Enduring Connection Policy 2.2 Constraints Report for Area B Solar and Wind

Q4 2022

Version 1.0

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Document History

Version	Date	Comment
1.0	21/12/2022	

Table of Contents

Document Structure

This document contains six main sections, and three Appendices with an Abbreviations and Terms section at the end.

The structure of the document is as listed below.

Much of this document describes study assumptions and methodology. For customers wishing to see the estimated Total Dispatch Down for Area B, please proceed to both Section 6 and Appendix C.

Section 1: Introduction: presents the purpose of the report and the definitions of over-supply, curtailment and constraint.

Section 2: Study Overview: introduces the study areas, the study years and the generation scenarios. Together, these comprise the study scenarios.

Section 3: Study Input Assumptions: describes the study assumptions as they relate to network, demand, interconnection, generation and system operational limits.

Section 4: Study Methodology: provides an overview of the software used and how the model is put together. A description of how Total Dispatch Down results are apportioned is also provided.

Section 5: Results Summary for Ireland: provides an overview of the reduction in renewable generation forecasted by this study at system level for Ireland.

Section 6: Results for Area B: outlines the area covered by this report. The section provides a network diagram of Area B and an overview of the results for Area B.

Appendix A: Network Reinforcements: lists the reinforcements that are included in the study for each study scenario. These reinforcements have a material impact on the resulting constraints. This section also lists the representative transmission outage scheduled included within the analysis.

Appendix B: Generator Details: provides an overview of the generation. It also provides a comprehensive list of the individual generators included in the study.

Appendix C: Area B Node Results: provides a table of results for every node in the area. This table documents the installed capacity, available energy, over-supply, curtailment and constraint for every node in Area B.

The **Abbreviations and Terms** provide a list of the abbreviations and terms used in the document.

Important Note

This ECP 2.2 constraints report presents an estimate of the reduction in available solar and wind generation based on the study assumptions described. The reduction in available generation has been split into three categories for the purposes of this study: over-supply, curtailment and constraint.

The treatment of renewable generation under these three categories of generation reduction will be determined by the implementation of Articles 12 and 13 of the EU Regulation 2019/943[1].

Following the SEMC decision on the 22nd of March 2022[2] (SEM-22-009 Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019/943. The detailed design of Articles 12 and 13 implementation has yet to be determined and may differ from the pro-rata implementation for constraints used in this study. Therefore, an assumed interpretation has been included in this study, as detailed in this report.

This report uses the term "Total Dispatch Down" to refer to the total reduction in available solar and wind generation i.e. the sum of over-supply, curtailment and constraint and is considered as the key indicator for the results. However, it is important to note that the term "dispatch down" is more correctly applicable only to TSO instructions to reduce generation output from a market position as is the case for curtailment and constraint and is not necessarily applicable to a generator reducing its own output from its availability to a market position so that supply and demand are balanced, as is the case for over-supply.

The term "non-priority" and "not-priority" generators are used synonymously in the report.

The results presented in this report are based on the simulation and modelling assumptions described. The findings are indicative only and this report should in no way be read as a guarantee as to future levels of over-supply, curtailment and constraint.

[1] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=NL

[2] https://www.semcommittee.com/sites/semc/files/media-files/SEM-22-009%20Decision%20Paper%20on%20Dispatch%2C%20Redispatch%20and%20Compensation%20Pursuant%20to%20Regulation%20EU%202019943.pdf

1 Introduction

1.1 Objective

It is a requirement of CRU's ECP 2 decision, CRU/20/060[3], that the Transmission System Operator (TSO) carry out system studies to inform applicants about possible generation constraint levels in Ireland. EirGrid will complete this requirement across twelve regional reports. The purpose of these reports is to provide generation developers with information on possible levels of generation output reduction for a range of scenarios.

The reports present results for a range of generation scenarios and indicate the levels of Total Dispatch Down that solar and wind generation might experience in the future, where Total Dispatch Down is defined as follows:

Total Dispatch Down[4] = Over-supply + Curtailment + Constraint

Figure 1-1 Total Dispatch Down Equation

The over-supply, curtailment and constraint results for Area B are included in Section 6 and in Appendix C.

1.2 Background

The core study years for this analysis are 2025 and 2027. A further sensitivity study considers a 2030 study year that aligns with the network assumptions used in the Shaping Our Electricity Future (SOEF) Roadmap[5] published in November 2021. This 2030 scenario also includes additional reinforcements that have received capital approval since the release of the SOEF Roadmap.

The evaluation of Total Dispatch Down is impacted by a range of assumptions: generation, demand, interconnection, network and operational limits. A summary of each of these is provided below. More details of these study assumptions are provided in Section 3.

1.2.1 Generation

Since Gate 3, EirGrid and ESB Networks have issued an additional 2 GW of wind and solar connection offers under the Non-GPA (Non-Group Processing Approach) rule set CER/09/099. In line with government policy and CRU direction, another 1.8 GW of wind and solar connection offers have been issued under Enduring Connection Policy – Stage 1 (ECP 1). The CRU decision on the Enduring Connection Policy – Stage 2 (ECP 2) mandates that this stage of the connection policy will progress in three separate batches: ECP 2.1, ECP 2.2 and ECP 2.3. This report includes the 2.7 GW of generation, processed under the second of these three batches – ECP 2.2, as part of the model portfolio. These reports present the total dispatch down results for wind and solar generation only.

It is not clear at this stage which generators will be successful in future renewable support auctions or other funding mechanisms, therefore the timing and location of future generation connections is uncertain. For this reason, results for various renewable generation scenarios are presented in this report.

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[3] https://www.cru.ie/wp-content/uploads/2020/06/CRU20060-ECP-2-Decision.pdf

[4] For the purposes of this report, the term "Total Dispatch Down" includes over-supply. Note however that "dispatch down" more correctly refers to dispatch away from a market position and as such, includes curtailment and constraint but not necessarily over-supply.

[5] https://www.eirgridgroup.com/the-grid/shaping-our-electricity-f/

1.2.2 Demand

Demand levels in Ireland have been increasing over the last number of years, which has led to a reduction in renewable generation dispatch down levels and in particular, curtailment levels associated with the operational metric SNSP (System Non-Synchronous Penetration), which is impacted by the demand.

The system demand forecast used in the 2025, 2027 and 2030 ECP 2.2 constraints analysis is the median demand forecast from the Generation Capacity Statement (GCS) 2022 - 2031[6].

1.2.3 Interconnection

As well as the existing Moyle and East-West (EWIC) HVDC interconnectors, the following future HVDC interconnectors have been assumed:

- 500 MW Greenlink HVDC interconnector to Great Britain – has been assumed in service for all study years.
- 700 MW Celtic HVDC interconnector to France – has been assumed in service for the 2027 and 2030 study years.

In addition to the existing North-South HVAC interconnector between Louth and Tandragee, a second North-South HVAC interconnector between County Tyrone and County Meath has also been assumed in service for the 2027 and 2030 scenarios.

1.2.4 Network

The network reinforcement assumptions used for the core 2025 and 2027 scenarios are aligned with the current estimated delivery dates for existing reinforcement projects.

The network assumed for the 2030 study is aligned with the SOEF Roadmap network assumptions, additional reinforcements that have received capital approval since the release of the SOEF Roadmap have also been included.

1.2.5 Operational Limits

Under the SOEF Roadmap, the System Operation workstream sets out a plan for further developing our operation capability to facilitate increases in wind and solar generation levels. This includes evolution of the SNSP, Rate of Change of Frequency (RoCoF), inertia, minimum number of conventional units and system service provision from new, low carbon sources. The current System Operation roadmap assumptions are included in the assumptions for this report.

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[6] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_SONI_Ireland_Capacity_Outlook_2022-2031.pdf

1.3 Definition of Over-Supply, Curtailment and Constraint

1.3.1 Over-Supply

The reduction of available renewable generation for over-supply reasons is necessary when the total available generation exceeds system demand plus interconnector export flows. In this study, generation reduction for over-supply is applied prior to curtailment and constraint.

Under the EU's Clean Energy Package, it has been mandated that priority dispatch of renewable generation will continue to apply only to generators which connected prior to July 4^{th} 2019 (Article 12). This will create a new type of generator for consideration in the dispatch process – the non-priority dispatch renewable generator, connected post July 4^{th} 2019.

For this study it has been decided to use the current operational interim arrangement, which is the same approach used within the ECP 2.1 constraints analysis, as the implementation of Article 12 post 2026 is yet to be finalised and will be determined through a separate workstream. This approach is summarised below.

During generation reduction for over-supply reasons, a distinction is made between the treatment of priority and non-priority renewable generators, and non-priority generators are reduced ahead of priority generators. Within these two categories of generation, over-supply is applied pro-rata across the all-island system for all generators in the category.

1.3.2 Curtailment

In order to operate a safe and secure electricity system, the TSO must operate the system within certain operational limits. These limits include:

- Maximum level of System Non-Synchronous Penetration (SNSP)
- Maximum Rate of Change of Frequency (RoCoF)
- Minimum level of system inertia
- Minimum number of conventional units for stability
- Minimum levels of reserve
- Conventional generator "must run" rules to ensure adequate system voltage and power flow control

Curtailment is applied to reduce the output of renewable generators in order to ensure that operational limits are not breached, and the system can remain secure and stable. Curtailment is applied to all renewable generators across the island on a pro-rata basis with no distinction made between the treatment of priority and non-priority generators.

1.3.3 Constraint

Generators may also need to be dispatched down due to transmission network limitations and, in particular, to ensure that the thermal overload limits of transmission circuits and transformers are not breached. Transmission equipment may become overloaded in an intact network or for network contingencies, where a line may become overloaded if another line were to trip. In order to avoid this, renewable generation may be dispatched down.

Changes in generator output for this reason are referred to as a 'constraint'. The constraining of generation is location-specific and can be reduced, for example, by transmission network reinforcements. The model accounts for N-1 contingencies, this means that the system will be dispatched in such a way that any single contingency will not cause overloads.

Constraints are applied pro-rata across renewable generators which are effective in managing a particular network limitation, with no distinction made between the treatment of priority and non-priority generators.

2 Study Overview

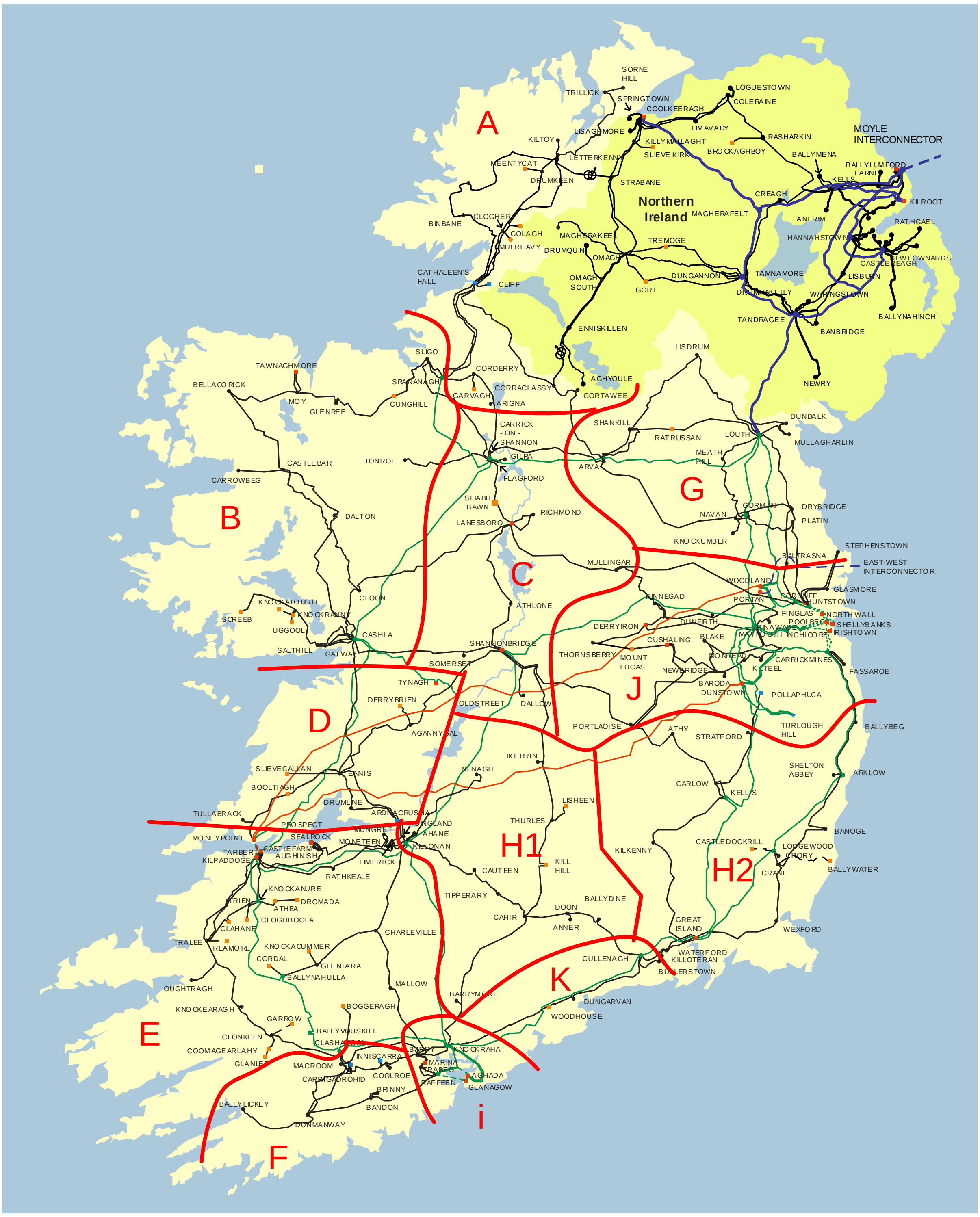

Figure 2-1 Areas Designated for Preparing Wind Energy Profiles, Generation Scenarios and Reporting Results

This section presents an overview of the over-supply, curtailment and constraints assessment. Descriptions of the study scenarios are provided which are a combination of generation scenarios and network study years.

An overview of the study areas is provided. These are fundamental to understanding the contents of the individual area reports. It also provides an overview of the demand, generation and network assumptions that are used in the study. Taken together this information provides an overview of this analysis.

2.1 Study Areas

The areas shown in Figure 2-1 are used for preparing wind energy profiles, for setting up generation scenarios and for reporting results. These areas are similar to those used for the ECP 1 and ECP 2.1 constraints analysis.

2.2 Study Scenarios

Studies were carried out for a number of study years with different network assumptions, and generation scenarios. An overview of the study scenarios can be seen in Figure 2-2.

The core ECP 2.2 study scenarios are highlighted and grouped in Figure 2-2 and cover the years 2025 and 2027. The core 2025 studies include the Greenlink interconnector while the core 2027 studies include both the Greenlink and Celtic interconnectors.

During the initial engagements with industry in advance of finalising assumptions, there were industry requests for a number of sensitivity studies to be carried out as part of the analysis in addition to the core study scenarios. As a result of this, several sensitivity scenarios were developed, these include:

- Sensitivity studies based upon the SOEF (Future Grid) network.
- Multiple sensitivities considering the impact of the connection of offshore wind.
- A sensitivity study to show the impact of the representative maintenance schedule.

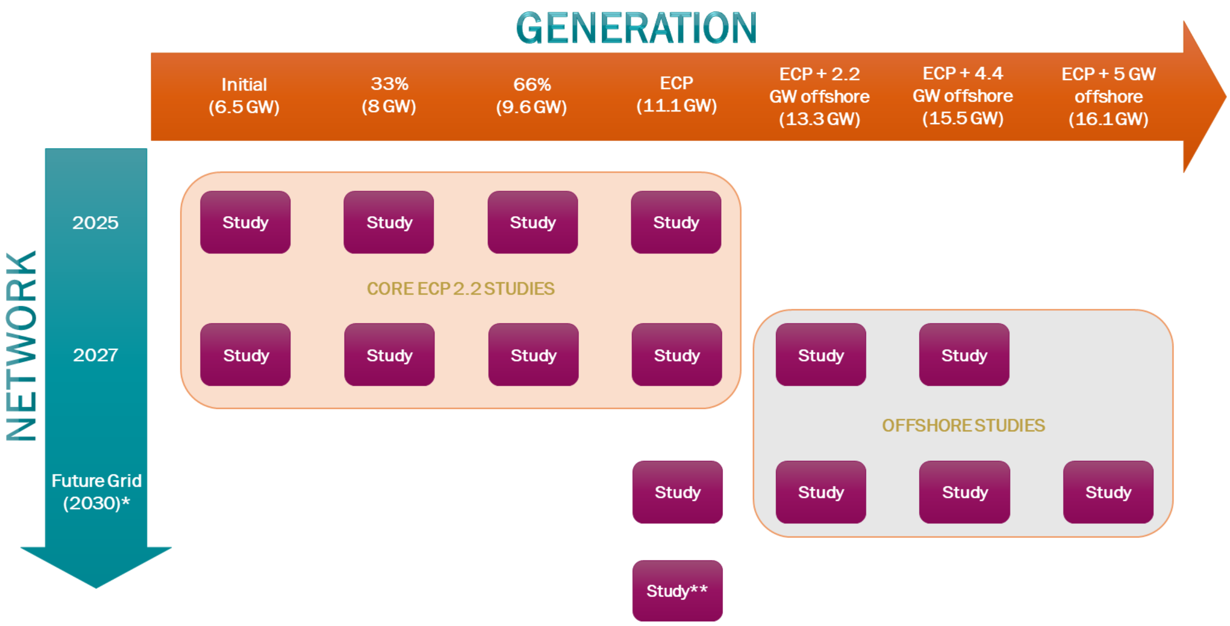

Figure 2-2 Study Scenarios: Matrix of Generation and Network Scenarios

*The Future Grid network is based upon the SOEF Roadmap network, however, network projects that have received capital approval since the publication of the SOEF Roadmap have also been included. **Additional maintenance sensitivity.

A description of the generation scenarios and study year scenarios are provided below in Section 2.3 and Section 2.4 respectively.

2.3 Renewable Generation Scenarios

The four core generation scenarios are summarised below:

- The "Initial" scenario includes all renewable generation currently connected plus all Gate 3, non-GPA, ECP 1 and ECP 2.1 renewable generation expected to connect before the end of 2024.
- The "33%" scenario includes the renewable generation in the "Initial" scenario plus 33% of the difference in renewable generation between the "Initial" and the "ECP" scenario.
- The "66%" scenario includes the renewable generation in the "Initial" scenario plus 66% of the difference in renewable generation between the "Initial" and the "ECP" scenario.
- The "ECP" scenario includes all renewable generation currently connected plus all Gate 3, non-GPA, ECP 1, ECP 2.1 and ECP 2.2 renewable generation.

During the consultations with industry in advance of this review, there was an industry request for further sensitivity studies considering the impact of offshore wind to be included in the study scope. As a result of this, three additional offshore generation scenarios were developed the: "ECP + 2.2 GW offshore", "ECP + 4.4 GW offshore" and "ECP + 5 GW offshore".

The three offshore generation scenarios are summarised below:

- The "ECP + 2.2 GW" offshore scenario includes all renewable generation in the "ECP" scenario plus an additional 2.2 GW of offshore wind.
- The "ECP + 4.4 GW" offshore scenario includes all renewable generation in the "ECP" scenario plus an additional 4.4 GW of offshore wind.
- The "ECP + 5 GW" offshore scenario includes all renewable generation in the "ECP" scenario plus an additional 5 GW of offshore wind.

A variety of renewable generation scenarios are included to take account of the possibility that not all generators will ultimately connect, and to give a view on the Total Dispatch Down seen under various renewable generation build out rates.

The results for each generation scenario are presented explicitly for each area in their respective area report. In this report the results for Area B are presented for each renewable generation scenario.

2.4 Study Year Scenarios

Network	TER (TWh)		
Year	**Ireland**	**Northern Ireland**	**All – Island**
2025	38.5	9.27	47.8
2027	41.3	9.74	51
Future Grid	45.1	10.17	55.2

Table 2-1 Total Electricity Requirement (TER) (TWh) from All-Island Generation Capacity Statement 2022-2031

The study years are chosen to capture expected progress over the short to medium term with regard to predicted operational limitation improvements, transmission reinforcements and forecast demand increase.

This is achieved by studying the years 2025 and 2027. For the years 2025 and 2027, the median demand forecast from EirGrid and SONI's All-Island Generation Capacity Statement 2022-2031[7] was used.

In consulting with industry in advance of this review, there was a request for an additional study showing the impact of the Shaping Our Electricity Future (SOEF) Roadmap. Hence, a Future Grid scenario has also been studied, which has the network and operational constraint assumptions that are aligned with the SOEF Roadmap study. The Future Grid study horizon also includes network reinforcements that have received capital approval since the publication of the SOEF Roadmap. The demand level for the Future Grid study is based on the All-Island Generation Capacity Statement 2022-2031 median demand scenario for the year 2030.

[7] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_SONI_Ireland_Capacity_Outlook_2022-2031.pdf

3 Study Input Assumptions

This section provides an overview of the input assumptions for the over-supply, curtailment and constraint modelling.

3.1 Valid for these Generation Assumptions

The estimated over-supply, curtailment and constraint levels in this report are valid for the generation assumptions used in these studies.

3.2 All-Island Model

As ECP 2.2 is an Ireland connection process, this report provides estimates of over-supply, curtailment and constraint levels for Ireland and not for Northern Ireland. However, for this study, the all-island system including Ireland and Northern Ireland has been modelled in Plexos. This is necessary in order to provide a more accurate estimate of generation reduction levels, given that both over-supply and curtailment are all-island issues.

3.3 Data Freeze

The data freeze for the input assumptions for this analysis was July 2022 for the 2025 and 2027 study years and November 2022 for the Future Grid study year. As a result, there may be some recent developments within the electricity network that are not included.

3.4 Transmission Network Outage Programme

The previous ECP 2.1 constraints analysis included a representative transmission outage schedule. The outages within this schedule represented a geographical spread of circuits across the system and were each configured for a three-month period. This allowed a representation of outage impact in each geographical area to be included within the studies.

After consultation with industry, it was decided for the ECP 2.2 constraints analysis to increase the number of outages and reduce the duration from three-months to one-month. These higher frequency, shorter duration outages were also geographically distributed across the system to give a representation of a transmission outage programme – this schedule was formulated by working alongside the outage planning team within EirGrid. The transmission outage schedule used in this analysis is given in Appendix A Table A4.

This outage schedule was included in the ECP 2.2 analysis, as in reality a transmission outage programme will be implemented each year, resulting in outages of transmission circuits and other equipment for periods of time. Transmission outages may be due to scheduled maintenance, forced outages, to facilitate new connections or for reinforcement reasons (e.g. circuit/busbar uprates).

3.5 Network Requirement for Batteries and Conventional Generators

For this analysis batteries have been modelled using the battery class within Plexos. They have been modelled using the general assumptions shown in Table 3-1.

General Battery Modelling Assumptions	
Max. State of Charge	95%
Min. State of Charge	5%
Charge Efficiency	90%
Discharge Efficiency	90%
Max Cycles per Day	1

Table 3-1 General Battery Modelling Assumptions

The battery capacity (MWh) and max power (MW) has also been entered into the model and were specific to each battery.

For this analysis, the shorter duration batteries (batteries with a storage duration of <= 2 hours), were modelled to supply reserve in the form of Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserve 1 (TOR1) & Tertiary Operating Reserve 2 (TOR2). The residual shorter duration batteries were also used for energy arbitrage when the reserve requirements were met. The reserve requirements used in the analysis is given in Section 3.12.2.4 (Table 3-9).

The longer duration batteries (batteries with a storage duration of > 2 hours) were used within the model for energy arbitrage. The cycling of these batteries was decided by the Plexos optimisation. Plexos identifies the optimal charge and discharge times to maximise returns.

This approach means that the longer duration batteries charge during times of high renewable generation when the system price is lower, therefore, integrating more solar and wind generation on the system. Note the batteries in the model are reacting to system wide prices and are not responding to local issues. In general, this approach means batteries do not export power to the system during times of high wind and solar generation.

For conventional generation, the dispatch is primarily economic in nature. As such, the software only runs the relatively expensive conventional generators infrequently in the simulation.

Hence, the model generally does not dispatch batteries and peaking generators at times of high solar and wind generation output. For this analysis, these assumptions are reasonable. However, in the future, if there was a need for concurrent output from batteries at the same time as wind and solar and/or if a future operation of the system required prolonged running of peaker generators, or that some network capacity be explicitly reserved for peaker generators, then this analysis method would need to be revised.

3.6 Priority Dispatch for Renewable Generation Connecting after July 2019

EU regulation 2019/943 published in June 2019 introduced a clause in relation to the treatment of priority dispatch for renewable generation which connected after the 4th July 2019.

The relevant clause (Article 12) is as follows:

> *REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity*[8]
>
> *Article 12 (6)*
>
> *Without prejudice to contracts concluded before 4 July 2019, power-generating facilities that use renewable energy sources or high-efficiency cogeneration and were commissioned before 4 July 2019 and, when commissioned, were subject to priority dispatch under Article 15(5) of Directive 2012/27/EU or Article 16(2) of Directive 2009/28/EC of the European Parliament and of the Council (20) shall continue to benefit from priority dispatch. Priority dispatch shall no longer apply to such power-*

[8] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

generating facilities from the date on which the power-generating facility becomes subject to significant modifications, which shall be deemed to be the case at least where a new connection agreement is required or where the generation capacity of the power-generating facility is increased.

Under Article 12, renewable generation that connected before the 4th of July 2019 will still hold priority dispatch status, while generation connected after this date will not. This will create a new type of generator for consideration in the dispatch process – the non-priority dispatch renewable generator, connected post July 4th 2019.

The SEMC published a decision paper in relation to Article 12 and 13 of the EU 2019/943 on the 22nd of March 2022[9] (SEM-22-009 Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019/943). The detailed design of Articles 12 and 13 implementation has yet to be determined and may differ from the pro-rata implementation for constraints used in this study. Therefore, an assumed interpretation has been included in this study, this interpretation has been outlined below.

During generation reduction for over-supply reasons, a distinction is made between the treatment of priority and non-priority renewable generators, with non-priority generators being dispatched down ahead of priority generators. Within, these two categories of generation, over-supply is applied pro-rata across the all-island system for all generators in the category.

During curtailment or constraint of renewable generation, no distinction is made between priority and non-priority generators, and dispatch down is applied pro-rata across either the all-island system (in the case of curtailment), or across the relevant transmission nodes (in the case of constraint).

[9] https://www.semcommittee.com/sites/semc/files/media-files/SEM-22-009%20Decision%20Paper%20on%20Dispatch%2C%20Redispatch%20and%20Compensation%20Pursuant%20to%20Regulation%20EU%202019943.pdf

3.7 Network

3.7.1 Transmission Network

This section details the modelling assumptions used in this study for the transmission network.

The transmission system in Ireland and Northern Ireland is a meshed network with voltage levels at 400 kV, 275 kV, 220 kV and 110 kV. The network is necessary to allow bulk power flows to be transported over long distances from power stations and renewable generation sites to the towns and cities in Ireland and Northern Ireland. A diagram of the Irish transmission system in 2021 can be seen in Figure 3-1. In addition to the current transmission network a number of network reinforcements are considered in each network scenario. A list of the network reinforcements used in the study is provided in Appendix A.

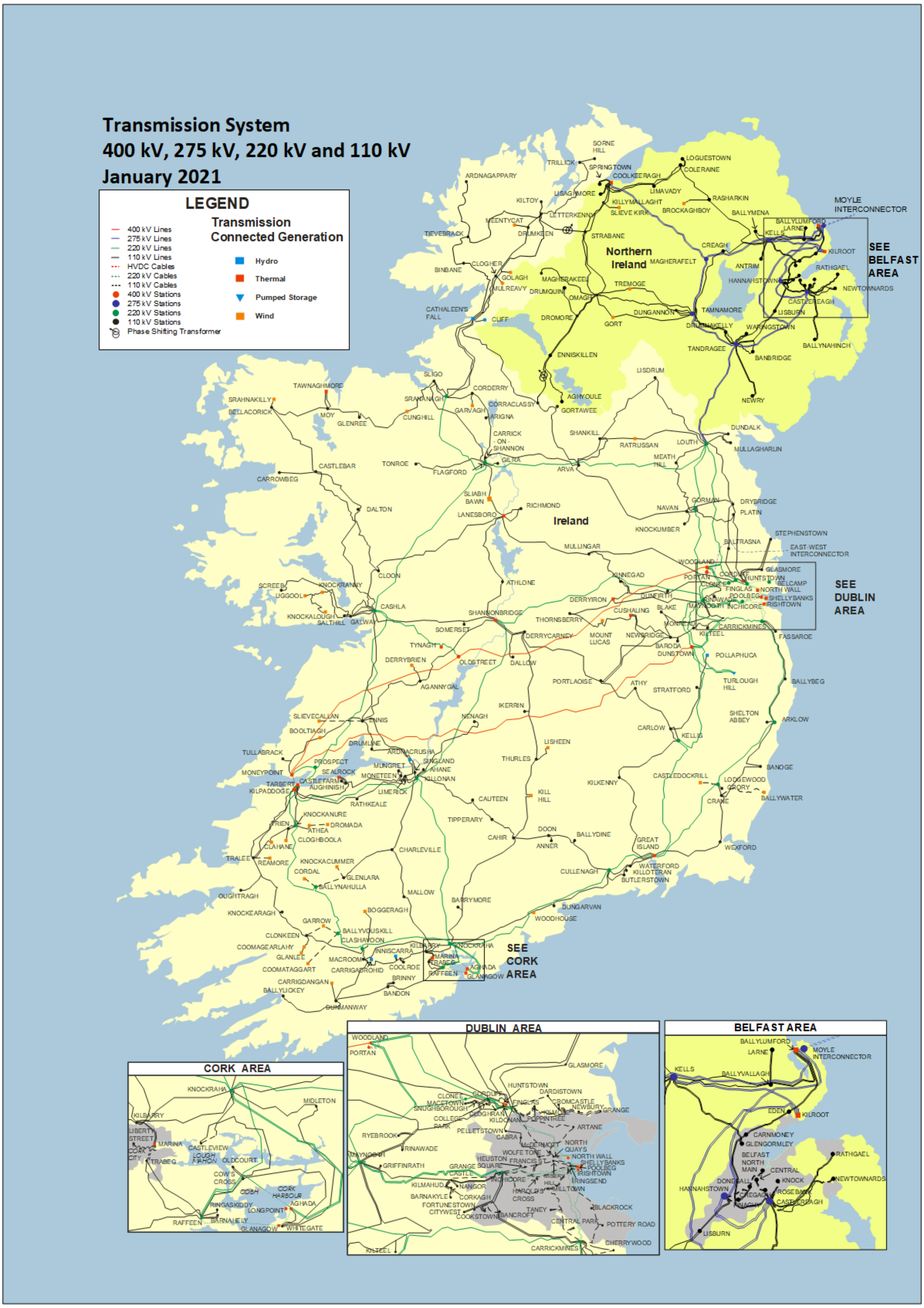

Figure 3-1 Ireland Transmission Network 2021

Figure 3-2 shows the Future Grid (2030) Ireland transmission network, this diagram shows the location of the large network projects that are included in the Future Grid scenario.

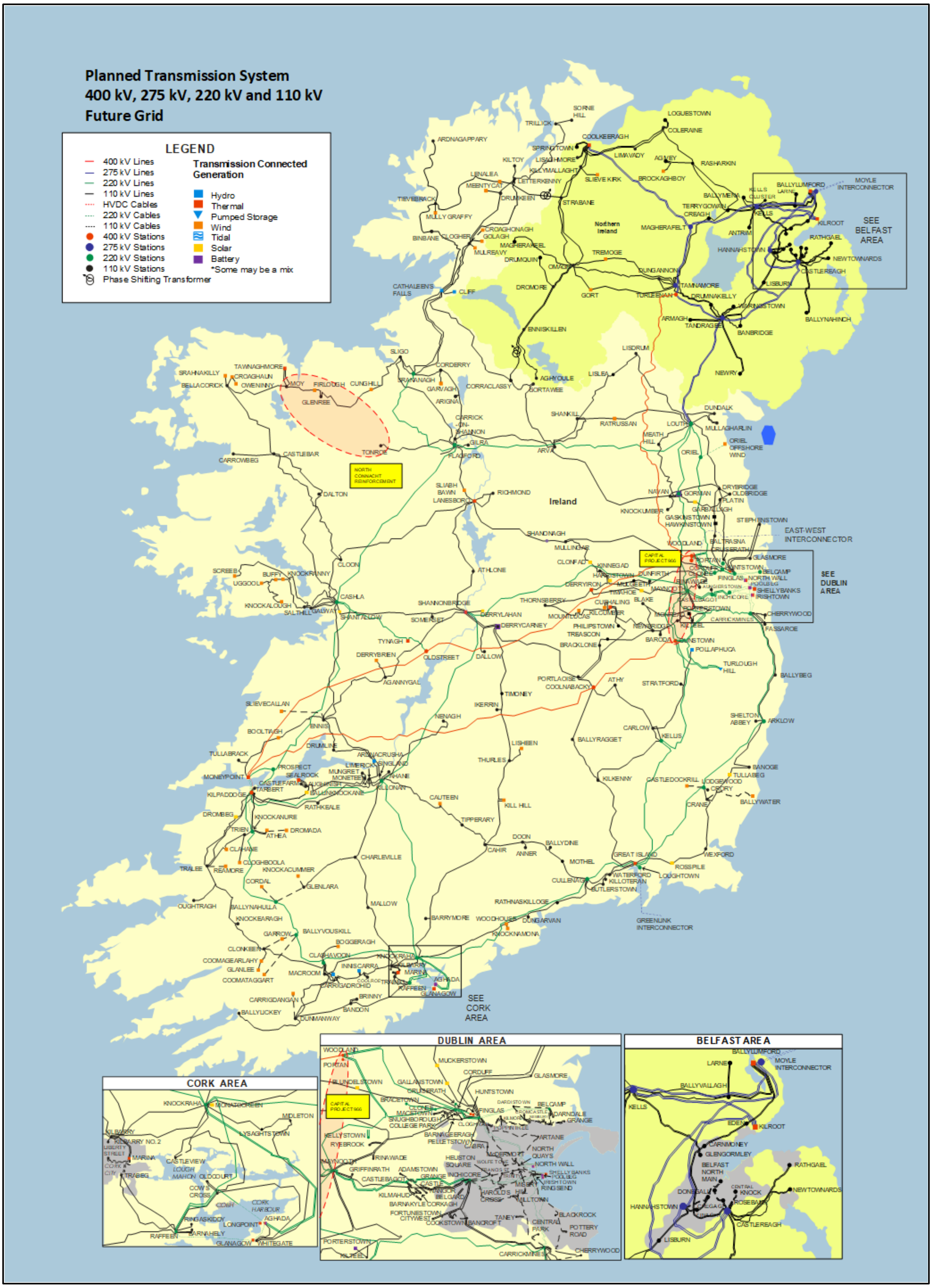

Figure 3-2 Ireland Transmission Network Showing Assumed Future Network Reinforcements

The indicative locations of new stations have been included in Figure 3-2.

3.7.2 Distribution System

For the purposes of the constraints modelling, a simplified representation of the distribution system is used whereby all load and generation is assumed to be aggregated to the nearest transmission node. Hence, this report does not account for the impact of constraints (if any) on the distribution network.

3.7.3 Ratings and Overload Ratings

The Ireland transmission system is operated to safely accommodate a single transmission asset loss (N-1 contingency). While formulating an optimum dispatch, system operation takes account of potential overloads that could be caused as a result of certain N-1 contingencies on the transmission system. When determining if the post-contingency flows are within limits, the system operator uses the overload rating of the apparatus or plant (for N-1) as well as the normal rating (for N flows). Where available, the overload rating is typically higher than the normal rating but is only allowed in emergency conditions and for short periods of time. The overload rating is plant specific. The Plexos models used for ECP 2.2 constraint reporting include N-1 contingency monitoring and both ratings and overload ratings.

3.7.4 Transmission Reinforcements

For each study year (2025, 2027 and 2030 Future Grid) a number of transmission reinforcements are added to the model. These additional transmission reinforcements include overhead lines (OHL) and cable upratings as well as new build OHLs, cables and transformers.

A full list of the transmission reinforcements (new build and uprates) assumed in the constraints modelling is included in Appendix A.1 – A.3.

Customers should recognise that the reinforcements listed will be subject to a full analysis and optimisation process under EirGrid's Framework for Grid Development before a decision is made to proceed with them. Inclusion of transmission reinforcement projects in this report is not confirmation that they will proceed, and other projects may be selected in their place. For the avoidance of doubt, any party making a decision based on this list should recognise that these are modelling assumptions only and should not be considered as a basis in fact. Additional information about reinforcements is available on the EirGrid website[10].

3.8 Demand

An introduction to the demand used in this report is provided in Section 2.

The demand profile shapes for Ireland and Northern Ireland are based on their 2019 historical demand profiles. The historical profiles are adjusted to reflect a future winter peak (Transmission Winter Peak) and Total Energy Requirement (TER) based on the All-Island Generation Capacity Statement 2022 – 2031 median demand for the 2025, 2027 and 2030 (Future Grid) years. The values used are shown in Table 3-2.

	TER (TWh)			Transmission Winter Peak (GW)		
Year	**Ireland**	**Northern Ireland**	**All-Island**	**Ireland**	**Northern Ireland**	**All-Island**
2025	38.5	9.27	47.8	6.4	1.7	8.07
2027	41.3	9.74	51	6.57	1.77	8.3
Future Grid	45.1	10.17	55.2	6.87	1.83	8.67

Table 3-2 Forecast Demand and Peak for Study Years 2025, 2027 and Future Grid

The nodal distribution of the load used in the constraints modelling is consistent with the "All-Island Ten Year Transmission Forecast Statement 2021[11]".

