Electricity Security of Supply Report 2018

Executive Summary

Legislation

The Commission for Regulation of Utilities (CRU) is required to produce and submit a report to the European Commission every two years on the details of its monitoring arrangements with respect to security of supply of electricity. The legal requirement to complete this report is contained in Statutory Instrument 60 of 2005 (SI 60). SI 60 (2005) transposed Directive 2003/54/EC and Directive 2005/89/EC into Irish law. In addition, under Directive 2009/72/EC the CRU is obliged to monitor security of supply as per Article 4 of that Directive. The purpose of this report is to present the findings and outcomes arising from the monitoring required under Section 11 of SI 60 of 2005, and Article 4 of Directive 2009/72/EC.

Background

The monitoring of security of electricity supply is a key legal obligation and priority for the CRU. In order to examine the security of supply position in the short, medium and long term, the CRU has formal monitoring and reporting arrangements in place with ESB Networks and EirGrid as the Irish System Operators (SO). In addition to the SOs, there are a number of other stakeholders involved in the security of supply framework including the European Commission and the Department of Communications, Climate Action and Environment along with market participants and customers.

Generation

The generation portfolio in Ireland is still heavily reliant on fossil fuels. In 2017, 64.8% of electricity generation came from fossil fuels, of which 52.2% was natural gas, 12.1% was coal and 0.5% was oil. However, renewable sources of energy are playing an increasingly important part in the generation portfolio with a particular emphasis on wind generation. In 2015 renewables contributed 27.3% of electricity needs with 22.8% coming from wind powered generation. In 2017 renewable generation rose to 29.6% with 24.8% of this figure arising from wind, 2.3% from hydro and 2.45% from other renewables.

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1 This report is published every two years, by 31st July and forwarded to the European Commission. In 2018, the report is published later due to the energy market has been undergoing a substantial change.

2 The Electricity Security of Supply Report is also published on the CRU website.
Demand

A key driver for electricity demand in Ireland for the next number of years is the connection of large data centres. Due to the expected growth in demand from large energy users, the electricity demand in Ireland could grow by up to 57% in the next 10 years. EirGrid analysis shows that demand from data centres could account for 31% of all demand by 2027. In Ireland, there is presently over 400 MVA of demand capacity that is contracted to data centres.

Electricity Generated from Natural Gas and Wind as a Percentage of Total Electricity Generation. Data Source: SEAI Fuel Mix Provisional

The Median Demand Scenario. Data Source: GCS 2018 – 2027

Adequacy

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
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<td>1470</td>
<td>1260</td>
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<td>Median Demand</td>
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<td>1360</td>
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<td>40</td>
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<td>Low availability, Median Demand</td>
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<td>1030</td>
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<td>-270</td>
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<td>Low Carbon, Median Demand</td>
<td></td>
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The forecast generation adequacy levels under the different scenarios. Data Source: GCS 2018 – 2027

In the median scenario, Ireland starts in a position of significant generation surplus in 2018. However, it is assumed that will cease some generation plant because of emissions restrictions. Without the second North South Interconnector in the median scenario, the Ireland system falls into a deficit by 2026 growing to a deficit of 50MW by 2027.

System Operation and System Operators Initiatives & Incentives

The technical rules governing the operation, maintenance, and development of the transmission and distribution system, and procedures governing the actions of transmission system users, are set out in the Grid Code and Distribution Code. The Grid Code and Distribution Code will be impacted by the implementation of the European Network Codes. As all the Codes have already entered into force, ESB Networks and EirGrid along with the CRU have commenced an engagement process for their implementation.

The SOs are also required to report annually on their performance against agreed targets. A number of performance incentives regarding network delivery and revenue incentives also are also implemented to promote supply security. In 2018, the CRU has reviewed the existing incentives and reporting regime and introduced improvements to the current incentives and reporting regime.

The improved reporting regime will provide the customer with better value for money and will improve quality of services provided to the customer.

Capital Expenditure

The successful rollout of an upgraded electricity network is a key requirement in achieving the ambitious targets for renewable generation and maintaining a secure system.

In Electricity Price Review 3 (2011-2015), the CRU approved €1.45 billion for transmission capital investment for that five year period. In Electricity Price Review 4 (2016-2020), the CRU approved €984 million for transmission capital expenditure for this five year period.

In January 2017, EirGrid published their second major review the Ireland’s grid development strategy, entitled Your Grid, Your Tomorrow. In drafting this, EirGrid took account of public

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4 EirGrid has prepared a range of scenarios to forecast electricity demand and supply balance in the GCS 2018 - 2027. The CRU used the median scenario in the Security of Supply Report 2018 as to be consistent with the previous Electricity Security of Supply Reports.
feedback which was accrued over an extensive consultation period beginning in March 2015
and also from consultations on proposed transmission projects. They also considered the
Government’s Energy White Paper. The forecasted costs are now in the range €2.6bn-
€2.9bn. A range is used as the final cost will vary depending on the circumstances and
technologies of each project.

**Maintenance**

The maintenance of the transmission and distribution system is undertaken by the SOs in
accordance with SO’s maintenance policy. The SOs keep their maintenance policy under
review to ensure that it continues to meet the requirements of the systems and best
international practice. Maintenance of the transmission and distribution systems ensures that
the systems can operate in a safe, secure and reliable manner.

**I-SEM**

To meet the requirements of the European Third Package of energy legislation, the SEM
Committee committed to redesign the SEM market through a project referred to as the
Integrated Single Electricity Market project. The revised I-SEM arrangements aim to
increase the efficiency of the wholesale trading arrangements and increase the operational
reliability of the system through more efficient cross border flows across the interconnectors
with Great Britain, and through closer to real time trading. Balance responsibility and the
introduction of within-day cross border trading are key features of the new I-SEM energy
market design. The I-SEM Project went live on 1st October 2018.

**ECP-1**

The CRU’s connection policy is currently undergoing a substantial reform which aims to
provide fair and non-discriminatory access to the electricity network for all technologies and
on an enduring basis. This reform was prompted by an unprecedented increase in the
volume of connection applications (36,000MW) going significantly beyond what is currently
required by the system (approx. 7,000MW). The CRU considered that its prevailing
connection policy was no longer fit for purpose to manage the surge in connection
applications. In March 2018, the CRU issued a decision on the first stage of the Enduring
Connection Policy (ECP-1).\(^5\)

**DS3 Programme**

One of the objectives of the DS3 programme is to enhance the capability of the system to
allow the TSO to safely operate the system at 75% System Non-Synchronous Penetration
(SNSP) up from the limit of 50% applied in 2014.

A 75% SNSP limit means that at any given time wind generation can contribute 75% of total
electricity generation. This will allow the system to make the best use of wind generation when

it is available, lowering curtailment levels and increasing the average share of renewable
generation to meet the 40% target. EirGrid have trialled and successfully implemented a
number of trials moving the SNSP limit from 50% to 60% during 2015-2017. Following a five
month trial period, EirGrid Group changed the operational policy in April 2018 to allow SNSP
to reach up to 65%.

**Secondary Fuel Obligations for Electricity Generators**

Since 2009 conventional gas-fired electricity generators are required to be capable of
operating on secondary fuel for five days in the event of a gas supply disruption. In 2015, the
CRU issued a consultation paper to examine whether the current five-day fuel stock regulatory
obligations are sufficient in light of recent changes in the gas and electricity sectors. The
DCCAE is liaising with GNI and EirGrid to develop a document to examine the long-term
resilience of the system. Due to the scale of changes, such as DS3 System Services and I-
SEM, the TSOs had a consultation regarding other system charges. In the consultation the
TSOs are proposing to introduce a secondary fuel availability incentive.

**Interconnection and Regional Transmission Development**

Interconnection will continue to play an important role in future security of supply in Ireland.
Along with the Moyle Interconnector that connects the transmission systems of Northern
Ireland and Great Britain, the East-West Interconnector connects the transmission systems of
Ireland and Great Britain, the proposed North-South interconnector connecting Northern
Ireland and Ireland will lead to a more secure, stable, and efficient all-island system.

In respect of other electricity interconnection, in December 2017, the CRU received an
application from Greenlink to determine if it is in the public interest that this interconnector be
considered part of the transmission system for the purposes of calculating and imposing
charges for the use of the transmission system. On 18th October 2018, the CRU published a
determination on the Greenlink electricity interconnector application. In this determination the
CRU assessed the “public interest” stage by conducting its own CBA and comparing the
results to those provided by the Greenlink project promotors. As part of the next stage,
following by sufficiently detailed financial and technical submissions from the Greenlink
developers the CRU expects to consult on a Cap and Floor regime in H1 2019.

In September 2018, EirGrid submitted an Investment Request as per Article 12 of the TEN-E
Regulation including a request for Cross Border Cost Allocation (CBCA). The CRU will assess
this investment request accordingly in cooperation with CRE (the French energy regulator).

In September 2018, the CRU published a decision on the Assessment Criteria for Electricity
Interconnection Applications.

**Conclusion**

The CRU is confident that the current monitoring arrangements are sufficient to identify

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6 Full details can be found on page 70
credible threats to the security of supply of electricity. The CRU is also satisfied that the market framework in place and the new ancillary services and I-SEM arrangements, including a new capacity mechanism, are appropriate to encourage new investment and enhance security of supply. However, given the vital importance of Ireland’s security of supply the CRU will continue to assess the appropriateness of the current framework both at national and EU level and identify where any improvements can be made.
Table of Contents

Table of Contents .................................................................................................................. 7

1. Introduction .......................................................................................................................... 12
   1.1 Commission for Regulation of Utilities ........................................................................... 12
   1.2 Background ....................................................................................................................... 12
   1.3 Purpose of this Paper ......................................................................................................... 12
   1.4 Legal Background ............................................................................................................ 12
   1.4.1 Directive 2005/89/EC ............................................................................................... 12
   1.4.2 Directive 2009/72/EC ............................................................................................... 13
   1.5 Related Documents ......................................................................................................... 13
   1.6 Structure of this Paper ..................................................................................................... 13

2. Security of Supply Framework ............................................................................................. 15
   2.1 Key Stakeholders .............................................................................................................. 15
       2.1.1 The European Commission .................................................................................... 15
       2.1.2 Department of Communications, Climate Action and Environment (DCCAE) .......... 16
       2.1.3 EirGrid .................................................................................................................... 17
       2.1.4 ESB Networks ........................................................................................................ 17
       2.1.5 Market Participants and Customers ....................................................................... 17
   2.2 Security of Supply Monitoring ......................................................................................... 17
   2.3 Security of Supply Initiatives .......................................................................................... 18
       2.3.1 Gas Electricity Emergency Planning Group (GEEP) .............................................. 19
       2.3.2 Construction and Connection ................................................................................. 20

3. Balance Between Supply and Demand ............................................................................... 21
   3.1 Generation Capacity Statement ....................................................................................... 22
   3.2 Fuel Diversity .................................................................................................................. 22
       3.2.1 Ireland’s Gas System and Supply ............................................................................ 23
       3.2.2 Categories of Plant .................................................................................................. 25
           3.2.2.1 Dispatchable Plant .......................................................................................... 25
       3.2.3 Partially Dispatchable and Non-Dispatchable Plant ............................................. 27
       3.2.4 Importance of Plant Availability ......................................................................... 29
   3.2.5 Generation Reporting ................................................................................................ 30
   3.3 Demand .......................................................................................................................... 31
       3.3.1 Peak Demand Forecast ......................................................................................... 33
   3.4 Supply and Demand Balance .......................................................................................... 35
       3.4.1 Demand Side Initiatives ......................................................................................... 35
       3.4.2 Smart Meters .......................................................................................................... 36
4. Longer Term Security of Electricity Supplies ........................................... 39

4.1 Government and EU Energy Policy ......................................................... 39
4.1.1 2015 White Paper on Energy ................................................................. 40
4.1.3 REFIT- Financial Support for long term security ..................................... 41
4.1.3.1 DCCAE’s Options Paper ................................................................. 42
4.1.3.2 DCCAE Proposed Decision Paper ...................................................... 43
4.1.3.3 DCCAE Decision Paper ................................................................. 44
4.1.3.4 Ex-ante PSO Calculations for a relevant PSO year ................................ 44
4.1.3.5 Ex-Post PSO Calculations for a relevant PSO year ................................ 46
4.1.4 The Industrial Emissions Directive ....................................................... 47
4.2 High Level Market Framework ................................................................ 47
4.2.1 The SEM and the Capacity Payment Mechanism .................................... 48
4.2.2 The SEM and the Capacity Remuneration Mechanism .............................. 49
4.3 Connection policy (ECP -1) ........................................................................ 51
4.3.1 Connection Policy Preceding the ECP Reform ....................................... 52
4.3.2 The CRU’s Review Process and Key Reforms to Date ............................. 53
4.3.3 Generator Connections Liaison Group .................................................... 54
4.4 Planned Investment and Maintenance ...................................................... 54
4.4.1 Connections Overview ............................................................................ 54
4.4.2 Conventional Generation ........................................................................ 55
4.4.3 Renewable Generation .......................................................................... 55
4.4.4 Wind Generation .................................................................................... 56
4.4.5 Other Renewable Generation ............................................................... 56
4.4.6 Energy Storage ...................................................................................... 57
4.4.7 Maintenance Works completed ............................................................. 57

5. Networks Investment .................................................................................. 58

5.1 Network Description ................................................................................ 58
5.2 Regulatory Framework ............................................................................. 59
5.2.1 Revenue Regulation ............................................................................. 59
5.2.2 Capital Expenditure ................................................................................ 59

6. Operational Network Security .................................................................... 61

6.1 System Operation ..................................................................................... 61
6.1.1 Operational Framework and Rules ......................................................... 61
6.1.2 Performance Reporting and Incentives ................................................. 63
6.1.3 Generator Availability ........................................................................... 64
6.1.4 Generator Forced Outage Rates ............................................................. 65
6.1.5 Generator Scheduled Outage Rate ......................................................... 65
6.2 DS3 Programme ......................................................................................... 66
6.3 Secondary Fuel Capability Obligations .................................................... 68
7. Interconnection and Regional Transmission Development ......................... 71

7.1 Celtic Interconnector (PCI 1.6) ................................................................. 73
7.2 Greenlink Interconnector (PCI 1.9) ......................................................... 73
7.3 North South Interconnector (PCI 2.13.1) ............................................... 74
7.4 North West Project Interconnector (PCI 2.13.1) ..................................... 74
7.5 Existing Interconnectors/Tie-lines ......................................................... 74
  7.5.1 North-South Tie-line ......................................................................... 74
7.5.2 Moyle Interconnector ......................................................................... 74
7.5.3 East West Interconnector (EWIC) ...................................................... 75
7.5.4 Regional Interconnection Projects ..................................................... 76
# Glossary of Terms and Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation or Term</th>
<th>Definition or Meaning</th>
</tr>
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<tbody>
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<td>Commission for Regulation of Utilities</td>
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<td>SONI</td>
<td>System Operator Northern Ireland</td>
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<td>SI</td>
<td>Statutory Instrument</td>
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<tr>
<td>DSO</td>
<td>Distribution System Operator</td>
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<td>TSO</td>
<td>Transmission System Operator</td>
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<td>SO</td>
<td>System Operator</td>
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<td>DCCAE</td>
<td>Department of Communications, Climate Action and the Environment</td>
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<td>ESB</td>
<td>Electricity Supply Board</td>
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<td>TAO</td>
<td>Transmission Asset Owner</td>
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<td>DAO</td>
<td>Distribution Asset Owner</td>
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<td>SNSP</td>
<td>System Non-Synchronous Penetration</td>
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<td>SEAI</td>
<td>Sustainable Energy Authority of Ireland</td>
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<td>RES-E</td>
<td>Renewable Energy Sources for Electricity</td>
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<td>Gas Electricity Emergency Planning Group</td>
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<td>CPM</td>
<td>Capacity Payment Mechanism</td>
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<td>Project of Common Interest</td>
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<td>Demand Side Unit</td>
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<td>Distribution Code Review Panel</td>
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<td>Reseau de Transport D'Electricite</td>
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<td>East-West Interconnector</td>
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<td>National Renewable Energy Action Plan</td>
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<td>International Energy Agency</td>
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<td>Intra Day Market</td>
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<td>Best New Entrant</td>
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1. Introduction

1.1 Commission for Regulation of Utilities

The Commission for Regulation of Utilities (CRU) is Ireland’s independent energy and water regulator. The CRU’s mission is to regulate water, energy and energy safety in the public interest. Further information on the CRU’s role and relevant legislation can be found in [here](http://www.irishstatutebook.ie/2005/en/si/0060.html).

1.2 Background

The CRU is required to produce and submit a report to the European Commission every two years on the details of its monitoring arrangements with respect to security of supply of electricity. This is the seventh such report. The legal requirement to complete this report is contained in Statutory Instrument 60 of 2005 (SI 60). SI 60 (2005) (transposed Directive 2003/54/EC and Directive 2005/89/EC) into Irish law. In addition, under Directive 2009/72/EC the CRU is obliged to monitor security of supply as per Article 4 of that Directive.

1.3 Purpose of this Paper

The purpose of this report is to present the findings and outcomes arising from the monitoring required under Section 11 of SI 60 of 2005, and Article 4 of Directive 2009/72/EC.

