# All-Island Resource Adequacy Assessment

## 2026-2035 Methodology for Ireland, Northern Ireland and All-Island Single Electricity Market

EirGrid

SONI

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# 1. Introduction

EirGrid and SONI, as the Transmission System Operators (TSO) for Ireland and Northern Ireland respectively, have a responsibility to operate the electricity transmission system every minute of every day, whilst also planning the future of the transmission grids in their relevant jurisdictions.

EirGrid, the TSO in Ireland, is required to publish forecast information about the power system, as set out in Section 38 of the Electricity Regulation Act 1999[1] and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations[2]. The forecast statement is a requirement of Condition 7 of EirGrid's Transmission System Operator licence, which also states that the methodologies on which the forecast statement is based shall be subject to the approval of the Commission for Regulation of Utilities in Ireland.

SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement (GCS), in accordance with Condition 35 of the Licence[3] to participate in the Transmission of Electricity granted to SONI by the Department for the Economy (DfE). Condition 35 also states that the statement shall be based on methodologies approved by the Utility Regulator for Northern Ireland.

The 'Clean Energy for all Europeans' package adopted in 2019 sets out a new framework for the transition away from fossil fuels to cleaner sources of energy which included the Regulation on the internal market for electricity (EU/2019/943) herein referred to as 'the Regulation'. Chapter IV (Articles 20-27) of the Regulation are focussed on resource adequacy.

Article 23 of the Regulation mandates the European Network for Transmission System Operators for Electricity (ENTSO-E) to conduct annual resource adequacy assessments based on projected supply and demand for electricity across the EU to identify resource adequacy concerns for Member States. ENTSO-E's obligations under Article 23 of the Regulation are fulfilled through the European Resource Adequacy Assessment[4] (ERAA), the methodology of which was approved by the European Union Agency for Cooperation of Energy Regulators (ACER) on 2nd October 2020. ACER also has a responsibility for approving the annual implementation of the ERAA methodology conducted by ENTSO-E and issuing opinions where national assessments indicate adequacy concerns which are not identified in the ERAA assessment.

Article 20(1) of the Regulation states that Member States may also carry out national resource adequacy assessments where necessary. Article 24 of the Regulation states that the national adequacy assessment should be based on the ERAA methodology, and capture market specific characteristics or risks that the European assessment may not capture in detail. Effectively, the national adequacy assessment provides the scope to run studies that are relevant on a national level but may not be relevant at a pan-EU level.

The All-Island Resource Adequacy Assessment publication replaces the existing Generation Capacity Statement (GCS) methodology for adequacy modelling for Ireland and Northern Ireland, aligning with EU Regulation 2019/943[5] Article 24. The All-Island Resource Adequacy Assessment publication will support signalling future system outlook and requirements to the energy market as well as to policy makers, regulators, industry, TSOs, Distribution System Operators (DSOs), electricity consumers, and the general public.

**This document prescribes the methodology to be used in the All-Island Resource Adequacy Assessment process for 2025.**

[1] https://www.irishstatutebook.ie/eli/1999/act/23/section/38/enacted/en/html
[2] https://www.irishstatutebook.ie/eli/2005/si/60/made/en/print#partx-article28
[3] https://www.uregni.gov.uk/files/uregni/media-files/SONI%20TSO%20Consolidated%20Feb%202019.pdf
[4] https://www.acer.europa.eu/Individual%20Decisions_annex/ACER%20Decision%2024-2020%20on%20ERAA%20-%20Annex%20I_1.pdf
[5] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

## 1.1. Changes from previous cycle

The All-Island Resource Adequacy Assessment (AIRAA) Methodology for the All-Island Resource Adequacy Assessment has been revised from the 2025-2034 cycle to the 2026-2035 cycle to include an Economic Viability Assessment (EVA). Inclusion of an EVA aligns the Methodology with EU Regulation 2019/943 Articles 23 and 24 and provides useful insights for resource projections in the medium to long term. The methodology for the EVA is discussed in Section 6.

The Demand Modelling, Adequacy Resources and Adequacy Modelling methodologies remain largely unchanged from the previous planning cycle. A summary of changes is provided in the table below.

| Section | Summary of Change |
|---|---|
| Global | Replace 'Climate Year' with 'Weather Scenario' to reflect change from PECD3.1 historic climatic years to PECD4.1 forecast weather scenarios |
| Global | Replace references to 'National Resource Adequacy Assessment' with 'All-Island Resource Adequacy Assessment' and references to 'core' with 'central' |
| 1. Introduction | Remove text to make section more concise, add note on Consultation |
| 2. Study Content | Minor textual revisions to improve clarity |
| 3.1.1 Residential, Commercial and Industrial Demand | Remove reference to exclusion of historic periods of economic turbulence from economic regression |
| 3.1.5 Annual Losses | Revise averaging period from 14 years to 10 years |
| 4.2.4 Interconnection Modelling Parameters | Add Line Losses (reference and counter reference direction) |
| 4.5.3 DSU Modelling Parameters | Revise modelling parameter 'Max Capacity Factor (%)' to 'Daily Operating Hours' to reflect run hour limitations |
| 5. Adequacy | Revise number of weather scenarios from 35 to 36 and number of outage patterns from 20 to 30 to reflect current modelling practice |
| 5.2.2 Surplus/Deficit (MW) Results | Add explanation of weather scenario reduction methodology |
| 5.7.2 Network Constraints | Revise explanation of network constraints to encompass both transmission outage planning and short circuit management constraints |
| 5.7.4 Dynamic Stability | Remove reference to 'short circuit strength' which is now considered as part of Network Constraints |
| Appendix 1 Economic Viability Assessment | Add section on Economic Viability Assessment |

# 2. Study Content

## 2.1. Assessing Resource Adequacy

Resource adequacy refers to having sufficient supply to meet the reliability standard. This includes providing for the capacity and energy needs of the system accounting for relevant operational requirements. To operate a reliable power system, reserve resources are required to ensure security of supply is maintained following a system disturbance. When planning the future power system, it is necessary to consider the provision of resources to ensure the system can be operated reliably according to the specified reliability standard.

A key consideration for conducting resource adequacy assessments is the availability of resources for the System Operators to operate a reliable system, accounting for various characteristics that can restrict the ability of a resource to contribute to resource adequacy. These characteristics can include:

- The dependency on weather dependent resources contributing to reliable operation of the evolving power system requires multi-year climate data to assess the correlated availability of variable or energy limited resources such as wind, solar, hydro, and storage technologies.
- The contribution from interconnection needs to consider the availability of neighbouring regions to provide energy, accounting for climate variation and the availability of lines.
- Forced Outages, Scheduled Outages, Annual Run Hour Limitations (ARHL), fuel supply restrictions and energy constraints that restrict power plant availability.

This employs a probabilistic methodology to assess resource adequacy accounting for the characteristics mentioned above. The methodology will be Monte Carlo based, solving a range of possible operating scenarios to converge on a deterministic output.

Figure 1 illustrates the resource adequacy balance, where the scales are balanced with reference to the defined reliability standard. Insufficient resources to operate a reliable system accounting for possible uncertainty and disturbances means the system could be operating outside the acceptable level of risk.

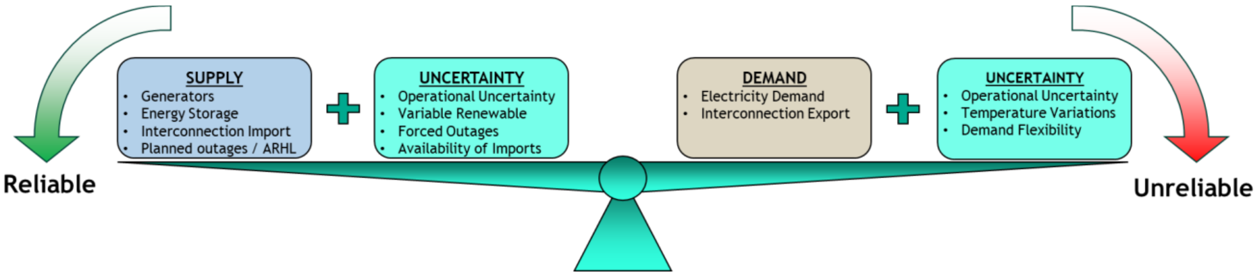


*Figure 1 - The Resource Adequacy Balance*

This methodology will use an industry standard techno-economic modelling package to perform, at a minimum, the Monte Carlo probabilistic calculation of regional LOLE and Energy Not Served (ENS). The equivalent MW surplus or deficit of the system will also be provided to provide insight on the amount of perfect demand or perfect plant that is required to balance the scales and return to standard.

## 2.2. Geographical Scope

This methodology is focussed on the modelling of resource adequacy for Ireland and Northern Ireland. France and Great Britain (GB) will be included in the model and interconnection between GB, France and the SEM will be economically optimised. Ireland, Northern Ireland, Great Britain and France will be modelled as market nodes effectively a 'copper plate model', therefore not explicitly modelling localised network constraints within the regions themselves.

To account for exchanges between GB and France with non-modelled regions, a European model will be used to produce typical market exchanges between these regions which will be fixed for the purpose of studies for this methodology. Further details on modelling interconnection are provided in Section 4.2.

## 2.3. Time Horizon & Resolution

This methodology will assess resource adequacy over a 10-year horizon such that for a given Publication Year (PY) resource adequacy will be assessed for years PY+1 to PY+10. This is consistent with the approach used in the ERAA methodology Article 4(1)(b).

The forecast years will be modelled at an hourly resolution for the purpose of the adequacy assessments, consistent with the ERAA methodology Article 4(1)(h).

## 2.4. Modelling Considerations

This methodology provides a framework for assessing resource adequacy in Ireland and Northern Ireland however, due consideration is required for the following:

- Economic decision making: The model will consider the optimal solution to match supply and demand taking into account availability of resources. The solution is optimised on an unconstrained basis and therefore may not reflect actual unit dispatch, operating hours etc.
- Perfect foresight: System stress in real time can be driven by uncertainty, however the modelling employed under this methodology will utilise perfect foresight such that the availability of variable generation and unit availability will be known by the model and optimised accordingly.
- Simplified modelling of resources: In the interest of reducing computational complexity, the modelling of units has been simplified by removing factors that are unlikely to impact on adequacy due to the perfect foresight in the model e.g. start times, ramp rates, min stable levels.
- Simplified operational security: Reserves and transmission system limitations will be modelled in a simplified manner reflecting the capacity needs of the system. Voltage and frequency stability limits are not considered within the scope of this methodology.
- Weather Scenarios: Where necessary, particular weather scenarios may be selected to represent a credible range of possible operating conditions.