[10] https://www.eirgridgroup.com/the-grid/projects/

[11] https://www.eirgridgroup.com/site-files/library/EirGrid/All-Island-Ten-Year-Transmission-Forecast-Statement-TYTFS-2021.pdf

3.9 Interconnection

Existing interconnection on the island consists of a tie line between Ireland and Northern Ireland plus two High Voltage Direct Current (HVDC) interconnectors to Great Britain (GB), referred to as the Moyle Interconnector and the East-West Interconnector (EWIC). This section describes the assumptions and modelling methodology used for interconnection in these studies.

3.9.1 North-South Tie Line

The connection of Ireland's power system to Northern Ireland is achieved via a double circuit 275 kV line running from Louth to Tandragee. In addition to the main 275 kV double circuit, there are two 110 kV connections: one between Letterkenny in Co. Donegal and Strabane in Co. Tyrone, and the other between Corraclassy in Co. Cavan and Enniskillen in Co. Fermanagh.

The purpose of these 110 kV circuits is to provide support to either transmission system for certain conditions or in the event of an unexpected circuit outage. Phase shifting transformers in Strabane and Enniskillen are used to control the power flow under normal conditions.

It is assumed that the Letterkenny - Strabane and Corraclassy - Enniskillen 110 kV connections are not used to transfer power between the two control areas for the purposes of this modelling exercise.

EirGrid and SONI are also currently developing a 400 kV North-South Interconnector between Woodland in Ireland and Turleenan in Northern Ireland. The new North-South Interconnector is assumed to be in place for the 2027 and 2030 (Future Grid) scenarios.

Prior to the 400 kV North-South Interconnector being built, the existing Louth - Tandragee Interconnector is assumed to be limited. The assumption in this study is that flows are limited to 300 MW from South to North and 300 MW from North to South. When the 400 kV second North-South Interconnector is in place, this limitation will be effectively raised to 1000 MW inter-area flow.

3.9.2 Moyle Interconnector

The Moyle Interconnector, which went into commercial operation in 2002, connects the electricity grids of Northern Ireland and Great Britain between Ballycronan More (Islandmagee) and Auchencrosh (Ayrshire). It has a transfer capacity of 500 MW, however, due to constraints on the transmission networks at either end this capacity can be reduced.

For the purposes of this study the Moyle Interconnector is assumed to have a 400 MW export capacity and a 450 MW import capacity for all study years.

3.9.3 East-West Interconnector (EWIC)

The East-West Interconnector links the electricity grids of Ireland and Great Britain, from convertor stations at Portan in Ireland to Shotton in Wales. It began commercial operation in December 2012.

The EWIC Interconnector is modelled for all study years with a maximum capacity of 500 MW.

3.9.4 Greenlink Interconnector

The Greenlink Interconnector is due to be commissioned in 2024 and will connect the electricity grids of Ireland and Wales between Great Island (Co. Wexford) and Pembroke (Co. Pembrokeshire). The Greenlink Interconnector is assumed to be connected for all study years with an import/export capacity of 500 MW.

3.9.5 Celtic Interconnector

The Celtic interconnector connecting Ireland with France is modelled in the 2027 and 2030 study years. This subsea HVDC (High Voltage Direct Current) cable is expected to be commissioned in 2026 and will have an import/export capacity of 700 MW.

An overview of the interconnector capacities can be seen in Table 3-3.

3.9.6 Interconnector Capacities

The interconnector rated capacities used in the model are shown in Table 3-3.

Interconnector Capacity	Export/Import	2025	2027	Future Grid
Moyle (MW)	Export	400	400	500
	Import	450	450	500
EWIC (MW)	Export	500	500	500
	Import	500	500	500
Greenlink (MW)	Export	500	500	500
	Import	500	500	500
Celtic (MW)	Export	-	700	700
	Import	-	700	700

Table 3-3 Interconnection Rated Capacities

It is a study assumption that interconnectors can be used to export renewable energy, with the provision that, when calculating an annual average behaviour, it would be optimistic to assume that maximum interconnector export will always be available when required.

Based on historical flow analysis, the interconnectors to GB are modelled to have a full export capacity for 65% of the time. As a result, the Moyle, EWIC and Greenlink interconnectors are modelled with an ability to export at full capacity for 63% of the time. While for 14% of the time all the three IC's to GB are considered to be available at 75% of their full capacity, and for 11% of the time they were available at 50%, and 5% of time with 25% of full capacity and remainder with 0% export capacity. Using this information, the capacity of these IC's were assigned for the year.

Additional interconnector analysis was undertaken using a modified Ten-Year Network Development Plan (TYNDP) model. This analysis suggested that during times of high wind (wind output > 3 GW) there would be considerable exports from Ireland to France through the Celtic interconnector.

Due to the lack of historical interconnector flow data, we assumed an export capacity of 560 MW (de-rated by 20%) for the Celtic interconnector. This has been assumed as there will be times when the market schedule will provide less export than theoretically possible. An example of this may include, when the receiving country may not be in a position to accept large trades. The use of full interconnection capacity may lead to the understating of dispatch down levels.

3.10 Priority Dispatch for Wind and Solar Generation

The priority dispatch status of renewable generation is only applicable for generators connected before the 4th July 2019.

For this study, when applying generation reduction for over-supply reasons, priority generators are given a negative offer price in the model to ensure their priority in the dispatch. During generation re-dispatch for curtailment and constraint reasons, the renewable generators are all given a zero-offer price without a distinction being made between priority and non-priority generators[12]. As Plexos seeks to provide the most economical solution while satisfying all system constraints it consequently will run as much wind and solar generation as is possible.

[12] These generator price assumptions have been applied for the purposes of modelling in this study only. The design of the implementation of Articles 12 and 13 in EU Regulation 2019/943, has yet to be agreed by the relevant industry stakeholders and may differ from the implementation used in this study.

3.11 Generation

An introduction and overview of the generation in this study is provided in Section 2. Additional detail is now provided in this section.

3.11.1 Conventional Generation

The model includes a portfolio of the thermal conventional generation in both Ireland and Northern Ireland. The operating characteristics of the existing conventional generation employed in the modelling are principally based on the SEM Generator Dataset. In some instances, minor changes to the dataset are made due to additional information becoming available to the TSOs.

The technical dataset includes the following information:

1. Fuel type (e.g. gas, wind, coal etc.) including emissions rates;
2. Maximum and minimum operating output (MW);
3. Capacity state and heat rates (used to determine how much fuel is burnt to produce 1 MW of output power);
4. Ramp rates (important to determine how quickly a machine can change its power output);
5. Minimum up-time and downtime.

This technical data allows the Plexos software to calculate the cost of generating a megawatt of electrical energy for each generator in the model. Note that each generator has a different cost.

Other factors that influence the generation dispatch over an extended study horizon are:

- Generation commissioning and decommissioning;
- Generation outages;
- Generation emissions restrictions.

3.11.2 Conventional Generation Outages

Scheduled and forced conventional generator outages are modelled in Plexos using Scheduled Outage Durations (SODs) and Forced Outage Probabilities (FOPs).

For this study, the Forced Outage Probabilities are used. The FOPs employed are those used for the Dispatch Balancing Costs (DBC) 2020 – 2021 Forecast. Plexos generates forced outage patterns from the FOP and mean time to repair data. This provides a deterministic outage pattern against which the model dispatches generation against demand.

3.11.3 Renewable Generation

The amount of electrical energy output from renewable generation is generally described in terms of capacity factor. The capacity factor relates to the amount of energy that may be achieved from a renewable technology over the period of one calendar year. Generally solar PV has lower capacity factor than the wind generators. One factor in the energy yield difference is that solar PV does not produce electrical energy at night, but the wind can blow at any time of the day or night.

The values used in this study for solar and wind are listed in the following sections.

3.11.3.1 Solar

On average, solar profiles tend to have a fairly predictable shape. Figure 3-3 shows the average hourly energy output from solar PV over a one-year period. The capacity factor for solar PV is largely dependent on latitude – the closer to the equator the higher the annual capacity factor. The solar capacity factor for a country like Spain will have a value of around 20%, i.e. double the output of Ireland.

The surface plot of Figure 3-3 highlights the typical Ireland solar profile characteristic. The lowest intensity of solar electrical output is in the four winter months November through to February with hourly values on average not exceeding 20% of the PV panels max output. As expected, the solar electrical energy output is highest in the summer months with average hourly solar electrical output peaking in the 50-60% range.

The main point is that the solar electrical available energy is fairly predictable and is typically there during times of increasing electrical demand such as the morning load demand rise. However, the winter peak demand will not be met by solar.

Additionally, solar energy output may be reduced if it is located on a part of the network that has constraint issues.

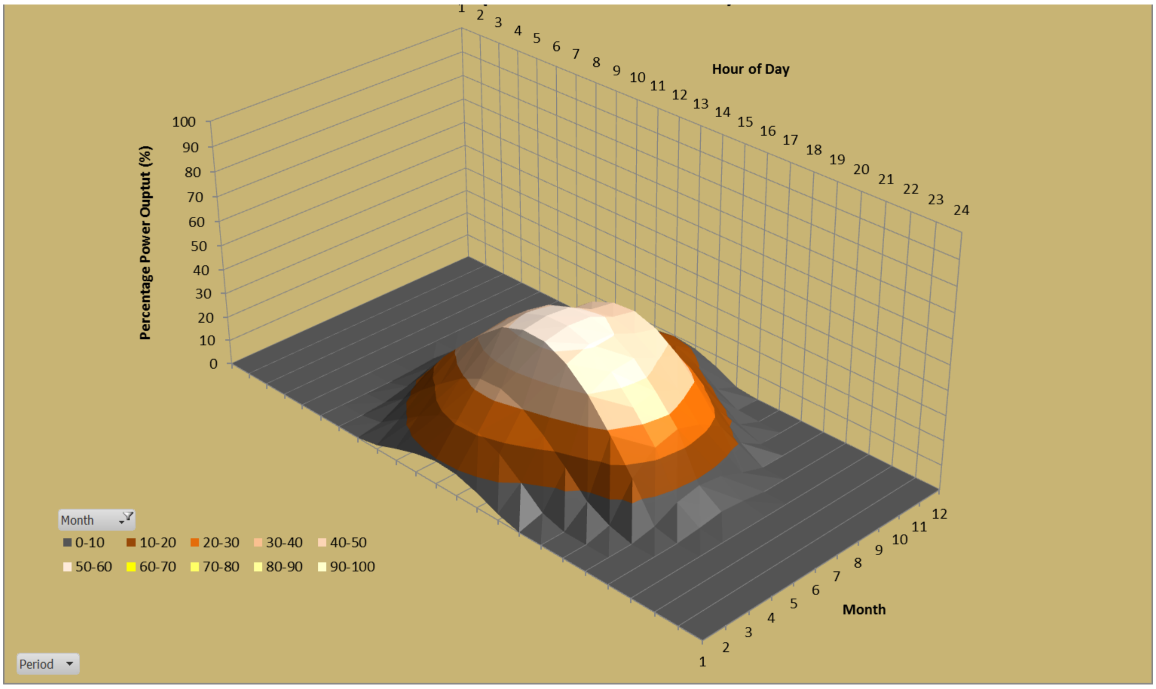

Figure 3-3 Representative Solar Energy Profile (Monthly Average – Hour of Day)

3.11.3.1.1 Solar Profiles

Solar generation is modelled in the analysis using an hourly solar power series at every transmission node where solar generation is connected.

For the previous ECP 2.1 analysis three solar profiles were used: solar north, solar middle and solar south. In the ECP 2.2 analysis the same approach is used, however, the solar profiles have been updated. The solar North data was obtained from the recorded data from solar plant in Northern Ireland (NI) for the year 2020. The solar Middle and solar South profiles were obtained by EirGrid through industry engagement. This 2020 solar data will ensure alignment with the 2020 wind profile.

This solar grouping approach captures the variations in solar energy when comparing solar farms in the north to solar farms in the south. Clearly, this approach does not consider hourly variations in solar power within each area, due to local cloud cover in that individual hour, etc. Since this study is focused on the over-supply, curtailment and constraint on the transmission system, it is reasonable to assume that these solar profiles capture the average behaviour of solar on the island.

The groupings used are shown in Figure 3-4. The capacity factors of the different profiles are shown in Table 3-4.

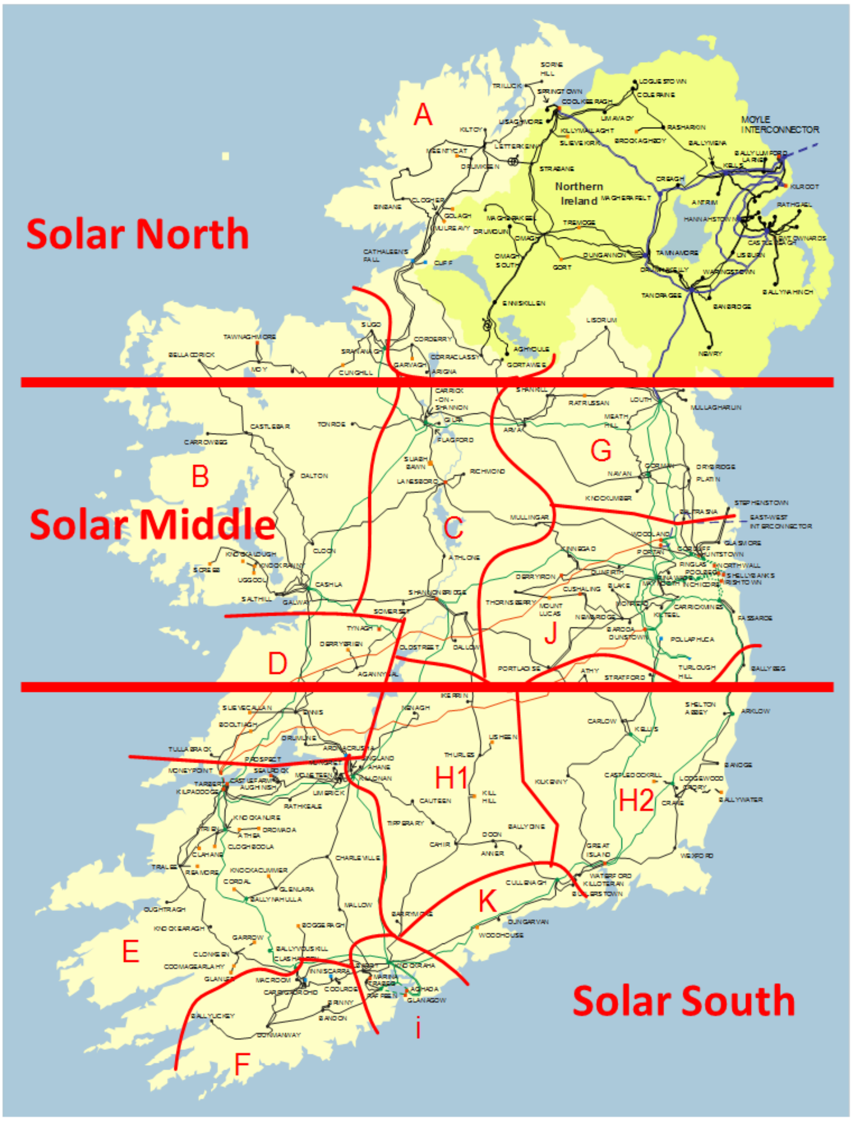

Figure 3-4 Groupings Used for Solar Profiles in Model

Solar	Capacity Factor
Solar North	11.9%
Solar Middle	12.1%
Solar South	12.7%

Table 3-4 Capacity Factor of Solar Profiles

3.11.3.1.2 Wind

This section details how wind generation on the island of Ireland is modelled in Plexos.

Wind generation is modelled using an hourly wind power series at every transmission node where wind generation is connected. To provide a representative wind series, wind profiles are used. In this study, wind profiles are used for all wind farms in an area, i.e. the same wind profiles are used for wind generators in a single area.

By using historical wind profiles, it is possible to account for the geographical variation of wind power across the island. The ECP 2.1 wind profiles were created using 2015 wind data. For ECP 2.2, 2020 wind data is used for the wind profiles. This 2020 wind data aligns with the 2020 solar data. The capacity factors of these wind profiles are shown in Figure 3-5 and in Table 3-5.

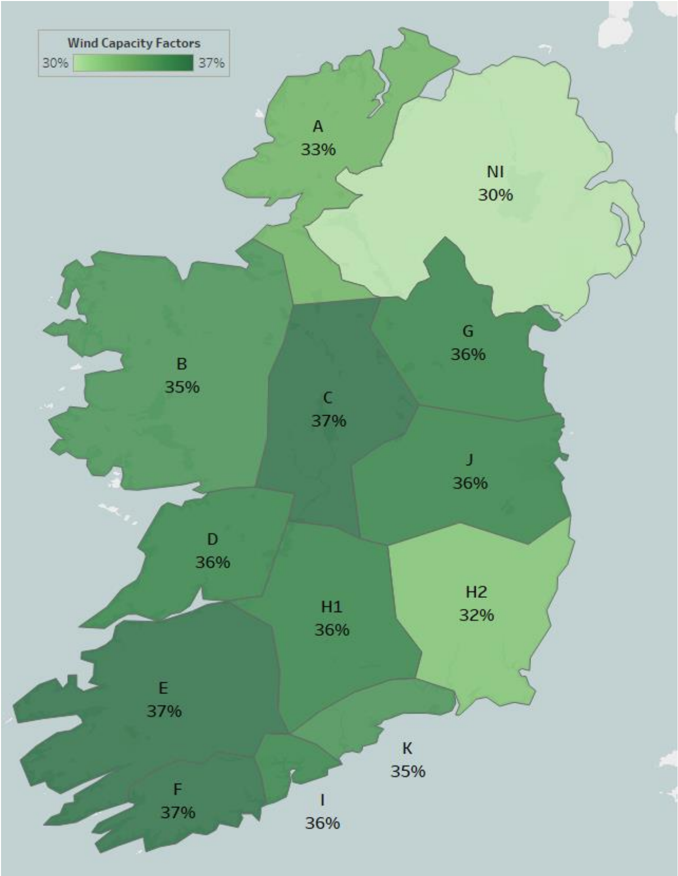

Figure 3-5 2020 Capacity Factor by Area for Wind

Wind Regions	2020 Capacity Factors
Ireland	
A	33%
B	35%
C	37%
D	36%
E	37%
F	37%
G	36%
H1	36%
H2	32%
I	36%
J	36%
K	35%
Offshore	45%
Northern Ireland	
NI	30%

Table 3-5 Capacity Factors for Future Wind

Similar to 2015 wind data, 2020 wind data has comparatively higher capacity factor (high wind year). This value is representative of a wind fleet that will include new onshore and offshore wind farms incorporating the latest available technology.

3.11.3.2 Installed Capacity

Section 2 describes the renewable generation scenarios that are considered as part of this analysis. Some further detail is provided here.

A variety of renewable generation scenarios are included to take account of the possibility that not all generators will ultimately connect, and to give a view on the Total Dispatch Down seen under various renewable generation build out rates. The levels of installed solar and wind generation included in each scenario are shown in Table 3-6.

The Initial scenario includes currently connected renewable generation plus all renewable generation expected to be connected by end of 2024. The "ECP" scenario includes all renewable generation up to and including ECP 2.2. The 33% and 66% scenarios were created by scaling the outputs of generators assumed to connect post-2024 by 33% and 66% respectively.

Gen Type (MW)	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Solar	1,389	2,442	3,496	4,549	4,549	4,549	4,549
Wind	5,072	5,581	6,090	6,599	6,599	6,599	6,599
Wind Offshore	-	-	-	-	2,197	4,394	4,994
Totals	**6,461**	**8,023**	**9,586**	**11,148**	**13,345**	**15,542**	**16,142**

Table 3-6 Connected and Contracted Solar and Wind Quantities in Ireland for the Study Scenarios

3.11.3.3 Generation Controllability

Historically smaller (and some older) wind farms and solar generators are not controllable. The study methodology takes into account all uncontrollable wind and solar generation and does not include these generators in any output reduction calculations.

Generally, apart from some older windfarms, it is assumed that all wind farms are controllable if their maximum export capacity (MEC) is greater than or equal to 5 MW (for generators which received a connection offer before 2015) or if their MEC is greater than or equal to 1 MW (after 2015). All solar farms with an MEC greater than or equal to 1 MW are assumed to be controllable.

3.11.3.4 Perfect Foresight – Wind Forecast

Building an economic power market model will always require input assumptions. One such assumption is that the climatic year will be from historical data. The use of historical data means that the power market model will create generation commitment and dispatch decisions based on the perfect foresight of wind and solar output. In real-time operation of the power system, this is not the case and there will be forecast errors associated with variable renewables and demand. Perfect foresight may mean that power market models show lower levels of curtailment since it may choose to de-commit units based on what it knows will happen. In reality, wind or demand forecast errors may mean that a different schedule of generators may be required than that modelled with perfect foresight.

3.12 System Operation

3.12.1 Safe Operation (Security Constrained N-1)

The basic principle of N-1 security in network planning states that if a component, such as a transformer or circuit, should fail in a network, then the network security must still be guaranteed and the remaining network resources must not be overloaded or exceed the short-term overload capability of the equipment. System voltage must also remain within permitted limits although Plexos, as a DC load flow analysis tool, does not monitor system voltage as part of this study.

EirGrid operates the Ireland transmission network to be N-1 secure. This Plexos study also monitors N-1 contingencies to ensure the results are valid for an N-1 secure network.

3.12.2 Operational Constraint Rules

This section presents the all-island operational constraints, which feed into the Plexos economic dispatch tool. The operational constraints cover System Non-Synchronous Penetration (SNSP), inertia, operating reserve requirements and minimum number of synchronous units required.

The purpose of this section is to define the set of operational constraints, and how these constraints may evolve over the proposed study horizons. Operational constraints are important as they define system limits that may require reductions in renewable generation, resulting in curtailment. In general, it is expected that certain operational constraints may be relaxed over time, as the system evolves.

3.12.2.1 System-Wide Operational Constraints

There are several system-wide operational constraints which ensure that the system operators can operate the system securely and within stability limits.

This study uses the operational constraints listed in Table 3-7. The RoCoF limit was not monitored in the Plexos study but is included in Table 3-7 for information.

Active System Wide Operational Constraints (SNSP, Inertia & Minimum Sets)		
Limit	**Operational Constraint Rule**	**Limit Across the Study Years**
Non-Synchronous Generation	There is a requirement to limit the instantaneous penetration of asynchronous generation connected to the All-Island system.	2025 – 85% 2027 – 85% 2030 – 95%
Operational Limit for RoCoF	There is a requirement to limit the RoCoF on the All-Island system.	2025 – 1 Hz/sec 2027 – 1 Hz/sec 2030 – 1 Hz/sec
Operational Limit for Inertia	There is a requirement to have a minimum level of inertia on the All-Island system.	2025 – 20,000 MWs 2027 – 17,500 MWs 2030 – 17,500 MWs
Minimum Sets (IE, NI)	There is a requirement to have a minimum number of conventional generators in Ireland and Northern Ireland.	2025 – 4, 2 2027 – 3, 2 2030 – 2, 2
Reserve (IE, NI)	The amount of spare capacity in the system to manage any system disturbance.	POR, SOR, TOR I, and TOR II

Table 3-7 Active System Wide Operational Constraints (SNSP, Inertia & Minimum Sets)

3.12.2.2 System Non-Synchronous Penetration (SNSP)

There is a system need to limit the amount of 'non-synchronous' generation at any point in time. The limit ensures that the power system operates within a stable zone.

A mathematical expression describing the SNSP rule is as follows:

$$\frac{All\ Island\ Asynchronous\ Generation + Interconnector\ Imports}{All\ Island\ Demand + Interconnector\ Exports} \leq SNSP\ Limit$$

An increase in the SNSP limit will allow more 'non-synchronous' generation to be accepted onto the system.

3.12.2.3 Minimum Number of Synchronous Generators

There is a requirement to have a minimum number of conventional generators synchronised at all times to provide inertia to the power system, ensure voltage stability, dynamic stability and to ensure that network limitations (line loading and system voltages) are respected. The minimum number of units in each study horizon is given in Table 3-7.

Changes to the rules are guided by operational and/or planning assumptions. Table 3-8 provides the current requirements for minimum number of conventional units required on the system.

Minimum Conventional Generation Assumptions
Ireland
A minimum of 2 large units in the Dublin region must be synchronised at all times. A minimum of 5 large units in Ireland must be synchronised at all times.
Northern Ireland
A minimum of 3 large units in Northern Ireland must be synchronised at all times.

Table 3-8 Summary of Current Conventional Minimum Generation Assumptions

3.12.2.4 Operating Reserve

Operating reserve is surplus operating capacity that can instantly respond to a sudden increase in load or decrease in generation output. Operating reserve provides a safety margin that helps ensure reliable electricity supply despite variability in the load and generation. To provide reserve, some generators are part-loaded i.e. are operated below their maximum output capacity to provide a fast-acting source of reserve. Reserve can also be provided by non-conventional sources such as batteries, storage, interconnectors and demand response, in the future, it is expected that a greater share of reserve may be maintained by such non-conventional sources.

For the ECP 2.2 constraints analysis, batteries with a storage duration of less than and equal to 2-hours were modelled to provide reserve. Batteries with a storage duration greater than 2-hours were modelled to provide energy arbitrage only. Due to the large volume of batteries within the analysis with a storage capacity of less than and equal to 2 hours the majority of the operating reserve required in the analysis was supplied by batteries – this is expected to be the case in the future. The operating reserve requirements modelled in the analysis can be seen in Table 3-9.

Operating Reserve Requirements			
Limit	**All-Island Requirement % of Largest In-Feed**	**Ireland Minimum (MW)**	**Northern Ireland Minimum (MW)**
Primary Operating Reserve (POR)	75%	155	50
Regulating Sources of Primary Operating Reserve (POR*)	-	75	50
Secondary Operating Reserve (SOR)	75%	155	50
Tertiary Operating Reserve 1 (TOR1)	100%	155	50
Tertiary Operating Reserve 2 (TOR2)	100%	155	50

Table 3-9 Active Operating Reserve Requirements

*Regulating Sources of Primary Operating Reserve must be provided by conventional generation.

4 Study Methodology

This section provides an overview of the modelling methodology employed to determine the likely over-supply, curtailment and constraint levels for renewable generation in this study.

The methodology of production cost modelling is utilised to conduct the studies for this report. This section includes a detailed description of production cost modelling, and an overview of Plexos (the modelling tool employed) is also provided. In addition, there is a description of the over-supply, curtailment and constraint modelling methodology.

4.1 Production Cost Modelling

In general terms, production cost models utilise optimisation algorithms with the objective of minimising the cost of generating power to meet demand in a region while satisfying operational, security and environmental constraints. A production cost model minimises the combined fuel cost, CO_2 cost, variable operation, maintenance and start-up cost. In the model, wind and solar generation are variable sources with zero production cost. Hydro generation also has zero production cost but is energy limited. Chronological production cost models optimise generator commitment and dispatch scheduling for every hour of a study period (typically one-year duration).

Production cost models require:

- Specification of individual generator capabilities including capacity, start-up energy, annual forced outage rate, annual scheduled outage duration, reserve provision capabilities, emission rates and heat rates (fuel input requirement per unit output generation).
- Specification of the hourly demand profile for the region.
- Specification of the fuel price for each type of fuel.
- Specification of the transmission network (required for studies where transmission constraint information is the desired output).
- Specification of contingencies.
- System security constraints such as the requirement for reserve.
- Generator operational constraints such as maximum and minimum operational levels, ramp rates, minimum runtimes and downtimes etc.
- Environmental considerations such as the cost of CO_2.

The commercially available production cost modelling tool employed in this study is Plexos.

4.2 The Software: Plexos Integrated Energy Model

Plexos is a detailed generation and transmission analysis program that has been widely used in the electricity industry for many years. EirGrid has extensive experience in using this simulation tool to model the Irish power system. It is a production cost modelling simulation program, used to determine power system performance and cost. It is a complex and powerful tool for power system analysis, with separate commitment and dispatch algorithms.

4.2.1 Commitment and Dispatch

The commitment process refers to the selection of a number of generators, from the total generation portfolio, that are available to meet customer demand. The decision as to when these generators should be on or off-line is also part of the commitment process. For example, additional generation is committed on Monday mornings to meet the higher weekday demand compared to the lower weekend demand where less generation is required.

The dispatch process refers to the decisions taken on the loading of individual generation units. Thus, the contribution from each online or committed unit towards meeting customer demand is determined by the dispatch decision.

4.2.2 Generator, Demand and Network

Full technical performance characteristics and operational cost details of each generation unit on the system are specified. An hourly system demand profile is also required. Additionally, in this study, the transmission system is modelled.

The program output provides complete details of the operation of each generation unit. These are aggregated into system totals. Flows on transmission lines can be monitored and potential constraints on the system can be identified. A wide range of output reports are available, from system summaries to hour-by-hour information on individual generators.

4.2.3 DC Loadflow

Plexos is a DC loadflow simulation tool. Therefore, it only models real power flows and does not consider voltage. Transmission plant and line ratings are MVA rated and ratings vary with voltage. For the purposes of modelling the DC load flow MW ratings for the circuits, the model assumes a conversion factor of 0.9.

The conversion factor allows the necessary spare capacity for reactive power on the circuits and it allows for post-contingency low voltage. This 0.9 conversion factor gives a good performance for a wide range of pre-contingency and post-contingency conditions.

The Plexos model, as constructed, does not account for losses. However, losses are accounted for within the Total Electricity Requirement (TER) demand figures.

4.3 System Model

For this study, the system is modelled at generator level where each conventional generator is modelled in detail. Characteristics such as heat rates, ramp rates, minimum runtime and downtime, start-up energy, reserve provision capabilities, annual forced outage rate, annual scheduled outage duration and emission rates of each individual generator are specified.

Solar and wind powered generators are modelled at 110 kV node level. In other words, if several windfarms are fed from a 110 kV node, the model represents them as a single windfarm at that node. The same is true for solar farms. These generators use hourly generation profiles series. More detail on the modelling of solar and wind powered generation is provided in Section 3.11.3.

Ireland and Northern Ireland are treated as a single dispatch system in the production cost model for the purposes of producing an optimal minimum cost commitment and dispatch. Generators are dispatched based on their short-run marginal costs (which include the costs of fuel and CO_2 emissions) and in accordance with the dispatch assumptions outlined below.

4.4 Software Determination of Over-Supply, Curtailment and Constraint

For this report, wind and solar generators are assumed to be Grid Code compliant and it is assumed that controllable wind and solar generators can be instructed to reduce their output if required. It is worth noting that there are a small number of older wind turbine sites that are uncontrollable, as mentioned in Section 3.11.3.3.

The Plexos model is used to calculate over-supply, curtailment and constraint. A number of supplementary studies are also needed to properly apportion each of these three types of reduction in generator output.

In the simulation, generators are committed and dispatched in the most economical manner while satisfying operational and security constraints such as limitations on the instantaneous wind/solar penetration, operating reserve requirements, requirement for a minimum number of synchronised conventional generators, system inertia limits, as well as the limitations of the transmission network.

The simulation is a security constrained N-1 study. This means that the network flows are constantly monitored to be safe against the possible loss of any item of transmission equipment.

The total reduction in energy for each renewable generator is calculated by comparing the renewable energy output from the simulation with the available renewable energy.

4.5 Apportioning of Over-Supply, Curtailment and Constraint

4.5.1 Over-supply

Per Article 12 of the EU's Clean Energy Package, priority dispatch of renewable generation will continue to apply only to generators which connected prior to July 4th 2019.

For this study, during generation reduction for over-supply reasons, a distinction is made between the treatment of priority and non-priority renewable generators, and non-priority generators are dispatched down ahead of priority generators. Within, these two categories of generation, over-supply is applied pro-rata across the all-island system for all generators in this category.

4.5.2 Curtailment

For hours when it is necessary to curtail wind and solar generation output, a decision must be made as to which generators should have their output reduced. It is assumed in this study that, where possible, all controllable wind and solar generators share the reduction in output energy arising from curtailment in proportion to their available energy in that hour i.e. on a pro-rata basis.

4.5.3 Constraint

When a transmission constraint occurs, Plexos will attempt to alleviate the constraint in the most cost-effective manner.

If a transmission constraint causes wind or solar generation to be constrained down, Plexos' internal dispatch logic may choose one generator to constrain down out of several that have the same flow impact on the constraint (due to the fact that, in the constraints model, all wind and solar generators are modelled with zero cost of production).

This report studies the connection of very large amounts of generation to the transmission network. As such, there are some areas where the levels of transmission constraints are both large and frequent. There are also areas where there are, at times, several overlapping operational and transmission constraints. This makes it more difficult to apportion curtailment and constraints to individual nodes.

Post-processing of the results is required to ensure study results are more representative of the application of a constraint instruction. The process involves sharing the constraint volume proportionally between generators that have a similar impact on a constraint issue.

5 Results Summary for Ireland

This section provides a summary of the Total Dispatch Down levels estimated by this study at a system level for Ireland.

Results are shown for the core study scenarios consisting of:

- Study year scenarios 2025 and 2027.
- Renewable generation scenarios Initial, 33%, 66% and ECP.

Results are also shown for the sensitivity study scenarios that were developed in consultation with industry, and in response to industry feedback, consisting of:

- A Future Grid study based on 2030 demand levels and aligned with the network from the SOEF Roadmap.
- Five offshore wind scenarios: ECP + 2.2 GW offshore (2027), ECP + 4.4 GW offshore (2027), ECP + 2.2 GW offshore (2030), ECP + 4.4 GW offshore (2030) and ECP + 5 GW offshore (2030).

Figure 5-1, Figure 5-2 and Figure 5-3 provide an overview of:

- System Total Dispatch Down percentage levels; broken down by over-supply, curtailment and constraint.
- System Total Dispatch Down and wind and solar generated energy levels in TWh; broken down by over-supply, curtailment, constraint and generation levels.
- Total Dispatch Down percentage levels per area; broken down by solar not priority, wind not priority and wind priority.

In general, a reduction in Total Dispatch Down levels is seen in later study years due to the benefits of network reinforcements, future interconnection, relaxation of operational constraints and increased demand levels.

An increase in Total Dispatch Down levels is seen for the offshore sensitivity studies, which is largely driven by over-supply.

More detailed results for Area B can be seen in Section 6.