1.4 Legal Background

1.4.1 Directive 2005/89/EC

Directive 2005/89/EC establishes measures aimed to further safeguard security of supply and to ensure the proper functioning of the internal market for electricity. This directive contains the following requirements:

- Article 7 (2) (reporting) refers to this report which is to be submitted to the European Commission. It details the reporting requirements regarding:
  - Operational network security;
  - The projected balance of supply and demand for the next five-year period;
  - The prospects for security of electricity supply for the period between five and 15 years from the date of the report; and,
(d) The investment intentions, for the next five or more calendar years, of transmission system operators and those of any other party of which they are aware, as regards the provision of cross-border interconnection capacity. 

- In relation to part (d) of Article 7, the arrangements need to take account of:
  a) Existing and planned transmission lines;
  b) Expected patterns of generation, supply, cross-border exchanges and consumption, allowing for demand management measures; and,
  c) Regional, national and European sustainable development objectives, including those projects forming part of the Axes for priority projects set out in Annex I to Decision 1229/2003/EC.

- Article 7(2) states that this report should be prepared in close cooperation with the TSO and that, if appropriate, the TSO should consult with neighbouring TSOs.

1.4.2 Directive 2009/72/EC

Article 4 of Directive 2009/72/EC states that Member States shall ensure the monitoring of security of supply issues. Such monitoring shall, in particular, cover the balance of supply and demand on the national market, the level of expected future demand and envisaged additional capacity being planned or under construction, and the quality and level of maintenance of the networks. This report is published every two years, by 31st July and forwarded to the European Commission.

1.5 Related Documents

- S.I. No. 60/2005 - European Communities (Internal Market in Electricity) Regulations 2005

1.6 Structure of this Paper

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

- **Executive Summary** gives an overview of the main highlights of the report.
- **Glossary of Terms and Abbreviations** explains some technical terms used in the document.

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10 It should be noted that the principles of congestion management for Article 7(d) were contained in Regulation 1228/2003/EC which has since been repealed
11 In the case of Ireland the Member State has delegated this task to CRU as the Regulatory Authority.
• **Section 1**, provides an introduction to the CRU and provides background information to this report.

• **Section 2**, sets out the high-level security of supply reporting framework employed by the CRU. It also sets out some security of supply initiatives currently in place.

• **Section 3**, takes a forward-looking view at the prospects for electricity supply and demand balances. The section also contains details of the peak demand reduction initiatives both in place and planned, and developments on the smart metering trials and roll out.

• **Section 4**, examines the prospects for future investment in generation in Ireland. Part of the section details the overall framework for new connections. The section also examines current investment plans and the market mechanisms that are in place to incentivise the required generation in the future including the new Integrated-Single Electricity Market arrangements and the revised capacity mechanism implemented in 2017 and 2018.

• **Section 5**, contains an overview of Ireland’s transmission system. The section also contains information on the transmission system investment program planned over the next number of years.

• **Section 6**, examines the operational security of the network and details the incentives and requirements placed on the TSO in operating the system. In particular reference will be made to the technical programmes put in place by EirGrid as TSO to facilitate non synchronous wind capacity (Delivering a Secure Sustainable Electricity System).

• **Section 7**, contains a description of current interconnector development plans in Ireland and further potential interconnection in addition to the existing East West and Moyle Interconnectors will positively impact on Ireland’s supply security.
2. Security of Supply Framework

Key Messages

1. The CRU has a security of supply monitoring framework in place to satisfy obligations in Directive 2009/72/EC and Directive 2005/89/EC.

2. There are a number of key stakeholders involved in security of supply in Ireland including the CRU, European Commission, DCCAE, TSO and DSO.

3. The CRU is of the view that the monitoring arrangements currently in place are comprehensive and are adequate to assist the CRU in protecting Ireland’s security of supply.

4. Since the submission of the last Security of Supply report there has been a slight some diversification of fuel sources in Ireland. The Corrib Gas Field came on line on 31st December 2015. After Corrib became operational, indigenous gas production met over 55% of Ireland’s gas needs. This contributes positively to supply security.

Security of electricity supplies is of paramount importance in building and sustaining the long term economic health of the country. For this reason the ongoing monitoring of security of supply is of great importance. Given this importance it is critical that a joined up approach is taken by all involved parties right through from the law makers, to market players and to customers.

As stated previously, the CRU’s security of supply monitoring obligations were established in Directive 2003/54/EC (which was replaced by Directive 2009/72/EC) which was transposed into Irish law through SI 60 of 2005. In addition, Directive 2005/89/EC placed further obligations and reporting requirements on the CRU.

In response to the legislative requirements a security of supply monitoring framework has been established. The framework sets out the items that are reported on and the frequency of reporting. The framework is useful for interested parties in understanding what level of reporting is available and what information can be accessed. The purpose of this section is to set out and explain the monitoring framework at a high level.

2.1 Key Stakeholders

2.1.1 The European Commission

The European Commission has been working with the Member States to create an internal electricity market in Europe. It states that a key objective for the successful operation of the
internal market is “the guarantee of a high level of security of electricity supply”. Securing European energy supplies is therefore high on the EU’s agenda. One of the key roles of the European Commission in security of supply is the pan-European legislation it develops to foster market integration across the European Union.

As part of the further integration of a single European electricity market the European Commission has published in November 2010 a communication titled “Energy 2020: A Strategy for competitive, sustainable and secure energy”. This document outlines the approach to be taken EU-wide to reach renewable targets of 20% and a 20% improvement in energy efficiency. In particular it makes reference to the continuing development of secure and competitive sources of energy to come from low carbon sources.

Additionally, the European Commission has produced a further communication, in December 2011 titled “Energy Roadmap 2050” which outlines the longer term goals of reaching a “secure, competitive and decarbonised” energy system by 2050. The EU is committed to reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050 in the context of necessary reductions by developed countries as a group. A key requirement for future energy is the focus on energy efficiency and switching to renewable energy sources.

In November 2012 the European Commission set up an electricity coordination group. The Electricity Coordination Group’s tasks are:

- To serve as a platform for the exchange of information and coordination of electricity policy measures having a cross-border impact and for the exchange of experiences, best practices and expertise and also to assist the Commission in designing its policy initiatives;
- To facilitate the exchange of information and cooperation regarding security of supply in electricity, including generation adequacy and cross-border grid stability.

The CRU notes the publication of the EU Commission’s Clean Energy Package, and its provisions relating to security of electricity supply and generation adequacy and is providing input and feedback as to its implications for security of supply through appropriate national and European channels.

2.1.2 Department of Communications, Climate Action and Environment (DCCAE)

The Department of Communications, Climate Action and Environment (DCCAE) has an overarching policy formation role, as prescribed in the Electricity Regulation Act 1999 (the Act), in relation to promoting the continuity, security and quality of supplies of electricity. Furthermore, certain specific actions, which may be taken by the CRU with respect to

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12 Introduction to Directive 2005/89/EC.
measures to protect the security of supply, require the consent of the Minister of that Department.

In 2015, the Department published a White Paper on Ireland’s Transition to a Low Carbon Energy Future. The White Paper set out a framework to guide policy up to the year 2030. Its objective is to guide a transition to a low carbon energy system which provides secure supplies of competitive and affordable energy to citizens and businesses.\(^\text{16}\)

### 2.1.3 EirGrid

EirGrid holds licences as independent electricity Transmission System Operator (TSO) and Market Operator (MO) in the wholesale trading system in Ireland, and is the owner of the System Operator Northern Ireland (SONI), the licensed TSO and market operator in Northern Ireland. The TSO, under section 28(4) of SI No 60 of 2005, has a specific duty to report and advise the CRU if it is of the view that security of supply is threatened or likely to be threatened. In the preparation of this report the CRU has consulted in depth with EirGrid and has relied on them for all operational information.

### 2.1.4 ESB Networks

Electricity Supply Board (ESB) was established in 1927 as a statutory corporation in the Republic of Ireland under the Electricity (Supply) Act 1927. A subsidiary within ESB Group, ESB Networks is the licensed operators of the electricity distribution system in the Republic of Ireland. Also, ESB Networks holds a Transmission Asset Owner (TAO) and Distribution Asset Owner (DAO) licences granted by the CRU. ESB Networks is responsible for building, operating, maintaining and developing the electricity network and serving all electricity customers across the country. ESB Networks also plays an active role in ensuring security and continuity of supplies to customers.

### 2.1.5 Market Participants and Customers

Collectively market participants are key in ensuring security of electricity supplies in Ireland. Participants provide the required generation to meet demand. Also, many of the required demand side measures and ancillary services offered by customers are facilitated and incentivised by market participants.

### 2.2 Security of Supply Monitoring

The CRU has security of supply monitoring and reporting arrangements with the System Operators (SO). Figure 2-1 below sets out CRU monitoring activities.

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\(^{16}\) 2015 White Paper - Ireland’s Transition to a Low Carbon Energy Future
The primary outputs of the above monitoring activities are a number of reports produced mainly by EirGrid but also by ESB Networks and other market participants. Many of the EirGrid’s published reports are referred to later in this report and include the Generation Capacity Statement, Winter Outlook Reports and the Transmission Forecast Statement. These reports feed into the security of supply monitoring activities of the CRU (and other stakeholders) and are available on the EirGrid website\textsuperscript{17}. In addition, the published reports are important for existing and potential market participants in assessing the viability of existing and new projects.

### 2.3 Security of Supply Initiatives

Ensuring security of electricity supply continues to form an important part of the CRU’s activities. In 2015, 43% of electricity generated in Ireland was produced from natural gas. In 2017 due to the Corrib Gas Field and increased electricity demand this increased to 52.2%. In 2015, 27.3% of electricity generated in Ireland was produced from renewables. In 2017 due to a corresponding increase in wind generation this increased to 29.6%.\textsuperscript{18} This highlights the impact that continuing wind connections can have on the system and the ability to reduce reliance on a single fuel source.

The East-West interconnector (EWIC) connects the transmission systems of Ireland and Wales with a capacity of 500MW in either direction. Along with the existing Moyle Interconnector that connects the transmission systems of Northern Ireland and Great Britain, this has significantly enhanced the overall interconnection between the island of Ireland and Great Britain. The proposed second major North-South interconnector connecting Northern

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\textsuperscript{17} EirGrid – Library

\textsuperscript{18} SEAI Electricity Generated % by Fuel Mix Provisional
Ireland and Ireland will lead to a more secure, stable, and efficient all-island system. The North-South Interconnector is expected to be available in 2023.\textsuperscript{19} Other interconnector projects are also being studied both by EirGrid and by merchant developers, some such projects have been designated PCI status. In March 2018, the CRU published an Information Paper on electricity interconnectors. The purpose of this paper was to inform the public and all relevant stakeholders that the CRU has received an application from a Project Promoter in relation to a proposed electricity interconnector with Project of Common Interest (PCI) status.\textsuperscript{20} In September 2018, the CRU published a decision on the Assessment Criteria for Electricity Interconnection Applications.\textsuperscript{21} In October 2018, the CRU published a determination on the Greenlink electricity interconnector application.\textsuperscript{22} In this determination CRU assessed the "public interest" stage by conducting its own CBA and comparing the results to those provided by the Greenlink project promoters.

Another area as outlined in DCCAE’s White Paper is the impact of different types of storage on the electricity grid. DCCAE and the Northern Ireland Department of Trade and Investment commissioned work to model the impact on the electricity grid of different types of storage. These included very short-term storage in intelligent storage heaters in domestic premises, intermediate-level storage in battery and ice banks, and very large-scale compressed air storage in salt caverns. The work demonstrated that significant levels of storage, in particular multi-megawatt-scale grid-connected storage, would be needed to maximise the utilisation of renewable energy sources for electricity (RES-E). Small-scale storage would facilitate more efficient use of the networks, maintain high standards of security of supply, and keep network operating costs lower than they would be without storage.\textsuperscript{23}

With reference to secondary fuel obligations, since 2009 conventional gas-fired electricity generators are required to be capable of operating on secondary fuel for five days in the event of a gas supply disruption. Due to the scale of changes, such as DS3 System Services and I-SEM, the TSOs are proposing to introduce a secondary fuel availability incentive. Moreover, the DCCAE is liaising with GNI and EirGrid to develop a document to examine the long-term resilience of the system. The CRU will continue to closely monitor secondary fuel requirements for conventional gas-fired electricity generators.

### 2.3.1 Gas Electricity Emergency Planning Group (GEEP)

The CRU chairs a group called the Gas and Electricity Emergency Planning group (GEEP), which comprises representatives from DCCAE, the CRU, ESB Networks, EirGrid and Gas Networks Ireland. The purpose of the GEEP group is to focus on short-term issues relating to security of supply and emergencies in electricity and gas, and provide a medium for interaction between the gas and electricity sectors. The GEEP also encompass some longer term and wider energy/emergency policy issues, which may emerge and be of relevance to the gas and electricity sectors. The purpose of the GEEP is to:

\begin{itemize}
\item Planning permission for this interconnector has been granted in both Ireland and Northern Ireland.
\item CRU18056
\item CRU18221
\item CRU18216
\item 2015 White Paper - Ireland’s Transition to a Low Carbon Energy Future
\end{itemize}
• Act as a focal point for those working in emergency planning and response management in the gas or electricity sectors, by informing GEEP members of relevant developments, and co-ordinating work to ensure preparedness for a robust response to emergencies in the gas or electricity sector;

• Foster an understanding of the gas and electricity sectors and the impact that an emergency or potential emergency in either sector can have on the other;

• Ensure that existing emergency procedures in the electricity and gas sectors are risk based, robust and are adapted to the changing energy environment, and ensure individual plans interface appropriately ensuring a co-ordinated response in an emergency;

• Ensure the Gas Emergency Planning Group (GEPG) meets annually to discuss forthcoming emergency exercises and exercises already conducted;

• Review annual emergency exercises conducted by the gas and electricity TSOs to ensure the adequacy and consistency of gas and electricity emergency procedures;

• Facilitate the integration of new European emergency planning requirements into existing emergency regimes for gas and electricity;

• Examine the interdependencies of the gas and electricity systems, and between electricity and gas and other sectors such as oil, telecoms etc.;

• Provide a forum for the development of robust and clear communication processes during an emergency, and ensure the operation of secure communication in the event of major emergency by examining communications protocols for emergencies;

• Examine the impacts of a major gas and/or electricity emergency in Ireland and advise on the procedures and protocols to be put in place to mitigate and manage such an event under the Major Emergency Management Framework;

• Examine requirements for strategic energy resources to mitigate the effects of a major gas and electricity emergency. Requirements will be identified through risk assessment with risk levels subject to continual revision to take account of changes in strategic asset infrastructure.

2.3.2 Construction and Connection

As part of its security of supply monitoring the CRU receives quarterly updates on the progress of new plant construction and the large scale refurbishment of older large plant. Other than supported generation such as wind and biomass there are no large-scale generation units that are committed to connect.\textsuperscript{24}

\textsuperscript{24} EirGrid GCS 2018-2027
3. Balance Between Supply and Demand

Key Messages

1. In 2017, 29.6% of electricity generated in Ireland was produced from renewables. This contributes positively both to EU renewable targets and to supply security.

2. In the last two years, over 60% of Ireland’s gas demand was supplied from indigenous sources, with the Inch and Corrib Entry Points providing 6% and 54% respectively.

3. Due to the expected growth in demand from large energy users, the electricity demand in Ireland could grow by up to 57% in the next 10 years.

4. The CRU approved the phased approach proposal from the DSO on the rollout of smart meters. Smart meters could cause a 2.5% reduction in overall electricity demand and a peak-time demand reduction of 8.8%.

The requirements in Directive 2005/89/EC build upon Directive 2003/54/EC (which was replaced by Directive 2009/72/EC) and require Member States to take appropriate measures to maintain a balance between the demand for electricity and the availability of generation capacity. More specifically, the Directive 2005/89/EC requires Member States to encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption and to require transmission system operators to ensure that an appropriate level of generation reserve capacity is available and/or to adopt equivalent market based measures.

In order to provide a framework for new generation investment, the CRU and the Northern Ireland Authority for Utility Regulation developed a Single Electricity Market (SEM) which went live on 1st November 2007. This is a gross mandatory pool market with an explicit Capacity Payment Mechanism (CPM). The SEM and CPM are being replaced by a revised market design and new capacity mechanism that will integrate the island of Ireland into the EU’s Internal Energy Market and provide sharper and more efficient entry and exit signals so as to enhance long term supply security. The wholesale market arrangements are discussed further in Section 4.2.
3.1 Generation Capacity Statement

The Generation Capacity Statement\textsuperscript{25} (GCS) covers the years 2018-2027 for both Northern Ireland and Ireland, and is produced jointly between SONI\textsuperscript{26} and EirGrid\textsuperscript{27}. This report informs market participants, regulatory agencies and policy makers of the likely generation capacity required to achieve an adequate supply and demand balance for electricity for the period up to 2027.

The GCS 2018-2027 forecasts the demand for electricity in a forward ten-year period, the likely production capacity that will be in place to meet this demand and assesses the consequences in terms of the overall supply and demand balance. The GCS 2018-2027 supersedes the joint EirGrid and SONI GCS 2017-2026, published in April 2017.