# 3. Demand Modelling

## 3.1. Total Electricity Requirement

The forecasted level of demand is estimated from four sectors, each with different driving factors and underlying trends.

1. Residential, commercial, and industrial demand
2. Electric Vehicle Demand
3. Heat Pump Demand
4. Data Centre and New Technology Demand

The forecast level of demand for each of these sectors are combined to give the estimated Total Electricity Requirement (TER) on an annual basis. The impact of transmission and distribution losses, as well as self-consumption are factored into the final TER forecast. Three different demand levels will be forecast to represent a low, median, and high demand level.

### 3.1.1. Residential, Commercial and Industrial Annual Demand

Residential, Commercial and Industrial demand is forecast on the basis of correlation between historic temperature corrected demand (including self-consumption) and economic performance. The correlation is extrapolated across the study horizon on the basis of an economic forecast. The predicted demand is adjusted to take into account external factors and policies such as efficiency improvements, smart meters effects and the electrification of heat.

The effect of temperature on demand in these sectors affects the demand shape significantly more than the annual demand.

Whilst the electrification of heat and transport as well as growth from data centres and new technology loads will affect these sector's demand, the impact of these factors are captured separately, to enable the underlying trends of this conventional load to be appropriately assessed and forecasted.

### 3.1.2. Electric Vehicle Annual Demand

Electric vehicle demand incorporates passenger vehicles, light commercial vehicles, and public service vehicles. Within these categories, both Battery Electric Vehicles and Plug-In Hybrid Electric Vehicles are included. The total demand from this sector considers:

- Number of vehicles.
- Vehicle efficiency.
- Average annual distance travelled.

These metrics are assessed for each class of vehicle and combined for the total electric vehicle demand for an average weather scenario.

### 3.1.3. Heat Pump Annual Demand for Space and Water Heating

Heat pump demand incorporates the space and water heating through heat pumps for both commercial and residential properties (including new builds and retrofits). The total electricity demand for this sector considers:

- Number of installations.
- Space and hot water heating demand (climate dependent).
- Type and efficiency of heat pumps installed.

These metrics are assessed for residential new builds, retrofits and commercial properties and combined together for the total heat pump demand.

This sector focuses on the use of heat pumps to provide space and hot water heating. It does not include the use of heat pumps in manufacturing and industry; this will be captured in the adjustment to Industrial demand under electrification of heat in industry. It also does not include the use of heat pumps for cooling, this sector is assumed to be captured already in the residential, commercial and industrial demand.

### 3.1.4. Data Centre & New Technology Annual Demand

Data Centre and New Technology Load demand incorporates connections at both the transmission and distribution system for these users that typically use large amounts of energy. A range of factors that will drive growth is considered for each site; these include historical demand growth rates from existing sites, contracted positions from companies and their growth potential, financial close, planning permission, and any relevant direction from regulatory authorities etc. This process creates three credible scenarios that drive demand across the low, median, and high forecast scenarios.

### 3.1.5. Annual Losses

Losses within the electricity system are forecast based on the historic trends of losses (differences between metered generation and metered demand and interconnection flows). Different levels of losses are assumed for demand connected at the transmission and the distribution level. Forecast losses are based on a 10-year average of historic network losses.

## 3.2. Demand Profile & Flexibility Modelling

The demand profile refers to the changing demand in each hour of the year. There are a multitude of factors that influence when consumers will use electricity, and these factors may change into the future. For the purpose of this forecast, the demand is again broken down into different sectors that each have distinctive usage patterns and influencing factors.

The intent is to align with the European Resource Adequacy Assessment (ERAA) methodology and utilise the ENTSO-E Demand Forecasting Tool (DFT) to forecast the demand profile. This tool utilises historic demand trends, correlated to temperature and economic factors and includes forecasted heating profiles and EV charging profiles.

### 3.2.1. ENTSO-E Demand Forecasting Tool

Within this tool (which has been built as an evolution of the TRAPUNTA tool used previously[6]), historic demand, economic and climatic factors are evaluated in relation to the assumptions around the key demand sectors (base load, electric vehicles, heat pumps and data centres and new technology loads). Modelling parameters can be adjusted to ensure a strong correlation between expected levels of demand and real historic data to ensure the model is representing the demand appropriately.

Forecasted levels of annual demand by sector, economic forecasts, behavioural patterns, electrification uptake and efficiency and demand profiles are inputs to the tool used to forecast the future demand shape.

This model utilises forecast climatic data covering irradiance, wind speed and population weighted temperature to forecast a range of climate dependent forecasted demand shapes.

The profile and peak output from the DFT tool will be validated against actual historical data, and where required the peak forecasting process from the Generation Capacity Statement process may be utilised for calibrating the DFT output.

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[6] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/MAF/2020/Demand_forecasting_methodology_V1_1.pdf

### 3.2.2. Residential, Commercial and Industrial Demand Shape & Flexibility

The projected demand shape for this sector is based on historical demand shape, projected trends and the impact of temperature. An average load factor is used to assess the ratio of temperature corrected peak demand to total energy demand for these sectors in historic years. The trend of this average load factor changing over time is projected into the future to assess the forecasted peak demand.

Historic demand profiles are scaled and translated to align with both the forecasted peak demand and forecasted total energy demand from these sectors. The shape of this temperature corrected demand is then adjusted to factor in weather patterns based on forecast model climatic data.

Demand flexibility in this sector is accounted for through reducing the peak demand, the scaling and translation process will result in the energy that is removed from peak times being distributed across the rest of the day.

### 3.2.3. Electric Vehicle Demand Shape & Flexibility

The forecasted electric vehicle demand shape is based on forecast vehicle usage patterns, temperature dependent efficiency and charging behaviour.

Vehicle usage patterns incorporates both day of the week and time of year impacts.

Temperature dependent efficiency includes the impact of temperature on battery performance and vehicle cabin heating demand.

Charging behaviour factors in when people choose to charge their electric vehicle. Multiple profiles will be utilised to reflect different consumer behaviour, with the number of people attributed to different profiles expected to change across the study horizon. The different categories of vehicles (private, commercial, and public service), as well as differentiation between PHEV and BEV, may also be assigned different charging patterns.

Demand flexibility in this sector will be modelled on the basis of uptake of charging profiles that avoid peak times.

### 3.2.4. Heat Pump Demand Shape & Flexibility

The shape of demand from heat pumps is heavily dependent on climatic temperature, and also factors in consumer behaviour.

Whilst the average space and hot water heating demand is utilised in calculating the annual demand, the daily heating demand will fluctuate on the basis of temperature. In addition to this, the coefficient of performance (COP) of heat pumps (which indicate their efficiency) is affected by climatic temperature with heat pumps becoming less efficient at lower temperatures. This compounds the impact of low temperatures with heating demand increasing and heat pumps becoming less effective. The differing COP impact of temperature on different technologies of heat pumps is factored into this assessment.

The behavioural use of heating with a heat pump is different to conventional boilers as heat pumps operate most efficiently when they are run for a higher number of hours each day at a lower heat output[7]. A behavioural usage profile is incorporated to reflect how consumers will utilise their heat pump in each hour of the day to ensure space and water heating is sufficient to reach desired comfort level.

The hourly profile based on behavioural use has the opportunity to be altered to provide demand flexibility.

### 3.2.5. Data Centre and New Technology Load Demand Shape

Historic trends show the shape of demand observed from data centres and new technology loads is relatively flat across the day. Previously the daily demand has, on average, gradually increased across the year to the forecasted peak based on the individual sites building out towards their contracted ramp. This will be

[7] https://www.seai.ie/publications/Low-Carbon-Heating-and-Cooling-Technologies.pdf

reflected by the daily demand gradually increasing throughout the year from the previous year's peak demand to the forecast peak demand.

For the purposes of modelling the demand profile, it can include a portion of flexibility that is represented through reduced demand during time of high tariffs. Historical data and policies can be used to assess the scale of the current and future flexibility.

For emergency situations, some sites will be required to curtail their demand requirements, altering their demand shape. These measures are assumed to be operational measures during a system Emergency State rather than contributing to system adequacy. As such these are not factored into the forecasted demand shape.

### 3.2.6. Demand Side Units / Demand Side Response

Demand Side Response (DSR) is an energy product that aims to reduce or shift demand on the transmission system. This can be achieved either through a reduction of demand at a particular site or using on-site generation to meet the demand. Further details on modelling DSR are described in Section 4.

## 3.3. Demand in Great Britain and France

Forecasted demand levels and profiles for both Great Britain and France are required to enable representative interconnection modelling. This will utilise the output from the latest published European Resource Adequacy Assessment (ERAA) with interpolation used to calculate the intermediate years not currently covered by the ERAA study.

# 4. Adequacy Resources

This section provides details on the various types of resources that will be included in this methodology as contributing to the operation of a reliable power system. The detail provided in this section is specific to modelling resources in the SEM region with the exception of the section on interconnection. The resources associated with France and Great Britain will be fully aligned with and modelled according to the latest ERAA methodology approach.

## 4.1. Conventional Generation

**This methodology will include existing and new conventional units on a unit-by-unit basis and apply capacity weighted class average forced and scheduled outage statistics, and applicable run hour restrictions.**

### 4.1.1. Technology Summary

Conventional generation units such as gas turbines and some steam turbines are necessary to provide inertia, fault current, voltage support, ramping needs and are still the primary source of reliability for the All-Island power system. The transition to increased supply from renewable generation will mean that these conventional units may be required less of the time, and many of the services they provide will be sourced from alternative low carbon sources including renewable generators, storage, synchronous compensators and more. However, replacing the value conventional capacity can bring to reliable system operation remains challenging and so it is expected these units will be required to support delivery of climate ambitions providing back up supply when other lower emissions generation is unavailable. EirGrid and SONI have seen through the Tomorrow's Energy Scenarios[8] (TES) work that renewable fuel-ready conventional generation capacity will be required to support the needs of a net-zero power system.