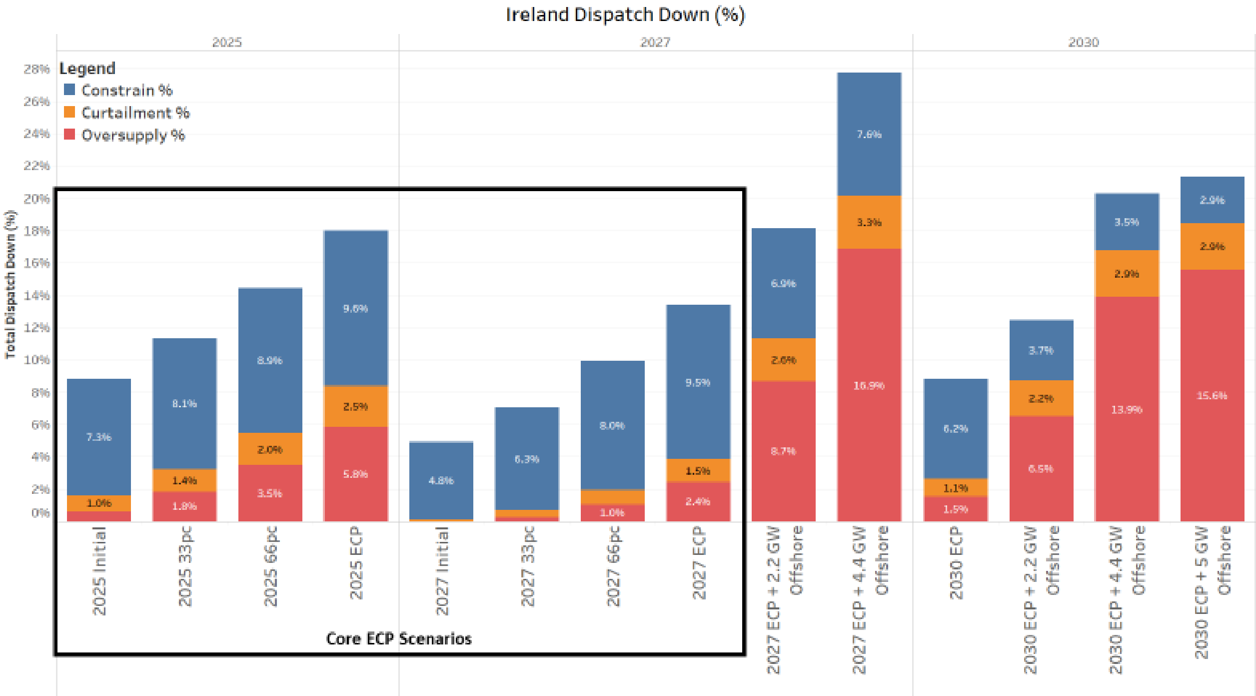

Figure 5-1 System Total Dispatch Down %

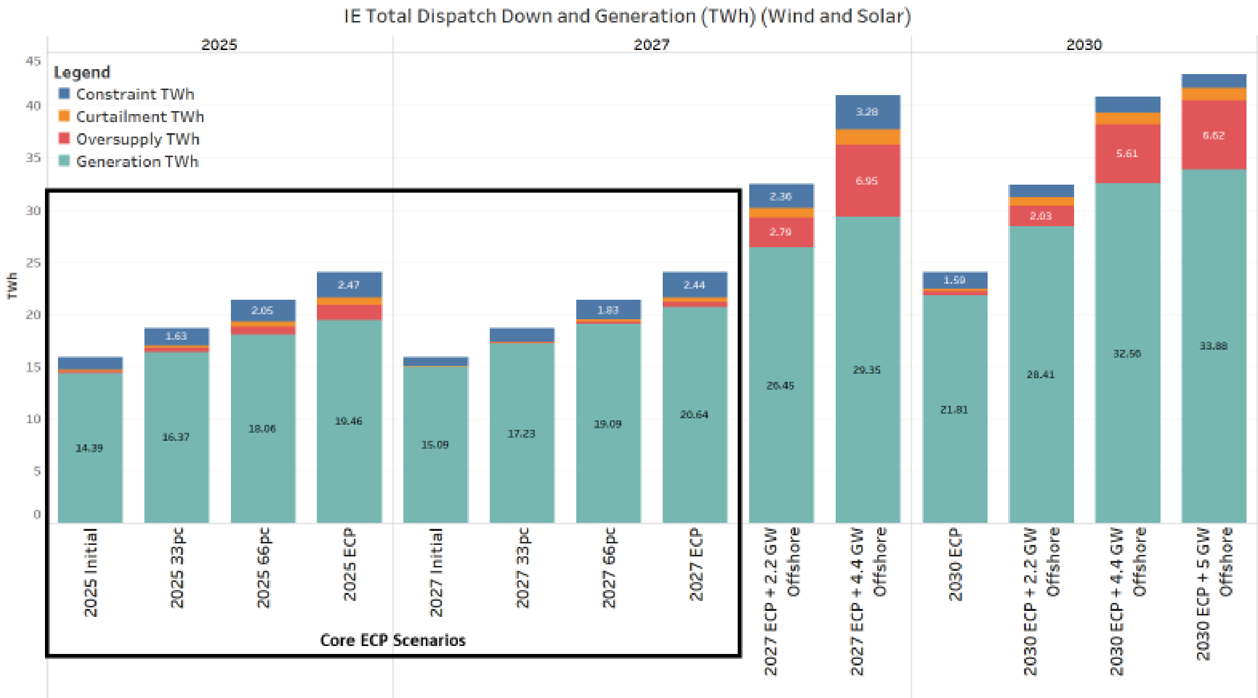

Figure 5-2 Total Dispatch Down and Generation (Wind and Solar) TWh

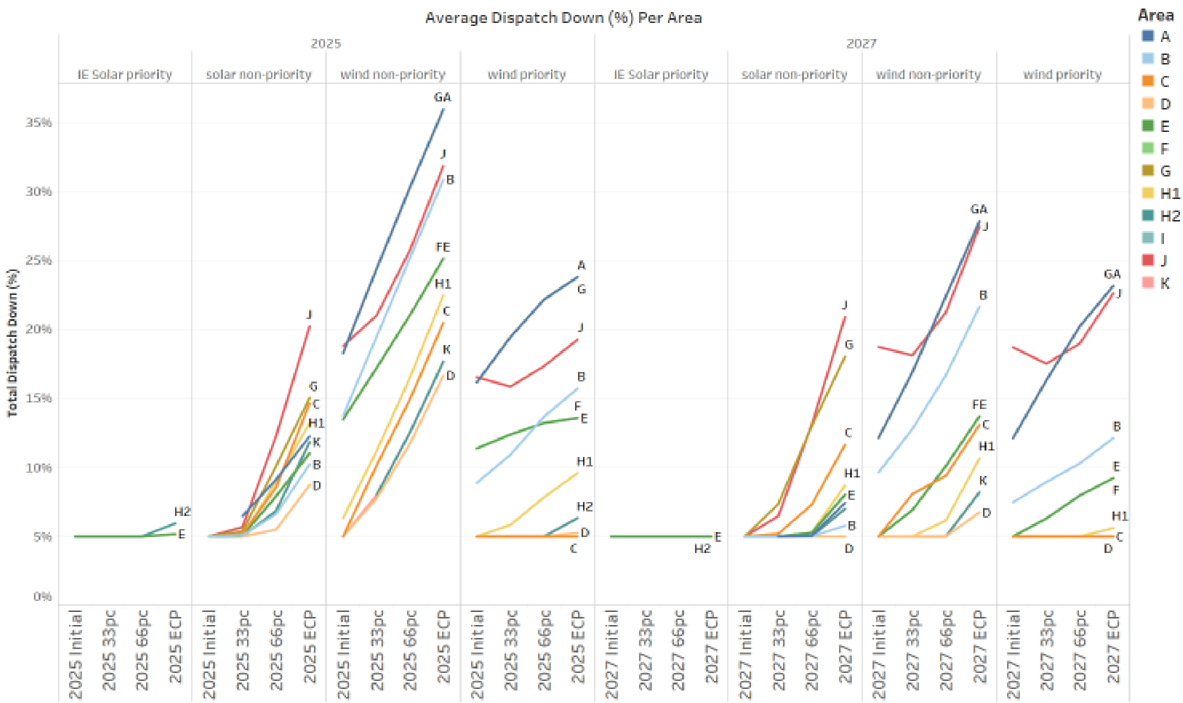

Figure 5-3 Total Dispatch Down % per Area

5.1 RES Percentage

Renewable Energy Source (RES) percentage is calculated using the base of the total load on the system, this represents the maximum utilization of RES to supply the demand in Ireland. The RES calculated below considers the wind, solar, hydro and wave generation and is given in Table 5-1Table 5-1 and Figure 5-1 System Total Dispatch Down %Figure 5-1Figure 5-4. Small scale wind and solar generation (less than 0.5 MW) is not considered in this calculation.

$$RES\ \% = \frac{RES\ Generation\ (GWh)}{Total\ Load\ (GWh)}\ X\ 100$$

Year	Initial	33%	66%	ECP	ECP + 2.2 GW Offshore	ECP + 4.4 GW Offshore	ECP + 5 GW Offshore
2025	41%	46%	51%	55%			
2027	40%	45%	50%	54%	68%	75%	
2030				52%	67%	76%	79%

Table 5-1 Ireland RES % in ECP 2.2 studies* (wind and solar)

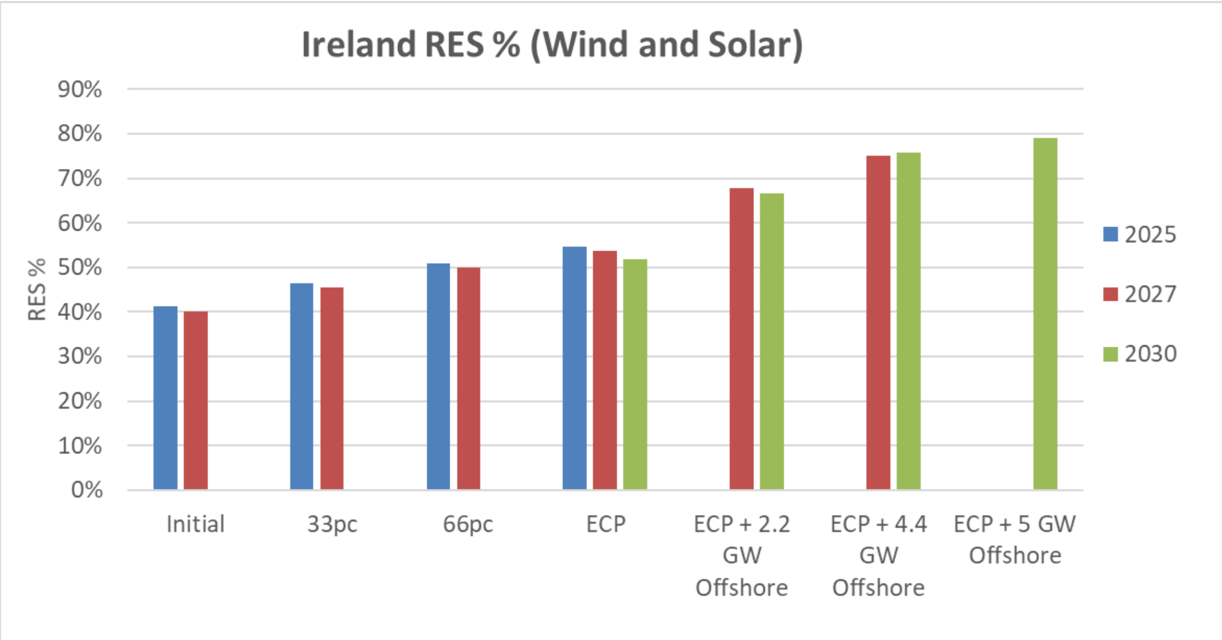

Figure 5-4 Ireland RES % in ECP 2.2 studies* (wind and solar)

*small scale generation, storage, peat and waste plants are not included in this calculation.

5.2 Maintenance Sensitivity Study Report

Following ECP 1.0, industry feedback suggested including a maintenance outage programme would be helpful. Hence, as part of ECP 2.1 a representative maintenance programme was included in the baseline models and further an addendum was published including a sensitivity to show the impact of this maintenance outage programme. Based on feedback from Industry ECP 2.2 follows the same methodology with an updated representative maintenance programme (given in Table A 4). The maintenance schedule was discussed with our internal operations team and it provides a reasonable representative outage programme for the network. However, every maintenance and outage season is different, and the results need to be interpreted with this in mind.

This section provides results of a sensitivity study performed to quantify the impact of the maintenance schedule used in the ECP 2.2. The studies selected for the sensitivity are the 2025 ECP (All) scenario, the 2027 ECP (All) scenario and 2030 ECP + 4.4 GW Offshore scenario. All other study assumptions have remained the same as the ECP 2.2 Constraints Analysis, however, the maintenance schedule has been removed.

The area-wise/subgroup results are presented for the three studies 2025 ECP (All) scenario, the 2027 ECP (All) scenario and 2030 ECP + 4.4 GW Offshore. The difference in constraints are reported as the difference between the study with maintenance and the study without maintenance (Maintenance Study Constraints – No Maintenance Study Constraints = Difference). The constraints calculated are pro-rata distributed in their respective area/subgroup. The details of subgroups selected in each area are given in section 6.6.4 of each area report. The percentage difference (Table 5 2 and Figure 5 5) is followed by the GWh difference tables (Table 5 3, Table 5 4 and Table 5 5).

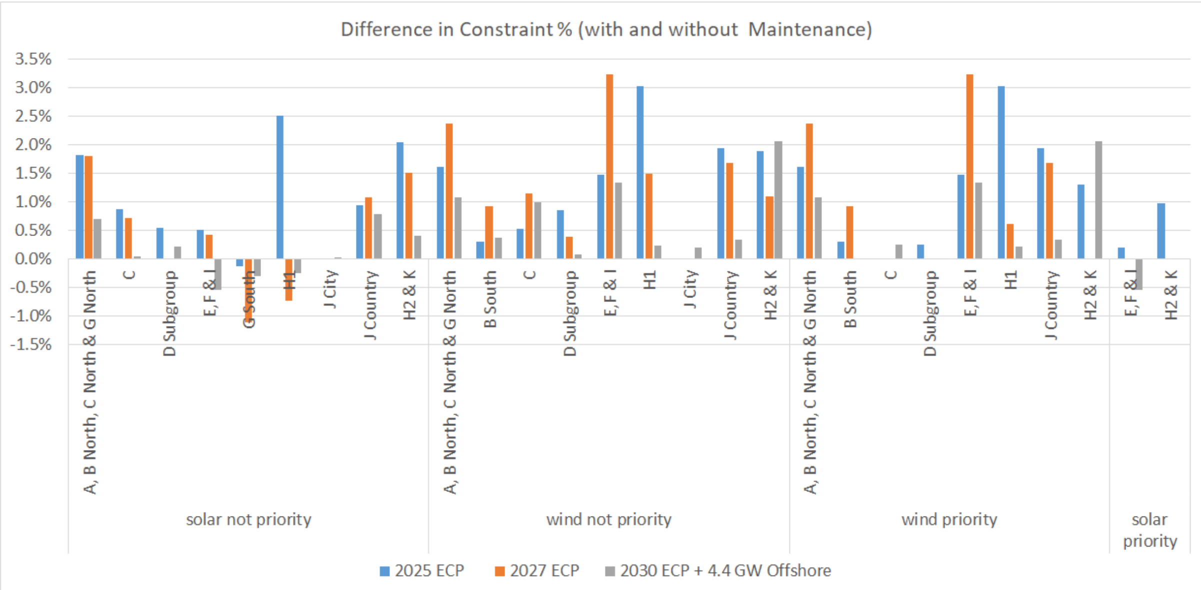

Figure 5-5 Difference in Constraint % (with - without maintenance)

Generation Category	Subgroup	2025 ECP	2027 ECP	2030 ECP + 4.4 GW Offshore
solar not priority	A, B North, C North & G North	1.8%	1.8%	0.7%
	C	0.9%	0.7%	0.0%
	D Subgroup	0.5%	0.0%	0.2%
	E,F & I	0.5%	0.4%	-0.6%
	G South	-0.1%	-1.1%	-0.3%
	H1	2.5%	-0.7%	-0.3%
	J City	0.0%	0.0%	0.0%
	J Country	0.9%	1.1%	0.8%
	H2 & K	2.0%	1.5%	0.4%
wind not priority	A, B North, C North & G North	1.6%	2.4%	1.1%
	B South	0.3%	0.9%	0.4%
	C	0.5%	1.1%	1.0%
	D Subgroup	0.8%	0.4%	0.1%
	E,F & I	1.5%	3.2%	1.3%
	H1	3.0%	1.5%	0.2%
	J City	0.0%	0.0%	0.2%
	J Country	1.9%	1.7%	0.3%
	H2 & K	1.9%	1.1%	2.1%
wind priority	A, B North, C North & G North	1.6%	2.4%	1.1%
	B South	0.3%	0.9%	0.0%
	C	0.0%	0.0%	0.3%
	D Subgroup	0.2%	0.0%	0.0%
	E,F & I	1.5%	3.2%	1.3%
	H1	3.0%	0.6%	0.2%
	J Country	1.9%	1.7%	0.3%
	H2 & K	1.3%	0.0%	2.1%
solar priority	E,F & I	0.2%	0.0%	-0.6%
	H2 & K	1.0%	0.0%	0.0%

Table 5-2 Difference in Constraint % (with - without maintenance)

Generation Category	Subgroup	Oversupply + Curtailment (GWh)	Constraint Without Maintenance (GWh)	Difference in Constraint with Maintenance (GWh)
solar not priority	A, B North, C North & G North	8	5	3
	C	38	3	3
	D Subgroup	5	0	1
	E,F & I	39	19	4
	G South	38	60	- 1
	H1	37	9	8
	J City	3	0	- 0
	J Country	112	126	9
	H2 & K	85	21	25
wind not priority	A, B North, C North & G North	623	563	49
	B South	117	49	2
	C	137	9	4
	D Subgroup	24	3	3
	E,F & I	101	109	19
	H1	96	15	17
	J City	-	-	-
	J Country	279	226	32
	H2 & K	45	4	8
wind priority	A, B North, C North & G North	64	385	33
	B South	7	74	3
	C	6	4	- 0
	D Subgroup	2	9	1
	E,F & I	111	352	61
	H1	54	35	40
	J Country	39	37	5
	H2 & K	43	12	11
solar priority	E,F & I	0	0	0
	H2 & K	0	0	0

Table 5-3 Area subgroup GWh difference in constraint (with - without maintenance) for 2025 ECP

Generation Category	Subgroup	Oversupply + Curtailment	Constraint Without Maintenance	Difference in Constraint with Maintenance
solar not priority	A, B North, C North & G North	4	2	3
	C	20	1	3
	D Subgroup	3	1	-
	E,F & I	17	25	3
	G South	24	137	-10
	H1	17	17	-2
	J City	4	0	-
	J Country	92	158	10
	H2 & K	41	13	19
wind not priority	A, B North, C North & G North	186	575	73
	B South	29	23	6
	C	64	3	10
	D Subgroup	9	0	1
	E,F & I	52	53	41
	H1	34	11	8
	J City	-	-	-
	J Country	149	314	28
	H2 & K	21	4	5
wind priority	A, B North, C North & G North	12	390	49
	B South	6	34	9
	C	2	7	-
	D Subgroup	5	18	-
	E,F & I	86	170	132
	H1	11	39	8
	J Country	23	51	5
	H2 & K	28	26	-
solar priority	E,F & I	0	0	-
	H2 & K	0	0	-

Table 5-4 Area subgroup GWh difference in constraint (with - without maintenance) for 2027 ECP

Generation Category	Subgroup	Oversupply + Curtailment	Constraint Without Maintenance	Difference in Constraint with Maintenance
solar not priority	A, B North, C North & G North	8	1	1
	C	38	0	0
	D Subgroup	5	1	0
	E,F & I	39	36	-4
	G South	38	41	-3
	H1	37	6	-1
	J City	3	0	0
	J Country	112	31	7
	H2 & K	85	6	5
wind not priority	A, B North, C North & G North	623	64	48
	B South	117	2	2
	C	137	3	8
	D Subgroup	24	2	0
	E,F & I	101	264	40
	H1	96	2	1
	J City	-	297	21
	J Country	279	96	5
	H2 & K	45	51	73
wind priority	A, B North, C North & G North	64	22	22
	B South	7	8	-
	C	6	2	1
	D Subgroup	2	4	-
	E,F & I	111	331	55
	H1	54	4	3
	J Country	39	15	1
	H2 & K	43	4	17
solar priority	E,F & I	0	1	-0
	H2 & K	0	0	-

Table 5-5 Area subgroup GWh difference in constraint (with - without maintenance) for 2030 + 4.4 GW Offshore

6 Results for Area B

6.1 Introduction

This section provides the over-supply, curtailment and constraint results for Area B that are estimated by this analysis. There is a total of eight core ECP 2-2 studies and seven sensitivity studies (including without maintenance) presented in this report. The study scenarios and the associated assumptions can be found in Section 2 and Section 3. An overview and discussion of the results is provided in this Section. The over-supply, curtailment and constraint results for each node are provided in Appendix C.

6.2 Study Notes

A list of the major study assumptions is provided in Section 3. For Area B, there are a number of key assumptions which drive the results, including network outages and capacity factors. These are thus, reiterated here. Similarly, it is worth highlighting again the differences between the various components of total dispatch down.

6.2.1 Network Outages

The scenarios in this report are intended to give a view of average long-term levels of over-supply, curtailment and constraint, subject to installed generation, demand, interconnection, operational constraints and reinforcement delivery.

The previous ECP 1 constraints analysis assumed that the existing network was available at all times. In reality, a transmission outage programme will be implemented each year resulting in outages of transmission circuits and other equipment for periods of time. Outages may be due to scheduled maintenance, forced outages, to facilitate new connections or for reinforcement reasons (e.g. circuit/busbar uprates).

In the ECP 2.1 constraint report a set of representative maintenance outages were included. After additional interest from industry, an addendum was published as a sensitivity of the maintenance outage to see the effect it had on the constraints in different areas. Following from the industry feedback on the ECP 2.2 study assumptions, the ECP 2.2 constraint forecast analysis applies a larger number of representative maintenance transmission outages for a shorter duration. The outages included in this schedule represent a geographical spread of circuits across the system and are each configured for a one-month period. This allows a representation of outage impact in each geographical area to be included in the studies. This representative transmission outage schedule is given in Appendix A – Table A-5. However, at times longer duration outages which may be required for certain connections, reinforcement works or forced outages are not considered and may result in higher wind and solar constraints.

6.2.2 Benefit of Capacity Factor

In practice a specific windfarm may be located at a site with higher wind speeds or may have a better performing type of wind turbine; the result is a higher capacity factor than neighbouring windfarms. This report doesn't reflect this localised diversity between windfarm sites, however, in reality a windfarm with a higher capacity factor may see lower percentage over-supply, curtailment or constraint levels than an adjacent windfarm with a lower capacity factor. This is because at times of medium or low wind speed, the high capacity factor windfarm can generate power when the low capacity factor windfarm cannot.

6.2.3 Notes on Over-supply, Curtailment and Constraint Modelling

6.2.3.1 Over-supply

During generation reduction for over-supply, a distinction is made between the treatment of priority and non-priority renewable generators, with non-priority generators being dispatched down ahead of priority generators. Within these two categories of generation, over-supply is applied pro-rata across the all-island system for all renewable generators in the category.

For any hour of the study the over-supply level will depend on system demand and interconnector flow capacity. In general, over-supply is expected to increase with increasing installed renewable capacity.

6.2.3.2 Curtailment

In this report, for each hour of the study, the curtailment is shared pro-rata on a system wide basis with no distinction made between priority and non-priority generators. This means that both curtailment reductions and curtailment increases are shared system wide.

Solar generation has different reported levels of curtailment compared to wind due to different capacity factors and annual profile shapes.

The applied curtailment is broadly constant across the system. However, due to differences in wind and solar profiles and capacity factors between areas, the percentage average curtailment differs between areas.

6.2.3.3 Constraints

During the constraint of renewable generation, no distinction is made between priority and non-priority generators, the dispatch down is applied across the relevant transmission nodes.

In general, there is a tendency for renewable bulk power to flow towards the demand in Dublin and the interconnectors. These flow patterns are relevant when seeking to understand constraint apportionment in the simulation.

When presented as percentage values, the constraint results look different for solar and wind, as they have a low correlation due to different profile shapes driven by weather patterns.

6.3 Generation Overview

A detailed system level overview of the renewable generation scenarios used in these studies is given in Section 2. The distribution of generation in each scenario based on technology, area and node is given in Appendix B. The node level installed wind and solar generation for Area B in the "ECP" scenario is given in Table 6 1.

Node	SO	Status	Solar	Wind
Bellacorick	DSO	due to connect		34
Bellacorick	TSO	due to connect		83
Bellacorick	DSO	due to connect		37
Bellacorick	TSO	connected		89
Bellacorick	TSO	due to connect		50
Bellacorick	DSO	connected		6
Bellacorick	DSO	connected		3
Cashla	TSO	due to connect	100	
Castlebar	DSO	connected		7
Castlebar	DSO	connected		9
Castlebar	DSO	connected		29
Cloon	DSO	due to connect	29	
Cloon	TSO	due to connect	50	
Cloon	DSO	due to connect		10
Cloon	DSO	connected		4
Cunghill	TSO	connected		35
Dalton	DSO	due to connect	8	
Dalton	DSO	connected		41
Dalton	DSO	connected		3
Firlough	TSO	due to connect		76
Glenree	DSO	connected		41
Glenree	DSO	connected		34
Glenree	DSO	connected		3
Knockranny	TSO	due to connect		156
Knockranny	TSO	connected		35
Moy	DSO	connected		6
Salthill	DSO	connected		41
Screeb	DSO	due to connect		5
Screeb	DSO	connected		6
Shantallow	TSO	due to connect	35	
Sligo	DSO	due to connect		9
Sligo	DSO	connected		14
Tawnaghmore	DSO	connected		19
Tonroe	DSO	connected		13
Uggool	TSO	connected		169
Total			222	1067

Table 6-1 Wind and Solar Generation Summary in Area B for Generation Scenario "ECP"

Table 6-2 and Table 6-3 show installed solar and wind generation for Ireland and Area B, and the available solar and wind generation for Area B for each generation scenario.

Solar	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Ireland (MW)	1389	2442	3496	4549	4549	4549	4549
Installed Area B (MW)	43	103	162	222	222	222	222
Installed Controllable Area B (MW)	43	103	162	222	222	222	222
Available Controllable Area B (GWh)	46	109	172	235	235	235	235

Table 6-2 Installed MW and Available GWh for Area B – Solar

Wind	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Ireland (MW)	5072	5581	6090	6599	8796	10993	11593
Installed Area B (MW)	781	876	972	1067	1067	1067	1067
Installed Controllable Area B (MW)	720	815	911	1006	1006	1006	1006
Available Controllable Area B (GWh)	2467	2778	3090	3402	3402	3402	3402

Table 6-3 Installed MW and Available GWh for Area B – Wind

6.4 Network Overview

Area B, in the west of the country, includes a mix of wind and solar generation. A summary of the generation is given in Table 6-1.

The transmission network in Area B and the surrounding areas is shown in Figure 6 1. The 220 kV circuits are shown in green, and the 110 kV circuits in black. Possible future transmission stations and lines for the connection of new generation are also shown on the map below.

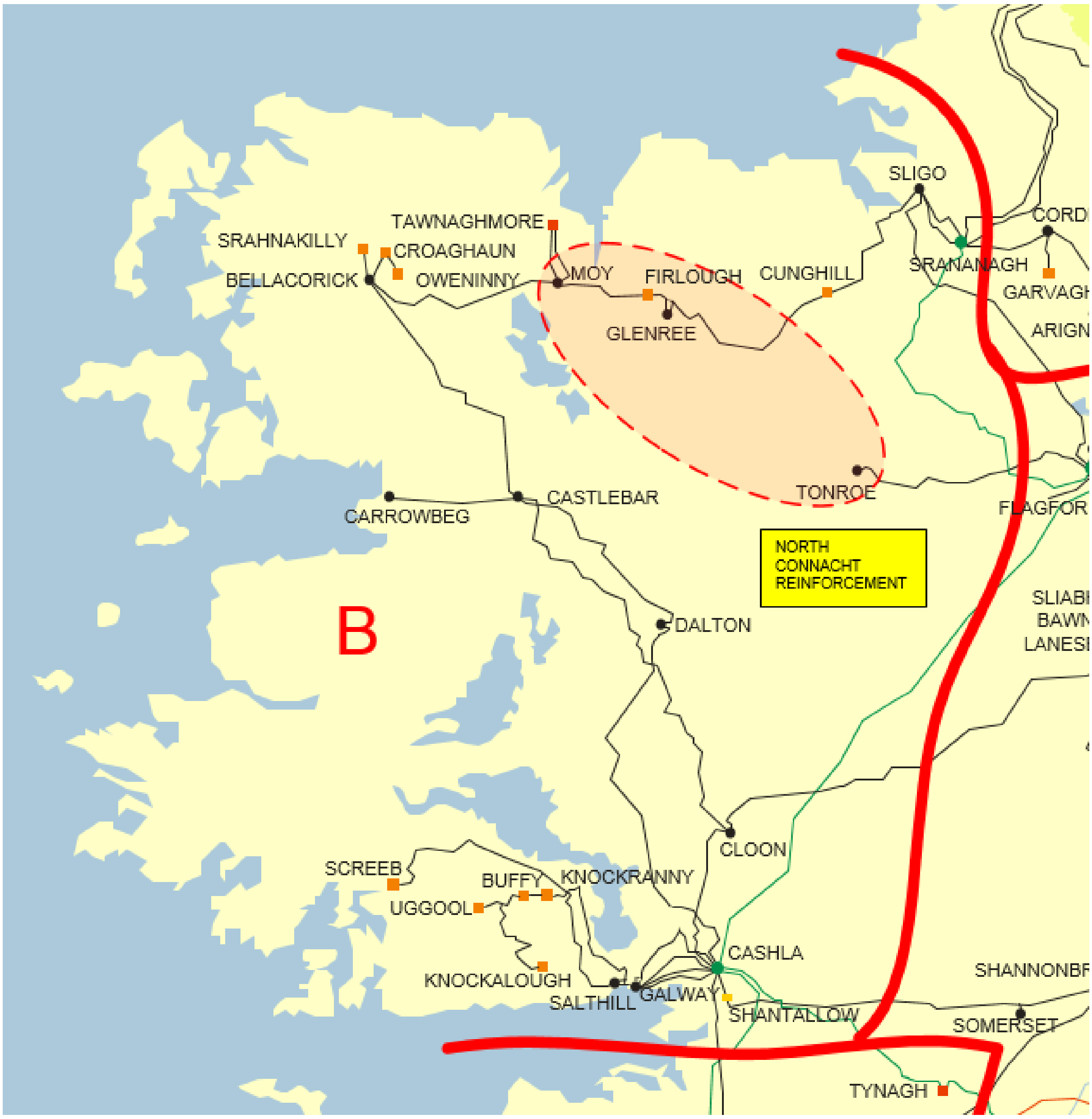

Figure 6-1 Network Map for Area B

At times of high renewable generation, there is a net export of power from Area B, and the dominant power flows tend to be from Area B towards the load centres on the east coast and the interconnectors. These flow patterns are relevant when seeking to understand constraint apportionment in the simulation.

Constraints in Area B can be caused both by local and wider system issues. Constraints in the model are optimised on a system-wide basis so, in theory, an increase in the installed generation in another area can increase constraints in Area B.

Also, the power flowing out of Area B meets and joins with power flows from other areas, as the power flows towards the demand centres and interconnectors. A transmission bottleneck between Area B and the east is shared with power flows coming from other areas.

6.5 Future Grid Sensitivity Scenario

In line with the ECP 2.1 studies and in response to feedback from industry, the Future Grid scenario is included in the analysis. All reasonable efforts have been made to align the network assumptions in the Future Grid scenario to the Shaping Our Electricity Future (SOEF) Roadmap. The network projects included in the study are given in Appendix A – Table A3. Additionally, any project that has progressed to stage three of the six stage project planning process after the publication of the SOEF roadmap publication are also included in the Future Grid studies. Note however, that the wind and solar generation portfolio in the ECP 2.2 Future Grid scenario differs from the wind and solar portfolio considered in SOEF, this is done to maintain compliance with the ECP 2.2 process. The ECP study includes all wind and solar projects which have applied through connection processes, whereas the SOEF study does not include the full set of wind and solar applicants.

The Future Grid study includes a base renewable generation scenario (ECP), along with three sensitivity generation scenarios (ECP + 2.2 GW offshore, ECP + 4.4 GW offshore, and ECP + 5 GW offshore). The latter three scenarios with additional offshore wind have been included to show the potential impact of increasing offshore wind on Total Dispatch Down levels.

The demand modelled for the Future Grid scenario is based on the medium demand scenario for 2030 as published in the All-Island Generation Capacity Statement 2022-2031.

This study is not intended as an assurance to individual generators that their Total Dispatch Down will change to the estimated levels. Rather, it is a consideration of the potential impact of the SOEF reinforcement portfolio on the dispatch down of wind and solar generators. This study is not intended to be exhaustive, and it is not intended to remove all transmission constraints.

6.6 Area B – Average Results

The Total Dispatch Down results for Area B are provided below in Table 6 6 to Table 6 10 and Figure 6 2 to Figure 6 6. These include the breakdown between over-supply, curtailment and constraint. The Total Dispatch Down percentages are based on the total available energy. The Total Dispatch Down is the sum of over-supply, curtailment and constraint. The node level breakdown of over-supply, curtailment and constraint are given in Appendix C. The results show that the system level Total Dispatch Down increases with additional installed capacity with a significant increase in over-supply. However, the Total Dispatch Down reduces when the 2027 studies are compared with 2025 and a further reduction in 2030 owing to increased demand, network reinforcement and relaxed system level constraints.

For each generation type in Area B (solar non- priority, wind non-priority and wind priority), the total installed capacity in MW and total available generation in GWh are given in Table 6 6, Table 6 7 and Table 6 10. The total generation in GWh, after dispatch down and corresponding percentage Total Dispatch Down are also included in the tables for each scenario. Details on the generation and network scenarios are given in Section 2.

6.6.1 Offshore Wind Sensitivity Studies

Results for the offshore wind-based sensitivity studies are also included, along with results for the core scenarios. The general trend with increasing levels of offshore wind, result in increases in the Total Dispatch Down due to significant increases in the available wind energy, which in turn leads to increased levels of over-supply.

6.6.2 Impact of Article 12

Higher Total Dispatch Down is observed for non-priority generators due to the impact of the implementation of Article 12 in the studies, which results in non-priority generators being reduced ahead of priority generators for over-supply reasons.

6.6.3 Future Grid Sensitivity Study

The results of the Future Grid scenario show a notable reduction in Total Dispatch Down over the core study years (2025 and 2027) due to the impact of the SOEF network reinforcements, increased demand levels in 2030 and the relaxation of operational constraints in 2030. However, increases in installed wind and solar generation, as seen in the offshore wind scenarios, result in rising over-supply levels, causing an increase in Total Dispatch Down. A detailed breakdown of the Total Dispatch Down components for Area B under the Future Grid scenarios and associated sensitivity case is given in Table 6 6, Table 6 7 and Table 6 10. Further node level details can be viewed in Appendix C.

6.6.4 Area Subgroups

The constraint forecast study performed using Plexos software applies mathematical optimisation to find the lowest cost generator dispatch schedule to meet demand, subject to a number of system and transmission level constraints. To ensure the model is impartial, the assumptions on the cost of renewable generators remain the same, irrespective of technology or location, and are always less than that of conventional plant. This ensures renewable generators are given priority in the Plexos optimisation. However, due to network congestion caused by line limits and N-1 contingency security checks, the power flows in certain lines are limited causing dispatch down in RES generators which may affect one generator or multiple generators chosen by Plexos' internal logic. During various initial studies, it was observed that Plexos may repeatedly choose the same generator(s) to dispatch down to manage an issue in a region shared by multiple generators.

There is often a post-processing step between the Plexos simulation and this report to ensure a fair allocation of constraints among generators sharing the bottlenecks creating constraint subgroups within an area or spanning multiple different areas. The subgroups are selected based on an assessment of the raw Plexos results and based on our experience of dispatch down on the real system. The subgroups are chosen to group those generators into a constraint group that are expected to experience similar constraint levels. The subgroups are selected on the basis that they share a common transmission bottleneck, or they are electrically close to a congested area within the network.

In Area B, during the high renewable energy scenarios, the Srananagh 220 kV and Flagford 220 kV region becomes a major bottleneck. The power flowing from Area A and generation from Area B merge in this region. The loss of a 220 kV circuit/transformer in this region creates an overload in the associated 110 kV circuits. In 2027, the area receives reinforcements, these reduce the stress in the region and increase the power flow towards the east. However, during the high-RES scenarios, the additional power from each of these areas tends to flow onto the 220 kV circuits, and then towards the load centres in Dublin causing congestion in the north side of Area G. A bottleneck in Area G North can cause power from Areas A, B and C to re-route to manage the issue and cause dispatch down in these areas. The lines overloading in these areas cause generators to be dispatched down in Area A, north of B and north of Area C depending on the contingency in the area.

Additionally, any loss of a 220 kV circuit will put additional stress on the supporting 110 kV circuits, causing considerable dispatch down of RES generators in the area. The 110 kV parallel paths are critical transmission infrastructure for these areas during times of high wind. Any loss of these 110 kV parallel lines results in additional dispatch down. For example, at times, a loss of a circuit in Area C can trigger dispatch down in Area A – and therefore constraints need to be shared amongst this subgroup.

Area B also sees binding issues for generators connected to the 110 kV lines that are connecting to Cashla 220 kV. However, the generators at Castlebar 110 kV and Dalton 110 kV experience rescue flows pushing back to Bellacorick station and are hence considered as a part of A, B North, C North & G North subgroup. The B South subgroup consist of generators connected towards west of Cashla 220 kV station. The Cashla 220 kV Station by itself is well connected using the 220 kV circuits and is not considered as a part of this subgroup. Furthermore, the Cloon 110 kV station is connected to Cashla and Lanesboro and sees less congestion and are also not part of either subgroup.

It was observed that the Plexos internal logic was constantly choosing the same set of generators to dispatch down with respect to multiple contingencies in the area, thus identifying a need to share the constraints. The contingencies and overloaded lines associated with the area are included in Appendix D.

Analysis of Area B identified three constraint subgroups for solar and wind generation. First including Area A, Area B North, Area C North and Area G North which is a path following the general power flow and the second B South and the final being C. The subgroup nodes are given in Table 6-4. The constraints are shared on a pro-rata basis amongst the subgroup generators. The individual node level dispatch down is given in Appendix C.

The subgroup arrangement is a significant difference from the ECP 2.1 constraint forecast study where Area's A, B, C and G North were all part of the same subgroup.

