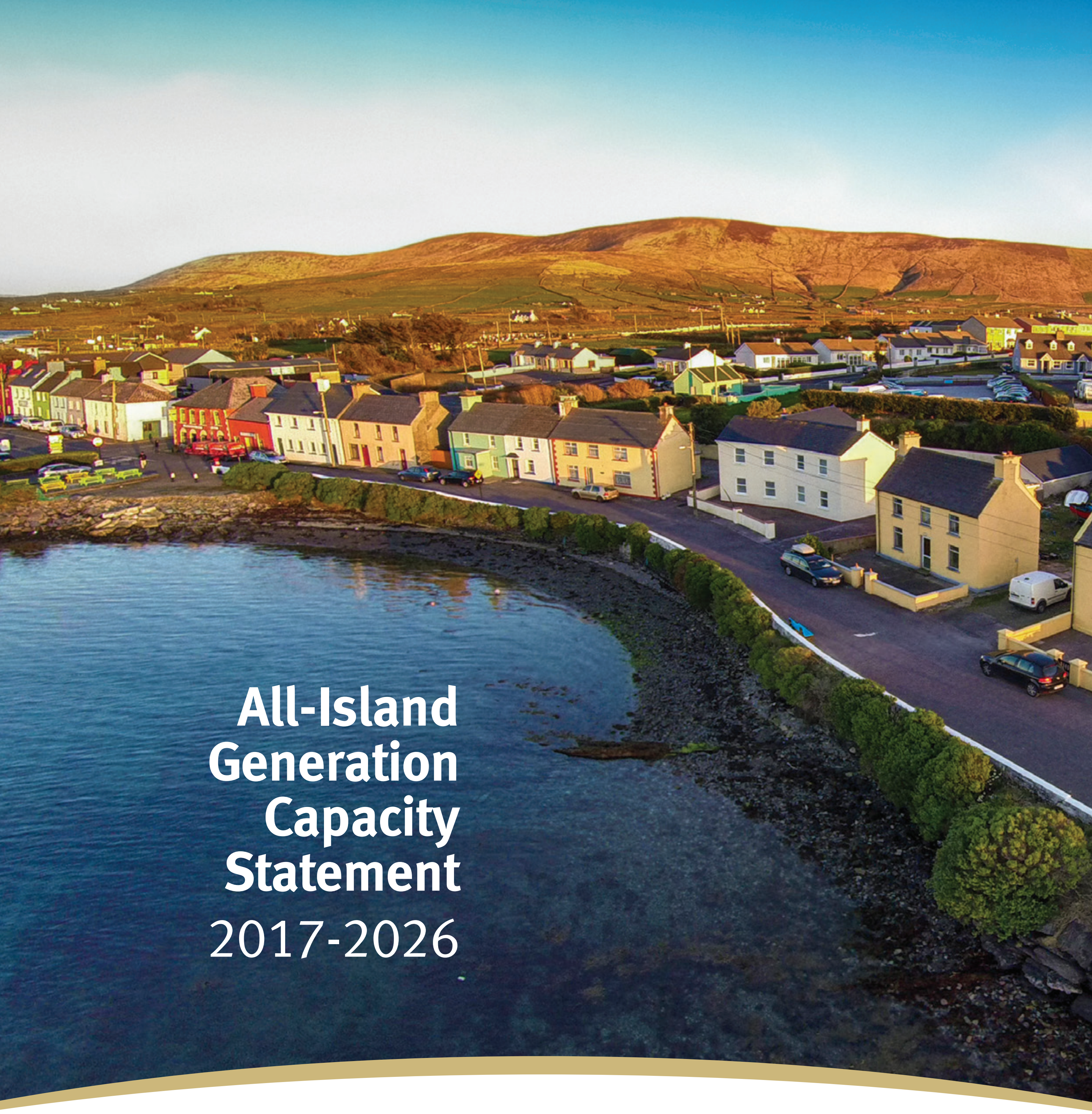

All-Island Generation Capacity Statement 2017-2026

The current. The future.

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

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Foreword

EirGrid and SONI, as transmission system operators (TSOs) for Ireland and Northern Ireland respectively, are pleased to present the All-Island Generation Capacity Statement 2017-2026.

This statement outlines the expected electricity demand and the level of generation capacity available on the island over the next ten years. Generation adequacy studies have been carried out to assess the balance between supply and demand for a number of realistic scenarios.

Demand in Northern Ireland has been relatively stable and this is expected to continue. Demand in Ireland is increasing and is forecast to increase significantly, largely due to new data centres connecting.

With the advent of the Integrated-Single Electricity Market in 2018, arrangements for a new Capacity Market will come into effect. The aim of the Capacity Market is to procure enough supply to meet the demand to the adequacy standard. Any generator outside of the Capacity Market could become commercially unviable. This is particularly so with the increasing amount of intermittent renewable generation on our system. There is greater uncertainty beyond the 5 year horizon, and this is better represented by a range of scenarios. To this end, we are now consulting on potential developments in our 'Tomorrow's Energy Scenarios' report. This will aid our assessment of future network needs.

We also consider the challenges posed by emissions legislation. In order to safeguard security of supply into the future, the decommissioning of high-emission generation plant will need to be carefully addressed. The second North South Interconnector will contribute to security of supply and will alleviate forecasted deficits in Northern Ireland from 2021.

The only new generation we confidently expect to connect over the next decade is renewable, primarily wind and also biomass/waste. This will contribute to the 2020 renewables targets.

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

Fintan Slye

Fintan Slye
CHIEF EXECUTIVE, EIRGRID GROUP

April 2017

Table of Contents

Document Structure

This document contains a Glossary of Terms section, an Executive Summary, five 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**.

Section 5 outlines the methodology for calculating the capacity requirement for the Capacity Market in the new I-SEM.

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
ALF	Annual Load Factor	The ALF is the average load divided by the peak load. E.g. TER=31,200 GWh, Peak = 5.53 GW (Median forecast for 2020) $ALF = \frac{(31{,}200/8760)}{5.53} = 64\%$ 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 is a Fixed Revenue system of payment for participants offering generation capacity in the SEM. The mechanism features at its core, a fixed “pot” of money that is calculated on an annual basis by the Regulatory Authorities, with technical assistance from the System Operators.
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.
DSM	Demand Side Management	The modification of normal demand patterns usually through the use of financial incentives.
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.

Acronym/ Abbreviation	Term	Explanation
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.
I-SEM	Integrated-Single Electricity Market	The wholesale market on the island is due to change 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

Glossary of Terms

Acronym/ Abbreviation	Term	Explanation
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	
SEM	Single Electricity Market	The Single Electricity Market (SEM) is the wholesale electricity market operating in Ireland and Northern Ireland since 2007. It is a gross mandatory pool market operating with dual currencies.
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.

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

Executive Summary

Executive Summary

In this Generation Capacity Statement (GCS), we forecast the likely balance between supply and demand for electricity during the years 2017 to 2026. 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.

We consulted widely with industry participants and most of the input data was frozen in November 2016. Initially, we estimated the future demand for electricity and the likely generation capacity to meet it. We then assessed this against the generation adequacy standards for Ireland, Northern Ireland and on an all-island basis.

The findings, in terms of the overall supply and demand 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, all available generators benefit from capacity payments. In the future, capacity payments will only be made to those generators who are successful in the Capacity Market to meet the capacity requirement. Therefore, it is possible that some generating units that fail to secure capacity payments may not be commercially viable. This future uncertainty makes it more difficult to predict how the generation portfolio will evolve.

All-Island

- The amount of generation required in the all-island Capacity Market will depend on the capacity requirement. The demand forecast scenarios outlined in this report have a major influence on this capacity requirement. The growth in energy demand for the next ten years varies between 11% in the low demand scenario, to 30% in the high scenario. Once the Capacity Market has matured, we have assumed (for the purposes of these adequacy calculations), that the all-island market will secure only enough generation plant to meet the adequacy standard.
- The adequacy standard for the all-island system is 8 hours Loss of Load Expectation per year. With a system that meets this standard, it is to be expected that the average duration of lost load will total 8 hours per year. In practice, some years could prove favourable, while some could have a less favourable outcome with in excess of 8 hours Loss of Load. For example, a number of large generators could become unavailable at a time of high load, and load shedding might be unavoidable for many hours.

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

- The Base Case scenario carries out an adequacy assessment against the median demand forecast to meet the standard. In the new I-SEM Capacity Market, a Least Worst Regret assessment is carried out over a range of demand scenarios. Based on the analysis done to date, this has tended to select a demand forecast higher than the median demand scenario.
- We have seen a substantial increase in demand side units in both Ireland and Northern Ireland in recent years. We are assuming that this level will continue, and this has been accounted for in our adequacy studies.
- Aside from supported generation such as wind or biomass, we are not aware of any other large-scale generation units that are committed to connect.

Northern Ireland

- In Northern Ireland, demand is not expected to grow significantly.
- However, the anticipated closure of some plant due to emissions restrictions will drive the system into capacity deficit after 2020. The commissioning of the second North South Interconnector with Ireland will alleviate these issues.
- While there are significant short-term increases foreseen in some sectors such as wind and solar, this has a limited impact on the security of supply.

Ireland

- Demand in Ireland has been growing, and is expected to continue to grow, mainly driven by new large users such as data centres. A significant proportion of this extra data centre load will materialise in the Dublin region. Given the lead times associated with transmission reinforcements, generation capacity or equivalent may need to be available in the Dublin region to accommodate this additional demand in the short-term.
- While we have reported a large surplus of plant in previous GCS reports, we now envisage that this surplus will be reduced if it is not required by the new Capacity Market. This is because the Capacity Market will only pay for enough generating units to meet the capacity requirement.
- We are envisaging a substantial expansion in renewable sources of energy, particularly wind. Based on current information, we have assumed that up to 100 MW of Biomass CHP will be delivered under the REFIT 3 biomass scheme. Altogether, this will make significant progress towards meeting Ireland's 40% RES target in 2020.

Demand Forecast

For both Ireland and Northern Ireland, the economic recession led to a drop in electricity demand. However, demand has stabilised in both jurisdictions and economic indicators are now predicting a return to growth, particularly in Ireland, see figure below.

In Ireland, the low, median and high scenarios assume different levels of load from the expanding data centre sector. Total electricity demand over the next ten years is forecast to grow by 15% in the low demand scenario, or by 36% in the high scenario.

In Northern Ireland, growth is more modest, based on recent trends and economic predictions. The low scenario predicts a decrease in demand of 2% over the next ten years, while the high scenario forecasts 9% growth.

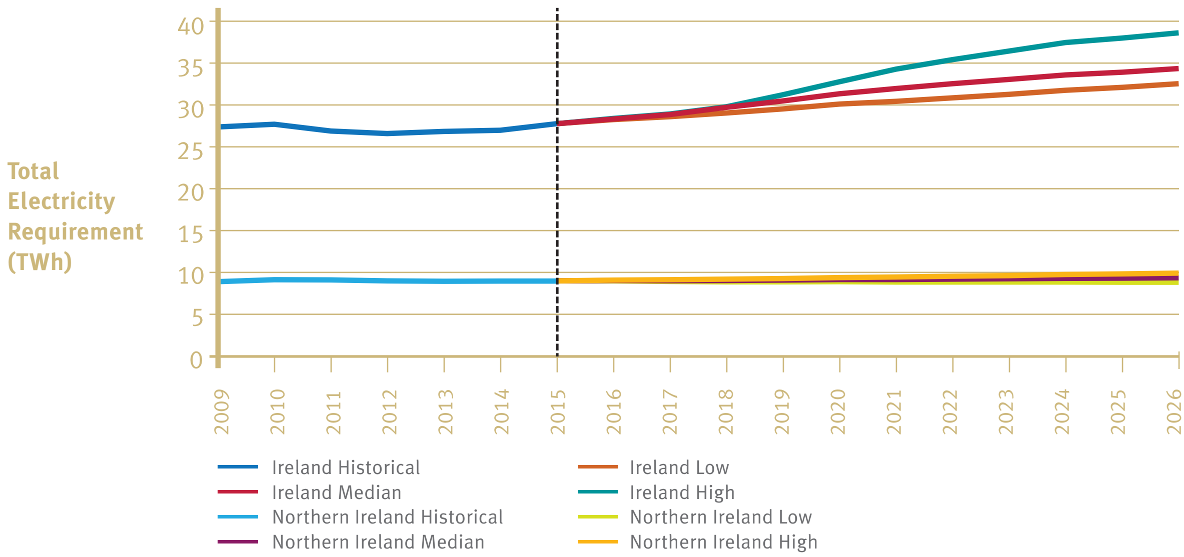


Figure 0-1 Total Electricity Requirement.

Generation

The aim of the proposed Capacity Market is to obtain enough generation to operate the system in a secure manner. Any excess capacity will not receive capacity payments, and may not be commercially viable. Therefore, as the Capacity Market comes into effect, some plant may decommission or be mothballed.

Under grid code regulations, generation plant is required to give at least 3 years notice for decommissioning (or 2 years notice for plant less than 50 MW).

Currently, the system in Ireland has a generation surplus. However, some plant has indicated that it will decommission due to emission restrictions. Coupled with the effect of the new Capacity Market, we assume that the amount of large-scale dispatchable plant will decrease or be mothballed over the coming years. The amount and timing of this decrease is uncertain. We have built a scenario to show the amount of plant that is required to maintain a secure system, i.e. at a standard of 8 hours LOLE.

In Northern Ireland, emissions legislation is causing a significant amount of plant to be restricted in its running hours, or to be decommissioned. This will lead to a deficit of supply. This situation would be alleviated by the second North-South Interconnector in 2021, or by the commissioning of new plant.

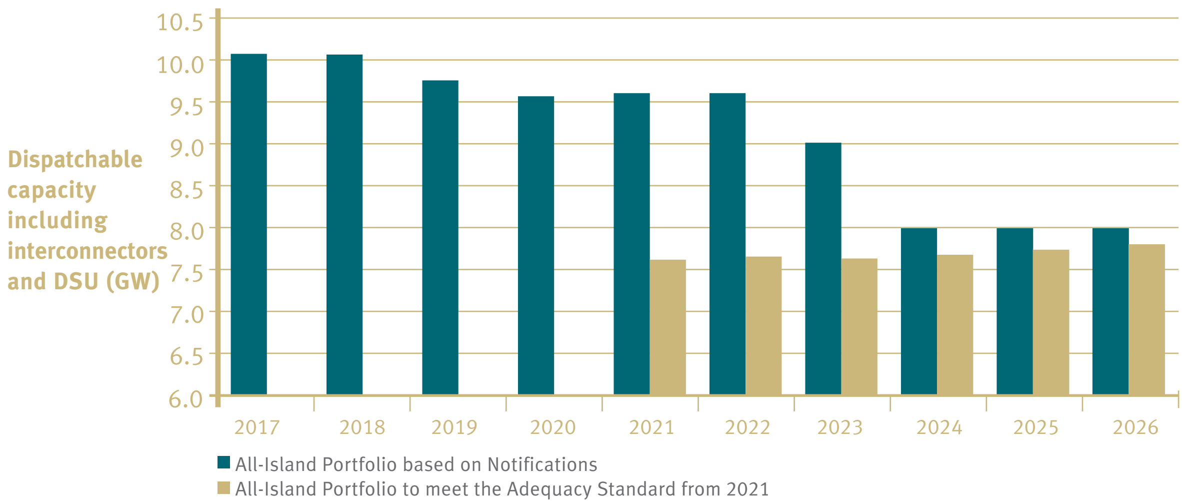


Figure 0-2 The green bars show the all-island dispatchable portfolio, including notified closures. The gold bars show the estimated all-island dispatchable portfolio, as required to meet the adequacy standard from 2021.

