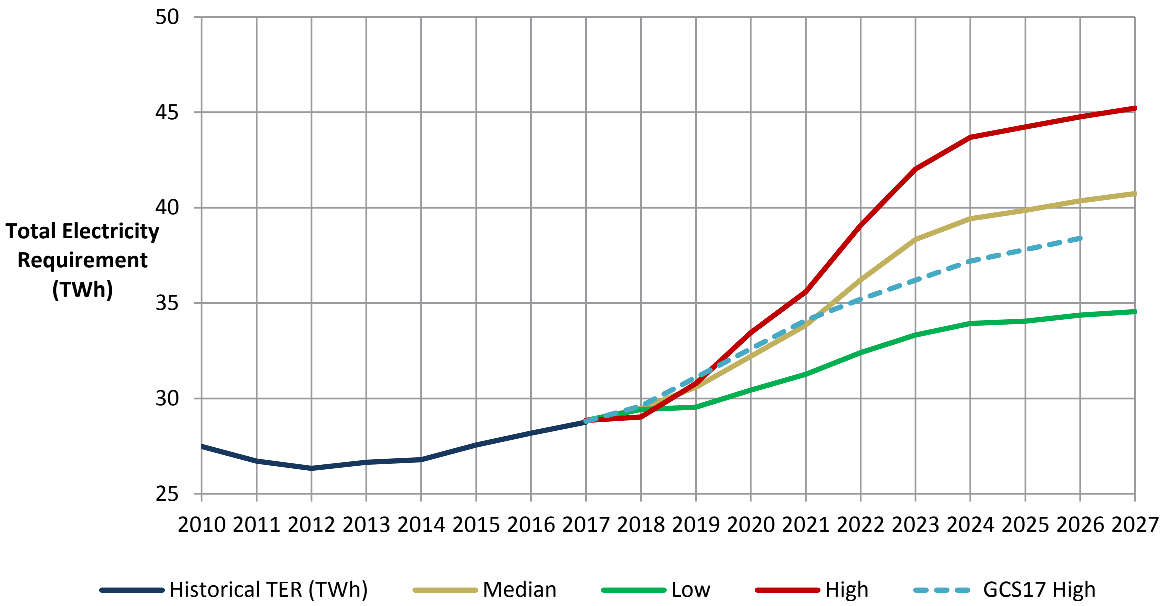


Figure 2-2 Total Electricity Requirement forecast for Ireland.

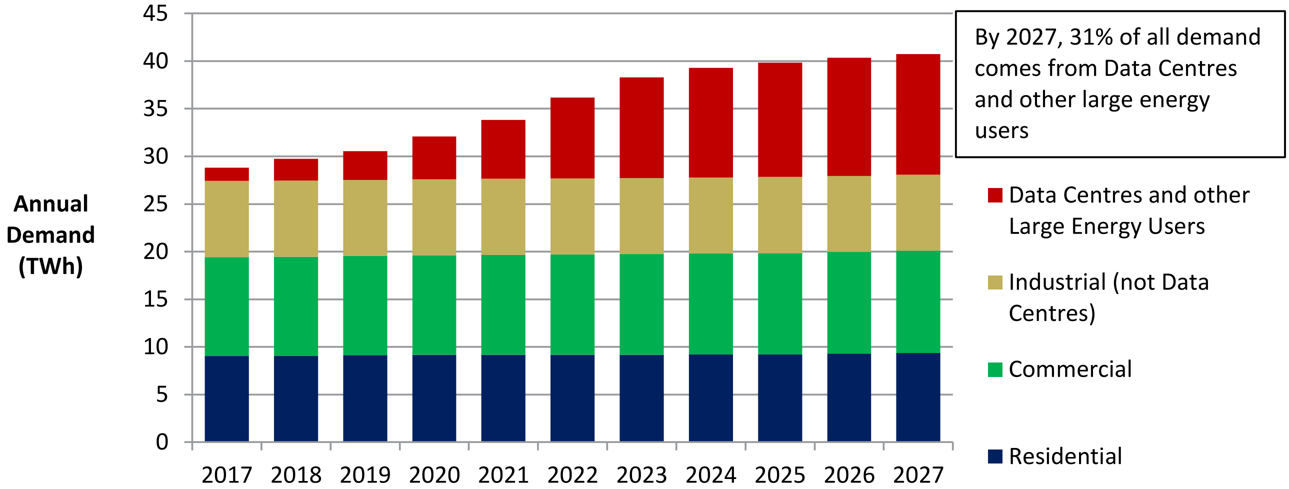


Figure 2-3 For the Median Demand scenario, this illustrates the approximate split into different sectors. We estimate that 31% of total demand will come from data centres by 2027.

2.2.6. 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 simply the average load divided by the peak load.

Temperature has a significant effect on electricity demand, particularly on the 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, see Figure 2-4. 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.

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.

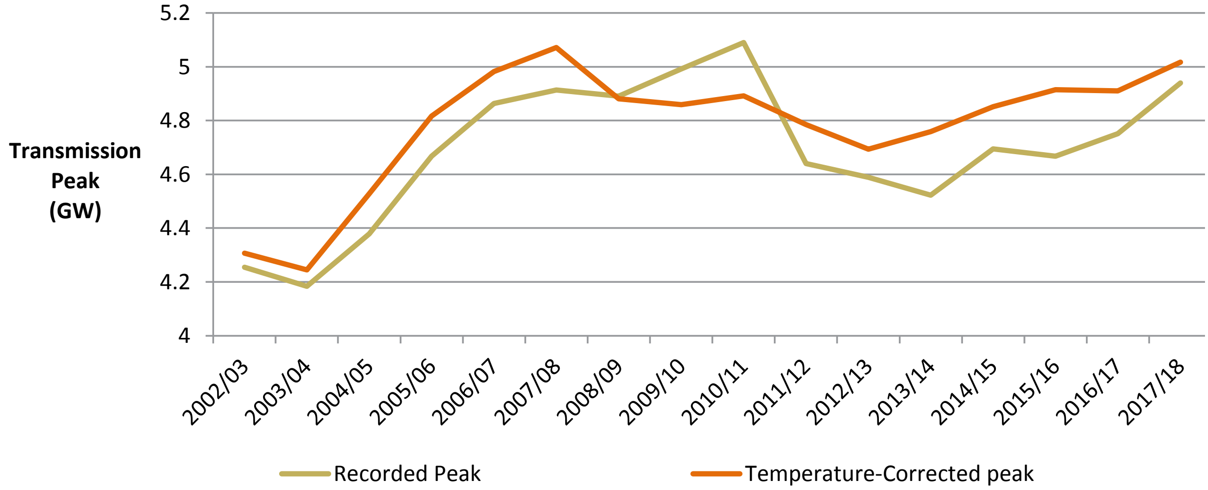


Figure 2-4 Past values of recorded maximum demand in Ireland, and the ACS temperature-corrected values.

This forecast is then tempered with estimates of energy efficiency savings, particularly to allow for the effect of smart meters. We assume that smart meters could cause the peak to decrease by up to 8% for domestic users, from the start of their roll-out in 2021/22.

In the early years of the forecast, we have allowed for more variation from temperature, i.e. for the Low peak forecast, we have considered that it might be a mild winter, and so the peaks would be lower than otherwise expected. Also, for the High scenario, we have considered the possibility that the winter might be severely cold, and thus result in higher peaks. This effect is swamped by the larger effects of data centre load variation in the later years of the forecast.

While we don’t expect an extremely warm or extremely cold winter every year, this range of scenarios is within the bounds of probability for the immediate winter. Therefore, it is included in our forecast to be provided for the Least Worst Regret analysis of the Capacity Requirement in the Capacity Market.

The main difference between the forecasts of low, median and high peaks is the differing amounts of load assumed from data centres and other large energy users.

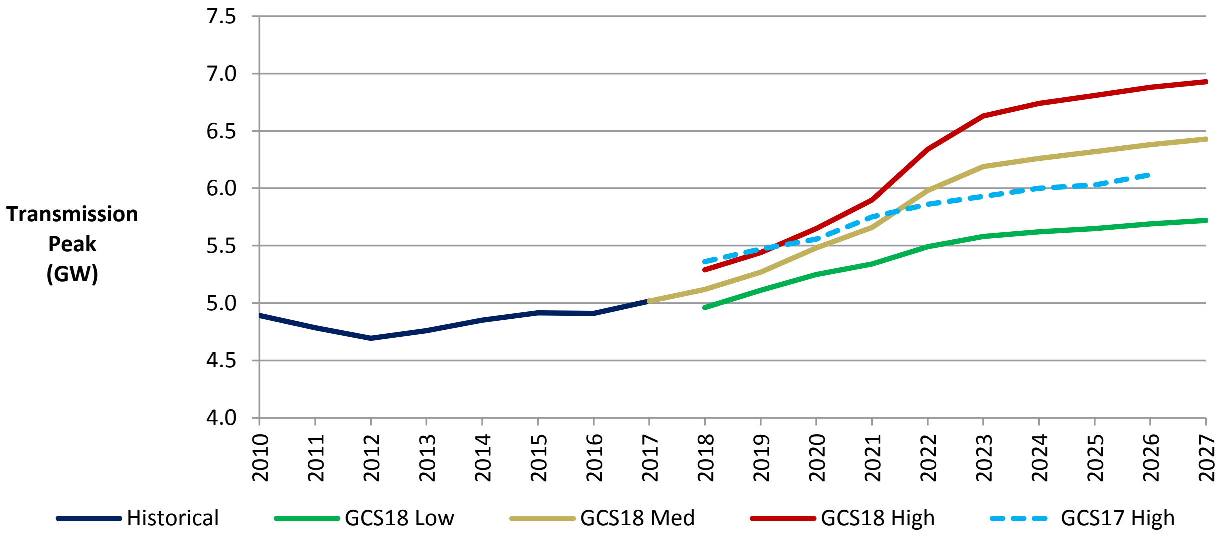


Figure 2-5 Transmission peak forecast for Ireland.

2.3. Demand Forecast for Northern Ireland

2.3.1. Methodology

The TER forecast for Northern Ireland is carried out with reference to economic parameters, primarily Gross Value Added (GVA). The consensus amongst economists is that there will be growth in the Northern Ireland's economy, although some uncertainty surrounds the pace of growth.

The Strategic Energy Framework for Northern Ireland sets out the Northern Ireland contribution to the 1% year-on-year energy efficiency target for the UK. Energy efficiency has also been incorporated in the demand forecast. The Department for the Economy is currently reviewing and refreshing the Strategic Energy Framework 2010-2020.

2.3.2. Demand Scenarios

Given the degree of economic uncertainty into the future, SONI believes it prudent to consider three alternative scenarios for the economy, each of which can then be factored in to derive an estimate of energy production. Combining both temperature and economic scenarios as well as energy efficiency allows for median, high and low demand forecasts to be formulated.

The median demand forecast is based on an average temperature year, including energy efficiency with the central economic factor being applied and this is our best estimate of what might happen in the future.

The low demand forecast is based on a relatively high temperature year, higher energy efficiency with the pessimistic economic factor being applied. Conversely, the high demand forecast is based on a relatively low temperature year, lower energy efficiency with the more optimistic economic factor being applied.

There have been some enquiries from data centres seeking to connect in Northern Ireland. SONI has assessed these applications and modified the demand forecast accordingly. The low demand scenario assumes no data centre load. The median demand scenario includes an amount of possible load in the connection offer process, modified by an estimated connection probability, from 2022. In addition to this, the high demand contains an estimated fraction of the potential load that has made a material enquiry.