The outputs from the GCS 2018-2027 are the main inputs to this report. Several findings from the GCS 2018-2027 are presented in this report.\textsuperscript{28}

3.2 Fuel Diversity

At the outset it is useful to set out the fuel mix of electricity generated. The most recent fuel mix refers to 2017 and are set out in Figure 3-1 below.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{fuel_mix_2017.png}
\caption{Ireland Fuel Mix 2017. Data Source: SEAI Fuel Mix Provisional}
\end{figure}

\textsuperscript{25} This statement outlines the expected electricity demand and the level of generation capacity available on the island over the next ten years.

\textsuperscript{26} SONI, the TSO in Northern Ireland, is required to produce an annual GCS, in accordance with Condition 35 of the Licence to participate in the Transmission of Electricity granted to SONI Ltd by the Department for the Economy.

\textsuperscript{27} EirGrid is required to publish forecast information about the power system, as set out in Section 36 of the Electricity Regulation Act 1999 and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations.

\textsuperscript{28} It should be noted that since 2012 EirGrid and SONI include an assessment of generation adequacy on an Ireland, Northern Ireland and All-Island basis in the GCS.
The generation portfolio in Ireland is still heavily reliant on fossil fuels. It should be noted however, that renewable sources of energy are playing an increasingly important part in the generation portfolio with a particular emphasis on wind generation. In 2015 renewables contributed 27.3% of electricity needs with 22.8% coming from wind powered generation. In 2017 renewable generation rose to 29.6% with 24.8% of this figure arising from wind, 2.3% from hydro and 2.45% from other renewables. The increase in electricity produced by wind powered generators has resulted in a corresponding reduction in electricity generation from coal.

![Electricity Generated from Natural Gas and Wind as a Percentage of Total Electricity Generation](image)

In 2017, 64.8% of electricity generation came from fossil fuels, of which 52.2% was natural gas, 12.1% was coal and 0.5% was oil. 7.2% of electricity was generated using peat. This compares with 61.3% of electricity generated in 2015 from fossil fuels of which 43.0% was gas, 16.9% coal and 1.4% oil. This highlights a decrease in dependence on coal and oil. The increase in power sector gas demands despite growth in wind capacity can be attributed to increasing electricity demand and in particular increasing electricity exports to Great Britain (GB).

### 3.2.1 Ireland’s Gas System and Supply

The electricity generation sector is heavily reliant on gas fired generators, therefore it is prudent to consider the gas supply when considering electricity supply. In terms of obtaining gas supplies, the Irish gas system (see figure 3.3 below) conveys gas from three entry points, namely:

- Moffat (Western Scotland);
- Inch (Southern Ireland); and
- Bellanaboy (Western Ireland).

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29 The Corrib Gas Field came on line on 31st December 2015, as the first indigenous source of natural gas since 1976.
The Corrib Gas Field came on line on 31st December 2015, as the first indigenous source of natural gas since 1976. This has led to dramatic change in Ireland supply position and on gas interconnector flows. In 2016, over 60% of Ireland’s gas demand was supplied from indigenous sources, with the Inch and Corrib Entry Points providing 6% and 54% respectively. The balance of supply of approximately 40% came through the subsea interconnectors via the Moffat Entry Point.

The majority of gas demand in Ireland can be attributed to power generation consumption, which averaged 57% of annual Ireland gas demand in 2015 and 2016. The industrial and commercial sectors make up, on average, 29% of annual gas demand. The residential sector accounts for approximately 14% of annual gas demand.

Ireland’s gas demands for 2016 and 2017 are anticipated to be 4.9% above 2015 and 2016 demands. In the power generation sector, annual gas demand for 2016 and 2017 is
anticipated to be 7.1% above 2015 and 2016 levels. The increase in power sector gas demands can be attributed to increasing electricity demand and in particular increasing electricity exports to GB.\textsuperscript{31}

### 3.2.2 Categories of Plant

When the TSO examines the plant available for planning and operational purposes, there is a distinction between certain categories of plant. There are three categories of plant: dispatchable, partially dispatchable and non-dispatchable.

Dispatchable plant is generation capacity that can be monitored and controlled by EirGrid. This would typically include thermal plants such as gas fired Combined Cycle Gas Turbines (CCGT) and coal stations.

Larger wind farms (above 5MW) can also be monitored and are considered partially-dispatchable i.e. their output can be reduced if required (e.g. due to transmission constraints).

In addition to dispatchable plant, there is generation connected to the system whose output is not currently monitored by EirGrid and whose operation cannot be controlled. This non-dispatchable plant includes small wind farms, small scale hydro and industrial backup generation etc.

#### 3.2.2.1 Dispatchable Plant

The generation portfolio is likely to change in Ireland due to the Capacity Market in the new Integrated-Single Electricity Market (I-SEM)\textsuperscript{32}. This is because only plant that are successful in the capacity auctions for the relevant years will receive capacity payments and therefore be liable for Reliability Options. Plant that does not receive capacity payments may seek to exit the market. A total of 7.2GW of capacity cleared in Ireland in the first capacity auction held in December 2017. The amount of unsuccessful plant was 0.7GW in Ireland.

In the GCS 2018-2027 EirGrid carried out a review of the plant that cleared the first T-1 Capacity Market auction, unsuccessful in the Capacity Market auction plant, Demand Side Units (DSU) and interconnectors over the next 10 years. Table 3-1 below sets out the dispatchable plant on the system in 2018 as per the GCS 2018-2027. Table 3-1 also notes any plant that has provided notification for commissioning or retirement.

<table>
<thead>
<tr>
<th>ID</th>
<th>Fuel Type</th>
<th>2018</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>All DSU</td>
<td>DSU</td>
<td>512</td>
<td>512MW was successful in the auction</td>
</tr>
<tr>
<td>Aghada</td>
<td>AD1</td>
<td>258</td>
<td>Unsuccessful in the Capacity Market auction</td>
</tr>
<tr>
<td></td>
<td>AT1</td>
<td>90</td>
<td>To be shut before end of 2023</td>
</tr>
<tr>
<td></td>
<td>AT2</td>
<td>90</td>
<td></td>
</tr>
<tr>
<td></td>
<td>AT4</td>
<td>90</td>
<td></td>
</tr>
</tbody>
</table>

\textsuperscript{31} This is as a result of the Carbon price floor introduced in GB which was raised to £18 per ton CO2 in April 2015.

\textsuperscript{32} The I-SEM went live on 1\textsuperscript{st} October 2018.
<table>
<thead>
<tr>
<th>Location</th>
<th>Plant Type</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dublin Bay</td>
<td>Gas/DO</td>
<td>431</td>
</tr>
<tr>
<td>Dublin Waste</td>
<td>Waste</td>
<td>61</td>
</tr>
<tr>
<td>Edenderry</td>
<td>Milled peat/biomass</td>
<td>118</td>
</tr>
<tr>
<td>Edenderry OCGT</td>
<td>DO</td>
<td>58</td>
</tr>
<tr>
<td>Great Island CCGT</td>
<td>Gas/DO</td>
<td>431</td>
</tr>
<tr>
<td>Huntstown</td>
<td>Gas/DO</td>
<td>342</td>
</tr>
<tr>
<td>Indaver Waste</td>
<td>Waste</td>
<td>17</td>
</tr>
<tr>
<td>Lough Ree</td>
<td>Peat</td>
<td>91</td>
</tr>
<tr>
<td>Marina CC</td>
<td>Gas/DO</td>
<td>85</td>
</tr>
<tr>
<td>Moneypoint</td>
<td>Coal/HFO</td>
<td>285</td>
</tr>
<tr>
<td>Moneypoint</td>
<td>Coal/HFO</td>
<td>285</td>
</tr>
<tr>
<td>Moneypoint</td>
<td>Coal/HFO</td>
<td>285</td>
</tr>
<tr>
<td>North Wall CT</td>
<td>Gas/DO</td>
<td>104</td>
</tr>
<tr>
<td>Poolbeg CC</td>
<td>Gas/DO</td>
<td>230</td>
</tr>
<tr>
<td>Poolbeg CC</td>
<td>Gas/DO</td>
<td>230</td>
</tr>
<tr>
<td>Rhode</td>
<td>DO</td>
<td>52</td>
</tr>
<tr>
<td>Rhode</td>
<td>DO</td>
<td>52</td>
</tr>
<tr>
<td>Sealrock</td>
<td>Gas/DO</td>
<td>81</td>
</tr>
<tr>
<td>Sealrock</td>
<td>Gas/DO</td>
<td>81</td>
</tr>
<tr>
<td>Tarbert</td>
<td>HFO</td>
<td>54</td>
</tr>
<tr>
<td>Tarbert</td>
<td>HFO</td>
<td>54</td>
</tr>
<tr>
<td>Tarbert</td>
<td>HFO</td>
<td>241</td>
</tr>
<tr>
<td>Tarbert</td>
<td>HFO</td>
<td>241</td>
</tr>
<tr>
<td>Tawnaghmore</td>
<td>DO</td>
<td>52</td>
</tr>
<tr>
<td>Tawnaghmore</td>
<td>DO</td>
<td>52</td>
</tr>
<tr>
<td>Tynagh</td>
<td>Gas/DO</td>
<td>400</td>
</tr>
<tr>
<td>West Offaly</td>
<td>Peat</td>
<td>137</td>
</tr>
<tr>
<td>Whitegate</td>
<td>Gas/DO</td>
<td>444</td>
</tr>
<tr>
<td>Ardnacrusha</td>
<td>Hydro</td>
<td>86</td>
</tr>
<tr>
<td>Erne</td>
<td>Hydro</td>
<td>65</td>
</tr>
<tr>
<td>Lee</td>
<td>Hydro</td>
<td>27</td>
</tr>
<tr>
<td>Liffey</td>
<td>Hydro</td>
<td>38</td>
</tr>
<tr>
<td>Turlough Hill</td>
<td>Pumped storage</td>
<td>292</td>
</tr>
<tr>
<td>EWIC</td>
<td>DC interconnector</td>
<td>500</td>
</tr>
</tbody>
</table>

| Total Dispatchable plant successful in the auction | 7,913 |

*Table 3-1: Registered Capacity of dispatchable generation and interconnectors in Ireland in 2018. Data Source: GCS 2018 – 2027*
Figure 3-4 below pulls the previous information together and sets out EirGrid’s expected trend in the levels of dispatchable plant, DSU and interconnectors out to 2027. Some generators have indicated decommissioning dates in the latter half of the decade, reducing the total capacity by approximately 1,100MW.

### 3.2.3 Partially Dispatchable and Non-Dispatchable Plant

As part of the GCS 2018-2027, EirGrid also carries out substantial analysis and forecasting of future levels of both partially and non-dispatchable plant. The technologies examined by EirGrid include:

- Industrial Generation;
- Small scale Combined Heat and Power (CHP);
- Solar PV;
- Small Scale Hydro;
- Biomass/LFG;
- Wind.

Wind farms represent the highest percentage of plant in both partially and non-dispatchable plant category and substantial analysis is being carried out on future levels of wind and also the input this generation can be given when planning for the future. In assessing the potential benefits of renewables EirGrid’s assessment takes into consideration the assumption that to achieve a 40% renewable target whilst maintaining system and supply security would require an installed capacity of between 4,000MW and 4,300MW.
The portion of wind energy in particular has increased dramatically in Ireland over the past decade from 1.6% in 2002 to 24.8% in 2017. Installed capacity of wind generation has increased from 145MW at the end of 2002 to over 3,000MW in 2018. This value is set to increase over the next few years as Ireland endeavours to meet its renewable target in 2020.\(^\text{33}\) In addition to wind there is other small but significant changes in the generation portfolio. These are:

- Industrial Generation;
- Small Scale CHP;
- Solar PV;
- Small Scale Hydro;
- Biomass/LFG.

Industrial generation refers to generation, usually powered by diesel engines, located on industrial or commercial premises, which acts as on-site supply during peak demand and emergency periods. The condition and mode of operation of this plant is uncertain, as some of these units would fall outside the control of the TSOs. Industrial generation contributes a total of 9MW.

CHP utilises generation plant to simultaneously create both electricity and useful heat. Due to the high overall efficiency of CHP plant, often in excess of 80%, its operation provides benefits in terms of reducing fossil fuel consumption and CO2 emissions.\(^\text{34}\) There are approximately 158MW of CHP units in Ireland currently, mostly gas-fired. This does not include the 161MW centrally dispatched CHP plant operated by Aughnish Alumina.

In Ireland, the future of government support in the solar PV sector is unclear. However, approximately 4,300MW of solar applications have been submitted through the non-GPA process.\(^\text{35}\)

It is estimated that there is currently 22MW of small-scale hydro capacity installed in rivers and streams across Ireland. Such plant generates approximately 43GWh per year, making up 0.2% of total annual generation.

There are a number of different types of biofuel-powered generation plant on Ireland. In Ireland, there is 24MW of generation capacity powered by biofuel, biogas or landfill gas. The peat plant at Edenderry, Lough Ree and West Offaly will be approximately 30%-35% powered by biomass by 2020.

\(^\text{33}\) The EU guidelines for our 2020 RES target, we normalise the annual energy from wind power. This is done by applying an average of the past 5 year’s capacity factor. This normalised annual energy has grown from 16% of total electricity demand in 2012 to 25% in 2017.

\(^\text{34}\) REFIT 3 provides an incentive for biomass-fuelled CHP plant. This will likely result in up to 100MW of plant, including Dublin Waste Energy. These plant will make a significant contribution to the 40% renewable target in 2020.

\(^\text{35}\) The non-GPA process was established in 2009 (CER/09/099, non-GPA decision) to enable smaller renewable and low carbon generators as well as experimental technologies to connect to the system outside the gate process.
An Coimisiún um Rialáil Fóntas Commission for Regulation of Utilities

<table>
<thead>
<tr>
<th>Year</th>
<th>Capacity 2018 (MW)</th>
<th>Capacity 2027 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial Generation</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>CHP</td>
<td>139</td>
<td>189</td>
</tr>
<tr>
<td>Biomass/LFG</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td>Hydro</td>
<td>22</td>
<td>22</td>
</tr>
<tr>
<td>Solar PV</td>
<td>10</td>
<td>300</td>
</tr>
<tr>
<td>Wind</td>
<td>3,500</td>
<td>5,510</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,704</strong></td>
<td><strong>6,054</strong></td>
</tr>
</tbody>
</table>

*Table 3-2: Assessment of Partially and Non-Dispatchable Plant in Ireland*. Data Source: GCS 2018 – 2027

As outlined in table 3-2 the total capacity from these renewable sources contributes 3,704MW to supply in 2018 with the vast majority (3,500MW) arising from wind capacity. By 2027 the total arising from renewable sources is expected to rise to 6,054MW. An installed wind capacity requirement of between 4,000MW and 4,300MW is expected to be sufficient to meet the 40% renewable targets.37

### 3.2.4 Importance of Plant Availability

Having sufficient capacity on the system is very important but it is equally important that the installed capacity represents a reliable supply of generation when required. For this reason, the availability of generation plant is very important. In general each power station goes on an annual planned outage for required maintenance. This is coordinated and planned with the TSO so that not all plant is unavailable at the same time and that there is sufficient plant available to meet demand. For example, if all baseload power plants went on annual outage in June there may not be enough remaining capacity left to satisfy demand or the remaining plant may be much more expensive to run causing price spikes (the TSO publishes an annual schedule of power station planned outages which is updated monthly throughout the year38).

In addition to planned outages there are unexpected or forced outages that occur throughout the year. These are where part or all the output of a power station is unavailable for generation due to an unforeseen problem. There may be many reasons for such outages. The TSO monitors the overall levels of these forced outages. The TSO also communicates with generators about forced outages to understand the underlying causes. A series of Generator Performance Incentives (GPI’s) are in place to optimise generator performance and ensure a balanced All-Island generation market. Late Synchronisation by generators for example will incur a penalty. GPI’s such as this incentivise generators to perform to best

36 Some CHP, Biomass and LFG units have registered as Demand Side units in the Capacity Market, and are therefore included in the previous Table 3-1 and not in this table from 2018 (to avoid double-counting).
37 EirGrid GCS 2018-2027
38 [http://www.eirgridgroup.com/customer-and-industry/general-customer-information/outage-information/generation-outages/]
capability at all times thus ensuring supply security. Figure 3-4 below shows the historic and forecast outage rates in Ireland.

There are five different technology classes in the Capacity Market, and a system-wide class, see table 3-3.

<table>
<thead>
<tr>
<th>Technology Category</th>
<th>Mean Forced Outage Rate (%)</th>
<th>Mean Scheduled Outage Duration (weeks)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSU</td>
<td>4.8%</td>
<td>4</td>
</tr>
<tr>
<td>Gas Turbine</td>
<td>3.0%</td>
<td>3</td>
</tr>
<tr>
<td>Hydro</td>
<td>3.8%</td>
<td>8</td>
</tr>
<tr>
<td>Steam Turbine</td>
<td>6.9%</td>
<td>3</td>
</tr>
<tr>
<td>Storage</td>
<td>8.8%</td>
<td>3</td>
</tr>
<tr>
<td>System Wide</td>
<td>4.8%</td>
<td>4</td>
</tr>
</tbody>
</table>

*Table 3-3: Availability parameters that were used in the T-1 Capacity Market auction in December 2017. Data Source: GCS 2018 – 2027*

Table 3-4 below is the total of dispatchable, partially dispatchable and non-dispatchable generation for 2018.

