All-Island

Generation Capacity Statement 2016-2025

EIRGRID GROUP

The current. The future.

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

For queries relating to this document or to request a copy contact:

Andrew.Gordon@soni.ltd.uk

or

Noelle.Ameijenda@EirGrid.com

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FOREWORD

EirGrid and SONI are responsible for a safe, secure and reliable supply of electricity: now and in the future. We develop, manage and operate the electricity transmission grid in Ireland and Northern Ireland respectively.

This document 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.

After some years of decline, electricity demand has now stabilised and there are signs of growth. This underlines the need for a secure electricity supply to support economic investment in Ireland and Northern Ireland in the future. A competitive electricity market is essential for security of supply, particularly a well-designed capacity remuneration mechanism.

Since the publication of the last Generation Capacity Statement, there has been significant new interest in the data centre sector in Ireland. This translates to higher demand forecasts, which we have accommodated over a range of different scenarios in the study.

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

A significant amount of plant is expected to close due to emission restrictions. Accordingly, we foresee that there could be a deficit of plant in the future. The proposed North South Interconnector will contribute to security of supply and help alleviate these deficits.

I hope you find this document informative. We welcome any feedback on this document and suggestions about changes we could make in providing information about future developments in the electricity market.

Fintan Slye
Chief Executive, EirGrid Group
February 2016

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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 provides an analysis of the need for a capacity remuneration mechanism.

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

GLOSSARY OF TERMS

Capacity Margin

The percentage excess of installed generation capacity (without regard to actual availability) over annual peak demand.

$$\textit{Capacity Margin} = \left[\frac{\textit{Installed Capacity}}{\textit{Peak Demand}} - 1\right] * 100$$

Capacity Factor

$$\text{Capacity Factor} = \frac{\textit{Energy output}}{\textit{Hours per year * Installed Capacity}}$$

Combined Cycle Gas Turbine (CCGT)

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.

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.

Demand-Side Management

The modification of normal demand patterns usually through the use of financial incentives.

Forced Outage Probability (FOP)

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.

Gigawatt Hour (GWH)

Unit of energy

1 gigawatt hour = 1,000,000 kilowatt hours = 3.6 x 10^{12} joules

Gross Domestic Product (GDP)

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.

Interconnector

The electrical link, facilities and equipment that connect the transmission network of one EU member state to another.

Maximum Export Capacity (MEC)

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.

Megawatt (MW)

Unit of power

1 megawatt = 1,000 kilowatts = 10^6 joules / second

Short run marginal cost (SRMC)

The instantaneous variable cost for a power plant to provide an additional unit of electricity, i.e. the cost of each extra MW it could produce excluding its fixed costs. The SRMC reflects the opportunity cost of the electricity produced, which is the economic activity that the generator forgoes to produce electricity. For example, in the case of a generator fuelled by gas, the opportunity cost includes the price of gas on the day that it is bidding in, because if the generator was not producing electricity it could sell its gas in the open market.

Total Electricity Requirement (TER)

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.

Transmission System Operator

In the electrical power business, a transmission system operator is the licensed entity that is responsible for transmitting electrical power from generation plants to regional or local electricity distribution operators.

Executive Summary

EXECUTIVE SUMMARY

In this Generation Capacity Statement (GCS), we forecast the likely balance between supply and demand for electricity during the years 2016-2025. This GCS covers both Northern Ireland and Ireland, and is produced jointly between SONI and EirGrid.[1]

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.

We consulted widely with industry participants and most of the input data was frozen in October 2015. 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

All-Island

- With the commissioning of the second North South Interconnector, the all-island system meets the adequacy standard for all years and for most scenarios. The second North-South Interconnector is vital to ensure the security of electricity supply for the future in both Northern Ireland and Ireland. In association with the competent authorities in the respective jurisdictions, we are actively progressing work to deliver this Project of Common Interest by 2019.
- We carried out adequacy studies using information given by generators. This data was provided based on the assumption that there will be a well-designed Capacity Remuneration Mechanism (CRM) in place post 2017.
- There has been significant growth of demand side participation in the market, and we expect this to continue. Having incorporated it into our studies, we anticipate that it will contribute significantly to adequacy.
- Our undersea interconnectors to Great Britain make an important contribution to adequacy. However, tightening capacity margins in Great Britain mean that we need to carefully assess how much reliance we should place on interconnection.
- The recent fall in demand has stabilised, and we can see signs of a return to growth.
- The contribution of the renewables electricity sector continues to grow strongly, placing both jurisdictions in a strong position to meet their 2020 renewable energy targets.

Northern Ireland

- We expect electricity demand growth in Northern Ireland to be modest over the coming years.
- The security of supply situation has been stabilised by local reserve services at Ballylumford. The situation will improve further with the repair of the Moyle Interconnector pole 2.[2]
- Post 2020, we have concerns for the security of supply in Northern Ireland. These would be addressed by the second North South Interconnector.

1 Where 'we' is used, it refers to both companies, unless otherwise stated.
2 Full restoration is expected by the end of 2016.

Ireland

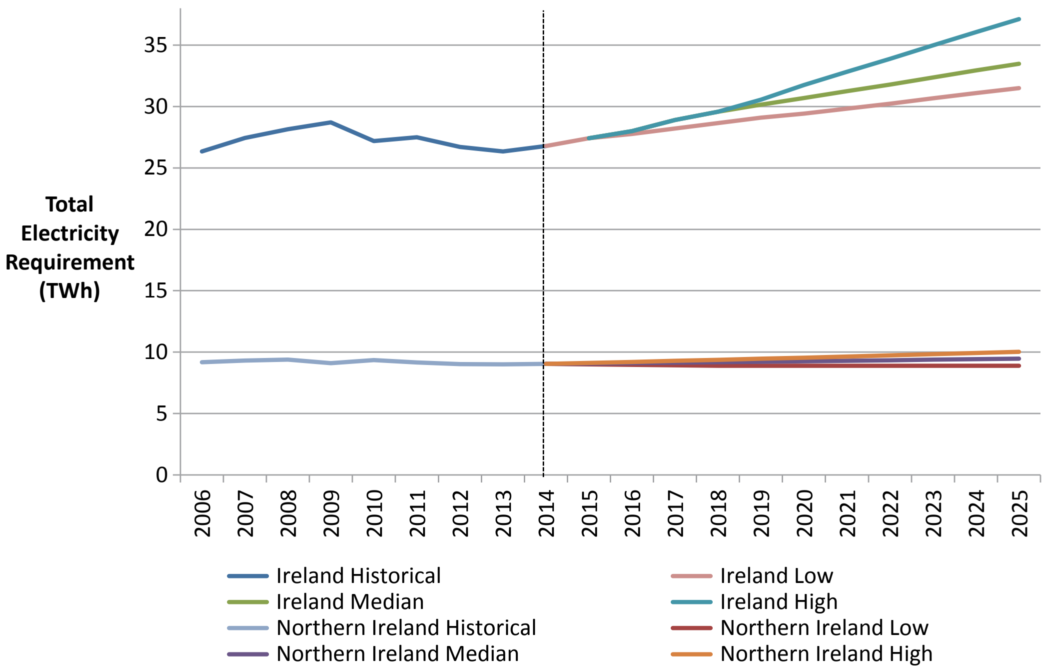
- We note a return to demand growth in Ireland, with growth in 2015 expected to be over 2%. Economic predictions are strongly positive for the next decade, leading to high electricity demand forecasts over this time.
- Since the publication of the last GCS, there has been significant new interest in the data centre sector in Ireland. This translates to higher demand forecasts, which we have accommodated over a range of different scenarios. Each scenario corresponds to a different data centre build rate.
- Our studies show the adequacy position in Ireland to be positive over the years covered by this report and for most scenarios. However, we note that this level is falling. Most of the new generation preparing to connect has some form of policy support. As older plant begins to retire, we foresee that margins will tighten.

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, see figure below.

In Ireland, the low, median and high scenarios assume different levels of load from the expanding data centre sector.

In Northern Ireland, growth is more modest, based on recent trends and economic predictions.



CONVENTIONAL GENERATION

The figure below shows the total amount of dispatchable and interconnector capacity expected over the next ten years.

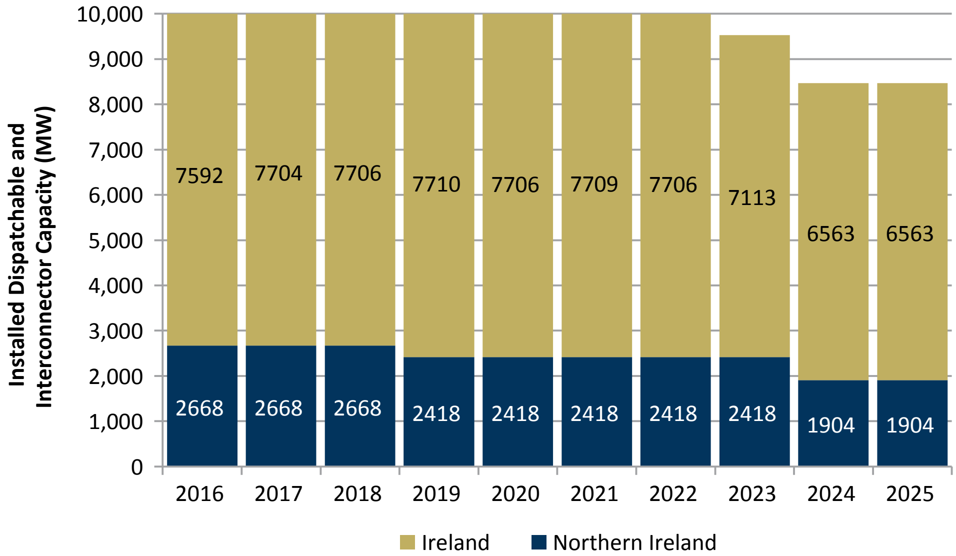


Figure 0-1 Expected installed capacity of dispatchable generation plant and interconnectors. Dispatchable plant is that which can be monitored and controlled from our control centres.

Key Assumptions

- The introduction of the Integrated-Single Electricity market (I-SEM) in 2017 will bring changes to market arrangements. We anticipate that a well-targeted, competitive CRM will encourage sufficient generators to remain in the market. This should safeguard the security of supply for all customers, particularly with higher levels of expected renewable generation.

- To evaluate the need for a CRM, we have tried to assess how the market might react in the absence of a CRM.

- We note the increased risk to security of supply for our neighbours in Great Britain. This affects the reliance that we can place on our undersea interconnectors: Moyle and EWIC. We will continue to review this situation.

Ireland

- A large gas generator successfully commissioned at Great Island during 2015. This contributes to the positive adequacy situation in Ireland.

- For our adequacy studies, the only other new generators that we include over the coming decade will be in receipt of policy support.

- The oil-fired generators at Tarbert are due to close at the end of 2022.

- We expect that some older generation plant will close or experience poor availability towards the end of the study period.

Northern Ireland

- Local reserves services came into effect in January 2016 at Ballylumford. These provide 250 MW of power for a three-to-five year period. Investment in emission-abatement technology and life-extension works has made this possible.
- We expect that pole 2 of the Moyle Interconnector will return to service in early 2016.
- Post 2021, emissions restrictions at the Kilroot generation station will reduce the running hours available for two large steam units. These units are due to close at the end of 2023.

RENEWABLE ENERGY

The governments in both jurisdictions have significant targets for the generation of electricity from renewable energy sources (RES) by 2020. The targets for Ireland were restated in the recent White Paper on Energy. In Northern Ireland, the Department of Enterprise, Trade and Investment (DETI) is currently reviewing and refreshing its Strategic Energy Framework 2010-2020.

While a large portion of this renewable electricity will come from wind power, other RES will also play a part, such as hydro, solar and biomass. Figure 0-2 and Figure 0-3 show the fuel mix in 2014 for Ireland and Northern Ireland respectively.

Ireland

The amount of wind capacity installed in Ireland has reached 2400 MW. Over the course of 2014, 19% of all electricity was provided by wind. At certain times, enough wind power has been available to satisfy more than half of electricity demand. Many more wind projects remain in the planning stages. We estimate the need for a further 1600 MW of wind to be installed by 2020 to reach the target of 40% renewable electricity.

Up to 150 MW of Biomass CHP (Combined Heat and Power) units are to be supported through the REFIT III (Renewable Energy Feed in Tariff [3]) scheme. This will contribute to our targets.

Hydro generators provided almost 3% of our electricity needs in 2014, and will continue to play their part in achieving our RES goals.

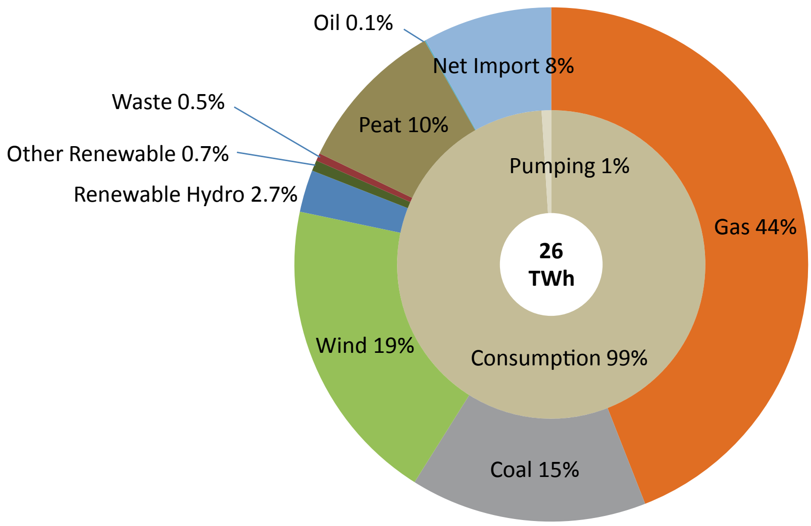


Figure 0-2 Fuel mix in Ireland in 2014

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

Northern Ireland

Currently, there is 700 MW of wind installed in Northern Ireland, providing 17% of electricity in 2014 (see Figure 0-3 below). We estimate that an installed wind capacity of circa 1250 MW will be enough to achieve the 40% RES target.

Significant contributions are also expected to come from the expanding solar photovoltaic sector and from biomass-burning plant. By 2017, there should be 35 MW of large-scale biomass plant. Lisahally Biomass, with a capacity of approximately 17 MW, began generation in 2015. We expect another large scale biomass connection will increase capacity to 35 MW. Over the coming years we anticipate large scale solar photovoltaic connections to be established with capacity passing 50 MW by 2020.

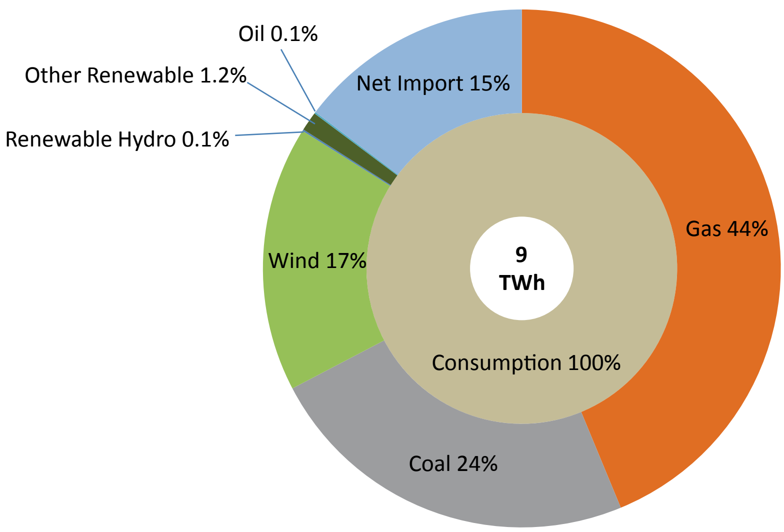


Figure 0-3 Fuel mix in Northern Ireland in 2014

APPROACH TO GENERATION ADEQUACY

Generation adequacy is determined by comparing generation capacity with demand. To measure the imbalance between them we use a statistical indicator. When this indicator is at an appropriate level, the supply/demand balance is judged to be acceptable.

The current interconnector between Ireland and Northern Ireland provides a significant capacity benefit, but it is limited. This means that Ireland must limit its assumed reliance on Northern Ireland to just 100 MW. Similarly, Northern Ireland has an assumed reliance of 200 MW on Ireland. The commissioning of an additional interconnector between the two jurisdictions will significantly increase the transfer capability between the two jurisdictions. Then, the two jurisdictions can be considered as one power system as far as adequacy calculations are concerned. This will improve overall adequacy in both.

A degree of uncertainty surrounds any forecast of generation and demand. Therefore, our report examines a number of different scenarios. This provides a range of relevant information that stakeholders can examine.

GENERATION ADEQUACY ASSESSMENTS

The figures below illustrate the generation adequacy results for three sets of studies: Ireland, Northern Ireland and on an all-island basis. Each set of studies is divided into scenarios depending on demand growth, plant availability and the availability of undersea interconnectors. The boxes are coloured orange when supply is in balance with demand. When there is a substantial surplus of plant, the boxes are green, and red when there is a deficit.

Ireland retains a surplus for all years if the demand falls into the low or median scenario. Deficits start to appear in 2023 due to plant closures, but only in cases with High Demand or without EWIC, as shown by orange/red colouring.

