ALL-ISLAND

Generation Capacity Statement 2015-2024

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System Operator for Northern Ireland

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

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Foreword

EirGrid and SONI, as Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively, are pleased to present the All-Island Generation Capacity Statement 2015-2024.

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

When the second North-South Interconnector joins the two jurisdictions on the island, studies have shown there to be sufficient generation plant on the island to meet the agreed adequacy standard. Should this vital project be delayed, the situation is not so secure in the long term, particularly for Northern Ireland.

The medium-term situation for security of supply in Northern Ireland has been alleviated by the recent signing of a contract which should provide sufficient generation capacity from 2016. The preferred, enduring solution, however, would be the installation of the second North-South Interconnector, which would enhance security of supply for both Ireland and Northern Ireland in the long term. We are actively progressing work to deliver this Project of Common Interest by 2019 in association with the competent authorities in the respective jurisdictions.

There will be changes to the renewable support mechanisms and market arrangements during the period covered by this statement. The introduction of the I-SEM in 2017, along with a new Capacity Remuneration Mechanism, will be a major change for all generators. We will closely follow this development, to study the implications it will have on generation adequacy.

In relation to meeting the demand peaks, the introduction of more demand side participation is particularly welcome. Managing the load in this way has clear benefits for the consumer, the generators, as well as the environment.

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

Fintan Slye
Chief Executive, EirGrid Group
February 2015

Table of Contents

FOREWORD		1
EXECUTIVE SUMMARY		4
1	INTRODUCTION	11
2	DEMAND FORECAST	13
2.1	Introduction	14
2.2	Demand Forecast for Ireland	14
2.3	Demand Forecast for Northern Ireland	18
2.4	All-Island Forecasts	21
2.5	Annual Load Shape and Demand Profiles	22
2.6	Changes in Future Demand Patterns	23
3	ELECTRICITY GENERATION	24
3.1	Introduction	25
3.2	Plant Types	25
3.3	Changes to Conventional Generation in Ireland	26
3.4	Changes to Conventional Generation in Northern Ireland	29
3.5	Interconnection	29
3.6	Wind Capacity and Renewable Targets	31
3.7	Changes in other Non-Conventional Generation	37
3.8	Plant Availability	40
4	ADEQUACY ASSESSMENTS	43
4.1	Introduction	44
4.2	Base Case	44
4.3	Scenario without Interconnection with Great Britain	46
4.4	Demand Scenarios	47
APPENDIX 1 DEMAND FORECAST		49
APPENDIX 2 GENERATION PLANT INFORMATION		51
APPENDIX 3 METHODOLOGY		56
APPENDIX 4 ADEQUACY ASSESSMENT RESULTS		60

Table of Figures

Figure 2-1 Total Electricity Requirement Forecast for Ireland 16

Figure 2-2 Past values of recorded maximum demand in Ireland, and the ACS corrected values 17

Figure 2-3 Forecast of Ireland's TER Peak for the Recovery and Stagnation scenarios 17

Figure 2-4 Northern Ireland TER Forecast 19

Figure 2-5 Recorded and ACS-corrected peaks (generated level) for Northern Ireland 20

Figure 2-6 ACS TER Peak forecasts for Northern Ireland 20

Figure 2-7 Combined All-island TER forecast 21

Figure 2-8 Combined all-island TER Peak forecast 21

Figure 2-9 Typical winter day profile 22

Figure 3-1 Fully dispatchable plant and undersea interconnectors installed in 2018 28

Figure 3-2 Band of possible wind capacity requirements to meet the 2020 renewable target 32

Figure 3-3 Historical wind generation in annual energy terms for Ireland (normalised) 33

Figure 3-4 Historical wind capacity factors for Ireland, with the average marked in a red line 33

Figure 3-5 Northern Ireland wind levels assumed for this report 34

Figure 3-6 Historical wind generation for Northern Ireland in annual electricity terms 35

Figure 3-7 Northern Ireland historical wind capacity factors, with average shown as a red line 36

Figure 3-8 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation 37

Figure 3-9 Historical and predicted Forced Outage Rates for Ireland 40

Figure 3-10 Historical and predicted Forced Outage Rates for Northern Ireland 41

Figure 4-1 Adequacy results for the Base Case scenario, shown for Ireland, Northern Ireland and on an all-island basis 45

Figure 4-2 The adequacy situation without the interconnectors to Great Britain 46

Figure 4-3 Different demand scenarios for Ireland and Northern Ireland 47



EXECUTIVE SUMMARY


EXECUTIVE SUMMARY

INTRODUCTION

This statement sets out estimates of the demand for electricity in the period 2015-2024 and the likely generation capacity that will be in place to meet this demand. This is then assessed against the generation adequacy standards for Ireland, Northern Ireland and on an all-island basis in terms of the overall supply/ demand balance.

KEY MESSAGES

All-Island

- According to our all-island studies, there should be sufficient generation plant on the island to meet the agreed adequacy standard for the years 2015-2024 on the basis that most of the current portfolio remains in the market and continuation of the current level of support from the interconnectors with Great Britain.

- We are working on the development of the second North-South interconnector[1], scheduled to be completed by 2019. Following the installation of this vital piece of infrastructure, there will be no significant transmission constraints between Ireland and Northern Ireland. This will improve security of supply in both jurisdictions.

Northern Ireland

- Last year's Generation Capacity Statement highlighted a particular risk to security of supply in Northern Ireland from 2016. Action has been taken to address this risk, and SONI has recently signed a contract to secure the provision of 250 MW of local reserve for a three year period from 2016, extendable by a further two years if required. This outcome will ensure, if other plant performs to expected standards, that the security of supply is maintained at adequate levels in the medium term.

- However, security of supply in Northern Ireland would again be at risk if the second North-South Interconnector is delayed. Restrictions to the availability of Kilroot power station resulting from the Industrial Emissions Directive would mean that the Generation Security Standard would not be met from 2021. Due to the wider benefits that could also be realised, the preferred, enduring solution to this situation is the installation of the second North-South Interconnector. We are focussed on the delivery of this Project of Common Interest by 2019, and are working in association with the competent authorities in each jurisdiction.

- While the Moyle Interconnector capacity is currently limited to 250 MW due to a cable fault, efforts are being made to restore it to full capacity of 450 MW before 2018. This will improve the adequacy situation in Northern Ireland.

- We estimate there to be over 35 MW of Photovoltaic generation connected in Northern Ireland. This growing sector contributes to the renewable targets in Northern Ireland, particularly as studies have shown that its performance complements wind generation.

Ireland

- We forecast that the security of supply in Ireland will exceed the adequacy standard for the next ten years, so long as most of the current portfolio remains available, and we can rely on capacity being available in Great Britain to import over EWIC when needed.

- This being so, there will be a surplus of generation in Ireland. However, with limited interconnection to Northern Ireland, much of this surplus cannot at present be utilised to alleviate the risk to security of supply there.

1 This project has been accorded the status 'Project of Common Interest' by the European Commission.

- After some years of decline, demand in Ireland has shown some signs of increase. In the near future, more growth is expected to come from the expanding data centre sector which already accounts for over 200 MW of demand, and which is incorporated in our demand forecasts.

- A new Combined Cycled Gas Turbine plant is due to be commissioned at Great Island early in 2015.

CONVENTIONAL GENERATION

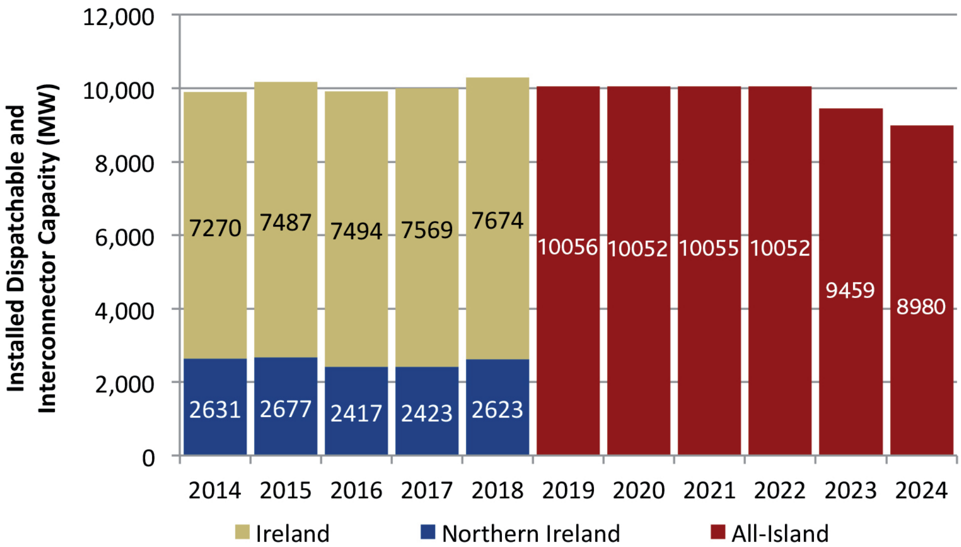
Key Assumptions

- There will be changes to market arrangements during the period of this statement. The introduction of the I-SEM in 2017, along with a new Capacity Remuneration Mechanism (CRM), will be a major change for all generators. A well-targeted, competitive CRM should ensure sufficient generators are in the market to provide adequate security of supply, particularly given the higher levels of renewable generation expected in the coming years. We will follow these developments closely to study the implications they would have on generation adequacy.

- Our methodology for capacity adequacy assessment assumes a high degree of support from the two interconnectors to Great Britain: Moyle and EWIC. However, the capacity margins in Great Britain now appear to be tighter than in recent years. We will continue to review this situation and the effect that interconnection has on generation adequacy.

- Demand-side participation in the electricity market is growing and makes an important contribution to capacity adequacy. The capacity of Aggregated Generating Units in Northern Ireland has expanded to 74 MW, while in Ireland more Demand Side Units have joined the SEM, bringing the total there to 160 MW.

- Apart from those generators with signed connection agreements, no other large-scale generators have been considered for these studies.



The assumptions for the generation portfolio are based on information received from the generators and connection agreements in place at the data freeze (October 2014).The graph above outlines the dispatchable generation and interconnector capacity assumed on the island over the next ten years. The generation from both jurisdictions can be summed together as the combined, all-island generation portfolio once the second North-South interconnector is in place.

Ireland

A new CCGT is due to be commissioned early in 2015 at Great Island, Co Wexford.

While connection agreements are in place for over 450 MW of further dispatchable conventional generation capacity, some of these projects are close to the end of their validity period, and may not be realised.

The oil units at Great Island are due to close following the commissioning of the CCGT on that site in early 2015. In addition, the oil units at Tarbert are scheduled to close at the beginning of 2023. Overall, this leads to a reduction of 800 MW of capacity.

Though we have received no other notifications of closure, it seems prudent to assume that some of the older plant on the system will close or experience higher forced outage rates towards the end of the study period.

Northern Ireland

There is no significant new conventional generation currently planned for Northern Ireland over the next ten years that this report covers. A licensing framework is being developed for Demand Side Units in Northern Ireland, and these will be incorporated in future studies.

In the past year, action has been taken to address a significant risk to security of supply in Northern Ireland. Following a competitive procurement process, a contract has been signed for the provision of 250 MW of local reserve services at Ballylumford for a three-to-five-year time period commencing in 2016.

This contract has secured the continued operation of plant at Ballylumford at a reduced capacity, to be made possible by investment in emission-abatement technology and life-extension works.

Some of the larger units at Kilroot will be affected by emissions restrictions imposed by the Industrial Emissions Directive (IED) post 2021. In preparing this document we have made assumptions, according to the best information available, about how the IED will affect the running regime of these units. We have assumed that the Kilroot coal-fired generators will have restricted running hours from 2021 and will shut down at the beginning of 2024.

One cable of the Moyle Interconnector is currently on a prolonged forced outage due to an undersea cable fault. Based on the latest information concerning its repair, we have assumed that the full import capacity of 450 MW will be available from 2018.

RENEWABLE ENERGY

The Governments in both jurisdictions have adopted a target of generating 40% of all electricity consumed from Renewable Energy Sources (RES) by 2020. While a large portion of this renewable electricity will come from wind power, other RES will also play a part, such as hydro and biomass.

Ireland

Currently there are approximately 2,000 MW of wind power connected to the Irish system. It is estimated that this will need to rise to between 3,200 and 3,800 MW by 2020 to meet the 40% target. This estimation assumes average historical capacity factors, and a small percentage of wind generation being unusable for system security reasons. It also takes into account the electricity demand forecast and other RES.

There are 80 MW of Waste-to-Energy projects connected or due to connect over the next few years. Approximately 50% of this waste is sourced from biomass. In addition, a significant growth in bioenergy is assumed.

Northern Ireland

A number of renewable generation projects are assumed to be commissioned over the next 10 years, equating to a total renewable generation capacity of over 2,200 MW in Northern Ireland by 2024. This includes 200 MW of tidal power and 45 MW of large scale biomass.

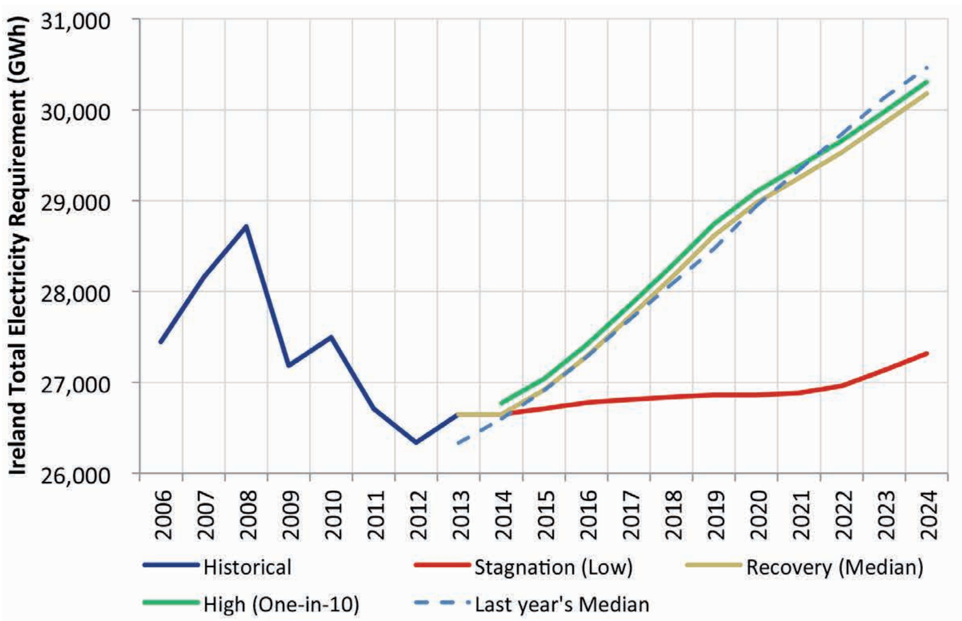
We have estimated that in order to achieve the 40% RES target by 2020, the wind capacity will have to almost double, to reach 1,100 MW.