Subgroup	Node
A, B North, C North & G North	Bellacorick
	Castlebar
	Cunghill
	Dalton
	Firlough
	Glenree
	Moy
	Sligo
	Srahnakilly
	Tawnaghmore
	Tonroe
B South	Knockranny
	Salthill
	Screeb
	Uggool
C	Cashla
	Cloon
	Shantallow
	Shantallow into Cashla Somerset T

Table 6-4 Area B Sub-Groups and Generator Nodes within each Subgroup

Area B (A, B North, C North & G North)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	4	5	7	8			
Installed Capacity (MW)	2027	4	5	7	8	8	8	
Installed Capacity (MW)	2030				8	8	8	8
Available Energy (GWh)	2025	4	6	7	8			
Available Energy (GWh)	2027	4	6	7	8	8	8	
Available Energy (GWh)	2030				8	8	8	8
Generation (GWh)	2025	4	5	6	7			
Generation (GWh)	2027	4	6	7	8	8	7	
Generation (GWh)	2030				8	8	7	7
Over-supply (%)	2025	1 %	2 %	4 %	7 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	8 %	13 %	
Over-supply (%)	2030				3 %	7 %	11 %	12 %
Curtailment (%)	2025	0 %	1 %	1 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	2 %	
Curtailment (%)	2030				1 %	2 %	2 %	2 %
Constraint (%)	2025	4 %	4 %	4 %	4 %			
Constraint (%)	2027	5 %	4 %	3 %	3 %	2 %	2 %	
Constraint (%)	2030				2 %	1 %	0 %	0 %
Total Dispatch Down (%)	2025	5 %	6 %	9 %	12 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	7 %	12 %	16 %	
Total Dispatch Down (%)	2030				6 %	9 %	13 %	14 %

Table 6-5 Over-supply, Curtailment and Constraint for Solar Non-Priority in Area B (A, B North, C North & G North)

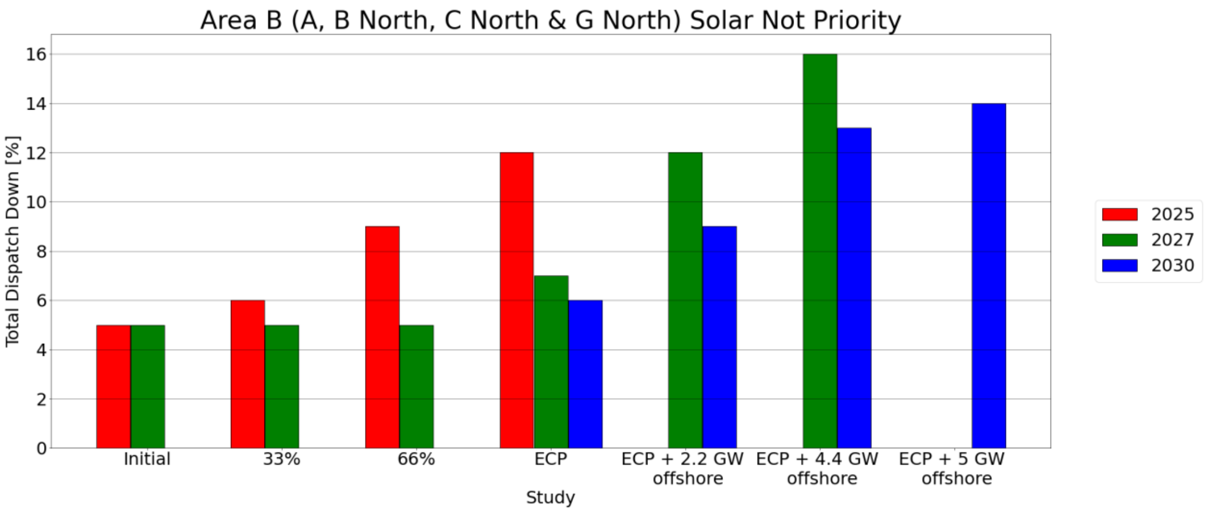

Figure 6-2 Results Solar Non-Priority Area B (A, B North, C North & G North)

Area B (A, B North, C North & G North)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	220	289	357	426			
Installed Capacity (MW)	2027	220	289	357	426	426	426	
Installed Capacity (MW)	2030				426	426	426	426
Available Energy (GWh)	2025	669	878	1086	1294			
Available Energy (GWh)	2027	669	878	1086	1294	1294	1294	
Available Energy (GWh)	2030				1294	1294	1294	1294
Generation (GWh)	2025	551	648	723	782			
Generation (GWh)	2027	656	833	967	1078	980	858	
Generation (GWh)	2030				1104	1029	920	896
Over-supply (%)	2025	3 %	6 %	10 %	15 %			
Over-supply (%)	2027	0 %	1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025	1 %	1 %	2 %	2 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025	15 %	17 %	18 %	19 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	12 %	7 %	
Constraint (%)	2030				8 %	3 %	1 %	0 %
Total Dispatch Down (%)	2025	18 %	24 %	30 %	36 %			
Total Dispatch Down (%)	2027	12 %	17 %	22 %	28 %	32 %	39 %	
Total Dispatch Down (%)	2030				13 %	18 %	27 %	29 %

Table 6-6 Over-supply, Curtailment and Constraint for Wind Non-Priority in Area B (A, B North, C North & G North)

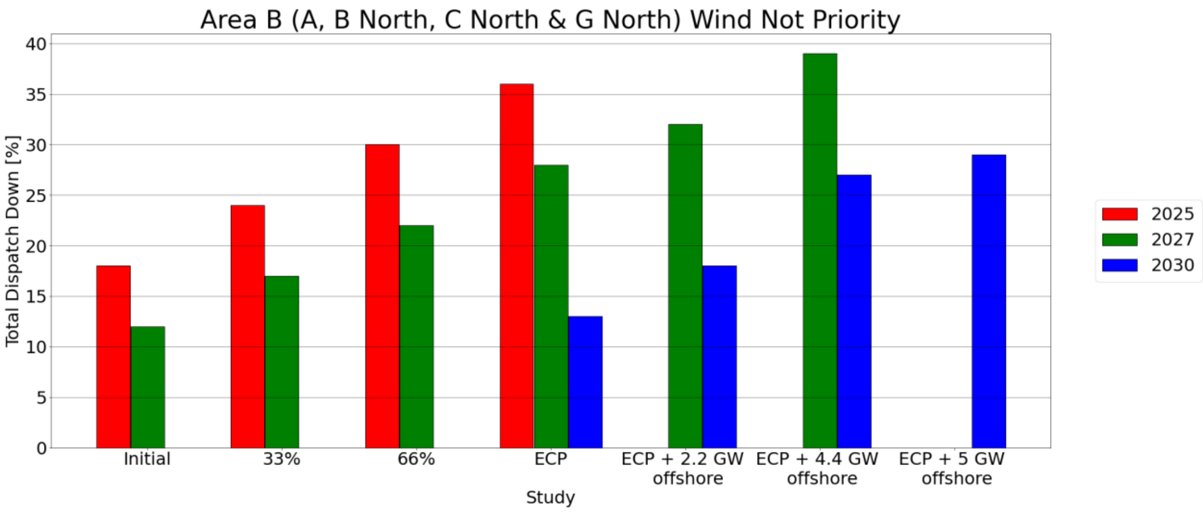

Figure 6-3 Results Wind Non-Priority in Area B (A, B North, C North & G North)

Area B (A, B North, C North & G North)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	164	164	164	164			
Installed Capacity (MW)	2027	164	164	164	164	164	164	
Installed Capacity (MW)	2030				164	164	164	164
Available Energy (GWh)	2025	499	499	499	499			
Available Energy (GWh)	2027	499	499	499	499	499	499	
Available Energy (GWh)	2030				499	499	499	499
Generation (GWh)	2025	366	341	323	309			
Generation (GWh)	2027	437	421	410	398	403	413	
Generation (GWh)	2030				451	462	466	467
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table 6-7 Over-supply, Curtailment and Constraint for Wind Priority in Area B (A, B North, C North & G North)

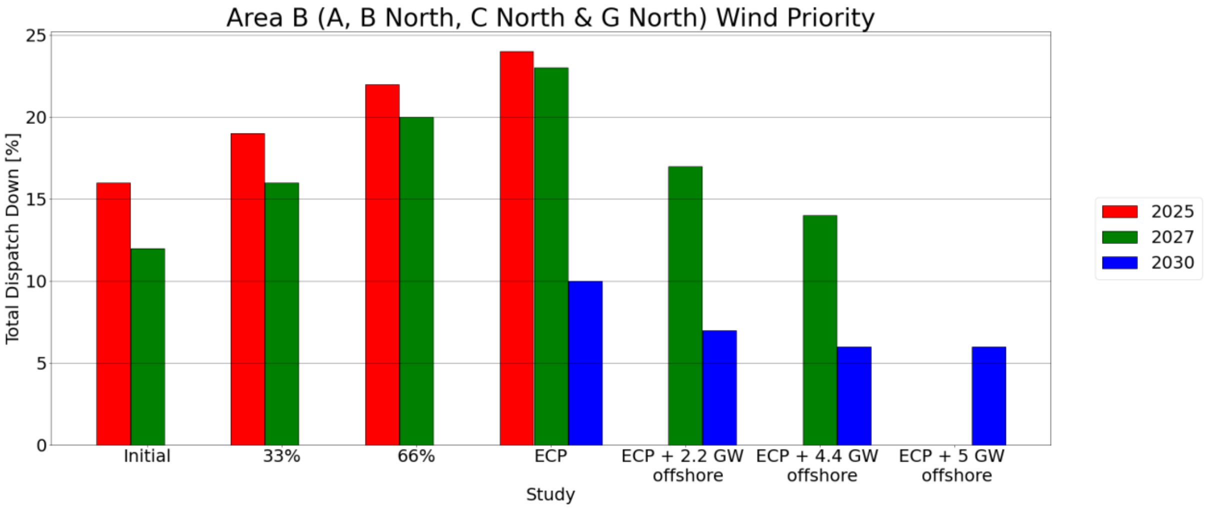

Figure 6-4 Results Wind Priority Area B (A, B North, C North & G North)

Area B (C)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	39	97	156	214			
Installed Capacity (MW)	2027	39	97	156	214	214	214	
Installed Capacity (MW)	2030				214	214	214	214
Available Energy (GWh)	2025	41	103	165	227			
Available Energy (GWh)	2027	41	103	165	227	227	227	
Available Energy (GWh)	2030				227	227	227	227
Generation (GWh)	2025	41	100	156	207			
Generation (GWh)	2027	41	102	160	215	204	193	
Generation (GWh)	2030				217	208	197	194
Over-supply (%)	2025	1 %	2 %	4 %	7 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	8 %	13 %	
Over-supply (%)	2030				3 %	7 %	11 %	12 %
Curtailment (%)	2025	0 %	1 %	1 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	2 %	
Curtailment (%)	2030				1 %	2 %	2 %	2 %
Constraint (%)	2025	4 %	2 %	1 %	2 %			
Constraint (%)	2027	5 %	4 %	2 %	1 %	1 %	0 %	
Constraint (%)	2030				1 %	0 %	0 %	0 %
Total Dispatch Down (%)	2025	5 %	5 %	7 %	10 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	10 %	15 %	
Total Dispatch Down (%)	2030				5 %	8 %	13 %	14 %

Table 6-8 Over-supply, Curtailment and Constraint for Solar Non-Priority in Area B (C)

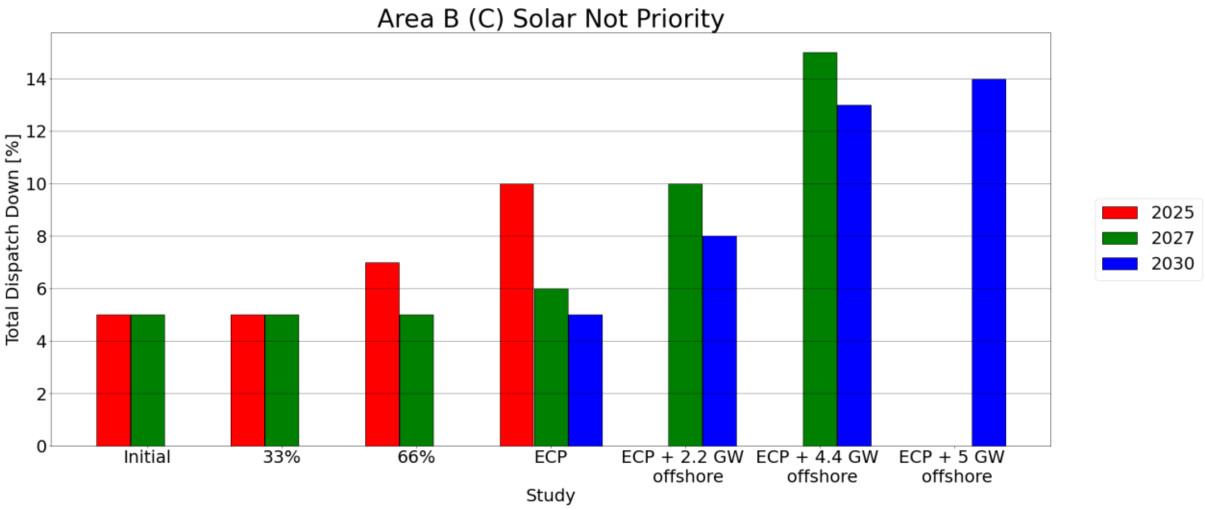

Figure 6-5 Results Solar Non-Priority in Area B (C)

Area B (C)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025		3	7	10			
Installed Capacity (MW)	2027		3	7	10	10	10	
Installed Capacity (MW)	2030				10	10	10	10
Available Energy (GWh)	2025		10	20	30			
Available Energy (GWh)	2027		10	20	30	30	30	
Available Energy (GWh)	2030				30	30	30	30
Generation (GWh)	2025		9	18	25			
Generation (GWh)	2027		10	19	28	24	21	
Generation (GWh)	2030				29	26	22	22
Over-supply (%)	2025		6 %	10 %	15 %			
Over-supply (%)	2027		1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025		1 %	2 %	2 %			
Curtailment (%)	2027		1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025		-1 %	-1 %	-1 %			
Constraint (%)	2027		4 %	1 %	0 %	-1 %	-1 %	
Constraint (%)	2030				1 %	-1 %	-1 %	-1 %
Total Dispatch Down (%)	2025		7 %	11 %	16 %			
Total Dispatch Down (%)	2027		5 %	5 %	7 %	19 %	30 %	
Total Dispatch Down (%)	2030				5 %	15 %	25 %	27 %

Table 6-9 Over-supply, Curtailment and Constraint for Wind Non-Priority in Area B (C)

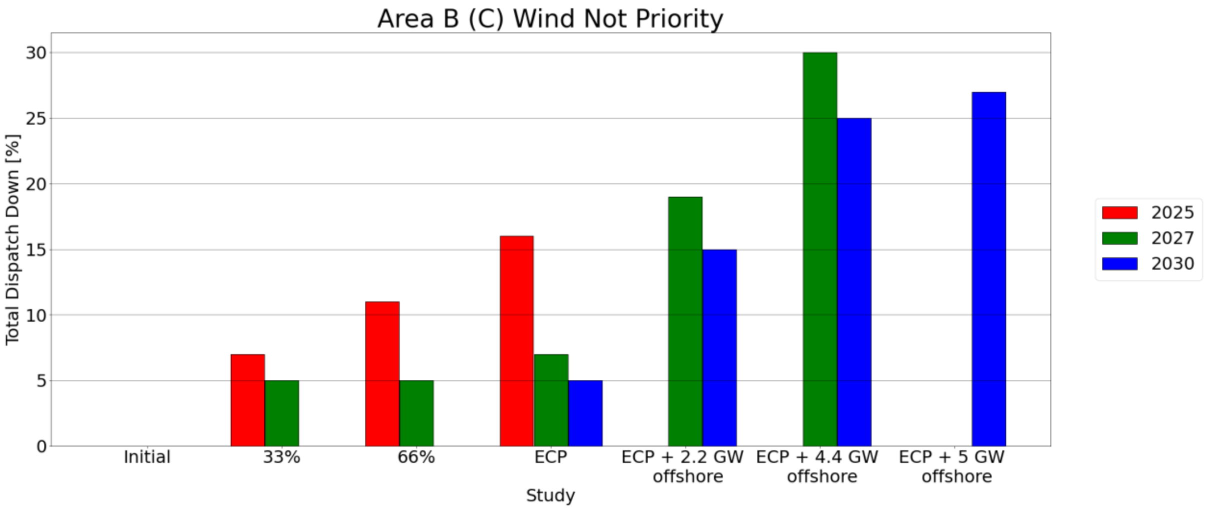

Figure 6-6 Results Wind Non-Priority in Area B (C)

Area B (B South)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	91	114	138	161			
Installed Capacity (MW)	2027	91	114	138	161	161	161	
Installed Capacity (MW)	2030				161	161	161	161
Available Energy (GWh)	2025	362	455	549	642			
Available Energy (GWh)	2027	362	455	549	642	642	642	
Available Energy (GWh)	2030				642	642	642	642
Generation (GWh)	2025	347	418	475	522			
Generation (GWh)	2027	361	449	524	592	533	467	
Generation (GWh)	2030				618	564	500	486
Over-supply (%)	2025	2 %	5 %	7 %	11 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	13 %	24 %	
Over-supply (%)	2030				2 %	10 %	19 %	22 %
Curtailment (%)	2025	1 %	1 %	2 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025	3 %	5 %	7 %	8 %			
Constraint (%)	2027	5 %	4 %	3 %	4 %	2 %	1 %	
Constraint (%)	2030				2 %	1 %	1 %	1 %
Total Dispatch Down (%)	2025	5 %	10 %	16 %	21 %			
Total Dispatch Down (%)	2027	5 %	5 %	6 %	10 %	18 %	28 %	
Total Dispatch Down (%)	2030				6 %	13 %	23 %	25 %

Table 6-10 Over-supply, Curtailment and Constraint for Wind Non-Priority in Area B (B South)

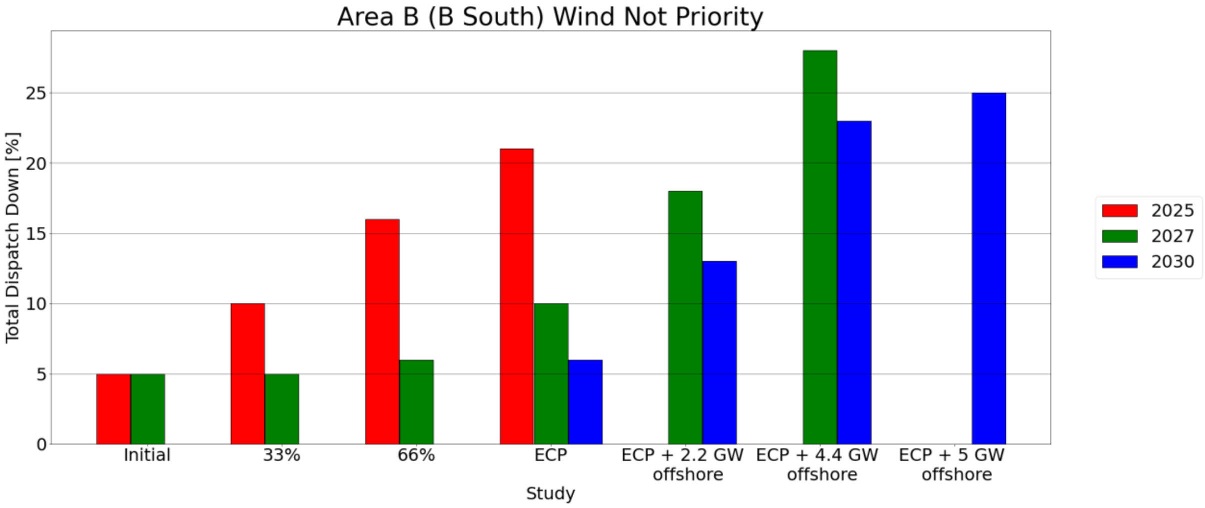

Figure 6-6 Results Wind Non-Priority in Area B (B South)

Area B (B South)	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	245	245	245	245			
Installed Capacity (MW)	2027	245	245	245	245	245	245	
Installed Capacity (MW)	2030				245	245	245	245
Available Energy (GWh)	2025	936	936	936	936			
Available Energy (GWh)	2027	936	936	936	936	936	936	
Available Energy (GWh)	2030				936	936	936	936
Generation (GWh)	2025	897	869	840	814			
Generation (GWh)	2027	918	910	891	866	878	880	
Generation (GWh)	2030				892	893	889	889
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	3 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				1 %	3 %	4 %	4 %
Constraint (%)	2025	4 %	5 %	7 %	8 %			
Constraint (%)	2027	5 %	4 %	4 %	4 %	2 %	1 %	
Constraint (%)	2030				4 %	2 %	1 %	1 %
Total Dispatch Down (%)	2025	5 %	6 %	9 %	11 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	6 %	6 %	
Total Dispatch Down (%)	2030				5 %	5 %	5 %	5 %

Table 6-11 Over-supply, Curtailment and Constraint for Wind Priority in Area B (B South)

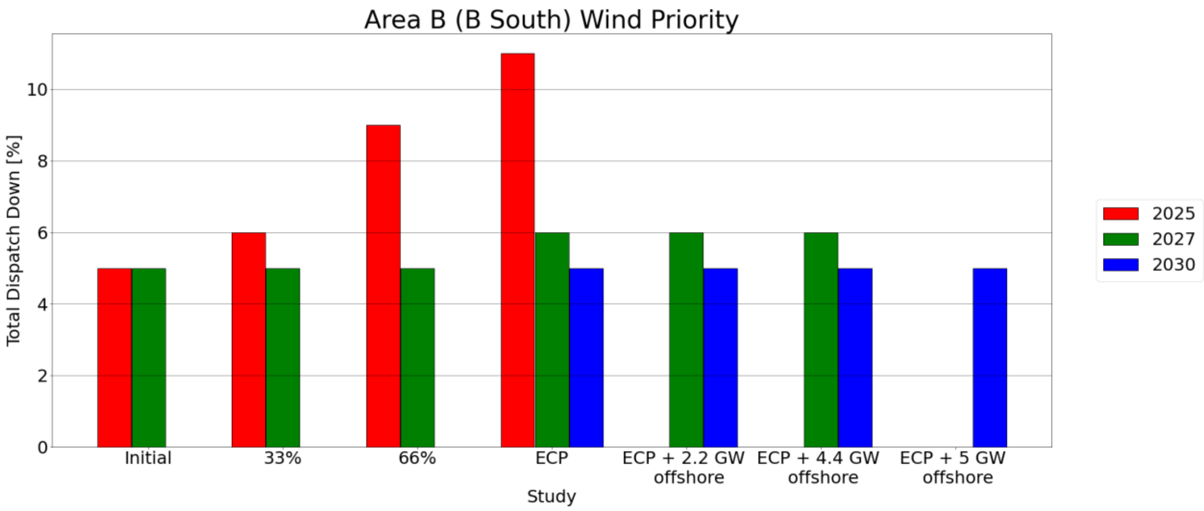

Figure 6-7 Results Wind Priority in Area B (B South)

6.7 Conclusion – Results for Area B

This section provides an overview of the estimated over-supply, curtailment and constraint values for Area B for a range of scenarios based on a number of installed generation assumptions (generation scenarios) and the study year (network and demand assumptions). The results highly depend on the study assumptions, which are described in this report.

Appendix C contains the detailed results consisting of energy (GWh), percentage over-supply, curtailment and constraint values for each node for both solar and wind in Area B.

Appendix A – Network Reinforcement & Maintenance

A.1 Reinforcements in 2025

The table below lists the reinforcements, additional to the current network, that are included in the 2025 study scenario.

Project Type	Project Name	Year
New Build	Laois Kilkenny (Coolnabacky) 400 kV Station - New Station & Associated Lines & Station Works	2025
Uprate	Corduff - Ryebrook 110 kV line uprate	2025
New Build	Kilpaddoge - Knockanure 220 kV cable	2025
Uprate	Clashavoon - Tarbert 220 kV line uprate	2025
Uprate	Castlebar 110 kV station busbar uprate	2025
Uprate	Flagford - Sliabh Bawn 110 kV circuit uprate	2025
Uprate	Arva - Carrick-on-Shannon 110 kV line uprate	2025
Uprate	Maynooth - Woodland 220 kV line uprate	2025
Uprate	Ballyvouskill Knockanure 220 kV Line Uprate	2025
Static Compensator	Thurles 110 kV Station - Starcom	2025
Static Compensator	Ballynahulla 220-110 kV Station - Statcom	2025
Static Compensator	Ballyvouskill 220-110 kV Station - Statcom	2025
Uprate	Great Island Kilkenny 110 kV Uprate	2025
New Build	Belcamp Shellybanks 220 kV Cable	2025
Uprate	Lanesboro - Mullingar 110 kV line LCA	2025
Uprate	Lanesboro – Sliabh Bawn Thermal Uprate	2025
Uprate	Binbane - Cathleen's Fall 110 kV Circuit Thermal Capacity	2025
New Build	Greenlink Interconnector	2025
Uprate	Glenree - Moy 110 kV Line Uprate	2025
Uprate	Gorman - Platin 110 kV line uprate	2025
Uprate	Drybridge - Oldbridge - Platin 110 kV line uprate	2025
Uprate	Louth - Ratrussan 110 kV No 1 Line Uprate	2025
Uprate	Newbridge - Cushaling 110 kV line, Stations bay conductors and lead-in conductor uprate	2025
Synchronous Condenser	Moneypoint Synchronous Condenser	2025

Table A-1 Reinforcements included in the 2025 study

A.2 Reinforcements in 2027

The table below lists the network reinforcements included in the 2027 study scenario, additional to the network in the 2025 study scenario.

Project Type	Project Name	Year
New Build	North South 400 kV Interconnector	2027
Uprate	Coolnabacky - Portlaoise 110 kV line uprate	2027
Uprate	Castlebar-Cloon 110 kV Line Uprate-Refurb	2027
Series Capacitor	Moneypoint 400 kV Series Capacitor	2027
Series Capacitor	Dunstown 400 kV Series Capacitor	2027
Series Capacitor	Oldstreet-Woodland 400 kV Series Capacitor	2027
New Build	Cross Shannon 400 kV Cable	2027
Uprate	Kinnegad 110 kV station, Derryiron 110 kV bay conductor uprate	2027
uprate	Sligo 110 kV Station - Srananagh 1 & 2 Bay uprates	2027
Uprate	Cashla-Salthill 110 kV Thermal Uprate	2027
Uprate	Newbridge - Portlaoise 110 kV Partial Thermal Uprate	2027
Uprate	Crane - Wexford 110 kV Circuit Thermal Capacity	2027
Uprate	Derryiron - Thornsberry 110 kV Circuit Uprate	2027
New Build	North Connacht 110 kV Project	2027
Uprate	Dalton 110 kV Busbar	2027
Uprate	Bandon Dunmanway 110 kV circuit thermal capacity	2027

Table A-2 Reinforcements included in the 2027 study scenario, additional to 2025 study reinforcements

A.3 Reinforcements in Future Grid

The table below lists the reinforcements, additional to the current network, that are included in the Future Grid study scenario.

Project Type	Project	Year
Station	Aghada Station Busbar Reconfiguration	Future Grid
Upvoltage	Arklow - Ballybeg - Carrickmines 220 kV (circuit 1)	Future Grid
Uprate	Arva - Carrick On Shannon 110 kV uprate (circuit 1)	Future Grid
Uprate	Athlone - Lanesboro 110 kV uprate (circuit 1)	Future Grid
Uprate	Athy - Carlow 110 kV uprate (circuit 1)	Future Grid
Uprate	Ballylumford - Eden 110 kV uprate	Future Grid
Static Compensator	Ballynahulla Station - Statcom	Future Grid
Uprate	Ballyvouskill - Ballynahula - Knockanure 220 kV uprate	Future Grid
Static Compensator	Ballyvouskill 220/110 kV Station - Statcom	Future Grid
Uprate	Bandon - Dunmanway 110 kV uprate (circuit 1)	Future Grid
Uprate	Baroda - Monread 110 kV uprate (circuit 1)	Future Grid
DLR	Baroda - Newbridge 110 kV (circuit 1)	Future Grid
DLR	Bellacorrick - Castlebar 110 kV (circuit 1)	Future Grid
Uprate	Binbane - Cathaleen's Fall 110 kV uprate (circuit 1)	Future Grid
New Build	Binbane - Clogher - Cathaleen's Fall - 110 kV Clogher tie in	Future Grid
DLR	Cashla - Dalton 110 kV (circuit 1)	Future Grid
Uprate	Cashla - Salthill 110 kV uprate (circuit 1)	Future Grid
Uprate	Castlebar - Cloon 110 kV uprate (circuit 1)	Future Grid
Station	Castlebar 110 kV station busbar	Future Grid
DLR	Cathaleen's Fall - Coraclassy 110 kV (circuit 1)	Future Grid
New Build	Clashavoon - Macroom No. 1 & associated station works & 250 MVA transformer	Future Grid
Uprate	Clashavoon - Tarbert 220 kV uprate (circuit 1)	Future Grid
New Build	Clogher - Srananagh 220 kV (circuit 1)	Future Grid
Uprate	Coleraine - Coolkeeragh 110 kV uprate (circuit 1)	Future Grid
Uprate	Coolkeeragh - Killymallaght 110 kV uprate (circuit 1)	Future Grid
Uprate	Coolkeeragh - Limavady 110 kV uprate (circuit 1)	Future Grid
Uprate	Coolkeeragh - Magherafelt 275 kV Circuits Refurbishment	Future Grid
Uprate	Coolkeeragh - Strabane 110 kV uprate (circuit 1)	Future Grid
Uprate	Coolnabacky - Portlaoise 110 kV uprate (circuit 1)	Future Grid
Station	Coolnabacky Station 400 kV - new station and associated lines and station works	Future Grid
Uprate	Corderry - Srananagh 110 kV uprate (circuit 1)	Future Grid
Uprate	Crane - Wexford 110 kV uprate (circuit 1)	Future Grid
DLR	Cushaling - Newbridge 110 kV (circuit 1)	Future Grid
Station	Dalton busbar	Future Grid
Uprate	Derryiron - Kinnegad 110 kV uprate (circuit 1)	Future Grid
Reactive Support	Distributed Series Reactors Project (Nationwide)	Future Grid
Uprate	Drumkeen - Clogher 110 kV uprate (circuit 1)	Future Grid
Uprate	Drumnakelly - Tamnamore 110 kV uprate (circuit 1)	Future Grid
Uprate	Drumnakelly - Tamnamore 110 kV uprate (circuit 2)	Future Grid
Uprate	Drybridge - Louth 110 kV uprate (circuit 1)	Future Grid
Series Capacitor	Dunstown Series Capacitor	Future Grid
Uprate	Finglas - North Wall 220 kV uprate (circuit 1)	Future Grid
Uprate	Flagford - Sliabh Bawn 110 kV uprate (circuit 1)	Future Grid
Upvoltage	Flagford - Srananagh 110 kV (circuit 1)	Future Grid
Uprate	Galway - Salthill 110 kV uprate (circuit 1)	Future Grid
Station	Galway Station Redevelopment Project	Future Grid
Transformer	Gort second transformer	Future Grid
Uprate	Great Island - Kellis 220 kV uprate (circuit 1)	Future Grid
Uprate	Great Island - Kilkenny 110 kV uprate (circuit 1)	Future Grid

Transformer	Great Island 220/110 kV transformer No.3	Future Grid
New Build	Inchicore - Carrickmines 220 kV (circuit 1)	Future Grid
Station	Kilbarry GIS Station	Future Grid
New Build	Kildare - Meath 400 kV Grid Upgrade Project (Capital Project 966)	Future Grid
Uprate	Killoteran - Waterford 110 kV uprate (circuit 1)	Future Grid
New Build	Kilpaddoge - Knockanure 220 kV cable	Future Grid
New Build	Kilpaddoge - Moneypoint 400 kV Project (Cross Shannon)	Future Grid
Uprate	Kilteel - Maynooth 110 kV uprate (circuit 1)	Future Grid
Reactive Support	Knockanure Reactor	Future Grid
Uprate	Knockraha - Cahir 110 kV uprate (circuit 1)	Future Grid
Station	Knockraha Short Circuit Rating Mitigation	Future Grid
Station	Knockraha station installation of additional couplers	Future Grid
Uprate	Lanesboro - Mullingar 110 kV uprate (circuit 1)	Future Grid
Uprate	Lanesboro - Sliabh Bawn 110 kV uprate (circuit 1)	Future Grid
Station	Lanesboro Station Redevelopment Project	Future Grid
Station	Letterkenny busbar	Future Grid
Uprate	Louth - Oriel 220 kV uprate (circuit 1)	Future Grid
DLR	Magherakeel - Omagh (circuit 1)	Future Grid
Uprate	Maynooth - Rinawade 110 kV uprate (circuit 1)	Future Grid
Uprate	Maynooth - Timahoe 110 kV uprate (circuit 1)	Future Grid
Uprate	Derryiron - Timahoe 110 kV uprate (circuit 1)	Future Grid
New Build	Mid Antrim Upgrade	Future Grid
New Build	Mid-Tyrone Project	Future Grid
Series Capacitor	Moneypoint Series Capacitor	Future Grid
Uprate	Moy - Glenree 110 kV uprate (circuit 1)	Future Grid
Station	Moy 110 kV Station reconfiguration and busbar uprate	Future Grid
New Build	North Connacht 110 kV Reinforcement Project	Future Grid
New Build	North South 400 kV Interconnector - NI	Future Grid
New Build	North South 400 kV Interconnector - IE	Future Grid
Uprate	North Wall - Poolbeg 220 kV uprate (circuit 1)	Future Grid
New Build	North West of NI 110 kV reinforcement	Future Grid
Series Capacitor	Oldstreet Series Capacitor	Future Grid
Uprate	Omagh - Strabane 110 kV uprate (circuit 2)	Future Grid
Uprate	Omagh Main - Dromore Uprate	Future Grid
Uprate	Poolbeg - Carrickmines 220 kV uprate (circuit 1)	Future Grid
Uprate	Poolbeg South - Inchicore 220 kV uprate (circuit 1)	Future Grid
Uprate	Poolbeg South - Inchicore 220 kV uprate (circuit 2)	Future Grid
Uprate	Rinawade - Dunfirth Tee 110 kV uprate (circuit 1)	Future Grid
Uprate	Sligo - Srananagh 110 kV uprate (circuit 3)	Future Grid
Static Compensator	Thurles Station - Statcom	Future Grid
New Build	Woodland - Finglas 400 kV cable cct	Future Grid
Uprate	Woodland - Oriel 220 kV uprate (circuit 1)	Future Grid

Table A-3 Reinforcements included in the Future Grid study

Project Type	Project Name	Year
Uprate	Kinnegad 110 kV station, Derryiron 110 kV bay conductor uprate	Future Grid
Uprate	Newbridge - Cushaling 110 kV line, Stations bay conductors and lead-in conductor uprate	Future Grid
Uprate	Gorman - Platin 110 kV line uprate	Future Grid
Uprate	Drybridge - Oldbridge - Platin 110 kV line uprate	Future Grid
Uprate	Louth - Ratrussan 110 kV No 1 Line Uprate	Future Grid
Uprate	Sligo 110 kV Station - Srananagh 1 & 2 Bay uprates	Future Grid
Uprate	Newbridge - Portlaoise 110 kV Partial Thermal Uprate	Future Grid
uprate	Derryiron - Thornsberry 110 kV Circuit Uprate	Future Grid

Table A-4 Additional reinforcements included in the Future Grid study

A.4 Maintenance within the Plexos Modelling

The table below outlines the representative transmission outage schedule applied within the Plexos model for this study.

Child Object	Timeslice	Category
Ballylumford Kells 275 NI	M8	NI
Coleraine Coolkeeragh 110 NI	M8	NI
Kells_110_81520_KEL_275_1	M5	NI
Tandragee 110 275 ckt 2 NI	M7	NI
Aghada - Glanagow_220_1	M4	IE
Aghada - Raffeen_220_1	M6	IE
Arklow - Carrickmines_220_1	M3	IE
Arva - Carrick on Shannon_110_1	M8	IE
Arva - Navan_110_1	M5	IE
Arva - Shankill_110_1	M7	IE
Carlow - Kellis_110_1	M3	IE
Carrick on Shannon - Flagford_110_1	M9	IE
Carrickmines - Dunstown_220_1	M9	IE
Carrickmines - Irishtown_220_1	M10	IE
Carrickmines - Poolbeg_220_1	M5	IE
Carrigadrohid - Kilbarry_110_1	M11	IE
Cashla - Cloon_110_1	M3	IE
Cashla - Flagford_220_1	M11	IE
Cashla - Galway_110_1	M6	IE
Cashla - Prospect_220_1	M4	IE
Castlebagot - Maynooth 220_1	M10	IE
Castlebar - Cloon_110_1	M5	IE
Cathaleen's Fall - Srananagh_110_1	M10	IE
Clashavoon - Knockraha_220_1	M8	IE
Clashavoon - Macroom_110_1	M5	IE
Cloon - Lanesboro110_1	M4	IE
Coolnabacky - Moneypoint_380_1 - new	M4	IE
Corduff - Cruiserath 220 1	M11	IE
Corduff - Ryebrook_110_1	M8	IE
Corduff - Woodland_220_1	M7	IE
Cullenagh - Great Island_220_1	M5	IE
Cullenagh - Knockraha_220_1	M9	IE
Cullenagh - Waterford_110_1	M3	IE
Cushaling - Portlaoise_110_1	M3	IE
Derryiron - Kinnegad_110_1	M4	IE
Drybridge - Gorman_110_1	M4	IE
Drybridge - Louth_110_1	M5	IE
Dunstown - Kellis_220_1	M8	IE

Dunstown - Maynooth_a_220_2	M9	IE
Flagford - Louth_220_1 - derated - no overload	M3	IE
Flagford - Sligo_110_1	M6	IE
Flagford - Srananagh_220_1	M4	IE
Glanagow - Raffeen_220_1	M7	IE
Gorman - Louth_220_1	M10	IE
Gorman - Maynooth_220_1	M4	IE
Gorman - Navan_110_1	M9	IE
Gorman - Platin_110_1	M6	IE
Great Island - Kellis_220_1	M6	IE
Great Island - Lodgewood_220_1	M7	IE
Great Island - Waterford_110_1	M9	IE
Inchicore - Poolbeg_220_1 - 266mva	M11	IE
Killonan - Kilpaddoge_220_1	M10	IE
Killonan - Knockraha_220_1	M11	IE
Killonan - Limerick_110_1	M4	IE
Killonan - Shannonbridge_220_1	M9	IE
Kilpaddoge - Tarbert_220_1	M3	IE
Kilpaddoge - Tralee_110_1	M11	IE
Knockraha - Raffeen_220_1	M8	IE
Maynooth - Blake-T_110_1	M5	IE
Maynooth - Shannonbridge_220_1	M10	IE
Newbridge - Portlaoise_110_1	M7	IE
Oldstreet - Woodland_380_1	M6	IE
Prospect - Tarbert_220_1	M3	IE
Raffeen - Trabeg_110_1	M7	IE
Sligo - Srananagh_110_1	M10	IE
Thurles - Ikerrin-T_110_1	M6	IE
Arklow T2102	M9	Transformer
Carrickmines T2101	M8	Transformer
Carrickmines T2102	M11	Transformer
Cashla T2101	M9	Transformer
Castlebagot T2101 new	M4	Transformer
Clashavoon T2102	M3	Transformer
Cullenagh T2101	M4	Transformer
Dunstown T4201	M5	Transformer
Dunstown T4202	M11	Transformer
Finglas T2101	M6	Transformer
Flagford T2101	M5	Transformer
Inchicore T2101	M7	Transformer
Killonan T2104	M8	Transformer
Kilpaddoge T2101	M7	Transformer
Knockraha T2101	M6	Transformer
Knockraha T2102	M10	Transformer
Louth T2101	M8	Transformer
Moneypoint T4202	M10	Transformer
Woodland T4201	M7	Transformer

Table A-5 Representative Transmission Outage Schedule

Appendix B – Generator

The following generator information is included in this Appendix:

- Generator Type for each Generation Scenario
- Generator Type by Area for each Generation Scenario

A full list of generators included in the study is published separately on the ECP 2.2 constraint forecast webpage[13]

Note: the tables in the following section include both Ireland and Northern Ireland generation.