Renewable Generation

Ireland

Progress has been made towards Ireland's target for renewable sources of energy. Much of this progress has been in the wind sector, with valuable contributions from hydro and biomass. The likelihood of meeting the targets for 2020 will depend largely on how much new wind and biomass can be built and accommodated on the system over the coming years.

Wind provided 22% of all electricity in Ireland in 2016, with an installed capacity of over 2800 MW. Hydro generators provided 3% of our electricity needs in 2016, and will continue to play their part in achieving the RES target. Though there has been some interest in developing solar PV, the future of this sector is unclear, and so modest growth is assumed.

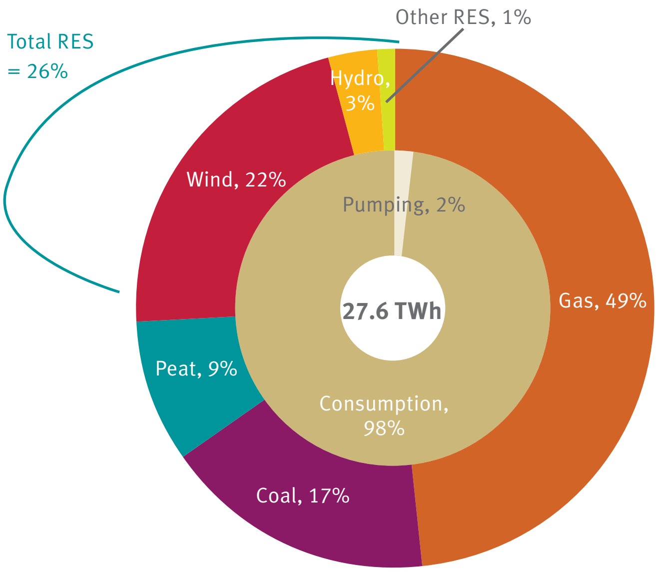


Figure 0-3 Fuel mix in Ireland in 2016

Northern Ireland

There is approximately 850 MW of wind currently installed in Northern Ireland. We expect that there will be a total installed capacity of approximately1300 MW of wind by 2020, which should be sufficient to achieve 40% of energy sourced from renewables.

A significant contribution to this target is expected to come from solar photovoltaic generation. The capacity of small scale PV has increased rapidly in recent years. The coming years will see the connection of large scale PV projects, with total photovoltaic capacity reaching approximately 250 MW.

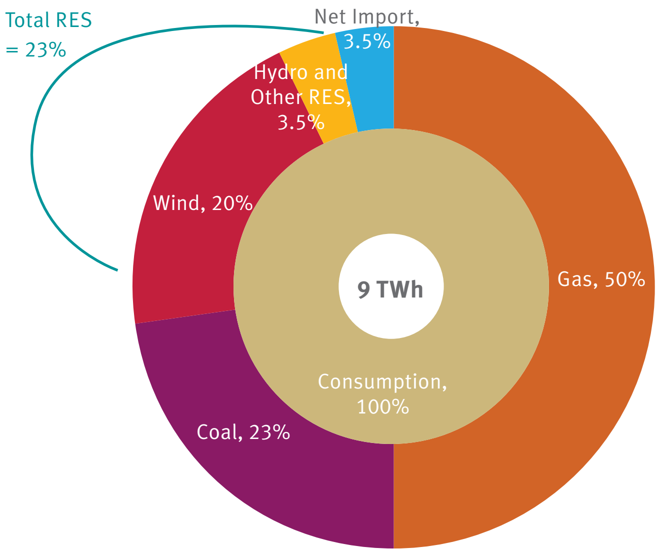


Figure 0-4 Fuel mix for Northern Ireland in 2016

Adequacy Analysis

We now use the information gathered and the assumptions made in order to model the balance between supply and demand of electricity. These are the results of our generation adequacy studies.

All-Island, with the second North South Interconnector

Once the second North South Interconnector is commissioned, the whole island can be studied altogether for adequacy purposes from 2021. With no transmission restrictions assumed between the two jurisdictions, all the generation is modelled to meet the combined load. This means that a deficit in one jurisdiction can be alleviated by surplus plant in the other. The table below shows the adequacy results assuming enough plant to meet the standard by 2021 in the median demand scenario.

The plant portfolio is chosen specifically for the median demand scenario. Therefore, if the low demand were to transpire, then there would be a surplus of plant, to the order of 290 MW by 2026. Alternatively, if the high forecast were to transpire, there would be a large deficit. In practice, each year the demand forecast would be updated, and so if the new forecast tended to rise above the previous year's forecast, then the Capacity Market should react to secure more capacity to meet this higher demand.

All-Island	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Scale
Low Demand	2340	2030	1590	810	340	240	350	290	290	290	› = 500
Median Demand	2280	1970	1500	640	130	0	90	20	20	10	0
High Demand	2200	1900	1390	440	-170	-370	-350	-480	-520	-550	‹ = -500

Figure 0-5 Adequacy results for the all-island system, where a positive number indicates a surplus of plant. A negative number indicates a deficit. The amounts are given in MW of perfect plant (i.e. that which does not experience forced or scheduled outages). The dark green colour shows where the surplus is over 500 MW, while red shows a deficit of greater than 500 MW. Yellow indicates a balanced system.

It should be noted that the first 4 years of this study are only shown for illustrative purposes, and overstate the surplus in the absence of the second North South Interconnector.

Jurisdictional Adequacy Analysis

In the following sections, we look at Ireland and Northern Ireland separately. Each jurisdiction is studied on their own, with a small reliance on the other, as provided by the current interconnection. As we have taken account of the current interconnection between the jurisdictions, the analysis is valid up to 2020. From 2021, this analysis is valid only in the absence of the second North South Interconnector. Both jurisdictions would require additional capacity to meet the adequacy standard in the absence of the second North South Interconnector.

Northern Ireland in the absence of the second North South Interconnector

In Northern Ireland, a significant amount of plant is due to decommission or be restricted in its running hours due to emissions legislation. By 2021, this causes the system to experience deficits over 100 MW in the median demand scenario. By 2024, the Kilroot steam units are assumed to have closed, and so the system goes into further deficit, over 200 MW. This situation would be relieved by the second North South Interconnector, or by the commissioning of new generation.

Without the second North South Interconnector, it will not be possible to share enough capacity from Ireland to alleviate the serious concerns over security of supply that Northern Ireland will face from 2021 onwards.

It can be seen that the high and low scenarios for Northern Ireland do not cause a large spread in results.

Northern Ireland	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Scale
Low Demand	550	530	310	200	-50	-70	-40	-160	-150	-150	› = 500
Median Demand	530	510	280	160	-100	-110	-90	-220	-220	-220	0
High Demand	520	490	250	130	-140	-160	-150	-290	-300	-310	‹ = -500

Figure 0-6 Adequacy results for Northern Ireland

Ireland in the absence of the second North South Interconnector

Without the second North South Interconnector, slightly more plant will be required to keep Ireland in standard, compared to that which is sufficient in the all-island case. In order to model the adequacy situation in Ireland post 2021, we are assuming that the Capacity Market will procure enough capacity to meet the standard in Ireland, for the median demand scenario.

The resulting adequacy table below shows that in the median scenario, Ireland is in large surplus in the short term (green cells up to 2020). By 2021, enough plant has been decommissioned so that there is a balance between supply and demand in the median demand scenario (see the yellow squares indicating almost zero surplus).

If the high scenario were to transpire with the same assumed portfolio, then the system would be in deficit to almost 500 MW. In practice, the Capacity Market should react to a rising demand by revising the forecast each year and by securing more capacity.

Ireland	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Scale
Low Demand	1560	1250	1050	350	300	210	250	230	230	230	› = 500
Median Demand	1520	1210	990	210	120	20	50	30	30	30	0
High Demand	1460	1160	920	50	-140	-300	-330	-410	-430	-450	‹ = -500

Figure 0-7 Adequacy results for Ireland

Capacity Requirement

The Regulatory Authorities have outlined their proposals for a Capacity Market in the new I-SEM. This new Capacity Market will pay for enough capacity to meet the Capacity Requirement. Generators will compete in a capacity auction to supply capacity to the Capacity Market. The calculation of the Capacity Requirement is an important part of the process, and it is reliant on the demand scenarios outlined in this GCS.

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 2026[3].

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 2017-2026 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 2016-2025, published in February 2016.

Input data assumptions have been reviewed and updated.

3 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/WinterOutlook2016_17_FINAL_UPDATE.pdf

2 Demand Forecast

2 Demand Forecast

2.1 Introduction

The forecasting of electricity demand is an essential aspect of assessing generation adequacy. This task has become more critical in the new Capacity Market. The aim of the Capacity Market auction is to secure just enough generation to keep the system within standard. The demand forecast developed here is to be used to ascertain the capacity requirement, towards which the capacity auction aims.

Should the actual demand turn out to be less than the demand forecast, then an excess of capacity has been acquired, with a resultant cost. Should the outturn demand overshoot the demand forecast, then not enough generation has been acquired, and there could be load-shedding.

To counter these significant effects, a spread of forecast demand scenarios is developed.

In recent years the economic downturn led to significant reductions in both peak demand and energy consumption across the island. However, there are now signs of economic recovery including stabilisation of electricity demand in Northern Ireland and a return to growth in Ireland.

The main considerations for demand forecasting are:

- The effect of weather on demand
- Economic forecasts
- Energy policy
- Typical load shapes
- The effects of energy efficiency measures
- Large industrial users

As the drivers for economic growth and energy policies can vary in both jurisdictions, we initially build the forecasts separately for Ireland and Northern Ireland. These are then combined to produce an all-island energy and peak demand forecast. We use this in the all-island adequacy studies.

2.1(a) Temperature Effect on Electricity Demand

Of all the meteorological elements we have found that temperature has the greatest effect on the demand for electricity in both Northern Ireland and Ireland. For this reason, we adjust historical demand data to Average Cold Spell (ACS) temperatures[4]. ACS analysis produces a peak demand which would have occurred had conditions been averagely cold for the time of year. This ACS adjustment to each winter peak seeks to remove any sudden changes caused by extremely cold or unusually mild weather conditions.

When forecasting forwards, we assume that the weather is average, i.e. no temperature variations are applied. However, we can also add on the effect of a severely cold winter. We don’t expect every winter to experience an extremely cold spell, but over the course of many years, we need to take into account the possibility that it can occur.

Conversely, we need to consider that a winter might be quite mild. For this, we develop a scenario of lower demands that might occur over the forecast horizon.

Providing a substantial range of forecast scenarios is particularly important as an input for the Least Worst Regret calculation of the Capacity Requirement in the Capacity Market. This range is influenced by weather variation in the earlier years. In the later years, differing economic factors are more dominant.

4 It should be noted that temperature has a lesser impact on annual electricity energy demand than it does on peak demand.

2.1(b) Self-Consumption and TER

Some industrial customers produce and consume electricity on site, many with the facility of Combined Heat and Power (CHP). This electricity consumption, known as self-consumption, is not included in sales or transported across the network. Consequently, we add an estimate[5] of this quantity to the energy which is exported by generators. The resultant energy is known as the Total Electricity Requirement (TER).

We quote forecasted demand figures in terms of Total Electricity Requirement (TER), and use this in adequacy calculations.

2.2 Demand Forecast for Ireland

2.2(a) Methodology for the Annual Electricity Demand Forecast Model

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.

We have sought the advice of the Economic and Social research Institute (ESRI) which has expertise in modelling the Irish economy[6]. They advised us to focus on the economic parameters of Personal Consumption[7] and adjusted GNP[8].

The demand forecast incorporates some reduction due to energy efficiency measures, in line with Ireland's National Energy Efficiency Action Plan[9]. This includes the effect of the installation of smart meters, which could reduce peak demand from domestic users by up to 8%.

2.2(b) Historical data

Historical records of electricity demand are gathered from the ESB. 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.

2.2(c) 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 out of the ESRI's Medium Term Review (MTR), published in July 2013.

5 Self-consumption represents approx. 2% of system demand, and so its estimation does not introduce significant error.

6 http://www.esri.ie/irish-economy/

7 Personal Consumption of Goods and Services (PCGS) measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.

8 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.

9 http://www.dccae.gov.ie/energy/en-ie/Energy-Efficiency/Pages/National-Energy-Efficiency-Action-Plan-(NEEAP).aspx

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

	2016-2020	2021-2025
GNP	4.0%	3.5%
Personal Consumption	3.2%	2.7%

Table 2-1 Average annual 5-year growths for macroeconomic parameters

2.2(d) Data Centres in Ireland

A key driver for electricity demand in Ireland for the next number of years is the connection of large data centres. A significant proportion of this extra data centre load will materialise in the Dublin region. Given the lead times associated with transmission reinforcements, generation capacity or equivalent may need to be available in the Dublin region to accommodate this additional demand in the short-term.

Whether connecting directly to the transmission system or to the distribution system, there is presently about 250 MVA of installed data centres in Ireland. Furthermore, there are connection offers in place (or in the connection process) for up to 600 MVA extra. At present, there are enquires for more than 1,000 MVA of additional data centres. We have examined the status of these proposed projects, and have made assumptions concerning the demand of these data centres in the future. This has formed the differences between our median, high and low scenarios.