### 4.1.2. Conventional Generation Information

Availability of current conventional generation capacity will consider existing and new generation capacity on a unit-by-unit basis. Availability across the study horizon will consider delivery of new capacity and exit dates for existing capacity, adjusted for risk, and based on the latest information available.

### 4.1.3. Conventional Generation Modelling Parameters

Conventional generation will be implemented in the model using the parameters in Table 1.

| Modelling Parameter | Description |
|---|---|
| Forced Outage Rate (%) | Annual % a unit is on an unplanned outage |
| Forced Outage Mean Time to Repair (hours) | No. of hours a unit resolves an unplanned outage |
| Maintenance Frequency | No. of times per year a unit has a planned outage |
| Scheduled Outage Duration (hours) | No. of hours a unit is on planned outage |
| Installed Capacity (MW) | Installed capacity of a unit |
| Rating Factor (%) | Scaling factor applied to reflect ambient availability across the year |
| Heat Rate (GJ/MWh) | Amount of energy required to generate one MW of electrical output for one hour |
| Fuel Type | Primary (and possibly secondary) fuel type(s) used by the unit |

[8] https://cms.eirgrid.ie/sites/default/files/publications/Tomorrows-Energy-Scenarios-2023-Consultation-Report-November-2023_0.pdf

| | |
|---|---|
| Variable Operation & Maintenance (VO&M) Charge (€/MWh) | Component used to reflect the operations and maintenance costs resulting from the unit generating power |
| Operating Hour Restriction (hours) | Limitations on the number of hours a unit or stack (exhaust shared by multiple units) can be on load. |

*Table 1 - Conventional Generation Modelling Parameters*

Technical parameters such as start-up times, ramp rates and min stable levels are excluded from this adequacy model. These parameters need to be considered in the context of real-world operation of the power system but have a negligible impact on adequacy modelling due to the perfect foresight in the optimisation.

#### 4.1.4. Conventional Generation Availability

EirGrid and SONI report on conventional unit availability on a monthly basis using the following metrics to reflect unavailability of units:

- Scheduled: Scheduled generator outage approved by the relevant TSO Generation Outage Planning Team.
- Forced: Any reduction in availability not approved in advance with the relevant TSO Generation Outage Planning Team (including trips, outage overruns, urgent repairs, partial outages etc.).
- Ambient: Reduction in generator availability due to ambient temperature conditions.

Monthly availability data is used to generate a capacity weighted class average probability of the technology class being on either forced or scheduled outage. Further details on the specific modelling approach for the types of outages in contained in Section 5.

The average is calculated using a number of years of data aimed at incorporating the latest trends and create a reasonable estimate for future plant performance. Applying the class average socialises the risk of poor unit performance outages across the class, as it cannot be predicted which specific unit might perform poorly in future.

The capacity weighted class average forced outage rate is calculated for each class using:

$$\frac{\sum_{unit}\sum_{year}(Capacity)_{Unit} \times (Average\ Forced\ Outage\ Rate)_{unit}}{\sum_{unit}\sum_{year}(Capacity)_{Unit}}$$

The process above is repeated for the derivation of scheduled outage statistics with one additional step in converting from a scheduled outage rate to scheduled outage duration:

$$SOD = SOR \times 8760$$

#### 4.1.5. Operating Hour Restrictions

Units may have limits on how many hours they can operate in a given timeframe, which may be in place because of Best Available Techniques (BAT) legislation and emissions directives, or a constraint imposed by planning permission. There is also a possibility of fuel supply constraints restricting operability of a unit if onsite fuel storage is limited or fuel supply chains are strained.

Restrictions on the number of hours a unit can be operated presents challenges to the system operators in terms of managing run hours on units and balancing against possible operational uncertainties that may require the units to run more frequently.

To account for operating hour restrictions, this methodology will restrict the hours during which units are available to the expected times of the day and year when the units are likely to be needed the most. Table 2 indicates the operational restriction implementation on units.

| Operating Hour Limit | Restricted Operation | Restricted Time |
|---|---|---|
| 500 | 4 hours per day | 17:00 - 21:00 |
| 1500 | 6 hours per day | 16:00 - 22:00 |

*Table 2 - Operating Hour Restriction Categories*

## 4.2. Interconnection

**This methodology will explicitly model Ireland, Northern Ireland, Great Britain, and France acknowledging transfer capacity limits between regions. Interconnection beyond GB and France will be fixed based on ERAA modelling outputs.**

### 4.2.1. Interconnection Summary

Increased interconnection provides the opportunity for power sharing between regions and is seen as a key enabler to increasing renewable integration and potential to support security of supply during periods of system stress. The availability of interconnection to support security of supply for a given region depends on the availability of surplus energy from the neighbouring region in addition to the operational availability of the interconnector.

The ERAA methodology for modelling cross border exchanges across interconnectors includes flow-based constraints within the core region, with Advanced Hybrid Coupling (AHC) for non-core countries connected to the core region and Net Transfer Capacities (NTC) for countries not connected to the core region. The NTC approach refers to a maximum possible transfer between two boundaries and will be utilised for the purpose of this methodology.

### 4.2.2. Interconnection Internal to the SEM

The tie line between Ireland and Northern Ireland will be modelled using the NTC approach enabling power exchanges between the jurisdictions. The NTC will account for future development of the link such as the introduction of the new North South interconnector.

### 4.2.3. Interconnection External to the SEM

This methodology is aimed at complementing the ERAA methodology, where the national assessment has the provision to assess local risk analysis through modelling scenarios and sensitivities. The chosen approach to enable this and reduce the computational time required to run simulations is to model the SEM and neighbouring regions which the SEM will be directly interconnected to within the study horizon.

1. **Explicitly modelled regions**

It has been observed that due to the close geographical proximity of the SEM to GB, that similar weather conditions may prevail across each of the regions such that a cold spell in the SEM could also be a cold spell in GB. The impact and risks associated with simultaneously occurring weather conditions needs to be appropriately understood and therefore Great Britain is explicitly modelled in this methodology.

Re-integration with Europe is anticipated to enhance security of supply for the SEM, considering that the weather correlation is less prevalent between the SEM and FR regions but also that it will bring support from the wider EU electricity system. On this basis, France is explicitly modelled in this methodology.

The approach for modelling the interconnection between explicitly modelled regions will be based on the NTC limits. This will account for future roll out of additional interconnection and reflect power transfer limits between the regions. Where necessary, this methodology will consider market developments that could influence on the availability of a region to provide interconnection support to the SEM.

2. **Non-explicitly modelled regions**

To appropriately represent the availability of interconnector support from GB and FR, it is important to also consider onward interconnection from GB and FR to other countries. Table 3 below provides a list of regions which have direct links to GB and FR. Interconnection to these countries will be represented through the use of fixed flows derived from a pan-EU model.

| Region | Interconnection to Great Britain | Interconnection to France |
|---|---|---|
| Belgium | ✓ | ✓ |
| Denmark | ✓ | ✓ |
| Germany | | ✓ |
| Italy | | ✓ |
| Netherlands | ✓ | |
| Norway | ✓ | |
| Spain | | ✓ |
| Switzerland | | ✓ |

*Table 3 - Implicitly modelled regions*

For this methodology, hourly fixed flows will be derived using the NTC approach, whereby market coupling limits are defined by transfer capacity limits. The ERAA model will be used to derive imports into and exports out of GB and FR from the countries in the table above, which will then be fixed for the purpose of conducting national adequacy assessments for Ireland and Northern Ireland. This approach implicitly captures an average representation for how interdependencies across Europe may affect security of supply in the SEM.

This approach will account for changes to interconnection capacity across the study horizon through developing fixed flows for each Study Year and will capture the effect of climatic variations on interconnection at a pan-European level through modelling multiple Weather scenarios.

The boundaries discussed above are shown in Figure 2.

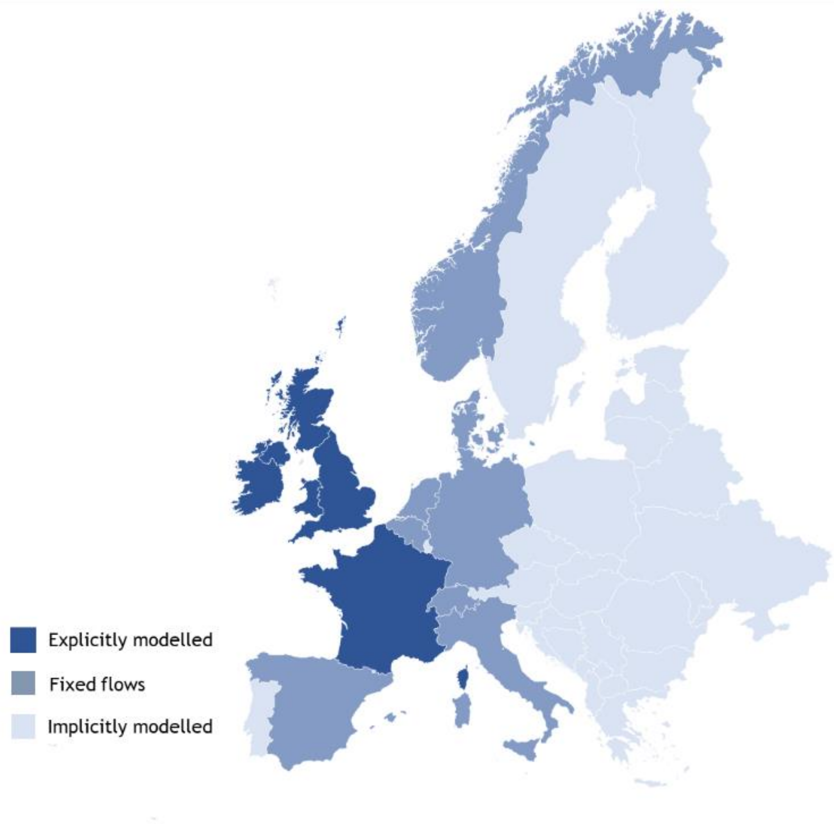


*Figure 2 - Modelling Regions*

### 4.2.4. Interconnection Modelling Parameters

Interconnection will be implemented in the model using the parameters in Table 4.

| Modelling Parameter | Description |
|---|---|
| Max Flow (MW) | Maximum allowable flow on the line in the reference direction |
| Min Flow (MW) | Minimum available flow on the line in the counter reference direction (-ve value for bi-directional lines) |
| Forced Outage Rate (%) | Annual % the line is on an unplanned outage |
| Forced outage Mean Time To Repair (hours) | No. of hours for a line to resolve an unplanned outage |
| Maintenance Frequency | No. of times per year a line has a planned outage |
| Scheduled Outage Duration (hours) | No. of hours a line is on planned outage |
| Wheeling Charge (€/MWh) | Charge on flow across lines, used to implement typical order of dispatch considering line losses and prevents circular flows between modelled regions |
| Line Loss (%) | A factor accounting for electric line losses over the interconnector in the reference direction |
| Line Loss Back (%) | A factor accounting for electric line losses over the interconnector in the counter reference direction<br>(-ve value for bi-directional lines) |

*Table 4 - Interconnection Modelling Parameters*

### 4.2.5. Interconnection Availability

The availability of High Voltage Direct Current (HVDC) interconnectors between the SEM and neighbouring regions is considered by using a combination of forced and scheduled outage statistics for the HVDC line. HVDC Interconnectors between GB and FR will be assigned outage statistics and repair times in accordance with the latest ERAA modelling methodology. High Voltage Alternating Current (HVAC) interconnectors will not be assigned outage statistics in line with the ERAA methodology.