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>Total Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatchable</td>
<td>7,913</td>
</tr>
<tr>
<td>Partially dispatchable (wind)</td>
<td>3,500</td>
</tr>
<tr>
<td>Non-dispatchable</td>
<td>204</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>11,617</strong></td>
</tr>
</tbody>
</table>

*Table 3-4: Total Dispatchable, Partially and Non-Dispatchable Capacity. Data Source: GCS 2018 – 2027*

### 3.2.5 Generation Reporting

The Generator Financial Performance in the SEM report prepared for the CRU and the Utility Regulatory in Northern Ireland, together the Regulatory Authorities (RAs) examines the financial performance of generation companies in the Single Electricity Market (SEM). The report provides aggregated information on the financial performance of generators in the SEM as a whole and broken down by generation fuel source and generation type. The report aims to enhance transparency around generator remuneration in the SEM while respecting individual generator commercial sensitivity by presenting aggregated information only. The Generator Financial Performance in the SEM report (SEM/16/086) focused on the period of the 2014 and 2015 financial years, and follows the previous 2013 (SEM/13/031) and 2014 (SEM/14/111) reports published by the SEM Committee. The most recent report (Generator Financial Performance in the SEM published on SEMC website on 20th December 2016) provides an update to the 2014 report by analysing two additional years of data, namely the 2014 and 2015 financial years. The main objectives of the report are to:
• Provide greater insight into the financial performance of generators in the SEM, which will inform policy decisions; and
• Improve the level of market data available to all industry stakeholders, which will assist in providing market transparency.

In order to gather the information to develop this report generators with a combined installed generation capacity equal to or greater than 25MW are required to complete the financial reporting template. This agreed template provides the RAs with sufficient data on all generation types and, with only a portion of wind generation companies required to report, excludes smaller generators from any reporting requirements. The information provided should align with the regulated accounts provided to the RAs, and a completed financial reporting template for each generation site must be delivered to the RAs within six months of the end of their financial year.

3.3 Demand

In developing the annual GCS, EirGrid carries out detailed analysis on future electricity demand forecasts using their electricity forecast model. The model is explained in detail in the GCS 2018-2027 and predicts electricity demand based on changes in Gross National Product (GNP)\(^{39}\) and Personal Consumption of Goods and Services (PCGS)\(^{40}\). EirGrid also factor in the effects of energy efficiency measures\(^{41}\), extreme weather events and the amount of self-consumption\(^{42}\).

A key driver for electricity demand in Ireland for the next number of years is the connection of large data centres. EirGrid analysis shows that demand from data centres could account for 31% of all demand by 2027\(^{43}\). In Ireland, there is presently over 400 MVA of demand capacity that is contracted to data centres. In addition, there are connection offers in place or in the connection process for 1400MVA. Furthermore, there are 370MVA of additional data centre connection enquiries.

In order to capture the impact of data centres and other large energy users, the TSO has based the different demand forecast scenarios for Ireland on different build-out scenarios. The Median demand is now higher than for last year’s forecast for high demand, indicating the progression of many of the data centre projects (see Figure 3-5 below).

\(^{39}\) Gross National Product is the total value of goods and services produced in a country, discounting the net amount of incomes sent to or received from abroad. It is modified for the effect of re-domiciled companies, i.e. foreign companies which hold substantial investments overseas but have established a legal presence in Ireland.

\(^{40}\) Personal Consumption of Goods and Services measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.

\(^{41}\) The demand forecast incorporates some reduction due to energy efficiency measures, in line with Ireland’s National Energy Efficiency Action Plan. This includes the effect of the installation of smart meters, which could reduce peak demand from domestic users.

\(^{42}\) Energy that is created and used on-site, without being transmitted to the grid or metered.

\(^{43}\) In EirGrid’s median demand scenario.
The GCS 2018-2027 was prepared on the expectation that GNP would increase by 4% average per year in the period 2017 - 2020 and increase by 3.5% average in the period 2021 - 2027. The median scenario electricity demand is influenced by this economic growth forecast, and by the expected addition of data centre load. The TSO estimates that 31% of total demand will come from data centres by 2027 (see Figure 3-6).

Figure 3-6: The Median Demand Scenario. Data Source: GCS 2018 – 2027

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44 EirGrid GCS 2018-2027
EirGrid qualify demand assessments by utilising a high, median and low demand scenario (see Figure 3-7). The median forecast is the most probable scenario to utilise for demand forecasting. A median forecast model assumes a return to growth over the next number of years.

**Figure 3-7: Historic Demand & Low, Median & High Demand forecasts. Data Source: GCS 2018 – 2027**

EirGrid carried out an analysis of electricity requirements in 2018 for the years up to and including 2027. In all scenarios total electricity requirements are expected to increase. In a low demand scenario, an increase of 2.0% is expected in 2018, 0.4% in 2019 and 3.0% in 2020. In a median demand scenario, a rate of 2.2% is expected in 2018 with 3.8% in 2019 and 5.3% in 2020. Finally, a high demand scenario, a rate of 0.6% would be expected for 2018 with this increasing to 6.1% in 2019 and 8.6% 2020.

### 3.3.1 Peak Demand Forecast

The EirGrid peak demand model is based on the historical relationship between the annual electricity consumption and the winter peak. The relationship between average and peak consumption is often referred to as the Annual Load Factor (ALF)\(^45\). In general large energy users with round the clock operations will have a high load factor as their demand is quite constant. A domestic customer on the other hand generally has an ALF factor where they use large amounts of electricity for short periods of time, typically between 17:00 and 19:00 and have small loads during the night. In general electricity is most expensive to generate at peak times as more expensive less efficient plants need to be called upon.

Historically, EirGrid has found that the winter peak is somewhat erratic and difficult to model as it is subject to many disparate influences. Figure 3-8 below shows the results of EirGrid peak demand forecasting as per the GCS 2018-2027.

\(^{45}\) The average load divided by the peak load.
Temperature has a significant effect on electricity demand, particularly on the Peak demand. By modelling historical energy and temperature data, it is possible to apply a temperature correction to past winter peaks. Average Cold Spell (ACS) correction has the effect of ‘smoothing out’ the demand curve so that economic factors are the predominant remaining influences, see Figure 3-9.

Figure 3-9: Past values of recorded maximum demand in Ireland, and the ACS temperature-corrected values. Data Source: GCS 2018 – 2027

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A peak demand of 5,090MW was reached on 21st December 2010 due to inclement weather.
### 3.4 Supply and Demand Balance

This section compares the forecast levels of generation capacity with the forecast demand that needs to be satisfied out to 2027.

EirGrid uses a software program for forecasting surplus available capacity or deficit. This software takes the outage rates for generators into account and also considers the system security of supply standard into account which is set using a loss of load expectation. A detailed description of the adequacy assessment methodology used by EirGrid is set out in their GCS 2018-2027. Table 3-5 below sets out the forecast generation adequacy levels under the different EirGrid scenarios.

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

*Table 3-5: The forecast generation adequacy levels under the different scenarios. Data Source: GCS 2018 – 2027*

For the purposes of the EirGrid's adequacy assessments, EirGrid has included all capacity unless generators have notified EirGrid that they will be not available. The results for Ireland shows that in the median scenario, Ireland starts in a position of significant generation surplus in 2018. Thereafter, some generation plant is assumed to shut down because of emissions restrictions. This would result in deficit of capacity in 2026.

With a low availability scenario (worst in 5 years), there would be a much larger deficit of plant by 2024. If high-carbon plant were unavailable from 2026, e.g. Moneypoint coal units, they would need to be replaced.

#### 3.4.1 Demand Side Initiatives

Article 5 of Directive 2005/89/EC allows Members States to take measures to encourage real-time demand initiatives. Demand side initiatives are generally used to reduce peak electricity demand. Under certain conditions it may be more cost effective to pay for a reduction in demand at peak times rather than starting a potentially inefficient high cost plant.

EirGrid is supporting the integration of more intermittent generation sources with initiatives that encourage flexibility such as ‘Delivering a Secure Sustainable Electricity System’ (DS3). The DS3 programme is discussed further in Section 6.2.

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47 EirGrid has been using a convolution probabilistic methodology for assessing adequacy for many years. In the GCS 2018-2027 EirGrid also included a Monte-Carlo probabilistic method for assessing adequacy.

48 This does not mean that unsuccessful capacity will, or will not, continue to operate in the market.
A Demand Side Unit (DSU) consists of one or more individual demand sites that it can be dispatched as if it was a generator. An individual demand site is typically a medium to large industrial premises. Where a DSU consists of more than one individual demand site it is called an aggregated DSU. A DSU uses a combination of on-site generation and/or plant shutdown to deliver a demand reduction in response to an instruction from EirGrid. Instructions to reduce electricity demand are called dispatch instructions. In Ireland, 500MW of DSU capacity cleared the 2018/19 T-1 Capacity Market auction held in December 2017. This is double what had been previously available. This is double what had been previously available.

3.4.2 Smart Meters

Smart meters are recognised at an EU wide level as an integral component in ensuring continuing security and allowing consumers to become more active in their consumption patterns. As stated earlier, Article 5 of Directive 2005/89/EC allows Members States to take measures to encourage real-time demand technologies including advanced metering systems. Smart metering promotes security of supply by transforming consumers from a passive state to being active, responsive consumers. This encourages efficiency in usage on the demand side.

As set out in the previous Electricity Security of Supply Report, the CRU established the Smart Meter Upgrade project in late 2007 in conjunction with the ESB Networks and Bord Gáis Networks (now GNI) and working closely with the Department of Communications, Climate Action and Environment. In Phase 1 electricity Customer Behaviour Trials (CBT) were carried out. The CBTs looked at the measurable reduction in electricity consumption overall and more specifically during peak demand periods. The trial concluded that there was:

- An average reduction of approximately 3% in consumption;
- A peak time reduction of 8.8%.

In July 2012, the CRU made the decision to proceed with the national rollout of electricity and gas smart metering to all residential consumers and a significant proportion of small-to-medium (SME) consumers. The decision was based on the positive results of the electricity and gas smart metering trials and associated cost-benefit analysis.

The strategic objectives of the smart meter upgrade are to:

1. Encourage Energy Efficiency;
2. Facilitate Peak Load Management;
3. Support Renewable and Micro Generation;
4. Enhance Competition and Improve Consumer Experience; and
5. Improve Network Services.

49 See CER/11/080a, CER/11/080b and CER/11/080c for further detail on the CBT, technology trials and cost benefit analysis.
With the successful conclusion of the CBTs and the cost benefit analysis, the smart meter upgrade project progressed to the development of a high level design for the smart metering solution.

The High Level Design (HLD) phase concluded in October 2014 with the publication of the HLD decision papers by the CRU. The HLD is a ‘thin’ smart metering solution i.e. with minimal functionality performed on the actual meter itself. The meter will record consumption at 30 minute interval (to align with the wholesale settlement arrangements). The consumption information is then collected remotely by the DSO every 24 hours and passed on to the customer’s supplier for billing.

The HLD supports the facilitation of Time-of-Use tariffs (ToU) and a new model of smart prepayment providing consumers with more choice and flexibility. A key feature of the HLD is the establishment of a home area network (HAN) operated by the electricity DSO which securely provides near-real time information into the consumer’s premises.

Following the publication of the HLD in October 2014, an interim cost benefit analysis was conducted by the CRU which resulted in a broadly neutral result. It was on this basis, the smart meter upgrade progressed to developing detailed design of the smart metering solution in early 2015. This phase of the project focussed on developing consumer policy regarding time-of-use tariffs, smart prepayment, and provision of information to consumers. The electricity DSO and gas DSO primarily focussed on development and enhancement of the market processes to cater for smart metering during this period.

Following the conclusion of detailed design of the solution in mid-2016, the smart meter upgrade encountered a number of issues which could potentially delay the rollout of smart meters to energy customers. These issues were primarily related to technical upgrades to the market processes. At this juncture, the CRU requested that the DSO review their delivery plans for the rollout and propose a new approach which would deliver smart meters to consumers but mitigate the technical complexity associated with the rollout. In early 2017, the DSO submitted to the CRU an updated delivery plan for the rollout of smart meters to energy consumers. This plan is based on a staggered implementation of the smart metering solution and its associated functionality

- **The first phase (2019 – 2020)** will see the DSO delivering 250,000 smart meters to those consumers (or potentially communities) who request a smart meter and those meters which require replacement. Smart services such as time-of-use tariffs, smart bills, access to historical consumption information, etc. will be made available by suppliers at the end of this phase in Q4 2020. This is an important element of the new delivery plan as it brings forward many of the primary benefits associated with smart metering in particular enabling consumers to access the additional services smart metering provides. The ability for a customer to request an updated meter reflects recent proposals from the European Commission contained in the ‘Clean Energy for All Europeans’ package of legislation.

- **The second phase (2021 – 2022)** will see an additional 1 million meters rolled out and will layer in additional functionality and make available a new form of smart prepayment (Smart PAYG) in the market in Q4 2022. This new model of prepayment will provide consumers with the opportunity to pay up-front for their energy without the need for an additional meter or device in the home.
• The **third phase (2023 – 2024)** of DSO’s delivery plan will commence following the completion of a second checkpoint review at the conclusion of phase 2. Following the review, a further 1 million meters will be rolled out. Additional functionality will be made available through the activation of a Home Area Network (HAN). This will allow consumers to access real-time data on their household energy usage via a device in their home. The activation of the in-home channel will also make gas smart services available to consumers by facilitating the pairing of the electricity meter with the gas meter.

The financial analysis of this proposed phased approach showed that delivering the smart metering programme in a phased approach proves better value for the Irish energy consumer than the previous proposal; representing a €13 million improvement in Net Present Value (NPV). This is due to two main drivers; namely:

1) **Earlier Roll-Out**: The functionality (in particular the offering of ToU tariffs) is turned on at an earlier stage. This brings forward the customer and generation benefits of reduced peak and overall electricity usage.

2) **Staggered investment**: The upfront costs of IT system updates/changes are phased over a longer time scale. This reduced the gap between upfront costs and the realisation of benefits.

The CRU approved the phased approach proposal in September 2017 following extensive analysis and engagement with key industry stakeholders, including consumer interest groups and the DCCAE. The smart meter upgrade project is now being recalibrated to reflect the new timelines.
4. Longer Term Security of Electricity Supplies

Key Messages

1. The I-SEM is a new wholesale electricity market arrangement for Ireland and Northern Ireland. The new market arrangements are designed to integrate the all-island electricity market with European electricity markets, enabling the free flow of energy across borders. The I-SEM went live on 1st October 2018.

2. In March 2018, the CRU published a decision on the ECP-1. Under ECP-1, the CRU seeks to expedite the connection of projects that are well developed, and capable of energisation in relatively short timeframes. However, only projects with planning permission are eligible to apply for connection under this policy.

3. Many new wind farms were commissioned in Ireland in 2017, contributing to the increase in overall Renewable Energy Sources (RES) percentage to 28%. Other sources of RES include biomass, hydro, solar PV and renewable waste. In the coming years, many new wind farms are due to connect, which are required in order to meet our 40% RES target in 2020.

4. Energy storage units are now anticipated to enter the Irish market.

5. The CRU maintains a watching brief on the longer-term security of electricity supplies and implements measures that are designed to provide for longer term security of supply.

Article 7 of Directive 2005/89/EC requires Member States to report on the prospects for security of electricity supply out to 10 years from the report date. While it is quite difficult to forecast new generation capacity out to ten years, this section of the report sets out the policy and market framework that is currently in place in Ireland and also the current generation investment intentions.

This section looks at matters relevant to the security of electricity supplies over ten years. In addition, it is also useful to examine the prospects for longer term security of supply.

4.1 Government and EU Energy Policy

As the EU looks towards 2030 and 2050, it is timely to reflect on what has been achieved and to reorient Irish energy policy priorities towards the 2030 horizon. The following section highlights key developments in the Irish, EU and international energy markets.
4.1.1 2015 White Paper on Energy

In 2015 The Department of Communications, Climate Action and Environment published a White Paper on Energy. The White Paper set out a framework to guide policy up to the year 2030. Its objective is to guide a transition to a low carbon energy system which provides secure supplies of competitive and affordable energy to citizens and businesses. More specifically, with regard to energy security in the transition, the White paper states:

“Ireland will further develop a coordinated energy security policy, which encourages diversification of energy supplies and facilitates more integrated energy markets, through our membership of the EU and the International Energy Agency (IEA).”

Furthermore, reaching our sustainable energy targets, and having fully integrated and well-functioning markets, will enhance Ireland’s energy security. The White Paper outlines Ireland’s energy security policy and explains how risks to security of energy supply will be managed.\(^{50}\)


The Government has set a target of 40% electricity consumption from renewable sources by 2020. Since setting this target Ireland has made major strides in accelerating renewable generation. In the 2001 EU RES-E Directive 2001/77/EC, Ireland was set a target of moving from 3.6% RES-E to 13.2% RES-E by 2010. Ireland achieved 14.8% RES-E in 2010\(^{52}\). In Ireland’s third NREAP progress report, RES-E accounted for 22.7% electricity consumption in 2014\(^{53}\). According to the most recent SEAI estimates, in 2017, electricity consumption from renewable sources was approximately 29.6%\(^{54}\).