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

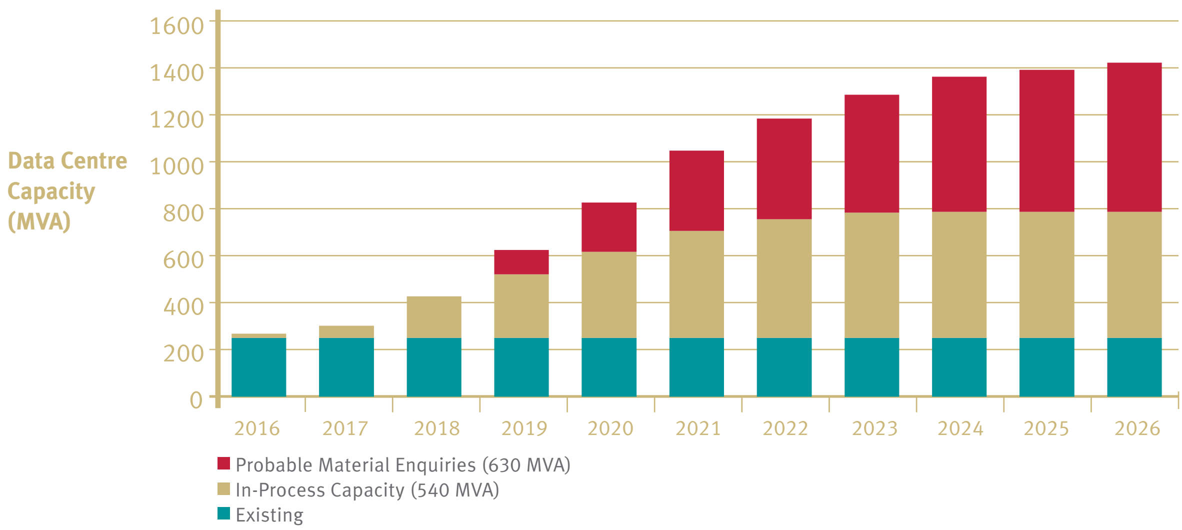


Figure 2-1 Demand expected from assumed build-out of new data centres.

2.2(e) Forecast Scenarios and 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. In order to capture the impact of data centres, we have based the different demand forecast scenarios for Ireland on different data centre build-out scenarios.

The demand forecast low scenario provides the demand forecast from the models using the recent demand growth and the economic inputs as discussed above. This low scenario is based on the assumption that approximately half of data centres in the connection process will connect (270 MVA).

The median scenario accounts for the connection of 540 MVA of data centres in the connection process. The high scenario, in addition to the demand in the median scenario, also assumes that 630 MVA of the data centres with material enquiries will connect.

These three scenarios give an appropriate view of the range of possible demand growths facing Ireland. This range is to be used in the determination of the capacity requirement for the new Capacity Market.

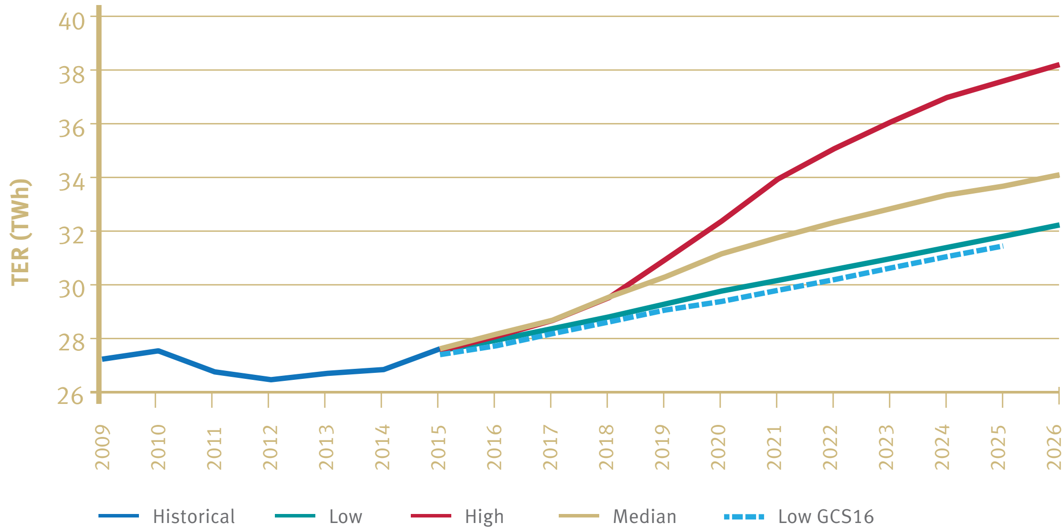


Figure 2-2 Total Electricity Requirement Forecast for Ireland. The figure for 2016 is based on real data available at EirGrid's National Control Centre up to October, and so estimates are made for the remaining months.

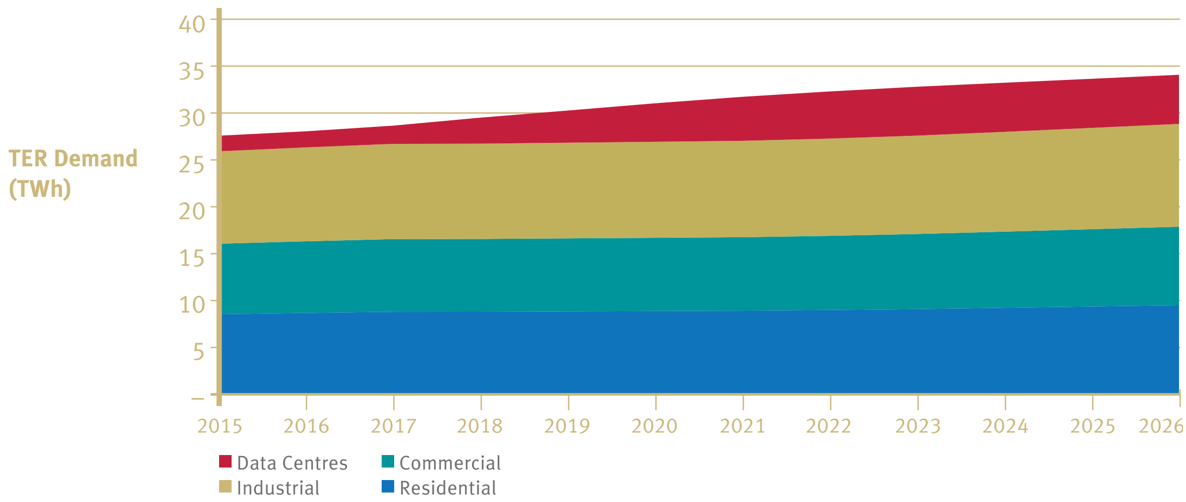


Figure 2-3 For the Median Demand scenario, this illustrates the approximate split into different sectors. We estimate that 15% of demand will come from data centres by 2026.

2.2(f) 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.

Before applying this model, it is necessary to assess the effect of **Demand-Side Management** (DSM) schemes. In the past, EirGrid has operated a number of different DSM schemes, while now it is Demand Side Units (DSUs) that are accounting for most of the demand side response that is available, see Section 3.6(a).

Temperature has a significant effect on electricity demand, as was particularly evident over the two severe winters of 2010 and 2011, when temperatures decreased and demand increased. 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.

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. In GCS16, we assumed that smart meters would take effect from 2017-2020. However, for the current GCS, we have delayed the introduction of this effect to account for the probability that the scheme will take longer to roll out. Therefore, the peaks rise more quickly in the current GCS than the last one, but they have similar values by 2024.

Another difference from GCS16 is that 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.

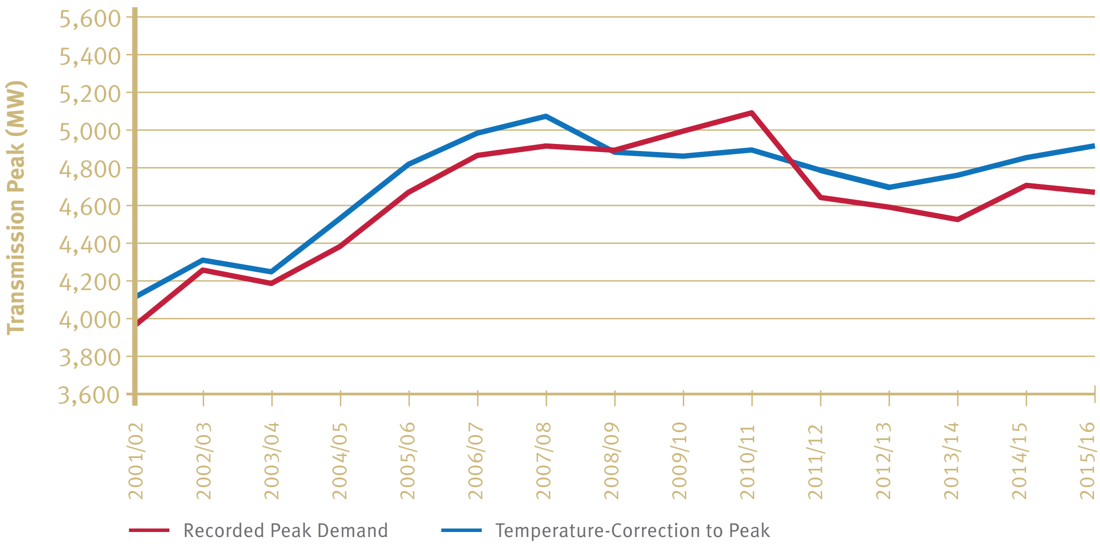


Figure 2-4 Past values of recorded maximum demand in Ireland, and the ACS corrected values.

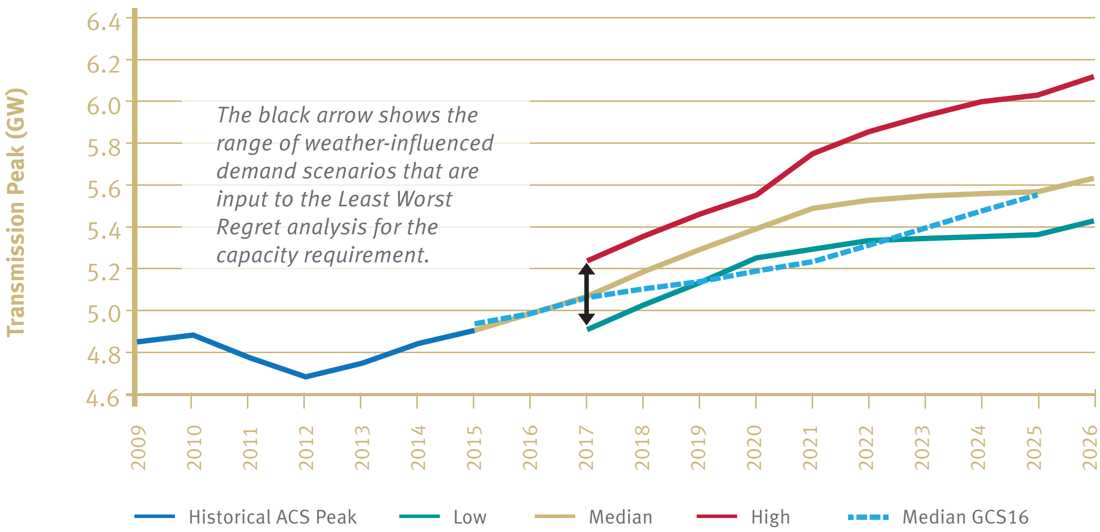


Figure 2-5 Forecast of Ireland's Transmission Peak for the Low Median and High scenarios, under Average Cold Spell conditions. For comparison purposes, last year's Low peak forecast is shown in pale blue dashes.

2.3 Demand Forecast for Northern Ireland

2.3(a) Methodology

The TER forecast for Northern Ireland is carried out with reference to economic parameters, primarily Gross Value Added (GVA). Various publications are forecasting growth in 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(b) Demand Scenarios

Given the degree of economic uncertainty into the future, we believe 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.

2.3(c) Self-Consumption

We have been working closely with Norther Ireland Electricity Networks (NIEN) and referencing the Renewable Obligation Certificate Register (ROC Register)[10] to establish the amount of embedded generation that is currently connected on the Northern Ireland system, as well as referencing Northern Ireland Planning Service[11] data to try and establish 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]

2.3(d) 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 2016-2025.

The Northern Ireland Median TER forecast predicts a return to 2008 levels by about 2022.

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

11 www.planningni.gov.uk

12 Self-consumption in Northern Ireland currently represents approximately 2% of TER.

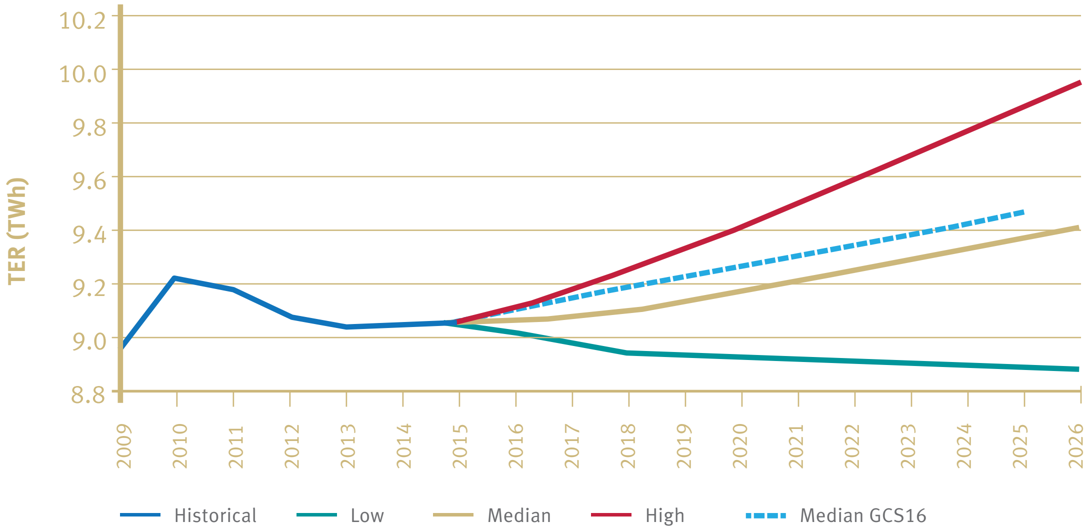


Figure 2-6 Northern Ireland TER Forecast

2.3(e) Peak Demand Forecasting

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

The Northern Ireland 2015/16 generated winter peak of 1795 MW occurred on Tuesday 12th January 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, we have 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.

