Benefits of Gas Storage at Islandmagee

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Islandmagee Gas Storage

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1. Introduction and Purpose

According to the latest SEAI figures available, natural gas supplied 29.4% of primary energy demand and supplied 40% of Ireland's electricity requirement in 2016 (Sustainable Energy Authority of Ireland, 2017). The natural gas supply to Ireland is via a single supply point at Moffat in Scotland and represents a significant security of supply risk. An ERSI study in 2010 estimated the total all island cost of a 1-day gas outage to be between €353m and €639m (2008 money) in 2020 (E. Leahy, 2012).

The Islandmagee Gas storage project aims to construct additional gas storage capacity in Northern Ireland with the aim of mitigating the severe risk to energy security on the island of Ireland resulting from a loss of supply at the single point of failure at Moffat. A proposal has been requested for a study which will estimate the potential benefits of such a project. These benefits are expected to be mainly in the form of increased security of supply as a result of additional gas storage capacity. This study has been carried out in accordance with the recommended methodology of the European Network of Transmission System Operators for Gas (ENTSOG).

1.1. About Energy Reform Ltd.

Energy Reform is a boutique engineering consultancy company operating in the international energy sector. Energy Reform has specialist expertise in advanced power system modelling and supports clients by applying this advanced capability to the challenges that arise during major reform and change in the energy sector. Energy reform is a recognized expert, particularly in system modelling that addresses the challenges associated with integrating new technologies into power systems, including increasing levels of variable renewable generation. Testament to this is the fact that Energy Reform represents Ireland on the International Energy Agency's Task 25 on the Design and Operation of Power Systems with Large Amounts of Wind Power. Energy Reform was established in Ireland in 2011 and the team has over 17 years' experience that spans across research and industry in the international energy sector.

2. Methodology and Assumptions

The ENTSOG methodology recommendations (ENTSOG, 2017) for calculating the benefits of natural gas infrastructure projects has been reviewed along with previous studies on the impact of natural gas shortages on the Island of Ireland (Devlin, 2016), (E. Leahy, 2012). The objective of the methodology is to estimate the high-level benefits of gas storage infrastructure on the island of Ireland. The following are the high-level features of the methodology that has been employed:

- The primary benefit is assumed to be enhanced security of supply by mitigating the impacts of an outage of the natural gas supply to the island of Ireland
- Previous studies on this subject have been examined and the fundamental methodology used has involved estimating the expected amount of unserved customer electricity demand in the event of gas supply outage (ENTSOG, 2017) (E. Leahy, 2012)
- Production cost modelling is used to estimate total unserved demand in the event of a gas outage of different durations. A production cost model of the All Island electricity market will be used to estimate the total unserved electricity demand resulting from a loss of the Moffat natural gas interconnection to the Island of Ireland for 30 days in winter and summer in a number in three study years.
- The model is run for 3 study years, 2020, 2025 and 2030, with all gas plant removed for a period of 30 days during summer and again during winter.
- The total amount of unserved energy that results during the 30-day outage period is used to calculate a daily, seasonal average as per ENTSO-G's recommended methodology. A value will be placed on this unserved energy using a range of VOLL prices found in the literature, including in ENTSOG's recommended methodology. Combining these results with the project's cost, the minimum supply shock that is required to obtain a net project benefit will be calculated.

2.1. Main Assumptions

A summary of the main study assumptions is presented in the table below. Detailed assumptions and data sources may be found in the appendix.

- All the major assumptions are taken from EirGrid's lastest All Island Generation Capacity Statement
- Plant technical and techno-economic characteristics are based on the regulatory authorities' published SEM electricity model
- The model includes in addition, all operational constraints on the electricity network as published by EirGrid such as reserves, minimum units online and the system non-synchronous penetration (SNSP) constraint
- According to EirGrid's 2017-2026 Generation Capacity Statement, there are retirements of gas plant between 2020 and 2025 leading to a forecasted capacity deficit in 2025 – this is observed in the results
- New gas capacity is added to the system in 2030 in order to meet the reliability target of 8 hours per year loss of load expectation
- Since a disruption to the gas supply is likely to impact GB in addition to Ireland, electricity imports from GB are assumed to be unavailable during a gas supply outage. However, an alternative scenario will examined the sensitivity of the results to this assumption