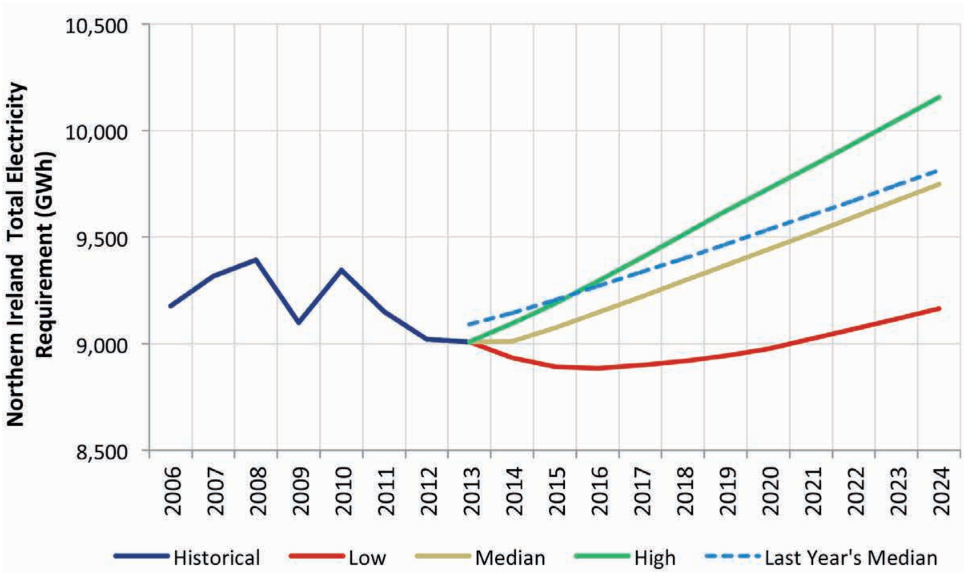
DEMAND FORECAST

For both Ireland and Northern Ireland, the economic recession has led to a drop in electricity demand in recent years. However, economic indicators are now predicting a return to growth, see figures below.

In Ireland, demand grew in 2013, exceeding the demand forecast for that year made in the previous GCS. Looking forward, our median scenario sees a recovery to 2008 electricity demand levels by about 2019. This scenario is informed by predictions of significant economic growth by the ESRI and other institutions.

For Northern Ireland, our demand forecast has been reduced slightly from the previous year. This is due to a lower 2013 outturn than forecast, and to indications from a number of institutions of lower economic growth than previously forecast. The median scenario predicts a return to 2008 levels by 2019.





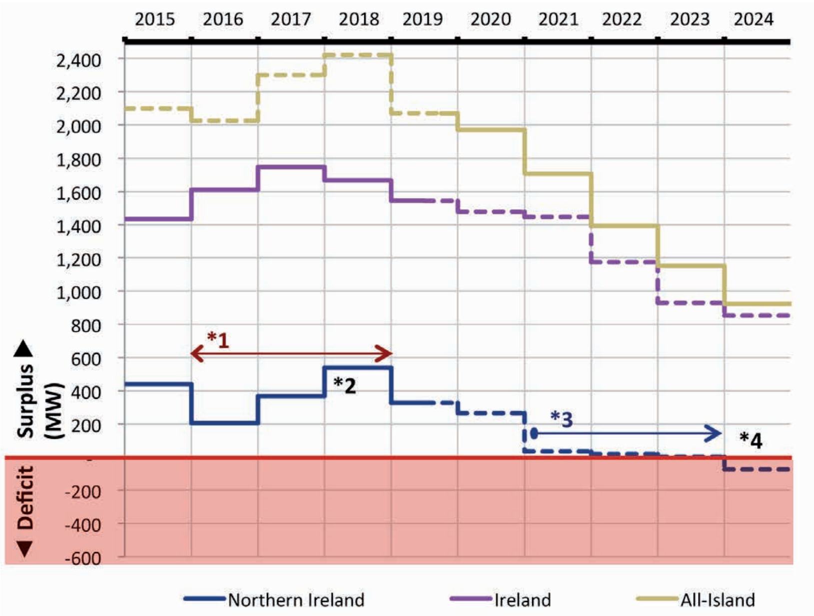
METHODOLOGY

Generation adequacy is essentially determined by comparing generation capacity with demand. To measure the imbalance between them we use a statistical indicator called the Loss of Load Expectation (LOLE). When this indicator is at an appropriate level, called the generation adequacy standard, the supply/demand balance is judged to be acceptable.

Currently, limited interconnection capacity between Ireland and Northern Ireland means that Ireland must limit its assumed capacity reliance on Northern Ireland to just 100 MW. Similarly, Northern Ireland has an assumed capacity reliance of 200 MW on Ireland. The commissioning of an additional interconnector between the two jurisdictions would significantly increase the transfer capability between the two jurisdictions, to the extent that the two jurisdictions can be considered as one power system as far as adequacy calculations are concerned. This would improve overall adequacy in both.

Given the uncertainty that surrounds any forecast of generation and demand, the report examines a number of different scenarios to provide a range of relevant information that stakeholders can use to inform their commercial decisions.

GENERATION ADEQUACY ASSESSMENTS



*Note *1: Duration of local reserve services contract, 2016-2018 (inclusive)*
*Note *2: 2018 – Moyle restored to full capacity*
*Note *3: Kilroot coal units severely restricted from 2021*
*Note *4: 2024 – Kilroot coal units shut*

The figure above illustrates the generation adequacy results for the Reference Case, i.e. with the most likely scenarios for demand forecast and generator availability. If a system is estimated to be below standard for a particular year, then the system is said to be in deficit. The amount of deficit is the MW capacity needed to bring the system back to standard. A plant surplus in any year indicates how much plant a system could do without and still meet the defined standard exactly.

Though results are shown for separate- and joint-system studies for all years above, it is only when the second North-South interconnector is in place (assumed to be in late 2019) that the combined, all-island assessment is applicable.

The dashed lines for the Ireland and Northern Ireland separate-system studies from 2020 illustrate the situation should the second North-South interconnector be delayed. The dashed line for the all-island results up to 2019 shows the benefit of having the second North-South interconnector in place earlier than this. This approach allows a full consideration of the impact that the second North South interconnector has on both jurisdictions over the entire period of generation adequacy assessment.

Ireland is shown to be in surplus for all years of the study. Without the second North-South interconnector, this surplus cannot be shared on an all-island basis with Northern Ireland.

Risk to security of supply in Northern Ireland

The risk to security of supply in Northern Ireland in the medium term has been addressed by the contract to provide 250 MW of local reserve services at AES Ballylumford for three years from 2016.

The adequacy levels are also improved by the restoration of Moyle by 2018.

However, when assessed on its own, Northern Ireland will fall into effective deficit in 2021 due to further restrictions at Kilroot. The second North-South interconnector is vital to ensure the security of electricity supply for the future in Northern Ireland, and to realise the potential economic benefits of the I-SEM. We are actively progressing work to deliver this Project of Common Interest by 2019[2], in association with the competent authorities in each jurisdiction.

2 http://www.eirgridprojects.com/projects/NorthSouth400kVInterconnectionDevelopment/



1 INTRODUCTION


1 INTRODUCTION

This report is produced with the primary objective of informing 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 2024[3].

Generation adequacy is a measure of the capability of the electricity supply to meet the electricity demand on the system. The development, planning and connection of new generation capacity to the transmission or distribution systems can involve long lead times and high capital investment. Consequently, this report provides information covering a ten-year timeframe.

EirGrid, the Transmission System Operator (TSO) in Ireland, is required to publish forecast information about the power system, as set out in Section 38 of the Electricity Regulation Act 1999 and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations.

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

This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2014-2023, published in February 2014.

All input data assumptions have been updated and reviewed. Any changes from the previous report, including those to the input data and consequential results, are identified and explained.

This report is structured as follows:

- 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.

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

3 EirGrid and SONI also publish a Winter Outlook Report which is focused on the following winter period, thus concentrating on the known, short-term plant position rather than the long-term outlook presented in the Generation Capacity Statement. http://www.eirgrid.com/media/Winter%20Outlook%202014-15.pdf


2 DEMAND FORECAST



2 DEMAND FORECAST

2.1 Introduction

The forecasting of electricity demand is an essential aspect of assessing generation adequacy. This task has become more complex in recent years with the changing economic climate. The economic downturn has led to significant reductions in both peak demand and energy consumption across the island. Some sectors have been affected more than others.

Also to be considered is the significant impact of severe winters. These effects need to be modelled with reference to historical weather data.

EirGrid and SONI use models based on historical trends, economic forecasts and energy policies at regional, national and European level to predict future electricity demand. These models are outlined in this section, along with the results they produce.

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

Forecasted demand figures are given in terms of Total Electricity Requirement (TER). All calculated TER and peak values are listed in Appendix 1. Finally, information on typical load shapes is presented. Electrical energy, peak demand forecasts and load factor predictions are used to calculate future profiles.

2.1(a) Temperature Correction of Historical Demand

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

Statistical analysis is carried out to determine the relationship between demand, temperature and day of the week using multivariate regression analysis over the winter periods. The resultant relationships are then applied to the current winter data to establish the adjusted ACS winter demand. When forecasting forwards, it is assumed that the weather is average, i.e. no temperature variations are applied.

2.1(b) Self-Consumption

Some industrial customers produce and consume electricity on site, many with the facility of Combined Heat and Power (CHP). This electricity consumption, known as , is not included in sales or transported across the network. Consequently, an estimate[5] of this quantity is added to the energy which must be exported by generators to meet sales. The resultant energy is known as the Total Electricity Requirement (TER). This TER is used in adequacy calculations, to be met by generation from all sources, including self-consumers.

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 sales based on changes in economic parameters. A spread of electricity forecasts are produced, covering the next ten years.

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

In the past, the economic parameters of GDP[6] and PCGS[7] were employed in the model, as advised upon by the Economic and Social research Institute (ESRI) who have expertise in modelling the Irish economy and who were consulted during the process[8]. However, the ESRI has recently recommended the use of a modified GNP[9] parameter, which has been adjusted for the effect of redomiciled PLCs[10]. This has led to a more robust model.

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, it is estimated that between 7 and 8% of power produced is lost as it passes through the electricity transmission and distribution systems. Recent figures have indicated that the proportion of losses is falling, though this needs careful analysis in the future to confirm the trend.

Past economic data is sourced from the most recent Quarterly National Accounts of the Central Statistics Office. Data from the past 20 years is analysed 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, forecasts of GNP and PCGS are required. These forecasts are provided by the ESRI.

The short-term data comes from the Quarterly Economic Commentary published by the ESRI in October 2014. 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 other institutions including the Department of Finance, the Central Bank of Ireland, the European Commission and the International Monetary Fund.

The following table shows the economic inputs for producing the median 'Base Case' electricity forecast.

	GNP (volume)	Personal Consumption
2016-2020	3.6%	2.8%
2021-2025	2.2%	2.7%

Table 2-1 Economic projections based on the Recovery scenario of the Medium Term Review.

2.2(d) Uncertainty around the median forecast

The Base Case demand forecast is the best estimate of what might happen in the future, and is related to the 'Recovery' scenario of the MTR. It also incorporates some reduction due to energy efficiency measures in line with Ireland's National Energy Efficiency Action Plan[11] (including the installation of smart meters).

In an effort to capture the uncertainty involved in any forecasting exercise, higher and lower forecasts have been made to bracket the median demand.

6 Gross Domestic Product is the total value of goods and services produced in a country.
7 Personal Consumption of Goods and Services measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.
8 http://www.esri.ie/irish_economy/
9 Gross National Product differs from GDP by the net amount of incomes sent to or received from abroad.
10 Redomiciled PLCs refer to foreign companies which hold substantial investments overseas but have established a legal presence in Ireland.
11 http://www.dcenr.gov.ie/energy/energy+efficiency+and+affordability+division/national+energy+efficiency+action+plan.htm

The lower TER forecast is based on the economic stagnation scenario of the MTR. This is quite a pessimistic scenario, where the EU as well as the Irish economy stagnates, and economic growth is much lower than in the recovery scenario. This low demand scenario should therefore capture the possible effects of lower than expected economic growth. It should also allow for the effects of milder-than-average weather and/or more energy saved through energy efficiency measures.

The higher electricity forecast is generated by imposing more severe weather conditions, specifically a winter where the lowest temperatures are as cold as a one-in-10 year minimum. It is not suggested that every year in the coming decade will be this cold, but it is to demonstrate an upper bound to the electricity forecast.

While temperature has a significant effect on the peak demand, it is not so influential on the annual energy.

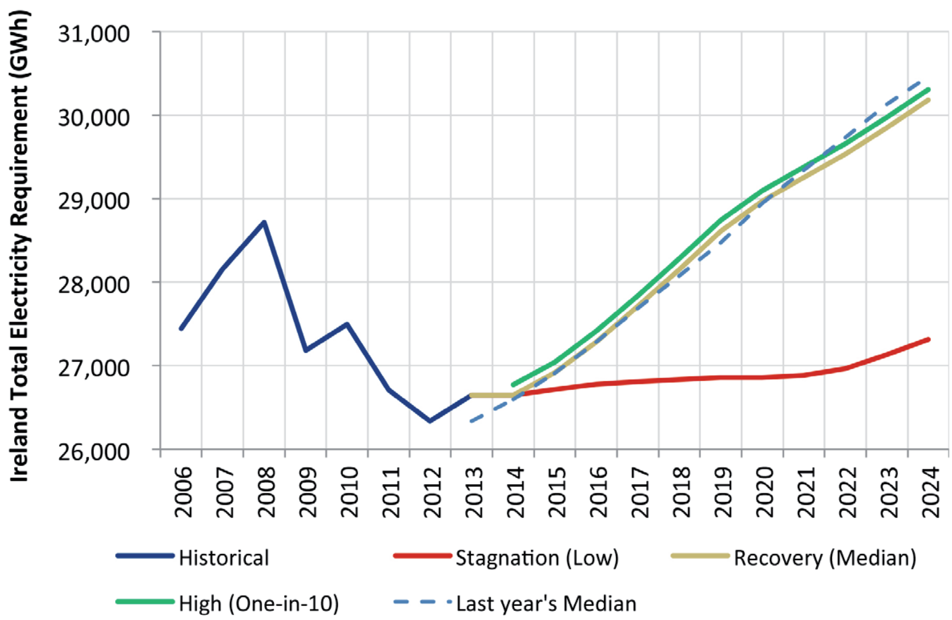


Figure 2-1 Total Electricity Requirement Forecast for Ireland. The figure for 2014 is based on real data available at EirGrid's National Control Centre up to October, and so estimates are made for the remaining months.

2.2(e) 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.