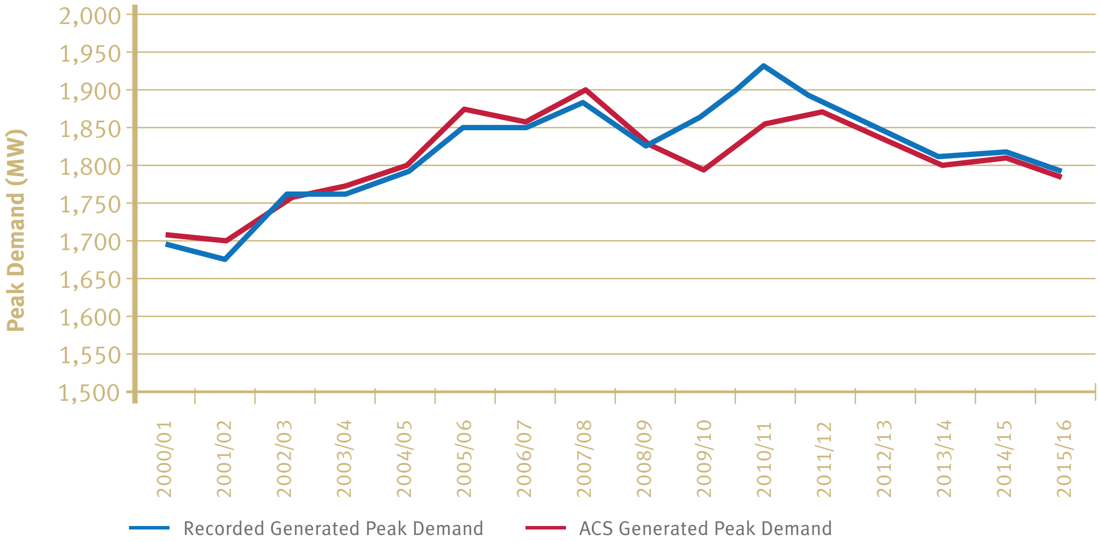


Figure 2-7 Recorded and ACS-corrected peaks (generated level) for Northern Ireland. The most significant corrections are for 2009/10 and 2010/11, when the temperature deviated most from normal.

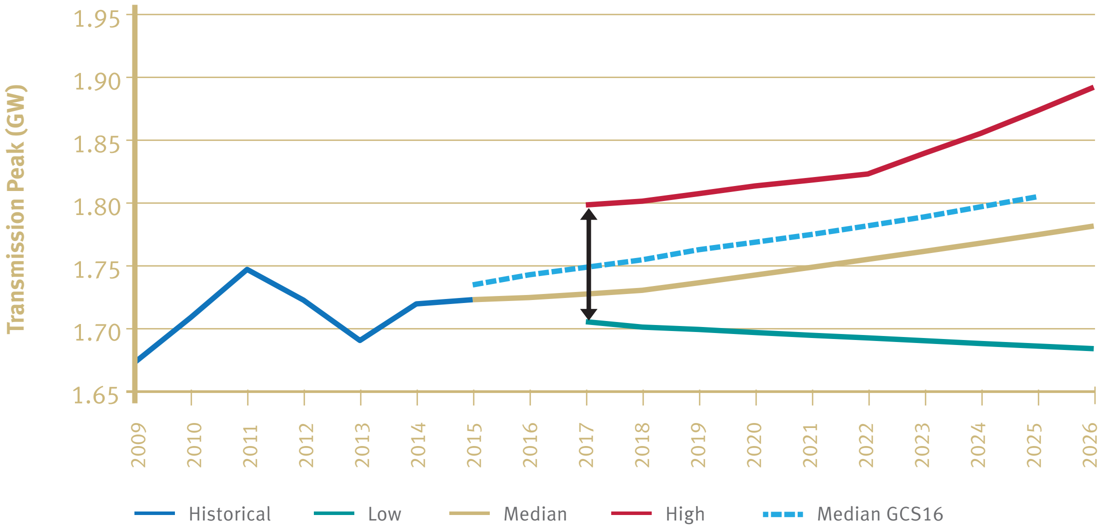


Figure 2-8 ACS Transmission Peak forecasts for Northern Ireland. The black arrow shows the range of weather-influenced demand scenarios that are input to the Least Worst Regret analysis for the Capacity requirement.

2.4 All-Island Forecasts

The combined all-island TER forecast comes from summing together the demands from each jurisdiction as shown in Figure 2-9. This range of demand scenarios is to be used for the determination of the capacity requirement in the new Capacity Market.

The annual peaks for Ireland and Northern Ireland do not generally coincide. In Northern Ireland, annual peaks may occur at the start or at the end of the year, whereas in Ireland peaks tend to occur in December.

To create a forecast of all-island peaks, future demand profiles have been built for both regions based on the actual 2015 demand shape. The forecasted all-island peaks are shown in Figure 2-10, where ACS conditions are assumed for the future.

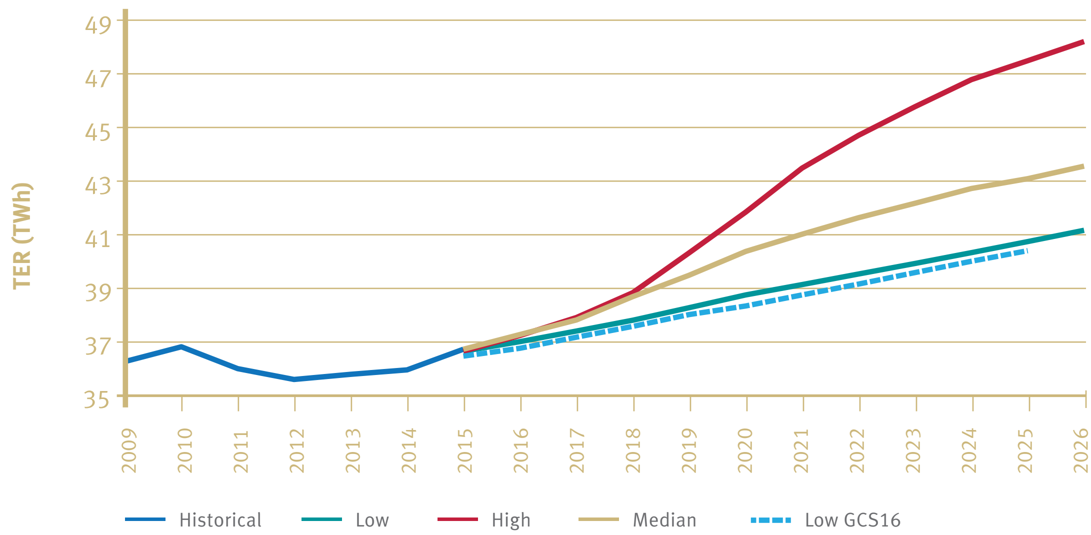


Figure 2-9 Combined all-island TER forecast

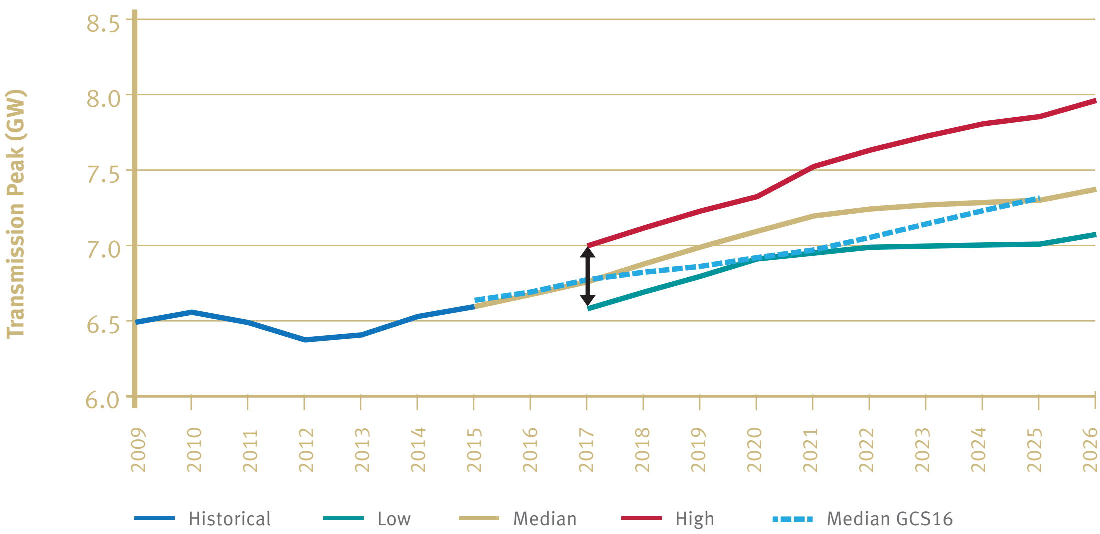


Figure 2-10 Combined all-island Transmission Peak forecast. The black arrow shows the range of weather-influenced demand scenarios that are input to the Least Worst Regret analysis for the Capacity Requirement.

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. The base year chosen for the profile creation was 2015 for both jurisdictions.

2015 was chosen because it was the most recent profile available, and it was deemed to be a year representative of contemporary demand patterns. The choice of a typical year 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.

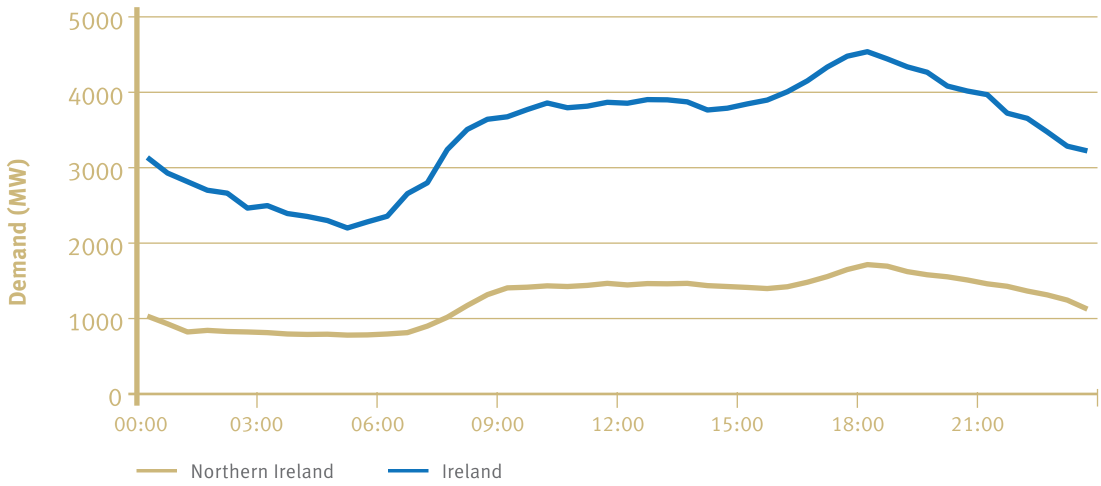
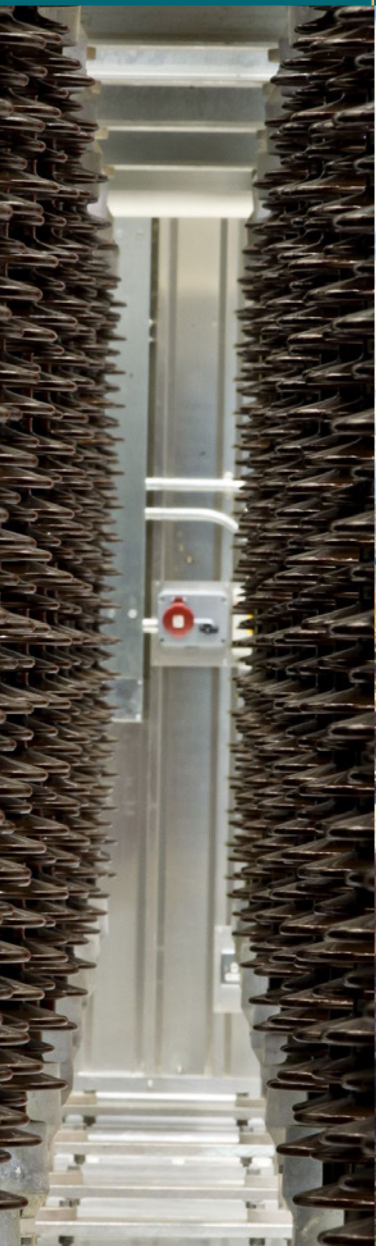


Figure 2-11 Typical winter day profile

3 Generation



3 GENERATION

This section describes all significant sources of electricity generation connected to the systems in Ireland and Northern Ireland and known to the system operators. The current portfolio is likely to change with the advent of 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. Plant that does not receive capacity payments might not remain commercially viable. Any changes to the portfolio are particularly significant to the operation of a power system such as ours, which has a high proportion of intermittent renewable generation with priority dispatch.

Therefore, we have endeavoured to paint a general picture of how the all-island portfolio might evolve from the present situation of surplus, to one where the system is adequate to an 8-hour LOLE standard.

For the latest portfolio, we have endeavoured to use the most up-to-date information available at the time of the data freeze for this report (November 2016).

In this chapter, supply is divided into conventional and non-conventional types, demand-side and interconnection.

For information, Figure 3-1 illustrates the age of the dispatchable plant on the island.

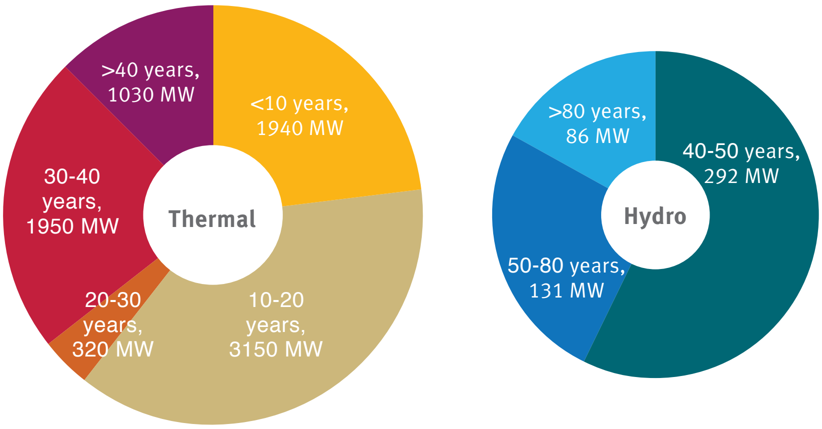


Figure 3-1 Age spread of dispatchable plant on the all-island system (Hydro includes pumped storage).

3.1 Changes to Conventional Generation in Ireland

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

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

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

Plant	Capacity (MW)
Dublin Waste to Energy	61

Table 3-1 Plant planned to be commissioned in Ireland

- Only one generation unit meets these criteria, that being the Dublin Waste plant.
- In recent years, two large CCGTs have been commissioned in the Cork region. Network reinforcements are required to enable all thermal generation to be exported from the Cork region. In the absence of such reinforcement, the output of generation in this region will occasionally have to be constrained. This would impact on the capacity benefit of this generation.

  Network reinforcements are planned for the Cork region, to come into effect by 2021. However, in the meantime, Whitegate is modelled at full capacity, and there is an export limit of 690 MW from the Aghada site. This site comprises of Aghada AD1 (258 MW), Aghada CT 1, 2 and 4 (3 X 90 MW), and the new Aghada AD2 (432 MW), with a total export capacity of 960 MW.
- Some older generators are due to close because of emissions restrictions. These are shown in Table 3-2.

Plant	Export Capacity (MW)	Expected to close by the end of year:
Aghada AD1	258	2023
Aghada AT1	90	2023
Marina CC	95	2023
North Wall 5	104	2023
Tarbert 1, 2, 3, 4	592	2022

Table 3-2 Closures of conventional generators.