- In 2030 a new interconnection with France is modelled. It is assumed that imports from France are possible during a gas supply outage

Table 1. Main Study Assumptions

Assumption	2020	2025	2030
All Island Demand Peak (MW)	7200	7420	7680
All Island Demand (TWh)	40.4	43.1	45.8
Installed Wind Capacity (MW)	5425	6125	7430
Installed PV (MW)	340	370	750
Total Gas Generation Capacity (MW)	4667	4225	5375

3. Results and Scenarios

3.1. VOLL Analysis

To estimate the security of supply benefit of gas storage on the island of Ireland, the methodology described above hinges on estimating the total volume of lost supply in the event of a gas supply outage. To estimate the value of this lost supply, a key parameter is the value of lost load or VOLL. Estimation of VOLL is a research topic in itself. A review of relevant VOLL values found in the literature was performed and an average value was used for the main results. A sensitivity analysis was then performed to examine the sensitivity of the results to variations in VOLL.

Table 2. VOLL Sources

VOLL Source	VOLL €/kWh
(ENTSOG, 2017) (Lowest estimate)	4
(E. Leahy, 2012) (Commercial users, inflation adjusted)	17.1
(E. Leahy, 2012) (residential users (average), inflation adjusted)	30.0
(ENTSOG, 2017) (Highest estimate)	40.0
Average	29.0

3.2. Base Case Results

The production code model was run six times in total to simulate a 30-day gas supply disruption for each of the three study years, in summer and in winter. These results were used to calculate a seasonal average daily unserved energy (USE) amount and the corresponding daily average supply disruption cost using the average VOLL for each year. These results are shown in Figure 1, below.

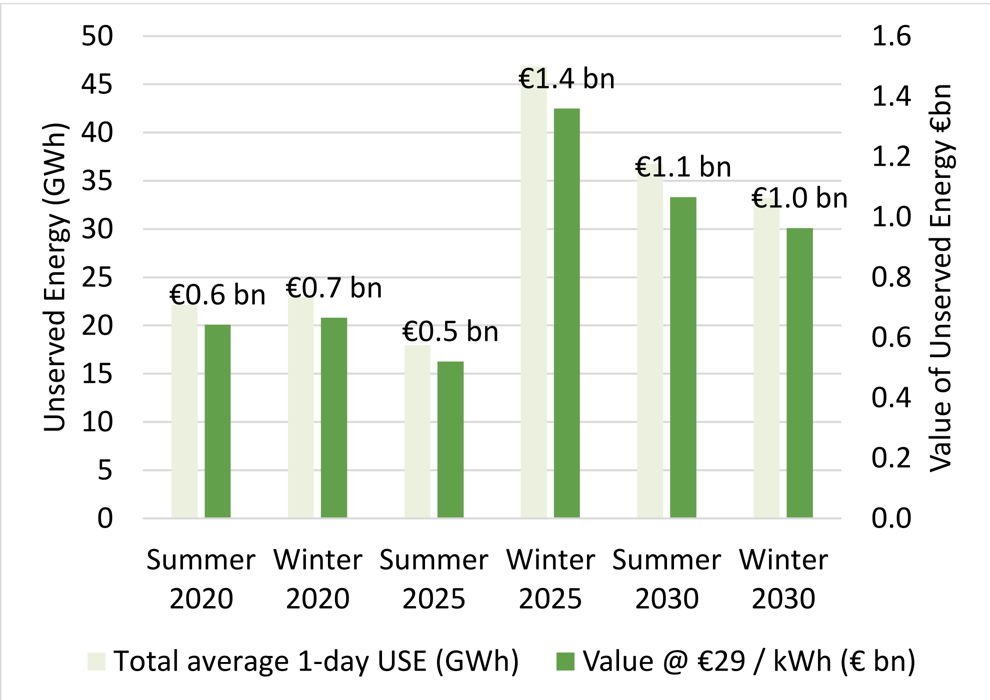

Figure 1. Seasonal average daily benefit for a system wide gas plant outage on the island of Ireland

The following should be noted:

- The value shown is the value of lost electricity supply. The value of loss of domestic gas heating supply has not been studied here but has been estimated in previous studies to be approximately 10% of the value of the lost electricity supply (E. Leahy, 2012).
- The values shown are based on an average value of lost load (VOLL) of €29/kWh as discussed in section 3.1 above.
- The impacts on voltage and frequency stability in the event of an outage of all gas generating plant on the all island network have not been studied and would likely result in additional loss over and above what is reported here.
- EirGrid forecasts a capacity deficit in 2025. The percentage of electricity supplied from gas is lower in 2025 compared to the other study years. However, due to increased renewables and retirements of old gas plant, the impact of a gas supply outage is highest in winter 2025 due to the capacity constrained nature of the system.

Table 3. All Island system results for a 30-day gas plant outage

	Average 1-day Supply Shortage	Value @ €29 / kWh (€ bn)
Summer 2020	664	€0.6 bn
Winter 2020	688	€0.7 bn
Summer 2025	539	€0.5 bn
Winter 2025	1406	€1.4 bn
Summer 2030	649	€1.1 bn
Winter 2030	632	€1.0 bn

3.3. Annual Base Case Results

In order to compare the magnitude of the risk that is mitigated by the project with the project costs, the average cost of a one day gas supply outage was calculated for each year based on the results for each study year. Between study years, the results were linearly interpolated. The general trend in the results show that the average daily gas supply disruption cost increases by year with increasing demand. Since the 2030 plant portfolio was determined so that the system reliability target is met, it was determined that this was a reasonable basis for subsequent years. Beyond 2030, the average daily gas supply disruption cost is assumed to grow annually. However, a scenario is also examined where beyond 2030, the average daily gas supply disruption cost is assumed to be static.

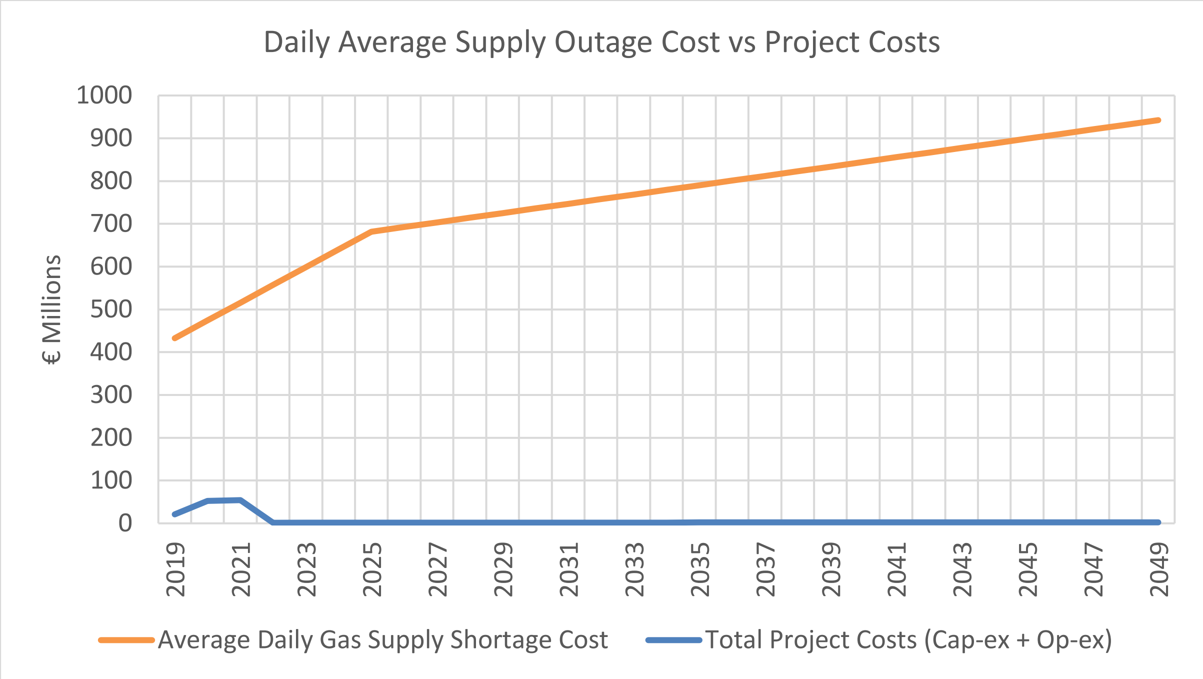

Figure 2. Total project costs and average daily supply outage cost by year, assuming a VOLL of €29/kWh.