2.3.3. Self-Consumption

SONI has been working with Northern Ireland Electricity Networks and referencing the Renewable Obligation Certificate Register (ROC Register)[11] to establish the amount of embedded generation that is currently connected on the Northern Ireland system and what amounts will be connecting in the future.

This has enabled us to make an informed estimate of the amount of energy contributed 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 Total Energy Requirement (TER)[12].

11 https://www.renewablesandchp.ofgem.gov.uk/

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

2.3.4. TER Forecast

It can be seen that the new TER forecast for Northern Ireland (Figure 2-6) is similar to the previous forecast published in the Generation Capacity Statement 2017-2026. The main difference is that caused by the addition of some potential data centre load.

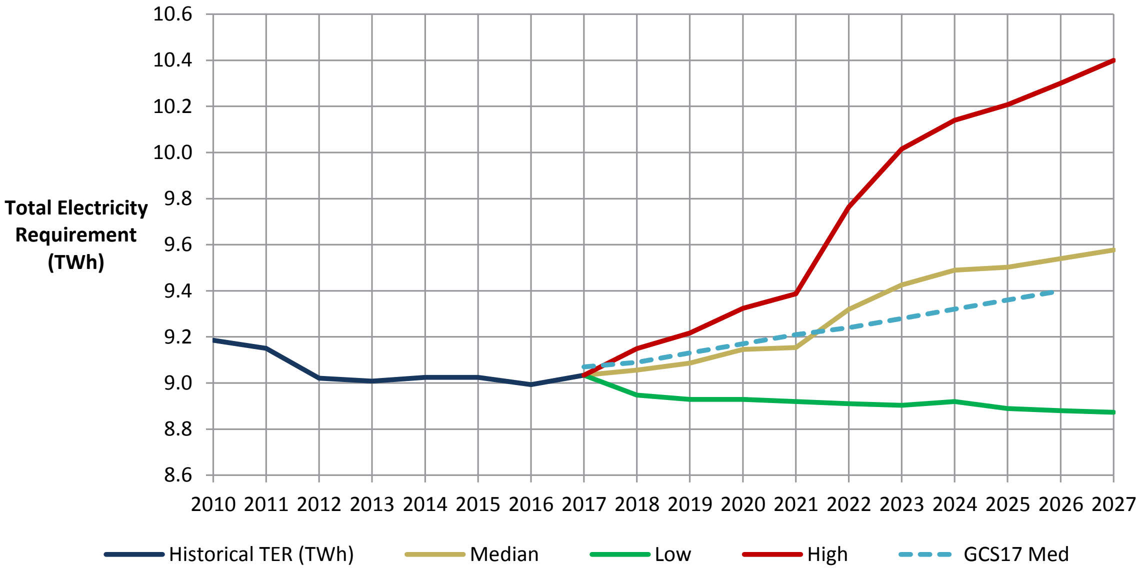


Figure 2-6 Northern Ireland TER Forecast

2.3.5. Peak Demand Forecasting

The Northern Ireland peak demand forecast is carried out using a similar methodology as the Ireland peak forecast described in Section 2.2.

The Northern Ireland 2016/17 generated winter peak of 1802 MW occurred on Monday 5th December 2016 at 17:30.

We applied the average cold spell temperature correction (ACS), to update Figure 2-7.

As with the annual electricity demand forecast outlined in section 2.3(b), three peak forecast scenarios have been built. These consist of a pessimistic, realistic and optimistic view with adjustments that take account of current economic outlook predictions.

In the early years of the forecast SONI used temperature variation to give a plausible range between the low and high peak forecast, i.e. the low peak forecast is based on a mild winter, and the high scenario is based on a very cold winter. This has been based on historical records over the last 10 years. In later years, variations caused by economic projections are more significant and are used instead.

Figure 2-8 shows the TER peak forecast for Northern Ireland. It can be seen that the resulting forecast for Northern Ireland is similar to the previous forecast.

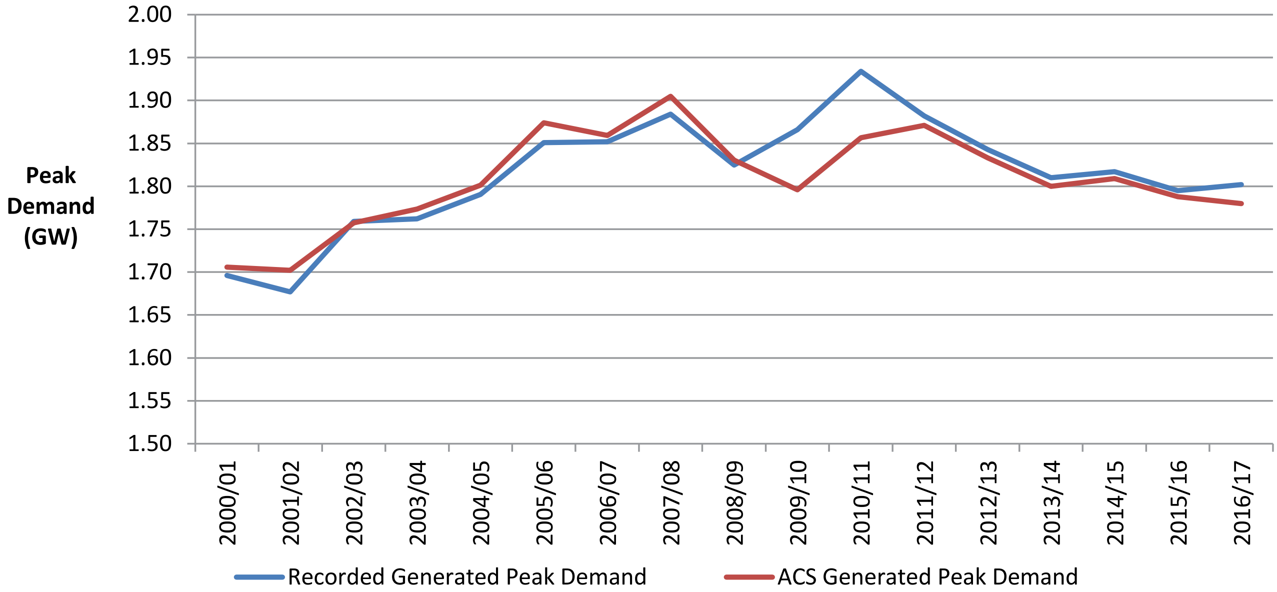


Figure 2-7 Recorded and ACS-corrected peaks (generated level) for Northern Ireland. The most significant corrections are for 2009/10 and 2010/11, when the temperature deviated most from normal.

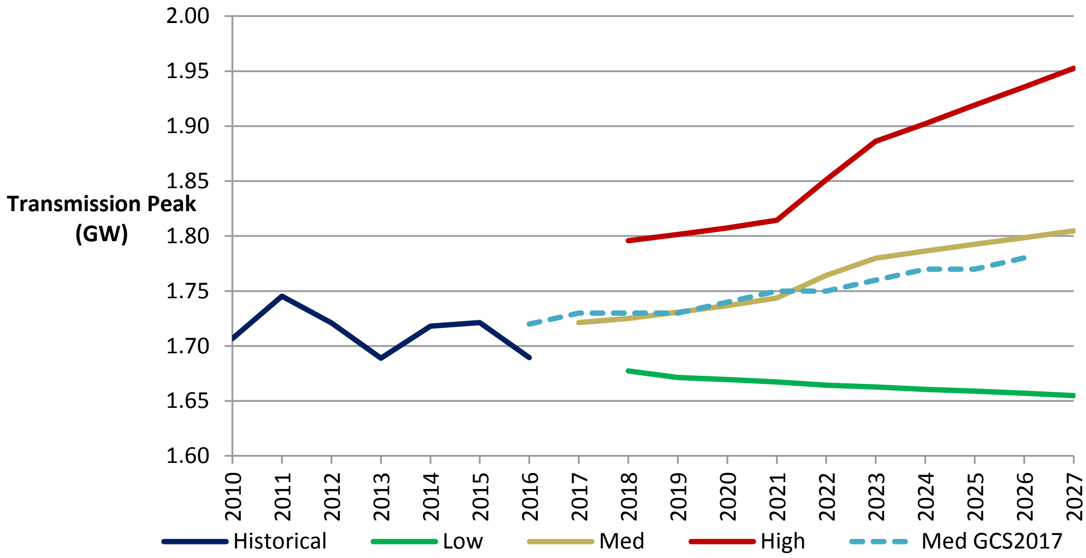


Figure 2-8 ACS Transmission Peak forecasts for Northern Ireland.

2.4. The Combined All-Island Forecast

In order to carry out combined studies for the all-island system, we add the two jurisdictional forecasts together, see Figure 2-9. Figure 2-10 shows the transmission peak forecast for the combined All-Island forecast.

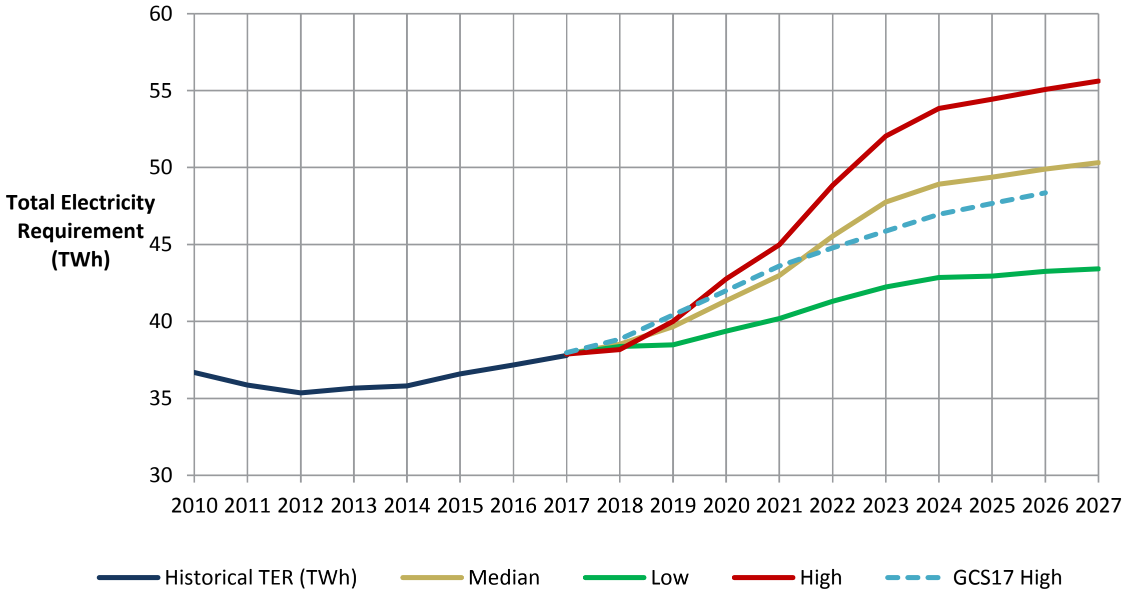


Figure 2-9 The combined TER forecast for the all-island system.