- For the purposes of compliance with the IED (Industrial Emissions Directive[14], see section 3.3), some ESB plant has been designated a ‘Limited Life-time Derogation’. These plant will have limited running hours and will need to shut by the end of 2023, see Table 3 2.
- We note the recent rulings in relation to the burning of peat at the Edenderry power plant. In December 2016, An Bord Pleanála granted planning permission fosr Bord na Móna to continue to operate the peat and biomass co-fired power station for another seven years.

Other than the generators listed in Table 3-2, we have received no other notification of plant closures. However, we have assumed that some older generators in Ireland may inform us of their intention to close if they don’t secure capacity payments in the new I-SEM.

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

3.2 Changes to Conventional Generation in Northern Ireland

In Northern Ireland, we will only consider new conventional generators that have a connection agreement with SONI or NIE Networks. In addition, to be included in our adequacy studies, plant needs to have planning permission, financial close and have indicated a commissioning date to SONI by the data freeze date.

Plant	Export Capacity (MW)	Expected to close by the end of year:
Ballylumford 4, 5	250	2018[15]
Kilroot ST1, ST2	514	2023

Table 3-3 Closures of conventional generators. (Dates are interpreted as 'by the end of each year'.)

- Some of the plant at Ballylumford was decommissioned in 2015. This was because of environmental constraints introduced by the Large Combustion Plants Directive[16].
- Life-extension works have been completed at Ballylumford with the installation of emission-abatement technology. This is in order that they can provide 250 MW of Local Reserve Services for a three-to-five year time period from 1st January 2016.
- ST1 and ST2 at Kilroot are required to comply with the Industrial Emissions Directive (IED), see section 3.3. We have discussed with AES Kilroot how the workings of the IED are affecting the running regimes of these units now and into the future. From July 2020 to the end of 2023, these units will be severely restricted in their running hours. These units are due to shut at the end of 2023.
- Belfast Power (Evermore Energy) is proposing a 480 MW gas fired power station in the Belfast Harbour Estate. They submitted a Pre Application Notice to the Northern Ireland Department of Infrastructure in October 2016 and have indicated their intention to apply for planning permission in February 2017. For the purposes of this report, this project it 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.
- 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.

3.3 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 entered into force on 6 January 2011 and had to be transposed by Member States by 7 January 2013. 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). For combustion plants, Emission Limit Values (ELVs) for Nitrous Oxide (NOx), Sulphur Dioxide (SO2) and particulate levels have been tightened.

15 With the option of a 2-year extension to 2020

16 Large Combustion Plants Directive: http://ec.europa.eu/environment/archives/industry/stationary/lcp/legislation.htm

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.

As part of the UK Transitional National Plan, Kilroot coal-fired power station will be allocated emission allowances for each year from 2016 to June 2020. If available, additional emission allowances may be purchased in the UK NOx trading scheme. In addition, Kilroot are planning to make plant adjustments to reduce their per unit NOx emissions.

For 2016 Kilroot has been able to purchase additional permits when required in the UK trading scheme. It is likely that Kilroot will need to purchase additional permits in the coming years to ensure that the plant would be available throughout the year. An inability to purchase additional emission allowances when required until June 2020 will reduce the security of supply margin in Northern Ireland.

From July 2020 to 2023, the Kilroot coal units will be limited to 1500 hours per year per stack (unless compliant with IED emissions limits). While it has not been confirmed that the Kilroot coal units are viable under this regime, we have assumed for these adequacy studies that these units will be available for these limited hours in January-February and November-December of each year from July 2020 to December 2023.

Unless compliant with IED emissions limits it is assumed that the coal-fired units will shut at the end of 2023.

3.4 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.

3.4(a) North-South Interconnector

With the completion of the second high capacity transmission link between Ireland and Northern Ireland (assumed for completion by the end of 2020), an all-island generation adequacy assessment can be carried out from 2021 onward. 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 3-4.

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

Table 3-4 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.

3.4(b) 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.

We note the tightening capacity margin in Great Britain over the coming years. Though with extra demand side measures in place, National Grid deem the situation to be manageable.

In the decision for the I-SEM Capacity Market, the Regulatory Authorities propose to reduce the capacity value of the undersea interconnectors by using a derating factor which reduces to 50% by 2021%[17] (indicative results). We use these derating values in our adequacy studies, and continue to review this and the effect it has on our capacity adequacy.

Previously, adequacy assessments have been carried out by ENTSO-E[18] using capacity margins at the time of highest demand[19]. However, ENTSO-E has now improved its existing adequacy methodology with a special emphasis on harmonised inputs, system flexibility and interconnection assessments. The Mid-Term Adequacy Forecast (MAF[20]) uses probabilistic methods to take into account the intermittency of the growing renewable generation sector.

In the future, we will look to these new methodologies to help inform our treatment of interconnectors in the GCS, where applicable.

3.4(c) 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 proposed I-SEM Capacity Market decision, we assume a 50% derating factor, i.e. 250 MW.

17 https://www.semcommittee.com/news-centre/publication-crm-capacity-requirement-and-de-rating-methodology-decision-paper
18 European Network of Transmission System Operators-Electricity
19 https://www.entsoe.eu/about-entso-e/system-development/system-adequacy-and-market-modeling/Pages/default.aspx
20 https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2016_FINAL_REPORT.pdf

3.4(d) 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). The total installed capacity of the link is 500 MW. Following a long outage, one cable of the Moyle Interconnector has been repaired in 2016, and it is now back to full operation.

All interconnector capacity is auctioned by SONI on behalf of Mutual Energy Limited[21]. This capacity is purchased by market participants. In the SEM the unused capacity can, in emergency situations, be used solely to meet peak demand.

For the purposes of adequacy studies, we treat the Moyle interconnector similarly to EWIC, i.e. with a suitable capacity reliance (50% of 450 MW which gives 225 MW) to account for the uncertain availability of generation in Great Britain.

3.4(e) 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[22]. 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
Gallant	Project providing interconnection to Great Britain
Greenconnect	Project providing interconnection to Great Britain
Greenlink	Project providing interconnection to Great Britain
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

3.5 Wind Capacity and Renewable Targets

In both Ireland and Northern Ireland, there are government policies 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[23].

21 www.mutual-energy.com
22 TYNDP 2016 is produced by the European Network of Transmission System Operators – Electricity (ENTSO-e), see http://tyndp.entsoe.eu/
23 http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

Biofuels, hydro and marine 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[24], while ESB Networks publishes that which is Distribution Connected[25].

	Existing (MW)	Planned (MW)
Ireland TSO	1070	1760
Ireland DSO	1420	1720
Subtotal for Ireland	2490	3480
Northern Ireland TSO	74	68
Northern Ireland DSO	756	503
Subtotal for Northern Ireland	830	571
Totals	**3320**	**4051**

Table 3-6 Existing (connected or energised) and planned (contracted or applied) wind farms, as of October 2016. 'Contracted' refers to wind farms that have signed a connection agreement in Ireland and Northern Ireland. 'Applied' in Northern Ireland refers to applications for grid connection with SONI or NIE Networks. These figures are based on the best information available.

Wind generation does not produce the same amount of energy all year round due to varying wind strength. The wind capacity factor gives the amount of energy actually produced in a year relative to the maximum that could have been produced had wind farms been generating at full capacity all year.

3.5(a) 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 (DfE) is currently reviewing its Strategic Energy Framework 2010-2020. For 2016, 23% 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 are due to close to new generation from 1 April 2017.

24 http://www.eirgridgroup.com/customer-and-industry/general-customer-information/gate-3/
25 https://www.esbnetworks.ie/new-connections/generator-connections/generator-connection-statistics

Figure 3-2 shows the expected growth of wind capacity installed in Northern Ireland, reaching 1325 MW by 2019. These assumptions are based on volumes of committed applications to SONI and NIE Networks for grid connection which are likely to qualify for support via the NIRO scheme. In the absence of a new policy for supporting renewables in Northern Ireland we have not included any further renewable generation within the base case model.

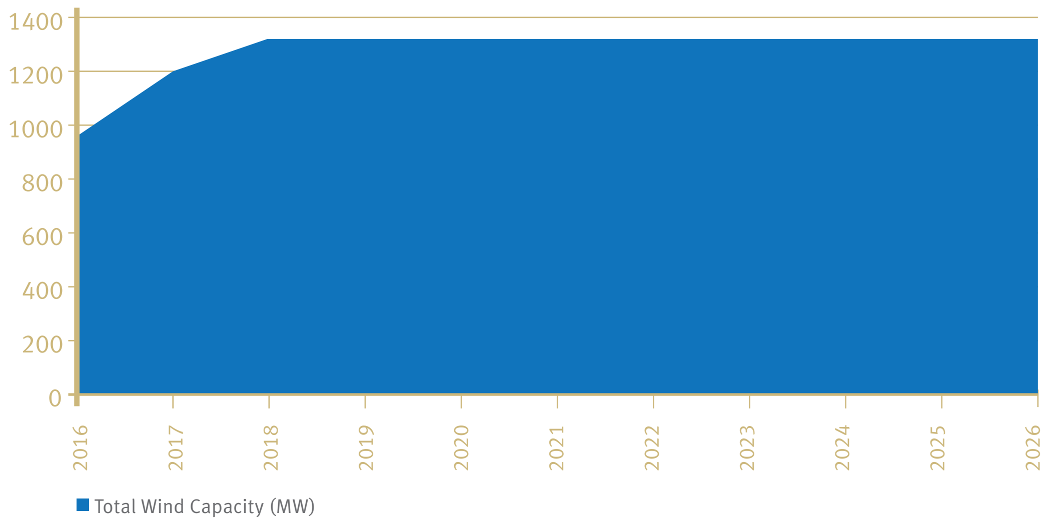


Figure 3-2 Growth assumed for Total Wind Capacity in Northern Ireland

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 1325 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 2026 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 20% by 2016.

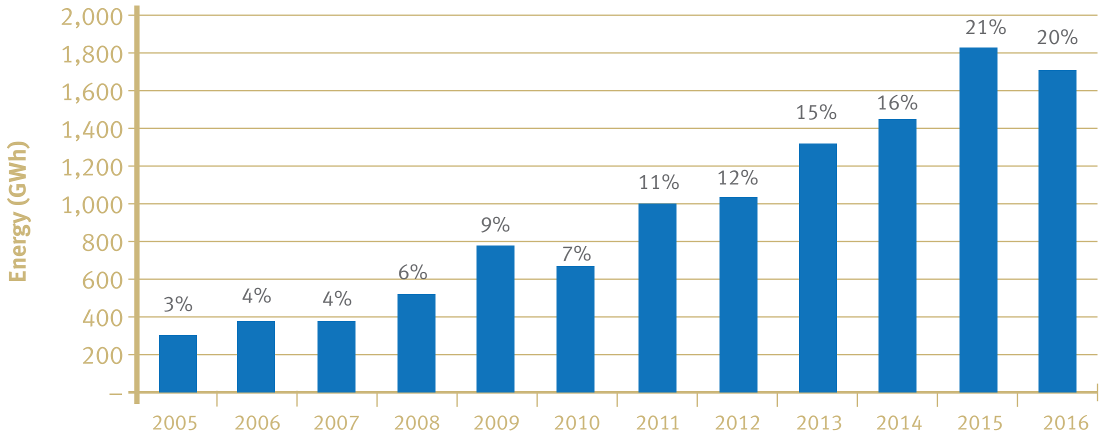


Figure 3-3 Energy supplied by wind in Northern Ireland

3.5(b) 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[26]. 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 2,600 MW at the time of writing. This value is set to increase over the next few years as Ireland endeavours to meet its renewable target in 2020.

The actual amount of renewable energy this requires will depend on the demand in future years, the forecast of which has increased due to the economic recovery. 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 2.8% in 2016[27]. As this has varied between 2.4% and 5.1% over the past six years, we assume a value of at least 5% for our future studies.

With these uncertainties in mind, not one figure but a band of possible outcomes has been estimated for wind capacity in 2020. Figure 3 4 illustrates where this band of targets lies, between about 3,900 and 4,300 MW. This would mean an average of about 340 MW of extra wind capacity installed per year. This represents an increase on last year's band which was between 3800 and 4100 MW – this increase is largely caused by more up-to-date assumptions for other generators.

Figure 3-5 shows the progress toward the 2020 target, in terms of energy generated from wind - this has been normalised over four years, in accordance with the EU definition[28].

Based on historical records, it is assumed that onshore wind in Ireland has a capacity factor of approximately 31%.

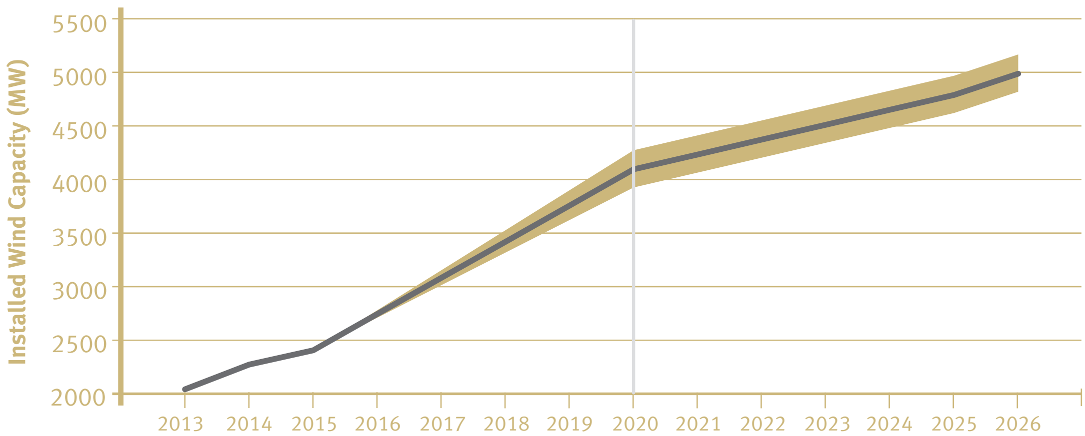


Figure 3-4 Shown in gold, the band of possible wind capacity requirements to meet the 2020 renewable target

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

27 http://www.eirgridgroup.com/how-the-grid-works/renewables/

28 http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0028&from=EN

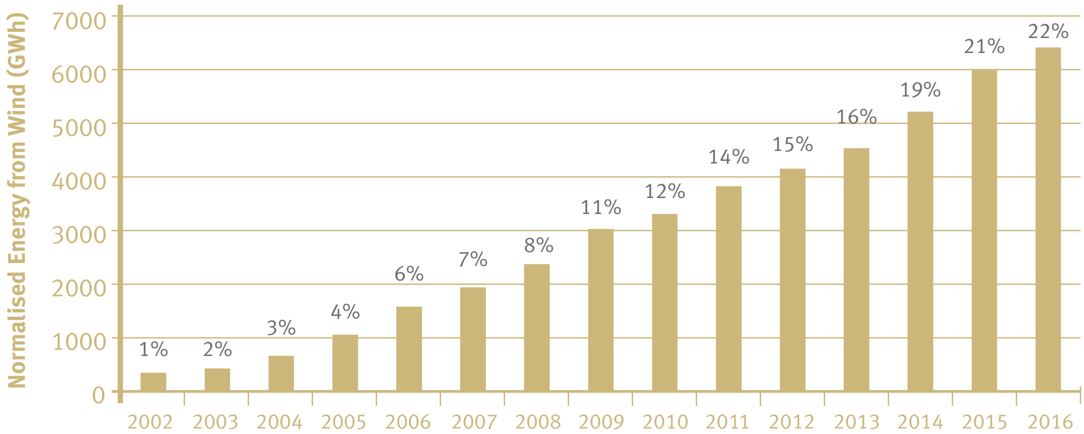


Figure 3-5 Historical wind generation in annual energy terms for Ireland (normalised), also given as a percentage of total electrical energy produced that year (2016 is a provisional estimate).