3.4. Annual Scenario Results

In addition to the base case, three further scenarios were examined:

- Static Post 2030: Here we make the conservative assumption that beyond 2030, the average cost of a 1-day gas supply disruption remains fixed at the 2030 level
- Full Interconnector Availability: As per (E. Leahy, 2012) we have made the assumption that in the event of a gas supply disruption, the UK is similarly impacted and that no electricity imports via Great Britain are possible. In this scenario we assume that imports are possible from the UK. In 2030, there is a new interconnection with France and this is assumed available in all scenarios.
- Static Post 2030 + Full Interconnector Availability: Here we assume full availability of the interconnection with GB and that beyond 2030, the average cost of a 1-day gas supply disruption remains fixed at the 2030 level

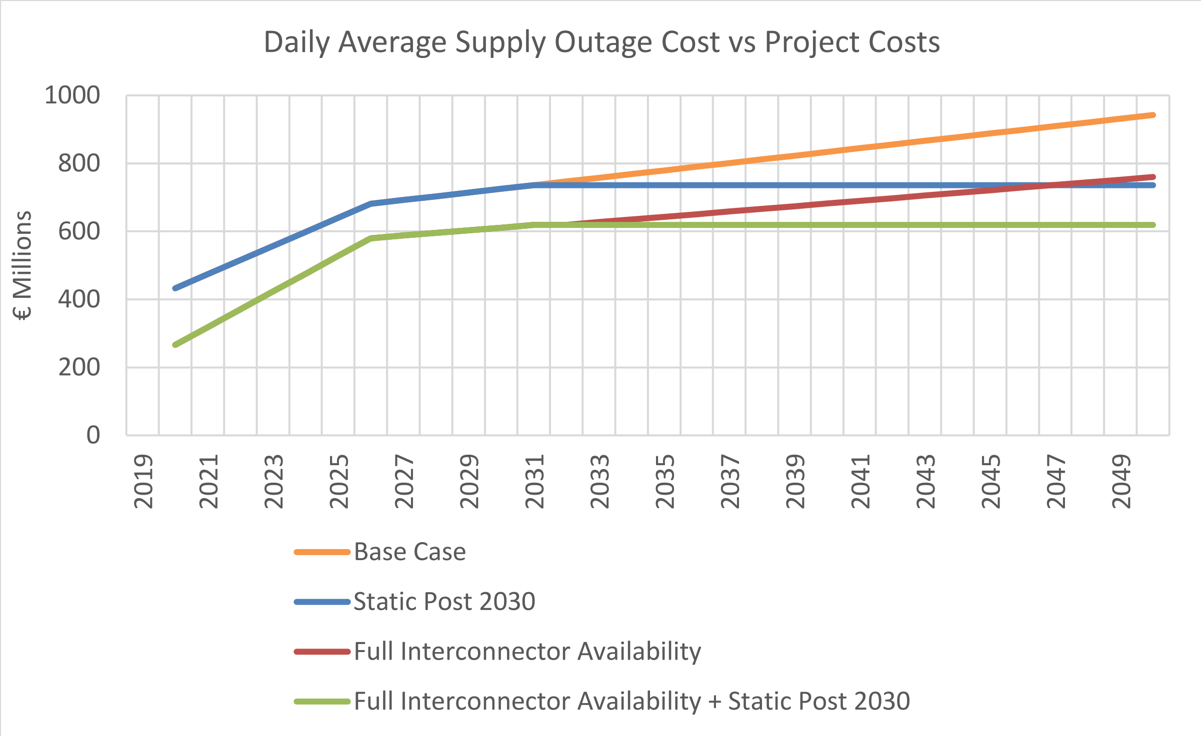

Figure 3. Average daily gas supply outage cost by year for each scenario

3.5. Minimum Supply Shock for Positive Project Benefit

To compare the benefit of the project with the project costs, we calculate the minimum gas supply shock that is required for the project to have a positive net benefit. This can be calculated in days by dividing the total project lifetime costs (assumed to be 30 years for this calculation) by the average daily gas supply outage cost. Since this result is a fraction of a day, we then convert to hours. The result is shown for each scenario in the table below. In the base case, this is saying that a gas supply disruption of 6.4 hours is all that is required for the potential benefit, using conservative assumptions, to outweigh the project costs.