[13] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.2-constraints-repor/index.xml

B.1 Generation Type for each Generator Scenario

The table below shows existing and expected wind, wind offshore, solar, wave, battery and other technologies (other technologies include: biomass, biogas, CHP, LFG and Anaerobic Digester (AD) plants) in both Ireland and Northern Ireland, which were included in this analysis.

Type	Initial (MW)	33% (MW)	66% (MW)	ECP (MW)	ECP+ 2.2 GW Offshore (MW)	ECP + 4.4 GW Offshore (MW)	ECP + 5 GW Offshore (MW)
battery	1,016	1253	1491	1729	1729	1729	1,729
offshore wind	-	0	0	0	2197	4394	4,994
solar	1,550	2603	3656	4710	4710	4710	4,710
wave	-	3	7	10	10	10	10
wind	6,481	7322	8163	9005	9005	9005	9,005
Other Technologies	36	36	36	36	36	36	36
Grand Total	**9082**	**11218**	**13353**	**15489**	**9942**	**19883**	**20483**

Table B-1 Total Generation per Generation Type

B.2 Generation Type by Area for each Generator Scenario

The table below shows existing and expected wind, wind offshore, solar, wave, battery and other technologies (other technologies include: biomass, biogas, CHP, LFG and AD plants) in both Ireland and Northern Ireland, which were included in this analysis.

Type and Area	Initial (MW)	33% (MW)	66% (MW)	ECP (MW)	ECP+ 2.2 GW offshore (MW)	ECP + 4.4 GW offshore (MW)	ECP+ 5 GW Offshore (MW)
battery	**1016**	**1253**	**1491**	**1729**	**1729**	**1729**	**1729**
B	11	15	19	23	23	23	23
C	263	268	274	279	279	279	279
E	7	7	7	7	7	7	7
G	110	180	250	319	319	319	319
H2	25	108	192	275	275	275	275
I	178	215	251	288	288	288	288
J	212	245	279	312	312	312	312
K	-	33	67	100	100	100	100
NI	210	215	221	226	226	226	226
offshore wind	**-**	**-**	**-**	**-**	**2197**	**4394**	**4994**
E	-	-	-	-	225	450	450
G	-	-	-	-	185	370	370
H2	-	-	-	-	400	800	1100
I	-	-	-	-	-	-	300
J	-	-	-	-	1387	2774	2774
solar	**1550**	**2603**	**3656**	**4710**	**4710**	**4710**	**4710**
A	-	15	30	45	45	45	45
B	43	103	162	222	222	222	222
C	134	174	215	256	256	256	256
D	-	42	83	125	125	125	125
E	158	242	327	411	411	411	411
F	9	22	35	48	48	48	48
G	262	376	489	603	603	603	603
H1	16	111	206	302	302	302	302
H2	213	429	645	862	862	862	862
I	35	109	183	258	258	258	258
J	397	652	906	1161	1161	1161	1161
K	122	167	213	258	258	258	258
NI	161	161	161	161	161	161	161

wave	**-**	**3**	**7**	**10**	**10**	**10**	**10**
B	-	3	7	10	10	10	10
wind	**6481**	**7322**	**8163**	**9005**	**9005**	**9005**	**9005**
A	811	888	966	1044	1044	1044	1044
B	781	876	972	1067	1067	1067	1067
C	132	238	344	451	451	451	451
D	311	316	320	325	325	325	325
E	1467	1500	1534	1567	1567	1567	1567
F	218	219	220	222	222	222	222
G	233	249	266	282	282	282	282
H1	540	567	594	621	621	621	621
H2	322	359	396	433	433	433	433
I	8	8	9	9	9	9	9
J	188	298	408	518	518	518	518
K	61	61	61	61	61	61	61
NI	1409	1741	2074	2406	2406	2406	2406
Other Technologies	**36**	**36**	**36**	**36**	**36**	**36**	**36**
B	2	2	2	2	2	2	2
E	3	3	3	3	3	3	3
F	5	5	5	5	5	5	5
G	17	17	17	17	17	17	17
J	8	8	8	8	8	8	8
K	2	2	2	2	2	2	2
Grand Total	**9082**	**11218**	**13353**	**15489**	**9942**	**19883**	**20483**

Table B-2 Generation Type by Area for each Generator Scenario

B.3 Generation List by Type, Node and Name

A full list of generators included in the study is published separately on the ECP 2.2 constraint forecast webpage[14] which includes existing and expected wind, wind offshore, solar, wave, battery and other technologies (other technologies include: biomass, biogas, CHP, LFG and AD plants) sorted A to Z by name in Ireland which were included in this analysis.

Note that the year of connection is rounded from the build-out rate date or target connection date.

These are in addition to the new large generators, which are listed in EirGrid and SONI's All-Island Generation Capacity Statement 2022 - 2031.

[14] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.2-constraints-repor/index.xml

Appendix C Area B Node Results

This appendix presents the results of the modelling analysis for Area B. The levels of over-supply, curtailment and constraint that controllable solar and wind generators in Area B

might expect to experience are reported on a nodal basis for the study scenarios. Details on the generation capacity at each node are also provided along with the assumed amount of controllable generation.

This appendix also presents a list for each node of those generators that are included in the study

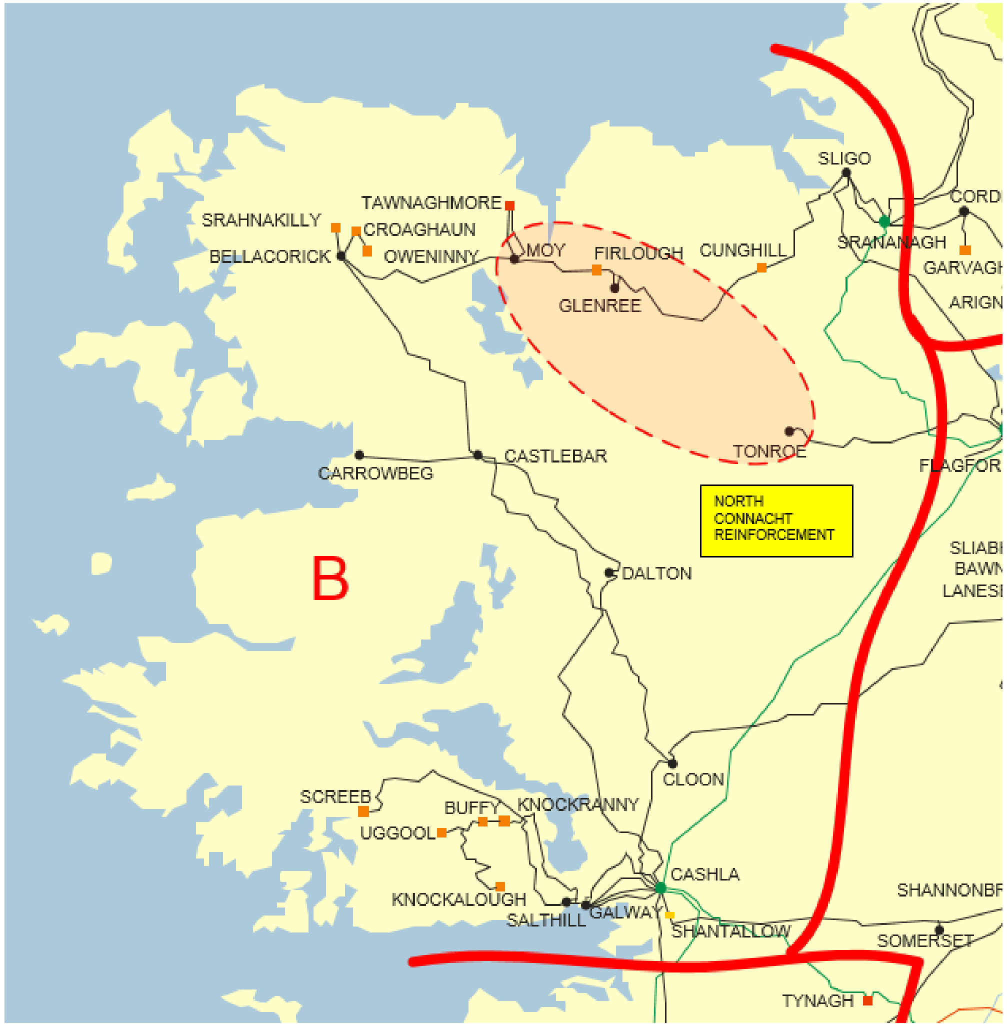

Figure C-0-1 Area B

C.1. Bellacorick

Figure C - 1 Location of node Bellacorick

Generator	SO	Capacity	Type	Status
Bellacorick (1)	DSO	6.0	wind priority	connected
Bunnahowen (1)	DSO	3.0	wind uncontrolled	connected
Corvoderry (was Gortnahurra (1))	DSO	34.0	wind not priority	due to connect
Dooleeg More (1)	DSO	3.0	wind not priority	due to connect
Dooleeg More Ext.	DSO	1.0	wind not priority	due to connect
Oweninny 3 (Previously Oweninny 5)	TSO	50.0	wind not priority	due to connect
Oweninny Power (1)	TSO	89.0	wind not priority	connected
Oweninny Power (2)	TSO	83.0	wind not priority	due to connect
Sheskin (1)	DSO	33.0	wind not priority	due to connect

Table C - 1 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	172	212	253	293			
Installed Capacity (MW)	2027	172	212	253	293	293	293	
Installed Capacity (MW)	2030				293	293	293	293
Available Energy (GWh)	2025	523	646	768	891			
Available Energy (GWh)	2027	523	646	768	891	891	891	
Available Energy (GWh)	2030				891	891	891	891
Generation (GWh)	2025	456	516	567	606			
Generation (GWh)	2027	512	611	676	728	671	590	
Generation (GWh)	2030				732	695	626	610
Over-supply (%)	2025	3 %	6 %	10 %	15 %			
Over-supply (%)	2027	0 %	1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025	1 %	1 %	2 %	2 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025	15 %	17 %	18 %	19 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	12 %	7 %	
Constraint (%)	2030				8 %	3 %	1 %	0 %
Total Dispatch Down (%)	2025	18 %	24 %	30 %	36 %			
Total Dispatch Down (%)	2027	12 %	17 %	22 %	28 %	32 %	39 %	
Total Dispatch Down (%)	2030				13 %	18 %	27 %	29 %

Table C - 2 Results for Wind Not Priority

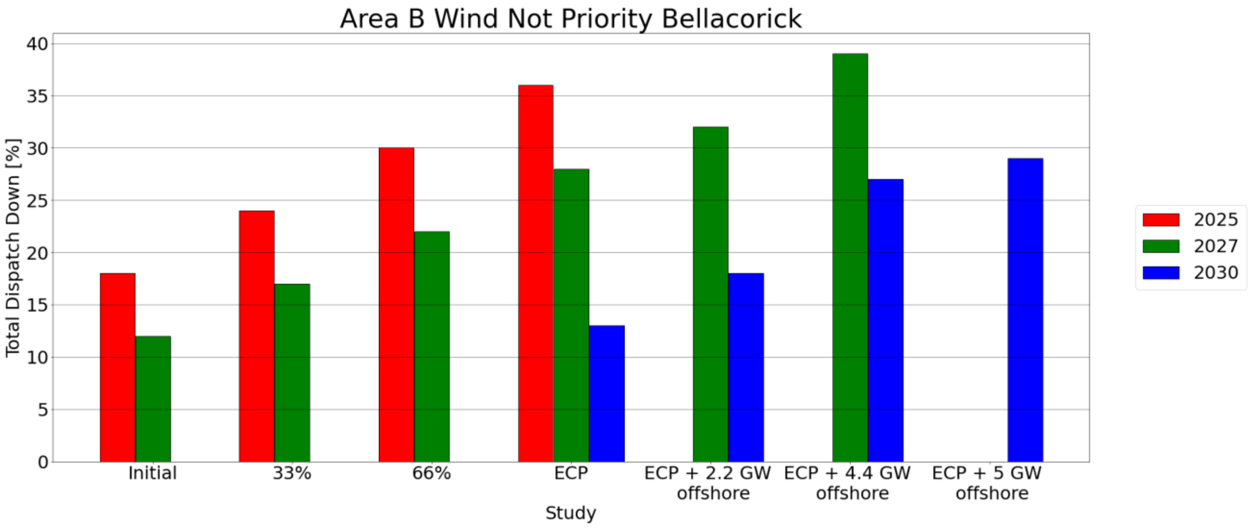

Figure C - 2 Total Dispatch Down for Wind Not Priority

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	6	6	6	6			
Installed Capacity (MW)	2027	6	6	6	6	6	6	
Installed Capacity (MW)	2030				6	6	6	6
Available Energy (GWh)	2025	18	18	18	18			
Available Energy (GWh)	2027	18	18	18	18	18	18	
Available Energy (GWh)	2030				18	18	18	18
Generation (GWh)	2025	14	12	11	10			
Generation (GWh)	2027	18	15	13	12	14	16	
Generation (GWh)	2030				13	15	16	16
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 3 Results for Wind Priority

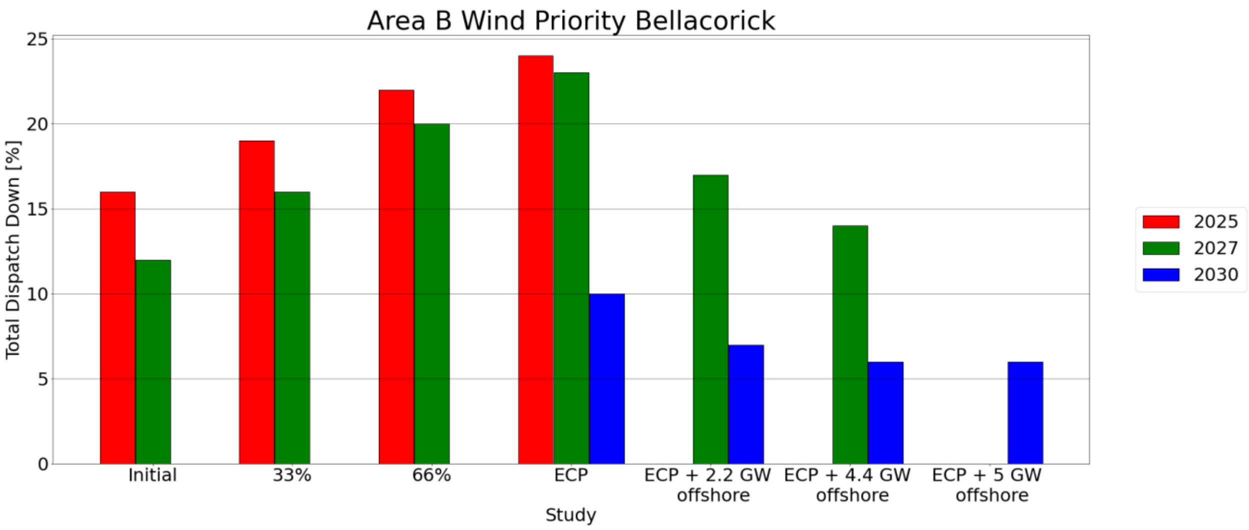

Figure C - 3 Total Dispatch Down for Wind Priority

C.2. Cashla

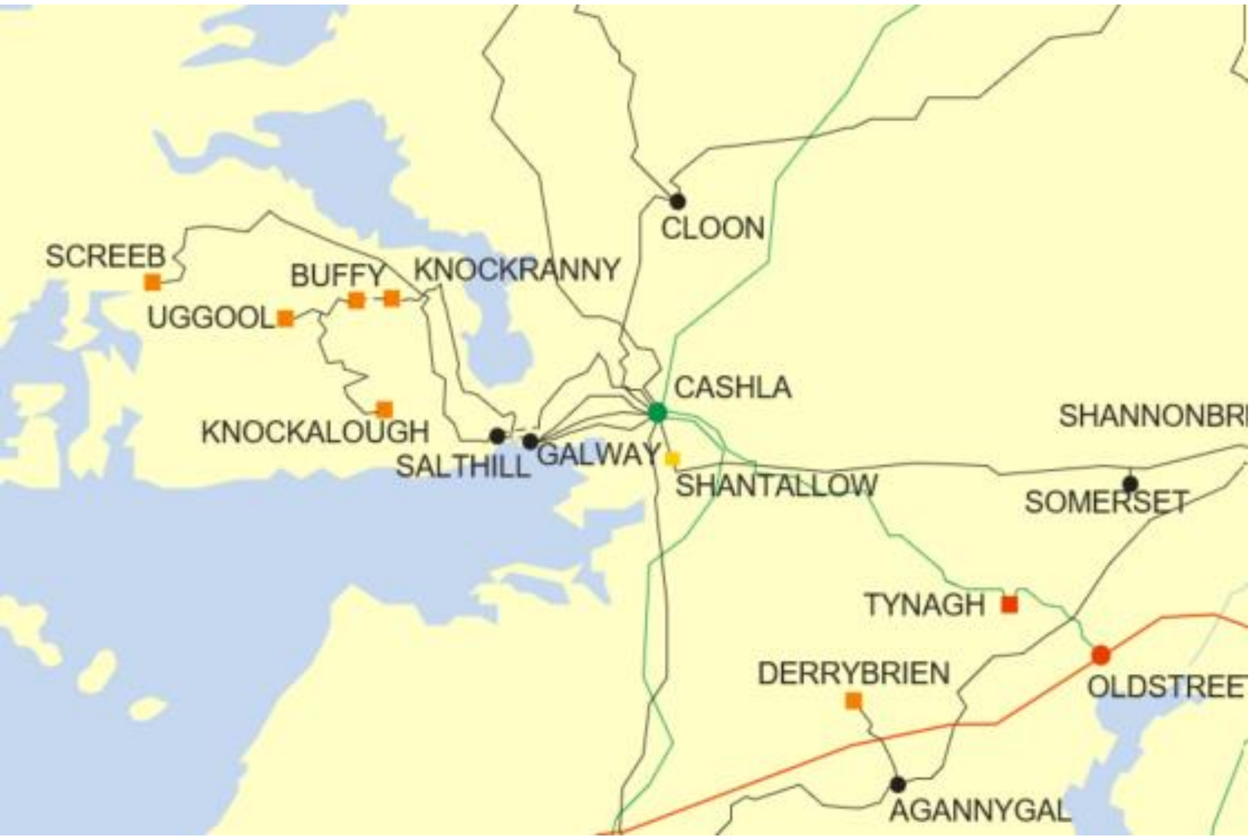

Figure C - 4 Location of node Cashla

Generator	SO	Capacity	Type	Status
Ballymoneen Solar Park	TSO	100.0	solar not priority	due to connect

Table C - 4 Generation Included in Study for Node

The solar not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025		33	67	100			
Installed Capacity (MW)	2027		33	67	100	100	100	
Installed Capacity (MW)	2030				100	100	100	100
Available Energy (GWh)	2025		35	71	106			
Available Energy (GWh)	2027		35	71	106	106	106	
Available Energy (GWh)	2030				106	106	106	106
Generation (GWh)	2025		34	67	97			
Generation (GWh)	2027		35	69	101	96	90	
Generation (GWh)	2030				101	97	92	91
Over-supply (%)	2025		2 %	4 %	7 %			
Over-supply (%)	2027		1 %	2 %	4 %	8 %	13 %	
Over-supply (%)	2030				3 %	7 %	11 %	12 %
Curtailment (%)	2025		1 %	1 %	2 %			
Curtailment (%)	2027		0 %	1 %	1 %	2 %	2 %	
Curtailment (%)	2030				1 %	2 %	2 %	2 %
Constraint (%)	2025		2 %	1 %	2 %			
Constraint (%)	2027		4 %	2 %	1 %	1 %	0 %	
Constraint (%)	2030				1 %	0 %	0 %	0 %
Total Dispatch Down (%)	2025		5 %	7 %	10 %			
Total Dispatch Down (%)	2027		5 %	5 %	6 %	10 %	15 %	
Total Dispatch Down (%)	2030				5 %	8 %	13 %	14 %

Table C - 5 Results for Solar Not Priority

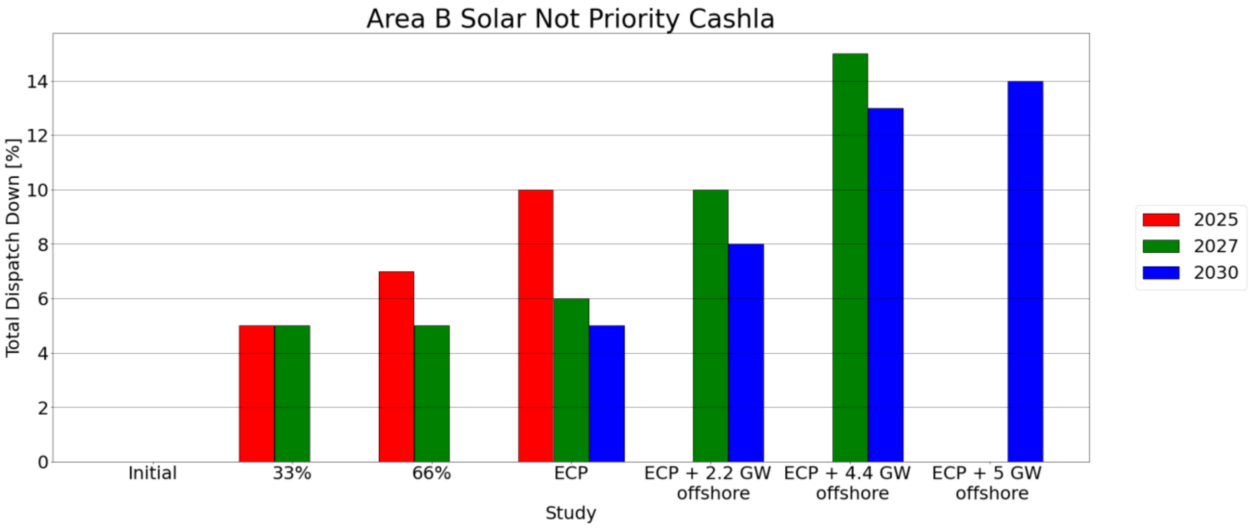

Figure C - 5 Total Dispatch Down for Solar Not Priority

C.3. Castlebar

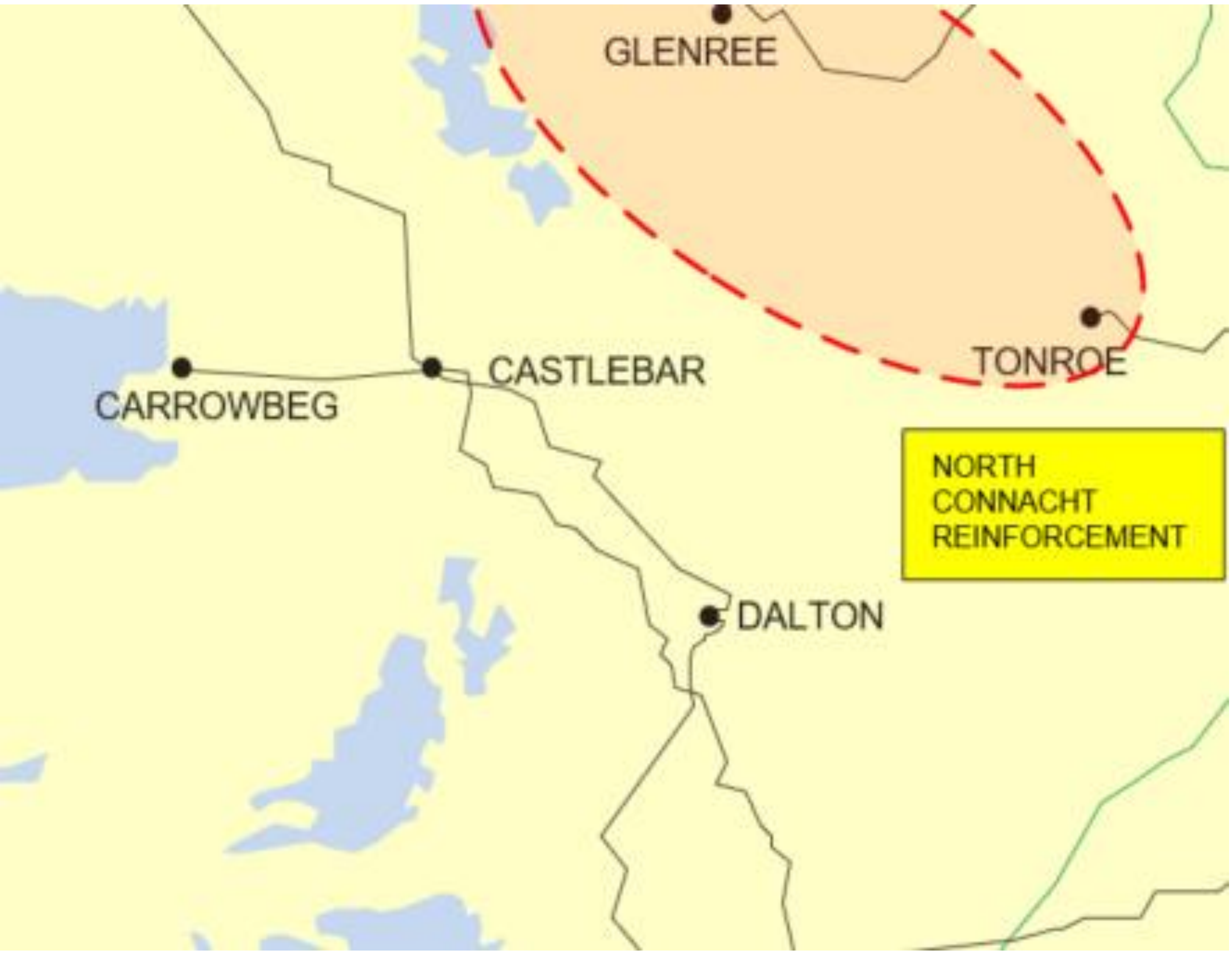

Figure C - 6 Location of node Castlebar

Generator	SO	Capacity	Type	Status
Cuillalea (1)	DSO	3.0	wind uncontrolled	connected
Cuillalea (2)	DSO	2.0	wind uncontrolled	connected
Derrynadivva Wind Farm (prev. Raheen Bar 2)	DSO	9.0	wind priority	connected
Lenanavea (Burren) Wind Farm	DSO	5.0	wind uncontrolled	connected
Raheen Barr (1)	DSO	19.0	wind uncontrolled	connected
Raheen Barr extension (was Derrynadivva extension)	DSO	7.0	wind not priority	connected

Table C - 6 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	7	7	7	7			
Installed Capacity (MW)	2027	7	7	7	7	7	7	
Installed Capacity (MW)	2030				7	7	7	7
Available Energy (GWh)	2025	21	21	21	21			
Available Energy (GWh)	2027	21	21	21	21	21	21	
Available Energy (GWh)	2030				21	21	21	21
Generation (GWh)	2025	18	17	16	15			
Generation (GWh)	2027	21	21	20	19	17	14	
Generation (GWh)	2030				19	17	15	15
Over-supply (%)	2025	3 %	6 %	10 %	15 %			
Over-supply (%)	2027	0 %	1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025	1 %	1 %	2 %	2 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025	15 %	17 %	18 %	19 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	12 %	7 %	
Constraint (%)	2030				8 %	3 %	1 %	0 %
Total Dispatch Down (%)	2025	18 %	24 %	30 %	36 %			
Total Dispatch Down (%)	2027	12 %	17 %	22 %	28 %	32 %	39 %	
Total Dispatch Down (%)	2030				13 %	18 %	27 %	29 %

Table C - 7 Results for Wind Not Priority

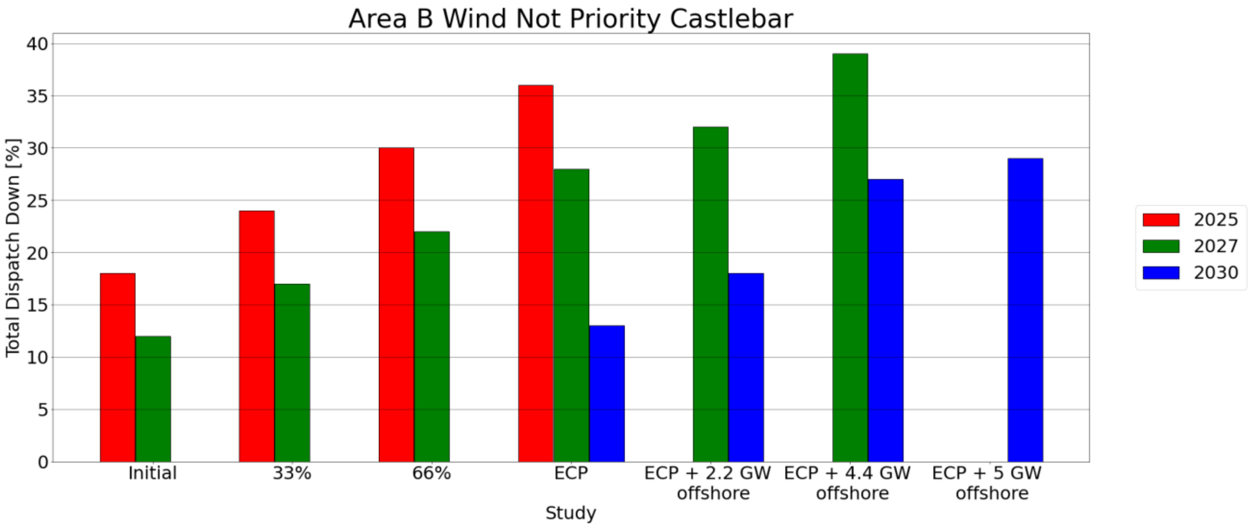

Figure C - 7 Total Dispatch Down for Wind Not Priority

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	9	9	9	9			
Installed Capacity (MW)	2027	9	9	9	9	9	9	
Installed Capacity (MW)	2030				9	9	9	9
Available Energy (GWh)	2025	27	27	27	27			
Available Energy (GWh)	2027	27	27	27	27	27	27	
Available Energy (GWh)	2030				27	27	27	27
Generation (GWh)	2025	24	23	23	23			
Generation (GWh)	2027	27	27	26	26	26	26	
Generation (GWh)	2030				25	25	25	25
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 8 Results for Wind Priority

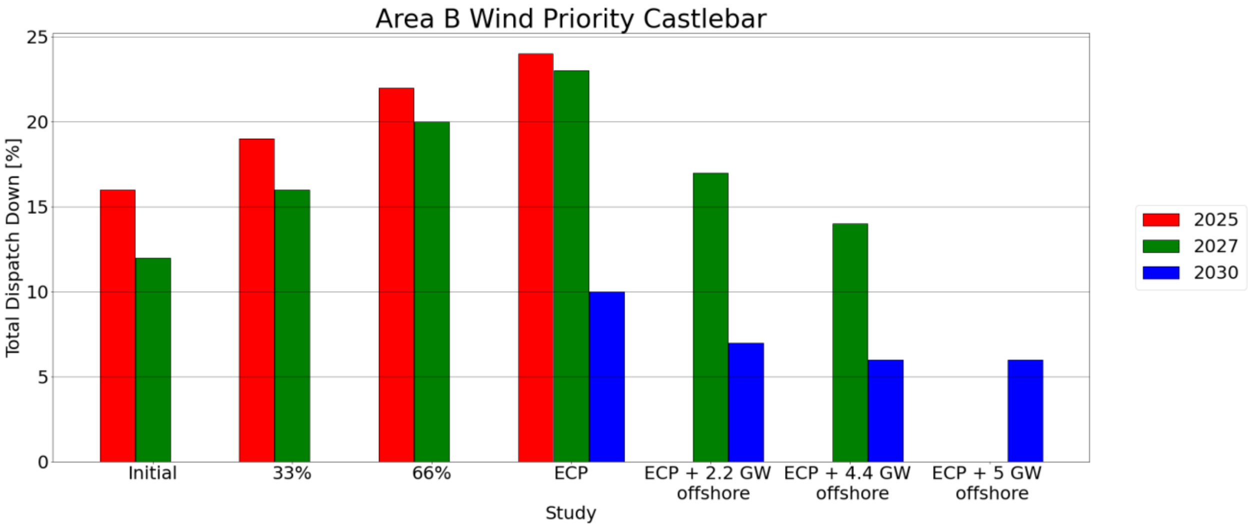

Figure C - 8 Total Dispatch Down for Wind Priority

C.4. Cloon

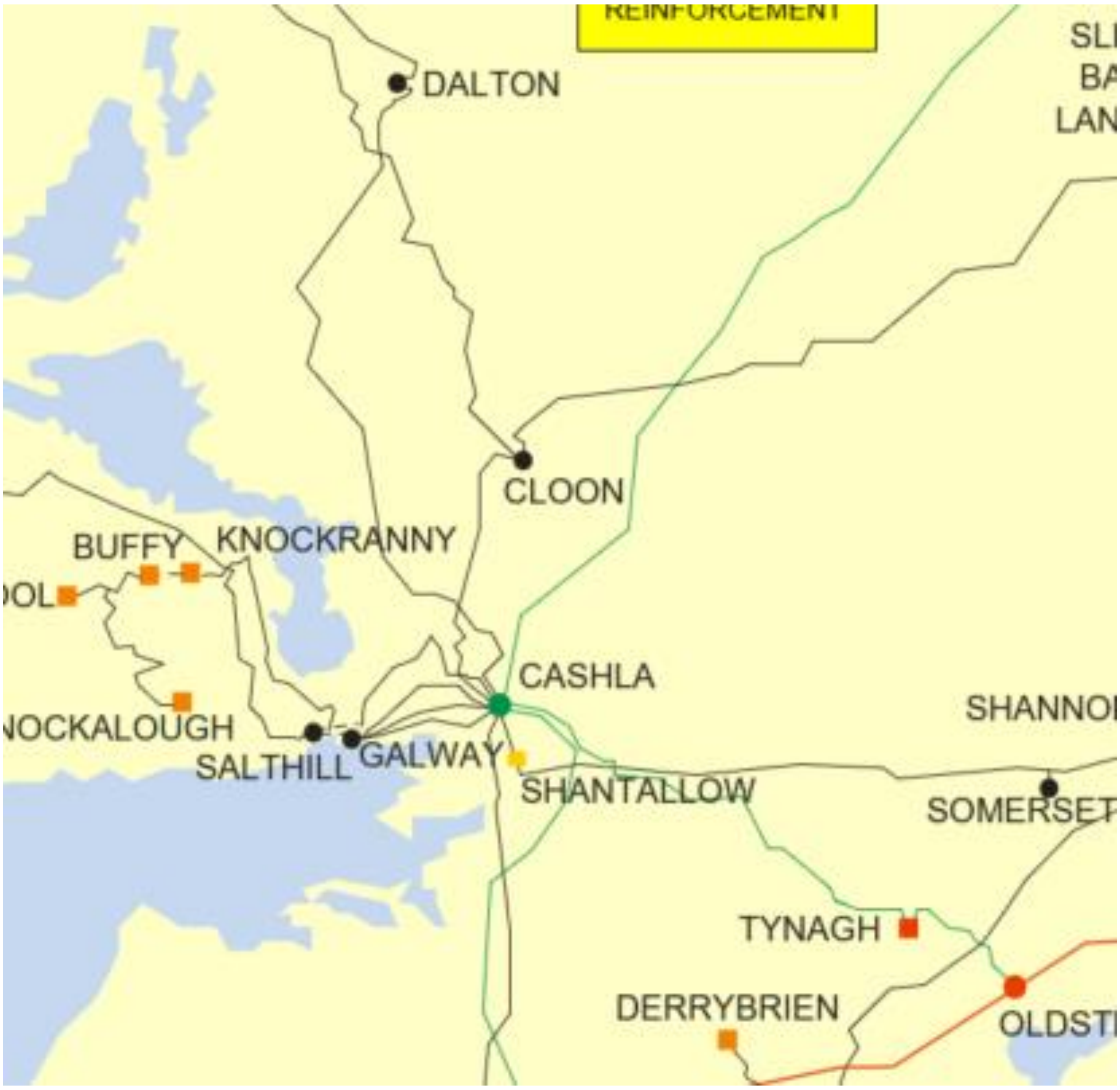

Figure C - 9 Location of node Cloon

Generator	SO	Capacity	Type	Status
Barnacurragh Solar Park	TSO	50.0	solar not priority	due to connect
Barnderg Solar Farm	DSO	4.0	solar not priority	due to connect
Cloonascragh Solar	DSO	20.0	solar not priority	due to connect
Clooninagh Wind Farm	DSO	5.0	wind not priority	due to connect
Cloonlusk (1)	DSO	4.0	wind uncontrolled	connected
Milltown Community Solar Farm	DSO	4.99	solar not priority	due to connect
Shantallow Wind Farm	DSO	4.99	wind not priority	due to connect