Outage statistics for interconnection between explicitly and non-explicitly modelled regions will be implicitly captured in the fixed flows used to represent these interconnections.

## 4.3. Variable Generation (Wind / Solar / Hydro)

**This methodology will model variable renewable energy availability aggregated by technology type on a jurisdictional basis using correlated climate availability profiles.**

### 4.3.1. Technology Summary

The transition to a power system predominantly supplied from variable renewable energy sources means the risks associated with periods of low renewable availability need to be dimensioned appropriately. It has been observed that risks to security of supply can result from correlation between weather patterns. This methodology will model variable energy generation using multiple weather scenarios to examine the impact of correlated weather events across the SEM, FR and GB on security of supply in the SEM region.

### 4.3.2. Variable Generation Information

Variable generation will be aggregated to a single installed capacity on a jurisdictional basis according to the following technology types:

- Offshore Wind
- Onshore Wind
- Solar Photovoltaic (Includes large scale and rooftop)
- Run of River Hydro

Solar PV aggregates two capacity types including small-scale behind the meter capacity (e.g. domestic rooftop PV) along with large scale distribution and transmission connected capacity. Wind capacity has been categorised into offshore and onshore capacity to reflect a possible increased contribution from offshore wind resulting from expected higher capacity factors.

### 4.3.3. Variable Generation Modelling Parameters

Variable renewable capacity will be modelled using the parameters in Table 5.

| Modelling Parameter | Description |
|---|---|
| Installed Capacity (MW) | Installed capacity of a unit |
| Rating Factor (%) | Availability profile of the resource at the model resolution e.g. hourly |

*Table 5 - Variable RES Modelling Parameters*

### 4.3.4. Variable Generation Availability

Availability of variable generation will be modelled using multi-year climatic data, reflecting correlated availability of these resources across possible climatic conditions. The profiles used will implicitly capture the effect of plant outages on availability.

## 4.4. Battery Storage

**This methodology will aggregate Battery Storage units by duration, accounting for Round Trip Efficiency and State of Charge limits.**

### 4.4.1. Technology Summary

Battery Energy Storage System (BESS) units provide a range of services including renewable energy balancing, congestion management and voltage and frequency support. Storage units can also contribute to system adequacy needs and typically through storing energy during periods of generation surplus and discharging during periods of tight margins to alleviate stress on the system.

### 4.4.2. Battery Storage Information

Availability of battery storage capacity will consider existing and new storage capacity on a unit-by-unit basis. Availability across the study horizon will consider delivery of new capacity based on the latest information available.

### 4.4.3. Battery Storage Modelling Parameters

BESS units will be modelled considering the factors set as per Table 6 below.

| Model Parameter | Description |
|---|---|
| Installed Capacity (MW) | Installed MW capacity of a unit |
| Installed Energy Capacity (MWh) | Installed MWh energy capacity of a unit |
| Initial State of Charge (%) | State of Charge in the initial period of the Horizon |
| Charge Efficiency (%) | Efficiency applicable to charging the unit |
| Maximum State of Charge (%) | The maximum state of charge a unit can achieve |
| Minimum State of Charge (%) | The minimum state of charge a unit can achieve |
| Maximum Cycles Per Day | The maximum number of cycles (charge and discharge) a unit can complete in a day |
| Pump Load (MW) | The maximum capacity the unit can import |
| Forced Outage Rate (%) | Annual % a unit is on an unplanned outage |
| Forced outage Mean Time To Repair (hours) | No. of hours for a unit to resolve an unplanned outage |
| Maintenance Frequency | No. of times per year a unit has a planned outage |
| Scheduled Outage Duration (hours) | No. of hours a unit is on planned outage |

*Table 6 - Battery Storage Modelling Parameters*

### 4.4.4. Battery Storage Availability

This methodology will use the latest information available in relation to the performance and availability of battery storage units, to appropriately reflect the contribution to adequacy from this technology. As data becomes available in respect of outage statistics for battery storage units, this will be considered as part of the modelling input assumptions.

## 4.5. Demand Side Units

**This methodology will model the Demand Side Units as an aggregated capacity, accounting for availability through applying an availability adjustment to the rated capacity and accounting for run hour restrictions where applicable.**

### 4.5.1. Technology Summary

The capacity of Demand Side Units (DSUs) has grown significantly in recent years, with a range of units supporting demand side management across a range of horizons. In terms of adequacy, units are dispatched before and during system alerts to provide demand reduction and alleviate stress on the system.

### 4.5.2. DSU Resource Information

Availability of DSU capacity will consider existing and new DSU capacity on a unit-by-unit basis. Availability across the study horizon will consider delivery of new capacity based on the latest information available.

### 4.5.3. DSU Modelling Parameters

DSU resources will be implemented in the model using the parameters in Table 7.

| Modelling Parameter | Description |
|---|---|
| Installed Capacity (MW) | Installed capacity of a unit |
| Rating Factor (%) | Availability of the resource |
| Max Daily Operating Hours | Daily run hour constraint applicable to DSUs with run hour limits |
| Offer Quantity (MW) | Quantity of generation offered |
| Offer Price (€/MWh) | Price of generation quantity offered |

*Table 7 - DSU Modelling Parameters*

### 4.5.4. DSU Availability

DSUs may be subject to run hour or energy limits due to individual demand sites being subject to energy or run hour limits or possibly only being available to reduce load at certain times of the day depending on the type of demand available at a particular site.

Due to the various configurations comprising DSUs, it is difficult to specify exact times when a DSU has reduced availability for maintenance reasons or is forced unavailable. As such, the monthly availability reporting conducted by EirGrid and SONI provides DSU availability as a percentage of capacity available on average across the month.

This methodology will use DSU availability data from the EirGrid and SONI monthly availability reports to construct a capacity weighted average availability for the resource. The average DSU availability value will be applied to both run hour limited and non-run hour limited DSU resources, with an additional constraint implemented to restrict the energy that can be delivered from the run hour units on a daily basis.

## 4.6. Pumped Storage

**This methodology will model pumped storage on a unit-by-unit basis. Availability to support adequacy will include outages based on historical availability and account for black start requirements.**

### 4.6.1. Technology Summary

The pumped storage facility provides a range of system support functions, including reserve provisions and black start capability which will be reflected in the modelling for this resource.

### 4.6.2. Pumped Storage Information

Pumped storage resources will consider existing capacity connected to the system. Additional projects will be considered where there are contractual obligations in place such as connection agreements or capacity market contracts etc.

### 4.6.3. Pumped Storage Modelling Parameters

Hydro resources will be implemented in the model using the parameters in Table 8.

| Modelling Parameter | Description |
|---|---|
| Installed Capacity (MW) | Installed capacity of a unit |
| Max Volume (GWh) | Upper volume bound for a storage reservoir |
| Min Volume (GWh) | Lower volume bound for a storage reservoir |
| Forced Outage Rate (%) | Annual % a unit is on an unplanned outage |
| Forced outage Mean Time To Repair (hours) | No. of hours a unit resolves an unplanned outage |
| Maintenance Frequency | No. of times per year a unit has a planned outage |
| Scheduled Outage Duration (hours) | No. of hours a unit is on planned outage |
| Initial State of Charge (%) | State of Charge in the initial period of the Horizon |
| Pump Efficiency (%) | Efficiency applicable when in pump mode |
| Discharge Efficiency (%) | Efficiency applicable when discharging |
| Pump Load (MW) | The maximum load drawn when in pump mode |

*Table 8 - Pumped Storage Modelling Parameters*

### 4.6.4. Pumped Storage Availability

Pumped storage will be free to optimise it's charging and discharging cycles within the bounds of the optimisation. Forced and scheduled outage statistics will be applied to individual pumped storage generator units based on class average statistics.

## 4.7. Other RES / Other Non-RES

The Other RES category contains units such as small-scale biomass units and small-scale hydro units for which inflows are unavailable. The Other Non-RES category consists of some smaller CHP units which will be aggregated together. The contribution from these categories to the overall reliability of the system is minimal due to the smaller nature of these capacities, however, will be included based on the latest estimates of available capacity.

These categories will be simplified in terms of modelled attributes and the availability of energy from each will be assumed using an availability profile consistent with the ERAA methodology.

# 5. Adequacy Modelling

## 5.1. Monte-Carlo Simulation

**The objective of the stochastic Monte Carlo simulations is to create a range of possible scenarios and conduct a probabilistic assessment on the likelihood of operating the system within the defined reliability standard.**

In real world operation of the power system, there are many factors which the system operators have little or no control over including weather, demand, and unplanned unit outages. Even planned outages may occur during undesired times of the year, either due to availability of maintenance personnel or late notice of requirements to carry out maintenance.

The intention of conducting a Monte Carlo type analysis, means a large number of possible scenarios can be constructed to vary each of the unknowns above, producing a range of credible operational scenarios. Figure 3 below illustrates the high-level building blocks used in the adequacy modelling, and further detail on these is provided thereafter.