In Republic of Ireland, under the "Secondary Fuel Obligations on Licensed Generation Capacity" (CER/09/100), base load gas plant are required to have the capability to run on a secondary fuel and to hold the required stock for 5 days' continuous operation. For mid merit and peaking plant, the requirement is 3 days. The minimum supply shock calculated below is after these emergency stocks are depleted. Apply the CER requirement to the whole island, a conservative assumption would be 5 days' emergency stocks.

Table 4. Minimum supply shock for net project benefit for each scenario, assuming VOLL of €29/kWh

Scenario	Break-even Minimum Supply Shock (hours)
Base Case	6.4
Static Post 2030	7.5
Full Interconnector Availability	7.9
Full Interconnector Availability + Static Post 2030	9.1

3.6. VOLL Sensitivity

In order to examine the sensitivity of the above result to the level of VOLL, the minimum gas supply shock required for a net positive project benefit has been calculated for different values of VOLL for each scenario. These values are shown in the figure below.

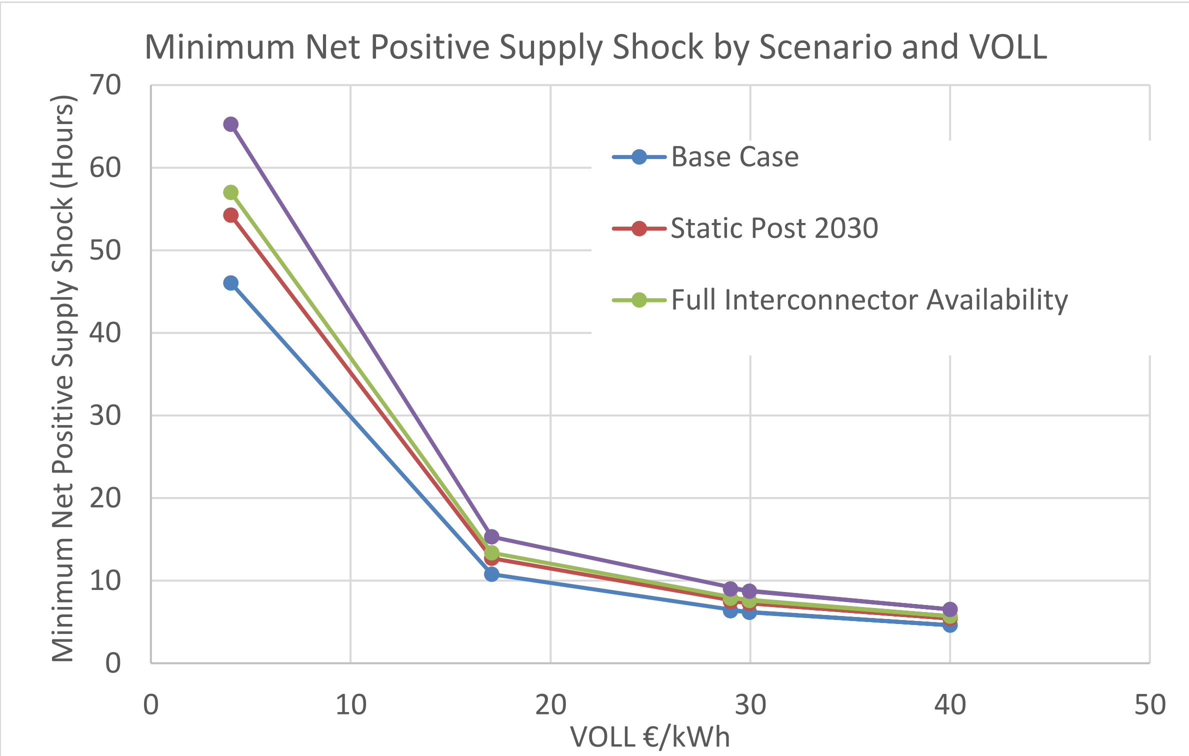

Figure 4. Average daily gas supply outage cost by year for each scenario

4. Conclusions and Discussion

Previous studies regarding the estimation of the value of gas infrastructure have been reviewed along with the recommended methodology published by ENTSOG in 2017. These have been used to develop a state of the art methodology to estimate the security of supply benefit of the proposed gas storage infrastructure at Islandmagee. The amount of electricity demand that would go unserved in the event of a gas supply outage has been estimated for a number of years, seasons and scenarios. This has been valued by using an average VOLL figure based on a review of relevant literature. This has then been used to estimate the minimum gas supply shock that would be required to justify the proposed project.

- The results show that in the base case, a gas supply outage of 6.4 hours over 30 years is all that is required for the proposed project to have a positive net benefit assuming a VOLL value equal to the average of those found in the literature surveyed.
- A range of scenarios were examined to test the robustness of the result and in the most conservative case, a gas supply outage of only 9 hours in 30 years is required to justify the project
- The results are sensitive to the assumed value of VOLL. The sensitivity analysis performed shows that for all reasonable values of VOLL (i.e. excluding the minimum value found in the literature) the minimum gas supply outage required to justify the project is only 15 hours.
- Domestic gas for cooking and heating not included but has been estimated in previous studies to represent an additional benefit of 10% (E. Leahy, 2012)
- Frequency and voltage stability have not been considered. The assumption has been made in this study that all other generation plant on the system can operate as normal – however with no gas plant providing voltage of frequency regulation support, additional generation outages may be necessary. Thus the result can be considered conservative