For ten years up to February 2013, EirGrid operated a DSM scheme called the Winter Peak Demand Reduction Scheme (WPDRS), which rewarded participating customers for reducing their electricity demand at peak winter hours. This scheme was effective in reducing the winter peak by over 100 MW.

In the future, it can be assumed that without this scheme, the peaks will be higher. To counter this, a significant capacity of Demand Side Units are now available to be called upon should the need arise. Many of the companies that participate now as a DSU were formerly providing demand reduction to the WPDRS. This DSU sector is expected to grow over the coming years.

As discussed already, **temperature** has a more 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 2-2.

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 2-3. This forecast is then tempered with estimates of energy efficiency savings, particularly to allow for the effect of smart meters.

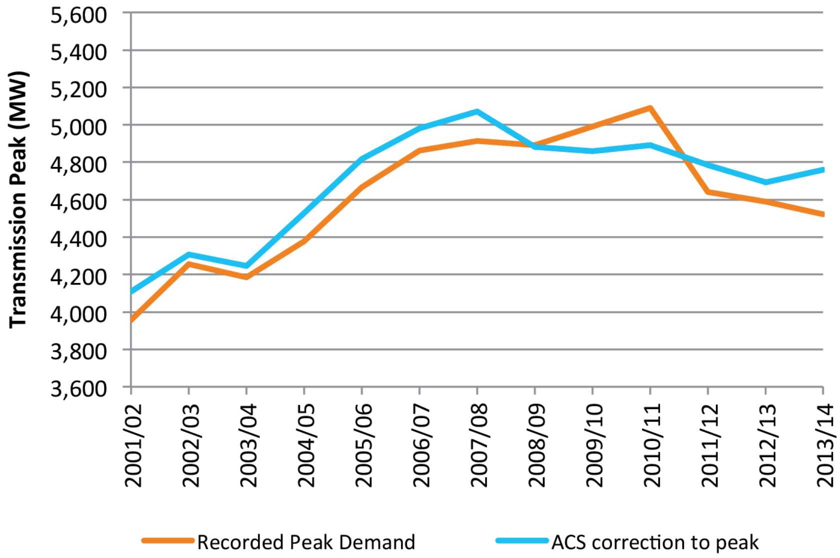


Figure 2-2 Past values of recorded maximum demand in Ireland, and the ACS corrected values.

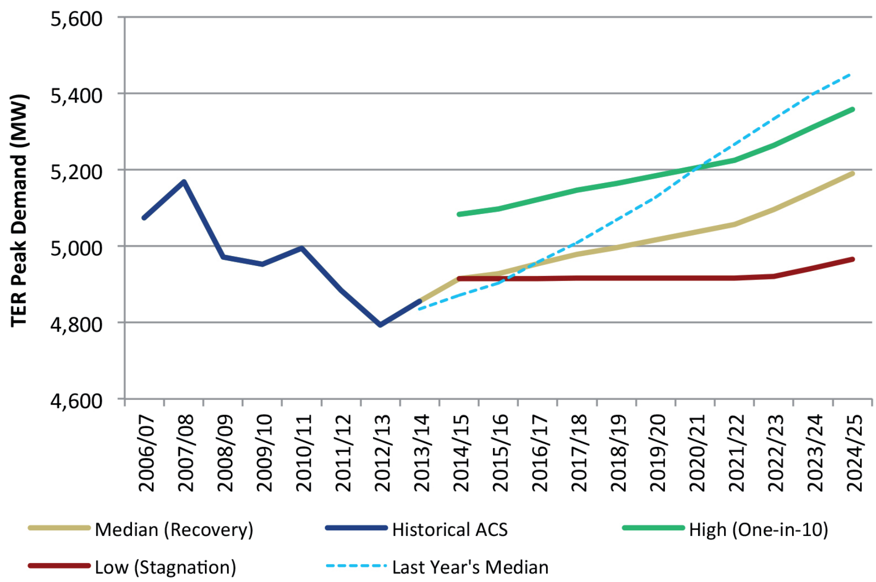


Figure 2-3 Forecast of Ireland's TER Peak for the Recovery and Stagnation scenarios, under Average Cold Spell conditions. The green line shows the peaks that could result if the weather were not average, but as severe as the coldest in 10 winters. For comparison purposes, last year's Median peak forecast 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. Various publications are forecasting growth in Northern Ireland's economy, although some uncertainty surrounds the pace of this recovery.

The Strategic Energy Framework for Northern Ireland[12] sets out the Northern Ireland contribution to the 1% year-on-year energy efficiency target for the UK. This has also been incorporated in the demand forecast.

2.3(b) Demand Scenarios

Given the high 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. The three scenarios consist of a pessimistic, realistic and optimistic view that take account of current economic outlook predictions.

Combining both the temperature and economic scenarios allows for median, high and low demand forecasts to be formulated.

The median demand forecast is based on an average temperature year, 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, with the pessimistic economic factor being applied. Conversely, the high demand forecast is based on a relatively low temperature year, with the more optimistic economic factor being applied.

2.3(c) Self-Consumption

In addition to industrial self-consumers[13], a growing amount of small scale embedded generation is appearing on the Northern Ireland system which produces and consumes electricity on site. These include technologies such as small scale wind turbines, photo-voltaic and biofuels which serve domestic dwellings, community centres, farms, etc. This self-consumption is not included in the Northern Ireland sent-out[14] annual energy.

In isolation each individual small scale embedded generator of this type does not have a significant effect on the demand profile; however they do become significant on a cumulative basis. We have been working closely with Northern Ireland Electricity (NIE) and referencing the Renewable Obligation Certificate Register (ROC Register)[15] to establish the amount of this embedded generation that is currently connected on the Northern Ireland system, as well as referencing Northern Ireland Planning Service[16] 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).[17]

12 http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf
13 SONI carry out an annual analysis to determine the amount of "Customer Private Generation" (CPG), where customers run their own generation effectively giving demand reduction.
14 Exported = Net of Generator House Loads
15 https://www.renewablesandchp.ofgem.gov.uk/
16 www.planningni.gov.uk
17 Self-consumption in Northern Ireland currently represents approximately 2% of TER.

2.3(d) TER Forecast

It can be seen that the new TER forecast for Northern Ireland (Figure 2-4) has been reduced compared to the previous forecast published in the Generation Capacity Statement 2014-2023. The reduced forecast is primarily due to a combination of the decrease in energy for 2013 and a forecast of reduced economic growth, as well as the continued drive for energy efficiency.

The Northern Ireland TER forecast predicts a return to 2008 levels by about 2019.

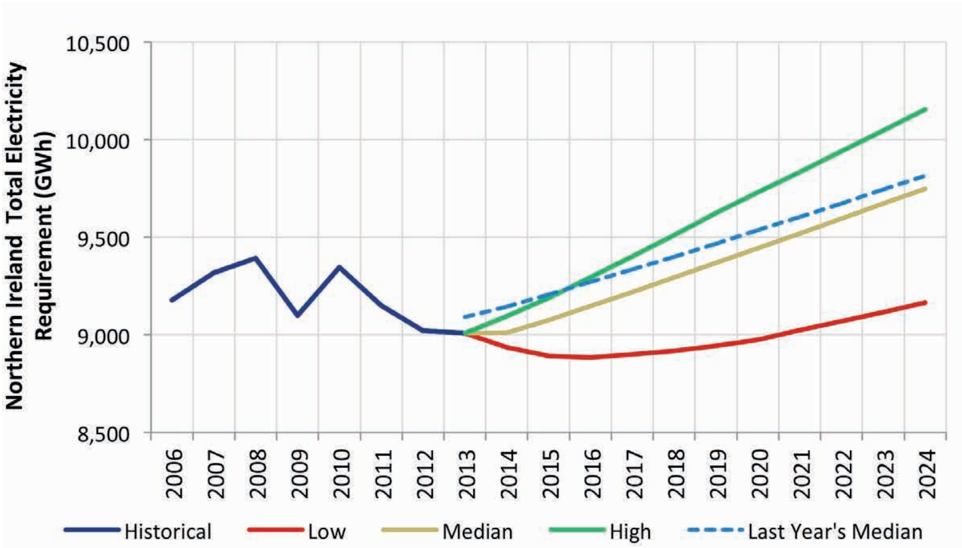


Figure 2-4 Northern Ireland TER Forecast.

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 2013/14 generated winter peak, which occurred on Tues 14th January @ 17:30, consisted of the following dispatch data:

Centrally Dispatched Generation Units + Interconnectors	1509 MW
Renewable + Small Scale	269 MW
Customer Private Generation	32 MW
TOTAL GENERATED PEAK	**1810 MW**

When average cold spell temperature correction (ACS) is applied using the methodology as described above, the figure of 1810 MW is corrected down by 10 MW, providing an ACS corrected figure of 1800 MW for the 2013/14 winter period, see Figure 2-5.

As with the annual electricity usage 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.

The ACS generated peak demand is converted to the ACS exported peak by assuming a house load of approximately 4.5% and is the equivalent to the Transmission Peak.

The TER Peak is then derived by adding a further estimation of the contribution to peak demand that the self-consuming small scale generation makes, as described in section 2.3(c). On average, this has the effect of adding approximately 2.5% to the Transmission Peak.

Figure 2-6 shows the TER peak forecast for Northern Ireland. It can be seen that the resulting forecast for Northern Ireland has been reduced compared to the previous forecast published in the 2014-2023 Generation Capacity Statement.

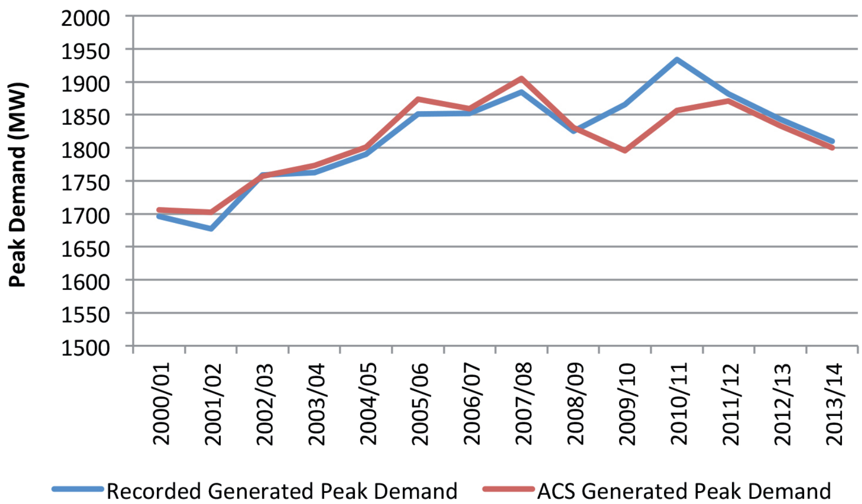


Figure 2-5 Recorded and ACS-corrected peaks (generated level) for Northern Ireland. The most significant corrections are for 2009/10 and 2010/11, when the temperature deviated most from normal.

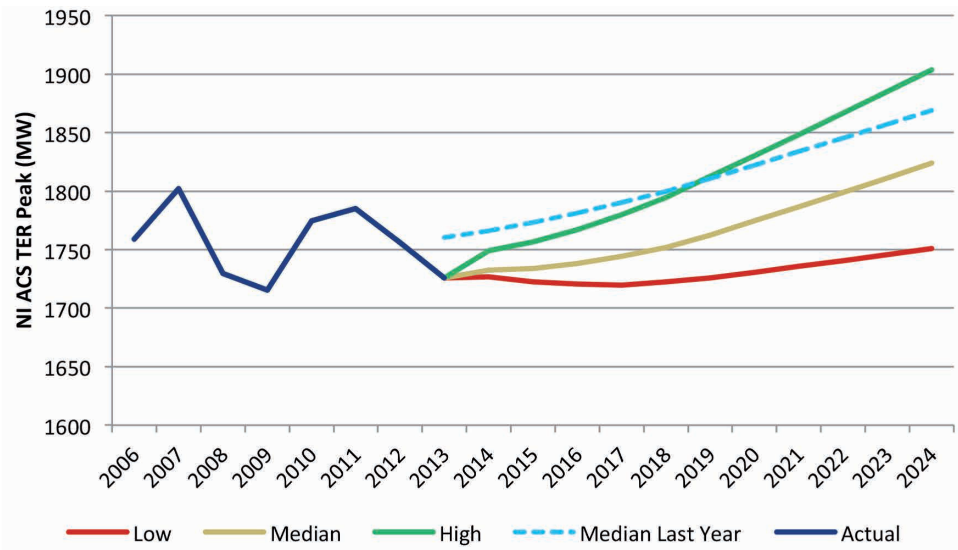


Figure 2-6 ACS TER Peak forecasts for Northern Ireland.

2.4 All-Island Forecasts

The combined all-island TER forecast comes from summing together the demands from each jurisdiction, see Figure 2-7.

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 2013 demand shape. This gives yearly all-island peaks which are less than the sum of the equivalent peaks for each region – just one of the benefits of switching to an all-island system. The forecasted all-island peaks are shown in Figure 2-8, where ACS conditions are assumed for the future.

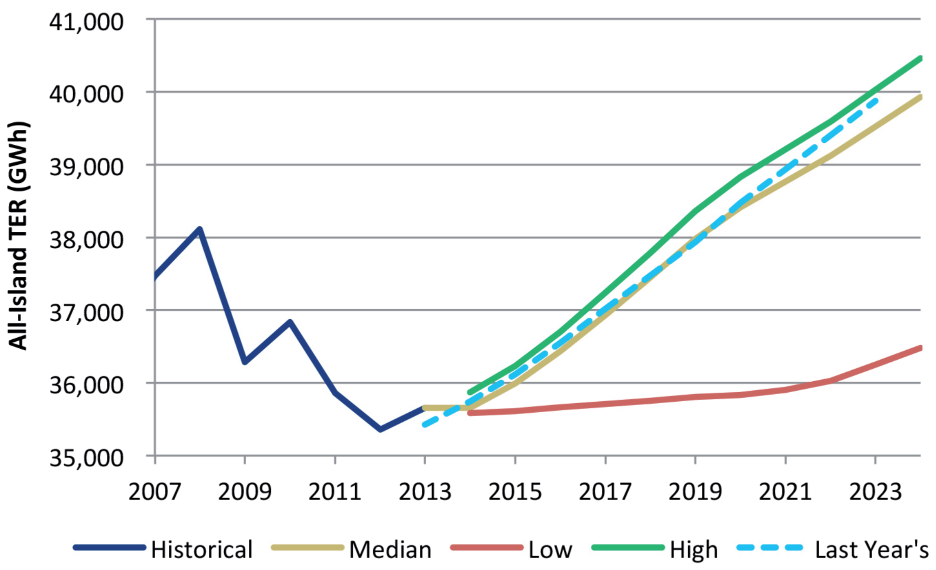


Figure 2-7 Combined All-island TER forecast.