Table C - 9 Generation Included in Study for Node

The solar not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	4	29	54	79			
Installed Capacity (MW)	2027	4	29	54	79	79	79	
Installed Capacity (MW)	2030				79	79	79	79
Available Energy (GWh)	2025	4	31	57	84			
Available Energy (GWh)	2027	4	31	57	84	84	84	
Available Energy (GWh)	2030				84	84	84	84
Generation (GWh)	2025	4	30	54	76			
Generation (GWh)	2027	4	30	56	79	75	71	
Generation (GWh)	2030				80	77	73	72
Over-supply (%)	2025	1 %	2 %	4 %	7 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	8 %	13 %	
Over-supply (%)	2030				3 %	7 %	11 %	12 %
Curtailment (%)	2025	0 %	1 %	1 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	2 %	
Curtailment (%)	2030				1 %	2 %	2 %	2 %
Constraint (%)	2025	4 %	2 %	1 %	2 %			
Constraint (%)	2027	5 %	4 %	2 %	1 %	1 %	0 %	
Constraint (%)	2030				1 %	0 %	0 %	0 %
Total Dispatch Down (%)	2025	5 %	5 %	7 %	10 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	10 %	15 %	
Total Dispatch Down (%)	2030				5 %	8 %	13 %	14 %

Table C - 10 Results for Solar Not Priority

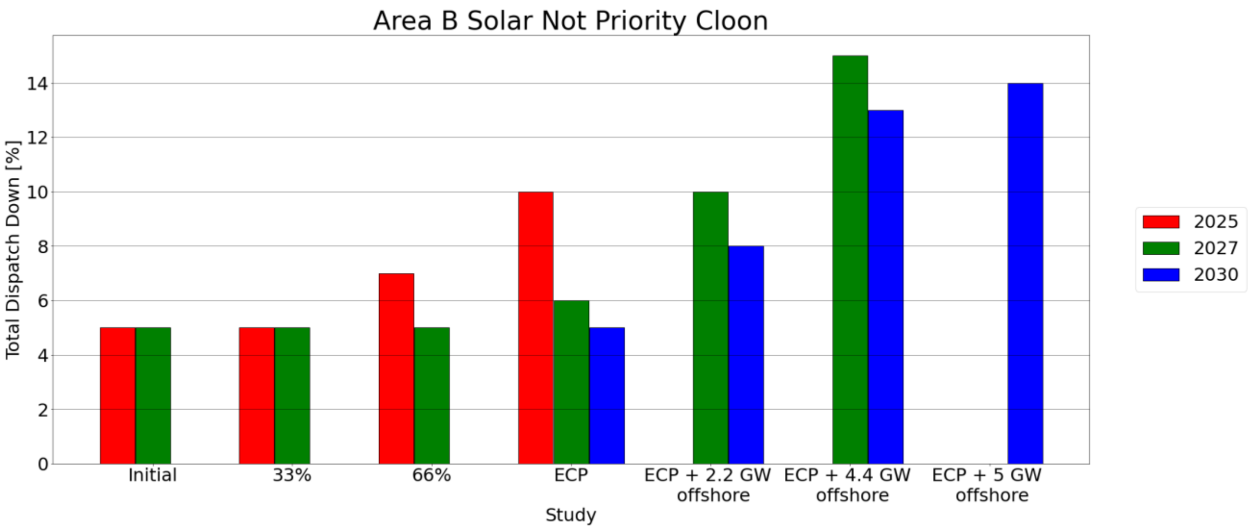

Figure C - 10 Total Dispatch Down for Solar Not Priority

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025		3	7	10			
Installed Capacity (MW)	2027		3	7	10	10	10	
Installed Capacity (MW)	2030				10	10	10	10
Available Energy (GWh)	2025		10	20	30			
Available Energy (GWh)	2027		10	20	30	30	30	
Available Energy (GWh)	2030				30	30	30	30
Generation (GWh)	2025		9	18	25			
Generation (GWh)	2027		10	19	28	24	21	
Generation (GWh)	2030				29	26	22	22
Over-supply (%)	2025		6 %	10 %	15 %			
Over-supply (%)	2027		1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025		1 %	2 %	2 %			
Curtailment (%)	2027		1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025		-1 %	-1 %	-1 %			
Constraint (%)	2027		4 %	1 %	0 %	-1 %	-1 %	
Constraint (%)	2030				1 %	-1 %	-1 %	-1 %
Total Dispatch Down (%)	2025		7 %	11 %	16 %			
Total Dispatch Down (%)	2027		5 %	5 %	7 %	19 %	30 %	
Total Dispatch Down (%)	2030				5 %	15 %	25 %	27 %

Table C - 11 Results for Wind Not Priority

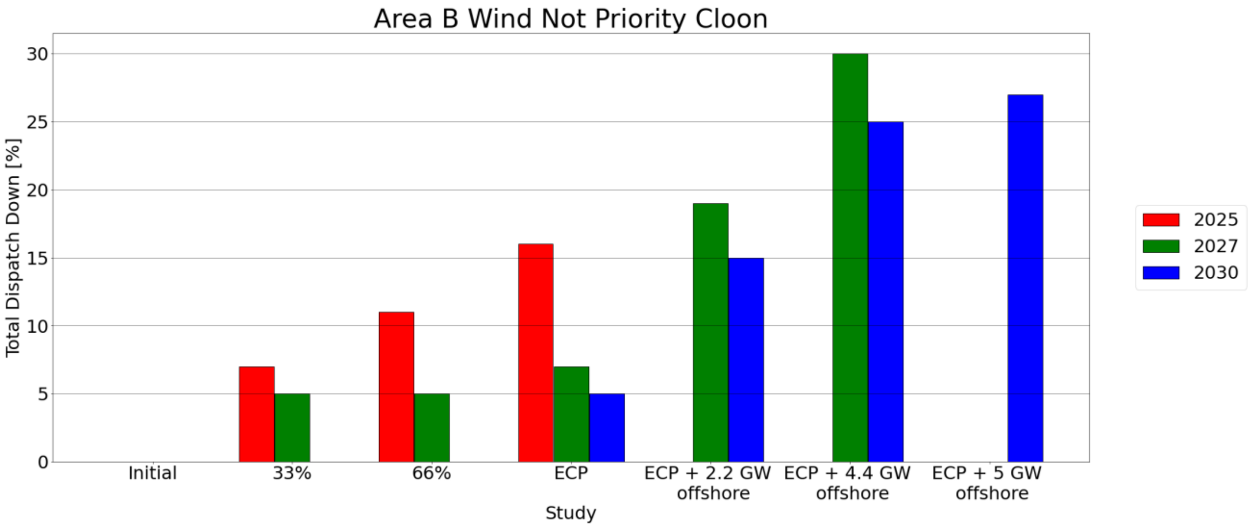

Figure C - 11 Total Dispatch Down for Wind Not Priority

C.5. Cunghill

Figure C - 12 Location of node Cunghill

Generator	SO	Capacity	Type	Status
Kingsmountain (1)	TSO	24.0	wind priority	connected
Kingsmountain (2)	TSO	11.0	wind priority	connected

Table C - 12 Generation Included in Study for Node

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	35	35	35	35			
Installed Capacity (MW)	2027	35	35	35	35	35	35	
Installed Capacity (MW)	2030				35	35	35	35
Available Energy (GWh)	2025	106	106	106	106			
Available Energy (GWh)	2027	106	106	106	106	106	106	
Available Energy (GWh)	2030				106	106	106	106
Generation (GWh)	2025	56	49	44	40			
Generation (GWh)	2027	68	61	58	52	56	65	
Generation (GWh)	2030				91	97	100	100
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 13 Results for Wind Priority

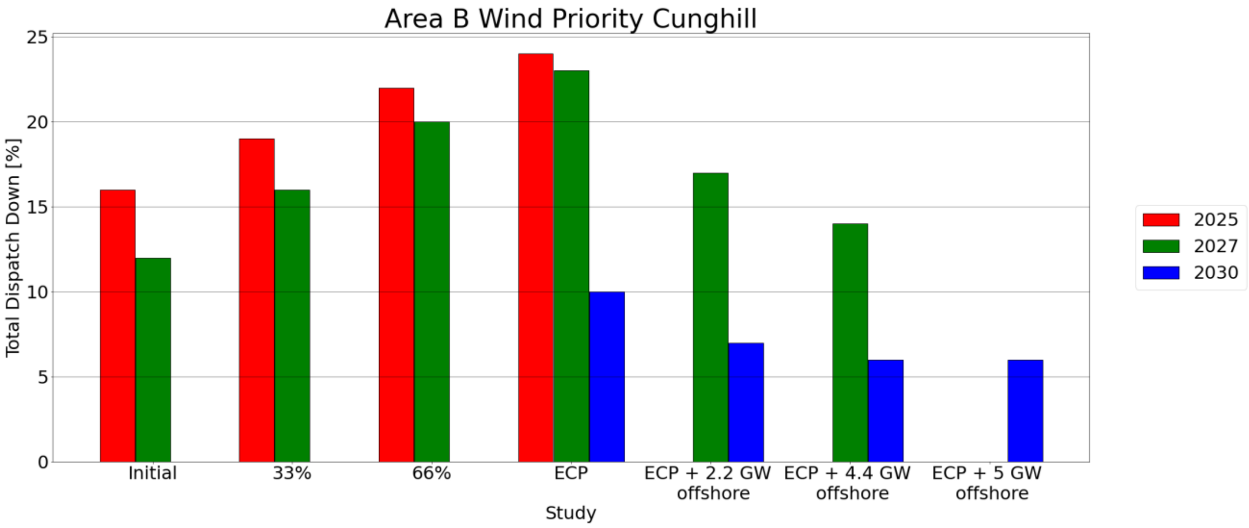

Figure C - 13 Total Dispatch Down for Wind Priority

C.6. Dalton

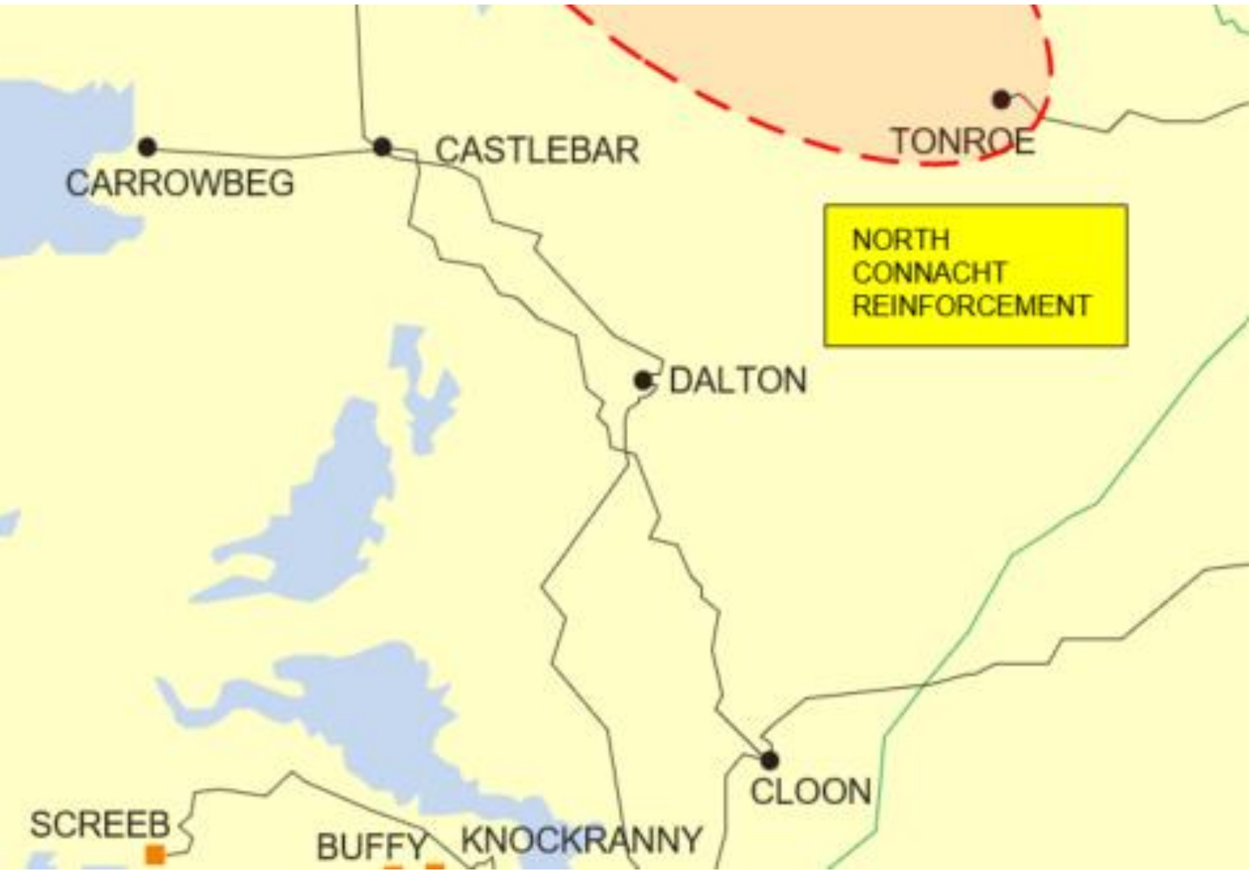

Figure C - 14 Location of node Dalton

Generator	SO	Capacity	Type	Status
Claremorris 2 Solar Farm	DSO	4.0	solar not priority	due to connect
Lisduff Solar Park (Claremorris)	DSO	4.0	solar not priority	due to connect
Mace Upper (1)	DSO	3.0	wind uncontrolled	connected
Magheramore and Cloontooa (1)	DSO	41.0	wind priority	connected

Table C - 14 Generation Included in Study for Node

The solar not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	4	5	7	8			
Installed Capacity (MW)	2027	4	5	7	8	8	8	
Installed Capacity (MW)	2030				8	8	8	8
Available Energy (GWh)	2025	4	6	7	8			
Available Energy (GWh)	2027	4	6	7	8	8	8	
Available Energy (GWh)	2030				8	8	8	8
Generation (GWh)	2025	4	5	6	7			
Generation (GWh)	2027	4	6	7	8	8	7	
Generation (GWh)	2030				8	8	7	7
Over-supply (%)	2025	1 %	2 %	4 %	7 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	8 %	13 %	
Over-supply (%)	2030				3 %	7 %	11 %	12 %
Curtailment (%)	2025	0 %	1 %	1 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	2 %	
Curtailment (%)	2030				1 %	2 %	2 %	2 %
Constraint (%)	2025	4 %	4 %	4 %	4 %			
Constraint (%)	2027	5 %	4 %	3 %	3 %	2 %	2 %	
Constraint (%)	2030				2 %	1 %	0 %	0 %
Total Dispatch Down (%)	2025	5 %	6 %	9 %	12 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	7 %	12 %	16 %	
Total Dispatch Down (%)	2030				6 %	9 %	13 %	14 %

Table C - 15 Results for Solar Not Priority

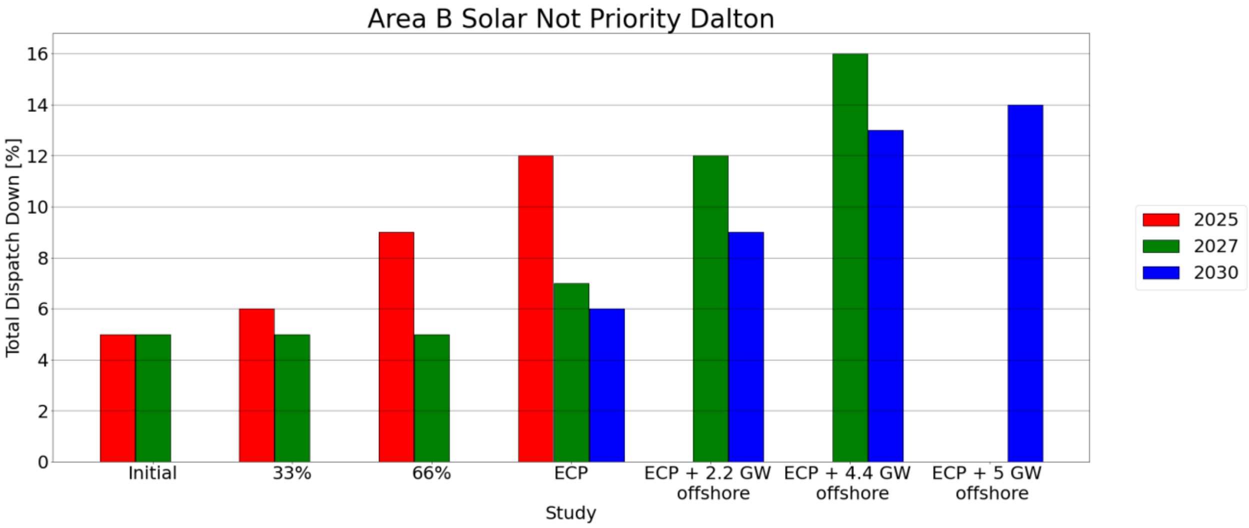

Figure C - 15 Total Dispatch Down for Solar Not Priority

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	41	41	41	41			
Installed Capacity (MW)	2027	41	41	41	41	41	41	
Installed Capacity (MW)	2030				41	41	41	41
Available Energy (GWh)	2025	125	125	125	125			
Available Energy (GWh)	2027	125	125	125	125	125	125	
Available Energy (GWh)	2030				125	125	125	125
Generation (GWh)	2025	119	119	117	116			
Generation (GWh)	2027	123	121	119	119	118	117	
Generation (GWh)	2030				115	116	116	117
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 16 Results for Wind Priority

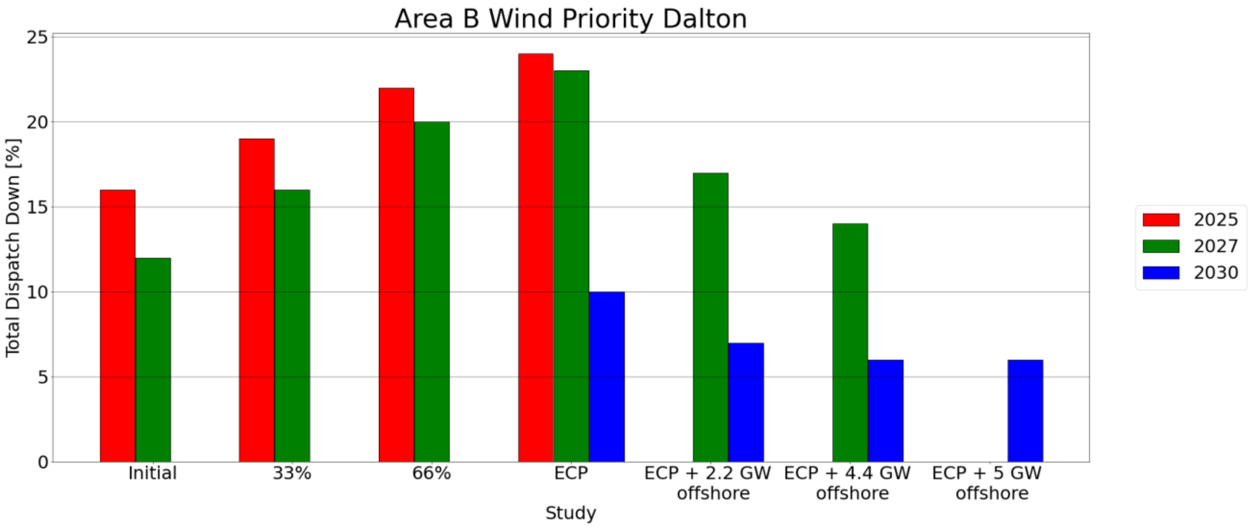

Figure C - 16 Total Dispatch Down for Wind Priority

C.7. Firlough

Figure C - 17 Location of node Firlough

Generator	SO	Capacity	Type	Status
Firlough TG371 was Carrowleagh-Kilbride DG741	TSO	48.3	wind not priority	due to connect
Firlough Wind Farm	TSO	27.3	wind not priority	due to connect

Table C - 17 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025		25	50	76			
Installed Capacity (MW)	2027		25	50	76	76	76	
Installed Capacity (MW)	2030				76	76	76	76
Available Energy (GWh)	2025		77	153	230			
Available Energy (GWh)	2027		77	153	230	230	230	
Available Energy (GWh)	2030				230	230	230	230
Generation (GWh)	2025		46	78	102			
Generation (GWh)	2027		75	146	210	183	158	
Generation (GWh)	2030				214	192	168	163
Over-supply (%)	2025		6 %	10 %	15 %			
Over-supply (%)	2027		1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025		1 %	2 %	2 %			
Curtailment (%)	2027		1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025		17 %	18 %	19 %			
Constraint (%)	2027		16 %	19 %	21 %	12 %	7 %	
Constraint (%)	2030				8 %	3 %	1 %	0 %
Total Dispatch Down (%)	2025		24 %	30 %	36 %			
Total Dispatch Down (%)	2027		17 %	22 %	28 %	32 %	39 %	
Total Dispatch Down (%)	2030				13 %	18 %	27 %	29 %

Table C - 18 Results for Wind Not Priority

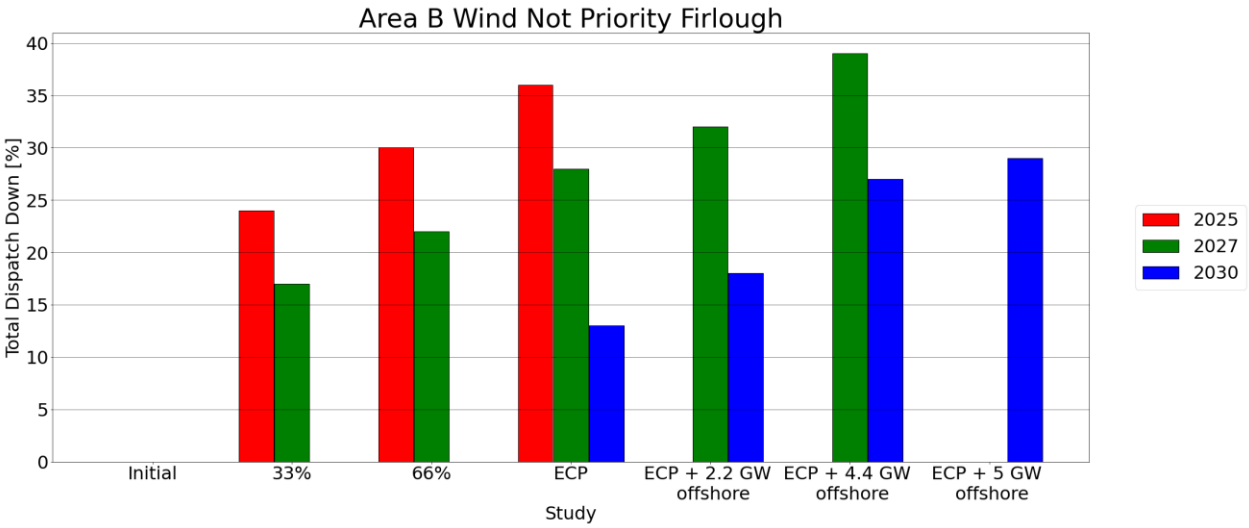

Figure C - 18 Total Dispatch Down for Wind Not

C.8. Glenree

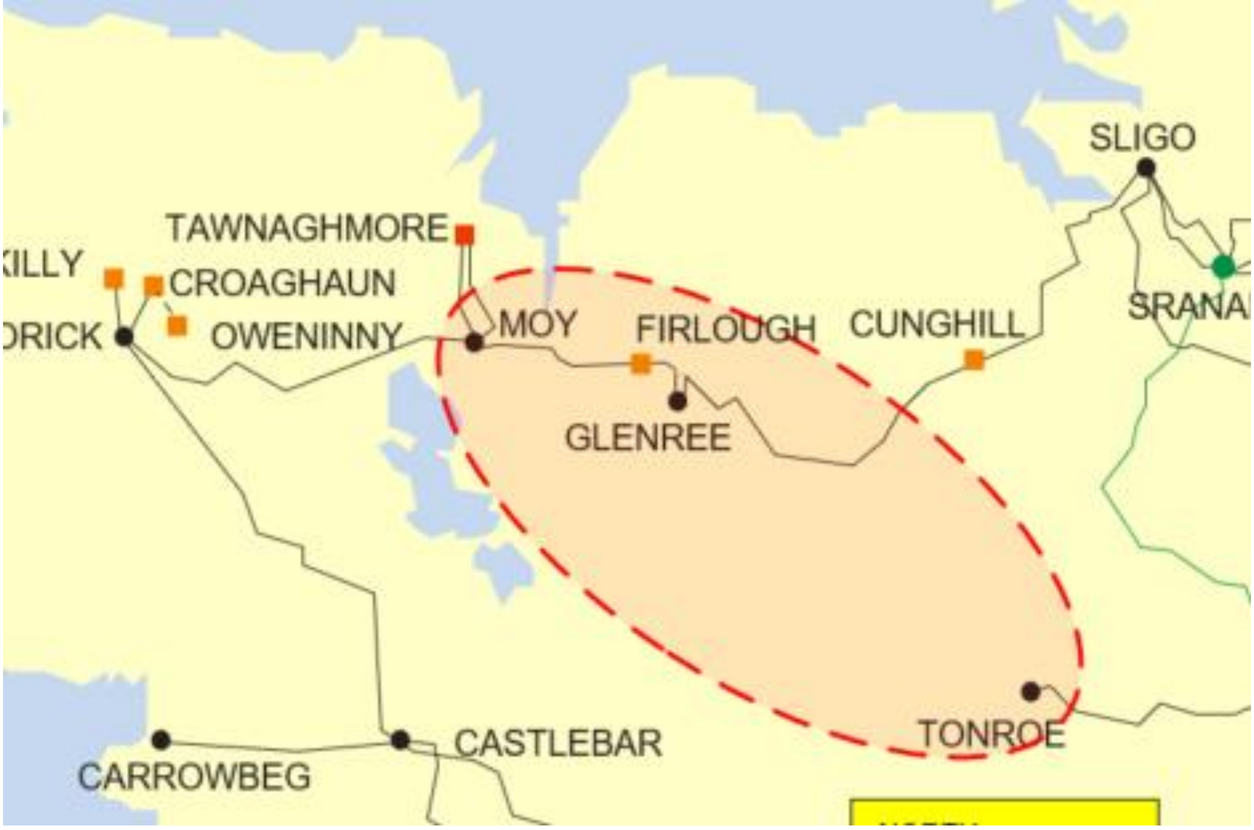

Figure C - 19 Location of node Glenree

Generator	SO	Capacity	Type	Status
Black Lough (1)	DSO	13.0	wind not priority	connected
Bunnyconnellan (1)	DSO	28.0	wind not priority	connected
Carrowleagh (1)	DSO	34.0	wind priority	connected
Carrowleagh (2)	DSO	3.0	wind uncontrolled	connected

Table C - 19 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	41	41	41	41			
Installed Capacity (MW)	2027	41	41	41	41	41	41	
Installed Capacity (MW)	2030				41	41	41	41
Available Energy (GWh)	2025	125	125	125	125			
Available Energy (GWh)	2027	125	125	125	125	125	125	
Available Energy (GWh)	2030				125	125	125	125
Generation (GWh)	2025	77	64	55	48			
Generation (GWh)	2027	123	122	117	110	98	85	
Generation (GWh)	2030				116	104	91	89
Over-supply (%)	2025	3 %	6 %	10 %	15 %			
Over-supply (%)	2027	0 %	1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025	1 %	1 %	2 %	2 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025	15 %	17 %	18 %	19 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	12 %	7 %	
Constraint (%)	2030				8 %	3 %	1 %	0 %
Total Dispatch Down (%)	2025	18 %	24 %	30 %	36 %			
Total Dispatch Down (%)	2027	12 %	17 %	22 %	28 %	32 %	39 %	
Total Dispatch Down (%)	2030				13 %	18 %	27 %	29 %

Table C - 20 Results for Wind Not Priority

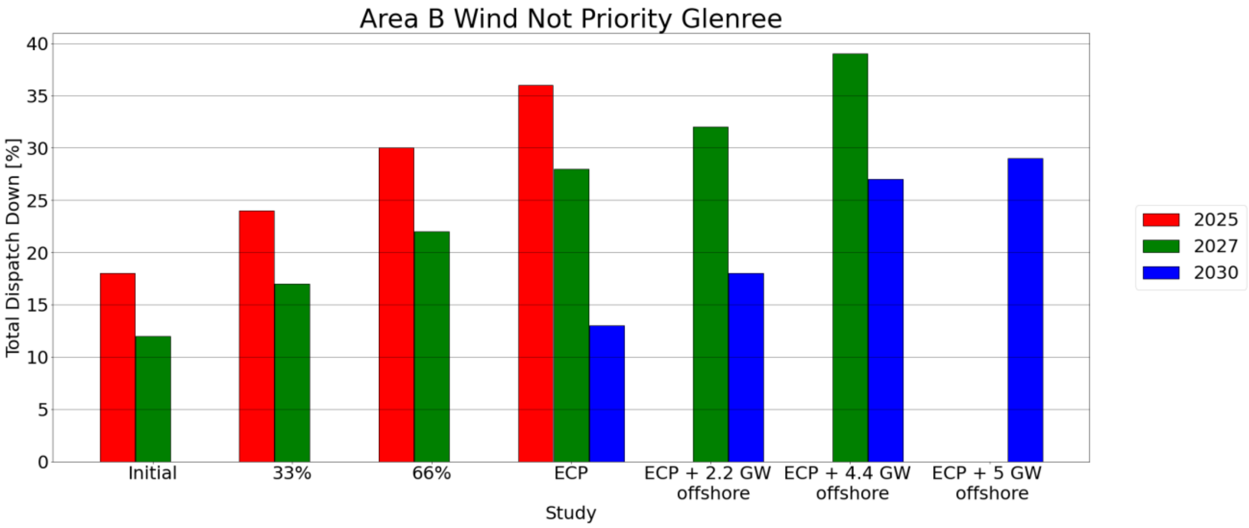

Figure C - 20 Total Dispatch Down for Wind Not Priority

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	34	34	34	34			
Installed Capacity (MW)	2027	34	34	34	34	34	34	
Installed Capacity (MW)	2030				34	34	34	34
Available Energy (GWh)	2025	103	103	103	103			
Available Energy (GWh)	2027	103	103	103	103	103	103	
Available Energy (GWh)	2030				103	103	103	103
Generation (GWh)	2025	64	55	49	44			
Generation (GWh)	2027	102	102	99	97	97	97	
Generation (GWh)	2030				99	99	98	98
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 21 Results for Wind Priority

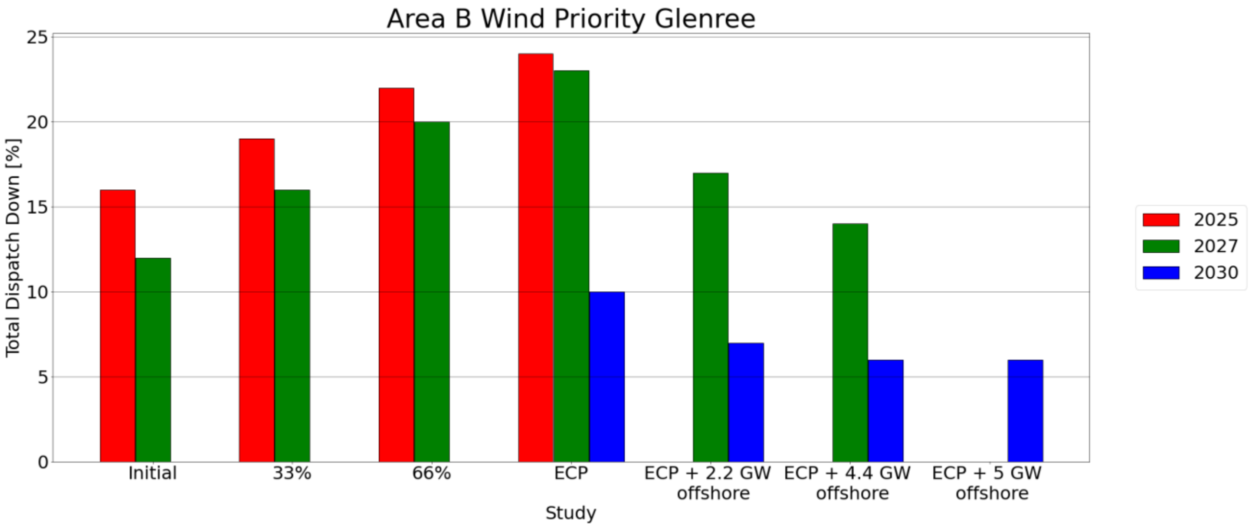

Figure C - 21 Total Dispatch Down for Wind Priority

C.9. Knockranny

Figure C - 22 Location of node Knockranny

Generator	SO	Capacity	Type	Status
Ardderoo 2 (Formerly Buffy)	TSO	64.0	wind not priority	due to connect
Ardderoo wind extension	TSO	18.0	wind not priority	due to connect
Ardderoo Wind Farm	TSO	27.0	wind not priority	due to connect
Knockalough (1)	TSO	35.0	wind priority	connected
Knockranny wind	TSO	47.3	wind not priority	due to connect

Table C - 22 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	91	113	135	156			
Installed Capacity (MW)	2027	91	113	135	156	156	156	
Installed Capacity (MW)	2030				156	156	156	156
Available Energy (GWh)	2025	362	449	535	622			
Available Energy (GWh)	2027	362	449	535	622	622	622	
Available Energy (GWh)	2030				622	622	622	622
Generation (GWh)	2025	347	415	470	515			
Generation (GWh)	2027	361	443	515	580	520	454	
Generation (GWh)	2030				600	547	485	471
Over-supply (%)	2025	2 %	5 %	7 %	11 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	13 %	24 %	
Over-supply (%)	2030				2 %	10 %	19 %	22 %
Curtailment (%)	2025	1 %	1 %	2 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025	3 %	5 %	7 %	8 %			
Constraint (%)	2027	5 %	4 %	3 %	4 %	2 %	1 %	
Constraint (%)	2030				2 %	1 %	1 %	1 %
Total Dispatch Down (%)	2025	5 %	10 %	16 %	21 %			
Total Dispatch Down (%)	2027	5 %	5 %	6 %	10 %	18 %	28 %	
Total Dispatch Down (%)	2030				6 %	13 %	23 %	25 %

Table C - 23 Results for Wind Not Priority

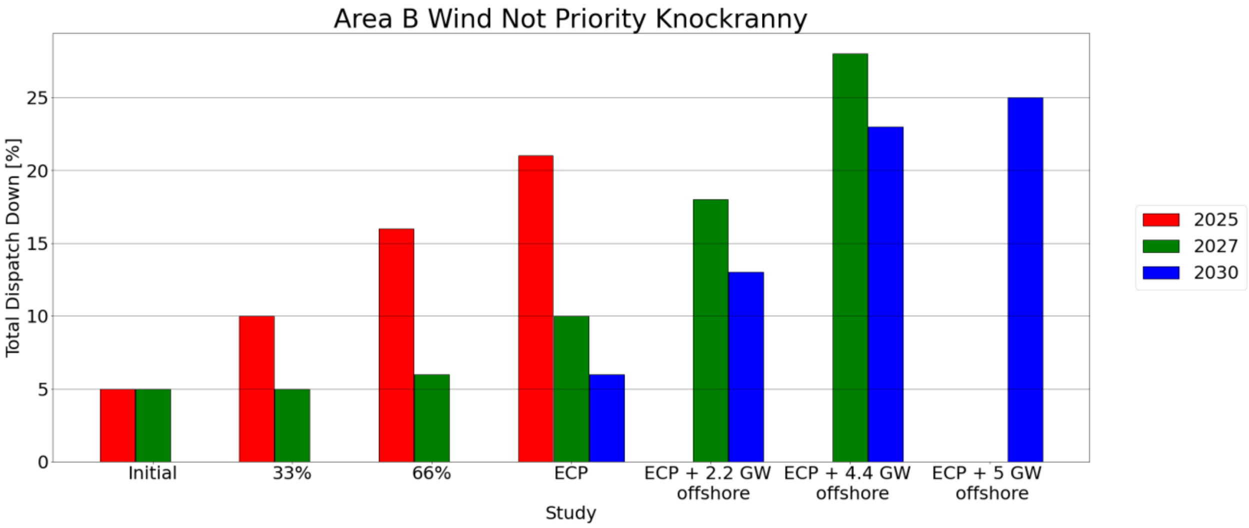

Figure C - 23 Total Dispatch Down for Wind Not Priority

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	35	35	35	35			
Installed Capacity (MW)	2027	35	35	35	35	35	35	
Installed Capacity (MW)	2030				35	35	35	35
Available Energy (GWh)	2025	139	139	139	139			
Available Energy (GWh)	2027	139	139	139	139	139	139	
Available Energy (GWh)	2030				139	139	139	139
Generation (GWh)	2025	132	125	114	98			
Generation (GWh)	2027	139	137	133	128	131	131	
Generation (GWh)	2030				137	135	134	133
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	2 %	3 %			
Curtailment (%)	2027	0 %	0 %	1 %	2 %	3 %	5 %	
Curtailment (%)	2030				1 %	3 %	4 %	4 %
Constraint (%)	2025	4 %	5 %	7 %	8 %			
Constraint (%)	2027	5 %	5 %	4 %	5 %	2 %	1 %	
Constraint (%)	2030				4 %	2 %	1 %	1 %
Total Dispatch Down (%)	2025	5 %	6 %	9 %	11 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	6 %	6 %	
Total Dispatch Down (%)	2030				5 %	5 %	5 %	5 %