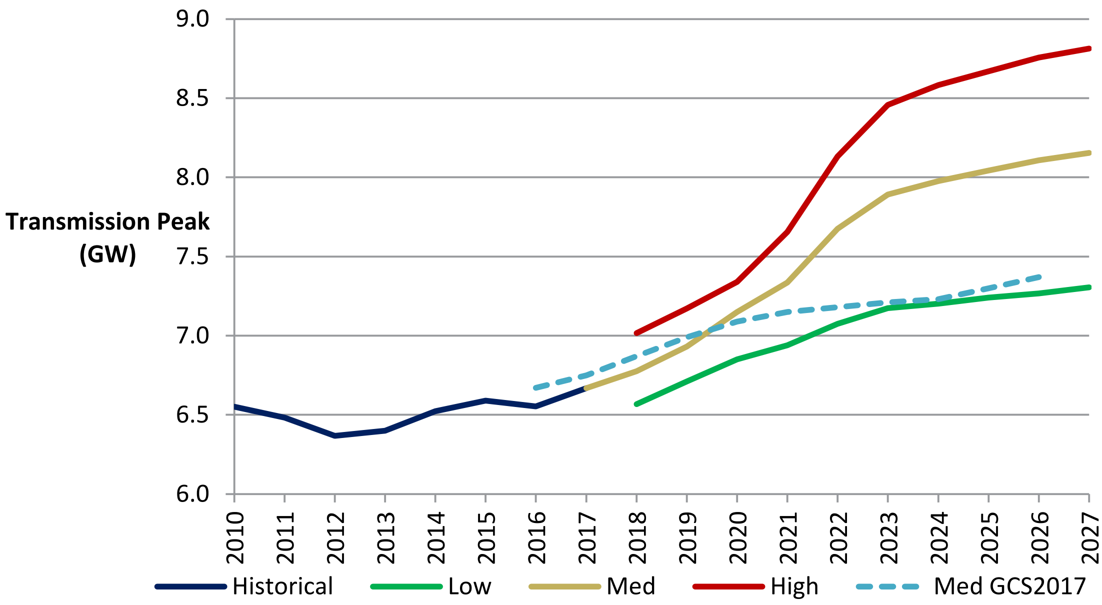


Figure 2-10 The Transmission Peak forecast for the combined All-Island forecast.

2.5. Annual Load Shape and Demand Profiles

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, 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 occurs during winter weekday evenings while minimum usage 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 2-11 shows typical daily demand profiles for a recent 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.

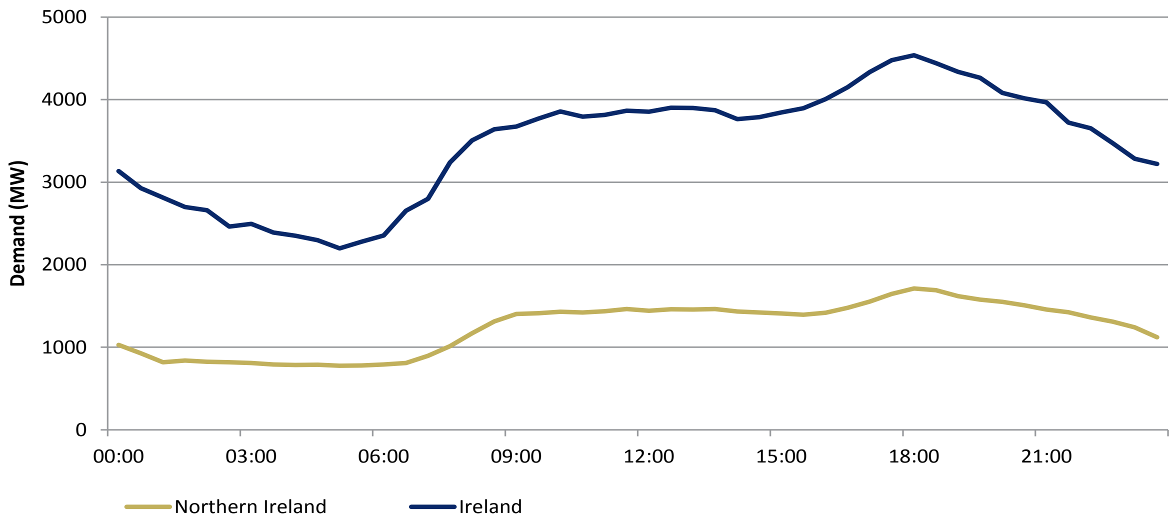


Figure 2-11 Typical winter day profile.

Generation 3

3. Generation

3.1. Introduction

This section describes the significant sources of electricity generation connected to the systems in Ireland and Northern Ireland, and known to the system operators. The portfolio may change due to the Capacity Market in the new I-SEM. This is because only plant that are successful in the capacity auctions for the relevant years will receive capacity payments and therefore be liable for Reliability Options. Plant that does not receive capacity payments may seek to exit the market.

A total of 9.4 GW of capacity cleared in the first T-1 All-Island capacity auction held in December 2017, as shown in Figure 3-1. The amount of unsuccessful plant was 0.7 GW in Ireland and 0.6 GW in Northern Ireland. For the purposes of adequacy studies, we have included this unsuccessful plant. This does not mean that unsuccessful capacity will, or will not, continue to operate in the market.

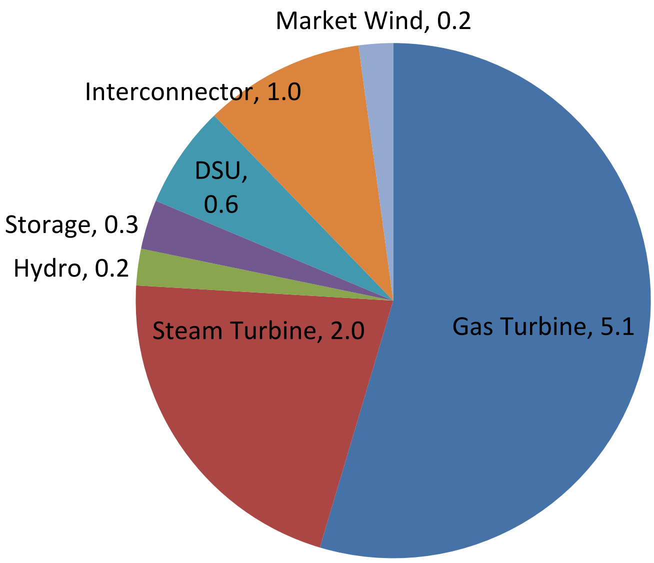


Figure 3-1 The total amount of capacity (GW) that cleared the first T-1 All-Island Capacity Market auction in December 2017 was 9.4 GW. Here it is divided into the technology categories used in the Capacity Market.

3.2. Changes to Conventional Generation in Ireland

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

For Ireland, the only new conventional generators to be included in our adequacy studies are those which have a signed connection agreement with EirGrid[13] or the DSO (Distribution System Operator). In addition, plant needs to have planning permission, financial close and have indicated a commissioning date to EirGrid by the data freeze date.

There are no potential new conventional generators which fulfil these criteria.

Some of the older generators have informed us of their intention to decommission, as detailed below. The main reason for decommissioning is because of emissions restrictions.

13 I.e. a signed Connection Offer has been accepted and any conditions precedent fulfilled.

Plant	Export Capacity (MW)	Expected to close by the end of year:	Comment
Aghada (AD1)	258	2018	IED Limited Life-time Derogation. Did not clear the 2018/19 T-1 auction. Closed in September 2018
Aghada (AT1)	90	2023	IED Limited Life-time Derogation.
Marina CC (MRC)	95	2018	IED Limited Life-time Derogation. Did not clear the 2018/19 T-1 auction. Closed in August 2018.
North Wall 5	104	2023	IED Limited Life-time Derogation.
Tarbert 1, 2, 3, 4	592	2022	Notified by SSE.

Table 3-1 Assumptions for Plant changes in Ireland.

For the purposes of compliance with the IED (Industrial Emissions Directive[14], see section 3.4), some ESB plant has been designated a 'Limited Life-time Derogation'. These plant will have limited running hours and are expected to shut by the end of 2023, see Table 3-1.

For the purposes of adequacy studies, we have included all plant that entered the auction, not just the capacity that was successful in the auction. This amounts to 7.4 GW of dispatchable plant in Ireland. This does not mean that unsuccessful capacity will, or will not, continue to operate in the market.

3.3. Changes to Conventional Generation in Northern Ireland

For the purposes of adequacy studies, all plant that entered the auction are included, not just the capacity that was successful in the auction. This amounts to 2.3 GW of dispatchable plant in Northern Ireland. This does not mean that unsuccessful capacity will, or will not, continue to operate in the market.

Ballylumford (units B4 and B5) have been providing 250 MW under a contract for Local Reserve Services. This contract will run out at the end of 2018. Unit B4 was successful in the capacity auction, however, B5 was unsuccessful. However, in the absence of any formal notification of closure, we have included both of these units for the purposes of the adequacy studies.

In Northern Ireland, transmission network capacity limitations can restrict the amount of power that can be exported onto the transmission network in the east of the province at Islandmagee (Ballylumford). Under these conditions it would not be possible to export the total plant capacity at Islandmagee. This restriction will be taken into account when and if it is applicable for the adequacy studies.

14 Industrial Emissions Directive (IED) http://ec.europa.eu/environment/industry/stationary/ied/legislation.htm

Plant	Export Capacity (MW)	Expected to close by the end of year:	Comment
Kilroot ST1	238	2024	AES have indicated that it will reduce to 199 MW from mid-2020. It is assumed not available after 2024 due to restrictions on coal-firing.
Kilroot ST2	238	2024	AES have indicated that it will reduce to 199 MW from mid-2020. It is assumed not available after 2024 due to restrictions on coal-firing.

Table 3-2 Assumptions for plant changes in Northern Ireland

AES has invested in a system at ST1 and ST2 to reduce emissions. They have been fully available in 2016 and 2017 as a result of this investment and an ability to purchase some additional emission allowances in the UK NOx trading scheme. They believe they can be fully available under this arrangement until the end of June 2020.

Emission restrictions become tighter in July 2020 when the Transitional National Plan ends and units could be limited to a rolling annual average of 1500 stack hours. In 2021 BAT and BREF restrictions will apply, so limits will further tighten. However, AES has been working with a supplier that has developed a solution to further reduce NOx emissions and is reasonably confident that with this in place, they could be fully available until the end of 2024. This solution would only apply to the coal rating of 398 MW. Note that AES have indicated that the solution is new technology so there is uncertainty - no investment decision has been made, and the business case is uncertain when taking into account the T-1 2018/19 capacity market results. However, in the absence of a formal notification of closure, we have modelled the units at the reduced capacity of 398 MW without run-hour or emissions restrictions for the purposes of the adequacy studies.

Current UK policy is to end coal-fired generation in Great Britain by 2025. While SONI is awaiting proposals for a devolved policy for Northern Ireland, it is seen as being prudent not to incorporate these coal units in the adequacy studies from 2025.

Belfast Power Limited (Evermore Energy) is proposing a 490 MW gas fired power station in the Belfast Harbour Estate. The proposed power station will use combined cycle gas turbine (CCGT) technology. SONI have received an application for grid connection. Belfast Power have submitted an application for Planning Permission to the Northern Ireland Planning Service which is currently under consideration. For the purposes of this report, this project is not included in the adequacy studies. SONI will continue to monitor the status of this project with a view to incorporating it in future studies if appropriate.

3.4. Impact of the 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. The IED replaces seven existing directives including the Integrated Pollution Prevention and Control Directive 2008/1/EC (IPPC) and the Large Combustion Plant Directive 2001/80/EC (LCPD).

In 2017, the European Commission published a final decision on the Best Available Techniques[15] (BAT) for large combustion plants, which will apply new standards on emissions from August 2021. For combustion plants, Emission Limit Values (ELVs) for Nitrous Oxide (NOx), Sulphur Dioxide (SO2) and particulate levels have been tightened.