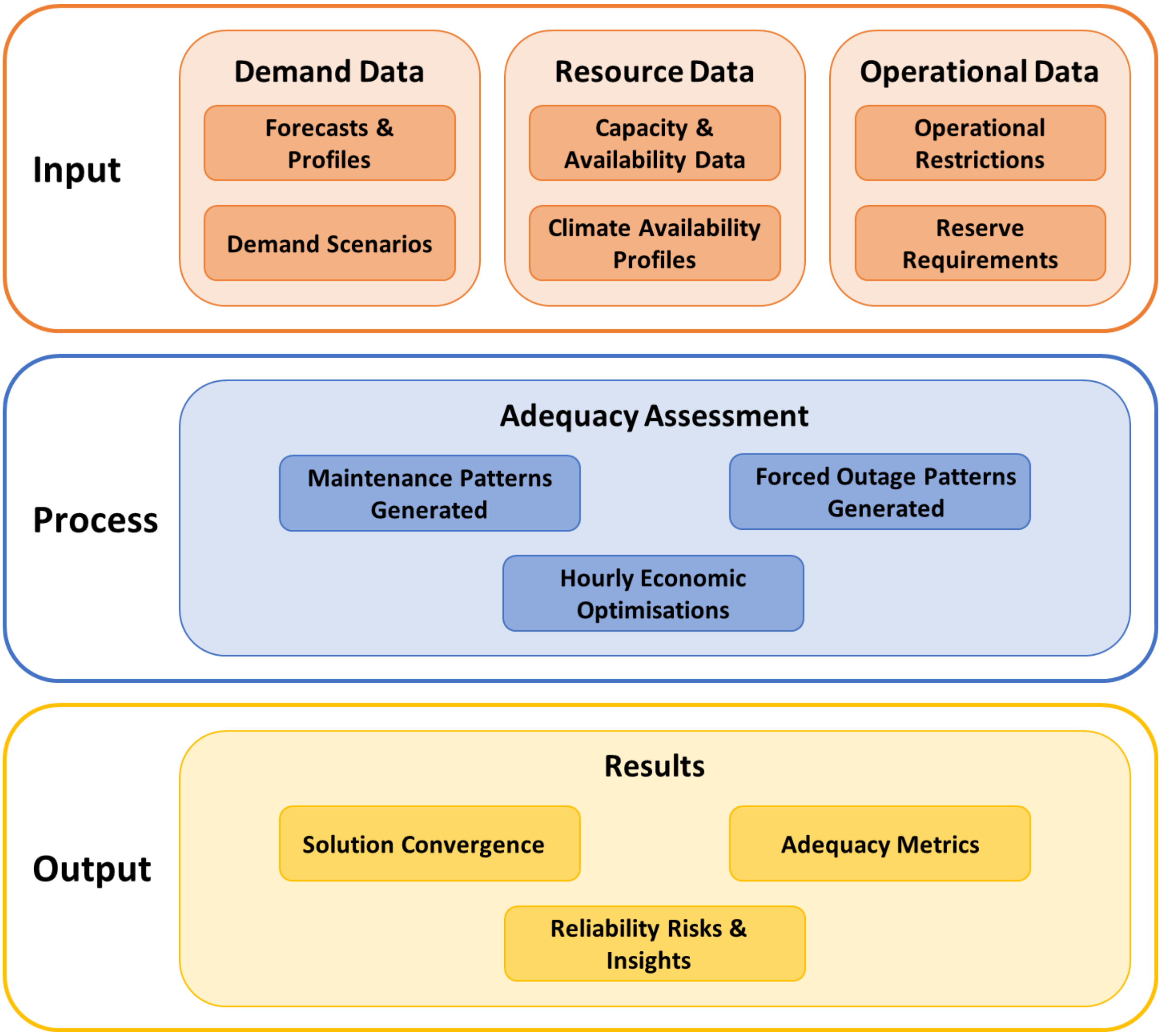


*Figure 3 - Overview of Monte Carlo Methodology*

### 5.1.1. Input Data

The input data has been described in detail throughout the earlier sections of this methodology document. In summary:

- A range of input demand forecasts are developed for each year of the study horizon, where the range consists of a minimum high, low, and median forecast levels. The demand forecasts are combined with projected climatic data to produce a range of demand scenarios which include the effects of temperature dependency. This is illustrated in Figure 4 below.
- An input portfolio specifies all of the resources to be considered as contributing to adequacy, along with relevant outage statistics and operational requirements.
- Climatic profiles for variable generation sources such as wind, solar and hydro are correlated to the climatic year used in the demand scenario.

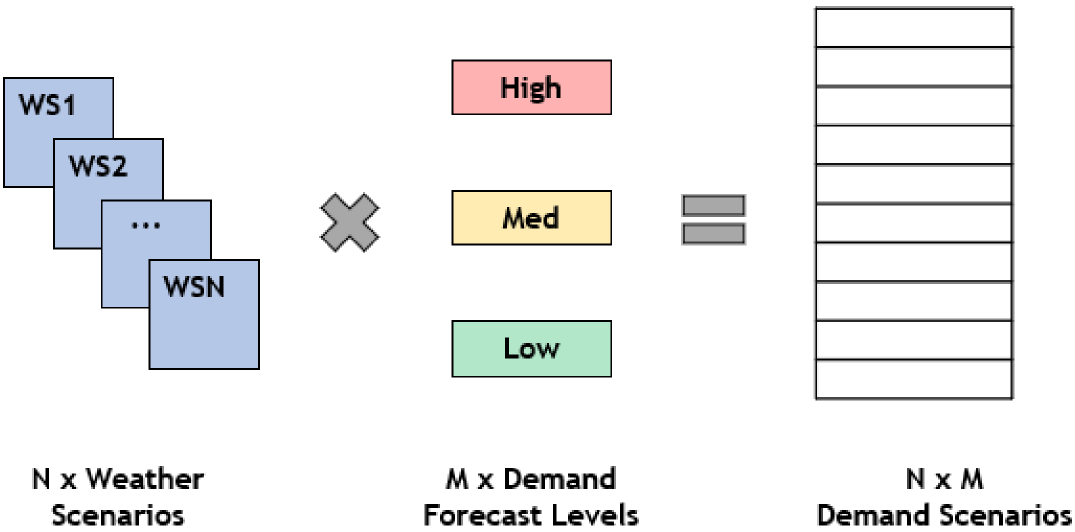


*Figure 4 - Construction of Demand Scenarios*

### 5.1.2. Adequacy Analysis

The Monte Carlo simulation is set to generate a number of different 'samples', with each sample having a different independent forced (unplanned) and scheduled (planned) outage pattern. For each sample, the scheduled outage patterns are generated first and forced outages are randomly applied to the remaining capacity after scheduled outages are considered.

Each sample simulated is solved to produce a least cost optimisation, respecting any additional bounds or constraints specified e.g. availability restrictions due to run hour or energy limits associated with unit(s).

### 5.1.3. Output Data

The output from the Monte Carlo simulation is a set of independent samples with unique optimisations. The relevant metrics can be observed at a sample level, or an average can be taken. A post optimisation processing step as part of the output process is to assess the convergence of the solution and the adequacy analysis will be rerun if the problem has not converged to within the tolerance. More information on convergence is provided below.

Figure 5 illustrates the optimisation process for a single demand scenario, where S is the number of Samples.

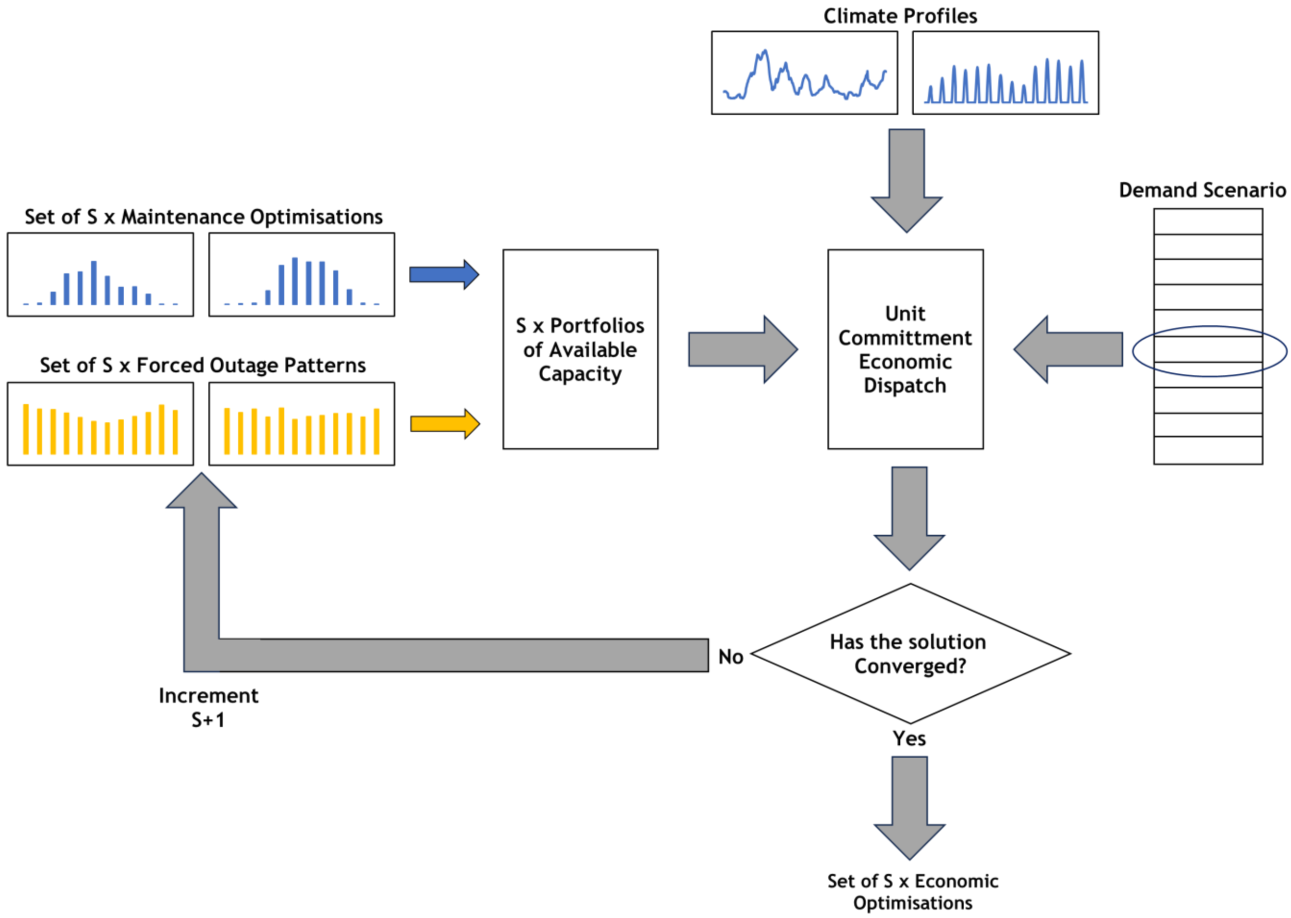


*Figure 5 - Monte Carlo process for a single demand scenario*

## 5.2. Adequacy Indicators

**This methodology will report on the adequacy of Ireland, Northern Ireland and the All-Island SEM using appropriate indicators to examine the risks to the evolving power system.**

To understand and represent power system reliability, various indicators have been selected as presented below. Each indicator may be expressed as an average, range, or as a percentile function (the 95th percentile is commonly used across industry) depending on the particular insights being communicated.