- The highest observed volume of unserved energy was found in winter 2025. In this year, EirGrid forecasts the system to be in deficit. This also happens to be the year with the lowest installed gas plant capacity, due to retirements in the previous years. This highlights the dependence of the system on a secure gas supply and that the security of supply benefit is actually increased with a lower amount of gas capacity on the system.
- In 2030 there is increased renewable generation on the system and increased interconnector capacity, yet the security of supply benefit of the proposed project is undiminished. Thus, the benefit is robust with respect to renewable capacity and increased interconnection.

5. Appendix – Detailed Assumptions

5.1. Data Sources

The following table lists some of the data sources used in this modelling exercise:

Data	Source(s)
Conventional generator portfolio	EirGrid Generation Capacity Statement 2017-2026
Conventional generator characteristics	• All Island Project website, published market model (Existing generation) • Previously published information (e.g. reserve capabilities) • New generation characteristics are based on existing generation of similar type and vintage
Fuel prices	• BEIS, formerly UK Department of Energy and Climate Change fuel price forecasts • All Island Project fuel price calculator (adds transport costs etc. to commodity prices to yield delivered prices)
Transmission system	A copper plate transmission system has been assumed for this study.
Operation rules	• Operational Constraints updates • EirGrid Area X Constraint report • EirGrid "DS3 Operational Capability Outlook" report (SNSP)
Generator scheduled outages	Maintenance schedule generated which minimises expected load unserved based on historical outage durations
Forced outages	Semi-markov process implemented to simulate forced outages based on forced outage rate and mean time to repair (published). Model iterates to ensure simulated forced outage rate equals nominal rate
Demand	• System level demand peak and energy is based on EirGrid Generation Capacity Statement 2017-2027 • Demand time series are based on regulators' published demand time series along with peak and energy forecasts from EirGrid
Wind time series	• SEM-O Market Model Regional all island wind time series.

5.2. Demand Forecast

The median demand peak and energy figures from the EirGrid Generation Capacity Statement 2017-2026 was used. For 2030 the 2026 result was extrapolated using growth rates for the previous years.

Table 5. Peak Demand Assumptions

Year	Ireland (GW)	Northern Ireland (GW)	All Island (GW)
2020	5.52	1,77	7,20
2025	5.70	1,80	7,42
2030	5.90	1,86	7,68

Table 6. Consumption Assumptions

Year	Ireland (TWh)	Northern Ireland (TWh)	All Island (TWh)
2020	31.2	9.2	40.4
2025	33.7	9.4	43.1
2030	35.8	9.9	45.8

5.3. Renewables Build Out

According to the 2017-2026 Generation Capacity Statement, the following are the installed wind and solar PV levels for the all island system.