Table C - 24 Results for Wind Priority

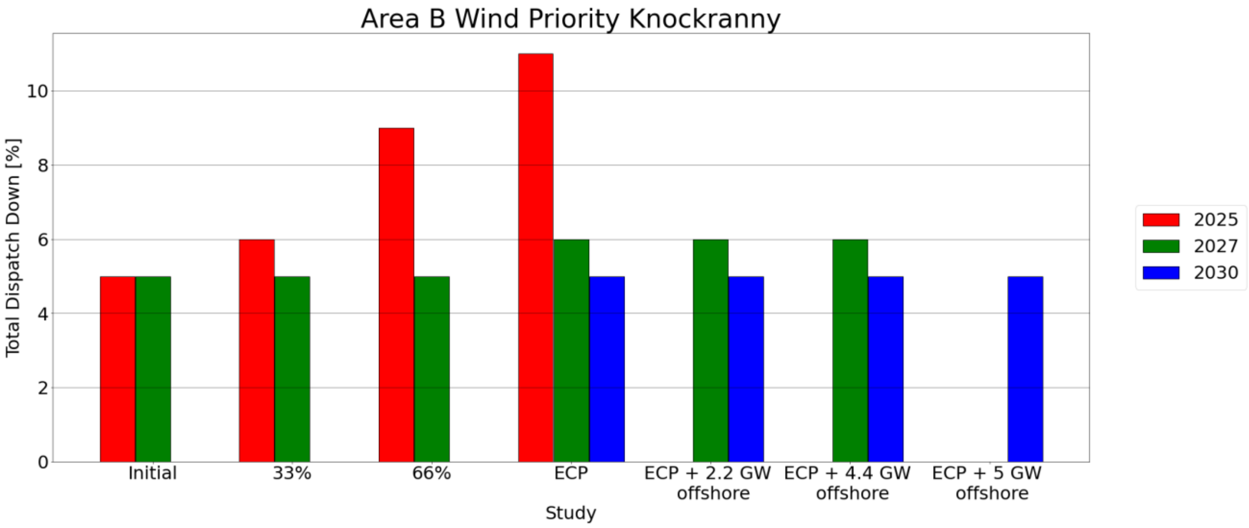

Figure C - 24 Total Dispatch Down for Wind Priority

C.10. Moy

Figure C - 25 Location of node Moy

Generator	SO	Capacity	Type	Status
Lackan (1)	DSO	6.0	wind priority	connected

Table C - 25 Generation Included in Study for Node

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	6	6	6	6			
Installed Capacity (MW)	2027	6	6	6	6	6	6	
Installed Capacity (MW)	2030				6	6	6	6
Available Energy (GWh)	2025	18	18	18	18			
Available Energy (GWh)	2027	18	18	18	18	18	18	
Available Energy (GWh)	2030				18	18	18	18
Generation (GWh)	2025	15	14	13	13			
Generation (GWh)	2027	18	18	18	18	17	17	
Generation (GWh)	2030				17	17	17	17
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 26 Results for Wind Priority

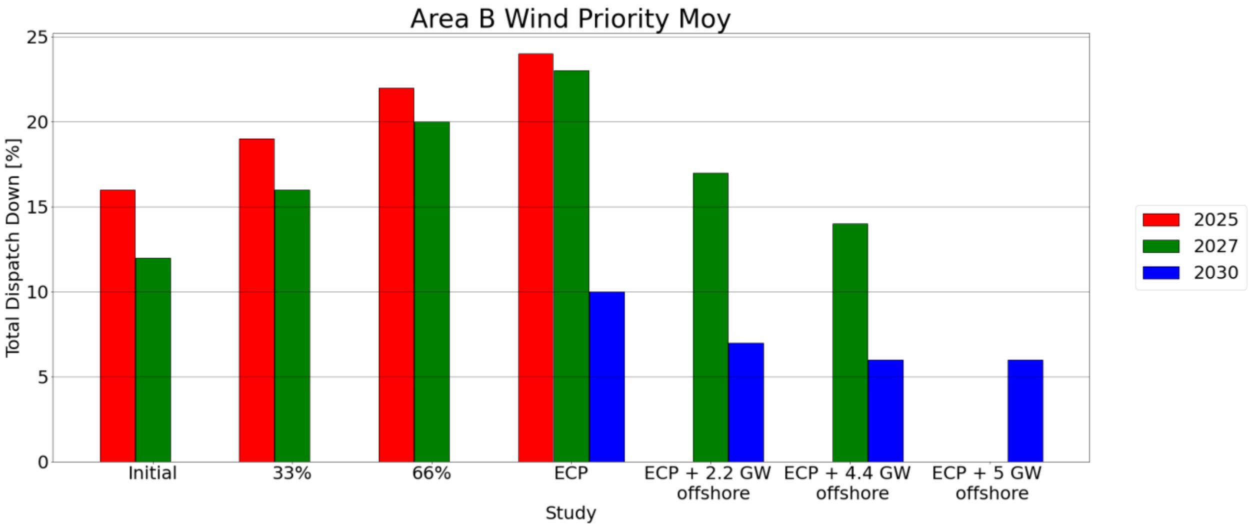

Figure C - 26 Total Dispatch Down for Wind Priority

C.11. Salthill

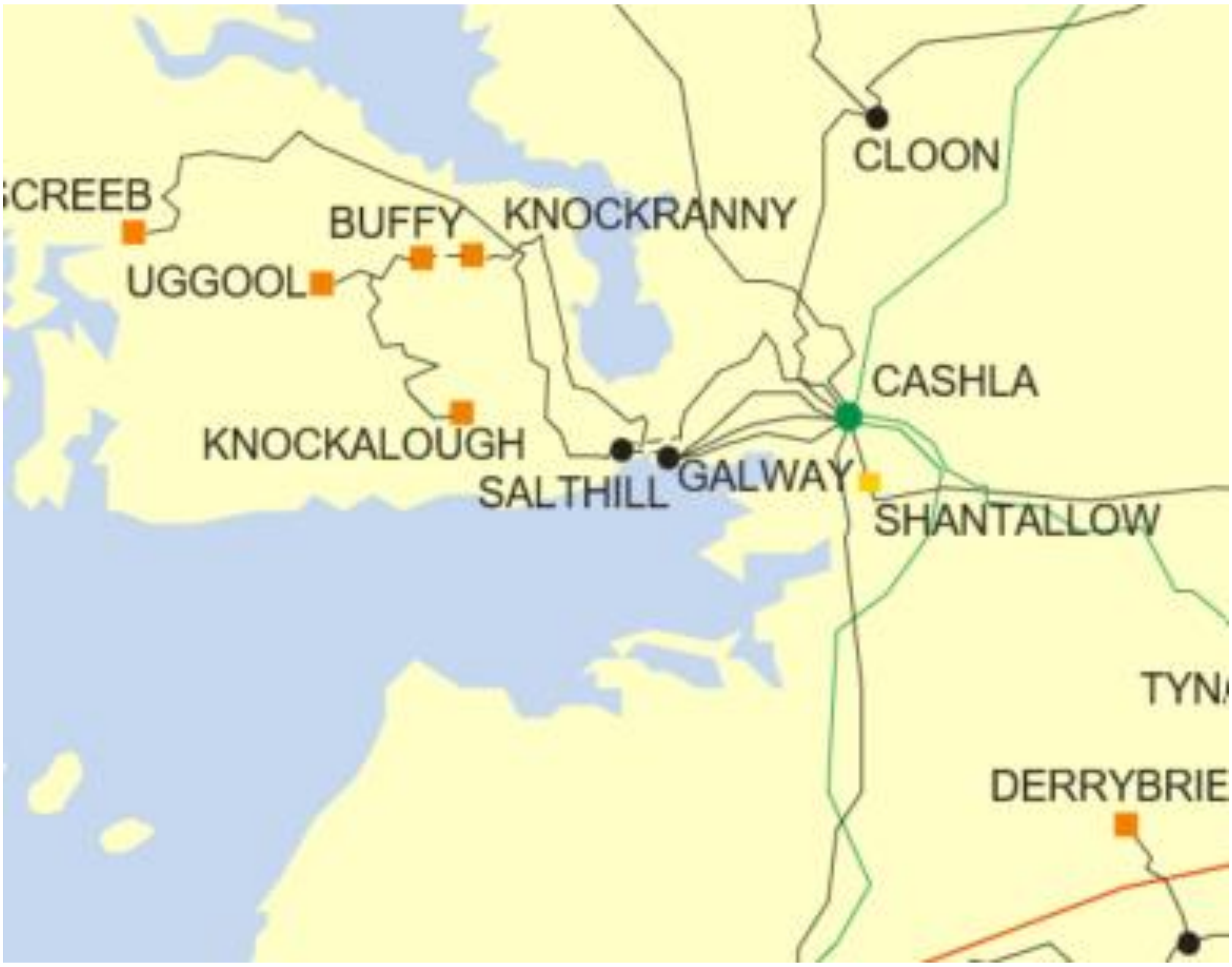

Figure C - 27 Location of node Salthill

Generator	SO	Capacity	Type	Status
Leitir Guingaid & Doire Chrith1 & 2 Merge	DSO	41.0	wind priority	connected

Table C - 27 Generation Included in Study for Node

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	41	41	41	41			
Installed Capacity (MW)	2027	41	41	41	41	41	41	
Installed Capacity (MW)	2030				41	41	41	41
Available Energy (GWh)	2025	125	125	125	125			
Available Energy (GWh)	2027	125	125	125	125	125	125	
Available Energy (GWh)	2030				125	125	125	125
Generation (GWh)	2025	110	90	78	72			
Generation (GWh)	2027	124	122	113	95	110	115	
Generation (GWh)	2030				122	121	119	119
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	4 %	4 %	6 %	8 %			
Constraint (%)	2027	5 %	4 %	4 %	4 %	2 %	1 %	
Constraint (%)	2030				3 %	2 %	0 %	0 %
Total Dispatch Down (%)	2025	5 %	6 %	9 %	11 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	6 %	6 %	
Total Dispatch Down (%)	2030				5 %	5 %	5 %	5 %

Table C - 28 Results for Wind Priority

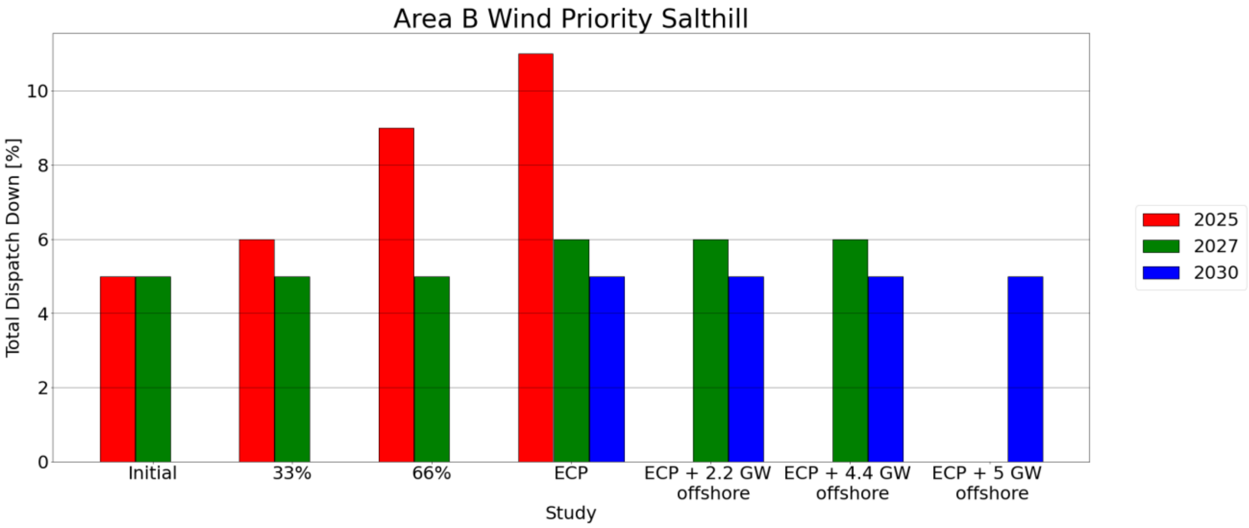

Figure C - 28 Total Dispatch Down for Wind Priority

C.12. Screeb

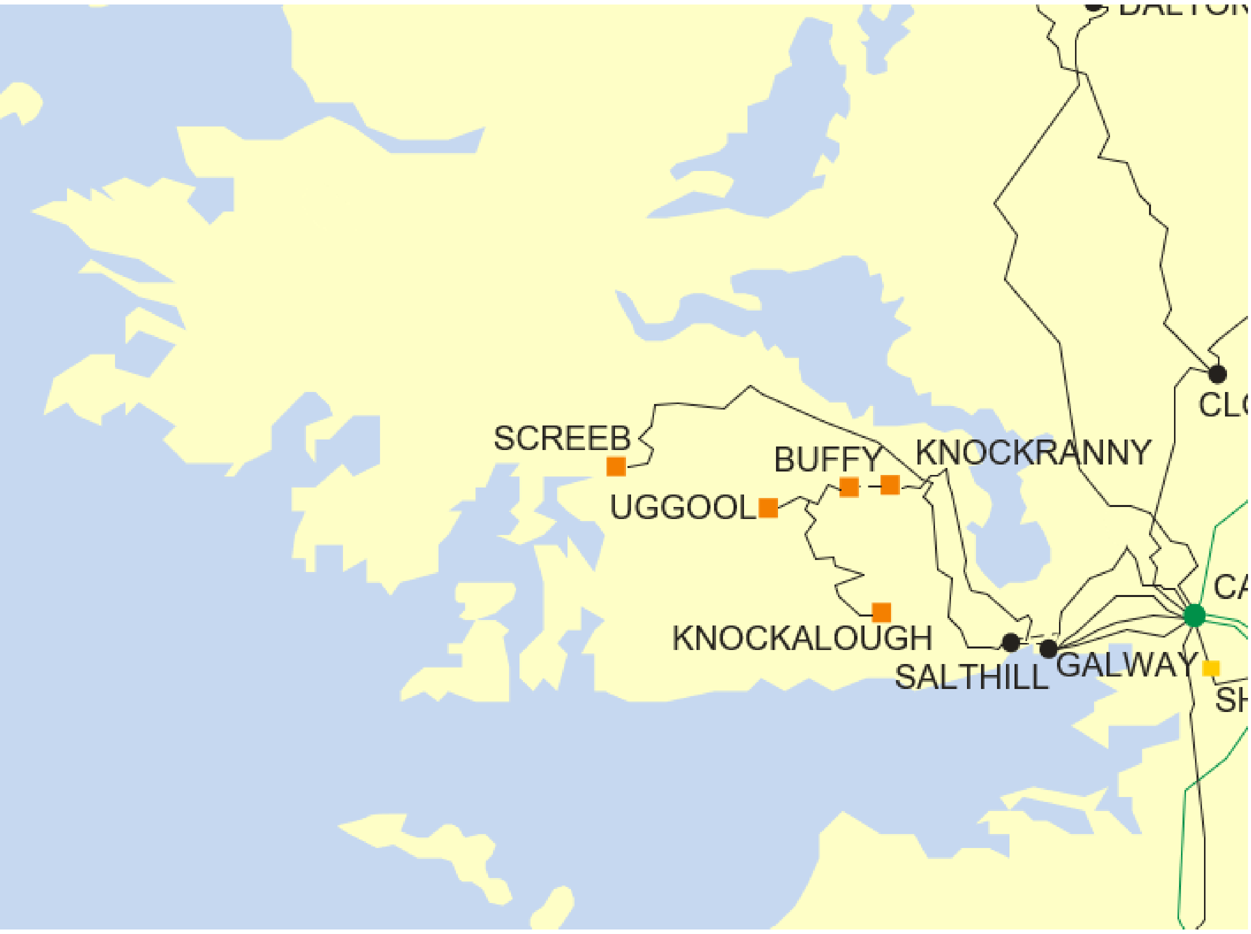

Figure C - 29 Location of node Screeb

Generator	SO	Capacity	Type	Status
Inverin (Knock South) (1)	DSO	3.0	wind uncontrolled	connected
Inverin Community Wind Turbine	DSO	4.99	wind not priority	due to connect
Rossaveel Wind	DSO	3.0	wind uncontrolled	connected

Table C - 29 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025		2	3	5			
Installed Capacity (MW)	2027		2	3	5	5	5	
Installed Capacity (MW)	2030				5	5	5	5
Available Energy (GWh)	2025		7	13	20			
Available Energy (GWh)	2027		7	13	20	20	20	
Available Energy (GWh)	2030				20	20	20	20
Generation (GWh)	2025		3	5	7			
Generation (GWh)	2027		6	9	11	13	13	
Generation (GWh)	2030				18	17	15	15
Over-supply (%)	2025		5 %	7 %	11 %			
Over-supply (%)	2027		1 %	2 %	4 %	13 %	24 %	
Over-supply (%)	2030				2 %	10 %	19 %	22 %
Curtailment (%)	2025		1 %	2 %	2 %			
Curtailment (%)	2027		0 %	1 %	1 %	2 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025		5 %	7 %	8 %			
Constraint (%)	2027		4 %	3 %	4 %	2 %	1 %	
Constraint (%)	2030				2 %	1 %	1 %	1 %
Total Dispatch Down (%)	2025		10 %	16 %	21 %			
Total Dispatch Down (%)	2027		5 %	6 %	10 %	18 %	28 %	
Total Dispatch Down (%)	2030				6 %	13 %	23 %	25 %

Table C - 30 Results for Wind Not Priority

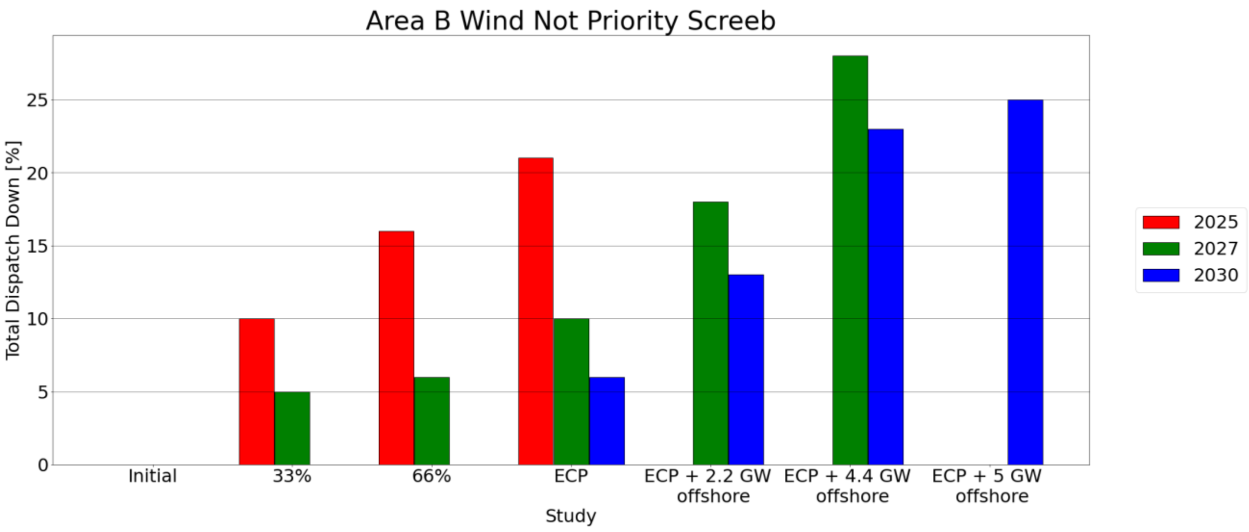

Figure C - 30 Total Dispatch Down for Wind Not Priority

C.13. Shantallow

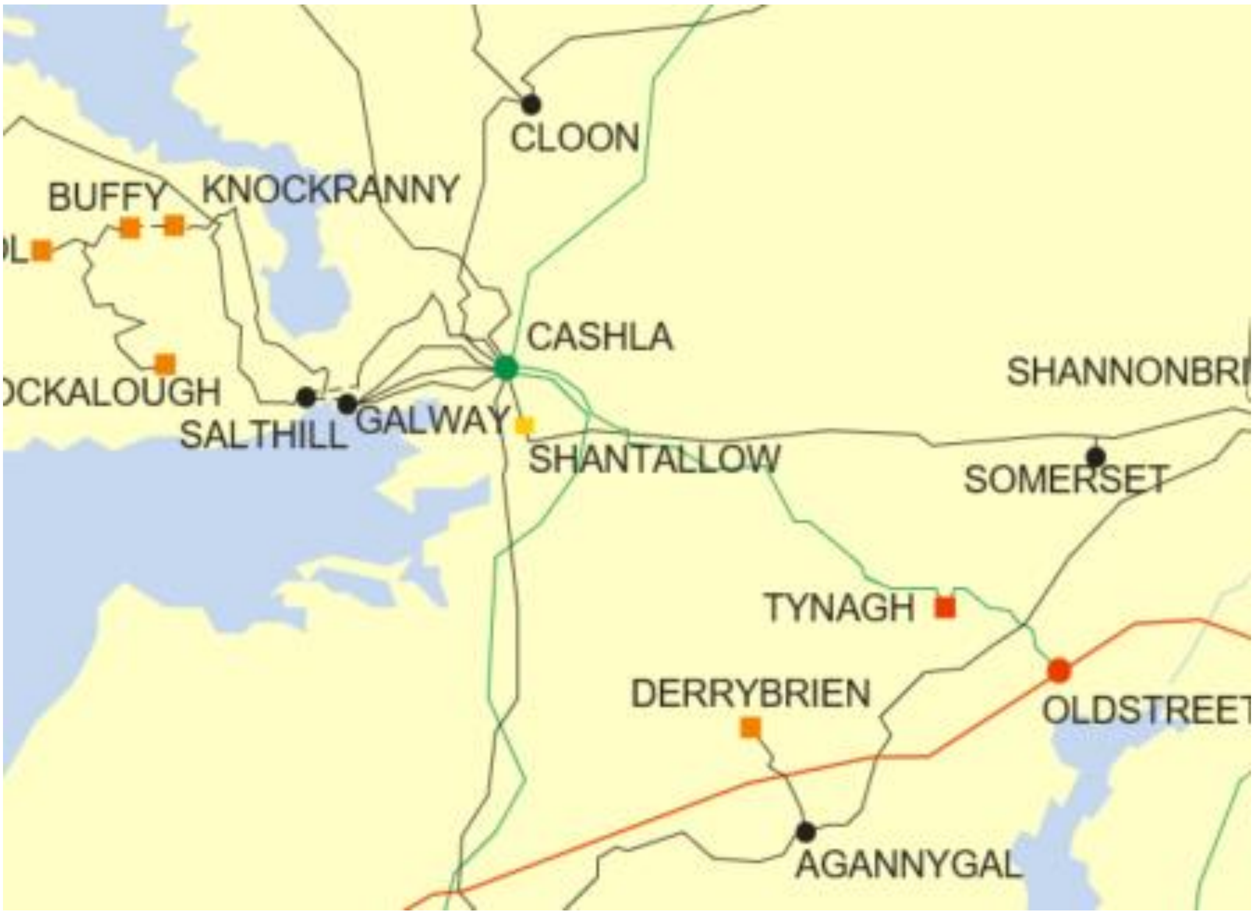

Figure C - 31 Location of node Shantallow

Generator	SO	Capacity	Type	Status
Shantallow Solar	TSO	35.0	solar not priority	due to connect

Table C - 31 Generation Included in Study for Node

The solar not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	35	35	35	35			
Installed Capacity (MW)	2027	35	35	35	35	35	35	
Installed Capacity (MW)	2030				35	35	35	35
Available Energy (GWh)	2025	37	37	37	37			
Available Energy (GWh)	2027	37	37	37	37	37	37	
Available Energy (GWh)	2030				37	37	37	37
Generation (GWh)	2025	37	36	35	34			
Generation (GWh)	2027	37	37	36	35	33	32	
Generation (GWh)	2030				35	34	32	32
Over-supply (%)	2025	1 %	2 %	4 %	7 %			
Over-supply (%)	2027	0 %	1 %	2 %	4 %	8 %	13 %	
Over-supply (%)	2030				3 %	7 %	11 %	12 %
Curtailment (%)	2025	0 %	1 %	1 %	2 %			
Curtailment (%)	2027	0 %	0 %	1 %	1 %	2 %	2 %	
Curtailment (%)	2030				1 %	2 %	2 %	2 %
Constraint (%)	2025	4 %	2 %	1 %	2 %			
Constraint (%)	2027	5 %	4 %	2 %	1 %	1 %	0 %	
Constraint (%)	2030				1 %	0 %	0 %	0 %
Total Dispatch Down (%)	2025	5 %	5 %	7 %	10 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	10 %	15 %	
Total Dispatch Down (%)	2030				5 %	8 %	13 %	14 %

Table C - 32 Results for Solar Not Priority

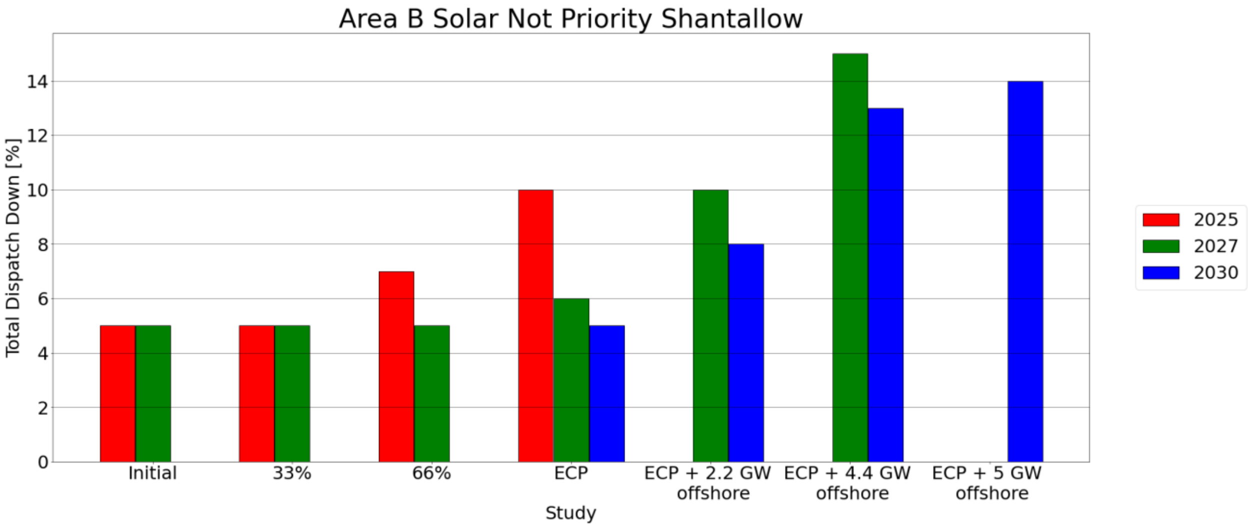

Figure C - 32 Total Dispatch Down for Solar Not Priority

C.14. Sligo

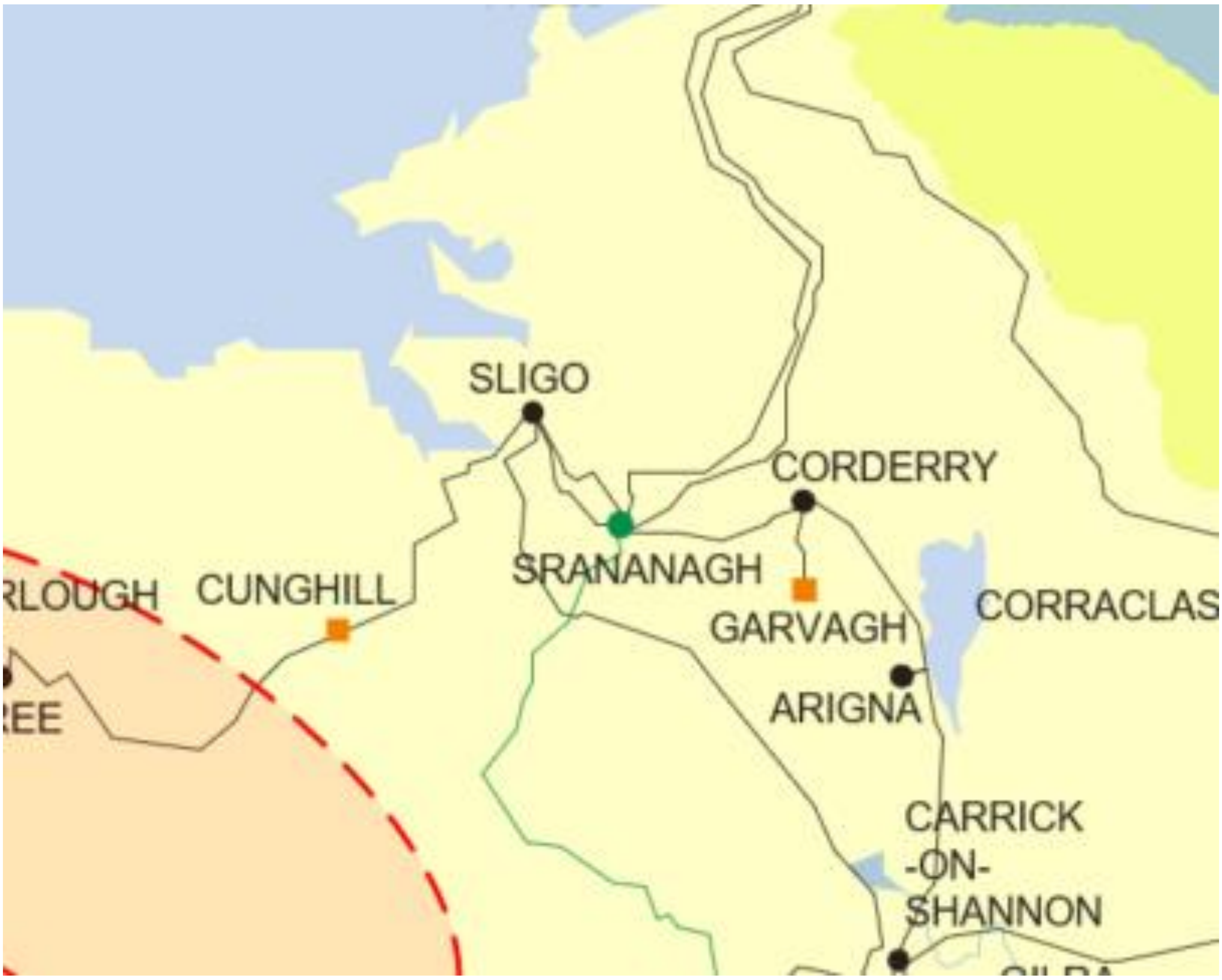

Figure C - 33 Location of node Sligo

Generator	SO	Capacity	Type	Status
Carrickeeney (1)	DSO	8.0	wind priority	connected
Faughary (1)	DSO	6.0	wind priority	connected
Riverstown Wind Farm	DSO	4.99	wind not priority	due to connect
Templehouse Community Wind Turbine	DSO	4.0	wind not priority	due to connect

Table C - 33 Generation Included in Study for Node

The wind not priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025		3	6	9			
Installed Capacity (MW)	2027		3	6	9	9	9	
Installed Capacity (MW)	2030				9	9	9	9
Available Energy (GWh)	2025		9	18	27			
Available Energy (GWh)	2027		9	18	27	27	27	
Available Energy (GWh)	2030				27	27	27	27
Generation (GWh)	2025		5	8	12			
Generation (GWh)	2027		4	8	12	11	11	
Generation (GWh)	2030				22	21	20	19
Over-supply (%)	2025		6 %	10 %	15 %			
Over-supply (%)	2027		1 %	3 %	6 %	17 %	28 %	
Over-supply (%)	2030				3 %	13 %	23 %	26 %
Curtailment (%)	2025		1 %	2 %	2 %			
Curtailment (%)	2027		1 %	1 %	2 %	3 %	3 %	
Curtailment (%)	2030				1 %	2 %	3 %	3 %
Constraint (%)	2025		17 %	18 %	19 %			
Constraint (%)	2027		16 %	19 %	21 %	12 %	7 %	
Constraint (%)	2030				8 %	3 %	1 %	0 %
Total Dispatch Down (%)	2025		24 %	30 %	36 %			
Total Dispatch Down (%)	2027		17 %	22 %	28 %	32 %	39 %	
Total Dispatch Down (%)	2030				13 %	18 %	27 %	29 %

Table C - 34 Results for Wind Not Priority

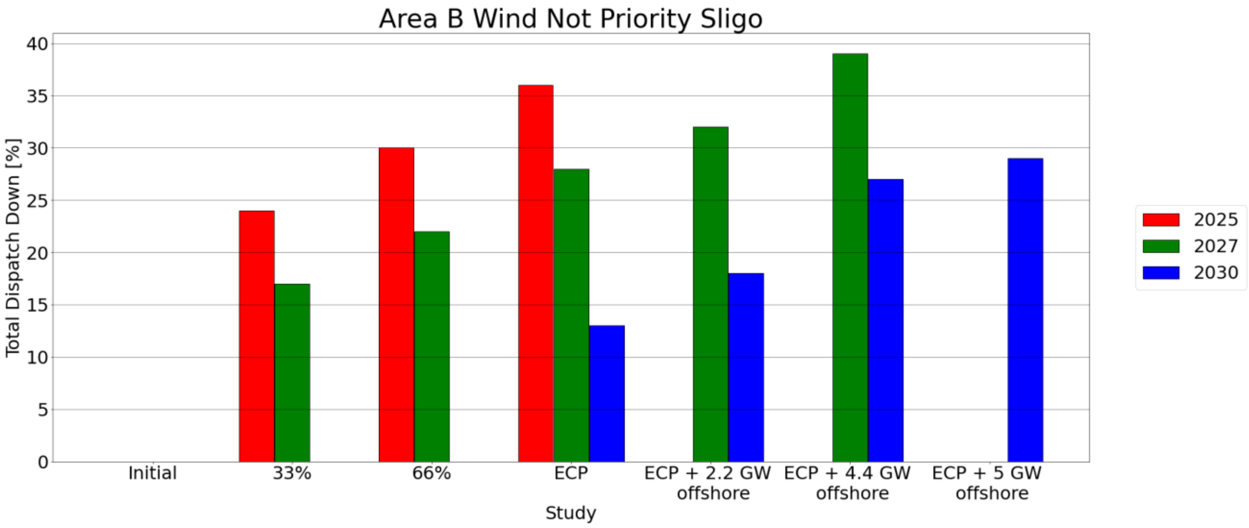

Figure C - 34 Total Dispatch Down for Wind Not Priority

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	14	14	14	14			
Installed Capacity (MW)	2027	14	14	14	14	14	14	
Installed Capacity (MW)	2030				14	14	14	14
Available Energy (GWh)	2025	43	43	43	43			
Available Energy (GWh)	2027	43	43	43	43	43	43	
Available Energy (GWh)	2030				43	43	43	43
Generation (GWh)	2025	24	22	21	20			
Generation (GWh)	2027	24	21	20	18	19	22	
Generation (GWh)	2030				35	38	39	40
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 35 Results for Wind Priority