Adequacy indicators required under Article 24 of Regulation(EU) 2019/943:

- **Loss of Load Expectation (LOLE) [hrs]:** For a number of samples $S$ across a given study scenario, LOLE represents the average number of hours in which it is expected there could be insufficient resource capacity to supply the required demand in which the LOLE for a single sample is a summation of the Loss of Load Hour (LOLH) periods.

$$LOLE = \frac{1}{S}\sum_{S=1}^{S} LOLH_S$$

- **Expected Energy Not Served (EENS) [GWh/year]:** The EENS is an average of the Energy Not Served over the total number of Monte-Carlo simulations. For each demand scenario, the optimisation solves for each Monte-Carlo sample (S).

$$EENS = \frac{1}{S}\sum_{S=1}^{S} ENS_S$$

Additional adequacy indicators which may be reported on as part of this methodology:

- **Loss of Load Hour (LOLH) [hrs]:** An hour in which there is insufficient resource capacity to supply the required level of demand.
- **Energy Not Served (ENS) [GWh]:** The shortfall between supply and demand in a given hour.
- **Loss of Load Duration (LOLD) [hrs]:** The duration of a reliability event, calculated as the number of consecutive LOLH periods.
- **Loss of Load Probability (LOLP) [%]:** The probability in a given hour there will be insufficient generation capacity to meet the required level of demand.
- **Capacity Surplus (+ve) / Deficit (-ve) (MW):** An indication of the MW position relative to the specified adequacy standard for a jurisdiction. This value is the amount of perfect (100% reliable) plant or perfect demand that is required to bring the system back to standard. Where the MW value for a given scenario is:
    - Equal to 0 – Indicates there is enough capacity to manage the power system for the scenario.
    - Greater than 0 – Indicates there is a capacity surplus, and the system could be operating below the LOLE Standard.
    - Less than 0 – Indicates there is a capacity deficit, and the system could be operating above the LOLE Standard.

### 5.2.1. LOLE and EENS Results

Figure 6 illustrates the components of a single Monte Carlo Year consisting of a single weather scenario and a single Outage Pattern. For each Study Year across the horizon, the process is repeated for other weather scenarios and outage patterns.

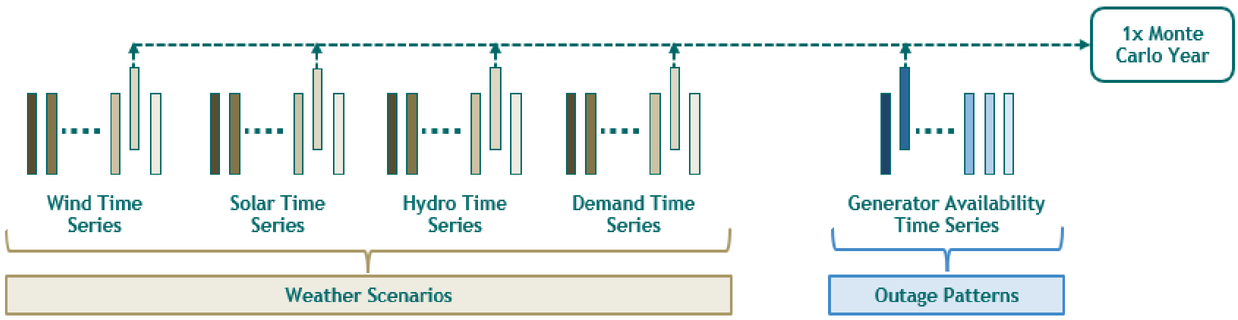


*Figure 6 - Constructing a Monte Carlo year for simulation*

For example, the process above may consider 36 weather scenarios and 30 Outage Patterns for each Study Year, resulting in 1080 Monte Carlo Years for each Study Year. For each of the Monte Carlo Years, the ENS and LOLH are used to produce the LOLE and EENS metrics.

### 5.2.2. Surplus/Deficit (MW) Results

The Surplus/Deficit calculation involves an iterative modelling process after the LOLE results have been calculated. It is computationally resource intensive to calculate the Surplus/Deficit MW requirement based on a large number of weather scenarios, and therefore the MW calculation identifies a subset of weather scenario(s) reflective of the LOLE results. The specific number of Weather scenarios required to reflect the average will be determined through the modelling.

The process for calculating the Surplus/Deficit is:

1. Identify weather scenario(s) representative of the LOLE results.
    a. Representative weather scenarios are identified by finding the subset of weather scenarios whose average for a given metric is minimally distant from the average of all 36 weather

scenarios. For example, given a weather scenario subset size of 3 weather scenarios and a metric of LOLE: First, the average LOLE for all 36 weather scenarios is calculated. Second, the average LOLE for all possible combinations of 3 weather scenarios is calculated (36 choose 3 = 7140 subsets). Third, the Euclidean distance is calculated between each subset and the 36 weather scenario LOLE. Finally, the subset with minimal distance is selected as the subset of representative weather scenarios.

2. For each weather scenario, if the LOLE is:
    a. Greater than the specified LOLE Standard – add perfect plant in increments of 100 MW until the LOLE is lower than the specified standard.
    b. Lower than the specified LOLE Standard – add perfect demand in increments of 100 MW until the LOLE is greater than the specified standard.
3. The incremental process above will derive 2 perfect plant values (100 MW apart) that return LOLE values either side of the LOLE Standard. The Surplus/Deficit at the LOLE Standard is calculated through interpolating between the 2 values of perfect plant/demand.
4. If multiple weather scenario(s) have been used, an average of the interpolated perfect plant/demand values for each weather scenario is taken.

To illustrate the process above, an example is provided below for a system with a 6-hour LOLE Standard.

- ***Step 1 –*** The average LOLE of 36 Weather scenarios for Study Year 2026 is 10 hours. Weather scenario X is selected as representative of the 36 weather scenario average, also with 10 hours LOLE in 2025 and therefore has been selected for Surplus/Deficit MW calculation.
- ***Step 2 –*** The initial LOLE of weather scenario X is greater than the 6-hour LOLE Standard, so perfect plant has been added in 100 MW increments until the LOLE is lower than the specified standard.

| Model Run | LOLE |
|---|---|
| 36 Weather scenario Average | 10 |
| Weather scenario X | 10 |
| Perfect Plant 100 MW | 9 |
| Perfect Plant 200 MW | 7.5 |
| Perfect Plant 300 MW | 5 |

*Table 9 - Surplus/Deficit Calculation Example LOLE Results*

- ***Step 3 -*** The LOLE is below standard with 300 MW of perfect plant, so the 2 values of perfect plant either side of the standard are interpolated the find the MW perfect plant required to achieve the 6-hour LOLE Standard using the following equation.

$$Perfect\ Plant = Y_1 + \frac{(Y_2 - Y_1)}{(X_2 - X_1)} * (X - X_1)$$

| Parameter Type | Parameter | Value |
|---|---|---|
| Input | $Y_1$ | 200 |
| Input | $Y_2$ | 300 |
| Input | $X_1$ | 5 |
| Input | $X_2$ | 7.5 |
| Input | $X$ | 6 |
| Output | $Perfect\ Plant$ | 240 |

*Table 10 - Surplus/Deficit Calculation Interpolation Results*

An example of the overall process outlined above for calculating LOLE, EENS and the Surplus/Deficit is illustrated in Figure 7 below for a single Study Year, where:

- 36 Weather scenarios and 30 Outage Patterns are simulated for LOLE and EENS.
- 1 Weather scenario and 30 Outage Patterns are simulated for calculating Capacity Surplus / Deficit.

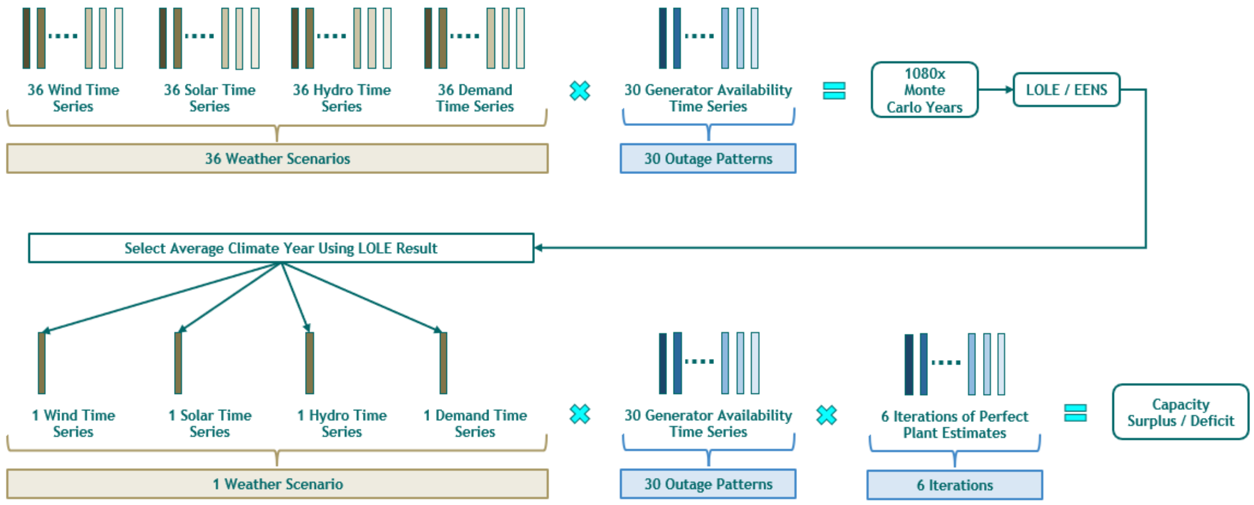


*Figure 7 – LOLE, EENS and Surplus/Deficit Metric Calculation Process*

## 5.3. Maintenance Profiles

**This methodology will include a probabilistic assessment when planned outages are most likely to occur when considering historical outages and forecast outage plans.**

A three-step process will be used to produce and verify maintenance profiles as shown in Figure 8 and further described below.