In Ireland, some plant are affected by the IED, and have entered into the Ireland TNP (Transitional National Plan). However, it is not anticipated that their running regimes will be curtailed. For example, under the TNP, Moneypoint's availability will be closely linked to the performance of its abatement equipment. While acknowledging the challenge, ESB's current projections are for full availability across the period of the TNP and beyond.

3.5. Interconnection

Interconnection allows the transport of electrical power between two transmission systems. Interconnection with Great Britain over the Moyle and the East-West interconnectors provides significant capacity benefit. It also allows opportunities for direct trading between the system operators, known as counter-trading. Further transmission links between Ireland and Northern Ireland would significantly enhance generation adequacy in both jurisdictions.

3.5.1. North South Interconnector

As the second high capacity transmission link between Ireland and Northern Ireland is assumed to commission in 2023, an all-island generation adequacy assessment can be carried out from 2024 onwards. This all-island assessment shows an increase in the security of supply for both jurisdictions, as the demand and generation portfolios for Northern Ireland and Ireland are aggregated to meet to combined demand.

Prior to the completion of this second North South Interconnector project, the existing interconnector arrangement between the two regions creates a physical constraint that affects the level of support that can be provided by each system to the other. On this basis each TSO is obliged to help the other in times of shortfall.

With this joint operational approach to capacity shortfalls, the TSOs agreed that the level of spinning reserve would be maintained by modifying interconnector flows. Reductions in reserve would be followed by load shedding by both parties as a final step to maintaining system integrity.

Generation adequacy assessments for each region are carried out with an assumed degree of capacity interdependence from the other region. This is an interim arrangement until the additional interconnector removes this physical constraint. The capacity reliance values used for the adequacy studies are shown in Table 3-3.

	North to South	South to North
Capacity Reliance	100 MW	200 MW

Table 3-3 Capacity reliance at present on the existing North South Interconnector

During real time operations, flows in excess of the capacity reliances can sometimes take place.

As it is within the all-island market, the interconnection between Ireland and Northern Ireland is treated as an element of the transmission system, rather than an interconnector to facilitate cross-border trading. As such, it is a different case compared to how the Moyle and EWIC interconnectors are considered.

15 http://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1502972300769&uri=CELEX:32017D1442

3.5.2. Generation Available in Great Britain

When assessing the contribution of an interconnector to generation adequacy, we need to consider the availability of generation at the other side, as well as the availability of the interconnector itself.

In the Final Auction Information pack[16] for the T-1 I-SEM Capacity Market auction, the Regulatory Authorities confirmed the External Market De-rating Factor of the undersea interconnectors to be 60%. We use these derating values in our adequacy studies, and continue to review this and the effect it has on our capacity adequacy.

In order to improve our understanding of how interconnection can provide benefit, we look to our European neighbours. ENTSO-E, in collaboration with EirGrid, SONI and other TSOs, has recently improved its adequacy assessment methodology with a special emphasis on harmonised inputs, system flexibility and interconnection assessments. The Mid-Term Adequacy Forecast (MAF[17]) uses probabilistic methods to take into account the intermittency of the growing renewable generation sector.

3.5.3. East West HVDC Interconnection between Ireland and Wales

The East-West interconnector (EWIC) connects the transmission systems of Ireland and Wales with a capacity of 500 MW in either direction. However, it is difficult to predict whether or not imports for the full 500 MW will be available at all times. Informed by the I-SEM Capacity Market decision, we use a 60% External Market De-rating Factor, i.e. 300 MW, and appropriate availability statistics.

3.5.4. Moyle Interconnector between Northern Ireland and Scotland

The Moyle Interconnector is a dual monopole HVDC link with two coaxial undersea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). When fully operational the transfer capacity of the Moyle Interconnector for the trading of electricity between the electricity markets of Ireland and Great Britain varies[18] as shown in Table 3-4.

Direction	Month	Capacity available to interconnector users	Capacity limit set by
West to East	May – August	80-287 MW	NG/ GB System
	September – April	80-295 MW	NG/ GB System SONI/ NI System
East to West	April – October	410 MW	SONI/ NI System
	November – March	450 MW	NG/ GB System

Table 3-4 Transfer capacity of the Moyle Interconnector

For the purposes of adequacy studies, we treat the Moyle interconnector similarly to EWIC, i.e. with a 60% External Market De-rating Factor (270 MW), and appropriate availability statistics.

16 http://lg.sem-o.com/ISEM/General/Final%20Auction%20Information%20Pack%20v1.0.pdf
17 https://www.entsoe.eu/outlooks/maf/Pages/default.aspx
18 http://www.mutual-energy.com/electricity-business/moyle-interconnector/trading-across-the-moyle-interconnector/

3.5.5. Further Interconnection

There are many proposed interconnector projects involving Ireland and Northern Ireland. Table 3-5 below contains a list of projects that has been assessed as part of the next European Ten Year Network Development Plan[19]. As these projects are at a preliminary stage, we have not included them in the adequacy assessments in this report.

Project	Description
Celtic	Interconnector between Ireland and France (with PCI status[20])
Gallant	Project providing interconnection to Great Britain
Greenconnect	Project providing interconnection to Great Britain
Greenlink	Project providing interconnection to Great Britain (with PCI status[20])
Greenwire North	Project providing interconnection to Great Britain
Greenwire South	Project providing interconnection to Great Britain
Irish-Scottish Links on Energy Study (ISLES)	Offshore wind hub potentially providing interconnection to Scotland
Marex	Project providing interconnection to Great Britain

Table 3-5 Proposed interconnection projects

3.6. Wind Capacity and Renewable Targets

In both Ireland and Northern Ireland, government policies have been in place which target the amount of electricity sourced from renewables. The integration of more variable renewable forms of generation on the power system means we must consider an additional complex range of demand and supply issues. Our 'Delivering a Secure Sustainable Electricity System' (DS3) programme aims to meet the challenges of operating the electricity system in a secure manner while achieving the 2020 renewable electricity targets[21].

Biofuels, hydro and solar energy will make an important contribution to these targets. However, it is assumed that these renewable targets will be achieved largely through the deployment of additional wind powered generation. Table 3-6 shows the totals for existing and planned wind generation on the island. EirGrid publish a list of all Transmission Connected wind generation in Ireland[22], while ESB Networks publishes that which is Distribution Connected[23]. The figures for Northern Ireland are based on volumes of applications to SONI and NIE Networks which have accepted a grid connection offer and do not include small scale generation.

19 TYNDP 2016 is produced by the European Network of Transmission System Operators – Electricity (ENTSO-e), see http://tyndp.entsoe.eu/
20 EC Project of Common Interest, see:
https://ec.europa.eu/energy/sites/ener/files/documents/memberstatespci_list_2017.pdf
21 http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/
22 http://www.eirgridgroup.com/customer-and-industry/general-customer-information/connected-and-contracted-generators/
23 https://www.esbnetworks.ie/new-connections/generator-connections/generator-connection-statistics

	Existing (MW)	Planned (MW)
Ireland TSO	1490	1380
Ireland DSO	1820	1260
Subtotal for Ireland	*3310*	*2640*
Northern Ireland TSO	121	0
Northern Ireland DSO	878	231
Subtotal for Northern Ireland	*999*	*231*
Totals	**4309**	**2871**

Table 3-6 Existing (connected or energised) and planned (contracted or applied) wind farms, as of the end of 2017.

3.6.1. Wind Power in Northern Ireland

The Strategic Energy Framework for Northern Ireland restated the target of 12% of electricity consumption from renewable resources by 2012 with a new additional target of 40% of electricity consumption from renewable resources by 2020. The Department for the Economy is currently reviewing its Strategic Energy Framework 2010-2020. For 2017, 30.5% of electricity consumption came from renewable sources in Northern Ireland (most of which was from wind power).

The Northern Ireland Renewables Obligation (NIRO) is the main policy measure for supporting the development of renewable electricity in Northern Ireland. It works alongside the Renewables Obligation (RO) for England and Wales and the Renewables Obligation Scotland (ROS). As part of UK-wide Electricity Market Reform, all three Renewables Obligations closed to new generation from 1 April 2017.

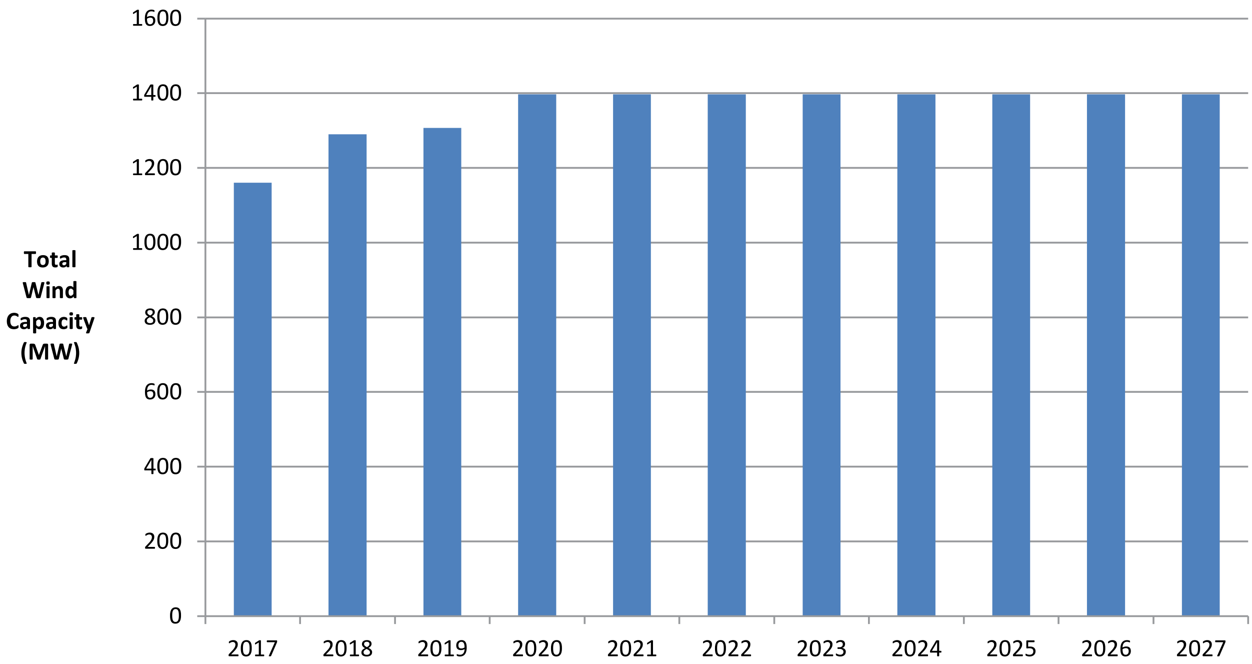


Figure 3-2 The expected growth of wind capacity installed in Northern Ireland, reaching almost 1400 MW by 2020. These assumptions are based on volumes of applications to SONI and NIE Networks which have accepted a grid connection offer and includes both large scale and small scale wind.