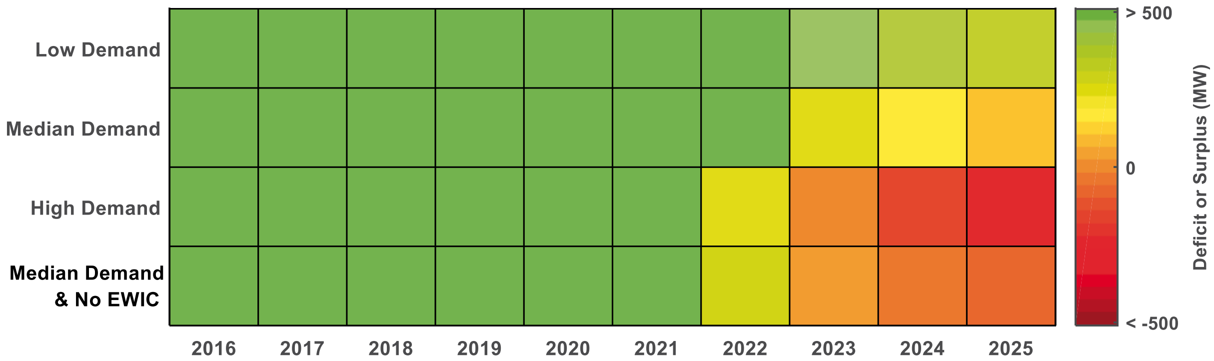


Figure 0-4 Adequacy Results for Ireland, showing surplus for many years, with green colouring.

For Northern Ireland, all demand scenarios start to show deficits in 2021, when emissions restrictions at Kilroot power station limit its contribution.

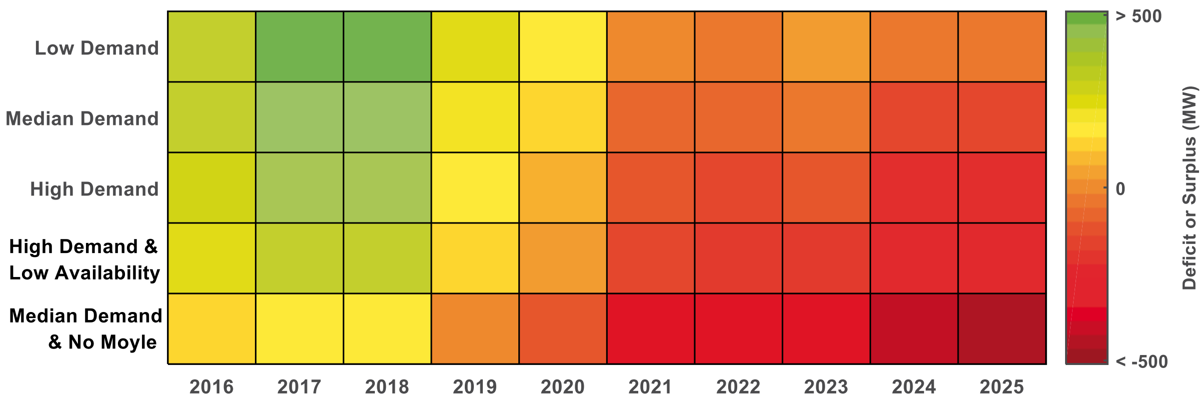


Figure 0-5 Adequacy results for Northern Ireland. Deficits appear in 2021.

With the second North South Interconnector in place by 2019, there will no longer be significant restrictions on the amount of flow between the two jurisdictions. Therefore, we can assess generation adequacy on an all-island basis, see Figure 0-6. With all of the generation available to meet the combined demand, the adequacy situation improves. However, if high demand were to transpire, we would expect there to be insufficient generation by 2024.

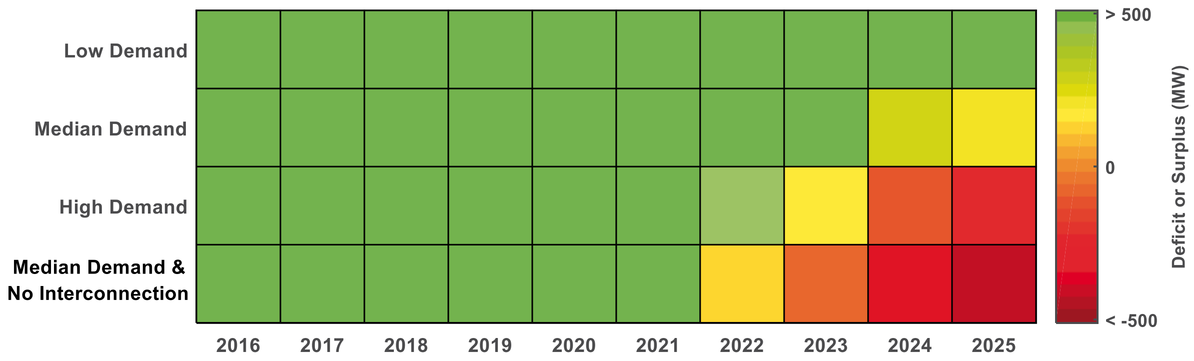


Figure 0-6 Adequacy results for the all-island system.

We have also examined a situation where the undersea interconnectors to Great Britain are unable to provide power when required. This could be due to physical cable problems, or due to electricity being scarce in Great Britain. The figures above show that this would result in difficulties in all three sets of studies.

Analysis of the Need for a Capacity Remuneration Mechanism

The results above are based on the assumption that the electricity market continues to provide participants with a CRM. Capacity payments are particularly important to conventional generators in a market which is transitioning to more intermittent renewable energy.

To demonstrate the need for a CRM in the future, we have examined a scenario of what would happen in a market devoid of capacity payments. In this case, some generators would become financially unviable and were removed from the portfolio. This would lead to severe adequacy difficulties, with significant deficits and risk to security of supply.

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 2025[4].

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 of Enterprise Trade and Investment.

This Generation Capacity Statement covers the years 2016-2025 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 2015-2024, published in February 2015.

All input data assumptions have been reviewed and updated.

4 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/EirGrid-Winter-Outlook-Final-25Sep2015.pdf

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 complex in recent years with the changing economic climate. 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

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 Correction of Historical 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 peak data to Average Cold Spell (ACS) temperatures[5]. 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.

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[6] 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. A spread of electricity forecasts are produced, covering the next ten years.

5 It should be noted that temperature has a lesser impact on annual electricity energy demand than it does on peak demand.
6 Self-consumption represents approx. 2% of system demand, and so its estimation does not introduce significant error.

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

2.2(b) Historical data

Transporting electricity from the supplier 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 data from the past 20 years 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. The short-term data comes from the Quarterly Economic Commentary published by the ESRI in September 2015. Longer-term trends arise out of the ESRI's Medium Term Review (MTR), published in July 2013.

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

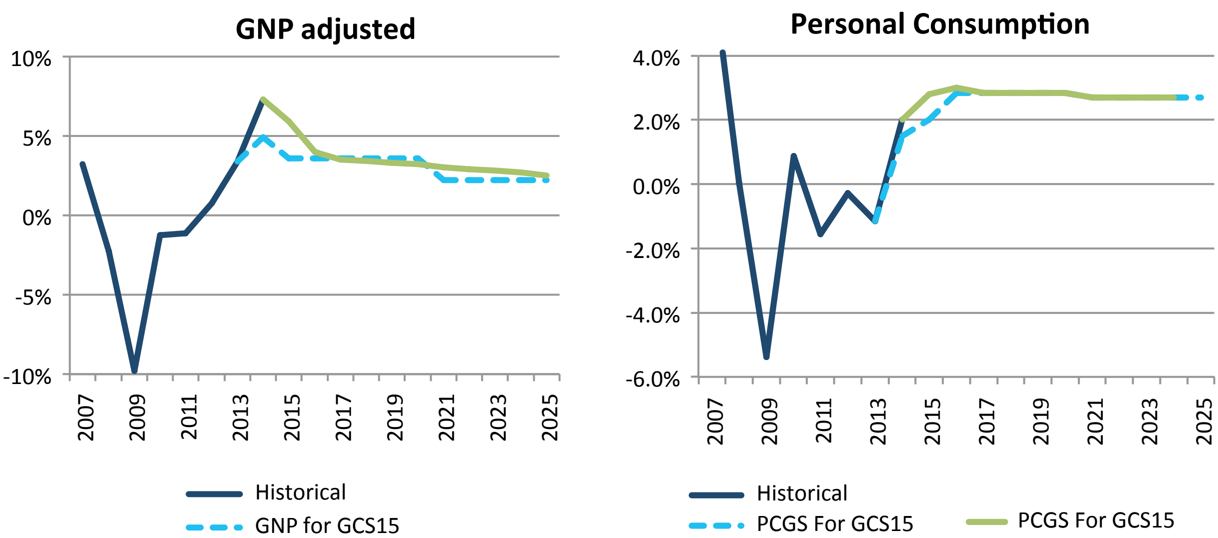


Figure 2-1 Economic parameters: Historical and predictions from ESRI

7 http://www.esri.ie/irish_economy/

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

9 Gross National Product is the total value of goods and services produced in a country, discounting the net amount of incomes sent to or received from abroad. It is modified for the effect of re-domiciled companies, i.e. foreign companies which hold substantial investments overseas but have established a legal presence in Ireland.

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.

Whether connecting directly to the transmission system or to the distribution network, 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 approximately a further 600 MVA. At present, there are enquires for another 1,100 MVA.

This possibility of an additional 1700 MVA of demand is significant in the context of a system with a peak demand in 2014/15 of about 4700 MW (where it would add 35%).

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

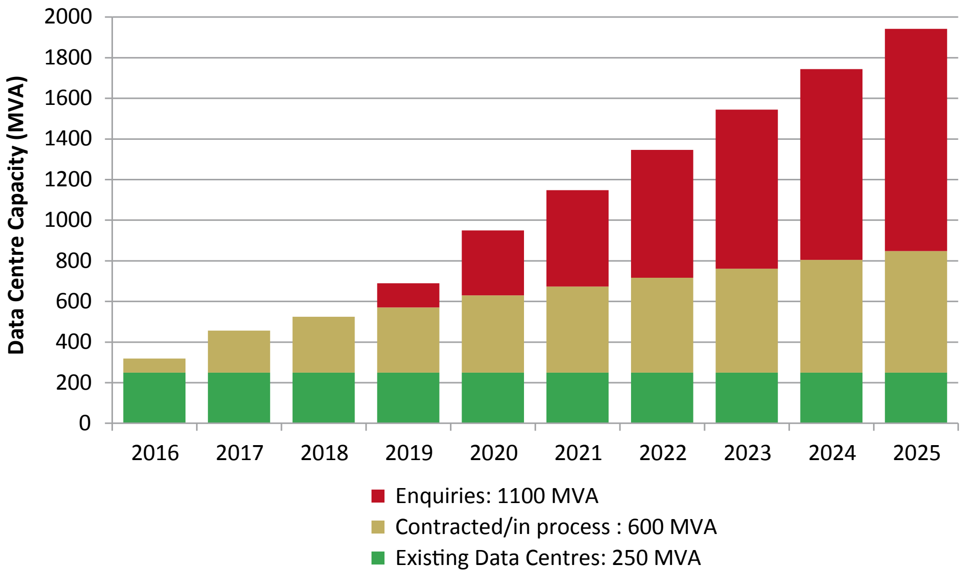


Figure 2-2 Data centre connections already existing in Ireland, in the connection process and enquiries

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 demand forecast scenarios for Ireland on data centre 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 50% of data centres in the connection process will connect. It also incorporates some reduction due to energy efficiency measures in line with Ireland's National Energy Efficiency Action Plan[10] (including the installation of smart meters).

The median scenario is predicated on the connection of 100% of data centres in the connection process. The high scenario, in addition to the demand in the median scenario, also assumes that 50% 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.

10 http://www.dcenr.gov.ie/energy/energy+efficiency+and+affordability+division/national+energy+efficiency+action+plan.htm

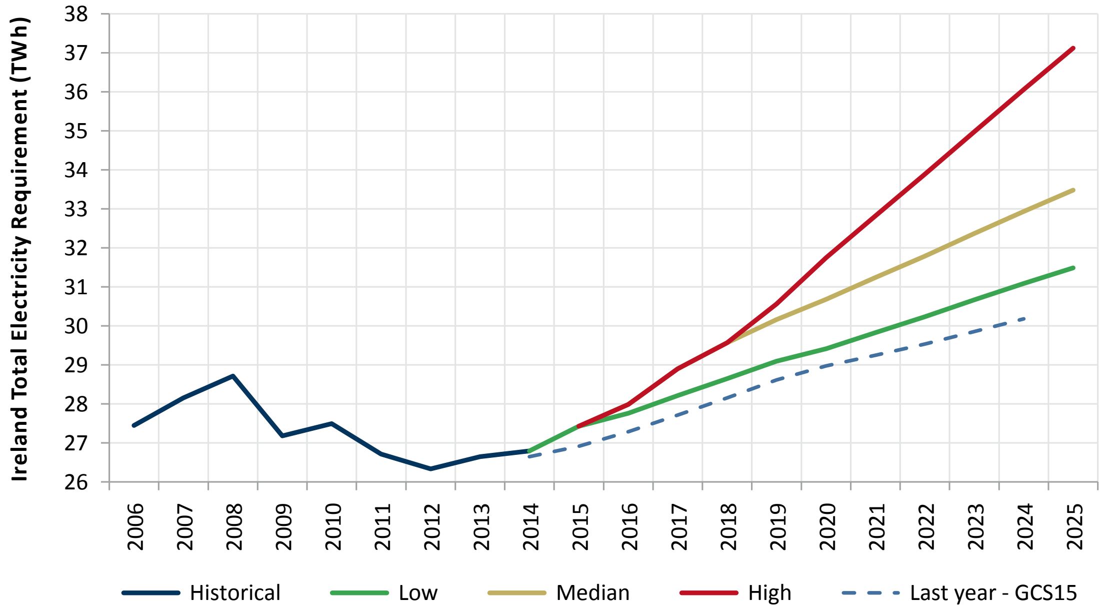


Figure 2-3 Total Electricity Requirement Forecast for Ireland. The figure for 2015 is based on real data available at EirGrid's National Control Centre up to October, and so estimates are made for the remaining months.

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 plunged and demand rose. 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, see Figure 2-5. This forecast is then tempered with estimates of energy efficiency savings, particularly to allow for the effect of smart meters.

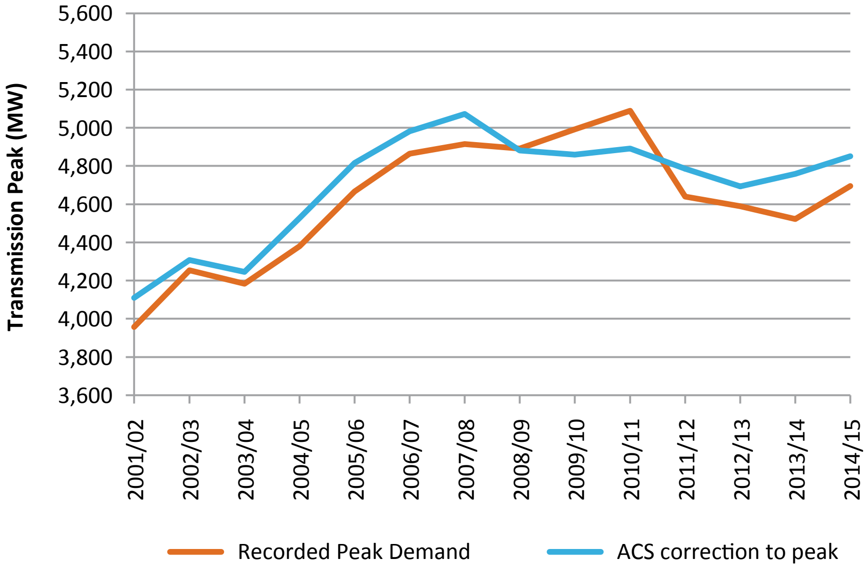


Figure 2-4 Past values of recorded maximum demand in Ireland, and the ACS corrected values

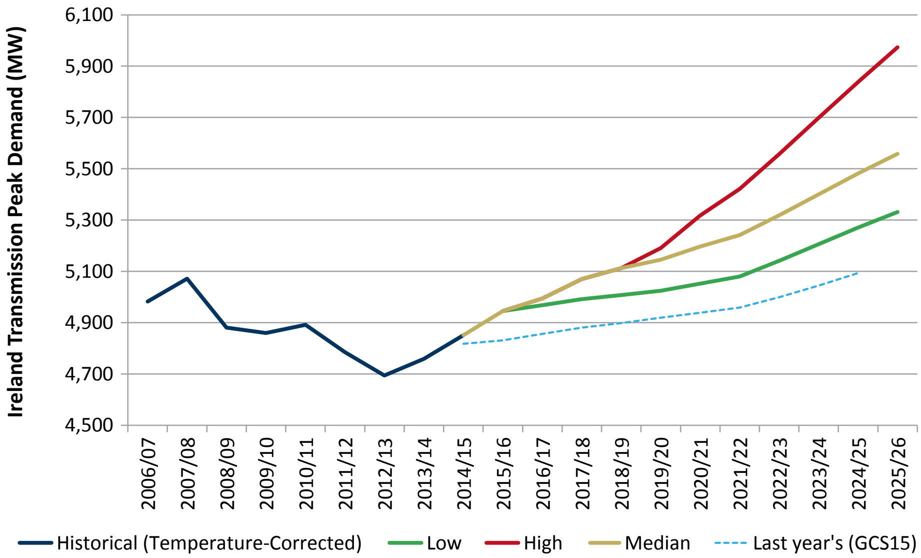


Figure 2-5 Forecast of Ireland's Transmission Peak for the Low Median and High scenarios, under Average Cold Spell conditions. For comparison purposes, last year's Median peak forecast is shown in pale blue dashes.