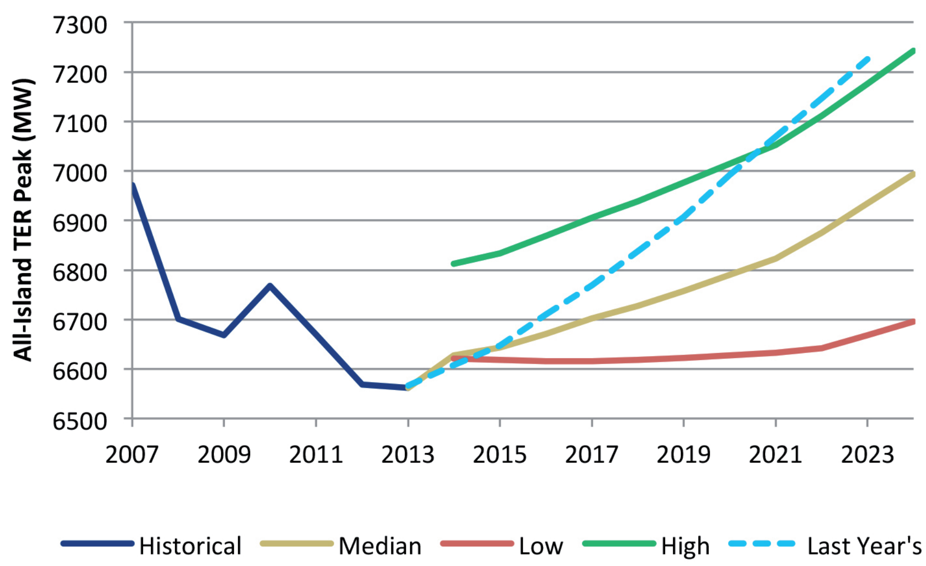


Figure 2-8 Combined all-island TER Peak forecast.

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 2013 for both jurisdictions.

2013 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 2-9 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.

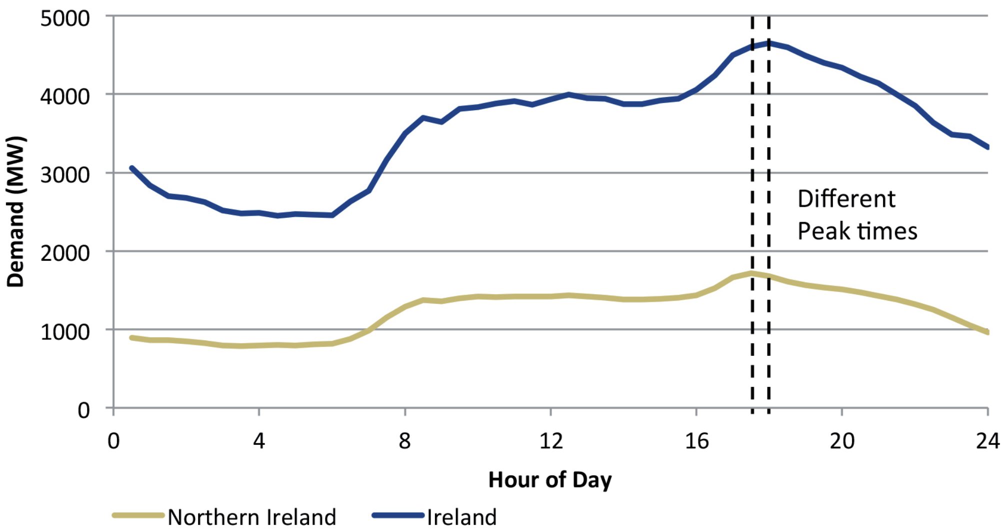


Figure 2-9 Typical winter day profile.

2.6 Changes in Future Demand Patterns

The Government of Ireland has a plan to increase energy efficiency by 20% by 2020. This includes such actions as replacing existing lighting with energy efficient sources, and increasing the thermal insulation standards for newly built housing, as well as government grants for retrofitting existing houses to improve their efficiency[18]. This will undoubtedly have an effect on the demand profile.

Developments in electric vehicles and the roll out of smart-metering will also have an influence on the demand shape in Ireland. While the exact effect is yet uncertain, we have carried out studies investigating the potential changes[19].

Similarly, the Northern Ireland Government, through the Department of Enterprise, Trade and Investment (DETI) have set targets of contributing to the 1% year-on-year energy efficiency savings target for the UK as set out in the Strategic Energy Framework for Northern Ireland[20]. It is envisaged that they will be able to achieve this through a number of different schemes.

These include, for example, the introduction of Energy Performance Certificates, amending building regulations to progressively improve the thermal performance of buildings, and providing services through the Government's regional business development agency (Invest NI[21]) to help businesses identify and implement significant energy efficiencies.

There are also moves by the Northern Ireland Executive to encourage a higher uptake of electric vehicles, by the introduction of a number of free car charging points throughout Northern Ireland through the ECAR project[22]. However, it is difficult to predict at this stage as to whether or not electric vehicles will have a significant effect on the Northern Ireland demand profile in the future due to the uncertainty around the actual uptake of electric vehicles.

Trials have been completed to evaluate the effect of the use of smart metering in Northern Ireland[23]. Results of this trial have indicated that smart metering could have a significant impact on electricity consumption particularly reducing peak demand.

18 http://www.seai.ie/Grants/Home_Energy_Saving_Scheme/, http://www.seai.ie/Grants/Warmer_Homes_Scheme/
19 See for e.g. GAR 2009-2015, GAR 2008-2014
20 http://www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf
21 http://www.investni.com/index/already/maximising/managing_energy_and_waste.htm, http://www.nibusinessinfo.co.uk/bdotg/action/layer?site=191&topicId=1079068363
22 http://www.nidirect.gov.uk/e-car-northern-ireland
23 http://www.nie.co.uk/Network/Future-networks/Shift-Save



3 ELECTRICITY GENERATION


3 ELECTRICITY GENERATION

3.1 Introduction

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Capacity added (Northern Ireland)		46		6	200						
Capacity removed (Northern Ireland)			-260			-250					-476
Capacity added (Ireland)		431	10	72	108	10					
Capacity removed (Ireland)		-212								-592	
Minor Adjustments		-2	-3	3	-3	-1	-4	3	-3	-1	-3
Net Impact		263	-253	81	305	-241	-4	3	-3	-593	-479
Total Dispatchable Capacity	9901	10164	9911	9992	10297	10056	10052	10055	10052	9459	9456

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

Generation adequacy describes the balance between demand and generation supply. 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 summarised in Table 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 2014). We have assumed that not all of the contracted plant will be commissioned, and that some of the older plant in Ireland will, in effect, shut down over the course of the study period.

Interconnection will continue to play an important role in future generation supply security. The East-West Interconnector has connected the transmission systems of Ireland and Wales, and can transmit 500 MW in either direction. Along with the existing Moyle Interconnector[24] that connects the transmission systems of Northern Ireland and Scotland, this has significantly enhanced the overall interconnection between the island of Ireland and Great Britain.

The second major North-South interconnector connecting Northern Ireland and Ireland will lead to a more secure, stable, and efficient all-island system. We are actively progressing work to deliver this Project of Common Interest by 2019 in association with the competent authorities in the respective jurisdictions.

3.2 Plant Types

One of the most important characteristics of a generator, from a TSO perspective, is whether or not the plant is 'fully dispatchable'. For a plant to be fully dispatchable, we must be able to monitor and control its output from our control centres. Since customer demand is also monitored from the control centres, we can adjust the output of fully-dispatchable plant in order to meet this demand.

24 The cable fault on Pole 2 of the Moyle Interconnector is due to be repaired and available for service again in 2018. Until then, the Moyle's import capacity is assumed to be 250 MW Jan-Dec. After repair, the Moyle import capacity will be 450 MW Nov-Mar and 410 MW Apr-Oct.

Although fully-dispatchable plant normally consists of the larger units on the system, smaller units may also be fully-dispatchable if they wish to take part in the market. For example, in Northern Ireland there are now four 3 MW gas units operated by Contour Global, and a 74 MW Aggregated Generating Unit operated by iPower. Also there are some new Demand Side Units in Ireland which take part in the market and are fully dispatchable.

There is an amount of generation whose output is not currently monitored in the control centres and whose operation cannot be controlled. This non-dispatchable plant, known as embedded generation, has historically been connected to the lower voltage distribution system and has been made up of many units of small individual size.

Large wind farms fall into a different category. Since the maximum output from wind farms is determined by wind strength, they are not fully controllable, i.e. they may not be dispatched up to their maximum registered capacity if the wind strength is too low to allow this. However, their output can be reduced by EirGrid or SONI controllers if required (for example, due to transmission constraints), and they are therefore categorised as being partially dispatchable. In accordance with the EirGrid Grid Code[25] and the Distribution Code[26] in Ireland, wind farms with an installed capacity greater than 5 MW must be partially dispatchable.

In accordance with the SONI Grid Code[27] and the Distribution Code[28] in Northern Ireland, a wind farm with a registered capacity of 5 MW or more must be controllable by the TSO and is defined as a “Controllable Wind Farm Power Station” (CWFPS). A “Dispatchable Wind Farm Power Station” is further defined as a DWFPS which must have a control facility in order to be dispatched via an electronic interface by the TSO. In both cases these would be categorised as being partially dispatchable.

3.3 Changes to Conventional Generation in Ireland

This section describes the changes in fully dispatchable plant capacities which are forecast to occur over the next ten years. Plant closures and additions are documented. In Ireland, the only new generators documented here are those which have a signed connection agreement with EirGrid[29] or the DSO (Distribution System Operator), and have indicated a commissioning date to EirGrid by the data freeze date.

3.3(a) Plant Commissionings

- SSE plans to commission a new Combined-Cycle Gas Turbine (CCGT) plant at Great Island in Co Wexford in early 2015. The existing oil units there will subsequently be decommissioned. 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 2016.

- The capacity of Demand Side Units has increased to 160 MW, and is set to increase further.

25 www.eirgrid.com/operations/gridcode/
26 www.esb.ie/esbnetworks/en/about-us/our_networks/distribution_code.jsp
27 www.soni.ltd.uk/gridcode.asp
28 http://www.nie.co.uk/documents/Connections/Distribution_Code_1_May_2010.aspx
29 i.e. a signed Connection Offer has been accepted and any conditions precedent fulfilled.

Table 3-2 lists the conventional plant with connection agreements in place:

Plant	Capacity (MW)
Great Island CCGT	431
Cahernagh OCGT	101
Dublin Waste to Energy	62
Nore OCGT	98
Suir	98
Cuilleen	98

Table 3-2 Contracted generation capacity for Ireland, up to 2024.

Of the plant in Table 3-2, only Great Island CCGT has a firm commissioning date in the near future. Some of the other projects are close to the end of their validity period, and may not be realised.

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.

3.3(b) Plant Decommissionings

Some older generators will come to the end of their lifetimes over the next ten years. The generators with confirmed decommissioning dates are shown in Table 3-3.

Plant	Export Capacity (MW)	Expected closure date
Great Island 1,2,3	212	2015
Tarbert 1, 2, 3, 4	592	2023

Table 3-3 Confirmed closures of conventional generators in Ireland.

3.3(c) Ireland's Base Case

Other than the generators listed in Table 3-3, EirGrid has received no other notification of plant closures. However, we have assumed that some older generators 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.

Also, with the connection agreements of some of the commissioning plant in Table 3-2 coming close to the end of their validity period, we have assumed that not all of the contracted generators will be realised.

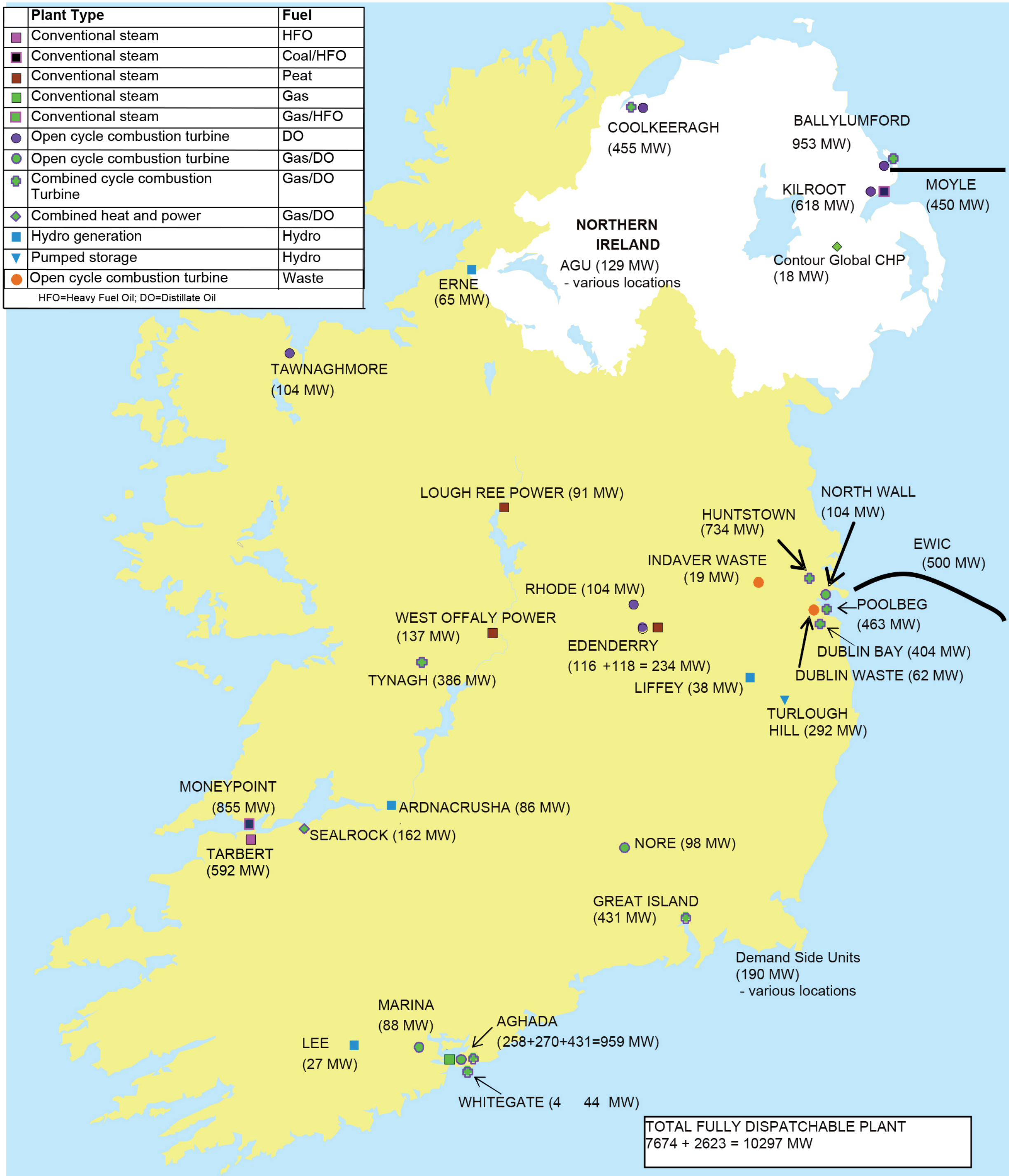


Figure 3-1 Fully dispatchable plant and undersea interconnectors installed in 2018, at exported capacities. All figures shown are Registered Capacities (except new plant which are at the planned Maximum Export Capacity) – generators and interconnectors may often operate at a lower capacity.