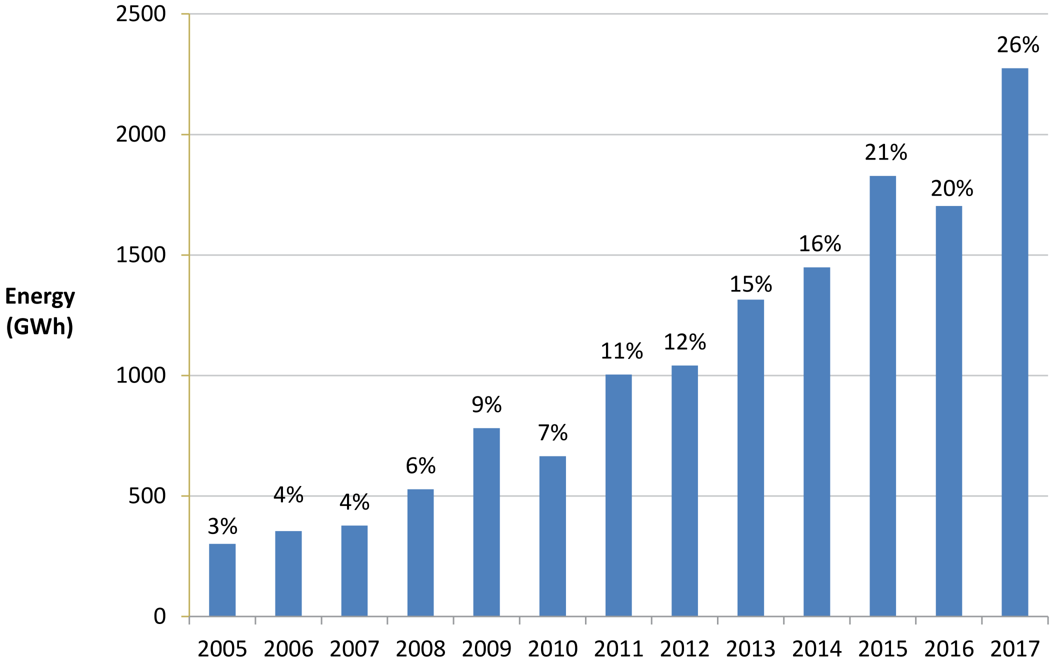


Figure 3-3 Energy supplied by wind in Northern Ireland, in GWh, and as a percentage of total demand.

We estimate that an installed wind capacity of circa 1250 MW, along with contributions from other renewables such as solar photo-voltaic and biomass (see Table A-9), will be enough to reach 40% renewables generation by 2020. Thus, the assumed value of 1400 MW of wind capacity in 2020 should achieve that target. We have assumed that large scale onshore wind has a capacity factor of 30%, PV 10% and large scale biomass 80%.

The analysis assumes that new wind farms in Northern Ireland will be connected to the grid and that the necessary reinforcements will be completed in a timely manner. No sensitivities around this assumption are considered. For the purposes of the studies for this report we assume that by 2027 there will not be any offshore wind or tidal connected.

Figure 3-3 shows the increase in energy supplied from wind generation in recent years. In 2005, just 3.4% of Northern Ireland's electricity needs came from wind generation. This share had increased to 26% by 2017.

3.6.2. Wind Power in Ireland

The Irish Government has a target of 40% of electricity to be generated from renewable sources by 2020, as was restated in the 2015 White Paper on Energy[24]. The 40% target is part of the Government's strategy to meet an overall target of achieving 16% of all energy consumed to come from renewable sources by 2020.

Installed capacity of wind generation has increased from 145 MW at the end of 2002 to over 3300 MW at the end of 2017. This value is set to increase over the next few years as Ireland endeavours to meet its renewable target in 2020.

24 http://www.dccae.gov.ie/energy/en-ie/Energy-Initiatives/Pages/White-Paper-on-Energy-Policy-in-Ireland-.aspx

In order to comply with the RES Directive (2009/28/EC) guidelines for our 2020 RES target, we normalise the annual energy from wind power[25]. This is done by applying an average of the past 5 year's capacity factor. This normalised annual energy has grown from 4200 GWh in 2012 to 7600 GWh in 2017, which accounts for approximately 25% of total electricity demand in 2017 (provisional figure for 2017), and is shown in Figure 3-4. The variation in wind capacity factors is also displayed. The average wind capacity factor over the last five years is 28.5%[26], and this is used for future predictions of energy from onshore wind.

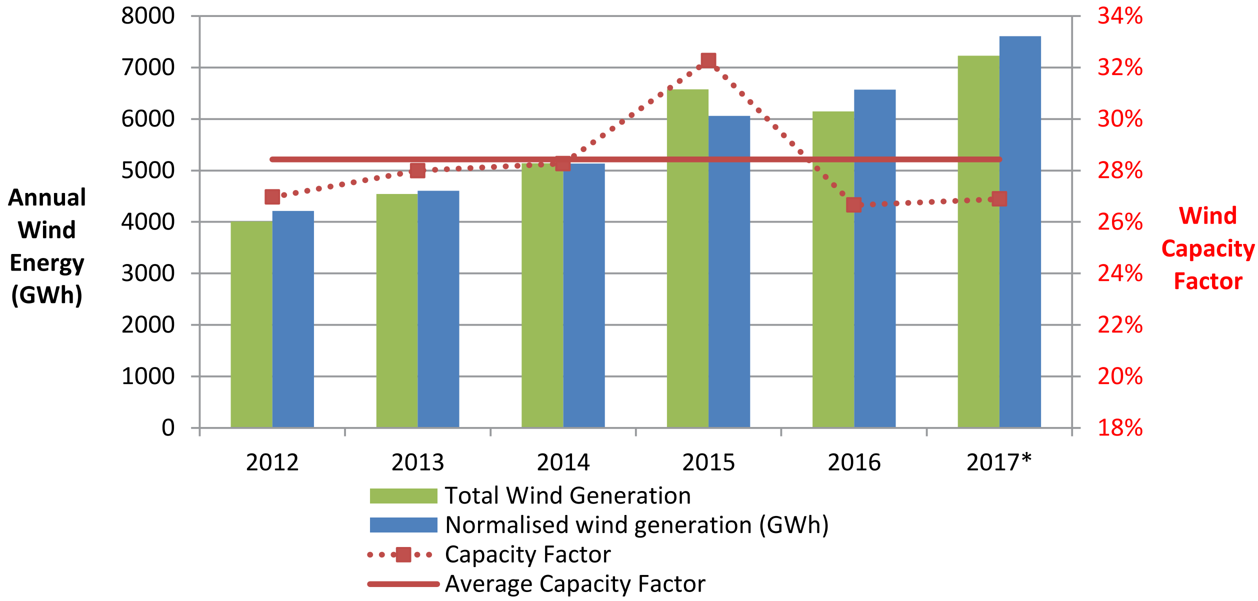


Figure 3-4 The actual and normalised annual energy produced from wind power in Ireland over the last six years. In red are the figures for annual wind capacity factor, and their average. Data for 2017 is provisional.

The actual amount of renewable energy this requires will depend on the demand in future years. Also, the assumptions made for other renewable generation will have a bearing on how much wind energy will need to be generated to reach the 40% target. Lastly, a small amount of available energy from wind cannot be used due to transmission constraints or system curtailment. We estimated this to be approximately 3.7% in 2017[27]. As this has varied between 2.4% and 5.1% over the past seven years, we assume a value of 5% for our future studies.

With these uncertainties in mind, we estimate that a band of 3,900 – 4,400 MW of on-shore wind capacity is required to meet the 2020 RES-E targets for Ireland, with 4,200 MW being the most likely figure. This would imply an average build-out of about 300 MW per year until the end of 2020, see Figure 3-5.

25 http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0028&from=EN
26 In previous years we have used a wind capacity factor which was not affected by windfarms that were commissioning during the year in question, or by dispatch down. Now we have moved to an assessment that is in line with the EU Renewables Directive 2009 definition which will be used to determine compliance with Ireland's 2020 RES-E target. This has the effect of lowering the capacity factor as shown here, and slightly increasing the amount of installed wind that will be needed to meet the target.
27 http://www.eirgridgroup.com/site-files/library/EirGrid/2017-Qtr4-Wind-Dispatch-Down-Report.pdf

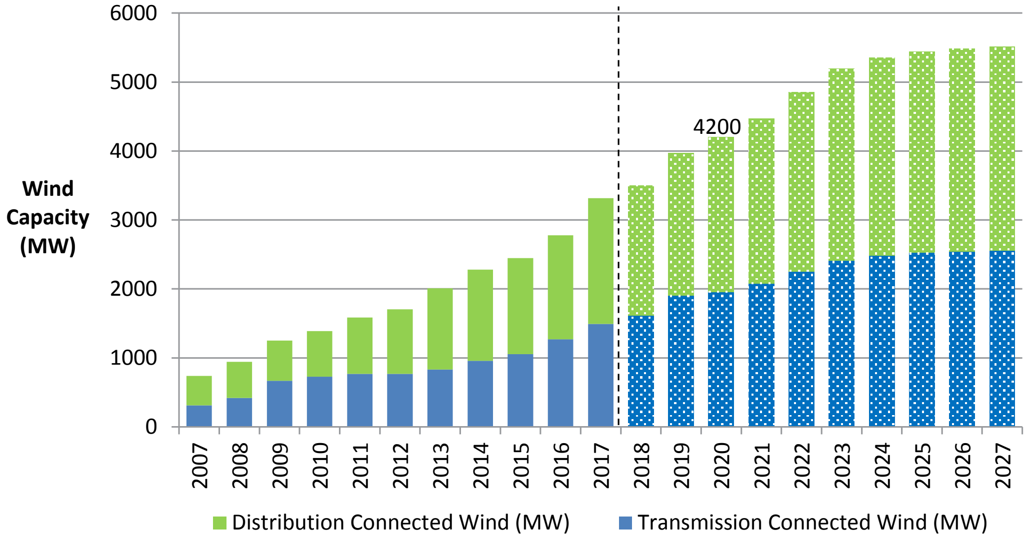


Figure 3-5 Historical and assumed growth of wind capacity in Ireland. The target of 40% RES is met by 2020, and sustained beyond.

3.6.3. Modelling of Wind Power in Adequacy Studies

Previous GCS adequacy studies included the contribution of wind as a capacity credit, e.g. 2000 MW of wind to be installed by a future year was assumed to contribute the same as a 300 MW conventional generator. This approach has been changed to match the treatment of wind in the Capacity Market calculations.

For the Capacity Market, a number of historical wind profiles are grown to match the installed capacity of wind expected in future years. These profiles are then used separately to modify the future demand forecast, where each historical year's profile for wind is matched with the same historical year's demand profile. It is these modified demand forecasts that are subsequently used in the adequacy calculations to obtain the Capacity Requirement for the Capacity Market.

The effect of this modelling resulted in a derating factor 0f 0.103 for wind[28], i.e. that 100 MW of wind would provide 10.3 MW of capacity for adequacy purposes. We have adopted this de-rating factor for the GCS adequacy studies, where the sum of all the wind power is de-rated by this factor.

3.7. Other Non-Conventional Generation

The assumed build-out of non-conventional generators is summarised in APPENDIX 3 (Table A-5 and Table A-8).

3.7.1. Demand Side Units

A Demand Side Unit (DSU) consists of one or more individual demand sites that we can dispatch as if it was a generator. An individual demand site is typically a medium to large industrial premises. A DSU Aggregator may contract with the individual demand sites and aggregate them together to operate as a single DSU.

Dispatchable Aggregated Generating Units (AGU) operate in Northern Ireland, which consist of a number of individual diesel generators grouping together to make available their combined capacity to the market. An AGU capacity of 78 MW and a DSU capacity of 94 MW were successful in the 2018/19 T-1 Capacity Market auction held in December 2017.

28 http://lg.sem-o.com/ISEM/General/Final%20Auction%20Information%20Pack%20v1.0.pdf

In Ireland, 500 MW of DSU capacity cleared the 2018/19 T-1 Capacity Market auction held in December 2017. This is double what had been previously available. We will continue to monitor this relatively new capacity in order to assess its contribution to adequacy appropriately.