Table 7. Renewable Energy Build Out Assumptions

Year	Installed Wind Capacity (MW)	Installed PV (MW)
2020	5425	340
2025	6125	370
2030	7430	750

5.4. System Non-Synchronous Penetration Limit

In the latest published DS3 Operational Capability Outlook, published by EirGrid, the SNSP is forecasted to reach 75% by 2020.

Table 8. Assumed SNSP Limit

Year	SNSP Limit
2020	75%
2025	75%
2030	75%

5.5. Interconnection

To simulate economic flows on the interconnectors with Great Britain, a methodology similar to the Regulator's Plexos model is used where a net generator is modelled on the UK side with a price duration curve. This will result in interconnector flows which are economically driven. Maximum interconnector flows for each interconnector are shown below. The EirGrid practice is to factor in a 20% de-rating of the interconnector to account for modelling and market imperfections. This de-rating has been included in the maximum flow limits below.

Table 9. Interconnector Flows

Direction	Flow Limit 2020 - 2025	Flow Limit 2030
Ireland – Wales	424 MW	424 MW
Wales – Ireland	424 MW	424 MW
Northern Ireland - Scotland	240 MW	240 MW
Scotland - Northern Ireland	424 MW	424 MW
France – Ireland	-	560 MW
Ireland - France	-	560 MW

5.6. North-South Transfer Capacity and Second N-S Link

According to the latest Associated Transmission Reinforcements update published by EirGrid, the second N-S link is expected to be in service by 2019. The present study thus assumes the second N-S interconnector is in service and that 2 units are required online in NI at all time and that there are no constraints on flows between Ireland and Northern Ireland.

5.7. Operational Constraints

As per EirGrid Operational Constraints update published in 2018, the following operational constraints are modelled:

Table 10. Operational Constraints Included in this Study

Constraint	Description
Ireland Stability Constraint	At least 5 large units must be online in Ireland at any time
Northern Ireland Stability Constraint	At least 3 large units must be online in Northern Ireland until 2019 and 2 units after 2019
Dublin Generation	At least one of DB1, PBC, HNC, HN2 must be online at any time
Dublin North Generation	At least one of PBC, HNC, HN2 must be online at any time
Dublin South Generation	At least one of PBC, DB1 must be online at any time
Ireland Replacement Reserve	Combined output of OCGTs in Ireland is limited to 493MW
Northern Ireland Replacement Reserve	Combined output of OCGTs in Northern Ireland is limited to 211MW
Moneypoint	At least one of MP1, MP2, MP3 must be online at any time to support the 400kV network.

5.8. Operating Reserve

Operating reserve requirements have been used based on details contained in the EirGrid Area X Constraint report and the latest published operational constraints update. Before the second N-S interconnector, there is a minimum amount of spinning reserve which must be held in each jurisdiction. In the present study, since the second N-S interconnector is assumed to be in place, reserve is optimised on an all-island basis with no minimum requirements in Ireland or Northern Ireland.

Table 11. POR Reserve Requirements

	Base Requirement	Star	EWIC/MOYLE	Total
Day	333.75	-43	-150	140.75
Night	333.75	0	-150	183.75

5.9. Generation Outages

Generation maintenance outages will be scheduled using an outage scheduling tool which minimises expected load un-served over a year taking account of the risk of generator outages as defined by their forced outage rate and mean time to repair. The forced outage rate and mean time to repair values used are as published by the regulatory authorities and, for existing plant, are based on actual historical forced unavailability.

5.10. Transmission

As the plant is assumed to have firm transmission capacity, the transmission system is not modelled in detail in this study.

5.11. Market Mechanism

The market mechanism modelled in this study is a general mandatory pool where all players bid short run marginal costs into the market. An unconstrained run which omits reserve and stability constraints will yield market positions and the system marginal price while a constrained run will include all operational constraints and simulate actual real time dispatch. Differences between the two runs will yield individual unit constrained running.

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