3.4 Changes to Conventional Generation in Northern Ireland

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

- Some of the plant at Ballylumford is due to be decommissioned by 2016. This is because of environmental constraints introduced by the Large Combustion Plants Directive[30].

- In 2015, units at Ballylumford are set to undergo life-extension works and will be fitted with emission-abatement technology. This is in order that they can provide 250 MW of Local Reserve services for a three-year time period commencing 1st January 2016.

- From 2016, KPS1 and KPS2 at Kilroot will be required to comply with the Industrial Emissions Directive (IED)[31]. We have discussed with AES Kilroot how the workings of the IED will affect the running regimes of KPS1 and KPS2. These units are due to shut at the beginning of 2024.

Our assumptions for KPS1 and KPS2 comprise limited running each year from 2016-2020, followed by severely restricted running hours from 2021-2022. The IED greatly affects their ability to contribute to system adequacy beyond 2020.

It should be noted that at this stage, the workings of the IED are not fully finalised and therefore these assumptions are AES Kilroot's best informed estimates at this stage, based on all the information they have to date as to what effect the IED will have on them.

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.

3.5 Interconnection

Interconnection allows the transport of electrical power between two transmission systems. Interconnection with Great Britain over the Moyle and the East-West interconnectors provides significant capacity benefit. Further transmission links between Ireland and Northern Ireland would enhance generation adequacy in both jurisdictions.

3.5(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. In this all-island assessment, the demand and generation portfolios for Northern Ireland and Ireland are aggregated.

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 it has been agreed that each TSO is obliged to help the other in times of shortfall.

With this joint operational approach to capacity shortfalls, it was 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.

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

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.

It should be noted that although the capacity reliance used in the studies limits the North-South flow to 100 MW and South-North flow to 200 MW, flows in excess of this can take place during real time operations.

3.5(b) 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 in 2018[32]. The Forced Outage Probability[33] (FOP) used in these studies for the Moyle has been adjusted to reflect the recent outages.

It should be noted that any increase in the Moyle Interconnector's capacity during the study period will help the Northern Ireland adequacy position.

All interconnector capacity is auctioned by SONI on behalf of Mutual Energy Limited[34]. This capacity is purchased by market participants. In the SEM the unused capacity can, in emergency situations, be used solely to meet peak demand. Therefore this capacity assessment assumes the capacity of the Moyle Interconnector as a maximum of 250 MW, with 200 MW extra once Pole 2 is repaired.

3.5(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 not easy to predict whether or not imports for the full 500 MW will be available at all times. Based on analysis[35], we have estimated the capacity value of the interconnector to be 440 MW for these generation adequacy studies. A FOP somewhat lower than that for the Moyle interconnector has been used to represent EWIC for the adequacy studies.

3.5(d) Generation Available in Great Britain

When assessing the generation adequacy of an interconnector, we need to consider the availability of generation at the other side: in the case of Moyle and EWIC, this is Great Britain.

32 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. www.mutual-energy.com/Download/110930%20MIL%20SONI%20NG%20Capacity%20Calc%20combined%20Sept%202011.pdf
33 Forced Outage Probability (FOP) is the time a generator is on forced outage as a proportion of the time it is not on scheduled outages.
34 www.mutual-energy.com
35 Interconnection Economic Feasibility Report: http://www.eirgrid.com/media/47693_EG_Interconnect09.pdf

National Grid's Future Electricity Scenarios (July 2014) states:

'We assume for all scenarios that at times of peak demand electricity will be exporting to Ireland and continental interconnection will be importing at a similar level. The result would be that GB as a whole would have a net position of zero MW being imported and exported. This assumption is based on analysis of historic flows'.

However, the capacity margins in Great Britain now appear to be tighter than in recent years. Though with extra demand side measures in place, National Grid deem the situation to be manageable. Capacity auctions in the future will contribute to long-term stability. For the moment we will assume that there will be generation available in Great Britain to the full importable amount on both Moyle and EWIC. We will continue to review this situation and the effect it has on our capacity adequacy.

3.6 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 3-5 shows the existing and planned wind generation on the island. Appendix 2 has detailed lists of all the currently installed windfarms on the island.

Compared to the previous GCS, there is a significant increase in the amount of wind contracted in Ireland, particularly from the 'Gate 3' process.

	Connected (MW)	Contracted/Planned (MW)	Subtotal
Ireland TSO	902	1720	2622
Ireland DSO	1086	2220	3306
Northern Ireland TSO	74	445	519
Northern Ireland DSO	584	686	1270
Totals	**2646**	**5071**	**7717**

Table 3-5 Existing (connected) and planned (contracted) wind farms, as of October 2014. Planned refers to wind farms that have signed a connection agreement in Ireland, or that have received planning approval in Northern Ireland. These figures are based on the best information available.

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

3.6(a) Wind Power in Ireland

In October 2009 the Irish Government announced a target of 40% of electricity generated to come from renewable sources by 2020. This is part of the Government's strategy to meet an overall target of achieving 16% of all energy from renewable sources by 2020.

Installed capacity of wind generation has grown from 145 MW at the end of 2002 to almost 2,000 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 decreased due to the economic downturn. 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 – the exact amount has to be estimated, and is therefore another source of potential error.

With these uncertainties in mind, not one figure but a band of possible outcomes has been estimated for wind capacity in 2020. Figure 3-2 illustrates where this band of targets lies, between about 3,200 and 3,800 MW. This would mean an average of about 240 MW of extra wind capacity installed per year.

Figure 3-3 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[36].

Based on historical records (historical wind capacity factors are shown in Figure 3-4), it is assumed that onshore wind has a capacity factor of approximately 31%.

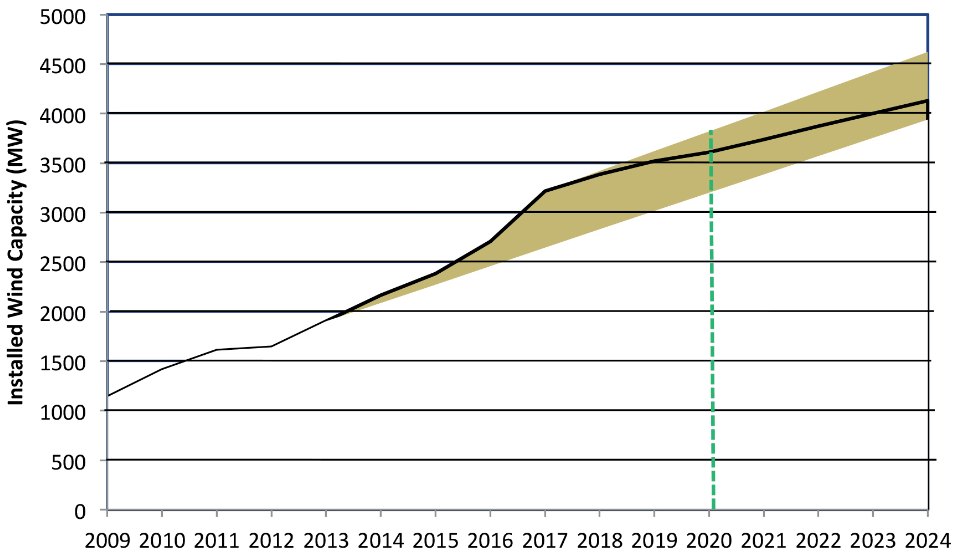

Figure 3-2 Band of possible wind capacity requirements to meet the 2020 renewable target.

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

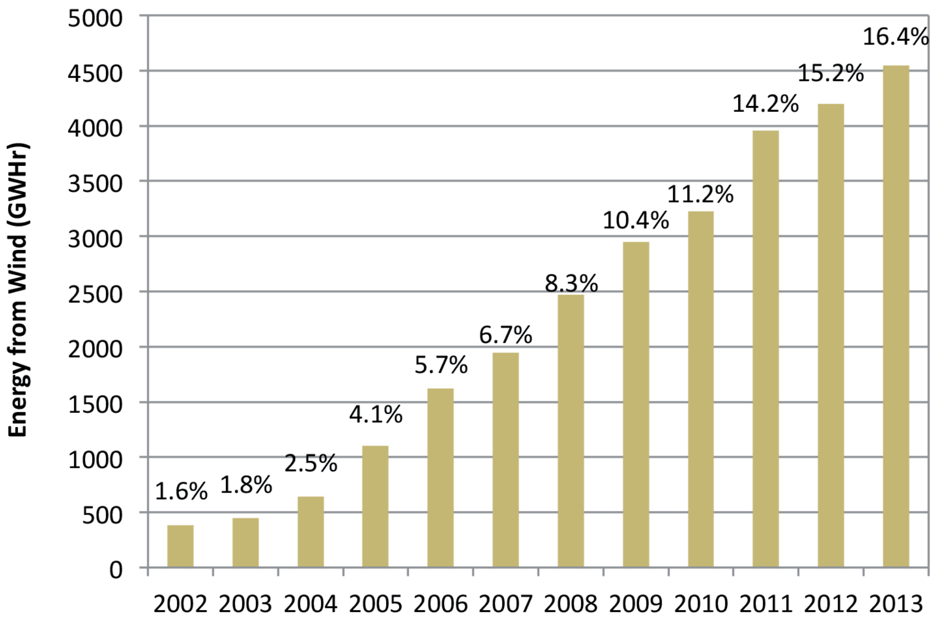

Figure 3-3 Historical wind generation in annual energy terms for Ireland (normalised), also given as a percentage of total electrical energy produced that year.

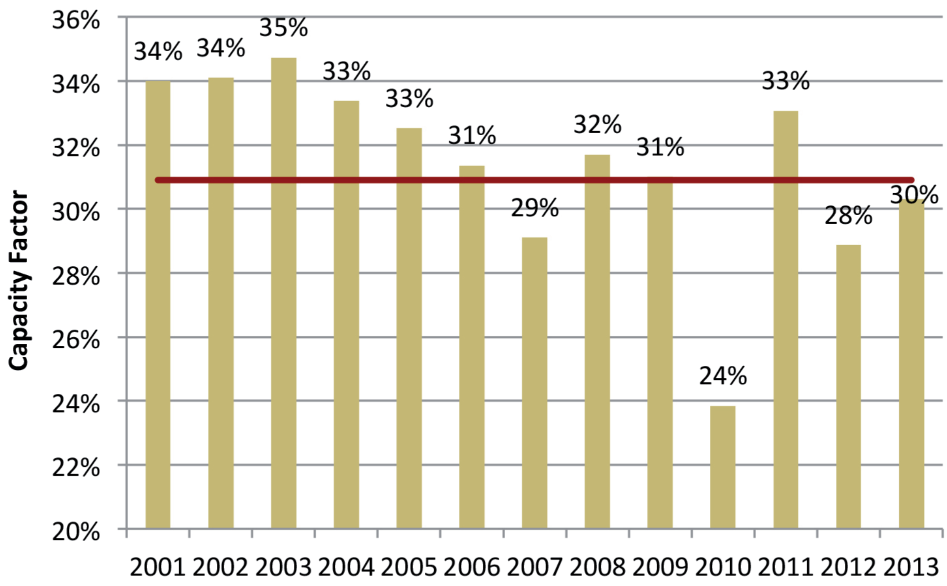

Figure 3-4 Historical wind capacity factors for Ireland, with the average marked in a red line.

3.6(b) Wind Power in Northern Ireland

The Strategic Energy Framework for Northern Ireland[37] 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. For 2012, 12.5% of electricity consumption came from renewable sources in Northern Ireland, and so surpassing the 12% target.

Installed capacity of wind generation has grown from 37 MW in 2002 to 658 MW (including 44 MW of small scale wind) at the time of writing. This is set to increase rapidly over the next number of years as increasing levels of planning applications[38] for new wind farms are made. While taking into account a contribution from other renewables such as tidal and biomass, it is this increasing level of wind that is expected to be the main contributor to achieving the 40% target by 2020.

It is estimated that an installed wind capacity of circa 1200 MW will be enough to achieve the 40% figure by 2020. The figures for the amount of large scale onshore wind in each study year have been derived by linearly incrementing the amount of connected onshore wind each year by an amount which will allow the target to be met by 2020.

For the purposes of the studies for this report we assume that by 2024 there will not be any offshore wind connected. A 600 MW offshore wind farm was to be installed off the County Down coast, but has recently been withdrawn. Development rights are still in place for tidal sites in Northern Ireland's coastal waters.

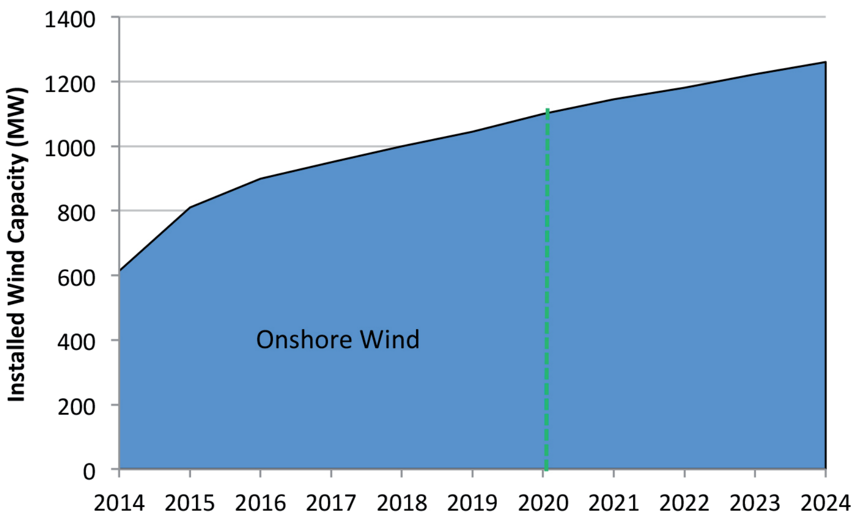

Figure 3-5 Northern Ireland wind levels assumed for this report.

Figure 3-5 shows the expected growth of wind installed in Northern Ireland. These assumptions have also referenced a number of other sources, including the Onshore Renewable Electricity Action Plan (OREAP)[39] produced by the Department of Enterprise, Trade and Investment (DETI).

37 Strategic Energy Framework (www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf)
38 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)
39 Onshore Renewable Electricity Action Plan (OREAP) (www.onshorerenewablesni.co.uk)

The wind energy assumptions incorporate information provided on wind farm connections by Northern Ireland Electricity (NIE) and the Northern Ireland Planning Service[40]. These sources indicate that even higher amounts of wind generation may connect over the next few years. However, we have taken a more conservative view on the amount that will be connected for the adequacy studies and have included enough capacity to meet the Northern Ireland Executive's 40% renewable target by 2020.