We have modified our DSU modelling approach to match what has been used in the Capacity Market. This uses an availability of approximately 90%. In GCS17, we used the previous year's average available statistics for DSUs.

The 12-month rolling average availability of DSUs to March 2018 was approximately 60%. Therefore there would need to be a substantial improvement in the performance of DSU's to match the assumption used in this report. Without such an improvement, the adequacy situation would dis-improve from the adequacy assessments presented here.

For the next T-1 auction (2019/20), this is changed so that a DSU's de-rating factor will be reduced to reflect the run-time limitations that it declares.

Industrial generation refers to generation, usually powered by diesel engines, located on industrial or commercial premises, which acts 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 would fall outside the control of the TSOs. Industrial generation has been ascribed a capacity of 9 MW in Ireland for the purposes of this report.

3.7.2. Small-scale CHP

Combined Heat and Power utilises generation plant to simultaneously create both electricity and useful heat. Due to the high overall efficiency of CHP plant, often in excess of 80%, its operation provides benefits in terms of reducing fossil fuel consumption and $CO2$ emissions.

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). With little further information, an assumption has been made that, for the purposes of this statement, this will not change.

There were approximately 158 MW of CHP units noted in Ireland in the previous GCS, mostly gas-fired. However, this amount has been lessened by an amount of CHP units that have now registered as a DSU. This does not include the 161 MW centrally dispatched CHP plant operated by Aughinish Alumina.

3.7.3. Biofuel

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

Currently in Northern Ireland, there is an estimated 44 MW of small scale generation powered by biofuels, including biomass, biogas and landfill gas. For the purposes of this report, and in the absence of more detailed information, it has been assumed that this capacity will not change.

Lisahally Waste Project became operational in 2015 in Northern Ireland. It is a wood-fueled 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.

For the previous GCS, EirGrid estimated there to be 54 MW of generation capacity powered by biofuel, biogas or landfill gas in Ireland. This amount has now been lessened by an amount of biofuel units that have registered as a DSU.

We have assumed that the peat plant at Edenderry, Lough Ree and West Offaly will be approximately 30-35% powered by biomass by 2020.

REFIT 3[29] provides an incentive for biomass-fuelled CHP plant. This will likely result in up to 100 MW of plant, including Dublin Waste Energy. These plant will make a significant contribution to the 40% RES target.

3.7.4. Small-scale Hydro

It is estimated that there is currently 22 MW of small-scale hydro capacity installed in rivers and streams across Ireland. Such plant generates approximately 43 GWh per year, making up 0.2% of total annual generation. While this is a mature technology, the lack of suitable new locations limits increased contribution from this source. It is assumed that there are no further increases in small hydro capacity over the remaining years of the study.

The capacity in Northern Ireland is approximately 6 MW and consists primarily of a large number of small run-of-the-river projects. For the purposes of this report it has been assumed that this capacity will not change.

3.7.5. Waste-to-energy

In early 2018, approximately 15 MW of energy from waste generation has been installed at the Bombardier site in Belfast. This is not currently dispatchable.

The 61 MW Dublin waste-to-energy plant was commissioned in 2017. Both this plant and Indaver (17 MW) use waste with over 50% renewable content, thus contributing to our RES targets.

3.7.6. Solar PV

In Northern Ireland, the capacity of small scale solar PV has increased rapidly in recent years. Connected capacity is approximately 100 MW (as of end 2017). SONI expects this capacity will continue to grow, reaching 116 MW by the end of 2018.

A number of large scale PV projects have connected in 2017. Capacity is approximately 120 MW (as of end 2017). SONI expects capacity to grow to 157 MW by the end of 2018.

In Ireland, the future of government support in this sector is unclear, and so we have assumed modest growth, reaching 100 MW by 2023.

Similar to the treatment of wind power, solar PV capacity is de-rated in our adequacy studies to the de-rating factor used in the 2018/2019 T-1 Capacity Market auction, i.e. 0.055[30].

3.7.7. Marine Energy

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

29 http://www.dccae.gov.ie/energy/en-ie/Renewable-Energy/Pages/Refit-3-landing-page.aspx
30 http://lg.sem-o.com/ISEM/General/Final%20Auction%20Information%20Pack%20v1.0.pdf

We note that there are some modest projects planned in the wave energy sector in Ireland. With the large amount of uncertainty associated with this new technology, we have taken the prudent approach that there will be no commercial marine developments available for adequacy purposes in Ireland before 2027.

3.7.8. Kilroot Energy Storage

AES completed the Kilroot Energy Storage Array located in Kilroot Power Station in 2016. This pilot scheme provides 10 MW of interconnected energy storage, as well as system services including frequency regulation as part of the system operators' DS3 System Services arrangements. While providing DS3 System Services is desirable, this type of capacity is not included in our models for adequacy calculation purposes.

3.8. Plant Availability

The assumptions made for availability of plant have a significant impact on the results of adequacy studies. For a number of years, the GCS has followed a certain procedure for projecting availability of plant in adequacy studies. However, the methodology for analysing availability in the Capacity Market is slightly different to this.

Therefore, we have aligned our methodology with that of the Capacity Market, in order that the analysis in the GCS is compatible with that of the Capacity Market. The methodology used to calculate plant availability for the Capacity Market uses 5-year averages per technology class. We also used long-term average availability data in previous GCS reports.

There are five different technology classes in the Capacity Market, and a system-wide class, see Table 3-7. For comparison, see the system-wide average FOR in Ireland in Figure 3-6.

Technology Category	Mean Forced Outage Rate (%)	Mean Scheduled Outage Duration (weeks)
DSU	4.8%	4
Gas Turbine	3.0%	3
Hydro	3.8%	8
Steam Turbine	6.9%	3
Storage	8.8%	3
System Wide	4.8%	4

Table 3-7 Availability parameters that were used in the first T-1 Capacity Market auction in December 2017.

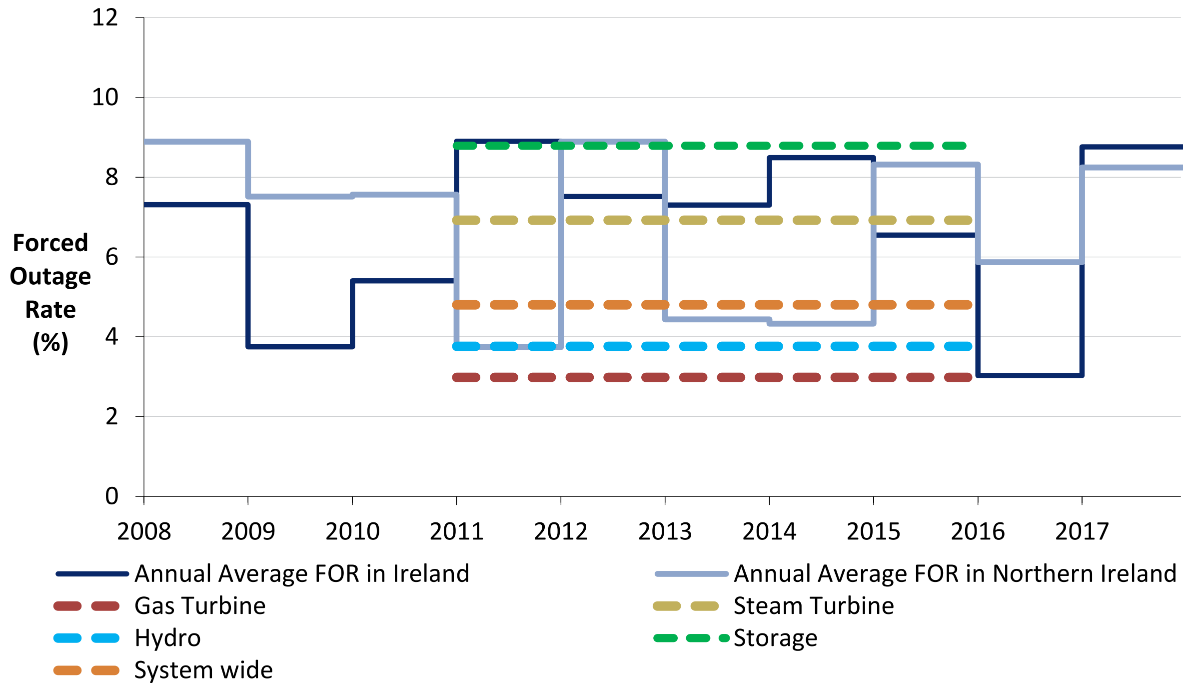


Figure 3-6 The average annual system-wide FOR in Ireland and in Northern Ireland for each of the past 10 years (solid lines in dark and light blue). Also shown (in dashed lines) are the 5-year average values of FOR for each technology type, as assumed in the first T-1 Capacity Market auction for 2018/19.

4 Adequacy Assessments

4. Adequacy Assessments

4.1. Introduction

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 3.

Studies are carried out in three different ways:

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

In this section, we describe the setup of each scenario and present the results of the adequacy studies in graphical format. Tables of the results are to be found in APPENDIX 4.

4.2. Assumptions

In our adequacy studies, we assume the following:

- The assessments were carried out for low, median and high demand scenarios. We also include a scenario at the 8th level demand forecast[31] for Ireland (this matches the level of demand chosen by the Least Worst Regrets methodology for the calculation of the Capacity Requirement in the 2018/19 T-1 Capacity Market auction).
- The portfolio excludes generation capacity that has notified us that they will be not available.
- The availability statistics match those used in the Capacity Market auction, i.e. 5-year average values for each technology category.
- The derating factor for the undersea interconnectors (EWIC and Moyle) was approximately 50%, as determined by the Regulatory Authorities.
- Typical profiles of demand and wind were used in the studies.
- The adequacy standard is set at 8 hours Loss of Load Expectation (LOLE) per year for Ireland and in the all-island case. For Northern Ireland, the standard is 4.9 hours LOLE.

For single-jurisdictional studies:

- Ireland assumes a 100 MW capacity reliance on Northern Ireland,
- Northern Ireland assumes a 200 MW capacity reliance on Ireland.

For the all-island study, these reliance values are not used.

The adequacy results are given in MW as a surplus (+) or deficit (-) of perfect plant (plant that is 100% available).

31 Demand Level 8 was selected in the 2018/19 T-1 Capacity Market auction. It is recalculated for each Capacity Market auction, which could result in different demand levels being selected in future.

4.3. Adequacy Results for Northern Ireland

Figure 4-1 shows a graphical representation of the adequacy studies' results for Northern Ireland over the ten years of the study.

There are separate traces for the low, median and high demand scenarios. The median demand scenario is shown to be in surplus of over 500 MW for most years. This reflects the fact that there is not much change expected in the median demand forecast, or in the plant portfolio. The dip in surplus in 2025 is caused by the assumed unavailability of the Kilroot coal units.