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[11] 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 of Enterprise, Trade and Investment (DETI) is currently reviewing and refreshing its Strategic Energy Framework 2010-2020. This is due to be completed in early 2016.

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 Northern Ireland Electricity (NIE) and referencing the Renewable Obligation Certificate Register (ROC Register)[12] to establish the amount of embedded generation that is currently connected on the Northern Ireland system, as well as referencing Northern Ireland Planning Service[13] 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).[14]

2.3(d) TER Forecast

It can be seen that the new TER forecast for Northern Ireland (Figure 2-6) has been reduced compared to the previous forecast published in the Generation Capacity Statement 2015-2024. The reduced forecast is primarily due to a combination of reduced economic growth, as well as the continued drive for energy efficiency.

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

11 http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf
12 https://www.renewablesandchp.ofgem.gov.uk/
13 www.planningni.gov.uk
14 Self-consumption in Northern Ireland currently represents approximately 2% of TER.

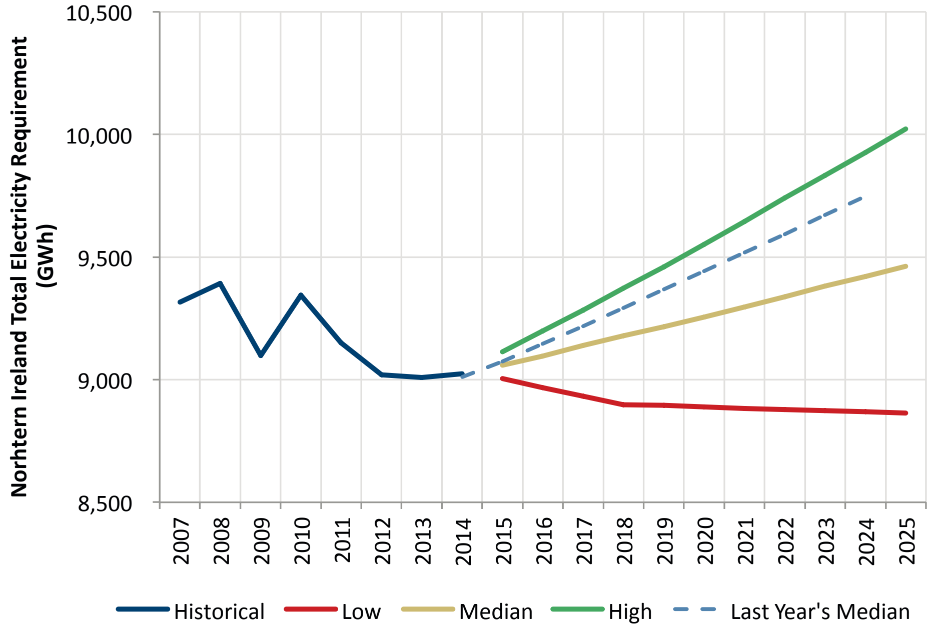


Figure 2-6 Northern Ireland TER Forecast

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 2014/15 generated winter peak, which occurred on Wednesday 10th December at 17:30, consisted of the following dispatch data:

Centrally Dispatched Generation Units + Interconnectors	1277 MW
Renewable + Small Scale	531 MW
Customer Private Generation	9 MW
TOTAL GENERATED PEAK	**1817 MW**

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.

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

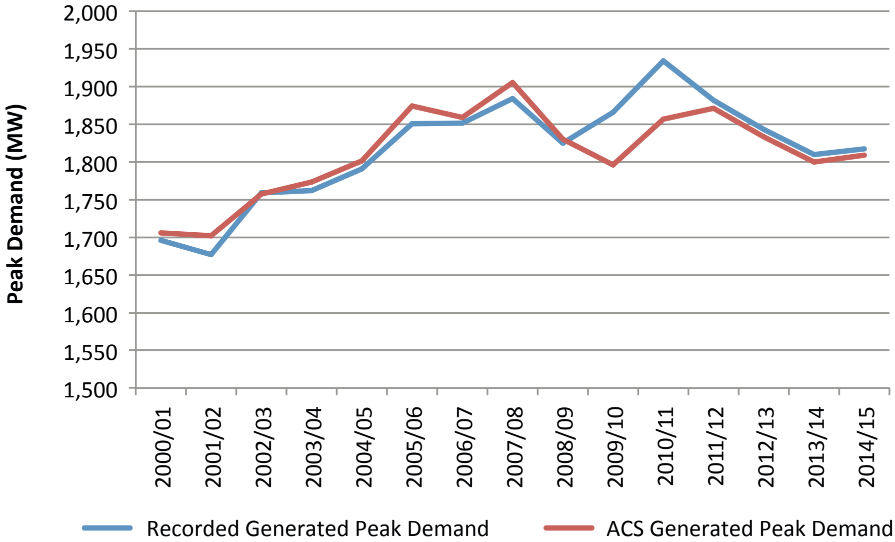


Figure 2-7 Recorded and ACS-corrected peaks (generated level) for Northern Ireland. The most significant corrections are for 2009/10 and 2010/11, when the temperature deviated most from normal.

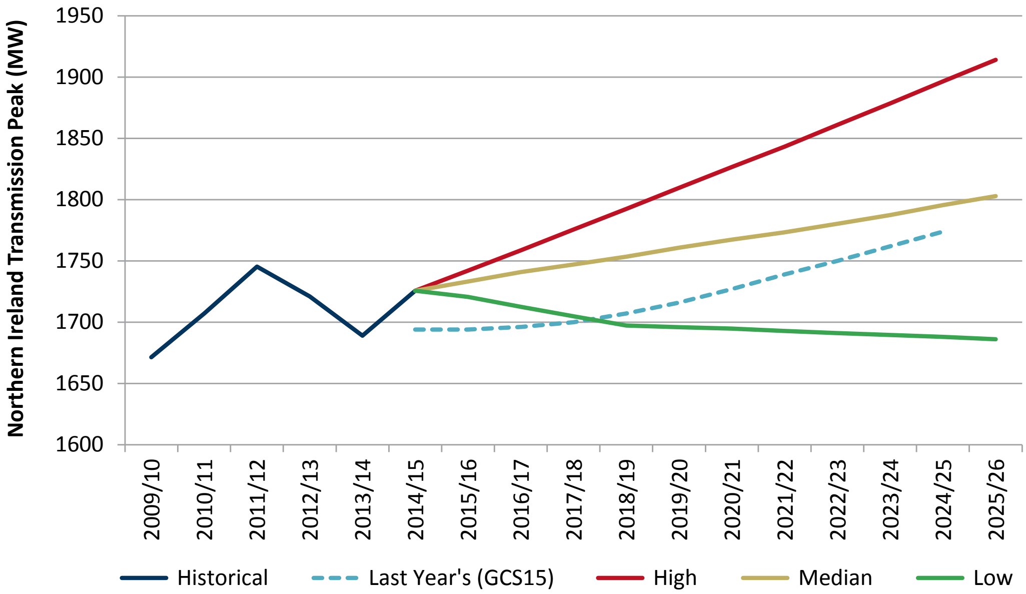


Figure 2-8 ACS Transmission Peak forecasts for Northern Ireland

2.4 All-Island Forecasts

The combined all-island TER forecast comes from summing together the demands from each jurisdiction as shown in Figure 2-9.

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 2014 demand shape. The forecasted all-island peaks are shown in Figure 2-10, where ACS conditions are assumed for the future.

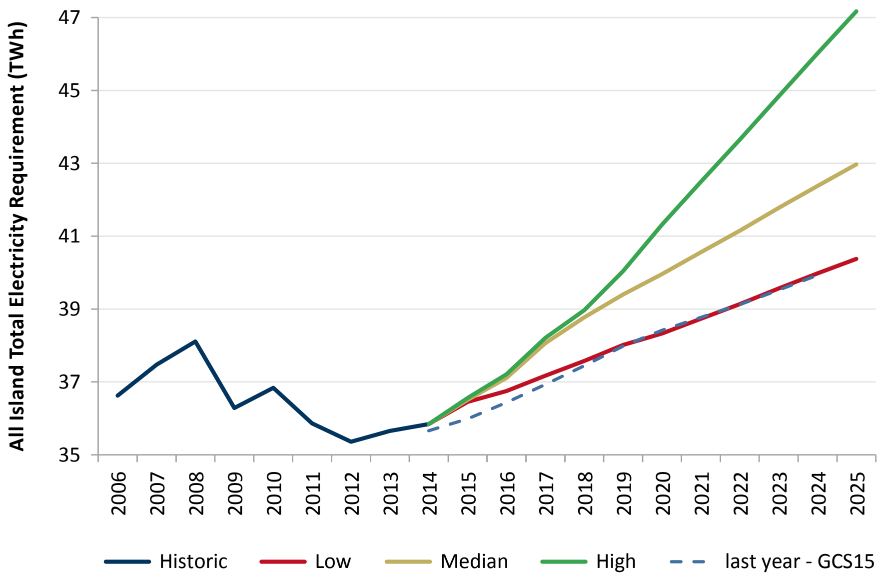


Figure 2-9 Combined All-island TER forecast

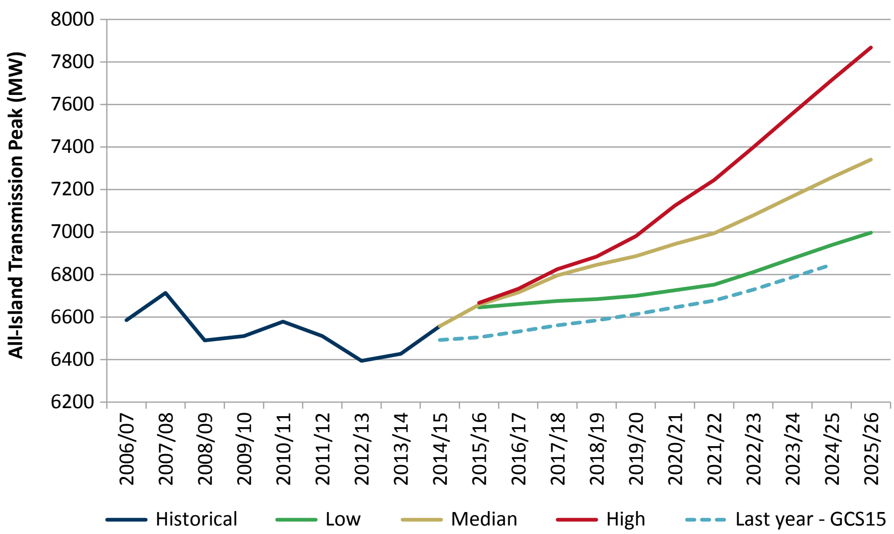


Figure 2-10 Combined all-island TER Peak forecast

2.5 Annual Load Shape and Demand Profiles

To create future demand profiles for the adequacy studies, it is necessary to use an appropriate base year profile which provides a representative demand profile of both jurisdictions. This profile is then progressively scaled up using forecasts of energy peak and demand. The base year chosen for the profile creation was 2014 for both jurisdictions.

2014 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.

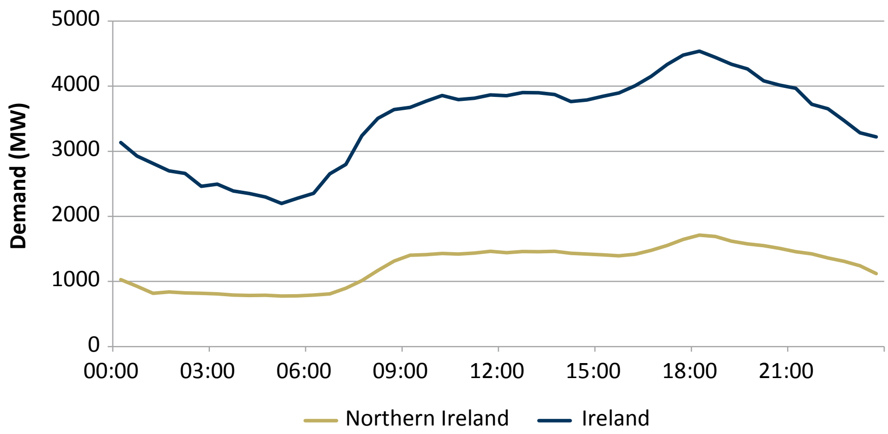


Figure 2-11 Typical winter day profile

Electricity Generation

3 ELECTRICITY GENERATION

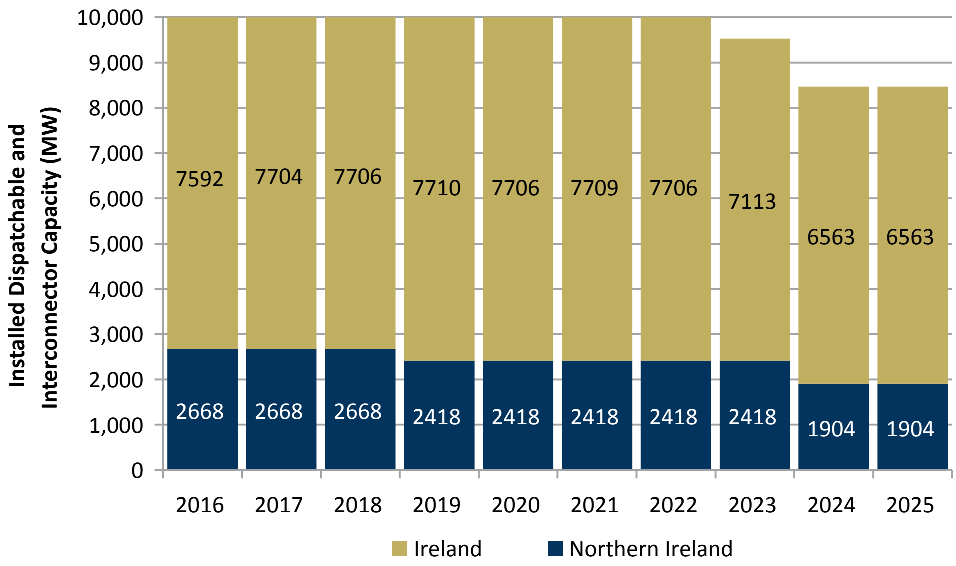


Figure 3-1 Changes in dispatchable capacity (including interconnection) on the island over the next 10 years. All figures are in MW.

This section describes all significant sources of electricity generation connected to the systems in Ireland and Northern Ireland, and how these will change over the next 10 years, as illustrated in Figure 3-1. Issues that affect security of generation supply, such as installed capacity, plant availability, and capacity credit of wind, are examined.

In predicting the future of electricity generation supply in Ireland and Northern Ireland, we have endeavoured to use the most up-to-date information available at the time of the data freeze for this report (October 2015).

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

3.1 Changes to Conventional Generation in Ireland

This section describes the changes in fully dispatchable plant capacities which are forecast to occur in Ireland over the next ten years. Plant closures and additions are documented.

3.1(a) Plant Commissionings

- SSE commissioned a new Combined-Cycle Gas Turbine (CCGT) plant at Great Island in Co Wexford in 2015. The Firm Access Quantity (FAQ) at this site is assumed to be initially 216 MW, until an additional FAQ of 215 MW is assigned.

- In Ireland, the only new conventional generators documented here are those which have a signed connection agreement with EirGrid[15] or the DSO (Distribution System Operator). In addition, plant included in our studies have planning permission, financial close and have indicated a commissioning date to EirGrid by the data freeze date, see Table 3-1.

15 i.e. a signed Connection Offer has been accepted and any conditions precedent fulfilled.

Plant	Capacity (MW)
Dublin Waste to Energy	61
Mayo Biomass CHP	43

Table 3-1 Contracted generation capacity for Ireland, up to 2025. These plant have financial close, planning permission and a firm commissioning date in the near future.

- In recent years, two large CCGTs have 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. 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.

3.1(b) Plant Decommissionings

Some older generators are due to close because of emissions restrictions. These generators are shown in Table 3-2.

Plant	Export Capacity (MW)	Expected to close before
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. (Dates are interpreted as 'by the end of each year'.)

- For the purposes of compliance with the IED (Industrial Emissions Directive[16], 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.

- We note the recent court ruling in relation to planning permission for the burning of peat at the Edenderry power plant. In November 2013, a decision to extend the life of Edenderry power station from the end of 2015 to 2023 was made by An Bord Pleanála. However, a ruling in October 2015 overturned this previously-granted planning permission, saying that An Bord Pleanala's assessment of the environmental impact of the continued operation of the plant was too narrow.
  - A stay on the ruling continues until April 2016 and a further stay may be sought.
  - It is also noted that a new planning application, for continued operations at Edenderry Power Plant until 2030 was approved by Offaly County Council in July 2015, this decision to grant was subsequently appealed to An Bord Pleanála and a final determination is expected in March 2016.

16 Industrial Emissions Directive (IED) http://ec.europa.eu/environment/air/pollutants/stationary/ied/legislation.htm

3.1(c) Base Case

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 will shut towards the latter end of the 10 year period. An alternative approach could be to model these units with higher forced outage rates, which would have a similar effect as closure.

3.2 Changes to Conventional Generation in Northern Ireland

- There is no significant new conventional generation currently planned for Northern Ireland over the next 10 years.

Plant	Export Capacity (MW)	Expected to close before
Ballylumford 6	170	2015
Ballylumford 4, 5	250	2018 - 2020
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 is because of environmental constraints introduced by the Large Combustion Plants Directive[17].

- 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 commencing 1st January 2016.

- From 2016, ST1 and ST2 at Kilroot will be required to comply with the Industrial Emissions Directive (IED)[18], see section 3.3. We have discussed with AES Kilroot how the workings of the IED will affect the running regimes of these units. 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.

- In Northern Ireland, transmission network capacity limitations can restrict the amount of power that can be exported to the transmission network to 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.