For the purposes of calculating the forecasted energy produced by renewable sources, we assume that large scale onshore wind has a capacity factor[41] of 30%, tidal 20% and large scale biomass 80%. There is also a factor to take account of an amount of potential energy from wind which cannot be used due to transmission or system constraints. It should be further noted that the actual amount of renewable energy required to meet the 40% target by 2020 will depend on the demand in future years, as the 40% figure is based on electricity consumption and not on installed capacity.

We assume that most of the new wind farms will be built in the west of Northern Ireland, and transmission reinforcements will be required to transport it to the east, where demand is highest. To avoid extensive potential wind energy constraints, and to enable Northern Ireland to meet Government renewable targets, considerable investment is now urgently required on the Northern Ireland transmission system. The levels of connected wind capacity required are dependent on a number of key transmission corridors being reinforced by the asset owner, Northern Ireland Electricity, alongside the completion of the second North South interconnector.

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 14.8% by 2013.

Historical capacity factors for Northern Ireland are shown in Figure 3-7. The average wind capacity factor for the last 9 years is 30.7%. It can be seen that some years, particularly in 2010, the wind capacity factor is lower than the average.

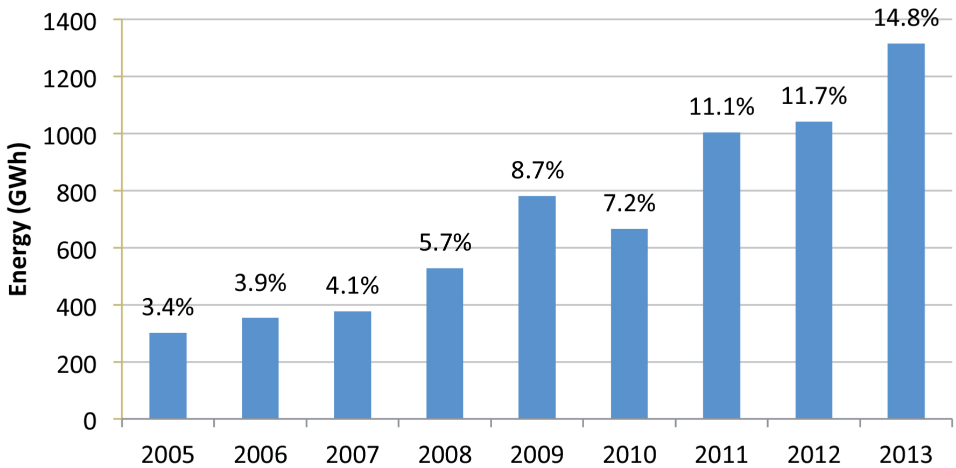

Figure 3-6 Historical wind generation for Northern Ireland in annual electricity terms, also given as a percentage of total electricity produced that year. Figures are based on sent-out metering available to SONI.

40 http://www.planningni.gov.uk/index/advice/advice_apply/advice_renewable_energy/renewable_wind_farms.htm

41 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.

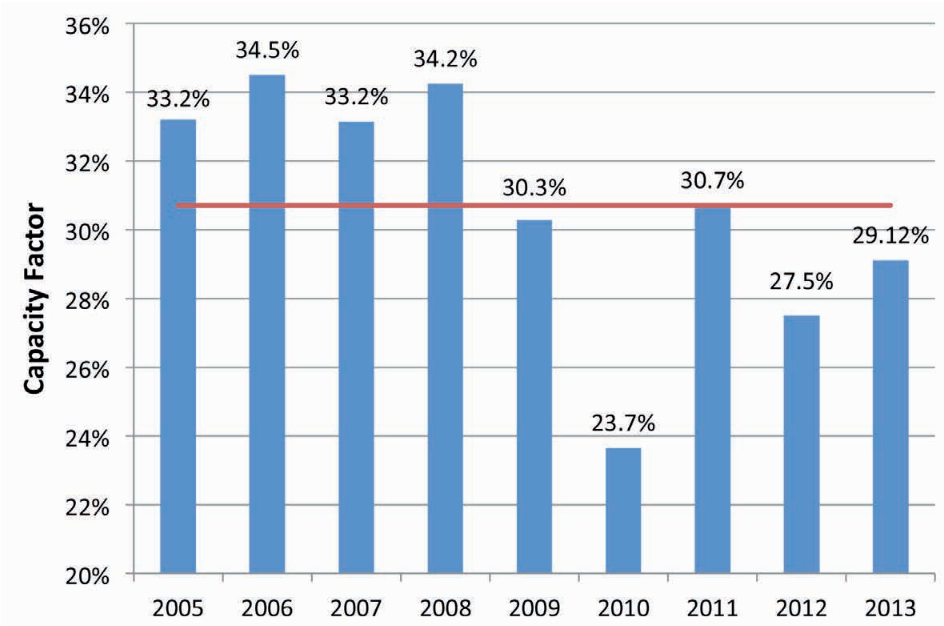

Figure 3-7 Northern Ireland historical wind capacity factors, with average shown as a red line. Figures based on sent-out metering available to SONI.

3.6(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. 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 3-8 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.

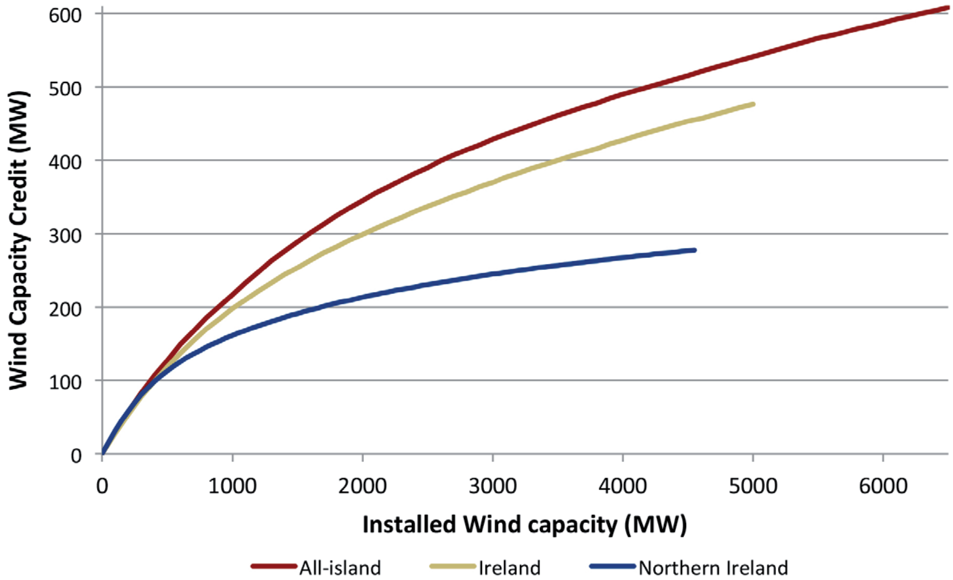

Figure 3-8 Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation. For Ireland, the wind profiles were taken from 2012, a recent, typical year. The curve for Northern Ireland is based on an average over several years.

Despite its limited contribution towards generation adequacy, wind generation has other favourable characteristics, such as:

- The ability to provide sustainable energy
- Zero carbon emissions
- Utilisation of an indigenous, free energy resource
- Relatively mature renewable-energy technology

This, combined with excellent natural wind resources in both Ireland and Northern Ireland, will ensure that wind generation will be developed extensively to meet the two Governments' renewable energy targets for 2020 in both jurisdictions.

3.7 Changes in other Non-Conventional Generation

This section discusses 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. Other sources, such as the Ofgem Renewable Obligation Certificate Register (ROC Register) and information for the Northern Ireland planning service have also been used to try and gain a better estimate of current and future levels. Based on these sources, we estimate there to be over 100 MW[42] of this small scale generation currently connected to the Northern Ireland system, with various levels of this being utilised for self-consumption on site.

3.7(a) Demand-Side/Industrial Generation

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.

Demand-side generation has been ascribed a capacity of 9 MW in Ireland for the purposes of this report.

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 this AGU is expected to increase to over 100 MW over the coming years. It should be noted that this is an exportable capacity and is not considered as demand side generation in this context.

3.7(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[43] 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[44] 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.

3.7(c) Biofuel

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

In Ireland, there is currently an estimated 47 MW of landfill gas powered generation. The peat plant at Edenderry now powers approximately 30% of its output using biomass. The REFIT 3[45] incentive for biomass-fuelled CHP plant aims to have 150 MW installed by 2020. With some of this plant already planned, 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.

42 Mainly includes Diesel Generators, CHP and Small Scale Wind but also PV, Gas, Hydro, Biofuels and Land Fill Gas
43 Energy White Paper 2007 'Delivering a Sustainable Energy Future for Ireland', March 2007.
44 www.detini.gov.uk/strategic_energy_framework__sef_2010_.pdf
45 http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/REFIT.htm

Currently in Northern Ireland, there is an estimated 28 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 65 MW by 2024.

For the studies it is also assumed in Northern Ireland that 45 MW of large scale biomass will be commissioned during the study period at 3 separate sites, each of which will have a capacity of 15 MW. These may be dispatchable due to their size, although at this stage there are no signed agreements or target connection dates in place.

3.7(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. It is assumed that there are no further increases in small hydro capacity over the remaining years of the study.

3.7(e) Marine Energy

With the large amount of uncertainty associated with this new technology, we have taken the prudent approach that there will be no commercial marine developments operational in Ireland before 2024.

In Northern Ireland the Strategic Environmental Assessment (SEA)[46] proposes a target of 300 MW from tidal generation by 2020. It is unclear at this stage as to which tidal technology will be used to achieve this. However, the Crown Estate[47] has awarded development rights for two 100 MW Tidal sites off the North Coast of Northern Ireland. Therefore, for the purposes of this report, we have used a conservative assumption for tidal generation of 200 MW by 2020.

3.7(f) Compressed Air Energy Storage (CAES)

SONI has an accepted connection offer in place with Gaelectric Energy Storage for connection of a proposed Compressed Air Energy Storage (CAES) Plant in the Larne area . The facility consists of 268 MW of generation and 210 MW of compression and is proposed to be connected to the transmission system. Such an energy storage facility could potentially act as an ancillary services and balancing facility for renewable generation. A CAES plant uses a large compressor to store excess energy off the grid. It converts the excess electric energy to compressed air which is stored in an underground geological cavern, then released through an electric generator for later use. This technology could be applied to store surplus renewable energy, whilst also enabling variability balancing on the transmission system. The scheme has been drawn up as a Project of Common Interest (PCI) by the European Commission.

For the purposes of this report, CAES has not been included in the adequacy studies for the Northern Ireland generation base case at this stage. SONI will continue to monitor the status of this project with a view to incorporating it in future studies.

3.7(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. The proposed waste-burning facility in Dublin also estimates 50% RES in the waste it will burn.

Lisahally Waste Project (Evermore/Maydown) is a proposed wood-fuelled energy-from-waste combined heat and power plant in Northern Ireland with a capacity of approximately 15 MW. It is due to become operational in 2015.

46 Strategic Environmental Assessment (www.offshorenergyni.co.uk). DETI is also developing an Onshore Renewable Electricity Action Plan (OREAP) for Northern Ireland. (www.onshorerenewablesni.co.uk)

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

3.8 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.

3.8(a) Ireland

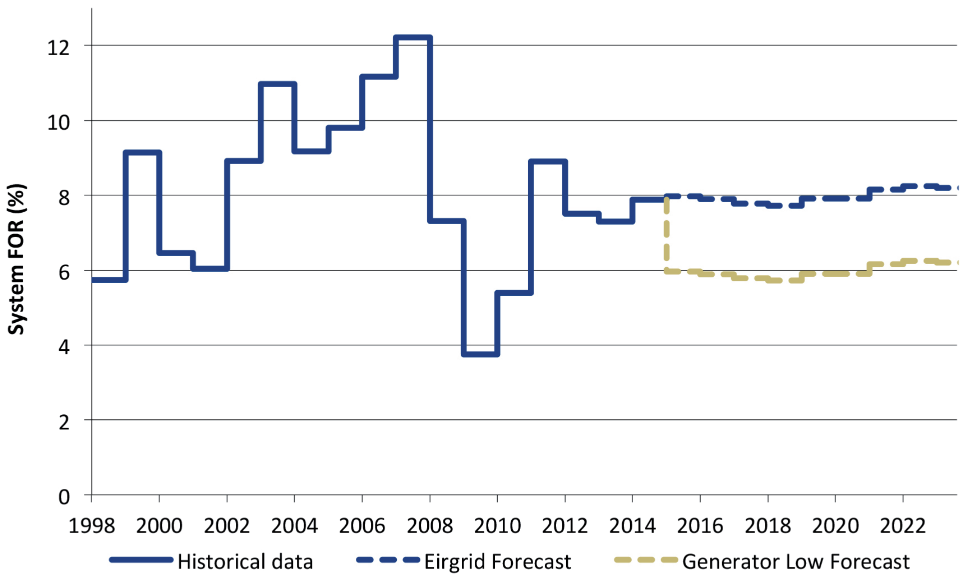

Figure 3-9 Historical and predicted Forced Outage Rates for Ireland. Future rates as predicted by both EirGrid and the generators are shown.

Figure 3-9 shows the system-wide forced-outage rates (FOR)[48] 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 2015 to 2024. 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[49] 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.

3.8(b) Northern Ireland

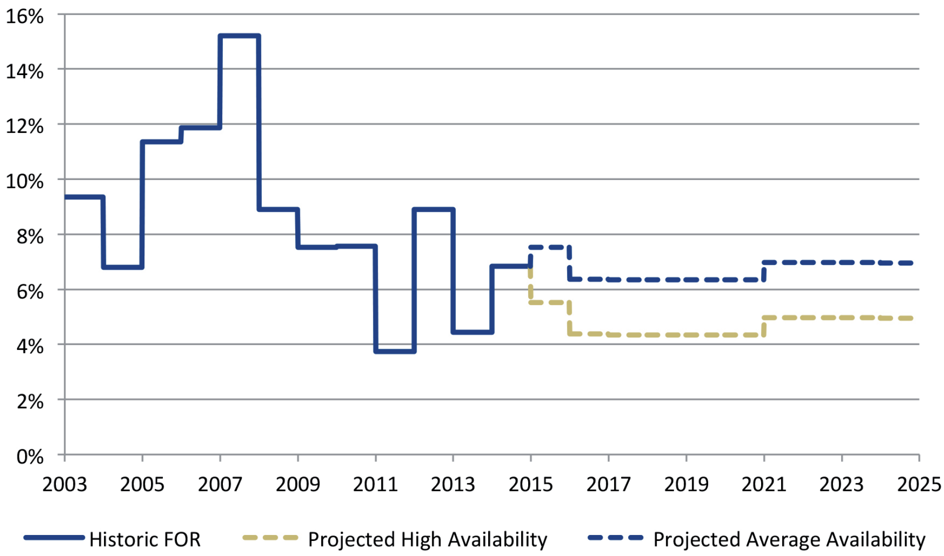

Figure 3-10 Historical and predicted Forced Outage Rates for Northern Ireland (not including the Moyle Interconnector).