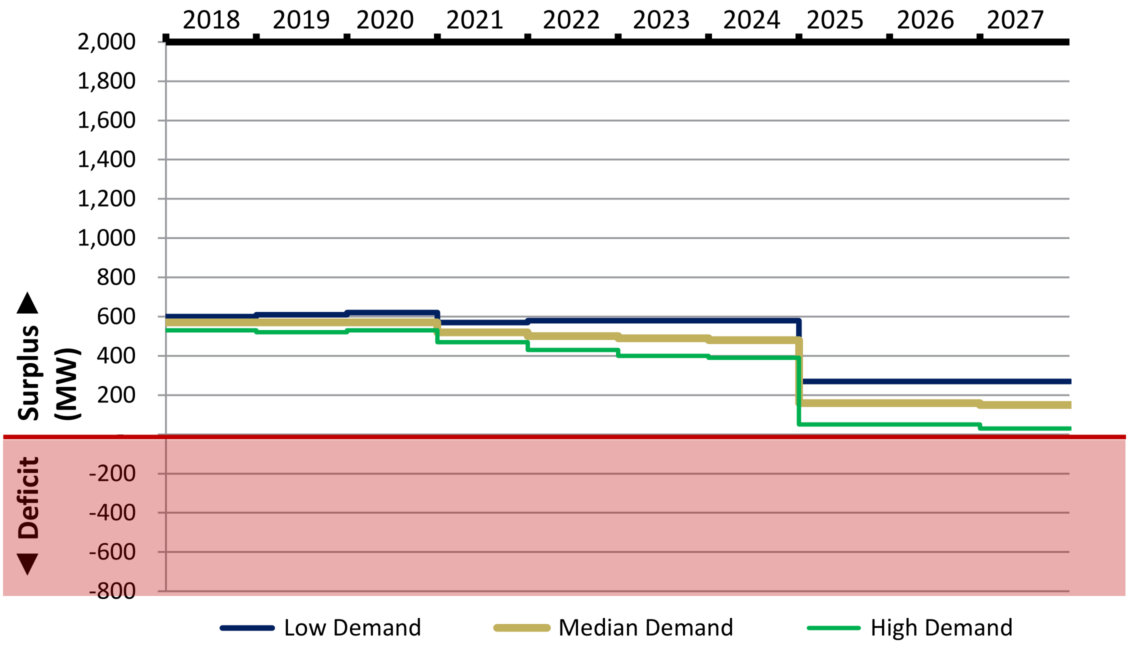


Figure 4-1 Adequacy results for Northern Ireland, in terms of surplus or deficit of plant. Results are given for the low, median and high demand scenarios.

4.4. Adequacy Results for Ireland

The Ireland system starts in a position of significant surplus, as shown in Figure 4-2. This is eroded as the demand forecast increases with each passing year and some generation plant is assumed to shut. If the 8th demand level is assumed, significant deficits are expected from 2024. If capacity unsuccessful in the December 2017 T-1 auction close sooner, then deficits could occur earlier.

We also look at the effects of the generators having low availability, i.e. five years' of availability data was assessed and the worst availability year identified - the availability of each unit in this year is used for the low availability scenario. In other words, there is a 20% chance of this availability scenario transpiring in any particular year. This applies to all generation units, except for the DSUs – the reason for this is that we don't have a sufficient set of historical data to analyse for the DSUs. The adequacy situation deteriorates when using these low availability statistics.

The final scenario that we looked at was one for which only low-carbon plant remains beyond 2025. For this, we started with the median demand scenario, then removed base load capacity with CO2 emissions › 550g/KWh. This is a study only and we have received no indications from generators that they are considering such closures. As ESB is experimenting with biomass co-firing at its peat stations, we made no assumptions on removing these plant in this low-carbon scenario.

You can see below how the adequacy situation dis-improves in this scenario. This shows how there is need for new low-carbon plant to be commissioned should the high-carbon plant shut.

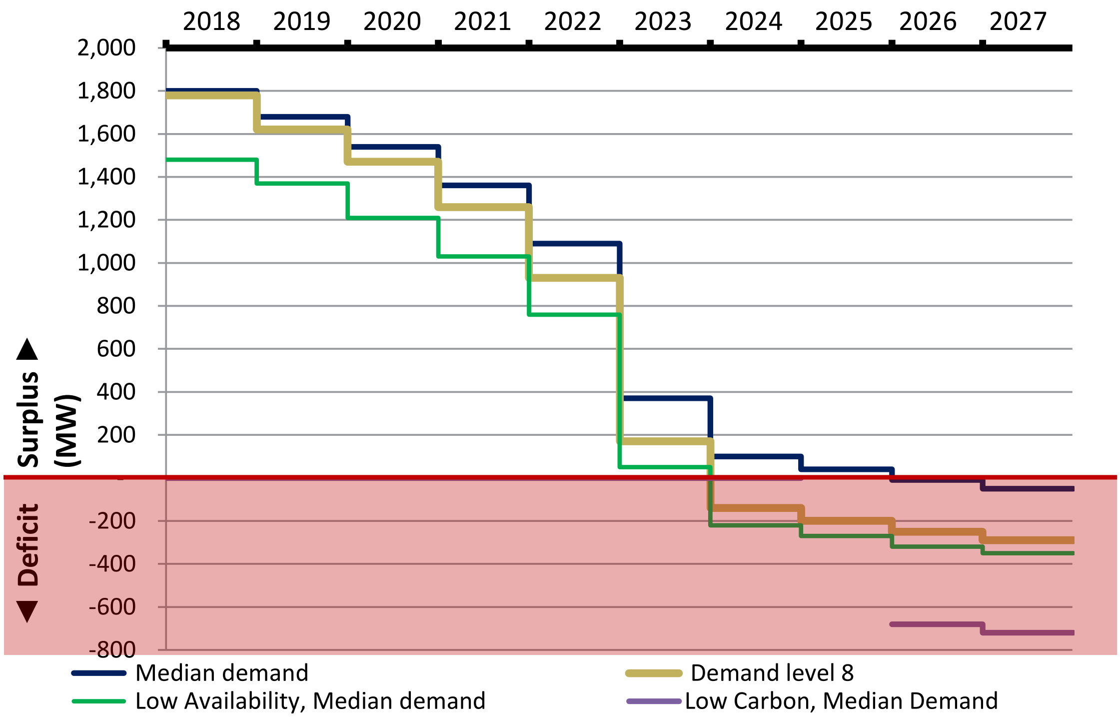


Figure 4-2 Adequacy results for Ireland, in terms of surplus or deficit of plant. Results are given for the median and 8th level demand scenarios. Also shown are the scenarios of low availability and low-carbon.

4.5. Adequacy Results for the All-Island System

There are also studies carried out on an all-island basis, which assume that the second North South Interconnector is available. The second North South Interconnector is assumed to be commissioned in 2023.

In the all-island case, the surplus for any particular year is greater than the sum of the two separate jurisdictional studies. This capacity benefit demonstrates some of the advantages of the second North South Interconnector.

Figure 4-3 shows the all-island adequacy results for different scenarios, all of which are initially in surplus. This surplus drops over time, due to demand increasing and the assumed plant closures. If capacity unsuccessful in the December 2017 T-1 auction, or any other plant, become unavailable, then deficits could occur.

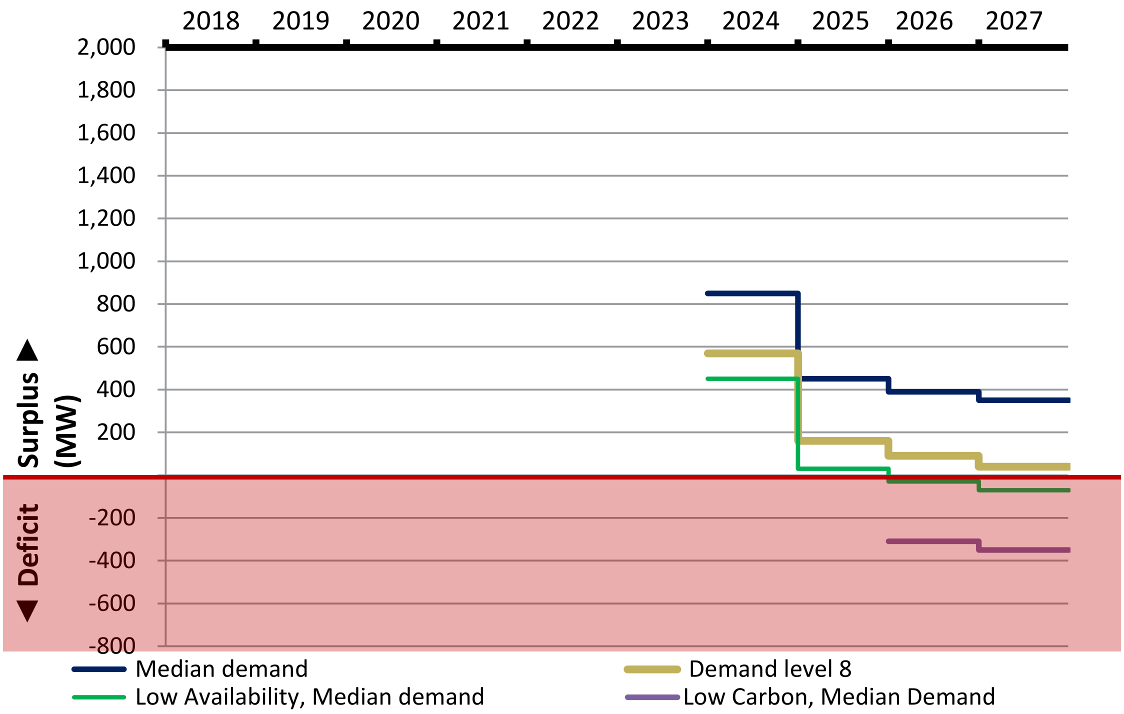


Figure 4-3 Adequacy results for the all-island system.

Appendices

Appendix 1 Demand Scenarios

Median	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2017	28.8		9.03		37.9		5.11	1.75	6.79	5.02	1.72	6.67
2018	29.5	2.2%	9.06	0.2%	38.5	1.7%	5.21	1.76	6.90	5.12	1.73	6.78
2019	30.6	3.8%	9.09	0.3%	39.7	3.0%	5.38	1.77	7.07	5.27	1.73	6.93
2020	32.2	5.3%	9.15	0.7%	41.4	4.2%	5.61	1.77	7.31	5.48	1.74	7.15
2021	33.8	5.1%	9.15	0.1%	43.0	4.0%	5.80	1.78	7.51	5.66	1.74	7.34
2022	36.2	7.0%	9.32	1.8%	45.5	5.9%	6.12	1.80	7.85	5.98	1.76	7.68
2023	38.3	5.8%	9.43	1.1%	47.8	4.9%	6.32	1.82	8.07	6.18	1.78	7.89
2024	39.4	2.8%	9.49	0.7%	48.9	2.4%	6.40	1.82	8.15	6.26	1.79	7.98
2025	39.9	1.1%	9.50	0.1%	49.4	0.9%	6.46	1.83	8.22	6.32	1.79	8.04
2026	40.4	1.2%	9.54	0.4%	49.9	1.1%	6.52	1.84	8.29	6.38	1.80	8.11
2027	40.7	1.0%	9.58	0.4%	50.3	0.9%	6.56	1.84	8.33	6.42	1.80	8.15

Table A-1 The Median 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.

Low	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2017	28.8		9.03		37.9		5.11	1.75	6.79	5.02	1.72	6.67
2018	29.4	2.0%	8.95	-0.9%	38.4	1.3%	5.05	1.71	6.69	4.96	1.68	6.57
2019	29.5	0.4%	8.93	-0.2%	38.5	0.3%	5.22	1.71	6.85	5.11	1.67	6.71
2020	30.4	3.0%	8.93	0.0%	39.4	2.3%	5.38	1.70	7.01	5.25	1.67	6.85
2021	31.3	2.7%	8.92	-0.1%	40.2	2.1%	5.48	1.70	7.11	5.34	1.67	6.94
2022	32.4	3.6%	8.91	-0.1%	41.3	2.8%	5.62	1.70	7.25	5.48	1.66	7.08
2023	33.3	2.8%	8.90	-0.1%	42.2	2.2%	5.72	1.70	7.35	5.58	1.66	7.17
2024	33.9	1.8%	8.92	0.2%	42.9	1.5%	5.75	1.70	7.38	5.61	1.66	7.20
2025	34.1	0.4%	8.89	-0.3%	42.9	0.2%	5.79	1.70	7.42	5.65	1.66	7.24
2026	34.4	0.9%	8.88	-0.1%	43.2	0.7%	5.82	1.69	7.44	5.68	1.66	7.27
2027	34.5	0.5%	8.87	-0.1%	43.4	0.4%	5.86	1.69	7.48	5.72	1.65	7.31

Table A-2 Low Demand Forecast.