The significant growth in electricity from renewable sources in recent years is largely attributable to onshore wind. As Ireland moves towards achieving circa 40% RES-E by 2020, the Irish grid is increasingly having to cope with the challenges posed by large amounts of intermittent power. As outlined in the plan, EirGrid, is involved in a detailed examination of the issues and is pioneering several renewables facilitation studies with a view to ensuring the appropriate management of the grid and stability of the electricity system during this transition.

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\(^{50}\) White Paper - Ireland’s Transition to a Low Carbon Energy Future


\(^{52}\) DCCAE - NREAP First Progress Report 2012

\(^{53}\) DCCAE - NREAP Third Progress Report 2016

\(^{54}\) SEAI – Electricity Generation 2017 provisional
The CRU’s connection and market policies aim to facilitate increasing volumes of renewable generation in the Irish electricity system. For more details on the CRU’s connection and market policies, see sections 4.2.2 – 4.2.4 and 6.2 below.

4.1.2 2009 Renewable Energy Sources Directive - a European Perspective

In addition to domestic targets there is new over-arching renewables legislation in the form of Directive 2009/28/EC on the promotion of the use of energy from renewable sources. This Directive, which came into force on 25th June 2009, establishes a common framework for the promotion of energy from renewable sources in order to limit greenhouse gas emissions by promoting renewable energy, cleaner transport and energy efficiency. This Directive sets an EU wide target for 20% of final gross energy consumption to be made up of renewables. As part of this Ireland is required to produce 16% of final gross energy from renewable sources and to meet this there is a government target for 40% of electricity consumption to come from renewable sources.

Additionally, there has been a number of communications and Directives at European level which Ireland is obliged to follow. This includes the Energy End Use Efficiency and Energy Services Directive 2006/32/EC. This Directive specifically references the aim of creating stronger demand side incentives55. Article 13 of the Directive also references the need for competitively priced smart meters availability to accurately reflect demand side consumption. There is ongoing discussion on a revised and updated Directive to accurately reflect energy targets beyond 2020.

4.1.3 REFIT- Financial Support for long term security

The Irish Government’s current primary support mechanisms for renewable electricity are the REFIT (Renewable Energy Feed-in Tariff) schemes (i.e. REFIT 1, 2 & 3), which have been designed to incentivise the development of renewable electricity generation in order to ensure Ireland meets its goal of 40% of electricity coming from renewable sources by 2020.56

The technologies supported under REFIT 1 and 2 are small wind (< 5MW), large wind (>5MW), Hydroelectricity and Biomass/Landfill gas, while REFIT 3 supports the addition of 310MW of renewable electricity capacity to the Irish grid composed of High Efficiency Combined Heat and Power (using both Anaerobic Digestion and the thermo-chemical conversion of solid biomass), biomass combustion and biomass co-firing.

The REFIT schemes (having received EU State Aid clearance) were introduced by the Irish State in order to provide certainty to renewable electricity generators by providing them with a minimum price for each unit of electricity exported to the grid over a 15 year period.

55 Article 7, Directive 2006/32/EC
56 Further details regarding the Irish Government’s REFIT schemes are available on the DCCAE website.
REFIT monies are paid to retail suppliers of electricity who enter into Power Purchase Agreements (PPA) with generators of renewable energy sources. However, the indirect beneficiaries of the grant aid are the renewable generators.

The REFIT schemes are closed to new applicants, and have the following backstop dates:

- REFIT 1: 31st December 2027;
- REFIT 2: 31st December 2032;
- REFIT 3: 31st December 2032.

The REFIT schemes/supports are funded by the Public Service Obligation (PSO) levy which is paid for by all electricity consumers. The PSO levy is set by the CRU on an annual basis, in accordance with Irish Government policy.

### 4.1.3.1 DCCAE’s Options Paper

In May 2017, the DCCAE commenced a review of its electricity support schemes (i.e. Alternative Energy Requirement, REFIT 1-3 and PSO peat supports) for electricity generation projects in order to ensure that DCCAE’s electricity support schemes are compatible with the new wholesale electricity market design arising from I-SEM implementation.

Within DCCAE’s Options Paper, the Department outlined the primary potential revenue streams that a generator can avail of SEM (i.e. Energy Payments, Capacity Payments and Constraint Payments). Additionally, DCCAE’s Options Paper identified existing circumstances, whereby PSO payments are made to and by suppliers under the PSO, in the event that they are contracted to purchase the output from a PSO supported generation unit, via a Power Purchase Agreement (PPA).

DCCAE’s Option’s Paper subsequently outlined the various sources of potential Total Market Revenue (TMR) for a generation unit arising from I-SEM implementation (i.e. Energy Market Payments, Capacity Remuneration Mechanism, Constraint Payment and DS3 System Services Revenues).

In the context of PSO supported wind generation units, DCCAE noted the following:

- Generation units’ total energy market payments will result from trading across a number of market windows (e.g. Day Ahead Market & Intra Day Market), as opposed to single market window that currently exists under SEM;

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57 Renewable Electricity Support Scheme: Transitioning to I-SEM (Options Paper).
58 With reference to REFIT, a PSO payment is made to a supplier in that the Total Market Revenue (consisting of an Energy Payment, Constraint Payment & Capacity Payment) of its PSO contracted generation unit is less than the Total REFIT Payment received by the supplier (consists of REFIT Reference Price, Balancing Payment & Technology Payment). With reference to the AER scheme, a PSO payment is made to a supplier in that the Total Market Revenue (consisting of an Energy Payment, Constraint Payment & Capacity Payment) of its PSO contracted generation unit is less than the Tendered Price received by the supplier. Additionally, under the AER scheme, a PSO payment is made by a supplier in that the Total Market Revenue (consisting of an Energy Payment, Constraint Payment & Capacity Payment) of its PSO contracted generation unit is greater than the Tendered Price received by the supplier.
• The balance responsibility obligation on generation units may reduce revenues to wind farms;
• Capacity payments made to wind farms may be eroded as part of the I-SEM transition; and
• A wind generation unit’s TMR will be composed of only energy market payments and constraint payments, and that DCCAE is minded not to include potential DS3 System Service revenues in a wind generation unit’s TMR calculation.

In order to align DCCAE’s existing renewable electricity support schemes with the new market arrangements arising from I-SEM implementation, the Department’s Option Paper considered how the Energy Payment component of a PSO supported generation unit’s TMR be derived for REFIT purposes, and presented two options:

• Option 1 – The energy payment component comprises of revenues only; 59 and
• Option 2 – The energy payment comprises revenues and costs from energy trading. 60

Additionally, DCCAE’s Option Paper considered the most appropriate reference price for the calculation of PSO supported generation unit TMR (e.g. Balancing Market (BM) price, Day Ahead Market (DAM) price, weighted average blended approach consisting of DAM price, BM price and Intra Day Market (IDM) price) for REFIT ex-ante calculations.

4.1.3.2 DCCAE Proposed Decision Paper

In November 2017, DCCAE published a Proposed Decision Paper regarding the transitioning of its electricity support schemes to I-SEM. 61 Specifically, DCCAE’s Proposed Decision Paper contained 3 decisions, which are summarised below:

a) Proposed Decision 1:

• Wind generators above or equal to 5MW and operating in AER or REFIT 1 and 2 (the energy payment component of a PSO supported wind generation unit’s TMR will be based on the lower of a blend of 80% of the DAM price and 20% of the BM price, and the DAM price);
• De minimis wind generators (less than 5MW) and operating in AER, REFIT 1 and 2 (the energy payment component of a PSO supported wind generation unit TMR) will be based on the lower of a blend of 70% of the DAM price and 30% of the BM Price, and the DAM Price)

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59 The energy component would be the sum of the generator’s metered generation in each trading period multiplied by the reference price. This option would not account for any differences between the reference price and the price in other market timeframe that the supplier actually traded in. Additionally, the value of any net energy that the generator had to purchase in the balancing market would not be included.

60 Any costs resulting from the supplier having to engage in energy trading in the Balancing Market would be included in the calculation of the energy payment, and therefore netted off against a generation unit’s energy market revenue.

61 Electricity Support Schemes: Transitioning to I-SEM Arrangements Proposed Decision Paper
b) Proposed Decision 2:

- The energy payment component of other PSO supported generation unit’s TMR will be based solely on the DAM price. Specifically, Proposed Decision 2 applies to peat, hydro and biomass generation units, operating under either REFIT 1-3 and the Peat PSO scheme.

c) Proposed Decision 3:

- For all PSO supported generation, capacity market costs will not be included in the calculation of a generator unit’s TMR for PSO levy calculation purposes.

In terms of implementing its proposed decisions, DCCAE noted that the CRU would likely require data from the relevant suppliers as well as from the Market Operator on the DAM and BM price for each trading period of the relevant PSO year. Additionally, DCCAE noted that it is expected that the CRU would use an estimate of the DAM and BM prices as additionally appropriate, derived from modelled forecasts, to set the ex-ante PSO calculation, the precise calculations and data input necessary for the determination of the TMR will be set out accordingly by the CRU.

4.1.3.3 DCCAE Decision Paper

The CRU’s current methodology for calculating the annual PSO levy is set out in the following decision papers:

- CER/08/15362: Arrangements for the Public Service Obligation Levy; and
- CER/08/23663: Calculation of the R-factor in determining the Public Service Obligation Levy.

These decision papers (i.e. CER/08/153 and CER/08/236) contain the ex-ante and ex-post methodologies that are applied by the CRU in order to determine the PSO levy. The details of the CRU’s ex-ante and ex-post methodologies for determining the PSO levy are summarised in the sections below.

4.1.3.4 Ex-ante PSO Calculations for a relevant PSO year

Decision paper (CER/08/153) sets out, inter-alia, the methodology that is used by the CRU in determining the ex-ante Benchmark Price for REFIT schemes in the context of the PSO levy. The primary purpose of the CRU’s ex-ante Benchmark Price is to facilitate the CRU in determining supplier’s additional costs incurred when contracting with a PSO supported generation unit (i.e. the Benchmark Price is used in the calculation of the opportunity cost stream of compensation for suppliers contracted under REFIT).

The decision paper (CER/08/153) states that “the ex-ante Benchmark Price will be an estimated time-weighted average SMP64, which will be a forecast of the relevant 12 month

62 CER/08/153
63 CER/08/236
64 As per CER/08/153, the time weighted average SMP has the same interpretation as that of a simple average SMP.
PSO period, with a capacity adder". For clarity, the Benchmark Price (derived using PLEXOS modelling software) is the CRU’s forecast of an “all-in” average annual market price (energy + capacity in €/MWh), which is expected to accrue to a generation unit supported under the PSO.

The REFIT supported generator unit’s Total Market Revenue/Total Revenue is therefore calculated through the CRU’s multiplication of the Benchmark Price by the generation unit’s forecasted electricity production, which is provided within the supplier’s PSO submission to the CRU.

The REFIT supported generator units’ forecasted Total Market Revenue/Total Revenue (for the relevant PSO year) is subsequently subtracted from the Total REFIT Payment/Total Allowable Cost accruing to the PSO contracted supply company. The Total REFIT Payment/Total Allowable Cost is calculated by the supplier (submitted to the CRU through the supplier’s annual PSO submission) consists of the following ring-fenced payments:

1. **Reference Price**: is an opportunity cost payment to cover any extra cost of contracting with REFIT generators (based on their metered generation, where the generator is not constrained down) relative to what the energy could have been bought/sold from/to the pool. As per CER/08/236, the methodology for calculating the REFIT opportunity cost payment is dependent on whether a REFIT generator is “In-Market” (i.e. bidding into SEM) or “Out-of-Market” (i.e. not bidding into SEM).
   - In Market Opportunity Cost Payment (i.e. energy sold to suppliers under REFIT and traded in SEM): The opportunity cost payment is calculated as the difference between the Total Market Revenue/Total Revenue received by a REFIT contracted generation unit versus the Total Costs/Total Allowable Costs of the supplier purchasing metered energy from the generator.
   - Out of Market Opportunity Cost Payment (i.e. energy traded bilaterally outside of SEM): is the difference between the cost to suppliers at the REFIT reference price and what it would have cost them to buy the equivalent volumes from the market.

2. **Balancing Payment (for in-market and out-of-market generation)**: paid to a supplier to cover balancing costs associated with contracting with undischippable generators, and

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65 In arriving at a methodology for the calculation of an ex-ante Benchmark Price for REFIT, the CRU was of the view that the methodology should be, inter-alia, consistent with the Notification to the EU regarding REFIT, be transparent, not impose an unnecessary administrative burden and provide for parity of treatment ab between those receiving support under the REFIT as appropriate and those receiving support under other PSO supported mechanisms (see CER/08/093 and CER/08/153).
66 As stated in CER/08/236, the onus is on the supplier to provide their best estimates regarding output for generation in order to ensure that the difference between ex-ante estimates and ex-post known values are minimised to keep the R-factor to a minimum. During the review of supplier’s PSO submissions, the CRU may request supporting data including information with regard to estimates of output.
67 As per CER/08/236, Metered Generation refers to Active Power produced at the Export Point (being the nominal commercial point of entry to the Transmission or Distribution System of the Active Power generated at a Transmission connected or Distribution connected site.
68 The REFIT Reference is published by the DCCAE. In order to take account of inflation, the CRU applies a CPI inflator to the relevant REFIT reference price (CPI figures obtained from ESRI). Ex-post, the actual values for CPI will be know and will be reconciled against ex-ante estimates (as per CER/08/236).
69 Total Market Revenue/Total Revenue is calculated as Energy Payment (i.e. SMP * MSQLF * TPD) + Capacity Payment. Total Allowable Cost/Total Cost to supplier is calculated as REFIT Reference Price * MG/MGLF* TPD.
is based on the metered generation (MG or MGLF) of the REFIT supported generating plant. As per CER/08/236, the balancing payment is not included as revenue in the determination of opportunity cost payment and Market Scheduled Quantities cannot be used in the calculation of the Balancing Payment; and

3. **Technology Payment (for in-market and out-of-market generation):** paid to supplier to promote diversity in renewable generation. As per CER/08/236, the technology difference payment is not included as revenue in the determination of opportunity cost payment and Market Scheduled Quantities cannot be used in the calculation of the Technology Payment.

In the event that a REFIT contracted PSO suppliers Total REFIT Payment/Total Allowable Cost is less than the REFIT generator’s Total Market Revenue/Total Revenue, a PSO payment is due to the supplier in the relevant PSO year (subject to any R-Factor adjustment).

With reference to the PSO supported AER scheme, a PSO payment is made to a supplier in that the Total Market Revenue/Total Revenue of its PSO contracted generation unit is less than the Tendered Price/Total Allowable Cost received by the supplier (subject to any R-Factor adjustment). Additionally, under the AER scheme, a PSO payment is made by a supplier in that the Total Market Revenue/Total Revenue of its PSO contracted generation unit is greater than the Tendered Price/Total Allowable Cost received by the supplier (subject to any R-Factor adjustment).

4.1.3.5 **Ex-Post PSO Calculations for a relevant PSO year**

With reference to decision paper (CER/08/236), this document sets out, inter-alia, the methodology to be applied to the ex-post calculation of the R-factors to apply in calculating the monies owed to/from suppliers (actual costs) in complying with their obligations in relation to the PSO.71

In order to calculate the R-Factor, suppliers are required to submit an independent auditor certificate to the CRU, which details the actual PSO monies they should have recovered in a particular PSO year (note: there is a 2 year lag between a supplier submitting ex-ante estimates and ex-post actual costs).72

The supplier’s actual outturn PSO costs are then subtracted from the estimates included in their previous PSO submissions, to determine how much money is owed to/from the supplier under the PSO. Specifically, CER/08/236 states the following:

“The R-factor (for the REFIT and other PSO mechanisms) shall be calculated as the difference between the ex-post amounts actually due to suppliers under the relevant PSO scheme (based on submitted, audited statements that are consistent with

70 As per CER/08/236, Metered Generation Loss Factored (MGLF) is defined as Metered Generation adjusted to reflect transmission losses and (where applicable) distribution losses (DLAFs and TLAFs) at the Trading Boundary.

71 The purpose of the R-Factor is to ensure that only the supplier’s actual additional costs are recovered under the PSO (i.e. no over or under recovery). It is therefore calculated on the actual difference between a supplier’s total revenues and total cost.

72 The independent auditor certificate is all required to contain a statement that the supplier’s PSO submission is in accordance with CER/08/236.
governing legislation and this decision paper) and the ex-ante estimates detailed to be paid to them under the relevant PSO levy”.

The R-Factor is then adjusted by the CRU to take account of any potential interest payments due (based on the EURIBOR over the relevant PSO period, and not the calendar year).

Additionally, decision paper (CER/08/236) confirmed the following:

- Calculation of the monies recoverable under the PSO (in relation to REFIT PPAs) are based on a per PPA basis between an individual generator and supplier, and not on an individual supplier basis.

4.1.4 The Industrial Emissions Directive


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

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

4.2 High Level Market Framework

The Single Electricity Market (SEM) is a bi-jurisdictional market governed by Ireland and Northern Ireland and consists of a gross pool market (also referred to as a gross mandatory pool) into which all electricity generated (from generators above 10MW in size) or imported onto the island of Ireland must be sold, and from which all wholesale electricity for consumption or export from the island of Ireland must be purchased. In addition to the pool there is also a capacity payment mechanism. The SEM which went live on 1st November 2007 is governed by the SEM Committee. The SEM Committee is a committee of both CRU and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CRU or NIAUR in relation to a SEM matter. Figure 4-1 below sets out the high level workings of the SEM.