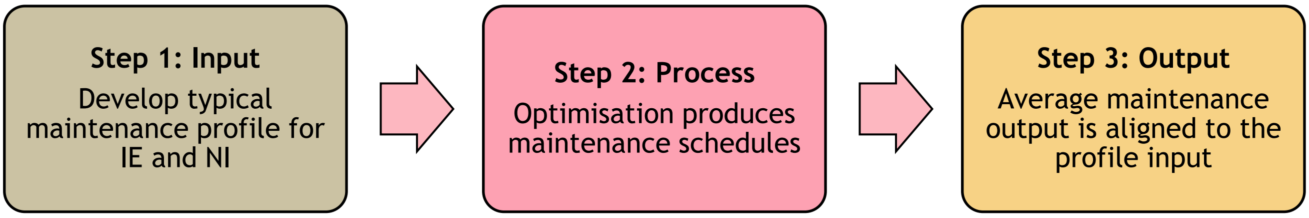


*Figure 8 – Maintenance Scheduling Process*

Step 1 of the process involves observed historic scheduled outage patterns, to construct a representative maintenance profile.

Step 2 of the process involves generating multiple maintenance schedules creating a distribution of possible maintenance events.

Step 3 of the process validates that the average of the maintenance schedules generated in Step 2, is aligned with the representative input profile generated in Step 1.

Following Step 3 the profiles are ready to be used for the adequacy analysis as described in section 5.1.2.

This process approach aims to account for the possible distributions of maintenance events occurring from time to time, whilst overall representing the typical scheduled outage patterns observed in Ireland and Northern Ireland. Producing different maintenance patterns across a range of samples captures the risk of correlated maintenance events and planned outages occurring outside of the typical maintenance window reducing availability of capacity to support security of supply.

FR and GB actual maintenance schedules will be developed based on the capacity reserve margin in each region considering firm resources only i.e. not considering interconnection support, variable generation, or storage. Where available, the maintenance schedules from the ERAA modelling outputs may be assessed in validating the maintenance schedules produced using this methodology.

## 5.4. Forced Outage Profiles

**This methodology will include a probabilistic assessment on unit availability accounting for forced unavailability of resources using randomly generated forced outage patterns.**

Forced outages are included in this methodology as part of the probabilistic assessment of resource availability. Section 4 includes information related to the outage statistics which are inputs to the Monte Carlo optimisation. A forced outage profile is produced for each individual unit that has a forced outage rate applied to it. The forced outage profiles for units are produced independently of other resource availability and system conditions. Through generating a large number of random forced outage profiles, the risk to system adequacy of simultaneous outages at various times during the year can be captured i.e. the uncertainty associated with forced plant unavailability.

When a unit is forced offline, the time before it becomes available for dispatch again can vary significantly from hours to days and in some cases months at a time. This methodology will use an average repair time.

## 5.5. Economic Dispatch

**This methodology will include unit commitment economic dispatch model to reflect operational and economic dispatch of units on the system.**

This methodology will implement economic dispatch to simulate the electricity market, whereby the solver will optimise to reduce the overall system costs across the study horizon. This includes making unit commitment decisions for modelled regions at the resolution of the study horizon. This methodology will make simplifications for some parameters relating to economic dispatch for units, within the interest of improving process efficiency and reducing computational complexity.

The cost associated with conventional generation considers the following marginal cost:

$$SRMC = VO\&M\ Cost + \frac{Fuel\ Price\ \times 3.6}{Unit\ Efficiency} + \frac{CO_2\ Intensity\ \times 3.6}{Unit\ Efficiency} \times CO_2\ Price$$

Where:

- Short-Run Marginal Cost (SRMC) (€/MWh) is the marginal cost of producing the next MW of generation.
- Fuel Price (€/MWh) is specific to each type of fuel, and the fuel types considered in this methodology include Nuclear, Coal, Gas and Oil (differentiated between heavy oil and light oil). Where 1 MWh is equal to 3.6 GJ.
- Unit Efficiency (%) will be based on the standard efficiency of the technology group in Net Calorific Value (NCV) terms.
- $CO_2$ Intensity ($tCO_2$/GJ) will be specific to the fuel type and reflect the technology being utilised e.g. gas with CCS will have a lower intensity than gas alone.
- $CO_2$ Price (€/$tCO_2$) is specific to the price associated with carbon emissions.
- VO&M (€/MWh) is a component used to reflect the operations and maintenance costs resulting from the unit generating power.

Renewable energy sources including variable renewable generation and hydro units are assumed to have 0 SRMC and therefore will utilise renewables before dispatching thermal generation. Within the economic dispatch, battery storage units are free to optimise within the bounds of the optimisation. Hydro and Pumped Storage are free to optimise, however are in some cases subject to constraints such as weekly reservoir limits and annual targets. As such, storage units typically optimise to charge / pump / minimise output during periods of low energy prices and discharge / generate / maximise output during periods of high energy prices. Overall this has a net impact of placing downwards pressure on system costs as storage can displace the need to bring on more costly generation whilst maximising net revenue for the storage assets. Conventional generation will supply the remaining net demand once renewable and storage resources have been optimised.

Unserved energy is priced at the Value of Lost Load (VoLL) in the model, which is effectively set such that the economic optimisation will only result in there being energy unserved as a last possible option (whilst adhering to hard constraints in the model).

The economic dispatch consists of two stages. The first stage will optimise constraints which are applied outside of the short-term horizon resolution. For example annual run hour limits, storage energy limits and annual hydro constraints and targets which are required to be optimised on an annual basis rather than over a day(s). This first stage will consist of grouping a number of periods into a number of blocks, over which the medium-term constraints can be optimised in a more computationally efficient way. The output from this first stage is a decomposition of the medium-term constraints into constraints which can be realised in the short-term optimisation i.e. a set of daily constraints or targets which are typically applied as soft constraints within the short-term optimisation.

The second stage of the economic dispatch optimisation looks at a more granular level such as a daily or multi day basis and produces a least cost optimised unit commitment schedule adhering to constraints active in the timeframe and constraints passed down from the first stage as mentioned above. The output from this stage is an hourly dispatch of units. This methodology will assess the full chronology for each Monte Carlo sample i.e. at the specified resolution instead of selecting representative weeks to model which could reduce computational time.

## 5.6. Monte Carlo Convergence

**This methodology will assess optimisation solutions to evaluate convergence of the solution in accordance with the approved ERAA methodology approach.**

The Monte Carlo samples will be assessed in terms of solution convergence for a given Study year and scenario. As stipulated in Article 4 (2) (e) of the ERAA methodology[9], the coefficient of variation will be assessed using the following equation:

$$a_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

Where $EENS_N$ is the expectation estimate of ENS over the number of Monte Carlo simulations i.e. $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}$, $i = 1 \dots N$ and $Var[EENS_N]$ is the variance of the expectation estimate, $Var[EENS_N] = \frac{Var[ENS_N]}{N}$.

As N increases, the incremental coefficient of variation $a_N$ is compared against a specified threshold θ as per the following:

$$\frac{|a_N - a_{N-1}|}{a_{N-1}} < \theta$$

Where the solution is considered to have converged when further incrementing N will not improve the accuracy of the simulation and as such no further increments are required.

Setting the threshold θ will consider the computational time associated with increasing number of Monte Carlo simulations as part of the convergence assessment, and sensitivity analysis may seek to implement a different value for θ where the benefit of providing insights outweighs the need for accuracy.

Figure 9 shows the impact of increasing samples on the coefficient of variation and relative change of coefficient.

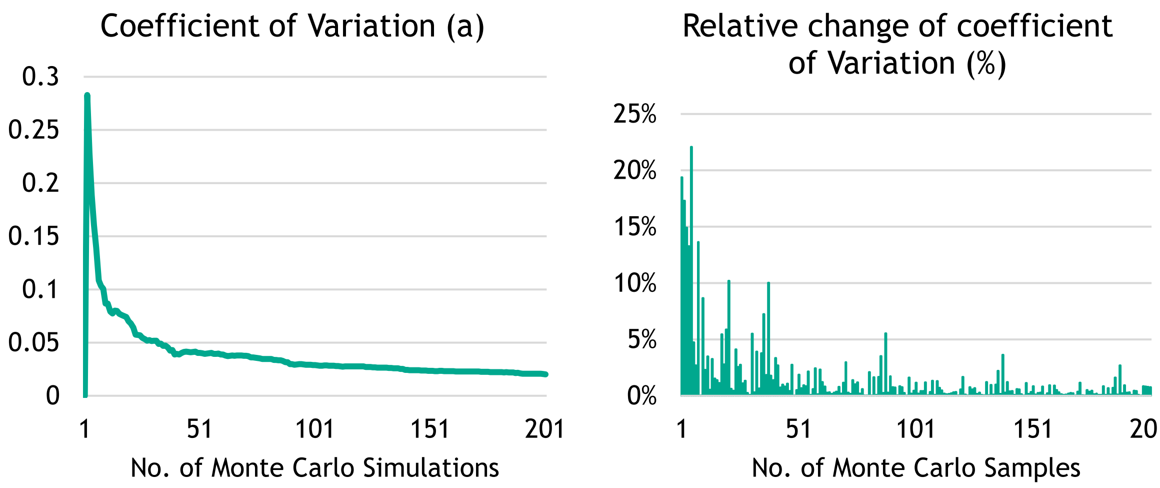


*Figure 9 - Convergence variation with increasing samples*

## 5.7. Operational Requirements

In the context of the SEM, to operate the power system in a safe, secure and reliable manner, a range of operational requirements are put in place as referred to in the Operational Security Standards[10] and

[9] https://www.acer.europa.eu/Individual%20Decisions_annex/ACER%20Decision%2024-2020%20on%20ERAA%20-%20Annex%20I_1.pdf
[10] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_Operating-Security-Standards_2021.pdf

Transmission System Security and Planning Standards[11] (TSSPS). Operational requirements include but are not limited to:

1. Reserves
2. Ramping
3. Network Constraints
4. Dynamic Stability

Furthermore, some of the above constraints are applied on a jurisdictional basis (specific to Ireland or Northern Ireland) and some constraints are relevant on an All-Island basis.