3.5(c) Modelling of Wind Power in Adequacy Studies with Wind Capacity Credit

The intermittent nature of wind power limits its ability to ensure continuity of supply and thus its benefit from a generation adequacy perspective.

The contribution of wind generation to generation adequacy is referred to as the capacity credit of wind. In our studies, capacity credit has been determined by subtracting a forecast of wind's half hourly generated output from the electricity demand curve. The use of this lower demand curve results in an improved adequacy position. This improvement can be described in terms of extra megawatts of installed conventional capacity (perfect plant). This MW value is taken to be the capacity credit of wind.

The capacity credit of wind will vary from year to year, depending on whether there is a large amount of wind generation when it is needed most. Analysis of many different years showed the behaviour of the 2015 profile to be close to average in terms of capacity credit.

It can be seen in Figure 3 6 that there is a benefit to the capacity credit of wind when it is determined on an all-island basis. The reason for this is that a greater geographic area gives greater wind speed variability at any given time. If the wind drops off in the south, it may not drop off in the north, or at the very least there will be a time lag. The result is that the variation in wind increases and the capacity contribution improves.

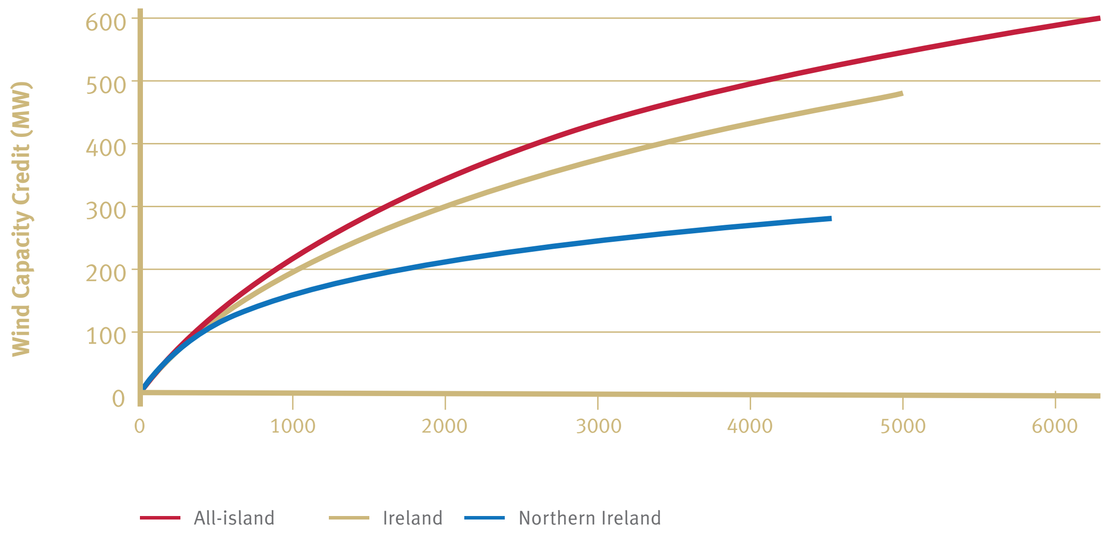


Figure 3-6 Wind Capacity Credit curves used in this analysis for Ireland, Northern Ireland, and for the all-island system.

3.6 Other Non-Conventional Generation

In this section, we discuss expected developments over the next 10 years in other non-conventional generation, such as demand side generation, CHP, biofuels and small scale hydro. All assumptions regarding this non-conventional generation are tabulated in APPENDIX 2. Though relatively small, this sector is growing and making an increasing contribution towards generation adequacy, and in meeting the 2020 renewables targets.

3.6(a) 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.

The amount of capacity available from Demand Side Units has risen substantially in recent years in both Ireland and Northern Ireland. This has made a contribution to generation adequacy. In the future, this sector is likely to grow, though by what amount is uncertain.

Dispatchable Aggregated Generating Units (AGU) operate in Northern Ireland, which consists of a number of individual diesel generators grouping together to make available their combined capacity to the market. The amount of capacity available to these AGUs is approximately 85 MW. The capacity of Demand Side Units in Northern Ireland is approximately 75 MW.

The amount of DSU is approximately 260 MW in Ireland currently.

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.

3.6(b) 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 CO_2 emissions.

Estimates give a current installed CHP capacity (mostly gas-fired) of roughly 150 MW in Ireland (not including the 161 MW centrally dispatched CHP plant operated by Aughinish Alumina).

In Northern Ireland, there is currently an estimated 11 MW of small scale CHP connected to the distribution system (3 MW of which is renewable and 8 MW non-renewable). With little further information, an assumption has been made that, for the purposes of this statement, this will not change.

3.6(c) Biofuel

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

In Ireland, we estimate there to be 54 MW of generation capacity powered by biofuel, biogas or landfill gas. The peat plant at Edenderry powers approximately 30% of its output using biomass. 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.

Currently in Northern Ireland, there is an estimated 38 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 will rise to 50 MW by 2019.

Lisahally Waste Project became operational in 2015. It is a wood-fuelled energy-from-waste/biomass combined heat and power plant in Northern Ireland with a capacity of approximately 17.6 MW. The plant is dispatchable and has been granted priority dispatch.

3.6(d) Small-scale Hydro

It is estimated that there is currently 22 MW of small-scale hydro capacity installed in rivers and streams across Ireland, with a further 5 MW in Northern Ireland. Such plant would generate roughly 60 GWh per year, making up approximately 0.1% of total annual generation. While this is a mature technology, the lack of suitable new locations limits increased contribution from this source. In Ireland 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 expected to grow to 8 MW by 2019. This capacity consists primarily of a large number of small run-of-the-river projects.

3.6(e) Marine Energy

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 little commercial marine developments operational in Ireland before 2026.

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

The Crown Estate[30] has awarded development rights for two 100 MW Tidal sites off the North Coast of Northern Ireland close to Torr Head and Fair Head. While applications for grid connection have been submitted, at present there are no connection offers in place for tidal projects. Therefore, for the purposes of this report, we have assumed that no additional tidal generation will connect within the study period.

3.6(f) Waste-to-energy

The Indaver plant in Co Meath is estimated to source half its waste from renewable sources, and so contributes to the overall renewables targets. We assume approximately the same RES content to be in the waste that will be burned in the Dublin Waste to Energy facility.

Bombardier has plans to establish approximately 14.8 MW of energy from waste generation at its Belfast site. This generation is expected to come online in 2017.

3.6(g) Solar PV

In Northern Ireland, the capacity of small scale PV has increased rapidly in recent years. At present connected capacity is approximately 80 MW. We expect this capacity will continue to grow, reaching 125 MW by 2019.

The coming years will see the connection of large scale PV projects. For the purposes of this report we have assumed capacity will grow rapidly reaching 145 MW by the end of 2017. However, after 2017, the NIRO supports will cease and so little growth is expected subsequently.

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

3.6(h) Kilroot Energy Storage

In January 2016 AES UK & Ireland completed the Kilroot Energy Storage Array located in Kilroot Power Station. This pilot scheme aims to provide 10 MW of interconnected energy storage, equivalent to 20 MW of flexible resource. It is the largest advanced energy storage system in the United Kingdom and Ireland, and the only such system at transmission scale. The Kilroot Array provides System Services including frequency regulation as part of the system operators' DS3 System Services arrangements. The Array utilises over 53,000 batteries, arranged in 136 separate nodes for increased reliability and responds to grid changes in less than a second.

Innovate UK Energy Catalyst is providing funding, in partnership with Queen's University Belfast, to demonstrate the full capabilities of energy storage by analysing the impact of this array. Queen's University will publish an independent report on the potential of the technology to benefit the All Island Electricity Market.

The 10 MW array is seen as a first step towards a planned 100 MW energy storage array adjacent to Kilroot Power Station.

While proving DS3 System Services is desirable, this type of capacity is not included in our models for adequacy calculation purposes.

3.6(i) Compressed Air Energy Storage (CAES)

Gaelectric is proposing a Compressed Air Energy Storage (CAES) Plant in Islandmagee, close to Ballylumford, to be connected to the transmission system. Gaelectric is designing the facility to realise

30 The Crown Estate: www.thecrownestate.co.uk

330 MW of generation and 250 MW of compression. This energy storage facility could provide ancillary services and balancing facilities for renewable generation.

A CAES plant uses a large compressor to store excess energy off the grid. It does this by converting the excess electric energy into compressed air which is stored in an underground geological cavern. This is then released through an electric generator for later use. This technology can be applied to store surplus renewable energy, whilst also enabling variability balancing on the transmission system.

The project is unique in being the only CAES Project of Common Interest (PCI) in Europe. It is the only electricity storage PCI on the island of Ireland. In February 2017, CAES was awarded funding of €90 million from the Connecting Europe Facility (CEF), the EU's funding support programme for priority energy infrastructure projects.

Gaelectric has submitted an application for planning permission with the Northern Ireland Planning Service which is currently under consideration. SONI has received an application for grid connection and is in the process of undertaking studies as part of the connection offer process.

As a final investment decision has not been made for this project it is not included in our base case adequacy studies. We will continue to monitor its status with a view to incorporating it into future studies.

3.7 Plant Availability

It is unlikely that all of the generation capacity connected to the system will be available at any particular instant. Plant may be scheduled out of service for maintenance, or forced out of service due to mechanical or electrical failure. Forced outages have a much greater negative impact on generation adequacy than scheduled outages, due to their unpredictability.

When examining past data on plant availability, it is apparent that some years can be less favourable for some plant. These high-impact low-probability (HILP) events can have a significant bearing on the overall system performance for the year in question.

HILP events are unforeseen occurrences that don't often transpire but, when they do, will have a significant adverse impact on a generator's availability performance, taking it out of commission for several weeks. The probability of this occurring to an individual generator is low. However, when dealing with the system as a whole, there is a reasonable chance that at least one generator is undergoing such an event at any given time.

The availability scenarios used in our base cases are considered to be the most likely, and so they incorporate the influence of HILPS, though other availability scenarios have been examined to prepare for a range of possible outcomes.

Another aspect of plant availability is that of two-shifting, which may result in a change to maintenance patterns. Two-shifting is where a generator is taken off overnight or at minimum load times. This will occur more frequently with increased penetration of wind generation, and may result in the requirement for additional maintenance and increased Scheduled Outage Days (SODs). We will continue to monitor the operation of plant and the impact of this on availability.

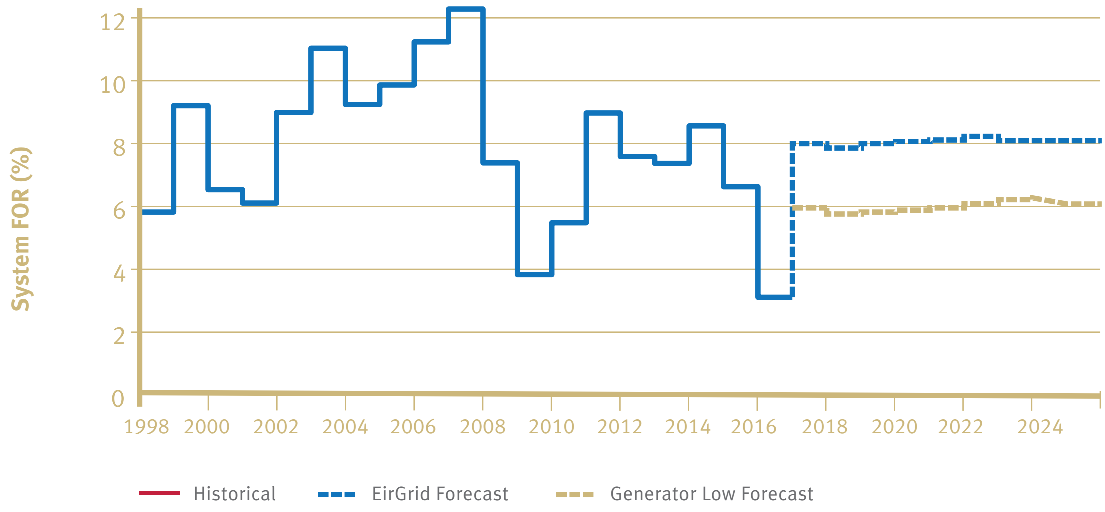


Figure 3-7 Historical (to October 2016) and predicted Forced Outage Rates for Ireland.

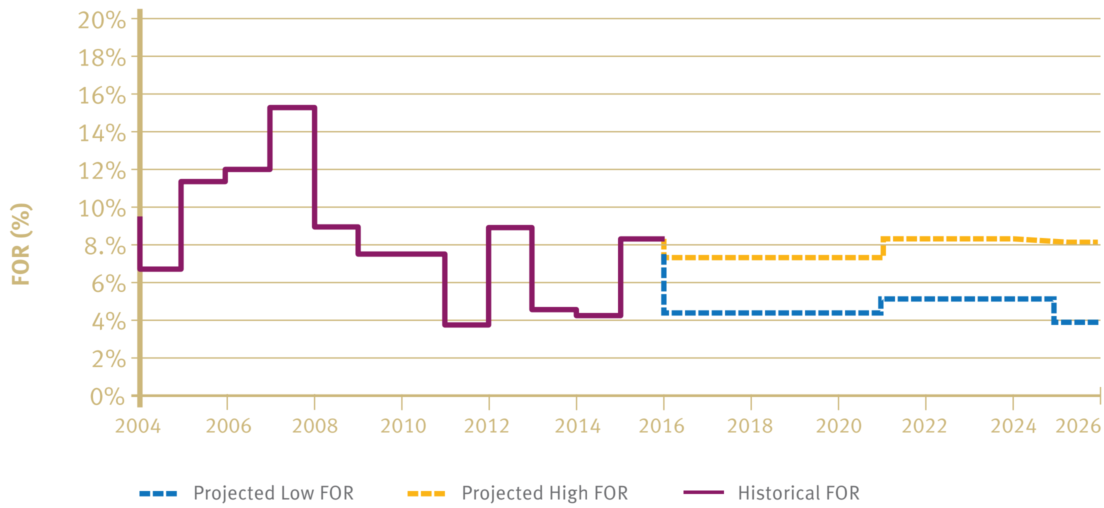


Figure 3-8 Historical (to October 2016) and predicted Forced Outage Rates for Northern Ireland.