17 Large Combustion Plants Directive: http://ec.europa.eu/environment/air/pollutants/stationary/lcp/legislation.htm
18 Industrial Emissions Directive (IED) http://ec.europa.eu/environment/air/pollutants/stationary/ied/legislation.htm

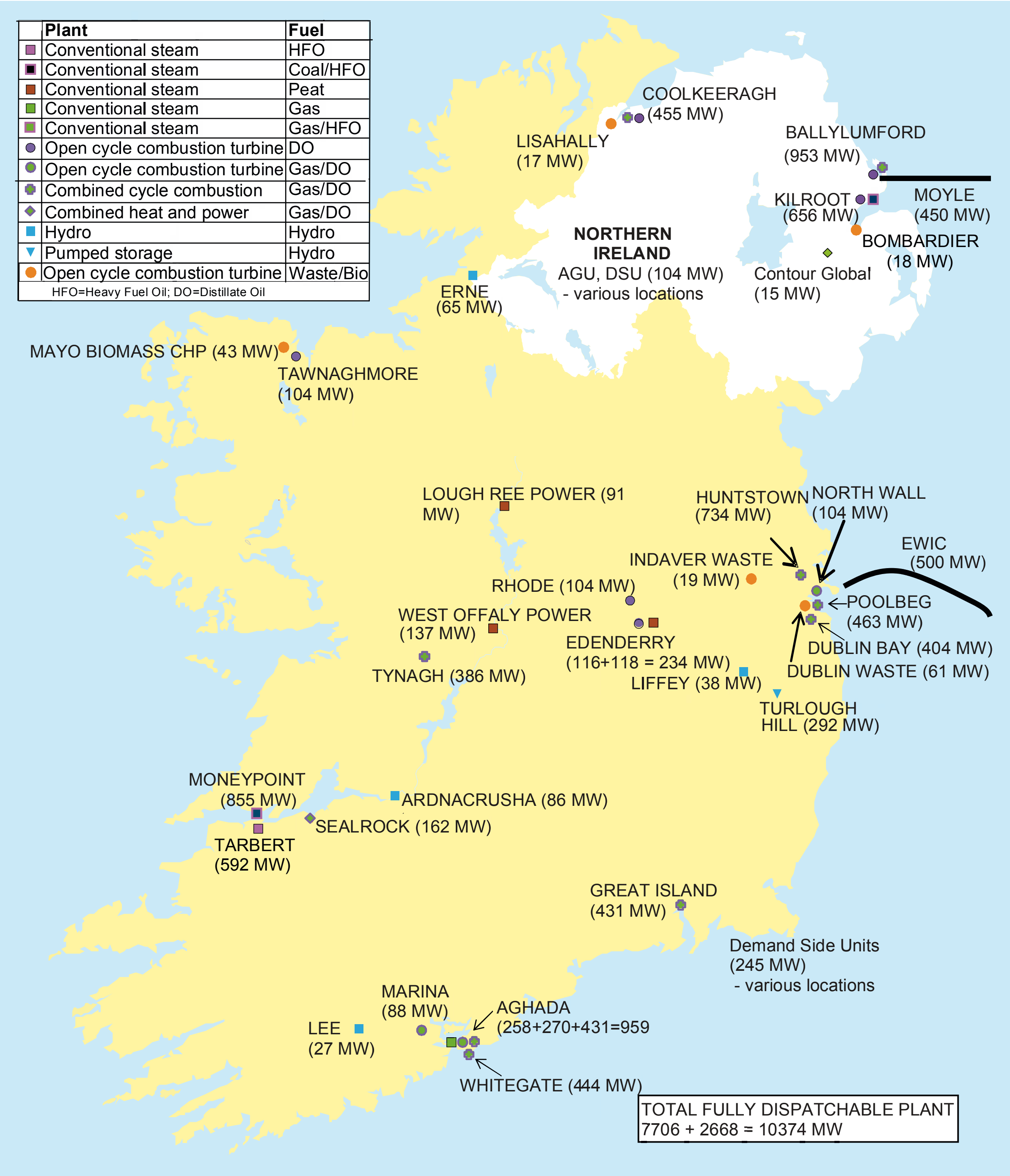


Figure 3-2 Dispatchable plant and undersea interconnectors installed in 2018, at exported capacities. All figures shown are Registered Capacities (except new plant which are at the planned Maximum Export Capacity) – generators and interconnectors may often operate at a lower capacity.

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 (SO_2) and particulate levels have been tightened.

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

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.

We have consulted data from the European Pollutant Release and Transfer Register on the historical emissions from Kilroot. Comparing this to the TNP ceilings for the period 2016-2020, it seems likely that Kilroot will need to purchase additional permits. This would ensure that the plant would be available throughout the year when required, but is dependent on the ability to purchase allowances when required in the UK trading scheme. An inability to purchase additional emission allowances during this time (2016 to 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 2019), an all-island generation adequacy assessment can be carried out from 2019 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 the additional 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 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.

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 that National Grid, in their recent FES report (Future Energy Scenarios, July 2015), have reduced their export assumptions to the island of Ireland from 750 MW to 500 MW from 2020. We also 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.

Due to this increased uncertainty, we have assumed, for the purposes of these studies, a reduced reliance on the interconnectors to Great Britain of 75% of the import capacities. We will continue to review this and the effect it has on our capacity adequacy.

Historically, adequacy assessments have been carried out by ENTSO-E[19] using capacity margins at the time of highest demand[20]. However, ENTSO-E is working to improve its existing adequacy methodology with a special emphasis on harmonised inputs, system flexibility and interconnection assessments. An ENTSO-E task force has been set up to develop a pan-European adequacy assessment model[21]. This model will use 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. Based on current and past analysis[22], we have estimated the capacity value of the interconnector to be approximately 75% of full capacity for these generation adequacy studies. A Forced Outage Probability[23] (FOP) similar to that for the Moyle interconnector has been used to represent EWIC for adequacy studies.

19 European Network of Transmission System Operators-Electricity
20 https://www.entsoe.eu/about-entso-e/system-development/system-adequacy-and-market-modeling/Pages/default.aspx
21 https://www.entsoe.eu/major-projects/adequacy-methodology/Pages/default.aspx
22 Interconnection Economic Feasibility Report: http://www.eirgrid.com/media/47693_EG_Interconnect09.pdf
23 Forced Outage Probability (FOP) is the time a generation source is on forced outage as a proportion of the time it is not on scheduled outages.

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.

However, at the time of writing this report, one cable of the Moyle Interconnector is on a prolonged forced outage due to an undersea cable fault. This follows previous prolonged faults on both cables in 2011 and on one of the two cables in 2010. Based on the latest information concerning its repair, it is expected to be returned to full capacity[24] on an interim basis in early 2016. After a substantial outage in mid-2016, permanent restoration is expected by the end of 2016. The FOP used in these studies for the Moyle has been adjusted to reflect the recent outages.

All interconnector capacity is auctioned by SONI on behalf of Mutual Energy Limited[25]. 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 (75%) 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 will be assessed as part of the next European Ten Year Network Development Plan[26]. 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
Irish-Scottish Links on Energy Study (ISLES)	Offshore wind hub potentially providing interconnection to Scotland
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
Marex	Project providing interconnection to Great Britain
Gallant	Project providing interconnection to Great Britain

Table 3-5 Proposed interconnection projects

24 Under non-fault conditions the Moyle import capacity is 450 MW Nov-Mar, and 410 MW Apr-Oct. Issues with transmission access rights in Scotland may further limit its export capacity to 80 MW from 2017

25 www.mutual-energy.com

26 TYNDP 2016 will be produced by the European Network of Transmission System Operators – Electricity (ENTSO-e) over the next year.

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.

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 existing and planned wind generation on the island. Appendix 2 has detailed lists of all the currently installed windfarms on the island.

	Connected (MW)	Contracted (MW)	Applied (MW)
Ireland TSO	1007	1788	
Ireland DSO	1373	1859	
Northern Ireland TSO	74	0	85
Northern Ireland DSO	567	587	578
Totals	**3021**	**4234**	**663**

Table 3-6 Existing (connected and energised) and planned (contracted) wind farms, as of October 2015. Planned 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. These figures are based on the best information available. More detail on connected wind farms can be seen in Appendix 2.

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, see Figure 5-2.

3.5(a) 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 recent White Paper on Energy[27]. 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 grown from 145 MW at the end of 2002 to over 2,300 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 4.4% in 2014[28].

With these uncertainties in mind, not one figure but a band of possible outcomes has been estimated for wind capacity in 2020. Figure 3-3 illustrates where this band of targets lies, between about 3,800 and 4,100 MW. This would mean an average of about 300 MW of extra wind capacity installed per year. This represents an increase on last year's band which was between 3200 and 3800 MW.

27 http://www.dcenr.gov.ie/energy/en-ie/Energy-Initiatives/Pages/White-Paper-on-Energy-Policy-in-Ireland-.aspx
28 http://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Summary-Report-2014.pdf

Figure 3-4 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[29].

Based on historical records (see Figure 5-2), it is assumed that onshore wind has a capacity factor of approximately 31%.

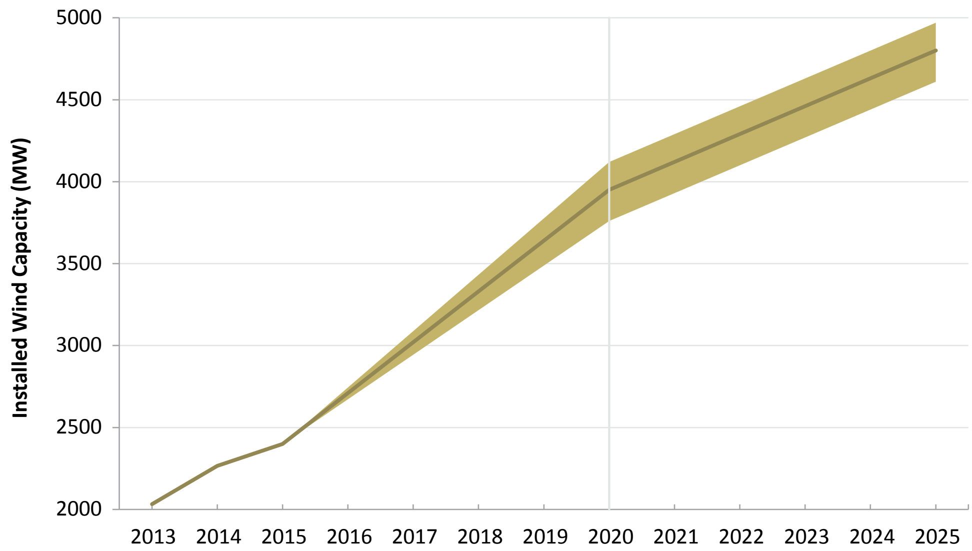


Figure 3-3 Shown in gold, the band of possible wind capacity requirements to meet the 2020 renewable target.

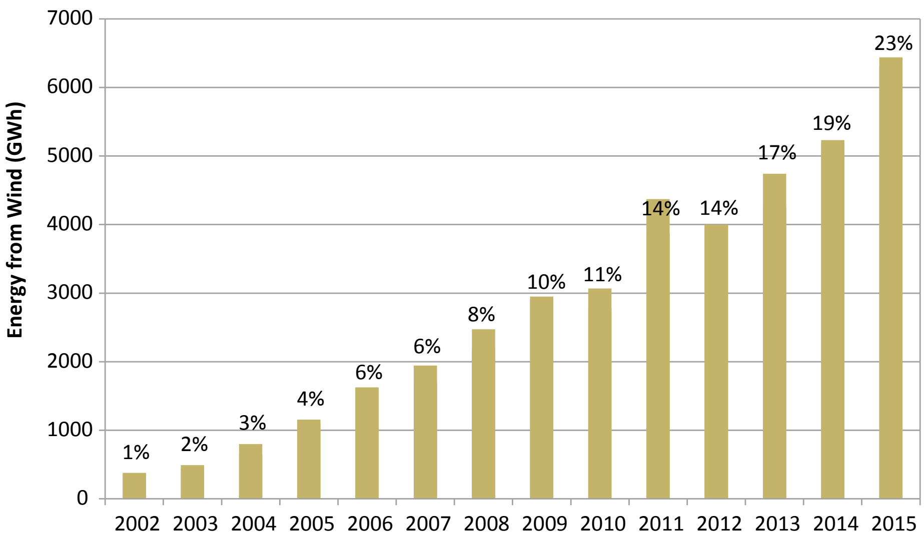


Figure 3-4 Historical wind generation in annual energy terms for Ireland (normalised), also given as a percentage of total electrical energy produced that year (2015 is a provisional estimate).

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

3.5(b) Wind Power in Northern Ireland

The Strategic Energy Framework for Northern Ireland[30] 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 of Enterprise, Trade and Investment (DETI) is currently reviewing its Strategic Energy Framework 2010-2020. This is due to be completed in early 2016. For 2014, almost 18% of electricity consumption came from renewable sources in Northern Ireland (most of which was from wind power).

Figure 3-5 shows the expected growth of wind installed in Northern Ireland. These assumptions are based on volumes of committed applications to SONI and Northern Ireland Electricity for grid connection[31]. We estimate that an installed wind capacity of circa 1250 MW, along with contributions from other renewables such as solar photo-voltaic and biomass, will be enough to reach 40% renewables generation by 2020. We have assumed that large scale onshore wind has a capacity factor[32] of 30%, PV 10% and large scale biomass 80%.

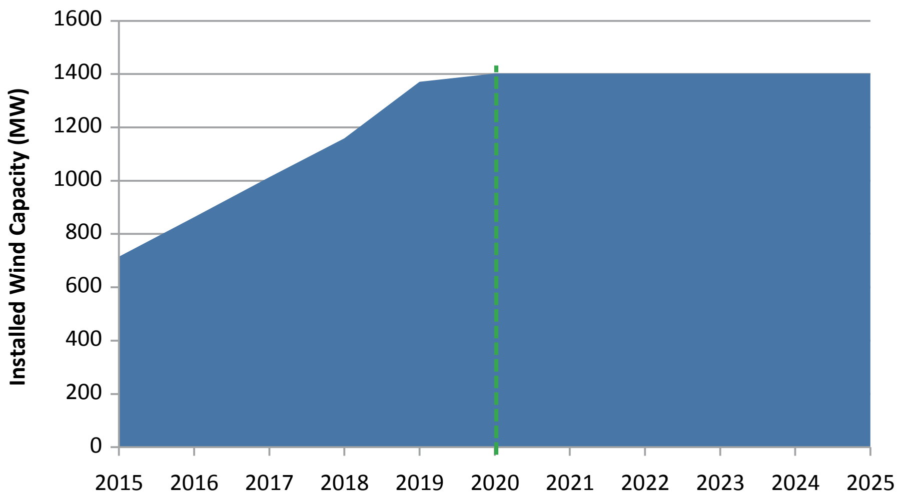


Figure 3-5 Northern Ireland wind levels assumed for this report

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 2025 there will not be any offshore wind connected.

Figure 3-6 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 grown to 16.4% by 2014. Historical capacity factors are shown in Figure 5-2.

30 Strategic Energy Framework https://www.detini.gov.uk/articles/strategic-energy-framework-2010

31 Information of current wind farm applications can be found on the Northern Ireland Planning Service website (http://www.planningni.gov.uk/index/advice/advice_apply/advice_renewable_energy/renewable_wind_farms.htm)

32 Capacity factor gives the amount of energy actually produced in a year relative to the maximum that could have been produced, had a generator been generating at full capacity all year.

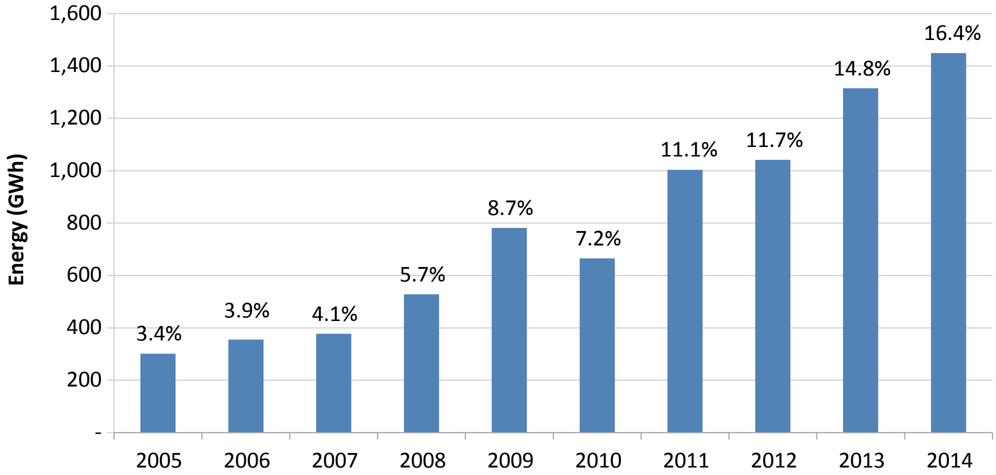


Figure 3-6 Historical wind generation for Northern Ireland in annual electricity terms, also given as a percentage of total electricity produced that year. Figures are based on sent-out metering available to SONI.

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

Due to its relatively small geographical size, wind levels are strongly correlated across the island. The probability that all wind generation will cease generation for a period of time 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 given 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 2012 profile to be close to average in terms of capacity credit. 2010 was considered a poor wind year, and so was not used for these studies.

It can be seen in Figure 3-7 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.