4.2.1 The SEM and the Capacity Payment Mechanism

As stated previously, the SEM is a gross mandatory pool with an explicit capacity mechanism. The Capacity Payment Mechanism (CPM) provides a stream of revenue for generators based on their availability rather than just receiving revenue when they generate electricity. Without this explicit capacity mechanism generators would need to recover all their costs when they run. This would have the potential to cause price spikes in times of low margin when lesser-used peaker plants are called on. Some of the advantages of an explicit capacity mechanism are below:

- Stability in pricing;
- Reduced barriers to market entry;
- Greater transparency;
- Increased potential for competition;
- Stable investment signal.

The CPM is designed to reimburse the fixed costs of a notional Best New Entrant (BNE) peaking plant in the SEM. The BNE peaker is seen as the marginal plant and may not run very often in the market. The CPM therefore ensures that the investment and ongoing costs of the BNE plant are reimbursed whether or not the plant actually runs thereby significantly reducing the risk on the investor. This process identifies the costs to be recovered by a notional new entrant. The amount that an efficient new entrant would need to recover on a per kilowatt basis, is the capacity payment paid to all generators based on their availability. The total pot of capacity revenue is currently calculated on a year ahead basis by looking at the cost of the BNE plant and also the capacity requirement for the coming year.
In March 2012 the SEM Committee published a Medium Term Review of the Capacity Payment Mechanism. The review led to some minor changes to the operation of the mechanism but has otherwise confirmed that the mechanism remains fit for purpose. A further bottom-up review was performed in 2015 to bring the CPM up to the end of the SEM.

### 4.2.2 I-SEM and New Capacity Remuneration Mechanism

In the context of meeting the requirements of the European Third Package of energy legislation, the SEM Committee committed to redesigning the SEM market through a project referred to as the Integrated Single Electricity Market project (I-SEM). The Regulatory Authorities for Ireland and Northern Ireland agreed the High Level Design of the market required in 2014.

The revised I-SEM arrangements aim to increase the efficiency of the wholesale trading arrangements and increase the operational reliability of the system through more efficient cross border flows across the interconnectors with Great Britain, and through closer to real time trading. Balance responsibility and the introduction of within-day cross border trading are key features of the new I-SEM energy market design.

The core changes to the I-SEM energy market are designed to bring the wholesale trading arrangements in line with the Internal Electricity Market, for trading as established in a series of EU regulations under the aegis of the Third Energy Package. In addition to these changes to the energy market, the I-SEM design changes include a significantly changed system of capacity payments to comply with State Aid Guidelines.

The new CRM in Ireland will place increased obligations on capacity providers to improve operational reliability at times of system stress and provide for cross border participation thereby increasing long run security of supply. In addition, greater emphasis will be placed on regional assessment of generation adequacy.

The I-SEM CRM is based around Reliability Options (ROs) with market participants receiving a capacity payment in return for providing capacity when demand is high, prices are rising and the system becomes tight. The CRM pays for the capacity to produce electrical energy through the option fee on a “per MW” basis. Capacity Providers can receive two payments – one for providing capacity and the other for the energy they actually produce.

![Figure 4-2: Reliability Option difference payments](image-url)
The I-SEM CRM has five key stages including:

**Determine key requirements:** This step involves fundamental analysis of the I-SEM requirements for capacity to determine:

- The level of capacity that will be needed to maintain security of supply in future years; and
- The extent to which each plant contributes to that need for capacity. This leads to factors that scale down the “name plate” capacity of each plant to give its “de-rated” capacity.

**Qualification:** Qualification is the start of the procurement of capacity from providers. This process aims to identify those potential providers of capacity that are genuinely credible – and are likely to be able to deliver the capacity they offer. Those “credible” providers “qualify” to participate in the subsequent auction.

**Auction:** The auction is a competition between qualified capacity providers to be awarded Reliability Options for the provision of capacity. This auction will allocate sufficient Reliability Options to at least meet the capacity requirement identified in the “Key Requirements” step. This allocation will aim to minimize the per-MW cost of those Reliability Options, based on prices submitted by each provider.

**Build:** Where the auction awards a Reliability Option to a new (as opposed to existing) capacity provider for new capacity to be built. The arrangements for this “build” phase will include incentives on the relevant party to build their capacity within the required timescales.

**Operate:** The “Operate” phase is when capacity is available to, and being paid by, the I-SEM. This leads to the following payments:

- “per MW” option-fee payments to capacity providers for their capacity
- “per MWh” difference payments from capacity providers at time when energy prices are high (above the Reliability Option Strike Price); and
- Payments from Suppliers to cover the “per MW” option fee payments to capacity providers; and
- Payments to Suppliers at times when energy prices are high (above the Reliability Option Strike Price).

The end to end process for the I-SEM CRM is illustrated in the Figure below:
In particular, there are three key elements of the overall CRM design which combine to deliver the key CRM objectives of ensuring all customers pay the same price for capacity. These three elements are the Administrative Scarcity Price (ASP) which is set as a function of the value of lost load, the Market Reference Price (which is set as a blend of the day ahead intra-day and balance markets) and the socialisation of any shortfall in difference payments.

The ASP provides sharp and cost reflective price signals at times of system stress. The ASP, combined with the chosen MRP option combine to give capacity providers a strong incentive to be available at times of system stress, and prevents unreliable generation from gaming the CRM, by being exposed to the ASP when not available. The ASP also provides Suppliers with a strong incentive to provide demand side response, reducing consumption at times of system stress, whilst at the same time, the choice of a blended MRP, ensures that Suppliers who are unable to respond to these price signals have their price exposure capped at the RO Strike Price. The CRM has also been designed to ensure that local security of supply is protected through transitional arrangements that will ensure security of supply in import constrained regions of the network on the island such as Dublin and Northern Ireland.

State Aid approval for the scheme was received in December 2017. The I-SEM CRM went live on 1st October 2018. The first T-4 Auction is planned for March 2019, for delivery in October 2022.

4.3 Connection policy (ECP -1)

The CRU’s connection policy is currently undergoing a substantial reform which aims to provide a fair and non-discriminatory access to the electricity network for all technologies on an enduring basis (enduring connection policy – ECP). This reform was prompted by an
unprecedented increase in the volume of connection applications (36,000MW) going significantly beyond what is currently required by the system (approx. 7,000MW). The CRU considered that its prevailing connection policy was not fit for purpose anymore to manage the surge in connection applications. The following paragraphs briefly set out (1) connection policy preceding the CRU’s reform, (2) the review process and (3) the key reforms under the ECP to date.

4.3.1 Connection Policy Preceding the ECP Reform

The connection policy preceding the ECP was captured under two broad policy approaches: (1) the group processing approach (GPA), also known as the “gate system”, and (2) the non-group processing approach (non-GPA).

The gate system was designed for larger renewable and conventional generators. Under the gate system, the system operators issued connection offers to these generators in separate lots known as “gates”. There have been three gates to date, the last one (gate 3) in 2008 and 2009. Generators included in a given gate were processed together and were further divided into specific groups and subgroups based on their level of interaction and geographic location. This allowed the applicants to share planned connection methods and reinforcements, connection charges and shallow connection assets. The first two gates of the GPA were relatively small in size (gate 1 was 400MW, gate 2 was 1,300MW) and connection offers under those gates were processed in relatively short timeframes in comparison to the last gate, gate 3, which was much larger and therefore took significantly more time than the previous two gates.

The size of gate 3 was driven by Ireland’s objective to move to a low-carbon economy. Under gate 3, the system operators issued an unprecedented number of offers to renewable projects (149 offers, mostly wind, amounting to 4,147MW) in order to meet the 40% RES-E target. In addition, 10 conventional projects received a connection offer (1,139MW).

The below table shows the offer acceptance status of gate 3 as of May 2018 indicating a significant positive uptake:
In addition to the gate process, there was also a need to have a process in place to connect small, renewable and low carbon generators outside the group process on a rolling basis. The non-GPA approach was introduced in 2009 mainly to provide a route for fast tracking new generation technologies which satisfy specific public interest criteria such as diversity of fuel mix, environmental benefits and research. While under the GPA, generators included in a given gate were processed together as a group, non-GPA applicants were processed individually and sequentially.

The non-GPA process was based on the assumption that the number and size of projects to be processed outside the gate system would be relatively small and therefore could be processed with no significant impact on the system and other connecting parties. However, since 2015, non-GPA process has been overwhelmed by small-scale solar applications in particular. This has led to unmanageable backlogs for the system operators. It is also accepted by industry that a significant number of these might be speculative applications which are preventing feasible projects from being realised.

### 4.3.2 The CRU’s Review Process and Key Reforms to Date

The CRU first consulted on this reform in December 2015 setting out its initial thinking on developing a new ECP.\(^{74}\)

In this consultation, the CRU also proposed a set of transitional arrangements to be introduced ahead of ECP-1 and made a decision in that respect in October 2016 ([CRU16284](#)). As part of those arrangements, the CRU decided to facilitate access to the electricity system for providers of DS3 system services (DS3 providers). DS3 system

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\(^{74}\) [CER/15/284](#)
services are required by the system in order to accommodate increasing volumes of non-synchronous renewable generation.

Throughout 2017, the CRU worked on the development of detailed proposals for the first stage of the enduring connection policy (ECP-1). This process involved a series of workshops with the system operators and extensive engagement with all the relevant stakeholders. This included a six-week-long public consultation on the ECP-1 proposals in November – December 2017 (CRU17309). The CRU concluded this phase of its work in March 2017 with an adoption of ECP-1 decision.75

Under ECP-1, the CRU seeks to expedite the connection of projects that are well developed, and capable of energisation in relatively short timeframes. Accordingly, only projects with planning permission are eligible to apply for connection under this policy. The system operators will still keep processing projects in groups (group processing approach), however within smaller and more regular batches (than Gate 3) which are open to all technologies. In April 2018, the system operators have opened a window to apply for the first batch under ECP-1, offering approximately 1,000MW of available capacity. 400MW of this capacity has been reserved to DS3 providers as per CRU/16/284. Smaller projects, regardless of technology, still have access to the system outside the batch, however this non-batch process is now capped at 30 offers per year. The system operators are expected to issue offers for the first batch over the course of 2019, and open the next batch in 2020. In parallel, the CRU is developing its proposals for next stages of the ECP.

4.3.3 Generator Connections Liaison Group

The CRU continues to chair the Generator Connections Liaison Group (GCLG, former “Gate 3 Liaison Group”), a group comprising the system operators and industry participants, which has been set up to address issues related to offer issuance under gate 3, and also providing a useful platform for the industry representatives to engage with the system operators and discuss various issues related to connection offer policy and process. It is expected that the GCLG will retain a similar role in 2018-2019 allowing the CRU to monitor the offer issuance under the ECP-1 batch.

4.4 Planned Investment and Maintenance

4.4.1 Connections Overview

In order to connect to the transmission system, all demand and generation customers must execute a Connection Agreement with EirGrid. A connection offer which is accepted in one year is unlikely to impact on connected generation capacity in the same year given the lead times associated with construction.
When a Connection Agreement is executed for a new connection, depending on technology, it typically takes a number of years before the demand or generation is connected to the transmission system. This period includes project development, time taken to obtain consents and to construct the connection. When the transmission connection is energised, it then takes a number of months for the generator to reach commercial operation. This period is generally much shorter for demand customers.

4.4.2 Conventional Generation

Apart from supported generation such as wind and biomass there are no conventional generation units that have signed the connection agreements with EirGrid or the DSO and are committed to connect.

Some of the older conventional generators have informed EirGrid of their intention to decommission, as detailed below in table 4-2. The main reason for decommissioning is because of emissions restrictions.

<table>
<thead>
<tr>
<th>Plant</th>
<th>Export Capacity (MW)</th>
<th>Expected to close by the end of year:</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aghada (AD1)</td>
<td>258</td>
<td>2018</td>
<td>Unsuccessful in the Capacity Market auction</td>
</tr>
<tr>
<td>Aghada (AT1)</td>
<td>90</td>
<td>2023</td>
<td></td>
</tr>
<tr>
<td>Marina CC (MRC)</td>
<td>95</td>
<td>2018</td>
<td>Unsuccessful in the Capacity Market auction</td>
</tr>
<tr>
<td>North Wall 5</td>
<td>104</td>
<td>2023</td>
<td></td>
</tr>
<tr>
<td>Tarbert 1, 2, 3, 4</td>
<td>592</td>
<td>2022</td>
<td></td>
</tr>
</tbody>
</table>

*Table 4-2: Plant planned to be decommissioned in Ireland. Data Source: GCS 2018 – 2027*

4.4.3 Renewable Generation

The Irish Government has a target of 40% of electricity to be generated from renewable sources by 2020. Since setting this target Ireland has made major strides in accelerating renewable generation. The integration of more variable renewable forms of generation on the power system means Ireland must consider an additional complex range of demand and supply issues. The DS3 programme aims to meet the challenges of operating the electricity system in a secure manner while achieving the 2020 renewable electricity targets.

Biofuels, hydro and solar energy will make an important contribution to these targets. However, it is assumed that these renewable targets will be achieved largely through the deployment of additional wind powered generation. Table 4-3 shows the totals for existing and planned wind generation in Ireland. EirGrid publish a list of all Transmission Connected wind generation in Ireland, while ESB Networks publishes that which is Distribution Connected.
Table 4-3: Existing (connected or energised) and planned (contracted or applied) wind farms. Data Source: GCS 2018 – 2027

4.4.4 Wind Generation

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

Installed capacity of wind generation has increased from 145MW at the end of 2002 to over 3,000MW in 2018. This value is set to increase over the next few years as Ireland endeavours to meet its renewable target in 2020. (See figure 4-4 below)

4.4.5 Other Renewable Generation

In addition to wind, it is expected that there will be significant connection of other renewable energy sources. There are also explicit government targets for these non-wind renewable sources. The table 4-4 below sets out the non-wind renewables greater than 5MW recently connected and contracted for connection to the system. The CRU believes that the Support
Scheme for Renewable Heat\(^76\) will help to increase the energy generated from renewable sources in the heat sector and will contribute to meeting Ireland’s 2020 renewable energy targets whilst also reducing greenhouse gas emissions.\(^77\)

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>22</td>
</tr>
<tr>
<td>Biomass/Landfill gas</td>
<td>55(^78)</td>
</tr>
<tr>
<td>CHP</td>
<td>158(^79)</td>
</tr>
<tr>
<td>Industrial</td>
<td>9</td>
</tr>
<tr>
<td>Solar PV</td>
<td>10(^80)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>251</strong></td>
</tr>
</tbody>
</table>

*Table 4-4: New Other Renewable Connections. Data Source: GCS 2018 – 2027*

### 4.4.6 Energy Storage

The move to renewable energy brings an imbalance to the grid, so improving the way energy is stored becoming more important for security of supply of electricity. Energy storage units can store energy when it's generated and use it when required, replacing the current system where generation has to match demand in real time.

Energy storage units are now anticipated to enter the Irish market, with (anecdotally) over 1,700MW of batteries in the planning process and significant interest in the DS3 System services market and ECP-1 connection policy by storage players.

### 4.4.7 Maintenance Works completed

Transmission maintenance is undertaken by EirGrid in accordance with EirGrid’s maintenance policy to ensure that the transmission system can operate in a safe, secure and reliable manner. The policy comprises continuous and cyclical condition monitoring (on-line and off-line), preventative maintenance on critical items of plant and the implementation of corrective maintenance tasks. The maintenance policy is kept under review to ensure that it continues to meet the requirements of the system and best international practice.\(^81\) On an annual basis, transmission maintenance activities dictated by the asset maintenance policy and protection maintenance policy, along with work identified from analysis of plant condition and work carried over from the previous year combine to form the planned maintenance requirements for the year. This is then included in the Transmission Outage Plan. Further information on the processes and procedures used by EirGrid in consultation with ESB Networks when maintaining transmission customer connection assets can be found in [here](https://www.dccae.gov.ie/en-ie/energy/topics/Renewable-Energy/heat/Pages/Heat.aspx).

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\(^77\) [https://www.seai.ie/sustainable-solutions/support-scheme-renewable/](https://www.seai.ie/sustainable-solutions/support-scheme-renewable/)

\(^78\) Includes Meath Waste to Power (17MW)

\(^79\) Includes Dublin Waste to Energy (62MW). Not including the 161MW centrally dispatched CHP plant operated by Aughinish Alumina.

\(^80\) EirGrid GCS 2018-2027

\(^81\) Protection Maintenance Policy reviewed and revised 2018
5. Networks Investment

Key Messages

1. The CRU regulates the transmission and distribution system operators and owners in Ireland.

2. The successful rollout of an upgraded electricity network is a key requirement in achieving the ambitious targets for renewable generation and maintaining an integral system especially with the ongoing renewable connections onto the system.

3. EirGrid is committed to a grid development strategy that will be continually reviewed to ensure it is up to date and continues to meet Ireland’s changing needs.

Article 6 of the 2005 Directive requires member states to establish a regulatory framework that provides investment signals for both the transmission and distribution system network operators to develop their networks in order to meet foreseeable demand from the market and facilitates maintenance and, where necessary, renewal of their networks. This section contains a description of the electricity network in Ireland. The section also sets out the regulation framework in place and a high level description of investment intentions.