4 Adequacy Assessments

4 ADEQUACY ASSESSMENTS

4.1 Introduction

This section presents the results from the adequacy studies, given in terms of the plant surplus or deficit (see APPENDIX 3 for detailed information on the methodology used). Generation adequacy assessments are carried out in three different ways:

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

It is only on the completion of the additional North-South Interconnector that the combined studies are applicable. These all-island studies show an overall improvement in the adequacy position from the single-system cases.

All results are presented in colour-coded tabular form in APPENDIX 4. The amount of surplus or deficit of plant is given in terms of perfect plant. Perfect plant may be thought of as a conventional generator which does not experience any outages, either scheduled or unexpected.

As part of the I-SEM Capacity Market, a methodology is being developed to identify Local Constraints requirements. The adequacy results presented in this report are developed in accordance with the methodology outlined therein, and should not be used to make inferences on the outcome of the Local Constraints assessment.

4.2 Base Case

The adequacy assessments from the base case are presented in Figure 4 1. The assessment is expressed in terms of the amount of surplus or deficit for the system for any particular year. When the result for any year is a deficit, it is plotted below the red line, e.g. Northern Ireland in 2021.

4.2(a) Presentation of Results

In our base case, we have made the following assumptions:

- The median load growth scenario will transpire in each jurisdiction.
- The plant availability figures are calculated from historical statistics by EirGrid and SONI.
- The significant generation surplus in Ireland will decrease. By 2021, the capacity market should ensure that just enough capacity remains to keep the system at standard.
- A large amount of plant in Northern Ireland will close due to emission restrictions. This leads to deficits by 2021.

The results for the combined, all-island system are applicable only from 2021 onwards, when the second North-South Interconnector is commissioned. Results prior to this overstate the surplus, and so are shown as a dotted line. These results illustrate the potential that is not being realised because of the delay in building the second North South Interconnector.

For the single-jurisdictional studies, we assume the following:

- Northern Ireland places a reliance of 200 MW on Ireland.
- Ireland places 100 MW reliance on Northern Ireland.

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

In the single-area studies, the Wind Capacity Credit (WCC) curve relevant to that particular jurisdiction is used. For the all-island studies, the combined all-island WCC curve is used, matching the total amount of installed wind on the island to its appropriate capacity credit, e.g. for 5700 MW of installed wind in 2022, the capacity credit is 570 MW.

Over the course of our studies, we assume that the import capability of the interconnectors from Great Britain is de-rated to approximately 50% of nominal capacity, see section 3.4(b). This is to account for the possible scarcity of generation availability in Great Britain, as well as the possibility of a physical outage of the interconnector itself.

4.2(b) Discussion of Results

The aim of the all-island Capacity Market is to secure enough generation to meet the adequacy standard. Therefore, we have assumed that much of the surplus generation plant will decommission by 2021. This leaves the all-island system with almost zero surplus.

Similarly, when studying Ireland on its own, we see the surplus falling to almost zero when the Capacity Market matures by 2021.

However, the situation in Northern Ireland, when studied separately, is different. Because of notified plant closures and restrictions, there is a deficit of plant by 2021. Without the second North South Interconnector, not enough of the surplus in Ireland can be shared to alleviate the security of supply concerns in Northern Ireland.

Less plant overall is needed to meet the standard in the combined system, than is needed in each jurisdiction individually. This demonstrates one of the advantages of the second North South Interconnector: combining the systems results in a capacity benefit, where less generation plant is required on the island overall to meet the combined loads.

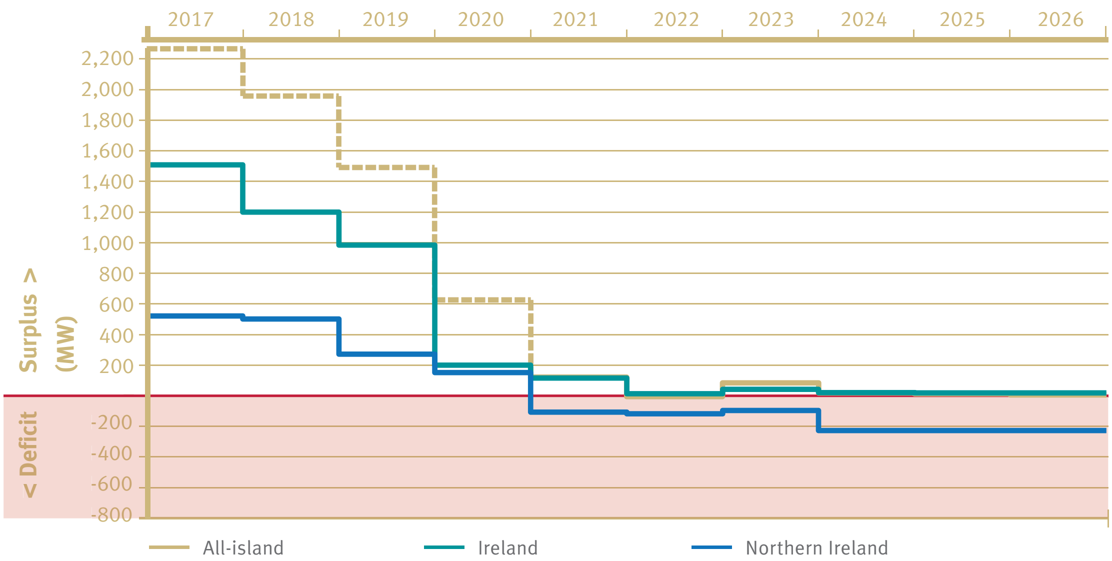


Figure 4 1 Adequacy assessment results for the base case, in terms of perfect plant. A positive number indicates the amount of plant that a system is in surplus, while a negative number shows the deficit. The dotted line for the all-island case indicates that results prior to the commissioning of the second North South Interconnector are shown for illustrative purposes only, as they overstate the surplus.

4.3 Alternative Scenario without Interconnection to Great Britain

Reliance on undersea interconnection is dependent on the availability of spare capacity in Great Britain, and on the cables being operational. We note the decreased capacity margins in Great Britain and the recent long-term outages on both the Moyle and EWIC Interconnectors. Due to these factors, we now examine a situation where both undersea interconnectors with Great Britain (Moyle and EWIC) are unavailable.

Without the two undersea interconnectors to Great Britain, and with the same generation portfolios as assumed in the Base Case above, then the adequacy results deteriorate significantly. Figure 4 2 shows the large deficits in these cases.

While the base case shows the all-island system in balance by 2021, this balance is dependent on the undersea interconnectors. Without these, there are significant deficits of up to 600 MW.

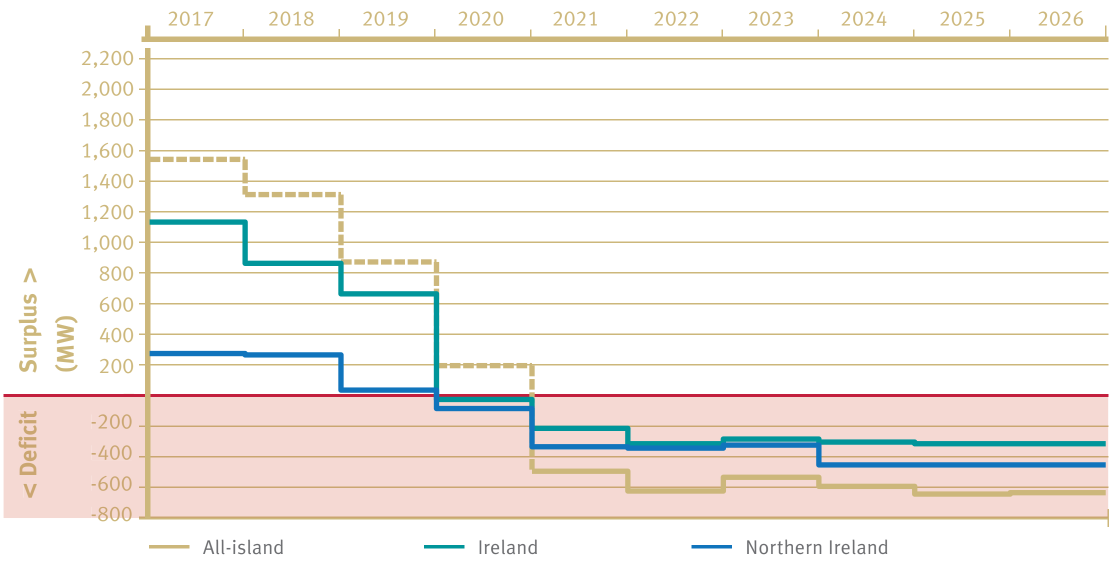


Figure 4 2 Adequacy results without interconnection to Great Britain.

5 DEMAND SCENARIOS FOR THE CAPACITY MARKET

5 DEMAND SCENARIOS FOR THE CAPACITY MARKET

5.1 Introduction

The Regulatory Authorities have outlined their proposals for a Capacity Market in the new I-SEM. This new Capacity Market will pay for enough capacity to meet a pre-determined capacity requirement. Generators will compete in a capacity auction to supply capacity to the Capacity Market.

The methodology for calculating the capacity requirement was set out in the SEM Committee decision paper and associated appendices in December 2016 [31]. The final demand scenarios to be used in the calculation of the capacity requirement are a combination of the GCS demand forecasts (adjusted for non-market demand) and a range of historical profile years.

5.2 Methodology for Determining the Capacity Requirement

The determination of the Capacity Requirement and the associated Derating Factors forms part of the "determination of key data" element of the I-SEM Capacity Market process.

The Capacity Requirement is the primary driver of the volume of capacity to be purchased by the market through the Capacity Market auction. The intention is that the level of capacity procured should be sufficient to maintain the agreed adequacy standard, i.e. the 8 hour LOLE standard.

A key element in the process is the determination of de-rating factors for the capacity providers wishing to take part in the auction. All providers of capacity will have an element of unreliability when they will be unavailable to perform, e.g. due to forced outages or intermittency. Such unavailability will require additional capacity to be procured to maintain the agreed adequacy standard. The De-rating Factors are used to adjust the nameplate capacity of capacity providers to reflect the contribution they can make to meeting the Capacity Requirement.

31 https://www.semcommittee.com/publication/sem-16-082-crm-capacity-requirement-and-de-rating-methodology-decision-paper

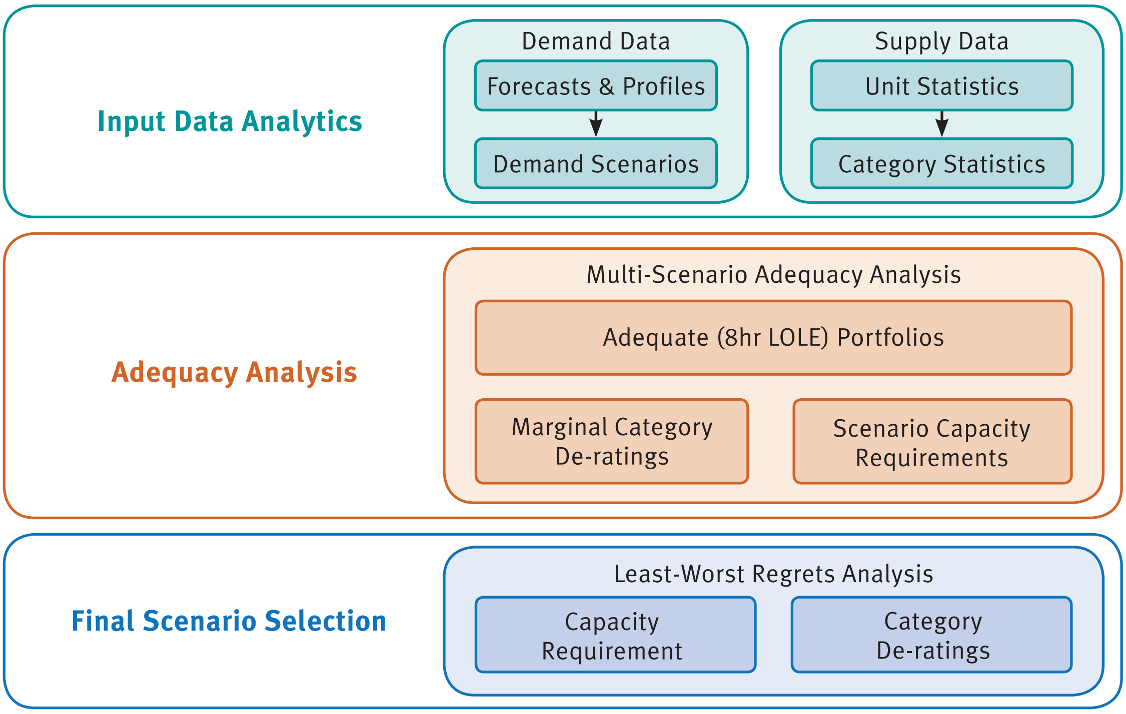


Figure 5-1 Conceptual overview of the Capacity Requirement and De-rating Factor methodology

5.3 Least-Worst Regrets Analysis

The GCS produces a range of demand scenarios from low to high. As can be seen in APPENDIX 1, the scenarios for the All-Island peak demand forecast range from 7.0 GW in the low scenario case for 2022, to 7.7 GW in the high scenario.

A "least-worst regrets" analysis is performed in order to identify which demand scenario will be chosen as the basis for de-rating factors and the de-rated capacity requirement for that Capacity Year.

- If the de-rated capacity requirement for the lowest demand scenario is implemented then the capacity adequate portfolios associated with it may fall significantly short of meeting the 8 hour LOLE standard if the highest demand scenario actually occurs. This could result in load shedding at times where there is inadequate capacity to serve the higher than expected demand. The cost of each unit of shortage is equal to the Value of Lost Load. Hence the market faces a high cost if it fails to procure enough capacity.
- If the de-rated capacity requirement for the highest demand scenario is implemented then the capacity adequate portfolios associated with it may significantly exceed the 8 hour LOLE standard if the lowest demand scenario actually occurs. The market would have paid for capacity which it turns out not to require. Hence the market faces a high cost in the form of idle capacity that must be funded by the capacity auction.

The SEM Committee has decided that a Least-Worst Regrets approach should be used to find a de-rated capacity requirement that seeks to minimise the combined cost of over-procuring capacity and incurring high demand curtailment costs (beyond those implied by the LOLE standard).