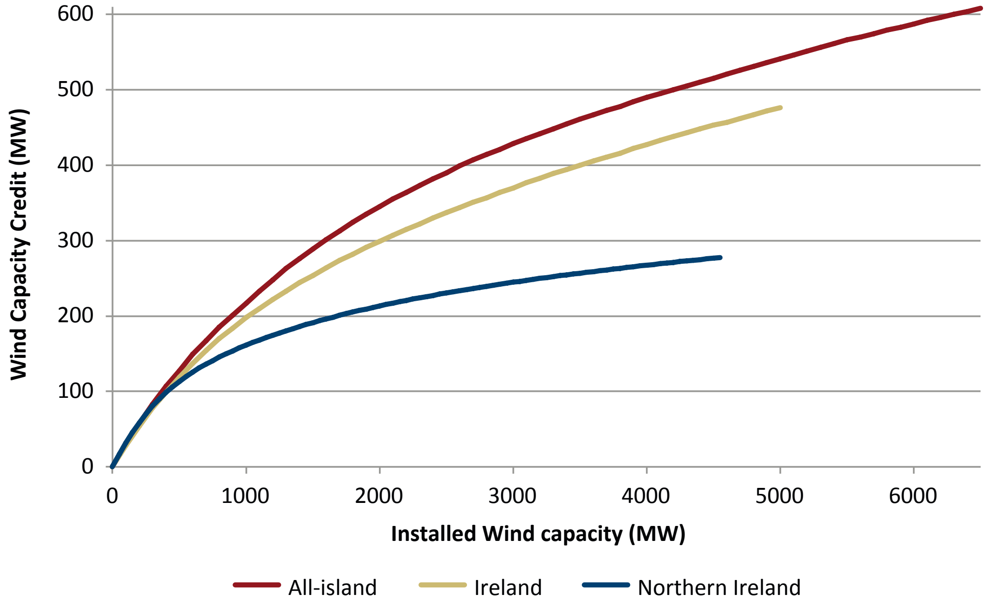


Figure 3-7 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation. For Ireland, the wind profiles were taken from 2012, a recent, typical year. The curve for Northern Ireland is based on an average over several years.

3.6 Changes in other Non-Conventional Generation

In this section, we discuss expected developments in demand side generation, CHP, biofuels, small scale hydro and marine energy over the next 10 years. 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.

As discussed in Section 2.3, we have obtained information from NIE on the estimated amount of embedded generation that is present on the Northern Ireland system. We have also consulted other sources, such as the Ofgem Renewable Obligation Certificate Register (ROC Register) and information for the Northern Ireland planning service. Based on these sources, we estimate there to be over 150 MW[33] of this small scale generation currently connected to the Northern Ireland system, with various levels of this being utilised for self-consumption on site.

3.6(a) Demand-Side and Industrial Generation

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 DSU Aggregator is a third party company specialising in demand side participation. Dispatch instructions are issued by the TSO at an aggregate level and the DSU Aggregator then coordinates the reduction from the Individual Demand Sites. The individual demand sites use a combination of on-site generation and plant shutdown to deliver the demand reduction.

The capacity of Demand Side Units in Ireland has increased to 230 MW, and is set to increase further.

33 Mainly includes Diesel Generators, CHP and Small Scale Wind but also PV, Gas, Hydro, Biofuels and Land Fill Gas

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 90 MW. The capacity of Demand Side Units in Northern Ireland is 18 MW and is expected to increase over the coming years.

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 jurisdiction 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 Combined Heat and Power (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 147 MW in Ireland (not including the 161 MW centrally dispatched CHP plant operated by Aughinish Alumina). The target for total CHP in Ireland[34] was 400 MW by 2010, whereas what was achieved was in the region of 300 MW. With the withdrawal of government incentives for fossil fuelled CHP, this area is not likely to grow much more.

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). Without more detailed information an assumption has been made that for the purposes of this statement, this will not change.

CHP is promoted in accordance with the European Directive 2004/8/EC. The Strategic Energy Framework[35] for Northern Ireland acknowledges that the uptake of CHP in the region has been limited and therefore DETI have decided to encourage greater scope for combined heat and power in Northern Ireland.

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. The REFIT 3[36] incentive for biomass-fuelled CHP plant aims to have 150 MW installed by 2020. With some of this plant already planned (including the dispatchable Mayo Biomass plant, 43 MW, see Table 3-1), it has been assumed for the purpose of this report that the whole 150 MW will be achieved on time. This plant makes a significant contribution to the 40% RES target.

Currently in Northern Ireland, there is an estimated 30 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 46 MW by 2025.

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. Bombardier has plans to establish 18 MW of generation at its Belfast site in 2016. This connection will be predominantly biomass.

34 Energy White Paper 2007 ‘Delivering a Sustainable Energy Future for Ireland’, March 2007.
35 www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf
36 http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/REFIT.htm

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 4 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 currently 4 MW, and expected to grow to 9 MW by 2020. 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 2025.

The Crown Estate[37] has awarded development rights for two 100 MW Tidal sites off the North Coast of Northern Ireland close to Torr Head and Fair Head. At present there are no connection offers in place for tidal projects, however, applications for grid connection have been submitted. Therefore, for the purposes of this report, we have assumed that no additional tidal generation will connect by 2025.

3.6(f) Compressed Air Energy Storage (CAES)

Gaelectric is proposing a Compressed Air Energy Storage (CAES) Plant in the Larne area, to be connected to the transmission system. SONI has an accepted connection offer in place with Gaelectric Energy Storage for this project. Gaelectric is designing the facility to realise 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.

This is the only electricity storage project on the island of Ireland which has the status of Project of Common Interest. In the last 12 months it has seen considerable progress. It has been awarded Connecting Europe Facility (CEF) grant funding of up to €6.45 million to complete, among other things, the environmental impact assessment (EIA) and submission of planning application at the end of 2015.

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.

3.6(g) 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.

3.6(h) Solar Photovoltaic

In Northern Ireland, incentives to install solar photovoltaic generating units have encouraged this sector, with up to 50 MW currently installed. This may grow over the coming years to approximately 200 MW.

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

In the absence of such incentives in Ireland, less solar PV has been installed there. However, there has been significant interest in recent years, and we assume moderate growth to reach approximately 50 MW by 2025.

As there is no sunlight during the winter peak demand, solar PV does not contribute significantly to adequacy, and so has little impact on our 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 ‘unlucky’ 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 will 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.

3.7(a) Ireland

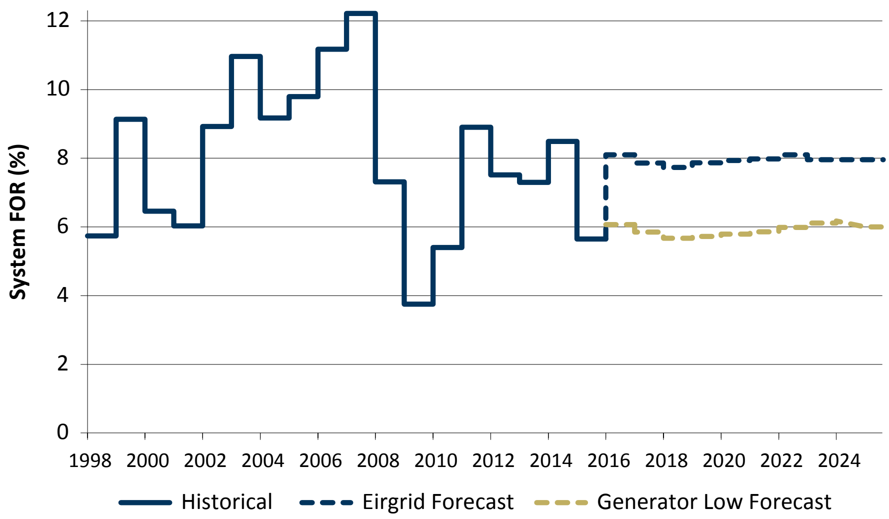


Figure 3-8 Historical (to October 2015) and predicted Forced Outage Rates for Ireland. Future rates as predicted by both EirGrid and the generators are shown.

Figure 3-8 shows the system-wide forced-outage rates (FOR)[38] for Ireland since 1998, as well as predicted values for the study period of this report.

After rising steadily in the years up to 2007, FORs in Ireland have started to drop in the past few years. One cause for this improvement is the introduction of new generators and removal of old generators. Another contributing factor is reduced demand, which means older peaking units are called on less often, giving them less of an opportunity to fail. However it must be noted that major impact events (e.g. Turlough Hill) have led to poorer availability in 2010 and 2011.

The operators of fully-dispatchable generators have provided forecasts of their availability performance for the ten year period 2016 to 2025. However, in the past these forecasts have not given an accurate representation of the amount of outages on the system. This is primarily due to the effect of HILP events. Our studies[39] have indicated that HILPs will make up around one third of forced outages on average.

We have incorporated these HILPs to create a more realistic system availability forecast. This EirGrid availability forecast is used as the base case for these studies.

3.7(b) Northern Ireland

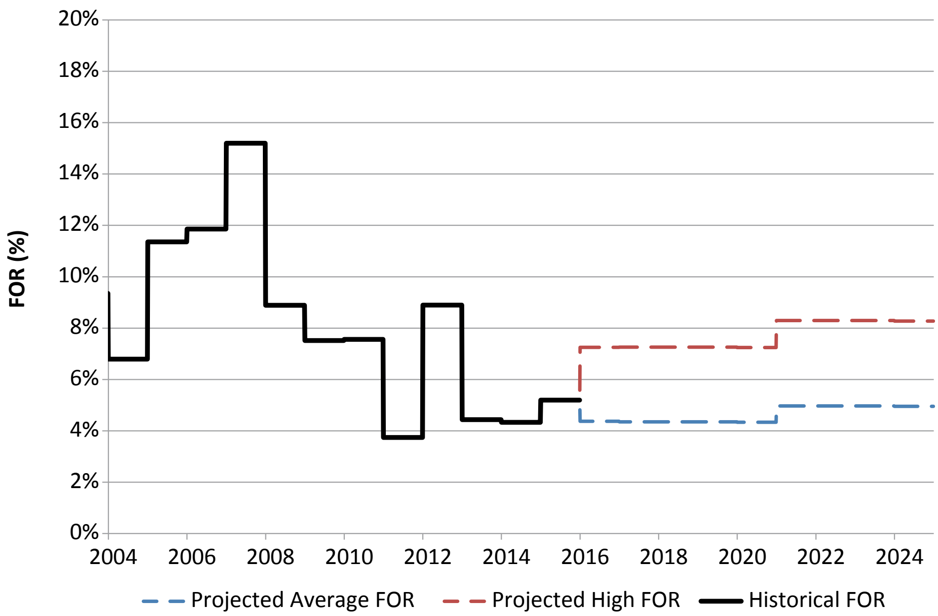


Figure 3-9 Historical (to October 2015) and predicted Forced Outage Rates for Northern Ireland (not including the Moyle Interconnector)

Generators are obligated to provide us with planned outage information in accordance with the Grid Code (Operating Code 2). Each power station provides this information for individual generating units indicating the expected start and finish dates of required maintenance outages.

Future FOR predictions are based on the historical performance of the generators and the Moyle Interconnector, and incorporate HILPs to give a more realistic scenario.

38 The FOR is the percentage of time in a year that a plant is unavailable due to forced outages.
39 GAR 2009-2015

Figure 3-9 shows the system forced-outage rates (FOR) for Northern Ireland since 2003, as well as predicted values for the study period of this report. This analysis is focused on fully dispatchable plant and does not include the Moyle Interconnector. After rising steadily in the years up to 2007, FORs in Northern Ireland have started to fall over the past few years. This coincides with the introduction of the Single Electricity Market (SEM) where incentives have been put in place to encourage better generator availability. Another contributing factor is reduced demand resulting from the recent economic downturn, which means older peaking units are called on less often, giving them less of an opportunity to fail.

A range of availability scenarios for the future are presented. The average availability scenario is based on the average historical performance of generators in Northern Ireland. The high availability scenario has been calculated without regard to the more extreme outage events.

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 information on the methodology used). Generation adequacy assessments are carried out in three different ways:

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

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 full 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 with no outages.

4.2 Base Case

4.2(a) Presentation of Results

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.

The base case assumes the following:

- median demand growth in both jurisdictions,
- the EirGrid-calculated availability for the generation portfolio in Ireland,
- and SONI-calculated availability (based on actual historical performance) for the Northern Ireland generation portfolio.

For the single-area studies, Northern Ireland is assumed to place 200 MW reliance on Ireland, and 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.

Over the course of our studies, we assume that the import capability of the interconnectors from Great Britain are de-rated to 75% of nominal capacity. This is to account for the possible scarcity of generation availability in Great Britain. In the early years, we assume that this interconnector deration is applied equally across both EWIC and Moyle. However, if a jurisdiction is in deficit, then the de-rating could be shared to reduce deficits.

The results for the combined, all-island system are applicable only from late 2019 onwards, when the second North-South Interconnector is commissioned.

4.2(b) Discussion of Results

The adequacy results for Ireland (gold line in Figure 4-1) show it to be in a large surplus of over 1,000 MW for many years. This begins to fall off as older plant is assumed to come to the end of their lives. In addition to these plant shut-downs, changes in adequacy are caused from year to year by demand growth, plant additions and increased wind penetration. By 2025, the generation adequacy supply in Ireland comes close to standard.

For Northern Ireland, the adequacy situation is sufficient in the medium term (blue line). This is largely due to two factors. Local reserve services at Ballylumford will provide 250 MW for three years from 2016. Moyle pole 2 will be restored to full capacity, though significant scheduled outages on Moyle will impact the adequacy in 2016 itself.

When assessed on its own, Northern Ireland will fall into deficit in 2021 due to severe restrictions at Kilroot. The closure of the coal units at Kilroot will push Northern Ireland into further deficit in 2024.

The significant surplus for all-island studies is shown by the purple line in Figure 4-1. This all-island surplus can only be realised by increasing the capacity of interconnection between Ireland and Northern Ireland. The second North-South Interconnector is therefore vital to ensure the security of electricity supply for the future in both Northern Ireland and Ireland. In association with the competent authorities in the respective jurisdictions, we are actively progressing work to deliver this Project of Common Interest by 2019.

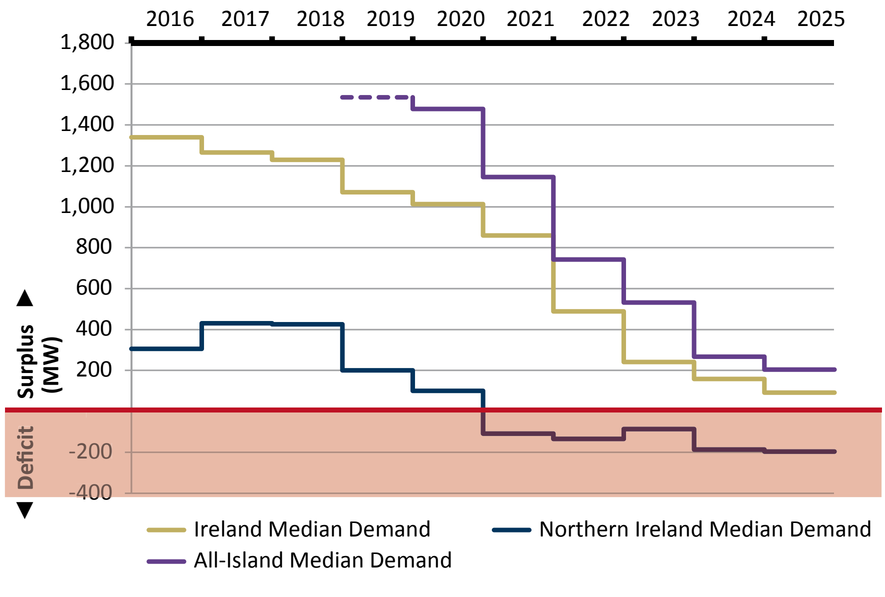


Figure 4-1 Adequacy results for the Base Case scenario, shown for Ireland, Northern Ireland and on an all-island basis.

4.3 Northern Ireland Scenarios

The figure below shows the different scenarios considered for Northern Ireland, depending on the demand forecast and the plant availability. All scenarios are in deficit from 2021, because of emissions restrictions at Kilroot. There is slightly more or less deficit depending on which demand scenario transpires. If the plant in Northern Ireland has low availability, the deficit grows larger.

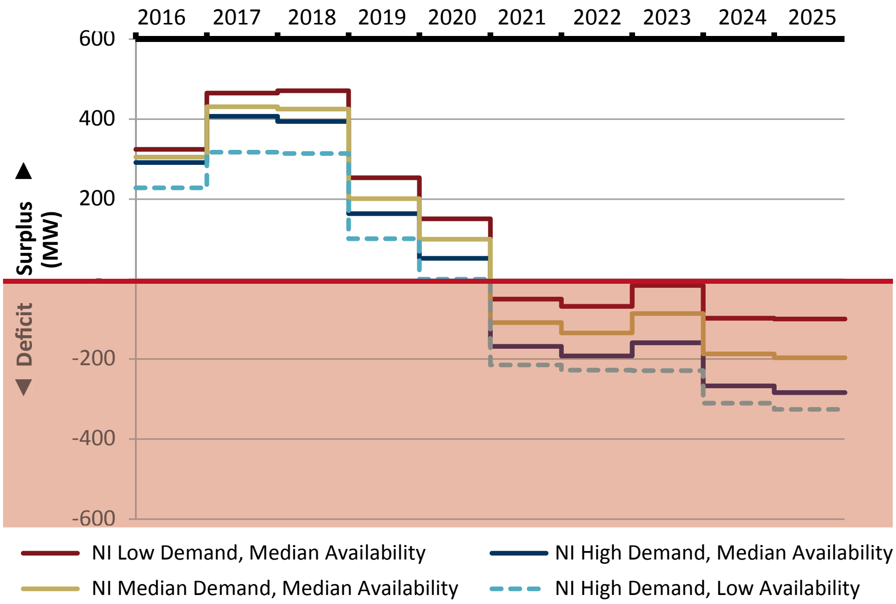


Figure 4-2 For Northern Ireland, the adequacy results from high, median and low demand forecasts, for median plant availability. Also shown are the effects of low plant availability and the unavailability of the Moyle Interconnector.