The electricity system in Ireland is regulated by the CRU with specific roles held by EirGrid as TSO and ESB Networks as TAO. As a result of changes occurring on the transmission and distribution systems a coordinated approach is required from all players to ensure continuing investment in the electricity network.

5.1 Network Description

The national grid plays a vital role in the supply of electricity, providing the means to transport power from the generators to the demand centres using a system comprising 400kV, 275kV, 220kV and 110kV networks. The 400kV and 220kV networks form the backbone of Ireland’s grid. The key components of the transmission system are set out in table 5-1 below.

<table>
<thead>
<tr>
<th>Power Lines</th>
<th>2016 Total Line Lengths (km)</th>
<th>2017 Total Line Lengths (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>400kV</td>
<td>439</td>
<td>439</td>
</tr>
<tr>
<td>275kV</td>
<td>97</td>
<td>97</td>
</tr>
<tr>
<td>220kV</td>
<td>1927.1</td>
<td>1934</td>
</tr>
<tr>
<td>110kV</td>
<td>4248</td>
<td>4345</td>
</tr>
<tr>
<td>Circuit Total</td>
<td>6711</td>
<td>6814</td>
</tr>
<tr>
<td>Transformers</td>
<td>Number of Items</td>
<td>Number of Items</td>
</tr>
</tbody>
</table>
In addition to the current transmission system in place there are a number of projects underway to provide stability and security to the system. This investment is focused on both increasing the capacity of the transmission system and refurbishing the existing system. This is of particular importance to maintain security of supply and facilitate the increasing amounts of renewable energy, much of which is located along the west coast of Ireland.

### 5.2 Regulatory Framework

The Irish transmission arrangements were certified by the CRU in accordance with Article 1 of the European Commission Decision of 12th April 2013, pursuant to Article 3(1) of Regulation (EC) No 714/2009 and Article 10(6) of Directive 2009/72/EC. EirGrid, a publicly owned company, is the transmission system operator. ESB, a publicly owned vertically integrated utility, is the transmission and distribution system owner through its ring fenced business unit ESB Networks. The distribution system is operated by ESB Networks Ltd, a wholly owned, legally separate, subsidiary of ESB.

#### 5.2.1 Revenue Regulation

Regulation of the monopoly network owners and operators is therefore a fundamental role for the CRU. The bodies involved – ESB Networks as Distribution System Operator (DSO) and Transmission Asset Owner (TAO) and EirGrid as Transmission System Operator (TSO) are required to submit their proposals for required revenues, including capital expenditure over the five-year period of the review. The CRU analyses and reviews their proposals, with the aim of achieving operational efficiencies while ensuring the correct level and type of investment in the electricity networks. The companies are benchmarked against similar organisations internationally and areas of their business where improvements need to be made are targeted. To date there have been four electricity networks revenue reviews.

#### 5.2.2 Capital Expenditure

The successful rollout of an upgraded electricity network is a key requirement in achieving the targets for renewable generation and maintaining a secure system. In 2008 EirGrid published Grid25, their long-term strategy to develop Ireland’s electricity grid looking out to 2025. At that time, demand for electricity had grown by an average of 4% a year over the previous decade. Forecasts suggested that this trend would continue.

Through Grid25, the aim was to deliver efficient and cost effective development that integrated with the existing grid. This approach also tried to avoid too many projects in one
area, if a single solution was viable. In 2011, following EirGrid’s first major review of the capital expenditure programme, the forecasted costs were reduced from €4bn to €3.2bn. This was possible due to lower forecasts for electricity demand in the recessionary period, and through the use of new technologies.

In Electricity Price Review 3 (2011-2015), the CRU approved €1.45 billion for transmission capital investment for that five year period. In Electricity Price Review 4 (2016-2020), the CRU approved €984 million for transmission capital expenditure for this five year period. These figures are part of the €3.2bn Grid25 capital expenditure programme.

In January 2017, EirGrid published their second major review on Ireland’s grid development strategy, entitled Your Grid, Your Tomorrow. In drafting this, EirGrid took account of public feedback which was accrued over an extensive consultation period beginning in March 2015 and also from consultations on proposed transmission projects. They also considered the Government’s Energy White Paper. The forecasted costs are now in the range €2.6bn-€2.9bn. A range is used as the final cost will vary depending on the circumstances and technologies of each project.

The significant investment in strengthening capacity connections between regions allows regional demand to be met in the best way possible. This is of particular importance due to the geographical distribution of demand in Ireland. Whereas maximum wind potential is located along the west coast where wind levels are high, Ireland’s population is concentrated along the east coast. As a result it is of vital importance that the grid is capable of facilitating this regional increase in future generation on the network and successfully facilitates its transmission.

The successful rollout of an upgraded electricity network is a key requirement in achieving the ambitious renewable generation targets and for maintaining a secure and reliable system. To this end there will be significant investment in the transmission and distribution networks in the coming years.
6. Operational Network Security

Key Messages

1. The technical rules governing the operation, maintenance, and development of the transmission and distribution system, and procedures governing the actions of transmission system users, are set out in the Grid Code and Distribution Code.

2. In 2018, the CRU has reviewed the existing incentives and reporting regime and introduced improvements to the current incentives and reporting regime. This will provide the customer with better value for money and will improve quality of services provided to the customer. The incentives will have a direct impact on transmission and distribution tariffs over the period 2019 to 2021.

3. The DS3 Programme is to enable high instantaneous penetration of non-synchronous generation while maintaining system stability.

4. EirGrid have trialled and successfully implemented a number of trials moving the SNSP limit from 50% to 60% during 2015-2017. Following a five month trial period, EirGrid Group changed the operational policy in April 2018 to allow SNSP to reach up to 65%.

5. Compliance with the primary and secondary fuel requirements is closely monitored by the TSO. The majority of generators are in compliance with these obligations.

6. Due to the scale of changes, such as DS3 System Services and I-SEM, the TSOs had a consultation on a secondary fuel availability incentive.

Article 4 of the 2005 Directive contains requirements in relation to operational network security. In particular the Directive requires Member States to ensure that TSOs (and where appropriate DSOs) set and comply with minimum operational rules and obligations on network security. This section describes the operational framework in place for the operation of the system and also the measures in place for ensuring operational network security.

6.1 System Operation

6.1.1 Operational Framework and Rules

The technical rules governing the operation, maintenance, and development of the transmission and distribution system, and procedures governing the actions of transmission
system users, are set out in the Grid Code and Distribution Code. The Grid Code and Distribution Code have been approved by the CRU in accordance with Section 33 of the Electricity Regulation Act 1999 (Act). The Grid Code and Distribution Code ensure that all users are treated in a transparent and equitable manner.

The Grid Code and Distribution Code documents are revised by the relevant SO when needed. EirGrid is responsible for the development and maintenance of the Grid Code in Ireland, through the Grid Code Review Panel (GCRP). ESB Networks is responsible for the development and maintenance of the Distribution Code in Ireland, through the Distribution Code Review Panel (DCRP). Any subsequent modifications and updates to the Grid Code and Distribution Code must be approved by the CRU.

In addition, EirGrid uses its own Operating Security Standards, which set out the criteria to which the TSO operates the system at all times.

The Grid Code and Distribution Code will be impacted by the implementation of the European Network Codes (EUNC). In particular the grid connection codes will require substantial revisions to the current Grid Code and Distribution Code documents. As all the Codes have already entered into force the SOs, ESB Networks and EirGrid along with the CRU have commenced an engagement process for its implementation. There are regular meetings held between both SOs and the CRU every six weeks where the EUNC implementation progress is considered, discussed and monitored.

The following table gives an update on the EUNC and their main focus:

<table>
<thead>
<tr>
<th>Name of Code/Framework Guideline</th>
<th>Status</th>
<th>Entry into Force date</th>
<th>Main Focus</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Allocation and Congestion Management (CACM)</td>
<td>Adopted by EU and published.</td>
<td>15th August 2015</td>
<td>Markets</td>
</tr>
<tr>
<td>Requirements for Generators (RfG)</td>
<td>Adopted by EU and published.</td>
<td>17th May 2016</td>
<td>Connections</td>
</tr>
<tr>
<td>High Voltage Direct Current systems (HVDC)</td>
<td>Adopted by EU and published.</td>
<td>28th September 2016</td>
<td>Connections/Operations</td>
</tr>
<tr>
<td>Demand Connection Code (DCC)</td>
<td>Adopted by EU and published.</td>
<td>7th September 2016</td>
<td>Connections</td>
</tr>
</tbody>
</table>

82 http://www.eirgridgroup.com/customer-and-industry/general-customer-information/grid-code/
83 https://www.esbnetworks.ie/who-we-are/distribution-code
84 Electricity Regulation Act, 1999
85 The GCRP is a standing body mandated to review and discuss the Grid Code, its workings and offer suggestions for amendments. Each member of the GCRP represents the interests of the constituents of their appointing body and has the responsibility of engaging with their constituents and discussing their views.
86 The DCRP is a standing body constituted to review the Distribution Code and propose amendments for approval by the CRU.
The EUNC establish deliverables that shall be developed by the SOs at different levels, i.e. European, regional and national level and require RAs approval. The CRU engages with the SOs and takes part of different ACER Task Forces for the EUNC implementation purpose. Also, the EUNC set deliverables that shall be developed by the NRAs. In that regard, the CRU will engage with the SOs to ensure that a transparent process of implementation occurs in accordance with the code deadlines.

### 6.1.2 Performance Reporting and Incentives

The CRU’s role is to protect electricity customers by ensuring that the network companies spend customers’ money appropriately and efficiently to deliver necessary services. The CRU does this through what is called a Price Review which is carried out every 5-years.

As part of PR3, the CRU implemented a scheme of performance incentives for the TSO. In July 2011 the CRU published a decision on Transmission Incentives to run until 201587.

In 2017, during PR4, the CRU consulted on a number of proposals that were designed to strengthen the transmission system reporting and incentive regime. In 2018, the CRU’s decision88 made the following changes to strengthen monitoring and reporting of how allowances are spent, and what levels of performance they deliver for customers:

- A re-positioned Annual Performance Report for the transmission system, jointly produced by the TSO and TAO, providing an accessible summary of network performance;
- A clear reporting framework for the TSO and TAO documenting the methodology applied to identify investment needs, assess options and deliver these investments for network users;
- A new mechanism and trigger point to amend Capex or Opex allowances during the Price Review period (e.g. where a material change in circumstances are agreed).

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87 [CER/11/128](#)
88 [CRU18087](#) - Reporting and Incentives under Price Review 4 Decision
In addition, and consistent with their TSO licence, EirGrid is required to publish the Transmission System Performance Report annually to cover performance over the previous year. This report is based on performance criteria approved by the CRU. The key areas that EirGrid report on are as follows:

- Basic System Data (i.e. throughput, number of connections etc.);
- Grid Development and Maintenance;
- Transmission System Availability and Outages;
- Generation Availability and Outages.

<table>
<thead>
<tr>
<th><strong>Generation &amp; Transmission Data</strong></th>
<th><strong>2017</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Operational Generation Capacity (ROI only)</td>
<td>7,281MW</td>
</tr>
<tr>
<td>Total Energy Produced (ROI only)</td>
<td>28,157GWh</td>
</tr>
<tr>
<td>Peak Winter Demand (All-Island)</td>
<td>6,531MW</td>
</tr>
<tr>
<td>Minimum Summer Night Valley (All-Island)</td>
<td>2,427MW</td>
</tr>
</tbody>
</table>

*Table 6-2: Generation and Transmission Data. Data Source: EirGrid Draft Transmission System Performance Report 2017*

<table>
<thead>
<tr>
<th><strong>System Availability</strong></th>
<th><strong>2017 %</strong></th>
<th><strong>2016 %</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>400kV Circuit</td>
<td>86.64</td>
<td>94.46</td>
</tr>
<tr>
<td>220kV Circuit</td>
<td>96.97</td>
<td>94.07</td>
</tr>
<tr>
<td>110kV Circuit</td>
<td>93.46</td>
<td>90.77</td>
</tr>
</tbody>
</table>

*Table 6-3: System Availability Data. Data Source: EirGrid Draft Transmission System Performance Report 2017*

### 6.1.3 Generator Availability

*Figure 6-1: Generator Availability Data. Data Source: EirGrid Draft Transmission System Performance Report 2017*
The average daily generation system availability in 2017 was 86.78%. The maximum daily generation system availability in 2017 was 94.87%. The minimum daily generation system availability in 2017 was 61.78%.

### 6.1.4 Generator Forced Outage Rates

![2017 All-Island Generator FOR](image1)

*Figure 6-2: Generator Forced Outage Rate Data. Data Source: EirGrid Draft Transmission System Performance Report 2017*

The average daily generation system forced outage rate in 2017 was 8.6%. The highest forced outage rate in 2017 was 22.89%. The minimum daily generation system forced outage rate in 2017 was 3.04%.

### 6.1.5 Generator Scheduled Outage Rate

![2017 All Island Generator Scheduled Outage Rates](image2)

*Figure 6-3: Generator Scheduled Outage Rate Data. Data Source: EirGrid Draft Transmission System Performance Report 2017*

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69 Draft All-Island Transmission System Performance Report 2017
The average daily generation system scheduled outage rate in 2017 was 3.46%. The maximum daily generation system scheduled outage rate in 2017 was 11.68%. The minimum daily generation system scheduled outage rate in 2017 was 0.57%.

6.2 DS3 Programme

As stated earlier, Article 5 of the 2005 Directive requires transmission system operators to ensure that an appropriate level of generation reserve capacity is available and/or to adopt equivalent market based measures. In Ireland this is currently achieved through mandatory Grid Code obligations to provide ancillary services and ancillary services contracts between EirGrid and the individual generators.

The Renewable Energy Directive 2009/28/EC states that SOs are obliged to "take appropriate grid and market related operational measures in order to minimise the curtailment of electricity from renewable sources on the electricity system". In accordance with this Directive EirGrid as TSO is implementing the “DS3 Programme” to ensure a secure, reliable and efficient electricity system in a changing energy environment. To successfully fulfil the 40% renewable electricity target a total of approximately 5,200MW of renewable generation will need to be connected to the system by 2020 on an All-Island basis. This portfolio change poses significant challenges to the network in Ireland above and beyond non-synchronous facilitation challenges posed to other jurisdictions.

The TSOs formally commenced the DS3 Programme in September 2011, following a review by the Regulatory Authorities of the TSOs’ Report on Ensuring a Secure, Reliable and Efficient Power System in July 2011. This followed a request by the SEM Committee for the TSOs to put in place a programme of work to solve the challenges which would occur with operating the electricity system in a secure manner as levels of wind penetration increase. These issues had been identified by the TSOs in the Facilitation of Renewables Study, a large body of work which concluded in 2010.

Currently Ireland has very high levels of non-synchronous variable generation (predominantly wind). The aim of the DS3 programme is to meet the challenges of operating the electricity system in a secure manner while achieving the 2020 renewable electricity targets. In this context, a key focus of the DS3 Programme is to enable high instantaneous penetration of non-synchronous generation while maintaining system stability.

The DS3 programme consists of eleven separate work streams:

1. System Services;
2. RoCoF;
3. Grid Code;
4. Demand Side Management;
5. Voltage Control;
6. Frequency Control;
7. Control Centre Tools;
8. Model Development and Studies;
9. WSAT;
10. Renewable Data; and

One of the objectives of the DS3 programme is to enhance the capability of the system to allow the TSO to safely operate the system at 75% SNSP (“System Non-Synchronous Penetration”) up from the limit of 50% applied in 2014. A 75% SNSP limit means that at any given time wind generation can contribute 75% of total electricity generation. This will allow the system to make the best use of wind generation when it is available, lowering curtailment levels and increasing the average share of renewable generation to meet the 40% target.

EirGrid have trialled and successfully implemented a number of trials moving the SNSP limit from 50% to 60% during 2015-2017. Following a five-month trial period, EirGrid Group changed the operational policy in April 2018 to allow SNSP to reach up to 65%. The increase in allowable SNSP levels from 50% to 65% since 2015 has been enabled as a direct result of the progress being made under several DS3 workstreams including Control Centre tools. The current status of all the DS3 work streams can be found on EirGrid’s website.