High	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2017	28.8		9.03		37.9		5.11	1.75	6.79	5.02	1.79	6.74
2018	29.0	0.6%	9.15	1.3%	38.2	0.8%	5.38	1.83	7.14	5.29	1.80	7.02
2019	30.8	6.1%	9.22	0.7%	40.0	4.8%	5.55	1.84	7.31	5.44	1.80	7.17
2020	33.4	8.6%	9.32	1.2%	42.8	6.9%	5.73	1.84	7.50	5.60	1.81	7.34
2021	35.6	6.4%	9.39	0.7%	45.0	5.2%	6.05	1.85	7.83	5.91	1.81	7.66
2022	39.1	9.8%	9.76	4.0%	48.8	8.6%	6.49	1.89	8.31	6.35	1.85	8.13
2023	42.0	7.6%	10.02	2.6%	52.0	6.6%	6.78	1.92	8.63	6.64	1.89	8.46
2024	43.7	4.0%	10.14	1.2%	53.8	3.4%	6.89	1.94	8.76	6.75	1.90	8.58
2025	44.2	1.2%	10.21	0.7%	54.4	1.1%	6.96	1.96	8.85	6.82	1.92	8.67
2026	44.8	1.2%	10.30	0.9%	55.1	1.1%	7.03	1.97	8.93	6.89	1.94	8.76
2027	45.2	1.0%	10.40	1.0%	55.6	1.0%	7.07	1.99	8.99	6.93	1.95	8.81

Table A-3 High Demand Forecast.

Appendix 2 Generation Plant Information

Ireland

	ID	Fuel Type	Technology Category	2018	Comment
All Demand Side Units	DSU	various	DSU	512	512 MW was successful in the auction
Aghada	AD1	Gas	Steam Turbine	258	Unsuccessful in the Capacity Market auction, and to be shut by end of 2018
	AT1	Gas/DO	Gas Turbine	90	To be shut before end of 2023
	AT2	Gas/DO	Gas Turbine	90	
	AT4	Gas/DO	Gas Turbine	90	
	AD2	Gas/DO	Gas Turbine	431	
Dublin Bay	DB1	Gas/DO	Gas Turbine	405	
Dublin Waste	DW1	Waste	Steam Turbine	61	
Edenderry	ED1	Milled peat/ biomass	Steam Turbine	118	
Edenderry OCGT	ED3	DO	Gas Turbine	58	
	ED5	DO	Gas Turbine	58	
Great Island CCGT	GI4	Gas/DO	Gas Turbine	431	
Huntstown	HNC	Gas/DO	Gas Turbine	342	
	HN2	Gas/DO	Gas Turbine	408	Unsuccessful in the Capacity Market auction
Indaver Waste	IW1	Waste	Steam Turbine	17	
Lough Ree	LR4	Peat	Steam Turbine	91	
Marina CC	MRC	Gas/DO	Gas Turbine	85	Unsuccessful in the Capacity Market auction, and to be shut by end of 2018
Moneypoint	MP1	Coal/HFO	Steam Turbine	285	
	MP2	Coal/HFO	Steam Turbine	285	
	MP3	Coal/HFO	Steam Turbine	285	
North Wall CT	NW5	Gas/DO	Gas Turbine	104	To be shut by end of 2023
Poolbeg CC	PBA	Gas/DO	Gas Turbine	230	
	PBB	Gas/DO	Gas Turbine	230	
Rhode	RP1	DO	Gas Turbine	52	
	RP2	DO	Gas Turbine	52	
Sealrock	SK3	Gas/DO	Gas Turbine	81	
	SK4	Gas/DO	Gas Turbine	81	

	ID	Fuel Type	Technology Category	2018	Comment
Tarbert	TB1	HFO	Steam Turbine	54	To be shut by end of 2022
	TB2	HFO	Steam Turbine	54	To be shut by end of 2022
	TB3	HFO	Steam Turbine	241	To be shut by end of 2022
	TB4	HFO	Steam Turbine	241	To be shut by end of 2022
Tawnaghmore	TP1	DO	Gas Turbine	52	
	TP3	DO	Gas Turbine	52	
Tynagh	TYC	Gas/DO	Gas Turbine	400	
West Offaly	WO4	Peat	Steam Turbine	137	
Whitegate	WG1	Gas/DO	Gas Turbine	444	
Ardnacrusha	AA1-4	Hydro	Hydro	86	
Erne	ER1-4	Hydro	Hydro	65	
Lee	LE1-3	Hydro	Hydro	27	
Liffey	LI1,2,4,5	Hydro	Hydro	38	
Turlough Hill	TH1-4	Pumped storage	Storage	292	
EWIC	EW1	DC Interconnector		500	
Total Dispatchable plant:				**7913**	

Table A-4 Registered Capacity of dispatchable generation and interconnectors in Ireland in 2018 (MW). DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil.

at year end:	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Wind	3310	3500	3970	4200	4470	4850	5190	5350	5440	5480	5510
Hydro	22	22	22	22	22	22	22	22	22	22	22
Biomass and LFG*	54	24	24	24	24	24	24	24	24	24	24
Biomass CHP	0	10	30	60	60	60	60	60	60	60	60
Industrial	9	9	9	9	9	9	9	9	9	9	9
Conventional CHP*	158	129	129	129	129	129	129	129	129	129	129
Solar PV	5	10	20	50	80	90	100	100	100	200	300
Total	3558	3704	4204	4494	4794	5184	5534	5694	5784	5924	6054

Table A-5 Partially/Non-Dispatchable plant in Ireland (MW).

***Some CHP, Biomass and LFG units have registered as Demand Side units in the Capacity Market, and are therefore included in the previous Table A-4 and not in this table from 2018 (to avoid double-counting). Hence there is an apparent reduction from the figures given in GCS17.**

at year end:	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
All Wind	3310	3500	3970	4200	4470	4850	5190	5350	5440	5480	5510
All Hydro	238	238	238	238	238	238	238	238	238	238	238
Biomass/LFG (including those units registered in the Capacity Market and Biomass CHP)	55	68	88	118	118	118	118	118	118	118	118
Waste (Assume 50% renewable)	40	40	40	40	40	40	40	40	40	40	40
Peat Stations on Biomass	35	35	35	121	121	121	121	121	121	121	121
Solar PV	5	10	20	50	80	90	100	100	100	200	300
Total RES	3683	3891	4391	4767	5067	5457	5807	5967	6057	6197	6327

Table A-6 All Renewable energy sources in Ireland (MW). We have assumed that the peat plant at Edenderry, Lough Ree and West Offaly will be approximately 30-35% powered by biomass by 2020.

Northern Ireland

	ID	Fuel Type	Technology Category	2018	Comment
Ballylumford	ST4 & 5	Gas*/ Heavy Fuel Oil	Steam Turbine	291	250 MW Contracted to the end of 2018.
	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	238	Reduces to 199 MW from mid-2020. Assumed unavailable after 2024.
	ST2	Heavy Fuel Oil*/ Coal	Steam Turbine	238	Reduces to 199 MW from mid-2020. Assumed unavailable after 2024.
	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	78	
DSU	DSU	Various	DSU	94	
Lisahally		Biomass		18	Not in Capacity Market, but assumed available for capacity requirement
Contour Global	CGA	Gas	Gas Turbine	12	
Moyle		DC Interconnector		450	
			Total Dispatchable plant:	**2731**	

Table A-7 Registered Capacity of dispatchable generation and interconnectors in Northern Ireland in 2018 (MW).

at year end:	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Large Scale Wind	1000	1123	1140	1230	1230	1230	1230	1230	1230	1230	1230
Small Scale Wind	160	167	167	167	167	167	167	167	167	167	167
Large Scale Solar	121	157	157	157	157	157	157	157	157	157	157
Small Scale Solar	100	116	116	116	116	116	116	116	116	116	116
Small Scale Biogas	22	22	22	22	22	22	22	22	22	22	22
Landfill Gas	16	16	16	16	16	16	16	16	16	16	16
Small Scale Biomass	6	6	6	6	6	6	6	6	6	6	6
Renewable CHP	3	3	3	3	3	3	3	3	3	3	3
Other CHP	6	6	6	6	6	6	6	6	6	6	6
Small Scale Hydro	6	6	6	6	6	6	6	6	6	6	6
Waste-to-energy*	0	15	15	15	15	15	15	15	15	15	15
Total	1440	1637	1654	1744	1744	1744	1744	1744	1744	1744	1744

Table A-8 Partially/Non-Dispatchable plant in Northern Ireland (MW). *Bombardier and Full Circle.

at year end:	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
All Wind	1160	1290	1307	1397	1397	1397	1397	1397	1397	1397	1397
Solar PV	221	273	273	273	273	273	273	273	273	273	273
All Biomass/Biogas/ Landfill Gas	62	77	77	77	77	77	77	77	77	77	77
Renewable CHP	3	3	3	3	3	3	3	3	3	3	3
Hydro	6	6	6	6	6	6	6	6	6	6	6
Total RES	1452	1649	1666	1756	1756	1756	1756	1756	1756	1756	1756

Table A-9 All Renewable energy sources in Northern Ireland (MW).

Appendix 3 Methodology

Generation Adequacy Standard

Generation adequacy is assessed by determining the likelihood of there being sufficient generation to meet customer demand. It does not take into account any limitations imposed by the transmission system, reserve requirements or the energy markets.

In practice, when there is not enough supply to meet load, the load must be reduced. This is achieved by cutting off electricity to customers. In adequacy calculations, if there is predicted to be a supply shortage at any time, there is a Loss Of Load Expectation (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. In Northern Ireland the adequacy standard 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.

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

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

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 A-10.

	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		

Table A-10 System for LOLE example.

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 A-11:

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.

1)	1)	2)	3)	3)	4)	4)
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**

Table A-11 Probability table.

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 mitigate against such known risks for their own units

Surplus & 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[32]. 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 critical services are not affected.

32 In line with international practice, some risk of such supply shortages are accepted to avoid the unreasonably high cost associated with reducing this risk to a negligible level.

Appendix 4 Adequacy Results

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Demand Level 8	1780	1620	1470	1260	930	170	-140	-200	-250	-290
Median Demand	1800	1680	1540	1360	1090	370	100	40	-10	-50
Low availability, Median Demand	1480	1370	1210	1030	760	50	-220	-270	-320	-350
Low Carbon, Median Demand									-680	-720

Table A-12 Results of adequacy studies for Ireland, given in MW of surplus plant (+) or deficit (-).

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Median Demand	570	570	570	520	500	490	480	160	160	150
Low Demand	600	610	620	570	580	580	580	270	270	270
High Demand	530	520	530	470	430	400	390	50	50	30

Table A-13 Results of adequacy studies for Northern Ireland, given in MW of surplus plant (+) or deficit (-).

Scenario	2024	2025	2026	2027
Demand level 8	570	160	90	40
Median Demand	850	450	390	350
Low Availability, Median Demand	450	30	-30	-70
Low Carbon, Median Demand			-310	-350

Table A-14 Results of adequacy studies for the All-Island system.

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