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.

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

Figure 3-10 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.



4 ADEQUACY ASSESSMENTS


4 ADEQUACY ASSESSMENTS

4.1 Introduction

This section presents the results from the adequacy studies, given in terms of the plant surplus or deficit (see APPENDIX 3 for 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 valid. These all-island studies show an overall improvement in the adequacy position.

Alongside the base case, results are presented for different plant scenarios, including the unavailability of interconnector flows between the island of Ireland and Great Britain,

Different demand growth and plant availability scenarios are also examined to illustrate their effect on generation adequacy. All results are presented in full tabular form in APPENDIX 4.

The amount of surplus or deficit 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, in terms of the amount of surplus or deficit as assessed for the system for any particular year. When a result for any year results in a deficit, it is plotted below the red line, e.g. Northern Ireland in 2024.

The base case assumes the following:

- median demand growth in both jurisdictions (this is referred to as the Recovery scenario in Ireland),
- the EirGrid-calculated availability for the generation portfolio in Ireland,
- and average 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.

The single-area studies are only relevant until the second North-South interconnector is commissioned, assumed to be by late 2019. However, the single-area studies have been continued beyond 2019 (as dashed lines) to illustrate the situation should the interconnector project be delayed.

Similarly, the results for the combined, all-island system are applicable only from late 2019 onwards. However, results are shown before this time in dashed lines to convey the situation should the interconnector be completed early.

4.2(b) Discussion of Results

The results for Ireland show it to be in a large surplus of over 1,000 MW for most years. This begins to fall off towards the later years 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.

For Northern Ireland, the adequacy situation is sufficient in the medium term largely due to the local reserve services contract to provide 250 MW for three years from 2016 (though significant scheduled outages on Moyle Pole 1 and another large unit will impact the adequacy in 2016 itself). The restoration of Moyle Pole 2 improves the situation further in 2018. However, when assessed on its own, Northern Ireland will fall into effective deficit in 2021 due to severe restrictions at Kilroot.

The significant surplus for all-island studies is shown by the gold 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.

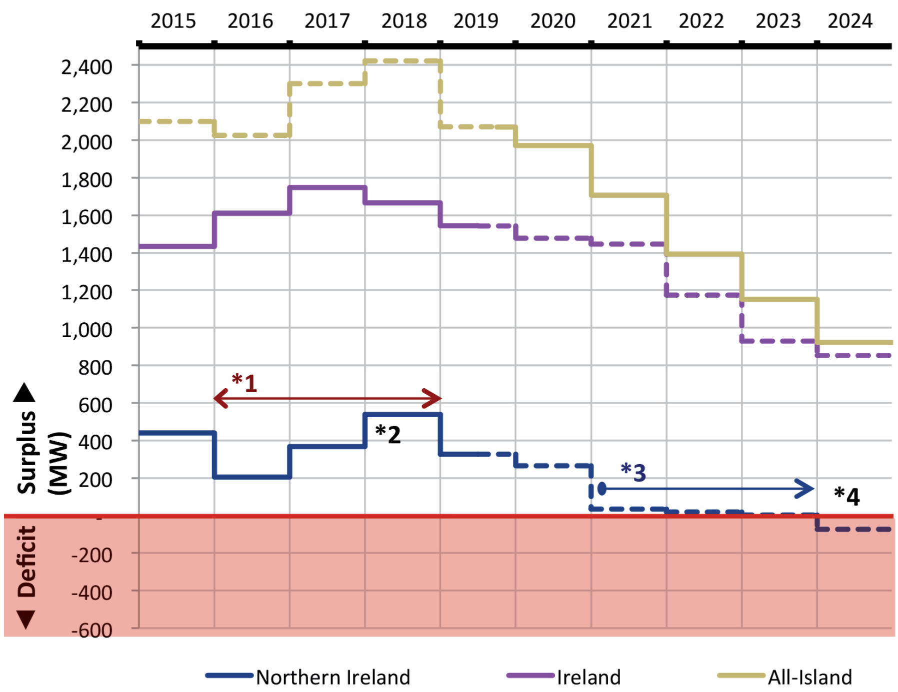

Figure 4-1 Adequacy results for the Base Case scenario, shown for Ireland, Northern Ireland and on an all-island basis.

*Note *1: Duration of local reserve services contract, 2016-2018 (inclusive)*
*Note *2: 2018 – Moyle restored to full capacity*
*Note *3: Kilroot coal units severely restricted from 2021*
*Note *4: 2024 – Kilroot coal units shut*

4.3 Scenario without Interconnection with Great Britain

Due to the recent long-term forced outages on the Moyle interconnector, and the decreased capacity margins in Great Britain, we now examine a situation where both undersea interconnectors with Great Britain (Moyle and EWIC) are unavailable.

Figure 4-2 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 a less favourable adequacy situation in Ireland, 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 3.5, 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.

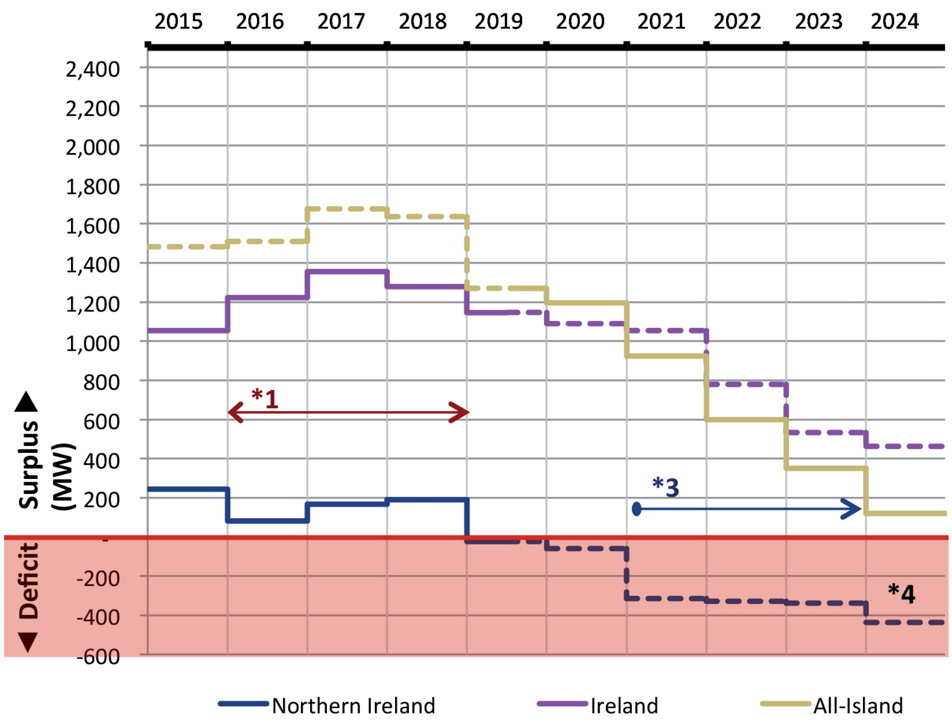

Figure 4-2 The adequacy situation without the interconnectors to Great Britain.

*Note *1: Duration of local reserve services contract, 2016-2018 (inclusive)*

*Note *3: Kilroot coal units severely restricted from 2021*

*Note *4: 2024 – Kilroot coal units shut*

4.4 Demand Scenarios

There is a level of uncertainty associated with the demand forecasts made. The economy could perform differently than expected, or there could be a severely cold winter. With this in mind, we examine the effect on generation adequacy of the higher demand scenarios transpiring.

For Ireland, the surplus is reduced by about 100 MW, as can be seen with the pink line in Figure 4-3.

For Northern Ireland, the high demand scenario reduces the adequacy by up to 60 MW towards the end of the study period.

It can be seen from the figure that this increase in demand does not have a large effect on generation adequacy. The previous sections in this chapter demonstrate how a greater influence comes from generators commissioning and decommissioning, and their overall availability.

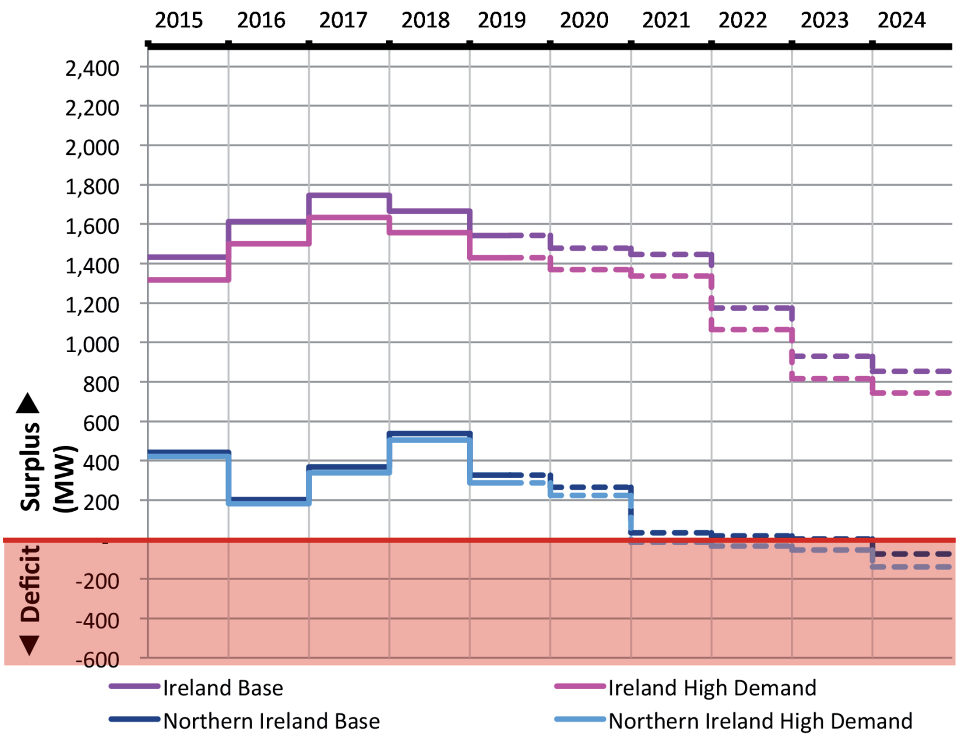

Figure 4-3 Different demand scenarios for Ireland and Northern Ireland.



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
2014	26,648	0.0%	9,011	0.0%	35,659	0.0%	4,915	1,732	6,627	4,818	1,694	6,492
2015	26,915	1.0%	9,074	0.7%	35,989	0.9%	4,929	1,734	6,643	4,831	1,694	6,505
2016	27,286	1.4%	9,146	0.8%	36,432	1.2%	4,953	1,738	6,671	4,856	1,696	6,532
2017	27,715	1.6%	9,219	0.8%	36,934	1.4%	4,978	1,744	6,702	4,881	1,700	6,561
2018	28,152	1.6%	9,293	0.8%	37,445	1.4%	4,995	1,752	6,727	4,898	1,707	6,585
2019	28,613	1.6%	9,368	0.8%	37,981	1.4%	5,016	1,762	6,758	4,919	1,716	6,614
2020	28,973	1.3%	9,443	0.8%	38,416	1.1%	5,036	1,774	6,790	4,939	1,727	6,646
2021	29,250	1.0%	9,518	0.8%	38,768	0.9%	5,056	1,787	6,823	4,959	1,739	6,678
2022	29,532	1.0%	9,594	0.8%	39,126	0.9%	5,096	1,799	6,875	4,999	1,750	6,729
2023	29,852	1.1%	9,671	0.8%	39,523	1.0%	5,143	1,811	6,934	5,045	1,762	6,788
2024	30,179	1.1%	9,748	0.8%	39,927	1.0%	5,190	1,824	6,994	5,093	1,774	6,847

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
2014	26,648	0.0%	8,934	-0.8%	35,582	-0.2%	4,915	1,727	6,621	4,818	1,688	6,486
2015	26,714	0.2%	8,892	-0.5%	35,607	0.1%	4,915	1,723	6,618	4,818	1,682	6,480
2016	26,780	0.2%	8,884	-0.1%	35,664	0.2%	4,915	1,720	6,616	4,818	1,678	6,476
2017	26,809	0.1%	8,898	0.2%	35,707	0.1%	4,916	1,720	6,616	4,819	1,676	6,474
2018	26,837	0.1%	8,917	0.2%	35,755	0.1%	4,916	1,722	6,619	4,819	1,677	6,476
2019	26,861	0.1%	8,943	0.3%	35,804	0.1%	4,917	1,726	6,622	4,819	1,679	6,479
2020	26,861	0.0%	8,975	0.4%	35,836	0.1%	4,917	1,731	6,628	4,820	1,684	6,483
2021	26,884	0.1%	9,022	0.5%	35,906	0.2%	4,917	1,736	6,632	4,820	1,688	6,488
2022	26,963	0.3%	9,069	0.5%	36,032	0.4%	4,921	1,741	6,642	4,824	1,692	6,496
2023	27,137	0.6%	9,116	0.5%	36,252	0.6%	4,943	1,746	6,668	4,845	1,697	6,522
2024	27,317	0.7%	9,164	0.5%	36,481	0.6%	4,965	1,751	6,696	4,868	1,701	6,549

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
2014	26,774	0.5%	9,096	1.0%	35,869	0.6%	5,083	1,749	6,812	4,986	1,711	6,677
2015	27,041	1.0%	9,189	1.0%	36,230	1.0%	5,097	1,757	6,834	5,000	1,716	6,696
2016	27,412	1.4%	9,294	1.1%	36,706	1.3%	5,122	1,767	6,869	5,025	1,725	6,729
2017	27,841	1.6%	9,401	1.1%	37,241	1.5%	5,146	1,780	6,906	5,049	1,735	6,765
2018	28,278	1.6%	9,509	1.2%	37,787	1.5%	5,164	1,794	6,938	5,067	1,749	6,796
2019	28,739	1.6%	9,623	1.2%	38,362	1.5%	5,184	1,812	6,976	5,087	1,766	6,833
2020	29,099	1.3%	9,728	1.1%	38,826	1.2%	5,204	1,830	7,015	5,107	1,783	6,870
2021	29,376	1.0%	9,833	1.1%	39,208	1.0%	5,225	1,848	7,053	5,127	1,801	6,908
2022	29,658	1.0%	9,939	1.1%	39,596	1.0%	5,264	1,866	7,111	5,167	1,818	6,965
2023	29,978	1.1%	10,046	1.1%	40,024	1.1%	5,311	1,885	7,176	5,214	1,836	7,030
2024	30,305	1.1%	10,155	1.1%	40,460	1.1%	5,359	1,904	7,242	5,261	1,854	7,095

Table A-3 The high scenario forecast of electricity demand.