The aim of the System Services workstream is to put in place the correct structure, level and type of service in order to ensure that the system can operate securely with higher levels of and other non-synchronous generation penetration (up to 75% instantaneous penetration). DS3 System Services are a key requirement in maintaining the stability of the system. System Services can be described as products, other than energy, that are required to ensure the secure operation of the transmission system. The previous ancillary services framework has been revised through the DS3 Programme, and has increased the range of products required by the TSOs from 7 to 14. These System Services provide increased operational security for the SO when operating the system (which has no A/C interconnection) with high levels of non-synchronous generation. The 14 System Services are as follows:

1. Synchronous Inertial Response (SIR);
2. Fast Frequency Response (FFR);
3. Primary Operating Reserve (POR);
4. Secondary Operating Reserve (SOR);
5. Tertiary Operating Reserve (TOR1);
6. Tertiary Operating Reserve (TOR2);
7. Replacement Reserve - Synchronised (RRS);
8. Replacement Reserve – Desynchronised (RRD);
9. Ramping Margin 1 (RM1);

http://www.eirgrid.com/operations/ds3/
10. Ramping Margin 3 (RM3);
11. Ramping Margin 8 (RM8);
12. Fast Post Fault Active Power Recovery (FPFAPR);
13. Steady State Reactive Power (SSRP);

The TSOs have statutory responsibilities in Ireland and Northern Ireland in relation to the economic purchase of services necessary to support the secure operation of the system. In 2016, a process was initiated to enable the procurement of 11 System Services under the standard contractual arrangements with payment based on a regulated tariff rate for each service. These contracts for the 11 services went live in October 2016 and a new round of procurement of System Services has been developed in 2018, which has allowed new types of providers (e.g. wind, demand side) to contract for provision of critical system services to the TSO. A further three (fast-acting) services will be procured in Q3 2018. In 2017, the SEM Committee decided to approve the TSOs' proposal to carry out a separate procurement process on a competitive basis for high-availability technologies for a subset of services. The arrangements for this competitive procurement process are currently being developed and it is expected that the tender process will be launched in September 2018. Successful applicants in this competitive process will be offered fixed term contracts with a fixed tariff rate for the subset of services. These contracts aim to provide a level of investment certainty to new providers of System Services which will be important as the levels of non-synchronous renewable generation on the system increase.

It is intended that enduring competitive procurement arrangements of DS3 System Services will be enabled following further development of possible options by the Regulatory Authorities.

6.3 Secondary Fuel Capability Obligations

Directive 2003/54/EC (which was replaced by Directive 2009/72/EC) as transposed in Ireland by S.I. 60 of 2005 enhanced the CRU’s role in relation to security of supply and enabled the CRU to take any necessary actions to protect security of supply. Regulation 5 of S.I. 60 of 2005 states that:

“The Commission shall take such measures as it considers necessary, to protect security of supply.”

Secondary fuel obligations are of particular importance for Ireland’s electricity market. This is due to the fact that the majority of electricity requirements on an all Island basis are being met from gas.

In the medium to long term the majority of gas is expected to be supplied through a single entry point onto the island of Ireland, from an electricity security of supply perspective it is essential that emergency provisions are put in place. To this end some generators are required to hold reserves of either their primary or secondary fuel and they must be capable of running at 90% plus of capacity on a secondary fuel. The specific requirements on
generators to hold reserves are set out in table 6-4 below. As TSO, EirGrid has an obligation to examine fuel stocks and may test fuel stocks twice per annum.

In May 2012, EirGrid carried out a Capacity Report to assess the possibility of increasing secondary fuel obligations above the current requirements. The report concluded that various scenarios were possible including an option for key generation plants in particular to increase their secondary obligations if necessary.

In its decision paper on Secondary Fuel Obligations in 2009, the CRU committed to keep secondary fuel obligations under continuous review to address potential issues arising from gas supply sources and the increase in intermittent renewable generation on the electricity network. In 2014, the CRU commenced analysis to estimate the impact of the current policy under various potential future scenarios.

In 2015, due to a number of significant changes in Ireland’s electricity and gas sectors, the CRU launched a consultation reviewing fuel stock obligations for electricity generators. The changes considered during the consultation are as follows:

- a declining proportion of gas use in electricity power generation;
- opening and closure of a number of electricity generation plants;
- increased wind generation;
- commissioning of the East-West Interconnector;
- increased investment in gas infrastructure (e.g. twinning of gas pipeline in South West Scotland Onshore System); and
- new sources of indigenous gas (i.e. Corrib) coming on stream.

Due to the importance of gas as a fuel for electricity generation the CRU require that in the event of a gas supply disruption, base load gas powered plants are required to stock five days of secondary fuel while peaking plants are required to stock three days of secondary fuel. Electricity generating plants with operating hours above 2630 hours per annum are categorised as higher merit while plants operating below 2630 hours per annum are categorised as lower merit generating units.

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91 CER/09/001
92 CER/15/213
93 CER/09/001
Due to the scale of changes, such as DS3 System Services and I-SEM, the TSOs ran consultation on the SEMC website regarding other system charges. In this consultation the TSOs proposed to introduce a secondary fuel availability incentive. This GPI had been introduced from 1st October 2018.

<table>
<thead>
<tr>
<th>Primary Fuel Type of the Generating Unit</th>
<th>Requirement to be capable of running on a secondary fuel</th>
<th>Requirement to hold stocks of that fuel</th>
<th>Number of Days Storage Required (Continuous running at primary fuel rated capacity)</th>
</tr>
</thead>
</table>
| Gas units and CHP units of more than 10MW | Yes (At 90% of units capacity) | Requirement to hold secondary fuel | Higher Merit 5  
Lower Merit 3  
CHP>10MW 1 |
| Non-gas units such as oil and coal (excluding renewable and peat units) | No requirement | Requirement to hold primary fuel | Higher Merit 5  
Lower Merit 3 |
| Renewable94 units | No requirement | No requirement | N/A |
| CHP units of 10MW and less | No requirement | No requirement | N/A |
| Peat units | No requirement | No requirement | N/A |

Table 6-4 Secondary Fuel Requirements

94 Renewables is as defined in the Electricity Regulation Act 1999  
95 CER/09/001  
97 This GPI has been developed as Ireland and Northern Ireland are heavily dependent on gas as a fuel source.
7. Interconnection and Regional Transmission Development

Key Messages

1. A number of Projects of Common Interest have been identified in Ireland. If these projects progressed, would increase cross border linkages between Ireland and neighbouring jurisdictions thus increasing security of supply.

2. There is one major operating electricity transmission line between the Ireland and Northern Ireland (NI) electricity grids consisting of a 275kV double circuit overhead line.

3. The Moyle interconnector connects Northern Ireland and Scotland and has an import capacity of 450MW.

4. The EWIC connects the transmission systems in Ireland and Wales and provides 500MW of power in each direction.

Article 22 of Directive 2009/72/EC requires TSOs to submit to the regulatory authority a ten-year network development plan based on existing and forecast supply and demand after having consulted all the relevant stakeholders. That network development plan shall contain efficient measures in order to guarantee the adequacy of the system and the security of supply.

The ten-year network development plan shall in particular:

a) Indicate to market participants the main transmission infrastructure that needs to be built or upgraded over the next ten years;

b) Contain all the investments already decided and identify new investments which have to be executed in the next three years;

c) Provide for time frame for all investment projects.

Regulation 347/2013 sets up guidelines for the timely development and interoperability of priority corridors and areas of trans-European energy infrastructure. In particular, this Regulation:

a) Addresses the identification of Projects of Common Interest (PCI)\(^{98}\) necessary to implement priority corridors and areas falling under the energy infrastructure categories in electricity, gas, oil and carbon dioxide;

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\(^{98}\) Projects of Common Interest
b) Facilitates the timely implementation of projects of common interest by streamlining, coordinating more closely, and accelerating permit granting processes and by enhancing public participation;

c) Provides rules and guidance for the cross-border allocation of costs and risk-related incentives for projects of common interest;

d) Determines the conditions for eligibility of projects of common interest for Union financial assistance.

The PCI projects in Ireland\(^9^9\) are outlined in table 7-1:

<table>
<thead>
<tr>
<th>PCI No.</th>
<th>Type (e.g. electricity)</th>
<th>PCI Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.6 - Cluster connecting Ireland to France</td>
<td>Electricity</td>
<td>France — Ireland interconnection between La Martyre (FR) and Great Island or Knockraha (IE) (currently known as “Celtic Interconnector”)*</td>
</tr>
<tr>
<td>1.9 - Cluster connecting Ireland to United Kingdom</td>
<td>Electricity</td>
<td>1.9.1 Ireland — United Kingdom interconnection between Wexford (IE) and Pembroke, Wales (UK) (currently known as “Greenlink”)*</td>
</tr>
</tbody>
</table>
| 2.13 - Cluster connecting Ireland to United Kingdom | Electricity | 2.13.1 Ireland — United Kingdom interconnection between Woodland (IE) and Turleenan (UK)  
2.13.2 Ireland — United Kingdom Interconnection between Srananagh (IE) and Turleenan (UK) |
| 5.1 - Cluster to allow bidirectional flows from Northern Ireland to Great Britain and Ireland and also from Ireland to United Kingdom | Gas | 5.1.1 Physical reverse flow at Moffat interconnection point (IE/UK)  
5.1.2 Upgrade of the SNIP (Scotland to Northern Ireland) pipeline to accommodate physical reverse flow between Ballylumford and Twynholm  
5.1.3 Development of the Islandmagee Underground Gas Storage (UGS) facility at Larne (Northern Ireland) |
| 5.3 - Shannon LNG Terminal | Gas | Shannon LNG Terminal and connecting pipeline (IE) |

\(^9^9\) The Third PCI List  
\(^1^0^0\) The Second list of PCI
7.1 Celtic Interconnector (PCI 1.6)

The two national TSOs, EirGrid in Ireland and its French counterpart, RTE (Réseau de Transport d’électricité), have completed a feasibility study on building a 700MW submarine electricity interconnector between Ireland and France (the Celtic Interconnector).

The preliminary studies indicated the following benefits of the Celtic Interconnector:

- **Competition** – facilitation of increased electricity trading in an economically efficient manner within Europe by directly linking the electricity market of mainland Europe with the Single Electricity Market on the island of Ireland;
- **Renewables** – further development of renewable sources, particularly variable sources such as wind, by reducing curtailment volumes;
- **Security of Supply** – providing an additional supply of power to Ireland, and also leading to increased diversification of fuel sources, making Ireland less reliant on its electricity interconnection to Great Britain.

The preliminary assessments also provided the basis for initial cost benefit assessments (CBAs). These CBAs show a range of consumer welfare outcomes for the project. In some scenarios these consumer welfare outcomes are relatively low or poor; in others they are favourable. The project moved into the next phase, the initial design and pre-consultation, in July 2016. To facilitate this phase, the CRU approved revenues of €4 million for EirGrid’s share of the initial design and pre-consultation stage, for more information see CER/17/007. The Celtic Interconnector project also received funding of some €4m for this phase from the Connecting Europe Facility (CEF) in July 2015.

On 7th September 2018, EirGrid submitted an Investment Request as per Article 12 of the TEN-E Regulation including a request for Cross Border Cost Allocation (CBCA). The CRU will assess this investment request accordingly in cooperation with CRE (the French energy regulator). For more see the information paper on Electricity Interconnectors CRU18056.

7.2 Greenlink Interconnector (PCI 1.9)

Greenlink is a 500MW electricity interconnector that could link the power markets in Ireland and Great Britain (GB). The project is being led by Element Power, an international developer of renewable energy and interconnection projects. The project consists of a high voltage subsea and underground cable between the Great Island transmission substation in Wexford and the Pembroke transmission substation in South Wales.

In December 2017, the CRU has received a request from Greenlink to determine if it is in the public interest that this interconnector be considered part of the transmission system for the purposes of calculating and imposing charges for the use of the transmission system. Greenlink also asked CRU to approve a 25 year “cap and floor” charging methodology based on symmetrical treatment with their Initial Project Assessment from Ofgem for the GB portion of the project. On 18th October 2018, the CRU published a determination on the Greenlink electricity interconnector application. In this determination the CRU assessed the “public interest” stage by conducting its own CBA and comparing the results to those provided by the Greenlink project promoters. As part of the next stage, following by
sufficiently detailed financial and technical submissions from the Greenlink developers the
CRU expects to consult on a Cap and Floor regime in H1 2019. For more see the
determination paper on the Greenlink electricity interconnector application CRU18216.

7.3 North South Interconnector (PCI 2.13.1)

A new North South Interconnector is currently proposed by EirGrid and SONI, which will
comprise a 400kV overhead line to connect the electricity grid of Ireland and Northern
Ireland (PCI No. 2.13.1). The proposed project will run from Woodland in County Meath
through counties Cavan, Monaghan and Armagh to Turleenan in County Tyrone. The EU
officially granted the North South Interconnector PCI status in 2013. The section of project in
Ireland was granted planning approval by An Bord Pleanala in December 2016. The section
of the project in Northern Ireland was granted planning permission by the Department of
Infrastructure in Northern Ireland in January 2018.

7.4 North West Project Interconnector (PCI 2.13.1)

An assessment of the transmission system in north-west Ireland and western Northern
Ireland by EirGrid and SONI resulted in a Project of Common Interest (PCI) status for a
project titled the Renewable Integration Development Project (RIDP). The project is still in a
study/pre-planning phase (phase 3), which means no major decisions have been made
regarding the location of projects or even the types of projects required to achieve objectives
(even though the Third PCI list details one such potential interconnector project).

7.5 Existing Interconnectors/Tie-lines

7.5.1 North-South Tie-line

There is one major operating electricity transmission line between the Ireland and Northern
Ireland (NI) electricity grids consisting of a 275kV double circuit overhead line. In addition,
there are also two small 110kV standby North-South tie-lines which allow the TSOs in
Northern Ireland (SONI) and Ireland (EirGrid) to provide mutual short-term technical
assistance.

7.5.2 Moyle Interconnector

The Moyle Interconnector connects the Northern Ireland and Scottish electricity systems and
contributes to the generation adequacy position in Northern Ireland and consequently,
benefits the Irish system in terms of capacity adequacy. Northern Ireland relies on the Moyle
Interconnector for 450MW of capacity.

In previous years the export capacity of Moyle from Ireland was contractually limited to
80MW. However due to EU obligations pertaining to Article 15(2) of Regulation 714/2009
EC\textsuperscript{101} this limitation has been extended to 295 MW\textsuperscript{102}. The trading conditions for Moyle have also been altered and have been moved towards a computerised auction system. This allows the Interconnector to provide a greater variety of products of differing durations. Revised access rules also allow participants to acquire capacity close to the start of the tariff year to align with customer contracts. An auction platform of both Moyle and East-West Interconnector has been procured together. This will provide flexible and competitive trading rules that help to bolster supply security on an All-Island basis.

The Moyle Interconnector is part of a wide scale programme of infrastructure which allows Ireland to connect to a European wide programme of interconnection. EirGrid published an Interconnection Economic Feasibility Report which outlines that Moyle and the East West Interconnector (outlined below), from an economic and supply security perspective, are integral to the island of Ireland. The report also concludes that a third interconnector is economically viable when more renewable generation is connected to the system.

7.5.3 East West Interconnector (EWIC)

The electricity transmission systems of Ireland and GB are connected via the East West Interconnector (EWIC), a high-voltage direct current submarine and underground power cable. It has a power rating of 500MW and is one of the largest High Voltage Direct Current schemes in the world to use Voltage Source Converter technology. The EWIC is a fully regulated interconnector which was developed and is owned by EirGrid Interconnector Designated Activity Company (EIDAC), part of the EirGrid Group. It has a total length of 261 kilometres, of which 186 kilometres is submarine cable and 75 kilometres is subsoil cable. The link connects Portan converter station in County Meath and Shotton converter station in North Wales. Figure 7-1 below sets out a schematic of the EWIC.

![Figure 7-1: East West Interconnector Schematic](image)

This Interconnector is of particular importance to overall energy policy and security in Ireland and within the EU. Specifically:

\textsuperscript{101} “A general scheme for the calculation of total transfer capacity and the transmission reliability margin based on the electrical and physical features of the network” shall be published.

\textsuperscript{102} Between September and April, 287MW May to August
• energy security for a growing population both within Ireland and in the UK;
• promotion of competition in the electricity sector, EWIC makes an additional 500MW of bi-directional capacity available between Ireland and GB;
• encourages the growth of renewable energy in Ireland by encouraging excess energy to be exported to GB;
• allows a wider energy market that enables companies in both Ireland and Great Britain to sell to a larger market. This helps foster wider competition and increase security through diversification of generation sources.

A study was carried out by the SEM examining the effect of EWIC on prices. The study examined the first six months of its operation, effectively rerunning the market schedule for those months and graphing the differential with and without EWIC in full operation. On average EWIC reduced the System Marginal Price (SMP) by €4/MWh, or 8%, for those months\textsuperscript{103}.

\textbf{7.5.4 Regional Interconnection Projects}

Great Britain has 4GW interconnection through four interconnectors – 2GW to France (through the interconnector known as IFA), 1GW to the Netherlands (BritNed) and two links of up to 500MW each to the Island of Ireland (Moyle and EWIC). IFA, which connects England with France, was developed in the mid-1980s by the state owned Central Electricity Generating Board on the Great Britain side and its French counterpart. Moyle, which goes between Scotland and Northern Ireland, began operation in 2002 and is owned by a mutualised company wholly owned by Northern Irish consumers. BritNed was developed as a merchant project jointly between National Grid Interconnector Limited\textsuperscript{104} and TenneT, the Dutch Transmission System Operator (TSO), coming online in 2011. The most recent interconnector to be developed was the East West Interconnector between Wales and Ireland which became active in 2012 – a project undertaken by EirGrid and wholly underwritten by Irish consumers.

These projects allow for the interconnection of energy jurisdictions across Northern Europe. This greatly enhances supply security by suitably absorbing the large volumes of wind capacity that are continuously being connected to European Grids as Europe progresses towards a more sustainable and efficient energy future. Thus, interconnectors ensure that Ireland as an EU Member State contributes to the dual goals of renewable energy targets and the development of a secure energy supply system.

\textsuperscript{103} EirGrid GCS 2018-2027
\textsuperscript{104} A commercial arm of National Grid plc.