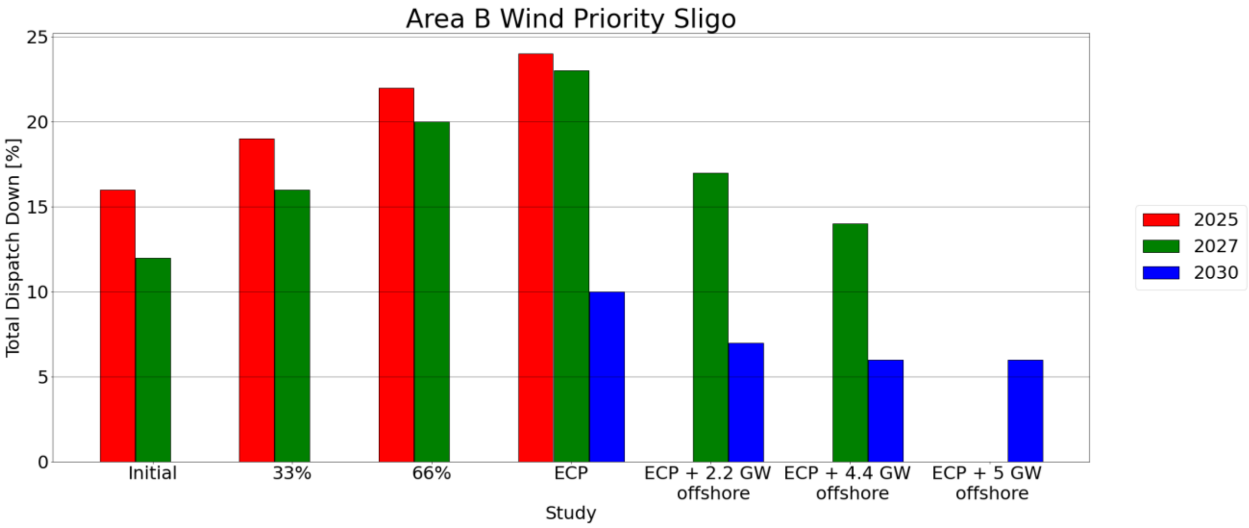

Figure C - 35 Total Dispatch Down for Wind Priority

C.15. Tawnaghmore

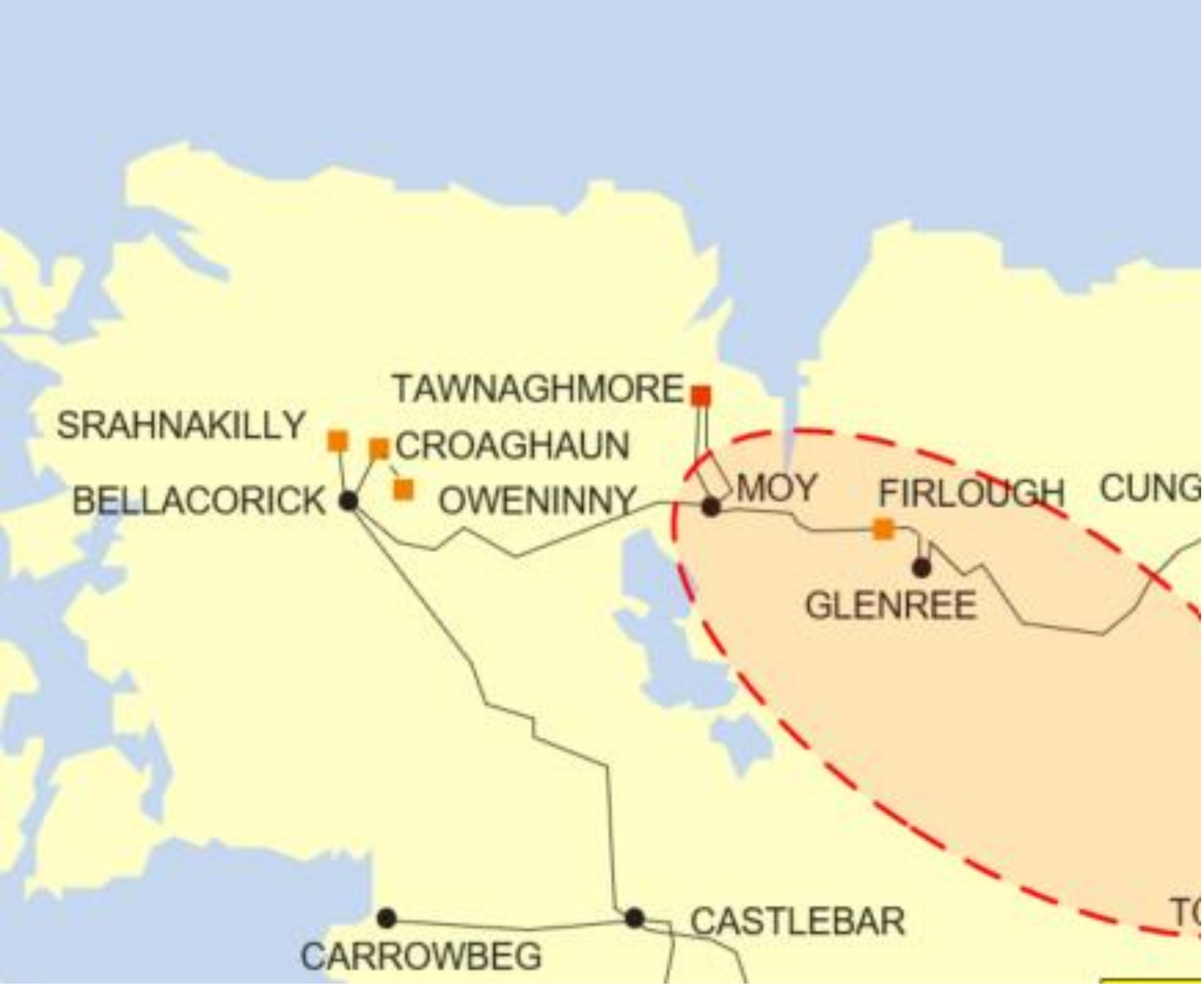

Figure C - 36 Location of node Tawnaghmore

Generator	SO	Capacity	Type	Status
Killala Wind Farm (Phase 1)	DSO	19.0	wind priority	connected

Table C - 36 Generation Included in Study for Node

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	19	19	19	19			
Installed Capacity (MW)	2027	19	19	19	19	19	19	
Installed Capacity (MW)	2030				19	19	19	19
Available Energy (GWh)	2025	58	58	58	58			
Available Energy (GWh)	2027	58	58	58	58	58	58	
Available Energy (GWh)	2030				58	58	58	58
Generation (GWh)	2025	49	47	45	43			
Generation (GWh)	2027	57	57	56	56	55	54	
Generation (GWh)	2030				55	54	54	55
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	3 %	4 %			
Curtailment (%)	2027	0 %	1 %	1 %	2 %	4 %	5 %	
Curtailment (%)	2030				2 %	3 %	5 %	5 %
Constraint (%)	2025	15 %	17 %	19 %	20 %			
Constraint (%)	2027	12 %	16 %	19 %	21 %	13 %	9 %	
Constraint (%)	2030				9 %	4 %	2 %	2 %
Total Dispatch Down (%)	2025	16 %	19 %	22 %	24 %			
Total Dispatch Down (%)	2027	12 %	16 %	20 %	23 %	17 %	14 %	
Total Dispatch Down (%)	2030				10 %	7 %	6 %	6 %

Table C - 37 Results for Wind Priority

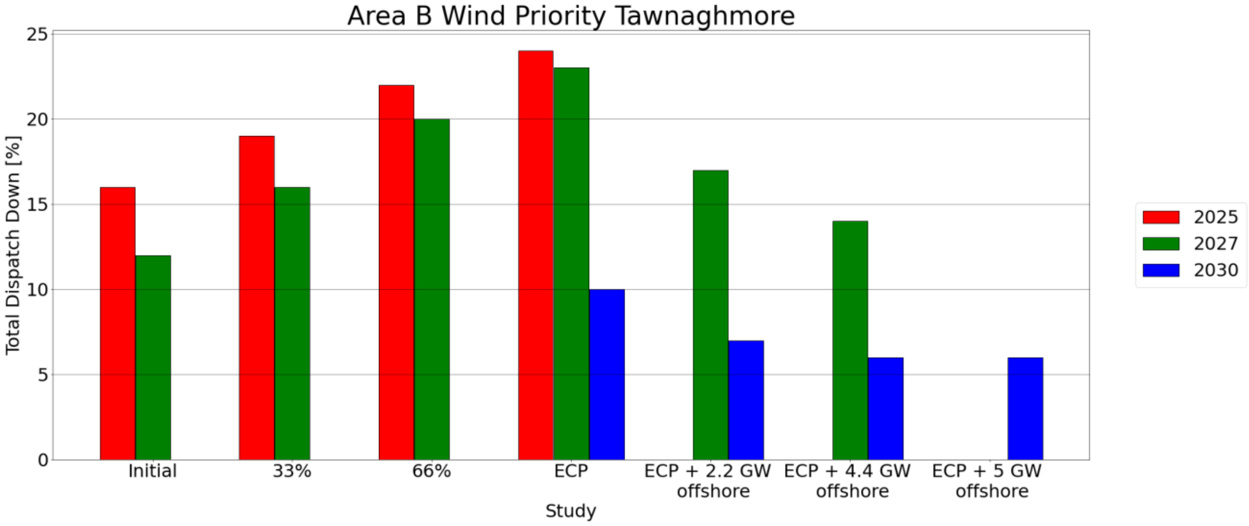

Figure C - 37 Total Dispatch Down for Wind Priority

C.16. Uggool

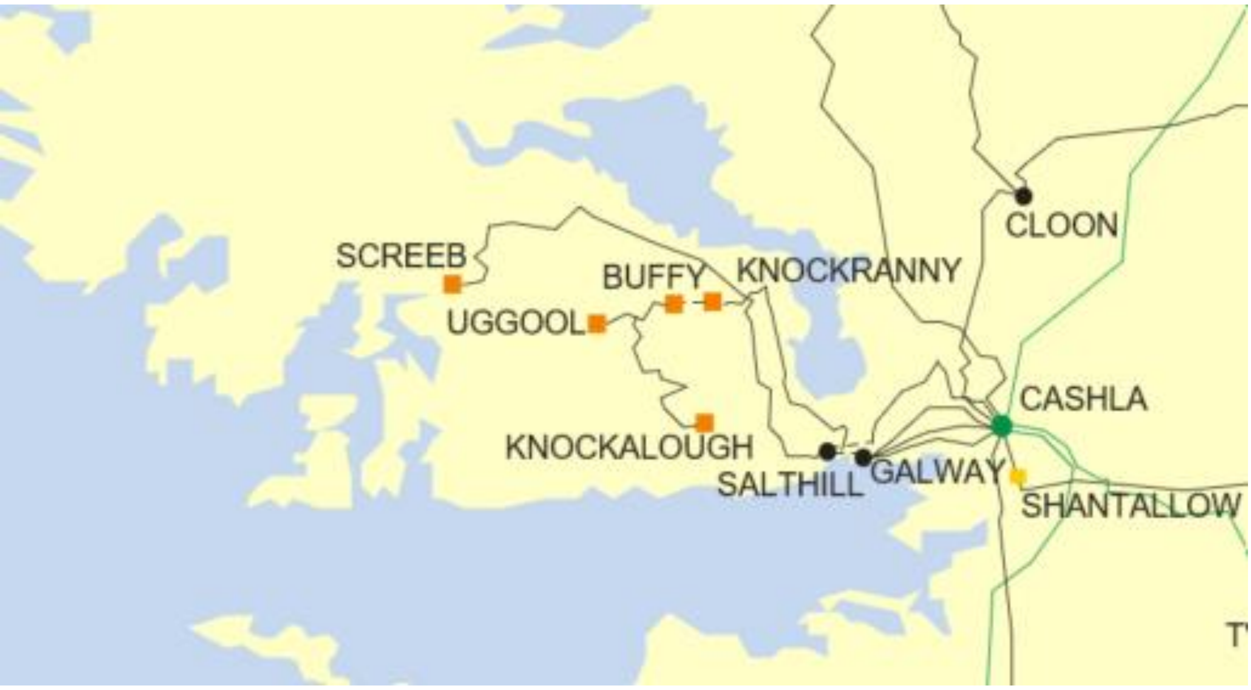

Figure C - 38 Location of node Uggool

Generator	SO	Capacity	Type	Status
Seecon (1)	TSO	105.0	wind priority	connected
Uggool (1)	TSO	64.0	wind priority	connected

Table C - 38 Generation Included in Study for Node

The wind priority data is given in the following table.

Area B	Year	Initial	33%	66%	ECP	ECP + 2.2 GW offshore	ECP + 4.4 GW offshore	ECP + 5 GW offshore
Installed Capacity (MW)	2025	169	169	169	169			
Installed Capacity (MW)	2027	169	169	169	169	169	169	
Installed Capacity (MW)	2030				169	169	169	169
Available Energy (GWh)	2025	673	673	673	673			
Available Energy (GWh)	2027	673	673	673	673	673	673	
Available Energy (GWh)	2030				673	673	673	673
Generation (GWh)	2025	656	653	648	644			
Generation (GWh)	2027	656	650	645	642	637	633	
Generation (GWh)	2030				633	637	636	637
Over-supply (%)	2025	0 %	0 %	0 %	0 %			
Over-supply (%)	2027	0 %	0 %	0 %	0 %	0 %	0 %	
Over-supply (%)	2030				0 %	0 %	0 %	0 %
Curtailment (%)	2025	1 %	2 %	2 %	3 %			
Curtailment (%)	2027	0 %	0 %	1 %	2 %	3 %	5 %	
Curtailment (%)	2030				1 %	3 %	4 %	4 %
Constraint (%)	2025	4 %	5 %	7 %	8 %			
Constraint (%)	2027	5 %	5 %	4 %	5 %	2 %	1 %	
Constraint (%)	2030				4 %	2 %	1 %	1 %
Total Dispatch Down (%)	2025	5 %	6 %	9 %	11 %			
Total Dispatch Down (%)	2027	5 %	5 %	5 %	6 %	6 %	6 %	
Total Dispatch Down (%)	2030				5 %	5 %	5 %	5 %

Table C - 39 Results for Wind Priority

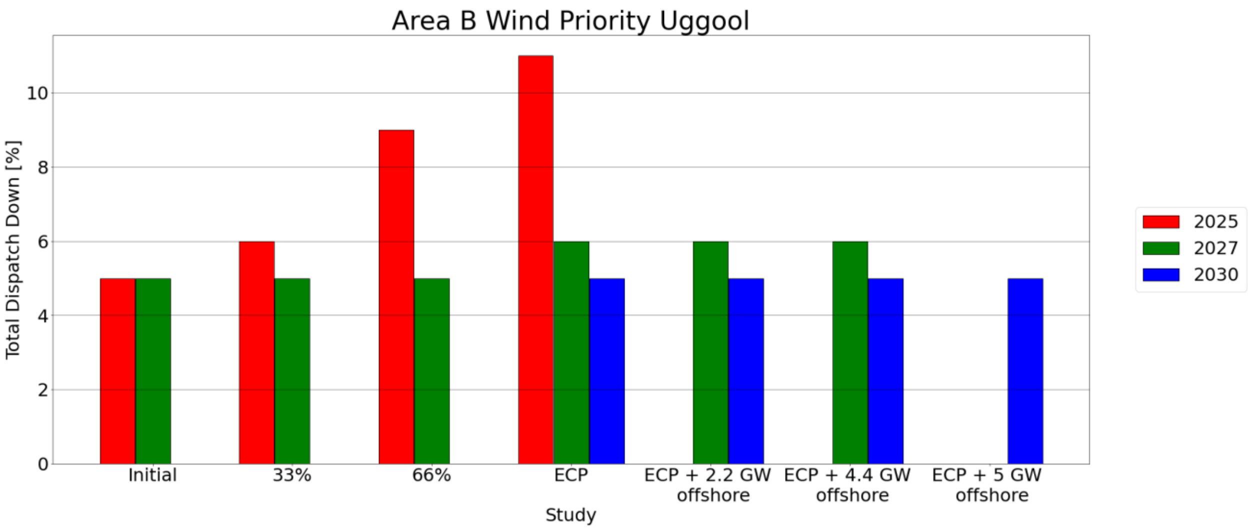

Figure C - 39 Total Dispatch Down for Wind Priority

Appendix D Contingencies and Lines Overloading

For different study scenarios, there were several transmissions boundaries that limit the power flow. Some of the main overload and contingency pairs binding for more than 150 hours for the two study years (2025 ECP (All) and 2027 (All)) can be seen below.

Year 2025

Line Name	Contingency Name	Hours Range
Line (Cushaling - Newbridge_110_1)	Loss of Mount Lucas - Thornsberry 110 1	3000-3250
Line (Cashla - Salthill_110_1)	Loss of Galway Salthill 110 1	2500-3000
Line (Moneypoint T4202)	Loss of Moneypoint 380-220 1	2000-2250
Line (Kilnap - Knockraha_110_1)	Loss of Clashavoon Knockraha 220	1750-2000
Line (Cushaling - Newbridge_110_1)	Loss of Philipstown - Portlaoise 110 1	1250-1500
Line (Maynooth - Timahoe North_110_1)	Loss of Kinnegad Harristown or Mulgeeth to Dunfi T	1000-1250
Line (Flagford - Sligo_110_1)	Loss of Flagford-Srananagh 220 circuit 1	1000-1250
Line (Coolnabacky - Portlaoise_110_1 - new)	Loss of Dunstown-Kellis 220	1000-1250
Line (Maynooth - Rinawade_110_1)	Loss of Maynooth - Timahoe North 110 1	1000-1250
Line (Sligo - Srananagh_110_2)	Loss of Flagford-Srananagh 220 circuit 1	1000-1250
Line (Bandon - Dunmanway_110_1)	Loss of Clashavoon Knockraha 220	1000-1250
Line (Great Island - Kellis_220_1)	Loss of Arklow Carrickmines 220 1	1000-1250
Line (Flagford - Sligo_110_1)	Loss of Srananagh 220-110 2	1000-1250
Line (Cahir - Doon_110_1)	Loss of Cullenagh-Knockraha 220	750-1000
Line (Sligo - Srananagh_110_2)	Loss of Srananagh 220-110 2	750-1000
Line (Castlebar - Cloon_110_1)	Loss of Cunghill Sligo 110 1	750-1000
Line (Great Island T2102)	Loss of Cullenagh-Great Island 220	750-1000
Line (Maynooth - Shannonbridge_220_1)	Loss of Oldstreet Woodland 380	750-1000
Line (Finglas - Mooretown_220_1)	Loss of Corduff Mooretown 220 1	750-1000
Line (Kellis - Kilkenny_110_1)	Loss of Coolnabacky Portlaoise 110 1	750-1000
Line (Coolnabacky - Portlaoise_110_1 - new)	Loss of Great Island - Kellis 220	750-1000
Line (Castlebar - Cloon_110_1)	Loss of Bellacorick-Moy 110 1	500-750
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Waterford 110 1	500-750
Line (Arklow T2101)	Loss of Arklow 220-110 2	500-750
Line (Lisheen - Thurles_110_1)	Base	500-750
Line (Maynooth - Timahoe North_110_1)	Loss of Cushaling Newbridge 110 1	500-750
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Great Island 220	500-750
Line (Oldstreet - Tynagh_220_1)	Loss of Cashla-Tynagh 220	500-750
Line (Arklow T2101)	Loss of Arklow Lodgewood 220	500-750
Line (Flagford - Sligo_110_1)	Loss of Carrick on Shannon - Arigna T 110 1	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Corduff Blundelstown 110 1	250-500
Line (Arklow T2101)	Loss of Lodgewood 220-110 1	250-500
Line (Coolnabacky - Portlaoise_110_1 - new)	Loss of Kellis Kilkenny 110 1	250-500
Line (Cashla - Dalton_110_1)	Loss of Cunghill Sligo 110 1	250-500
Line (Blundelstown_Mullingar_110_1 -)	Loss of Clonfad- Kinnegad 110 1	250-500
Line (Great Island T2102)	Loss of Great Island 220-110 1	250-500
Line (Crane - Wexford_110_1)	loss of Great Island - Rosspile 110 1	250-500

Line (Maynooth - Blake-T_110_1)	Loss of Oldstreet Woodland 380	250-500
Line (Galway - Knockranny A1_110_1)	Base	250-500
Line (Crane - Wexford_110_1)	Loss of Great Island - Lodgewood 220	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Maynooth - Timahoe North 110 1	250-500
Line (Lisdrum - Lislea 110 1)	Loss of Louth - Ratrussan 110 1	250-500
Line (Kilnap - Knockraha_110_1)	Loss of Killonan Knockraha 220	250-500
Line (Drybridge - Louth_110_1)	Loss of Oriel Woodland 220	250-500
Line (Corduff - Macetown_110_1)	Loss of Drybridge Gastkinstown 110 1	250-500
Line (Coolnabacky - Portlaoise_110_1 - new)	Loss of Arklow Carrickmines 220 1	250-500
Line (Shannonbridge - Timoney_110_1)	Loss of Cahir - Kill Hill 110 1	250-500
Line (Cushaling - Newbridge_110_1)	Loss of Maynooth - Timahoe North 110 1	250-500
Line (Maynooth - Shannonbridge_220_1)	Loss of dunstown moneypoint 380	250-500
Line (Castlebar - Cloon_110_1)	Loss of Cashla Dalton 110 1	250-500
Line (Baroda - Monread_110_1)	Loss of Mount Lucas - Thornsberry 110 1	250-500
Line (Cahir - Kill Hill_110_1)	Loss of Shannonbridge - Timoney 110 1	250-500
Line (Carrickmines - Poolbeg_220_1)	Loss of Oldstreet Woodland 380	250-500
Line (Drybridge - Louth_110_1)	Loss of Gorman Louth 220	250-500
Line (Drybridge - Louth_110_1)	Loss of Louth-Oriel (Woodland) 220	250-500
Line (Cathaleens Fall - Srananagh_110_2)	Loss of Cathaleens Fall - Corraclassy 110 1	250-500
Line (Corduff - Macetown_110_1)	Loss of Oriel Woodland 220	<250
Line (Corduff - Macetown_110_1)	Loss of Louth-Oriel (Woodland) 220	<250
Line (Derryiron - Kinnegad_110_1)	Loss of Maynooth - Timahoe North 110 1	<250
Line (Great Island T2102)	Loss of Great Island - Lodgewood 220	<250
Line (Corduff - Macetown_110_1)	Loss of Maynooth - Timahoe North 110 1	<250
Line (Cashla - Dalton_110_1)	Loss of Bellacorick-Moy 110 1	<250
Line (Coolnabacky - Portlaoise_110_1 - new)	Loss of Cullenagh-Knockraha 220	<250
Line (Sligo - Srananagh_110_2)	Loss of Carrick on Shannon - Arigna T 110 1	<250
Line (Moneypoint T4201)	Base	<250
Line (Carlow - Kellis_110_2)	Loss of Dunstown-Kellis 220	<250
Line (Cushaling - Newbridge_110_1)	Loss of Newbridge Treascon 110 1	<250
Line (Maynooth - Rinawade_110_1)	Loss of Corduff Blundelstown 110 1	<250
Line (Baltrasna - Corduff_110_1)	Loss of Drybridge Gastkinstown 110 1	<250
Line (Maynooth - Timahoe North_110_1)	Loss of Rinawade Dunfirth T 110 1	<250
Line (Crane - Wexford_110_1)	Loss of Arklow Carrickmines 220 1	<250
Line (Corduff - Macetown_110_1)	Loss of Corduff-Ryebrook 110 1	<250
Line (Cushaling - Newbridge_110_1)	Loss of Bracklone or Treascon to Newbridge	<250
Line (Dunstown T4202)	Loss of Oldstreet Woodland 380	<250
Line (Bellacorick coupler a to b_110_1 - new)	Loss of Cunghill Sligo 110 1	<250
Line (Cathaleens Fall - Srananagh_110_2)	Loss of Cathleens Fall -Srananagh 110 1	<250
Line (Clashavoon - Macroom_110_2)	Loss of Clashavoon Knockraha 220	<250
Line (Great Island - Kellis_220_1)	Loss of Great Island - Lodgewood 220	<250
Line (Lisdrum - Louth_110_1)	Loss of Louth - Ratrussan 110 1	<250
Line (Rinawade - Dunfirth-T_110_1)	Loss of Oldstreet Woodland 380	<250

Table D - 1 Binding contingency and overloading lines in 2025 ECP (All) study

Year 2027

Line Name	Contingency Name	Hours Range
Line (Cushaling - Newbridge_110_1)	Loss of Mount Lucas - Thornsberry 110 1	2500-3000
Line (Kilnap - Knockraha_110_1)	Loss of Clashavoon Knockraha 220	2500-3000
Line (Ballyragget - Kilkenny_110_1 - new)	Loss of Kellis Kilkenny 110 1	2000-2250
Line (Galway - Salthill_110_1)	Base	1750-2000
Line (Bellacorick - Moy_110_1)	Loss of Bellacorick-Castlebar 110 1	1250-1500
Line (Maynooth - Timahoe North_110_1)	Loss of Harristown - Dunfirth 110 1	1250-1500
Line (Flagford - Sligo_110_1)	Loss of Flagford-Srananagh 220 circuit 1	1000-1250
Line (Drybridge - Louth_110_1)	Loss of Turleenan Woodland 380	1000-1250
Line (Maynooth - Rinawade_110_1)	Loss of Maynooth - Timahoe North 110 1	1000-1250
Line (Flagford - Sligo_110_1)	Loss of Srananagh 220-110 2	1000-1250
Line (Cushaling - Newbridge_110_1)	Loss of Philipstown - Portlaoise 110 1	750-1000
Line (Great Island T2102)	Loss of Cullenagh-Great Island 220	750-1000
Line (Knockraha - Barrymore-T_110_1)	Loss of Killonan Knockraha 220	750-1000
Line (Arklow T2101)	Loss of Arklow 220-110 2	750-1000
Line (Great Island - Kellis_220_1)	Loss of Arklow Carrickmines 220 1	500-750
Line (Drybridge - Louth_110_1)	Loss of Gorman Louth 220	500-750
Line (Finglas - Mooretown_220_1)	Loss of Corduff Mooretown 220 1	500-750
Line (Maynooth - Timahoe North_110_1)	Loss of Cushaling Newbridge 110 1	500-750
Line (Blundelstown_Mullingar_110_1 -)	Loss of Clonfad - Kinnegad 110 1	500-750
Line (Clonee - Woodland_220_1)	Loss of Corduff Woodland 220 1	500-750
Line (Lisheen - Thurles_110_1)	Base	500-750
Line (Corduff - Macetown_110_1)	Loss of Gorman (or Woodland) to Maynooth 220	500-750
Line (Arklow T2101)	Loss of Lodgewood 220-110 1	500-750
Line (Knockraha - Barrymore-T_110_1)	Loss of Cahir-Doon 110 1	500-750
Line (Cashla - Dalton_110_1)	Loss of Castlebar Cloon 110	500-750
Line (Cahir - Kill Hill_110_1)	Loss of Shannonbridge - Timoney 110 1	250-500
Line (Shannonbridge - Timoney_110_1)	Loss of Cahir - Kill Hill 110 1	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Corduff Blundelstown 110 1	250-500
Line (Maynooth - Shannonbridge_220_1)	Loss of Oldstreet Woodland 380	250-500
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Great Island 220	250-500
Line (Oldstreet - Tynagh_220_1)	Loss of Cashla-Tynagh 220	250-500
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Waterford 110 1	250-500
Line (Maynooth - Blake-T_110_1)	Loss of Oldstreet Woodland 380	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Maynooth - Timahoe North 110 1	250-500
Line (Galway - Knockranny A1_110_1)	Base	250-500
Line (Kilnap - Knockraha_110_1)	Loss of Killonan Knockraha 220	250-500
Line (Arklow T2101)	Loss of Arklow Lodgewood 220	250-500
Line (Cahir - Doon_110_1)	Loss of Cullenagh-Knockraha 220	250-500
Line (Great Island T2102)	Loss of Great Island 220-110 1	250-500
Line (Cushaling - Newbridge_110_1)	Loss of Maynooth - Timahoe North 110 1	250-500
Line (Cashla - Dalton_110_1)	Loss of Bellacorick-Moy	250-500
Line (Great Island T2102)	Loss of Cullenagh 220-110 1	250-500
Line (Athlone - Lanesboro_110_1)	Loss of Lanesboro - Shanonagh 110 1	250-500
Line (Louth - Meath Hill_110_1)	Loss of Gorman Louth 220	250-500
Line (Maynooth - Timahoe North_110_1)	Loss of Derryiron Kinnegad 110 1	250-500
Line (Carrickmines - Poolbeg_220_1)	Loss of Oldstreet Woodland 380	250-500

Line (Kellis - Kilkenny_110_1)	Loss of coolnabacky dunstown 380	250-500
Line (Moneypoint T4202)	Loss of kilpaddoge moneypoint 3 - 380 or 220	250-500
Line (Carlow - Kellis_110_2)	Loss of Dunstown-Kellis 220	250-500
Line (Cunghill - Sligo_110_1)	Loss of Bellacorick-Castlebar 110 1	250-500
Line (Kellis - Kilkenny_110_1)	Loss of Dunstown-Kellis 220	250-500
Line (Cathaleens Fall - Srananagh_110_1)	Loss of Cathleens Fall - Srananagh 110 2	250-500
Line (Corduff - Macetown_110_1)	Loss of Drybridge Gastkinstown 110 1	250-500
Line (Dunstown T4202)	Loss of Oldstreet Woodland 380	250-500
Line (Great Island T2102)	Loss of Great Island - Lodgewood 220	250-500
Line (Cahir - Barrymore-T_110_1)	Loss of Cahir-Doon 110 1	250-500
Line (Maynooth - Shannonbridge_220_1)	Loss of Coolnabacky Moneypoint 380	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Blundelstown Mullingar 110 1	250-500
Line (Flagford - Sligo_110_1)	Loss of Carrick on Shannon - Arigna T 110 1	250-500
Line (Drybridge - Louth_110_1)	Loss of Arva Navan 110 1	250-500
Line (Ballynahulla - Glenlara_wind_110_1)	Base	250-500
Line (Maynooth - Timahoe North_110_1)	Loss of Rinawade - Dunfirth T 110 1	<250
Line (Lisdrum - Lislea 110 1)	Loss of Louth - Ratrussan 110 1	<250
Line (Cashla - Galway_110_3)	Loss of cashla - galway 110 2	<250
Line (Cashla - Galway_110_2)	Loss of cashla - galway 110 3	<250
Line (Cushaling - Newbridge_110_1)	Loss of Bracklone - Newbridge 110 1	<250
Line (Cauteen - Killonan_110_1)	Loss of Cauteen Tipperary 110 1	<250
Line (Cahir - Kill Hill_110_1)	Loss of Thurles - Ikerrin-T 110 1	<250
Line (Thurles - Ikerrin-T_110_1)	Loss of Cahir - Kill Hill 110 1	<250
Line (Lisdrum - Louth_110_1)	Loss of Louth - Ratrussan 110 1	<250
Line (Cushaling - Newbridge_110_1)	Loss of Newbridge Treascon 110 1	<250
Line (Cathaleens Fall - Srananagh_110_2)	Loss of Cathleens Fall - Srananagh 110 1	<250
Line (Maynooth - Blake-T_110_1)	Loss of Castlebagot Maynooth 220 1	<250
Line (Maynooth - Rinawade_110_1)	Loss of Corduff Blundelstown 110 1	<250
Line (Great Island - Rosspile_110_1)	Loss of Arklow Carrickmines 220 1	<250
Line (Baroda - Monread_110_1)	Loss of Mount Lucas - Thornsberry 110 1	<250
Line (Corduff - Macetown_110_1)	Loss of Corduff-Ryebrook 110 1	<250
Line (Inchicore - Irishtown_220_1)	Loss of Kellystown - Woodland 220	<250
Line (Corduff - Macetown_110_1)	Loss of Castlebagot Maynooth 220 1	<250
Line (Cahir - Kill Hill_110_1)	Loss of Timoney - Ikerrin T 110 1	<250
Line (Timoney - Ikerrin-T_110_1)	Loss of Cahir - Kill Hill 110 1	<250
Line (Clashavoon - Macroom_110_2)	Loss of Clashavoon Knockraha 220	<250
Line (Kellis - Kilkenny_110_1)	Loss of Arklow Carrickmines 220 1	<250
Line (Knockraha - Barrymore-T_110_1)	Loss of Ballydine - Mothel 110 1	<250
Line (Knockraha - Barrymore-T_110_1)	Loss of Ballynahulla Knockanure 220	<250
Line (Irishtown - Shellybanks_220_1)	Loss of Kellystown - Woodland 220	<250
Line (Dunstown T4201)	Loss of Oldstreet Woodland 380	<250
Line (Great Island - Kellis_220_1)	Loss of Great Island - Lodgewood 220	<250
Line (Great Island - Rosspile_110_1)	Loss of Great Island - Lodgewood 220	<250
Line (Athy - Carlow_110_1)	Loss of coolnabacky dunstown 380	<250
Line (Drybridge - Louth_110_1)	Loss of Garballagh Platin 110 1	<250
Line (Kilteel - Maynooth_110_1)	Loss of Baroda Newbridge 110 1	<250
Line (Knockraha - Barrymore-T_110_1)	Loss of Cullenagh-Knockraha 220	<250

Table D - 2 Binding contingency and overloading lines in 2027 ECP (All) study

Abbreviation and Terms

Active Power

The product of voltage and the in-phase component of alternating current measured in Megawatts (MW). When compounded with the flow of 'reactive power', measured in Megavolt-Amperes Reactive (Mvar), the resultant is measured in Megavolt-Amperes (MVA).

Busbar

The common connection point of two or more circuits.

Capacity Factor

The capacity factor of a generator is the ratio of the actual electrical energy output over a given period of time to the maximum possible electrical energy output over that period.

$$Capacity\ Factor = \frac{Energy\ Output}{Hours\ per\ year * Installed\ Capacity}$$

Combined Cycle Gas Turbine (CCGT)
This is a type of thermal generator that typically uses natural gas as a fuel source. It is a collection of gas turbines and steam units; where waste heat from the gas turbines(s) is passed through a heat recovery boiler to generate steam for the steam turbines.

Commission for Regulation of Utilities (CRU)

The CRU is the regulator for the electricity, natural gas and public water sectors in Ireland.

Constraint
The reduction in output of a generator due to network limits. Usually, constraints are local to a transmission bottleneck.

Contingency
The unexpected failure or outage of a system component, such as a generation unit, transmission line, transformer or other electrical element. The transmission network is operated safe against the possible failure or outage of any system component. Hence, contingency usually refers to the possible loss of any system component. A contingency may also include multiple components, when these are subject to common cause outages.

Curtailment
Curtailment is when the transmission system operators EirGrid and SONI ask generation to reduce their output to ensure system security is maintained. Usually, curtailment is shared across the whole system.

Demand
The amount of electrical power that customers consume and which is measured in Megawatts (MW). In a general sense, the amount of power that must be transported from transmission network connected generation stations to meet all customers' electricity requirements.

Dispatch Balancing Costs (DBC)
Dispatch Balancing Costs refers to a number of payments related to the differences between generators' market position and their actual output. They include Constraint Payments, Uninstructed Imbalance Payments and Generator Testing Charges. The Transmission System Operators (TSOs) are responsible for forecasting and managing Dispatch Balancing Costs.

Enduring Connection Policy (ECP)
The Commission for Regulation of Utilities (CRU) has put in place a revised approach to issuing connection offers to generators. This approach is called the Enduring Connection Policy (ECP). With ECP, it is envisaged that batches of generator connection offers will issue on a periodic basis.

Enduring Connection Policy - 2 (ECP-2)
ECP-2 is the second stage of the CRU's development of enduring connection policy in Ireland. In June 2020 the CRU published their decision on ECP-2, this decision set policy for at least three batches of connection offers (ECP-2.1, ECP-2.2 and ECP-2.3).

Forced Outage Probability (FOP)
This is the statistical probability that a generation unit will be unable to produce electricity for non-scheduled reasons due to the failure of either the generation plant or supporting systems. Periods, when the unit is on scheduled outage, are not included in the determination of forced outage probability.

Generation Dispatch
This is the configuration of outputs from the connected generation units.

Interconnector
The electrical link, facilities and equipment that connect the transmission network of one power market to another.

Loadflow
Study carried out to simulate the flow of power on the transmission system given a generation dispatch and system load.

A DC loadflow is a study, which uses simplifying assumptions in relation to voltage and reactive power. DC loadflow studies are used as part of an overarching study. For example, Plexos uses DC loadflow because it is performing studies for every hour of every study year and is performing a large optimisation calculation for each of these.

Maximum Export Capacity (MEC)
The maximum export value (MW) provided in accordance with a generator's connection agreement. The MEC is a contract value that the generator chooses as its maximum output.

Megawatt (MW) and Gigawatt (GW)
Unit of power: 1 megawatt = 1,000 kilowatts = 106 joules / second
1 gigawatt = 1,000 megawatts

Megawatt Hour (MWh), Gigawatt Hour (GWh) and Terawatt Hour (TWh)
Unit of energy: 1 megawatt hour = 1,000 kilowatt hours = 3.6 x 10^9 joules
1 gigawatt hour = 1,000 megawatt hours
1 terawatt hour = 1,000 gigawatt hours

Operational Constraints/Limits
In order to operate a safe, secure and stable electricity system, the TSO must operate the system within certain operational constraints/limits which include; maximum SNSP, maximum RoCoF, minimum level of system inertia, minimum number of conventional units, minimum levels of reserve.

Conventional generator "must run" rules to ensure adequate system voltage and power flow control

Over-supply
Reduction of renewable generation to a level below its availability for over-supply reasons is necessary when the total available generation exceeds system demand plus interconnector export flows. Over-supply is applied through market processes prior to dispatch or balancing actions taken by the transmission system operator such as curtailment and constraint.

Plexos
Plexos is a commercially available power system simulation tool used in this study to evaluate over supply, curtailment and constraint. Plexos is a detailed generation and transmission analysis program that has been widely used in the electricity industry for many years.

Rate of Change of Frequency (RoCoF)
As low inertia non-synchronous generators displace high inertia synchronous generators in system dispatch, then the system gets lighter. Then, for the loss of a large infeed (e.g. trip of an interconnector or generator), the system frequency will change more quickly.

RoCoF is the agreed limit to which the system is agreed to be operated and which generators, demand and system protection schemes are expected to manage. In Ireland, the TSOs are proposing to increase the RoCoF value. This will allow more renewable generation and may require confirmation by participants that they can meet the proposed RoCoF.

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

System Non-Synchronous Penetration (SNSP)
The introduction of large quantities of non-synchronous generators such as solar and wind poses challenges to a synchronous power system. For Ireland, a system non-synchronous penetration (SNSP) ratio is defined to help identify the system operational limits. The present allowable ratio is 75% but future system services arrangements and proposed amendments to system operation are expected to allow SNSP to increase in future years.

Total Dispatch Down
For the purpose of this report Total Dispatch Down is equivalent to the sum of over-supply (generation self reduction due to market position), plus curtailment (re-dispatch due to system operational constraints), plus constraint (re-dispatch due to network limitations).

Total Electricity Requirement (TER)
TER is the total amount of electricity required by a country. It includes all electricity exported by generating units, as well as that consumed on-site by self-consuming electricity producers, e.g. CHP.

Transmission Peak
The peak demand that is transported on the transmission network. The transmission peak includes an estimate of transmission losses.

Transmission System
The transmission system is a meshed network of high-voltage lines and cables (400 kV, 275 kV, 220 kV and 110 kV) for the transmission of bulk electricity supply around Ireland and Northern Ireland.

Transmission System Operator (TSO)
In the electrical power business, a transmission system operator is the licensed entity that is responsible for transmitting electrical power from generation plants to regional or local electricity distribution operators and Large Energy Users connected at the transmission level.

Uprating
A network reinforcement solution whereby an existing circuit’s rating can be increased. This is achieved by increasing ground clearances and/or replacing conductor, together with any changes to terminal equipment, support structures and foundations.

Winter Peak
This is the maximum annual system demand. Historically this occurs in the winter period October to February, inclusive in Ireland and in the period November to February in Northern Ireland.

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