APPENDIX 2 GENERATION PLANT INFORMATION

Year end:	ID	Fuel Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
DSU	DSU	DSU	160	160	170	180	190	200	200	200	200	200	200
Aghada	AD1	Gas	258	258	258	258	258	258	258	258	258	258	258
	AT1	Gas/DO	90	90	90	90	90	90	90	90	90	90	90
	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	404	403	402	405	404	403	402	405	404	403	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	GI1	HFO	54	0	0	0	0	0	0	0	0	0	0
	GI2	HFO	49	0	0	0	0	0	0	0	0	0	0
	GI3	HFO	109	0	0	0	0	0	0	0	0	0	0
Great Island CCGT	GI4	Gas/DO	0	431	431	431	431	431	431	431	431	431	431
Huntstown	HNC	Gas/DO	340	340	339	339	338	338	337	337	336	336	335
	HN2	Gas/DO	398	398	397	397	396	396	395	395	394	394	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	95	95
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	104	104
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	54	0	0
	TB2	HFO	54	54	54	54	54	54	54	54	54	0	0
	TB3	HFO	241	241	241	241	241	241	241	241	241	0	0
	TB4	HFO	243	243	243	243	243	243	243	243	243	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	387	386	386	386	386	386	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	AA1-4	Hydro	86	86	86	86	86	86	86	86	86	86	86
Erne	ER1-4	Hydro	65	65	65	65	65	65	65	65	65	65	65
Lee	LE1-3	Hydro	27	27	27	27	27	27	27	27	27	27	27
Liffey	LI1,2,4,5	Hydro	38	38	38	38	38	38	38	38	38	38	38
Turlough Hill	TH1-4	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*			0	0	0	62	160	160	160	160	160	160	160
Total Dispatchable:			**7270**	**7487**	**7494**	**7569**	**7674**	**7683**	**7679**	**7682**	**7679**	**7086**	**7083**
Year end:			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**

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	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Ballylumford	ST4,5 & 6	Gas* / Heavy Fuel Oil	510	510	250	250	250	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	238	238	238	238	238	238	238	238	238	238	0
	ST2	Heavy Fuel Oil* / Coal	238	238	238	238	238	238	238	238	238	238	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
Moyle Interconnector	Moyle	DC Link #	250	250	250	250	450	450	450	450	450	450	450
Contour Global (AGU)	CGC	Gas	12	12	12	18	18	18	18	18	18	18	18
Additional AGU		Distillate Oil	9	53	53	53	53	53	53	53	53	53	53
iPower AGU		Distillate Oil	74	76	76	76	76	76	76	76	76	76	76
Total Dispatchable			**2631**	**2677**	**2417**	**2423**	**2623**	**2373**	**2373**	**2373**	**2373**	**2373**	**1897**

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 be restricted to a maximum of 250 MW until 2018 due to an undersea cable fault on Pole 2.

Year end:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Large Scale On-Shore Wind	614	810	900	950	1000	1045	1100	1145	1180	1222	1260
Large Scale Biomass	0	15	30	45	45	45	45	45	45	45	45
Tidal	1	1	1	11	11	11	201	201	201	201	201
Small Scale Wind	44	60	75	86	94	100	105	111	117	123	129
Small Scale Biogas	10	13	16	18	20	22	24	26	28	30	31
Landfill Gas	13	13	14	14	15	15	16	16	16	16	16
Waste To Energy	0	15	15	15	15	15	15	15	15	15	15
Small Scale Biomass	5	9	10	11	12	13	14	15	16	17	18
Other CHP	8	8	8	8	8	8	8	8	8	8	8
Renewable CHP	3	3	3	4	4	4	4	4	4	4	4
Small Scale Hydro	4	4	4	4	4	4	4	4	4	4	4
Small Scale Solar	36	48	60	76	85	92	98	105	111	116	121
Total (MW)	**738**	**999**	**1136**	**1241**	**1312**	**1373**	**1633**	**1694**	**1744**	**1800**	**1851**

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

Year end:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
All Wind	658	870	975	1036	1094	1145	1205	1256	1297	1345	1389
All Biomass/Biogas/Landfill Gas	28	50	70	88	92	95	99	102	105	108	110
Tidal	1	1	1	11	11	11	201	201	201	201	201
Waste To Energy	0	15	15	15	15	15	15	15	15	15	15
Renewable CHP	3	3	3	3	3	3	3	3	3	3	3
Hydro	4	4	4	4	4	4	4	4	4	4	4
Solar	36	48	60	76	85	92	98	105	111	116	121
Total (MW)	**730**	**991**	**1128**	**1233**	**1304**	**1365**	**1625**	**1686**	**1736**	**1792**	**1843**

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
	Owenreagh 2	5.1		Tappaghan	19.5
	Owenreagh	5.5		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
	Snugborough	13.5		Dunbeg	42
	Carn Hill	13.8		Mantlin (Slieve Rushen 2)	54
				Total	**614**

Table A-8 Existing wind farms in Northern Ireland as of end October 2014.

Year end:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wind-Onshore	2140	2361	2684	3194	3360	3495	3575	3702	3829	3957	4084
Wind-Offshore	25	25	25	25	25	25	25	25	25	25	25
Wind-Total	2165	2386	2709	3219	3385	3520	3600	3727	3854	3982	4109
Small-scale Hydro	22	22	22	22	22	22	22	22	22	22	22
Biomass and Landfill gas	47	47	47	47	47	47	47	47	47	47	47
Biomass CHP	0	0	30	60	90	120	150	150	150	150	150
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
Total	**2390**	**2611**	**2964**	**3504**	**3700**	**3865**	**3975**	**4102**	**4229**	**4357**	**4484**

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

Year end:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
All Wind	2165	2386	2709	3219	3385	3520	3600	3727	3854	3982	4109
All Hydro	237	237	237	237	237	237	237	237	237	237	237
Biomass/LFG (including Biomass CHP)	47	47	77	107	137	167	197	197	197	197	197
Waste (assume 50% renewable)	9	9	9	40	40	40	40	40	40	40	40
Edenderry on Biomass	29	35	35	35	35	35	35	35	35	35	35
Total RES	**2486**	**2713**	**3066**	**3637**	**3833**	**3999**	**4109**	**4236**	**4363**	**4490**	**4617**

Table A-10 All Renewable Energy Sources in Ireland.

Name	MEC (MW)	Name	MEC (MW)
Athea (1)a	34.4	Derrybrien (1)	59.5
Ballywater (1)	31.5	Dromada (1)	28.5
Ballywater (2)	10.5	Garvagh-Glebe (1a)	26
Boggeragh (1)	57	Garvagh-Tullynahaw (1c)	22
Booltiagh (1)	19.5	Glanlee (1)	29.8
Booltiagh (2)	3	Golagh (1)	15
Booltiagh (3)	9	Kingsmountain (1)	23.75
Castledockrell (1)	20	Kingsmountain (2)	11.05
Castledockrell (2)	2	Lisheen (1)	36
Castledockrell (3)	3.3	Lisheen (1a)	23
Castledockrell (4)	16.1	Meentycat (1)	70.96
Clahane (1)	37.8	Meentycat (2)	14
Coomacheo (1)	41.2	Mountain Lodge (1)	24.8
Coomacheo (2)	18	Mountain Lodge (3)	5.8
Coomagearlahy (1)	42.5	Mountlucas (1)	79.2
Coomagearlahy (2)	8.5	Ratrussan (1a)	48
Coomagearlahy (3)	30	**Total**	**902**

Table A-11 Transmission connected wind farms in Ireland, as of end of October 2014.

Name	MEC (MW)	Name	MEC (MW)	Name	MEC (MW)
Altagowlan (1)	7.65	Currabwee (1)	4.62	Loughderryduff (1)	7.65
Anarget (1)	1.98	Curraghgraigue (1)	2.55	Lurganboy (1)	4.99
Anarget (2)	0.02	Curraghgraigue (2)	2.44	Mace Upper (1)	2.55
Anarget (3)	0.5	DePuy	2.5	Meenachullalan (1)	11.9
Arklow Bank (1)	25.2	Donaghmede Fr Collins Park	0.25	Meenadreen (1)	3.4
Ballaman (1)	3.6	Dromdeeveen (1)	10.5	Meenanilta (1)	2.55
Ballincollig Hill (1)	15	Dromdeeveen (2)	16.5	Meenanilta (2)	2.45
Ballinlough (1)	2.55	Drumlough Hill (1)	4.8	Meenanilta (3)	3.4
Ballinveny (1)	2.55	Drumlough Hill (2)	9.99	Meenkeeragh (1)	4.2
Ballycadden (1)	11.5	Dundalk IT (1)	0.5	Meenkeeragh (2)	0.4
Ballycadden (1)	14.45	Dunmore (1)	1.7	Mienvee (1)	0.66
Ballymartin (1)	6	Dunmore (2)	1.8	Mienvee (2)	0.19
Ballymartin (2)	8.28	Flughland (1)	9.2	Milane Hill (1)	5.94
Ballynancoran (1)	4	Garracummer (1)	36.9	Moanmore (1)	12.6
Bawnmore (1)	24	Garranereagh (1)	8.75	Moneenatieve (1)	3.96
Beale (2)	2.55	Gartnaneane (1)	10.5	Moneenatieve (2)	0.29
Beale Hill (1)	1.6	Gartnaneane (2)	4.5	Mount Eagle (1)	5.1
Beallough (1)	1.7	Geevagh (1)	4.95	Mount Eagle (2)	1.7
Beam Hill (1)	14	Gibbet Hill (1)	14.8	Mountain Lodge (2)	3
Beenageeha (1)	3.96	Glackmore Hill (1)	0.6	Muingnaminnane (1)	15.3
Bellacorick (1)	6.45	Glackmore Hill (2)	0.3	Mullananalt (1)	7.5
Black Banks (1)	3.4	Glackmore Hill (3)	1.4	Owenstown (1)	0.018
Black Banks (2)	6.8	Glanta Commons (1)	19.55	Raheen Barr (1)	18.7
Burtonport Harbour (1)	0.66	Glanta Commons (2)	8.4	Raheen Barr (2)	8.5
Caherdowney (1)	10	Glenough (1)	33	Rahora (1)	4.25
Cark (1)	15	Gneeves (1)	9.35	Rathcahill (1)	12.5
Carnsore (1)	11.9	Gortahile (1)	21	Reenascreena (1)	4.5
Carrane Hill (1)	3.4	Greenoge (1)	4.99	Richfield (1)	20.25
Carrig (1)	2.55	Grouse Lodge (1)	15	Richfield (2)	6.75
Carrigcannon (1)	20	Holyford (1)	9	Seltanaveeny (1)	4.6
Carrons (1)	4.99	Inverin (Knock South) (1)	2.64	Shannagh (1)	2.55
Carrowleagh (1)	34.15	Inverin (Knock South) (2)	0.69	Skehanagh (1)	4.25
Clydaghroe (1)	4.99	Kealkil (Curraglass) (1)	8.5	Skrine (1)	4.6
Coomatallin (1)	5.95	Killybegs (1)	2.55	Slievereagh (1)	3
Coreen (1)	3	Kilronan (1)	5	Slievereagh (1)	3
Corkermore (1)	9.99	Kilvinane (1)	4.5	Sonnagh Old (1)	7.65
Corrie Mountain (1)	4.8	Knockaneden (1)	9	Sorne Hill (1)	31.5
Country Crest (1)	0.5	Knockastanna (1)	7.5	Sorne Hill (2)	7.4
Crocane (1)	1.7	Knockawarriga (1)	22.5	Spion Kop (1)	1.2
Crockahenny (1)	5	Knocknagoum (1)	42.55	Taurbeg (1)	26
Cronalaght (1)	4.98	Knocknagoum (1d)	1.8	Templederry (1)	3.9
Cronelea (1)	4.99	Knocknalour (1)	5	Tournafulla (1)	7.5
Cronelea (2)	4.5	Knocknalour (2)	3.95	Tournafulla (2)	17.2
Cronelea Upper (1)	2.55	Lackan (1)	6	Tullynamoyle (1)	9
Cronelea Upper (2)	1.7	Lahanaght Hill (1)	4.25	Tursillagh (1)	15
Cuillalea (1)	3.4	Largan Hill (1)	5.94	Tursillagh (2)	6.8
Cuillalea (2)	1.59	Lenanavea (2)	4.65	WEDcross (1)	4.5
Culliagh (1)	11.88	Lios na Carraige (1)	0.017	Wind Energy Project (Janssen)	2
				TOTAL	**1086**

Table A-12 Distribution connected wind farms in Ireland, as of end of October 2014.

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-15 Probability table.

ALTERNATIVE TREATMENT OF WIND IN ADEQUACY STUDIES: LOAD MODIFICATION

An alternative approach to modelling wind was also examined, because there are some concerns that the Wind Capacity Credit (WCC) methodology might not be appropriate with more and more wind coming on the system.

Instead of ascribing a WCC to an amount of future wind capacity in an adequacy study, this alternative approach lowers every half hour of the load forecast for a future year by a wind profile built from a past year wind shape. This wind profile was 'grown' proportionally from a past year wind shape to represent a future year with the appropriate wind capacity installed.

The choice of this past year is crucial.

From an analysis of the results of many adequacy studies with different past wind year shapes, a 'representative wind year' was chosen, i.e. a year who's wind shape is typical, that affected the generation adequacy study in the most 'average' way.

This 'Load Modification' approach can then be used with the representative year, on future generation adequacy studies. When this was carried out, the results differed only slightly from those with the WCC approach. These two methods will be further investigated and compared in the future.

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[50]. 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.

50 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:**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Surplus / Deficit (MW)	Northern Ireland	441	204	367	538	326	265	34	18	3	-73
	Ireland	1433	1611	1746	1666	1543	1477	1446	1174	929	853
	All-Island	2099	2025	2301	2422	2071	1972	1707	1394	1151	922

Table A-16 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:**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Surplus / Deficit (MW)	Northern Ireland	243	80	167	190	-24	-60	-315	-329	-338	-437
	Ireland	1054	1223	1356	1279	1147	1089	1054	779	533	463
	All-Island	1482	1509	1676	1636	1270	1195	923	598	350	119

Table A-17 Results for the Base Case, ***without the two interconnectors to Britain****.*

	Year:	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Northern Ireland	**Median Demand**	441	204	367	538	326	265	34	18	3	-73
	High Demand	422	182	339	503	287	224	-14	-33	-53	-139
Ireland	**Median Demand**	1433	1611	1746	1666	1543	1477	1446	1174	929	853
	One-in-10 year Demand	1317	1501	1632	1557	1430	1369	1337	1064	816	743

Table A-18 Comparison of ***different Demand scenarios.***

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