4.4 Scenario without Interconnection with 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 the Moyle Interconnector. Due to these factors, we now examine a situation where both undersea interconnectors with Great Britain (Moyle and EWIC) are unavailable.

Figure 4-3 shows how the surplus reduces dramatically from the base case scenarios. Northern Ireland would be in deficit from 2019, and particularly so from 2021. This again shows the importance of the planned extra North-South Interconnector to maintain generation security standards in Northern Ireland.

In combination with the plant being shut down in Ireland, this scenario would result in effective deficits in Ireland by 2023, as well as in the all-island combined study.

This scenario also highlights the implications if energy is unavailable to import from Great Britain to either Ireland via EWIC, or to Northern Ireland via Moyle, due to any capacity shortfall or market conditions that may occur in GB. However, as discussed in Section 3.4, National Grid and Ofgem treat both the EWIC and Moyle as negative generation even at their peak demand times, and they have taken steps to address their own capacity issues with demand side measures and capacity auctions. We will continue to monitor this situation.

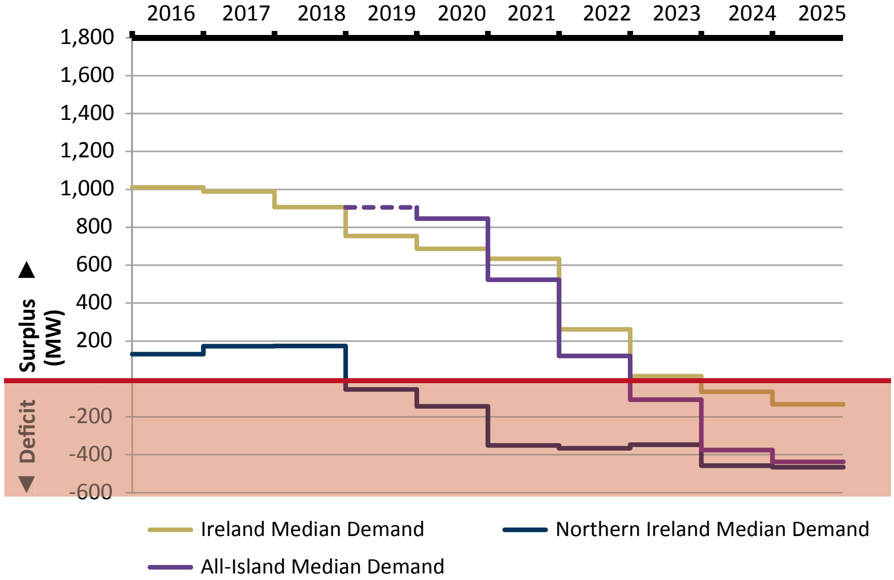


Figure 4-3 The adequacy situation without the interconnectors to Great Britain.

The Need for a Capacity Remuneration Mechanism in the I-SEM

5 THE NEED FOR A CAPACITY REMUNERATION MECHANISM IN THE I-SEM

5.1 Introduction

Portfolio projections were provided by industry participants for the purposes of these adequacy studies. These were combined with other relevant information (e.g. historical data and government policy objectives) to provide an informed estimate of the future plant portfolio and generation adequacy on the island. In general, for the adequacy scenarios that have been presented in the GCS, we are not making an assessment of the financial performance or viability of capacity providers.

It is important to note that there has been a Capacity Payment Mechanism (CPM) in the SEM since its establishment in 2007. The Regulators in Ireland and Northern Ireland have decided that there will also be a capacity remuneration mechanism in the new I-SEM. This is a key underlining assumption of the industry participants who have provided the supply inputs for this report.

As part of the I-SEM High Level Design process, in 2014 the Regulators requested that EirGrid perform an assessment of generation adequacy in an energy only market. This analysis[40] was published with the ISEM High Level Design draft decision paper where the Regulators decided that a capacity remuneration mechanism would be part of the I-SEM. In this chapter of the GCS we provide an update to that study.

The key difference from the original study is that we have now incorporated ancillary service revenues into the assessment (i.e. for each generator we calculate the energy market revenues and their ancillary service revenues). Other differences from the original study are that it covers all years from 2016-2025 and uses the latest energy demand forecast and projections for demand side participation, generation (renewable, conventional and small scale) and interconnection. The study uses a stochastic approach to study the impact of multiple wind, demand and outage profiles.

5.2 Transition to a low carbon and sustainable electricity system

The electricity system is evolving to being low-carbon and sustainable. Ireland and Northern Ireland are moving to up to 40% renewable electricity sources for 2020. In 2015, the European heads of state agreed that total renewable energy sources will increase by 35% over 2020 targets by 2030. For Ireland and Northern Ireland renewable and low-carbon generation is predominantly wind generation.

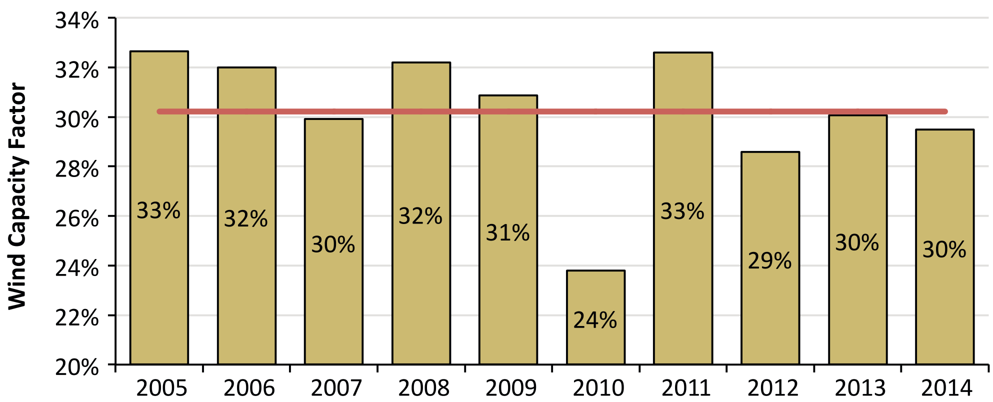


Figure 5-1 Historical all-island wind capacity factors for 2005-2014, the red line gives the average.

40 Assessment of Generation Adequacy in an Energy Only Market, May 2014.
http://www.allislandproject.org/GetAttachment.aspx?id=cc1ca497-4737-4a84-ab0a-a54242e32f7a

Figure 5-1 shows the all-island capacity factor of wind over the last ten years. The average capacity factor is 30%, yet it can vary between 24% and 33%. 2010 was a particularly poor year for wind. The contribution of wind at peak demand is even more variable.

Figure 5-2 shows the forecasted peak demand over the next 10 years in red (median scenario, as listed in Appendix 1). The green line shows the mean projected peak non-wind generation requirement based on studies using 8 historical wind and demand profiles and the shaded area gives the range. Wind build out is as in Table A-7 and Table A-10 in Appendix 2. This figure demonstrates the variability of wind generation with regard to peak demand.

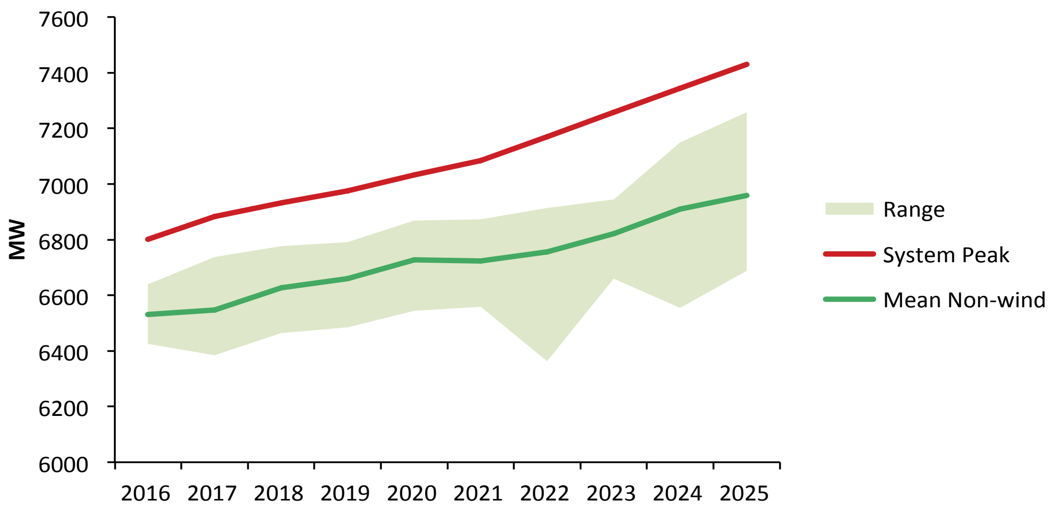


Figure 5-2 Peak non-wind requirement (green line is the mean and shaded area is the range) from 8 different wind and demand base profiles. System peak is given in red.

Figure 5-3 gives the highest non-wind generation requirement (the upper edge of the green shaded area in Figure 5-2) for each year as a percentage of peak demand. While this will not occur each year it can be expected to occur in some years over the next 10 years and it is not possible to predict when it will occur. It shows that conventional generation will be required to provide at least 96% of peak demand even though on energy terms it will provide 60% or less.

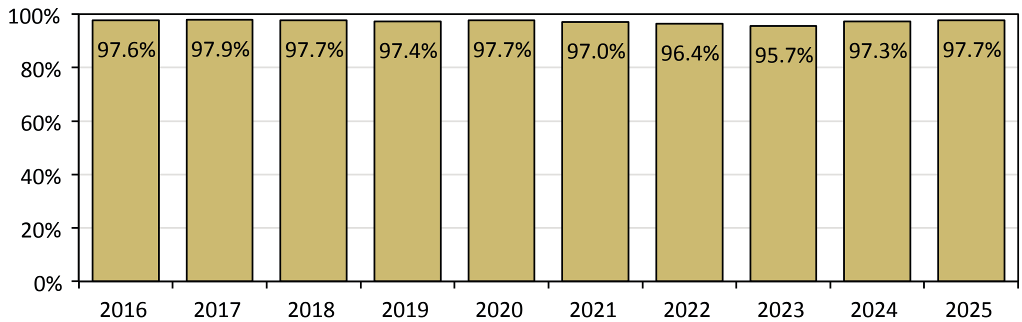


Figure 5-3 Maximum non-wind generation requirements as a percentage of peak demand using 8 different wind and demand base profiles.

5.3 Methodology and Assumptions

This section outlines the methodology and workflow utilised in this study and the steps are summarised in Figure 5-4.

A. Fixed Annualised Costs

Estimate O&M costs and Capital costs for each generator unit

↓

B. Generation Volumes

Use market model to calculate generation volume for each unit

↓

C. Required Average Price

Calculate using (Fixed Annualised Cost/Generation Volume) for each unit

↓

D. Calculate Ancillary Service Revenues for each unit

This is based on a units running and the system service tarrifs

↓

E. Remove units

Remove from the generation portfolio generators whose combined revenues from energy and ancillary services payments are less than their annual costs

↓

F. Adequacy Calculation

Carry out adequacy studies using the updated generation portfolio

Figure 5-4 Outline of methodology and workflow used in this study

A. Estimates have been made of the annual revenue required in order for each unit to recover costs. The fixed operational and maintenance (O&M) and annualised capital costs are taken from a study carried out by Pöyry in collaboration with EirGrid[41]. The annual revenue required in order for each unit are generalised by plant type and two annual revenues are examined:

- the first assumes that a generator's capital costs have not been recovered and are included as part of their annual revenue requirement.
- the second excludes the generator capital costs, so that they are only expected to recover their O&M costs.

41 Low Carbon Generation Options for the All-Island Market, March 2010

B. The market dispatch is modelled using an industry standard market modelling tool[42]. This software creates an annual chronological unit commitment and dispatch schedule with an hourly granularity. The dispatch is obtained on an economic basis. This means the software will switch on and off generation to exactly meet demand in the most economical way possible, taking into account any technical limitations of generators.

   Renewable generators are given a zero or very low price to reflect their priority dispatch status (note that these price assumptions are only used for modelling purposes). A representative model of the British power system is therefore included, with a projected British portfolio dispatched on an SRMC (Short Run Marginal Cost) basis. The modelling software estimates prices in each region and determines interconnector flows based on arbitrage.

   Fuel prices are taken from the International Energy Association's World Energy Outlook 2015 report[43], as is the forecasted European Carbon ETS price. Carbon prices in Great Britain are adjusted to account for the carbon floor.

C. The base cut-off price used to determine whether or not a unit would be viable is 3,000 €/MWh. This price is in line with the proposed European Price cap for the day-ahead price coupling in the European target model. While this price cap is only proposed for the day-ahead timeframe at present, this does not necessarily imply that the intra-day and balancing timeframes will be uncapped. For the purpose of this study, any units requiring an average price above this level are considered unable to recover their costs. A sensitivity scenario is studied where the cut-off price is set to 11,000 €/MWh (approximately equal to SEM Value of Lost Load).

D. Calculate the unit's ancillary service revenues based on the 2015/16 ancillary service tariffs and the unit's running.

E. For each year, if a unit is found to not earn enough money to recover its costs using its generation from the market modelling study and the cut-off price given above plus its ancillary service revenues, it is removed from the portfolio for that year.

F. The updated portfolios are then used for the adequacy assessments. The reference adequacy standard is set to 8 hours LOLE/year and the adequacy assessments are performed on an all-island basis. The median demand scenario is used and the portfolio assumptions are the same as used in the base case GCS adequacy assessments. For example, we assume 75% interconnector import reliance.

5.4 Stochastics Market Modelling Results

Market model simulations covering the 2016-2025 year period were performed to estimate the run hours and generation of each unit in the portfolio. A range of sensitivity simulations (totalling 400 model years of simulations) were performed to establish if our simulation results were robust under different demand, wind and outage profile assumptions.

For each year, if a unit is found to not earn enough money to cover its costs, it is removed from the portfolio for that year. Figure 5-5 gives the average MW amount of capacity removed from the base portfolio using different demand and wind profiles. The large decrease in the amount of capacity removed between 2016 and 2025 is primarily due to two factors. Firstly, the base GCS portfolio has already assumed some plant closures during the 10 year period (as discussed in 3.1(c)). Secondly, the reduction is also due to the demand growth. Once satisfied of the robustness of the simulation results to these sensitivities the market modelling output was then used as input into the GCS adequacy assessment tool.

42 PLEXOS Integrated Energy Model – Energy Exemplar
43 http://www.worldenergyoutlook.org – International Energy Agency, November 2015

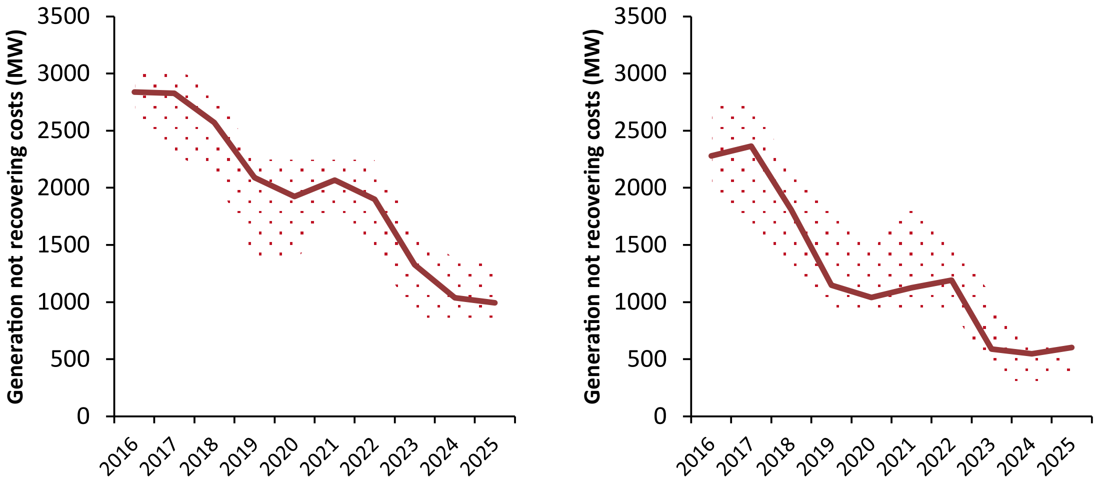


Figure 5-5 Sensitivity analysis of market modelling to different demand and wind profiles. The left graph gives generation not recovering capital and O&M costs and the right graph O&M costs only. The red line gives the average and the shaded area gives the range.