Under the Least-Worst Regrets approach the selected demand scenario is that for which the sum of the Regret Cost of Capacity Surplus and the Regret Cost of Capacity Shortfall is lower than for any other demand scenario. The de-rated capacity requirement for this demand scenario is selected as the result of this analysis.

In the indicative results to date, the LWR analysis has chosen a demand scenario that is higher than the Median demand. It should be noted that the Capacity Requirement structure allows for adjustments closer to the time within T-1 to adjust for more realistic forecast (compared to that assumed for T-4 for the same capacity year).

5.4 Conclusions

The demand scenarios in this GCS will be used in the determination of the Capacity Requirement for the first capacity auction, proposed for December 2017. The TSOs will work with the Regulators in order to process these calculations.

Appendices


FREQUENCY
49.99
Hz
STANDARD TIME
SYSTEM TIME
TIME DEVIATION
14.29

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
2015	27.6	2.9%	9.05	0.0%	36.7	2.2%	5.03	1.74	6.77	4.91	1.72	6.59
2016	28.2	2.0%	9.06	0.1%	37.3	1.6%	5.11	1.74	6.77	4.99	1.72	6.67
2017	28.7	1.9%	9.07	0.2%	37.8	1.4%	5.19	1.75	6.86	5.08	1.73	6.75
2018	29.6	3.0%	9.09	0.2%	38.7	2.3%	5.31	1.75	6.98	5.19	1.73	6.87
2019	30.3	2.6%	9.13	0.4%	39.5	2.1%	5.42	1.76	7.10	5.30	1.73	6.99
2020	31.2	2.8%	9.17	0.4%	40.4	2.3%	5.52	1.77	7.20	5.40	1.74	7.09
2021	31.8	2.0%	9.21	0.4%	41.0	1.5%	5.62	1.77	7.26	5.49	1.75	7.15
2022	32.4	1.8%	9.24	0.4%	41.6	1.5%	5.66	1.78	7.30	5.53	1.75	7.18
2023	32.9	1.6%	9.28	0.4%	42.2	1.3%	5.68	1.79	7.33	5.55	1.76	7.21
2024	33.4	1.6%	9.32	0.4%	42.8	1.4%	5.69	1.79	7.34	5.56	1.77	7.23
2025	33.7	1.0%	9.36	0.4%	43.1	0.8%	5.70	1.80	7.42	5.57	1.77	7.30
2026	34.2	1.3%	9.40	0.4%	43.6	1.1%	5.77	1.81	7.49	5.64	1.78	7.37

Table A-1 The Median Demand Forecast, given in Calendar year format, for Total Electricity Requirement (TER). TER is the total electricity required by the region, i.e. it includes all electricity produced by large-scale, dispatchable generators, all small-scale exporting generators, and an estimate of electricity produced by self-consuming generators.

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
2015	27.6	2.9%	9.05	0.0%	36.7	2.2%	5.03	1.74	6.77	4.91	1.72	6.59
2016	28.1	1.7%	9.01	-0.4%	37.2	1.3%	4.95	1.73	6.60	4.84	1.71	6.49
2017	28.5	1.3%	8.97	-0.4%	37.5	0.8%	5.03	1.73	6.68	4.92	1.71	6.57
2018	28.9	1.5%	8.94	-0.4%	37.9	1.1%	5.15	1.72	6.79	5.03	1.70	6.69
2019	29.4	1.7%	8.93	-0.1%	38.4	1.2%	5.27	1.72	6.90	5.14	1.70	6.79
2020	30.0	1.9%	8.92	-0.1%	38.9	1.5%	5.39	1.72	7.02	5.26	1.70	6.91
2021	30.3	1.1%	8.91	-0.1%	39.2	0.7%	5.43	1.72	7.03	5.30	1.69	6.92
2022	30.7	1.3%	8.90	-0.1%	39.6	1.0%	5.47	1.72	7.04	5.34	1.69	6.93
2023	31.1	1.3%	8.89	-0.1%	40.0	1.0%	5.48	1.72	7.05	5.35	1.69	6.94
2024	31.6	1.6%	8.89	-0.1%	40.5	1.3%	5.49	1.71	7.06	5.36	1.69	6.94
2025	31.9	1.1%	8.88	-0.1%	40.8	0.7%	5.50	1.71	7.12	5.37	1.68	7.01
2026	32.4	1.3%	8.87	-0.1%	41.3	1.0%	5.56	1.71	7.19	5.43	1.68	7.07

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
2015	27.6	2.9%	9.05	0.0%	36.7	2.2%	5.03	1.74	6.77	4.91	1.72	6.59
2016	28.3	2.2%	9.11	0.6%	37.4	1.9%	5.28	1.81	6.95	5.16	1.79	6.91
2017	28.8	1.9%	9.17	0.7%	38.0	1.5%	5.36	1.82	7.04	5.24	1.80	6.99
2018	29.6	3.0%	9.25	0.9%	38.9	2.5%	5.48	1.82	7.18	5.36	1.80	7.11
2019	31.1	4.8%	9.33	0.9%	40.4	3.9%	5.59	1.83	7.30	5.47	1.81	7.23
2020	32.6	4.9%	9.41	0.9%	42.1	4.1%	5.68	1.84	7.41	5.56	1.81	7.32
2021	34.1	4.6%	9.49	0.9%	43.6	3.7%	5.88	1.84	7.58	5.75	1.82	7.48
2022	35.2	3.3%	9.58	0.9%	44.8	2.8%	5.99	1.85	7.69	5.86	1.82	7.58
2023	36.2	2.8%	9.67	0.9%	45.9	2.4%	6.06	1.86	7.78	5.93	1.84	7.67
2024	37.2	2.8%	9.76	0.9%	47.1	2.5%	6.13	1.88	7.87	6.00	1.85	7.75
2025	37.8	1.4%	9.86	1.0%	47.6	1.2%	6.16	1.90	7.97	6.03	1.87	7.86
2026	38.4	1.7%	9.95	1.0%	48.4	1.5%	6.25	1.92	8.08	6.12	1.89	7.96

Table A-3 High Demand Forecast

Appendix 2 Generation Plant Information

	ID	Fuel Type	2016	Comment
All DSU	DSU	DSU	260	Modest growth assumed
Aghada	AD1	Gas	258	To be shut before end of 2023
	AT1	Gas/DO	90	To be shut before end of 2023
	AT2	Gas/DO	90	
	AT4	Gas/DO	90	
	AD2	Gas/DO	431	
Dublin Bay	DB1	Gas/DO	402	
Dublin Waste		Waste	-	Due to commission in 2017 (61 MW)
Edenderry	ED1	Milled peat/ biomass	118	Planning permission extended
Edenderry OCGT	ED3	DO	58	
	ED5	DO	58	
Great Island CCGT	GI4	Gas/DO	464	
Huntstown	HNC	Gas/DO	339	
	HN2	Gas/DO	397	
Indaver Waste	IW1	Waste	17	
Lough Ree	LR4	Peat	91	PSO levy runs out in 2019
Marina CC	MRC	Gas/DO	95	To be shut before end of 2023
Moneypoint	MP1	Coal/HFO	285	
	MP2	Coal/HFO	285	
	MP3	Coal/HFO	285	
North Wall CT	NW5	Gas/DO	104	To be shut by end of 2023
Poolbeg CC	PBC	Gas/DO	463	
Rhode	RP1	DO	52	
	RP2	DO	52	
Sealrock	SK3	Gas/DO	81	
	SK4	Gas/DO	81	
Tarbert	TB1	HFO	54	To be shut by end of 2022
	TB2	HFO	54	To be shut by end of 2022
	TB3	HFO	241	To be shut by end of 2022
	TB4	HFO	243	To be shut by end of 2022

	ID	Fuel Type	2016	Comment
Tawnaghmore	TP1	DO	52	
	TP3	DO	52	
Tynagh	TYC	Gas/DO	386	
West Offaly	WO4	Peat	137	PSO levy runs out in 2019
Whitegate	WG1	Gas/DO	444	
Ardnacrusha	AA1	Hydro	86	
Erne 1	ER1	Hydro	65	
Lee	LE1	Hydro	27	
Liffey	LI1	Hydro	38	
Turlough Hill	TH1	Pumped storage	292	
EWIC	EW1	DC Interconnector	500	
Total Dispatchable, including DSU			**7617**	

Table A-4 Registered Capacity of dispatchable generation and interconnectors in Ireland in 2016.
DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil.

at year end:	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Wind	2740	3080	3420	3760	4100	4240	4380	4520	4660	4800	5000
Hydro	22	22	22	22	22	22	22	22	22	22	22
Biomass and LFG	54	54	54	54	54	54	54	54	54	54	54
Biomass CHP	0	0	10	30	60	60	60	60	60	60	60
Industrial	9	9	9	9	9	9	9	9	9	9	9
Conventional CHP	151	151	151	151	151	151	151	151	151	151	151
Solar PV	15	20	25	50	70	80	90	100	100	100	100
Total	**2991**	**3336**	**3691**	**4076**	**4466**	**4616**	**4766**	**4916**	**5056**	**5196**	**5396**

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

at year end:	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
All Wind	2740	3080	3420	3760	4100	4240	4380	4520	4660	4800	5000
All Hydro	238	238	238	238	238	238	238	238	238	238	238
Biomass/LFG (including Biomass CHP)	54	54	64	84	114	114	114	114	114	114	114
Waste (Assume 50% renewable)	9	40	40	40	40	40	40	40	40	40	40
Edenderry on Biomass	35	35	35	35	35	35	35	35	35	35	35
Solar PV	15	20	25	50	70	80	90	100	100	100	100
Total RES	**3091**	**3467**	**3822**	**4207**	**4597**	**4747**	**4897**	**5047**	**5187**	**5327**	**5527**

Table A-6 All Renewable energy sources in Ireland

	ID	Fuel Type	2016	Comment
Ballylumford	ST4,5 &6	Gas*/Heavy Fuel Oil	250	To be shut before end of 2018 with the option of a 2-year extension to 2020
	B31	Gas*/Heavy Fuel Oil	245	
	B32	Gas*/Heavy Fuel Oil	245	
	B10	Gas*/Heavy Fuel Oil	97	
	GT7 (GT1)	Distillate Oil	58	
	GT8 (GT2)	Distillate Oil	58	
Kilroot	ST1	Heavy Fuel Oil*/Coal	257	To be shut before end of 2023
	ST2	Heavy Fuel Oil*/Coal	257	To be shut before end of 2023
	KGT1	Distillate Oil	29	
	KGT2	Distillate Oil	29	
	KGT3	Distillate Oil	42	
	KGT4	Distillate Oil	42	
Coolkeeragh	GT8	Distillate Oil	53	
	C30	Gas*/Distillate Oil	402	
All AGU/DSU	AGU/ DSU	Distillate Oil	160	
Lisahally		Biomass	17.6	
Bombardier		Waste to Energy	0	14.8 MW to be commissioned in 2017
Moyle		DC Interconnector	450	
Total Dispatchable			**2692**	

*Table A-7 Dispatchable plant and Interconnectors in Northern Ireland in 2016. *Where dual fuel capability exists, this indicates the fuel type utilised to meet peak demand.*

at year end:	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Large Scale Wind	830	1044	1145	1145	1145	1145	1145	1145	1145	1145	1145
Small Scale Wind	115	145	175	180	180	180	180	180	180	180	180
Large Scale Solar	30	145	145	145	145	145	145	145	145	145	145
Small Scale Solar	82	102	122	125	125	125	125	125	125	125	125
Small Scale Biogas	17	20	23	26	26	26	26	26	26	26	26
Landfill Gas	16	16	16	16	16	16	16	16	16	16	16
Small Scale Biomass	5	6	7	8	8	8	8	8	8	8	8
Renewable CHP	3	3	3	3	3	3	3	3	3	3	3
Other CHP	8	8	8	8	8	8	8	8	8	8	8
Small Scale Hydro	5	6	7	8	8	8	8	8	8	8	8
Total	**1,111**	**1,495**	**1,651**	**1,664**	**1,664**	**1,664**	**1,664**	**1,664**	**1,664**	**1,664**	**1,664**

Table A-8 Partially/Non-Dispatchable plant in Northern Ireland

at year end:	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
All Wind	945	1189	1320	1325	1325	1325	1325	1325	1325	1325	1325
Solar PV	112	247	267	270	270	270	270	270	270	270	270
All Biomass/ Biogas/Landfill Gas	56	70	74	78	78	78	78	78	78	78	78
Renewable CHP	3	3	3	3	3	3	3	3	3	3	3
Hydro	5	6	7	8	8	8	8	8	8	8	8
Tidal	0	0	0	0	0	0	0	0	0	0	0
Total RES	**1121**	**1515**	**1671**	**1684**	**1684**	**1684**	**1684**	**1684**	**1684**	**1684**	**1684**

Table A-9 All Renewable energy sources in Northern Ireland

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 from 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. Ireland has an agreed standard of 8 hours LOLE per annum, and Northern Ireland has 4.9 hours. 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.

It is important to make a further comparison of the proportional Expected Unserved Energy (EUE). LOLE is concerned only with the likely number of hours of shortage; EUE goes further and takes account also of the extent of shortages.

System	LOLE hrs/year	EUE per million
Ireland	8.0	34.5
Northern Ireland	4.9	33.8

Table A-10 LOLE standards for both jurisdictions, and their related Expected Unserved Energy (EUE)

The comparison of Ireland and Northern Ireland standards in terms of EUE suggests that the standard in Northern Ireland when expressed in LOLE terms is appropriate for a relatively small system with relatively large unit sizes. The standard in Northern Ireland, taken in conjunction with the larger proportional failures, results in a comparable EUE to Ireland.

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

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

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-11.

	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-11 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-12:

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.

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-13 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

All-Island	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Scale
Low Demand	2340	2030	1590	810	340	240	350	290	290	290	>= 500
Median Demand	2280	1970	1500	640	130	0	90	20	20	10	0
High Demand	2200	1900	1390	440	-170	-370	-350	-480	-520	-550	<= -500
Median Demand, no Interconnectors	1550	1320	880	200	-490	-620	-530	-590	-640	-630	

Northern Ireland	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Scale
Low Demand	550	530	310	200	-50	-70	-40	-160	-150	-150	>= 500
Median Demand	530	510	280	160	-100	-110	-90	-220	-220	-220	0
High Demand	520	490	250	130	-140	-160	-150	-290	-300	-310	<= -500
High Demand, Low Availability	460	410	200	100	-180	-190	-220	-330	-350	-360	
Median Demand, no Moyle	280	270	40	-80	-330	-340	-320	-450	-450	-450	

Ireland	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Scale
Low Demand	1560	1250	1050	350	300	210	250	230	230	230	>= 500
Median Demand	1520	1210	990	210	120	20	50	30	30	30	0
High Demand	1460	1160	920	50	-140	-300	-330	-410	-430	-450	<= -500
Median Demand, no EWIC	1140	870	670	-20	-210	-310	-280	-300	-310	-310	

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