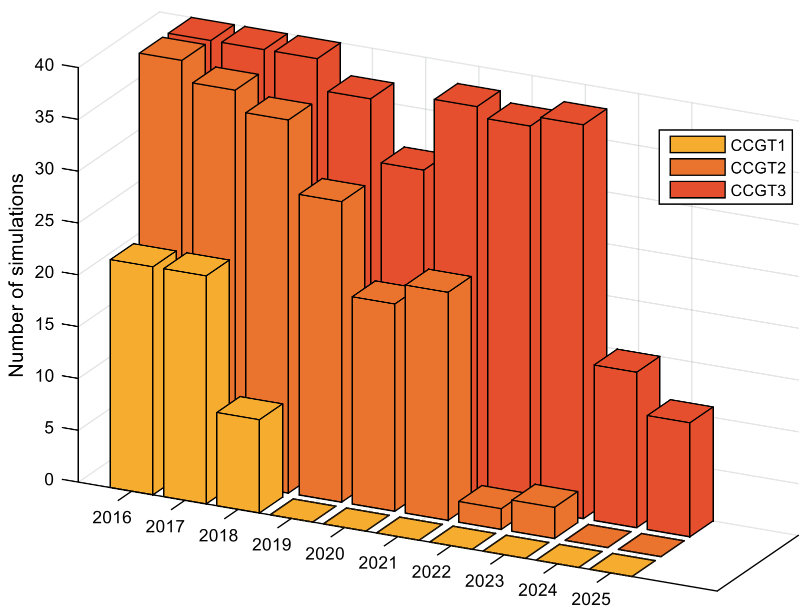


Figure 5-6 The number of simulations out of 40 for each year a selection of 3 CCGT units have not recovered their costs in the market model simulations.

To illustrate the potential revenue volatility for conventional generating units, Figure 5-6 above gives the number of market model simulations (out of 40 for each year) where a selection of three large CCGT units have not recovered their capital and O&M costs. Of particular concern is the number of times the CCGT units have not recovered their costs in the earlier years of the study. In the later years they receive more running in the simulations which indicates that they are critical to generation adequacy in those years. That is, if these units were to close as a result of the years of low running it would likely lead to capacity shortfalls in subsequent years.

5.5 Adequacy Assessments

Results of adequacy assessments performed using the results from the market modelling as inputs are presented in Figure 5-7 and Figure 5-8 (numerical values are summarised in Table 5-1). Figure 5-7 presents results using the cut-off price of 3,000 €/MWh and ancillary service revenues, and indicates that there are capacity shortfalls all years if units had to recover their capital and O&M costs. The analysis still indicates capacity shortfalls in most years if units had to recover their O&M costs only. As a reference the median demand base GCS case which indicates a large surplus in most years (see Executive Summary and Chapter 4) is also shown. This illustrates the impact on generation adequacy of removing units which have not recovered their costs in the study.

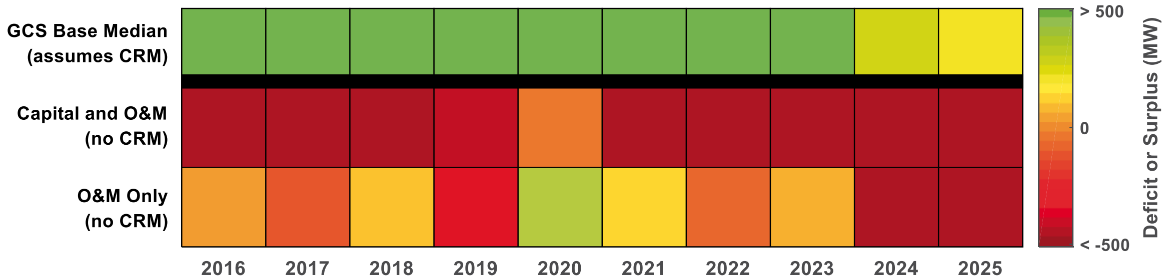


Figure 5-7 Generation adequacy assessments when units that have not recovered their costs in the cost recovery modelling have been removed. In this figure a cut-off price of 3,000 €/MWh plus ancillary service revenues was used.

Figure 5-8 below presents results using a cut-off price of 11,000 €/MWh plus ancillary service revenues. This value is approximately equal to the SEM VoLL (Value of Lost Load). The results indicate that even if units could achieve a price this high, enough units would still not recover their costs from the energy only market to ensure generation adequacy at the 8 hour LOLE standard. This is due to the number of units with either zero or very low run hours in the simulations.

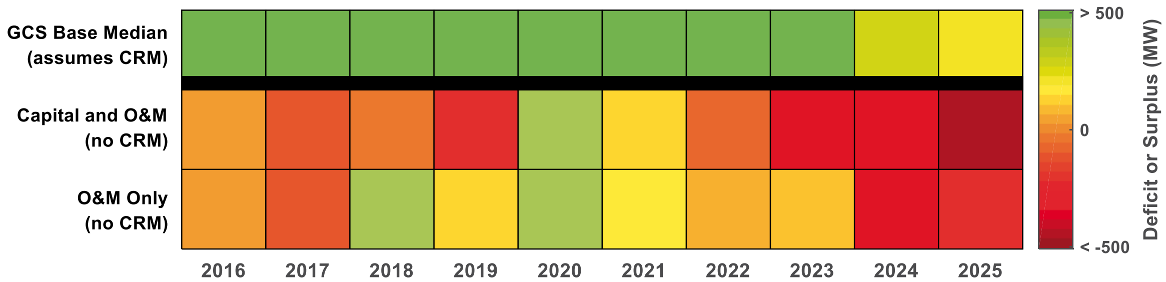


Figure 5-8 Generation adequacy assessments when units that have not recovered their costs in the cost recovery modelling have been removed. In this figure a cut-off price of 11,000 €/MWh was used.

In the all-island market, units also receive ancillary service revenues if they are available to provide such services. The revenues have been calculated using the unit's modelled generation and the 2015/16 tariffs in real 2014 values. The forecasted revenues have been sense-checked against the actual 2014/15 revenues received by units in the SEM.

In the reference case shown in Figure 5-7 there is a high reliance placed on the two interconnectors connecting Ireland and Northern Ireland to Great Britain. It is assumed that these interconnectors will flow 75% of their capacity into the island of Ireland. In Figure 5-9 we show the results if there was less power available in Great Britain to flow into Ireland and Northern Ireland. The assumption in Figure 5-9 is that 50% of the interconnector capacity will flow into Ireland and Northern Ireland.

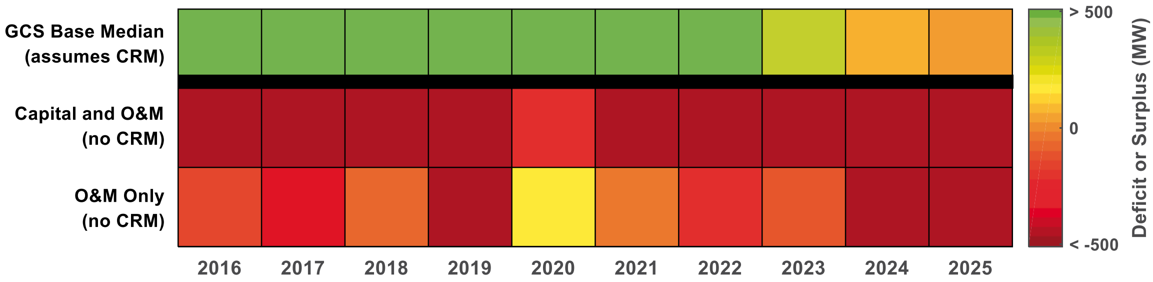


Figure 5-9 Generation adequacy assessment when units that have not recovered their costs in the cost recovery modelling have been removed. This scenario is the same as in Figure 5-7, but now assumes a 50% interconnector reliance.

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GCS Base Median Demand Case										
GCS Base Median	1941	2071	1960	1535	1478	1145	743	533	267	205
3,000 €/MWh Cut-Off Price + Ancillary Service Revenues										
Capital & O&M	-622	-521	-598	-443	-70	-474	-588	-586	-872	-933
O&M Only	-2	-174	73	-347	362	110	-107	40	-469	-530
11,000 €/MWh Cut-Off Price + Ancillary Service Revenues										
Capital & O&M	-2	-174	-96	-294	413	110	-107	-357	-376	-530
O&M Only	-2	-174	398	102	413	160	46	84	-376	-281

Table 5-1 Summary table of adequacy assessment MW surplus/deficit results. GSC Base Median Demand results are shown for reference.

5.6 Discussion and Conclusions

The updated analysis indicates that in the majority of scenarios and years studied there would be a capacity shortfall if units were to rely on energy market and ancillary service revenues only. This occurs for the median demand forecast and high interconnector reliance. Using the more onerous scenarios of a higher demand forecast or reducing the reliance on interconnection would increase the shortfalls further. The results are consistent with those of the previously published analysis. It is worth noting that ancillary service payments are primarily paid to units that are providing ancillary services when they are generating. Therefore it was observed that units with little or no run hours received little or no ancillary service payments.

It should be noted that this study assesses security of supply in the context of revenues from energy market and ancillary services only. It indicates that there may not be enough revenue from energy and ancillary service payments to ensure capacity adequacy, but it does not give the level of revenue shortage or the best approach to remedy this shortage. The current capacity payment mechanism has helped ensure that there has been enough capacity in the SEM to meet the adequacy standard. We consider such a mechanism is of particular importance to a small market like the SEM where there are concerns, among other things, about the effects of lumpy investment. In a small market like the SEM: "while market prices may be sufficiently high before a new investment, the efficient scale of a new investment may be so large that for some time it depresses the market price. The effect may be that no single player is ever prepared to invest." [44]

The governments in Ireland and Northern Ireland have the stated policy objectives of sourcing a substantial proportion of electricity from renewable sources by 2020. This rapid transition to renewables is leading to a more challenging operating environment for conventional generators which are required for generation adequacy. The proposed CRM is designed to competitively procure sufficient capacity to meet the adequacy standard in an efficient manner.

44 Capacity Mechanisms in the EU Energy Market – Law, Policy and Economics (pp 64-67), Oxford University Press 2015

Appendices

APPENDIX 1 DEMAND FORECAST

Med	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2015	27,425	2.4%	9,058	0.1%	36,483	1.8%	5043	1752	6746	4945	1733	6631
2016	27,989	2.1%	9,097	0.4%	37,086	1.7%	5092	1761	6805	4994	1741	6687
2017	28,899	3.3%	9,139	0.5%	38,038	2.6%	5167	1769	6888	5070	1747	6769
2018	29,566	2.3%	9,178	0.4%	38,745	1.9%	5209	1777	6938	5112	1753	6818
2019	30,159	2.0%	9,216	0.4%	39,375	1.6%	5243	1785	6980	5146	1761	6858
2020	30,681	1.7%	9,255	0.4%	39,935	1.4%	5294	1792	7038	5196	1767	6916
2021	31,238	1.8%	9,297	0.5%	40,535	1.5%	5338	1799	7089	5241	1773	6966
2022	31,788	1.8%	9,337	0.4%	41,125	1.5%	5416	1807	7174	5319	1780	7051
2023	32,365	1.8%	9,381	0.5%	41,746	1.5%	5498	1815	7264	5400	1787	7140
2024	32,934	1.8%	9,420	0.4%	42,354	1.5%	5578	1823	7354	5481	1795	7229
2025	33,480	1.7%	9,463	0.5%	42,943	1.4%	5655	1832	7439	5558	1803	7313

Table A-1 Median Electricity Demand Forecast – all figures are for a 52-week year.

Notes: Electricity sales are measured at the customer level. To convert this to Total Electricity Requirement (TER), it is brought to exported level by applying a loss factor (for both transmission and distribution) and adding on an estimate of self-consumption.

The Transmission Peak (or Exported peak) is the maximum demand met by centrally-dispatched generation, measured at exported level by the Control Centre. To calculate the TER Peak, an estimation of the contribution from embedded generation is added to the Transmission peak. When forecasting the transmission peak, it is assumed that the wind contribution is zero.

Low	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2015	27,425	2.4%	9,004	-0.5%	36,428	1.6%	5,043	1,739	6,734	4,945	1,721	6,618
2016	27,761	1.2%	8,968	-0.4%	36,873	1.2%	5,065	1,733	6,750	4,968	1,713	6,633
2017	28,213	1.6%	8,933	-0.4%	37,293	1.1%	5,088	1,727	6,767	4,991	1,705	6,648
2018	28,651	1.6%	8,899	-0.4%	37,700	1.1%	5,105	1,721	6,778	5,008	1,697	6,657
2019	29,094	1.5%	8,899	0.0%	38,146	1.2%	5,121	1,720	6,793	5,024	1,696	6,672
2020	29,416	1.1%	8,899	0.0%	38,471	0.9%	5,149	1,720	6,821	5,052	1,695	6,699
2021	29,828	1.4%	8,899	0.0%	38,886	1.1%	5,177	1,719	6,848	5,080	1,693	6,725
2022	30,233	1.4%	8,899	0.0%	39,294	1.0%	5,238	1,718	6,908	5,141	1,691	6,784
2023	30,664	1.4%	8,899	0.0%	39,728	1.1%	5,304	1,717	6,972	5,206	1,689	6,848
2024	31,089	1.4%	8,899	0.0%	40,155	1.1%	5,368	1,716	7,036	5,271	1,688	6,911
2025	31,489	1.3%	8,899	0.0%	40,558	1.0%	5,428	1,715	7,095	5,331	1,686	6,969

Table A-2 The low scenario forecast of electricity demand

High	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2015	27,425	2.4%	9,114	0.7%	36,538	1.9%	5043	1760	6755	4945	1742	6639
2016	27,989	2.1%	9,198	0.9%	37,187	1.8%	5092	1779	6823	4994	1759	6705
2017	28,899	3.3%	9,284	0.9%	38,183	2.7%	5167	1798	6917	5070	1776	6797
2018	29,566	2.3%	9,373	1.0%	38,939	2.0%	5209	1816	6977	5112	1792	6857
2019	30,559	3.4%	9,461	0.9%	40,020	2.8%	5288	1834	7074	5191	1810	6953
2020	31,746	3.9%	9,552	1.0%	41,298	3.2%	5415	1852	7219	5318	1827	7097
2021	32,819	3.4%	9,645	1.0%	42,463	2.8%	5519	1869	7340	5422	1843	7217
2022	33,884	3.2%	9,741	1.0%	43,625	2.7%	5655	1887	7494	5558	1861	7371
2023	34,976	3.2%	9,833	0.9%	44,808	2.7%	5796	1906	7653	5699	1879	7529
2024	36,061	3.1%	9,927	1.0%	45,988	2.6%	5935	1924	7812	5838	1897	7687
2025	37,122	2.9%	10,021	0.9%	47,143	2.5%	6071	1943	7966	5974	1914	7840

Table A-3 The high scenario forecast of electricity demand

APPENDIX 2 GENERATION PLANT INFORMATION

Year end:	ID	Fuel Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
All DSU	DSU	DSU	230	235	240	245	250	250	250	250	250	250	250
Aghada	AD1	Gas	258	258	258	258	258	258	258	258	258	0	0
	AT1	Gas/DO	90	90	90	90	90	90	90	90	90	0	0
	AT2	Gas/DO	90	90	90	90	90	90	90	90	90	90	90
	AT4	Gas/DO	90	90	90	90	90	90	90	90	90	90	90
	AD2	Gas/DO	431	431	431	431	431	431	431	431	431	431	431
Dublin Bay	DB1	Gas/DO	403	402	405	404	403	402	405	404	403	402	402
Edenderry	ED1	Milled peat/ biomass	118	118	118	118	118	118	118	118	118	118	118
Edenderry OCGT	ED3	DO	58	58	58	58	58	58	58	58	58	58	58
	ED5	DO	58	58	58	58	58	58	58	58	58	58	58
Great Island CCGT	GI4	Gas/DO	464	464	464	464	464	464	464	464	464	464	464
Huntstown	HNC	Gas/DO	340	339	339	338	338	337	337	336	336	335	335
	HN2	Gas/DO	398	397	397	396	396	395	395	394	394	393	393
Indaver Waste	IW1	Waste	17	17	17	17	17	17	17	17	17	17	17
Lough Ree	LR4	Peat	91	91	91	91	91	91	91	91	91	91	91
Marina CC	MRC	Gas/DO	95	95	95	95	95	95	95	95	95	0	0
Moneypoint	MP1	Coal/HFO	285	285	285	285	285	285	285	285	285	285	285
	MP2	Coal/HFO	285	285	285	285	285	285	285	285	285	285	285
	MP3	Coal/HFO	285	285	285	285	285	285	285	285	285	285	285
North Wall CT	NW5	Gas/DO	104	104	104	104	104	104	104	104	104	0	0
Poolbeg CC	PBC	Gas/DO	463	463	463	463	463	463	463	463	463	463	463
Rhode	RP1	DO	52	52	52	52	52	52	52	52	52	52	52
	RP2	DO	52	52	52	52	52	52	52	52	52	52	52
Sealrock	SK3	Gas/DO	81	81	81	81	81	81	81	81	81	81	81
	SK4	Gas/DO	81	81	81	81	81	81	81	81	81	81	81
Tarbert	TB1	HFO	54	54	54	54	54	54	54	54	0	0	0
	TB2	HFO	54	54	54	54	54	54	54	54	0	0	0
	TB3	HFO	241	241	241	241	241	241	241	241	0	0	0
	TB4	HFO	243	243	243	243	243	243	243	243	0	0	0
Tawnaghmore	TP1	DO	52	52	52	52	52	52	52	52	52	52	52
	TP3	DO	52	52	52	52	52	52	52	52	52	52	52
Tynagh	TYC	Gas/DO	386	386	386	386	386	385	385	385	385	385	385
West Offaly	WO4	Peat	137	137	137	137	137	137	137	137	137	137	137
Whitegate	WG1	Gas/DO	444	444	444	444	444	444	444	444	444	444	444
Ardnacrusha	AA1	Hydro	86	86	86	86	86	86	86	86	86	86	86
Erne 1	ER1	Hydro	65	65	65	65	65	65	65	65	65	65	65
Lee	LE1	Hydro	27	27	27	27	27	27	27	27	27	27	27
Liffey	LI1	Hydro	38	38	38	38	38	38	38	38	38	38	38
Turlough Hill	TH1	Pumped storage	292	292	292	292	292	292	292	292	292	292	292
EWIC	EW1	DC Interconnector	500	500	500	500	500	500	500	500	500	500	500
Extra Planned Generation					104	104	104	104	104	104	104	104	104
Total Dispatchable including DSU			**7590**	**7592**	**7704**	**7706**	**7710**	**7706**	**7709**	**7706**	**7113**	**6563**	**6563**
Year end:			**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**

Table A-4 Registered Capacity of dispatchable generation and interconnectors in Ireland. Some capacities include minor degradation over the years.

DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil.
**Note- The figures for extra planned generation are based on assumptions derived from generator information, and do not constitute EirGrid's formal acceptance of commissioning dates.*

Year end:	ID	Fuel Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ballylumford	ST4,5 & 6	Gas* / Heavy Fuel Oil	510	250	250	250	0	0	0	0	0	0	0
	B31	Gas* /Distillate Oil	245	245	245	245	245	245	245	245	245	245	245
	B32	Gas* /Distillate Oil	245	245	245	245	245	245	245	245	245	245	245
	B10	Gas* /Distillate Oil	97	97	97	97	97	97	97	97	97	97	97
	GT7 (GT1)	Distillate Oil	58	58	58	58	58	58	58	58	58	58	58
	GT8 (GT2)	Distillate Oil	58	58	58	58	58	58	58	58	58	58	58
Kilroot	ST1	Heavy Fuel Oil* / Coal	257	257	257	257	257	257	257	257	257	0	0
	ST2	Heavy Fuel Oil* / Coal	257	257	257	257	257	257	257	257	257	0	0
	KGT1	Distillate Oil	29	29	29	29	29	29	29	29	29	29	29
	KGT2	Distillate Oil	29	29	29	29	29	29	29	29	29	29	29
	KGT3	Distillate Oil	42	42	42	42	42	42	42	42	42	42	42
	KGT4	Distillate Oil	42	42	42	42	42	42	42	42	42	42	42
Coolkeeragh	GT8	Distillate Oil	53	53	53	53	53	53	53	53	53	53	53
	C30	Gas* / Distillate Oil	402	402	402	402	402	402	402	402	402	402	402
Contour Global	AGU	Gas	12	15	15	15	15	15	15	15	15	15	15
Empower	AGU	Distillate Oil	3	7	7	7	7	7	7	7	7	7	7
iPower	AGU	Distillate Oil	73	73	73	73	73	73	73	73	73	73	73
Powerhouse	DSU	Distillate Oil	18	24	24	24	24	24	24	24	24	24	24
Lisahally		Biomass	17	17	17	17	17	17	17	17	17	17	17
Bombardier		Biomass		18	18	18	18	18	18	18	18	18	18
Moyle Interconnector DC Link #			250	450	450	450	450	450	450	450	450	450	450
Total Dispatchable			**2697**	**2668**	**2668**	**2668**	**2418**	**2418**	**2418**	**2418**	**2418**	**1904**	**1904**

Table A-5 Dispatchable plant and interconnectors in Northern Ireland.

** Where dual fuel capability exists, this indicates the fuel type utilised to meet peak demand.*

 # Moyle Interconnector normal capacity: Import = 450 MW Nov-Mar & 410 MW Apr-Oct. (Export = 295 MW Sep-Apr & 287 MW May-Aug). It is assumed that the import capacity on the Moyle Interconnector will return to 450MW in early 2016.

Year end:	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Large Scale On-Shore Wind	641	769	899	1025	1217	1228	1228	1228	1228	1228	1228
Small Scale Wind	74	94	114	134	154	174	174	174	174	174	174
Large Scale Solar	0	10	45	45	45	56	56	56	56	56	56
Small Scale Solar	59	77	95	113	131	149	149	149	149	149	149
Small Scale Biogas	10	12	15	18	22	22	22	22	22	22	22
Landfill Gas	15	15	15	15	15	15	15	15	15	15	15
Small Scale Biomass	5	5	6	7	8	9	9	9	9	9	9
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	4	5	6	7	8	9	9	9	9	9	9
Tidal	1	1	1	1	1	1	1	1	1	1	1
Total	**819**	**998**	**1206**	**1375**	**1611**	**1673**	**1673**	**1673**	**1673**	**1673**	**1673**

Table A-6 Partially/Non-Dispatchable Plant in Northern Ireland

Year end:	2015	2016	2017	2018	2019	2020	2021	2021	2023	2024	2025
All Wind	715	863	1013	1159	1371	1402	1402	1402	1402	1402	1402
All Biomass/Biogas/Landfill Gas	47	67	71	75	80	81	81	81	81	81	81
All Solar	50	87	140	158	176	205	205	205	205	205	205
Renewable CHP	3	3	3	3	3	3	3	3	3	3	3
Hydro	4	5	6	7	8	9	9	9	9	9	9
Tidal	1	1	1	1	1	1	1	1	1	1	1
Total (MW)	**829**	**1026**	**1234**	**1403**	**1639**	**1701**	**1701**	**1701**	**1701**	**1701**	**1701**

Table A-7 All Renewable energy sources in Northern Ireland

	Wind Farm	Capacity (MW)		Wind Farm	Capacity (MW)
Transmission Connected	Slieve Kirk	74	**Distribution Connected**	Garves	15
Distribution Connected	Corkey	5		Curryfree	15
	Rigged Hill	5		Callagheen	16.9
	Elliott's Hill	5		Crockagarran	17.5
	Bessy Bell	5		Church Hill	18.4
	Molly Mountain	15		Tappaghan	19.5
	Owenreagh	10.5		Hunters Hill	20
	Lendrum's Bridge	5.9		Screggagh	20
	Lendrum's Bridge 2	7.3		Thornog	20
	Lough Hill	7.8		Carrickatane	20.7
	Bin Mountain	9		Dunmore	21
	Bessy Bell 2	9		Gruig	25
	Tappaghan 2	9		Altahullion	26
	Wolf Bog	10		Slieve Divena	30
	Altahullion 2	11.7		Crighshane	32.2
	Gortmullan	13.5		Dunbeg	42
	Carn Hill	13.8		Mantlin (Slieve Rushen 2)	54
				Total	**630**

Table A-8 Existing wind farms in Northern Ireland as of end October 2015.

Year end:	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Wind-Onshore	2375	2685	2995	3305	3615	3925	4095	4265	4435	4605	4775
Wind-Offshore	25	25	25	25	25	25	25	25	25	25	25
Wind-Total	2400	2710	3020	3330	3640	3950	4120	4290	4460	4630	4800
Small-scale Hydro	22	22	22	22	22	22	22	22	22	22	22
Biomass and Landfill gas	54	54	54	54	54	54	54	54	54	54	54
Biomass CHP	0	0	25	50	75	107	107	107	107	107	107
Industrial	9	9	9	9	9	9	9	9	9	9	9
Conventional CHP	147	147	147	147	147	147	147	147	147	147	147
Solar PV	10	15	20	25	30	35	40	45	50	50	50
Total	**2642**	**2957**	**3297**	**3637**	**3977**	**4324**	**4499**	**4674**	**4849**	**5019**	**5189**

Table A-9 Partially/Non-Dispatchable Plant in Ireland

Year end:	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
All Wind	2400	2710	3020	3330	3640	3950	4120	4290	4460	4630	4800
All Hydro	237	237	237	237	237	237	237	237	237	237	237
Biomass/LFG (including Biomass CHP)	54	54	122	147	172	204	204	204	204	204	204
Waste (assume 50% renewable)	9	9	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	10	15	20	25	30	35	40	45	50	50	50
Total RES	**2745**	**3060**	**3474**	**3814**	**4154**	**4501**	**4676**	**4851**	**5026**	**5196**	**5366**

Table A-10 All Renewable energy sources in Ireland

Name	MEC (MW)	Name	MEC (MW)
Athea (1)a	34	Derrybrien (1)	60
Ballywater (1)	32	Dromada (1)	29
Ballywater (2)	11	Garvagh - Glebe (1a)	26
Boggeragh (1)	57	Garvagh - Tullynahaw (1c)	22
Booltiagh (1)	19	Glanlee (1)	30
Booltiagh (2)	3	Golagh (1)	15
Booltiagh (3)	9	Kill Hill (1)	36
Castledockrell (1)	20	Kingsmountain (1)	24
Castledockrell (2)	2	Kingsmountain (2)	11
Castledockrell (3)	3	Lisheen (1)	36
Castledockrell (4)	16	Lisheen (1a)	23
Clahane (1)	38	Meentycat (1)	71
Cloghboola (1)	46	Meentycat (2)	14
Coomacheo (1)	41	Mountain Lodge (1)	25
Coomacheo (2)	18	Mountain Lodge (3)	6
Coomagearlahy (1)	43	Mountlucas (1)	79
Coomagearlahy (2)	9	Ratrussan (1a)	48
Coomagearlahy (3)	30	Woodhouse (1)	23
		TOTAL	**1007**

Table A-11 Transmission connected wind farms in Ireland, as of end of October 2015

Name	MEC(MW)	Name	MEC(MW)	Name	MEC(MW)
Altagowlan (1)	7.65	Culliagh (1)	11.88	Lios na Carraige (1)	0.017
Anarget (1)	1.98	Currabwee (1)	4.62	Loughderryduff (1)	7.65
Anarget (2)	0.02	Curraghgraigue (1)	2.55	Lurganboy (1)	4.99
Anarget (3)	0.5	Curraghgraigue (2)	2.44	Mace Upper (1)	2.55
Arklow Bank (1)	25.2	DePuy	2.5	Meenachullalan (1)	11.9
Ballaman (1)	3.6	Donaghmede Fr Collins Park	0.25	Meenadreen (1)	3.4
Ballincollig Hill (1)	15	Dromdeeveen (1)	10.5	Meenanilta (1)	2.55
Ballinlough (1)	2.55	Dromdeeveen (2)	16.5	Meenanilta (2)	2.45
Ballinveny (1)	2.55	Drumlough Hill (1)	4.8	Meenanilta (3)	3.4
Ballybane (2a)	11.5	Drumlough Hill (2)	9.99	Meenkeeragh (1)	4.2
Ballycadden (1)	14.45	Dundalk IT (1)	0.5	Meenkeeragh (2)	0.4
Ballycadden (1)	9.762	Dunmore (1)	1.7	Mienvee (1)	0.66
Ballycurreen (1)	4.99	Dunmore (2)	1.8	Mienvee (2)	0.19
Ballymartin (1)	6	Faughary (1)	6	Milane Hill (1)	5.94
Ballymartin (2)	8.28	Flughland (1)	9.2	Moanmore (1)	12.6
Ballynancoran (1)	4	Garracummer (1)	36.9	Monaincha Bog (1)	35.95
Barranafaddock (1)	32.4	Garranereagh (1)	8.75	Moneenatieve (1)	3.96
Bawnmore (1)	24	Gartnaneane (1)	10.5	Moneenatieve (2)	0.29
Beale Hill (1)	1.6	Gartnaneane (2)	4.5	Mount Eagle (1)	5.1
Beale Hill (2)	2.55	Geevagh (1)	4.95	Mount Eagle (2)	1.7
Beallough (1)	1.7	Gibbet Hill (1)	14.8	Mountain Lodge (2)	3
Beam Hill (1)	14	Glackmore Hill (1)	0.6	Muingnaminnane (1)	15.3
Beenageeha (1)	3.96	Glackmore Hill (2)	0.3	Mullananalt (1)	7.5
Bellacorick (1)	6.45	Glackmore Hill (3)	1.4	Owenstown (1)	0.018
Black Banks (1)	3.4	Glanta Commons (1)	19.55	Pluckanes (1)	0.85
Black Banks (2)	6.8	Glanta Commons (2)	8.4	Raheen Barr (1)	18.7
Bruckana (1)	39.6	GlaxoSmithKline	0	Raheen Barr (2)	8.5
Burtonport Harbour (1)	0.66	Glenough (1)	33	Rahora (1)	4.25
Burtonstown AP 2	0.15	Glentanemacelligot (1)	18	Rathcahill (1)	12.5
Caherdowney (1)	10	Gneeves (1)	9.35	Reenascreena (1)	4.5
Cark (1)	15	Gortahile (1)	21	Richfield (1)	20.25
Carnsore (1)	11.9	Greenoge (1)	4.99	Richfield (2)	6.75
Carrane Hill (1)	3.4	Grouse Lodge (1)	15	Seltanaveeny (1)	4.6
Carrickeeney (1)	7.65	Holyford (1)	9	Shalveys Poultry Ltd. (1)	0.017
Carrig (1)	2.55	Inverin (Knock South) (1)	2.64	Shannagh (1)	2.55
Carrigcannon (1)	20	Inverin (Knock South) (2)	0.69	Skehanagh (1)	4.25
Carrons (1)	4.99	Kealkil (Curraglass) (1)	8.5	Skrine (1)	4.6
Carrowleagh (1)	34.15	Killybegs (1)	2.55	Slievereagh (1)	3
Carrownawelaun (1)	4.6	Kilronan (1)	5	Slievereagh (1)	1.6
Clydaghroe (1)	4.99	Kilvinane (1)	4.5	Sonnagh Old (1)	7.65
Coomatallin (1)	5.95	Knockacummer (1)	87	Sorne Hill (1)	31.5
Coreen (1)	3	Knockaneden (1)	9	Sorne Hill (2)	7.4
Corkermore (1)	9.99	Knockastanna (1)	7.5	Spion Kop (1)	1.2
Corrie Mountain (1)	4.8	Knockawarriga (1)	22.5	Taurbeg (1)	26
Country Crest (1)	0.5	Knocknagoum (1)	42.55	Templederry (1)	3.9
Crocane (1)	1.7	Knocknagoum (2)	1.8	Tournafulla (1)	7.5
Crockahenny (1)	5	Knocknalour (1)	5	Tournafulla (2)	17.2
Cronalaght (1)	4.98	Knocknalour (2)	3.95	Tullow Mushroom Growers Ltd	0.133
Cronelea (1)	4.99	Lackan (1)	6	Tullynamoyle (1)	9
Cronelea (2)	4.5	Lahanaght Hill (1)	4.25	Tursillagh (1)	15
Cronelea Upper (1)	2.55	Largan Hill (1)	5.94	Tursillagh (2)	6.8
Cronelea Upper (2)	1.7	Leitir Guingaid & Doire Chrith1 & 2 Merge	40.9	WEDcross (1)	4.5
Cuillalea (1)	3.4	Lenanavea (2)	4.65	Wind Energy (Janssen)	2
Cuillalea (2)	1.59			**TOTAL**	**1373**

Table A-12 Distribution connected (and energised but not exporting) wind farms in Ireland, as of end of October 2015

APPENDIX 3 METHODOLOGY

GENERATION ADEQUACY AND SECURITY 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 a security 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 security 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-13 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 security 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

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

This equation is used in the following practical example.

SIMPLIFIED EXAMPLE OF LOLE CALCULATION

Consider a system consisting of just three generation units, as in Table A-14.

	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-14 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-15:

1) How many different states can the system be in, i.e. if all units are available, if one is forced out, if two are forced out, or all three?

2) How many megawatts are in service for each of these states?

3) What is the probability of each of these states occurring?

4) Add up the probabilities for the states where the load cannot be met.

5) Calculate expectation.

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

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

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

Table A-16 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[45]. 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.

45 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 ASSESSMENT RESULTS

This section shows the results from the adequacy studies as presented in Section 4.

Median	**Year:**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Surplus / Deficit (MW)	Northern Ireland	305	431	425	201	100	-109	-134	-86	-187	-197
	Ireland	1339	1265	1229	1072	1014	860	488	242	158	92
	All-Island	1941	2071	1960	1535	1478	1145	743	533	267	205

Table A-17 The surplus/deficit of perfect plant in each year for the ***base case scenario****, i.e. Median demand growth, and availability as calculated by EirGrid for the generation in Ireland, and the average availability scenario for the Northern Ireland portfolio. All figures are given in MW of perfect plant. See Section 4.2 for details.*

Median	**Year:**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Surplus / Deficit (MW)	Northern Ireland	130	172	173	-56	-144	-351	-365	-348	-458	-466
	Ireland	1010	989	907	753	687	634	262	14	-68	-134
	All-Island	1372	1474	1322	905	846	523	121	-110	-376	-437

Table A-18 Results for the Base Case, ***without the two interconnectors to Britain****.*

Northern Ireland	**Year:**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Median Availability	**Low Demand**	325	465	471	253	151	-50	-68	-16	-98	-100
	Median Demand	305	431	425	201	100	-109	-134	-86	-187	-197
	High Demand	291	407	394	164	52	-168	-192	-159	-267	-284
Low Availability	**High Demand**	228	318	314	101	0	-215	-228	-229	-310	-326

Table A-19 Comparison of different demand scenarios for ***Northern Ireland****.*

Ireland	**Year:**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Median Availability	**Low Demand**	1,365	1343	1334	1193	1158	1021	666	436	369	319
	Median Demand	1339	1265	1229	1072	1014	860	488	242	158	92
	High Demand	1,339	1265	1229	1026	892	679	249	-56	-199	-324

Table A-20 Comparison of different demand scenarios for ***Ireland****.*

EirGrid plc
The Oval
160 Shelbourne Road
Ballsbridge
Dublin 4
Tel: +353 (0)1 677 1700
Fax: +353 (0)1 661 5375
www.eirgrid.com

SONI Ltd
Castlereagh House
12 Manse Road
Belfast
BT6 9RT
Tel: +44 (0)28 9079 4336
Fax: +44 (0)28 9070 7560
www.soni.ltd.uk