Consideration has been given to each of the above areas and the impact each could have on operating an adequate system and therefore the relevance to be included under this methodology. Securing the power system of the future is not just limited to the supply of energy, but a range of services and policies will be required. Many of these have been highlighted in EirGrid and SONI's Shaping Our Electricity Future Roadmap[12]. The evolution of EirGrid and SONI's operational policy roadmap[13] will also be considered on an ongoing basis.

### 5.7.1. Reserves

**This methodology will consider the provision of operational reserves and replacement reserves in accordance with the latest operational policy and relevant Grid Code requirements.**

Reserves are required to balance the frequency across the power system. Reserves are specified across various timeframes depending on the service required to contain, restore, and maintain system frequency.

The dimensioning of reserves capacity requirements for reliable system operation is consistent with:

- Transmission System Security and Planning Standards (TSSPS[14]).
- Operating Security Standards (OSS[15]).
- Commission Regulation (EU) 2017/1485[16] establishing a guideline on electricity transmission system operation (System Operation Guideline – SOGL).
- Operational Policy Roadmap[17].

Reserves are classified as per the following:

- Frequency Containment Reserves (FCR) – refers to the reserves available within the seconds following a trip which can act to contain the system frequency and mitigate against the potential magnitude of the under-frequency event.
- Frequency Restoration Reserves (FRR) – refers to the reserves available within the minutes following the trip which can act to restore the frequency to nominal levels.
- Replacement Reserves (RR) – refers to the additional reserves available to support the level of FRR and prepare for any additional disturbances.

The FCR and FRR act within seconds to minutes following a frequency event, which is a significantly shorter timeframe than the hourly granularity implemented in this methodology for the reliability assessments. This methodology will account for the provision of FCR and FRR through excluding capacity from the portfolio input to the economic dispatch.

[11] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Transmission-System-Security-and-Planning-Standards-TSSPS-Final-May-2016-APPROVED.pdf
[12] https://www.eirgridgroup.com/site-files/library/EirGrid/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf
[13] https://www.eirgridgroup.com/site-files/library/EirGrid/Operational-Policy-Roadmap-2023-to-2030.pdf
[14] EirGrid-Transmission-System-Security-and-Planning-Standards-TSSPS-Final-May-2016-APPROVED.pdf
[15] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid_Operating-Security-Standards_2021.pdf
[16] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32017R1485
[17] https://cms.eirgrid.ie/sites/default/files/publications/Operational-Policy-Roadmap-2023-to-2030.pdf

The RR are required for up to 4 hours, which is multiples of the hourly granularity implemented in this methodology. This methodology will account for RR through including a reserve provision in the model that will be economically optimised in each hour of the economic dispatch.

The provision for FCR, FRR and RR as described above is consistent with Article 4 (6) (g) of the ACER approved ERAA methodology. Additionally, to maintain consistency with the ERAA methodology, the requirements for the provision of each reserve type will be specified for each Study Year, therefore implementing a static requirement in each hour of the economic dispatch.

### 5.7.2. Network Constraints

**This methodology will make provision for an adjustment to account for the impact of transmission outage restrictions and short circuit management.**

In both Ireland and Northern Ireland there are conditions in which parts of the network may be stressed due to thermal, voltage or short circuit limitations. For the purpose of adequacy studies, this methodology will use a simplified approach to account for the impact of network constraints, transfer limits and transmission outage planning. Acknowledging the network is not modelled as part of this assessment, this methodology will account for network constraints.

- Transmission outage planning is handled through a post modelling adjustment.
- Short circuit limitations which have the potential to impact adequacy are managed in Plexos by applying constraints that limit the output of affected generators.

### 5.7.3. Ramping

**This methodology iteration will not explicitly model ramping constraints or requirements.**

Ramping requirements are driven by the need to account for uncertainty in renewable forecasts. For example, if renewable generation ramps down earlier than expected generation from alternative resources is required to ramp up in a shorter timeframe. Moving to a system increasingly dependent on variable renewable resources means managing the possible impact of forecast errors becomes increasingly challenging as the impact of forecast uncertainty increases.

The model implemented for this methodology has perfect foresight of renewable availability and does not explicitly capture the possible impacts of forecast uncertainty.

### 5.7.4. Dynamic Stability

**This methodology iteration will not include dynamic stability constraints.**

System Non-Synchronous Penetration (SNSP) was introduced to manage the facilitation of non-synchronous technologies onto the Irish power system such as variable renewable generation and interconnector imports. The SNSP limit tends to come into effect during periods of high renewable generation, and therefore modelling the SNSP constraint does not impact adequacy assessments. Other real-world constraints such as minimum number of conventional units online, inertia and RoCoF constraints also do not impact on adequacy. On this basis, dynamic constraints are not included in this methodology.

## 5.8. Out of Market Adequacy Measures

**This methodology will consider out of market measures contribution to system adequacy as a post processing step outside of the central adequacy analysis.**

The central adequacy scenarios will reflect in-market options only however, approved out of market measures will be considered as part of a post-processing step. This post processing step will assess relevant Monte Carlo samples to assess possible reductions in ENS and corresponding possible reductions in LOLE i.e. where ENS in a sample can be removed in an hour this will result in a decrease in LOLE.

# 6. Appendix 1: Economic Viability Assessment

An Economic Viability Assessment (EVA) is used to assess the economic decisions about entry and exit of units in the electricity market. EU Regulation 2019/943 on the internal market for electricity sets out in Article 23 and Article 24 that the methodology for adequacy assessments shall include an economic assessment of the likelihood of retirement, mothballing, and new-build of generation assets in their central reference scenarios.

This methodology implementation is the first year of introducing an EVA and the process is expected to evolve over future iterations of the AIRAA.

It is important to note the EVA is not a forecast of market outcomes or investor decisions, and therefore the process outputs should be interpreted with caution. Furthermore, this process is a standalone piece of analysis looking at specific scenarios and has no influence or implications with respect to the SEM capacity auction processes. It is acknowledged the factors included in this EVA represent a simplification, and do not capture the range of uncertainties which would be assessed by prospective market entrants.

## 6.1. Optimisation Methodology

The methodology for the revenue-based EVA process is shown below in Figure 10. The process broadly follows the description below with more detail on each step described in the subsequent sections:

1. The starting scenario of the EVA is an adequacy assessment adjusted to approximate the day-ahead market.
2. An economic dispatch of the scenario is modelled for all study years.
3. The generation and economic outputs of the simulation are processed against relevant unit costs to assess the economic viability of units through a calculation of the internal rate of return (IRR) for all units.
4. The capacity portfolio is adjusted based on the economic viability subject to relevant capacity build constraints.
5. The process iterates until convergence is reached such that all remaining units reach their most economically viable status.
6. Once convergence is reached, this is the final post-EVA portfolio.

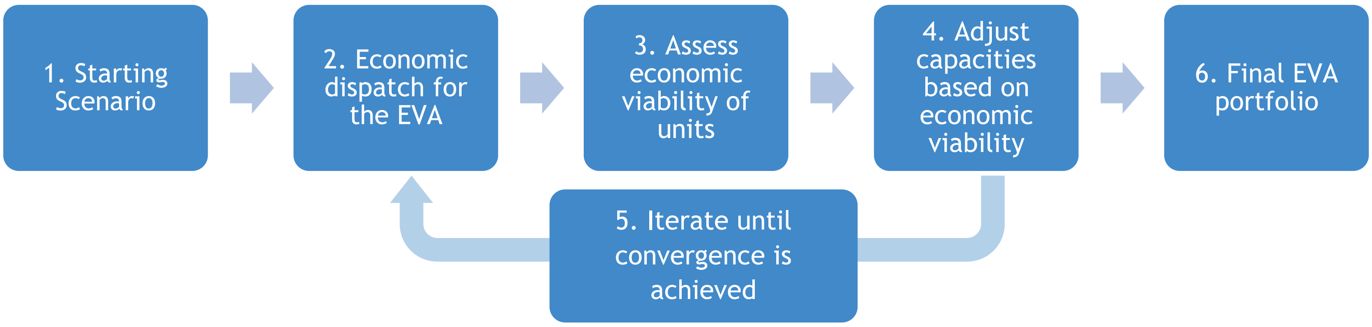


*Figure 10 - Revenue-based EVA process*

## 6.2. Starting Scenario

The initial setup for the EVA includes the median demand and generation forecasts. The objective of the EVA is to approximate the day-ahead market (DAM) revenues for the SEM (with operational and network constraints excluded from the EVA). To better reflect the SEM DAM, the following adjustments are made for the EVA compared to the standard adequacy runs:

1. Reserves are removed from the modelling so as not to affect day ahead clearing price.
2. No restrictions on the North-South tie line (which means the flows between Ireland and Northern Ireland are fully unconstrained).

### 6.2.1. Weather scenarios

A subset of weather scenarios is modelled to reduce the computational burden of the analysis. Weather scenario selection is performed in a similar manner to that used in the adequacy modelling methodology described in Section 5.2.2 to ensure the subset of weather scenarios is representative of the full climatic variability.

## 6.3. Economic dispatch for the EVA

The modelling configuration of the economic dispatch for the EVA is consistent with the process described in the adequacy modelling section. The economic dispatch seeks to represent the day-ahead market revenues for resources and therefore excludes balancing constraints such as must run requirements, inertia constraints and System Non-Synchronous Penetration (SNSP).

### 6.3.1. Price cap

The specified value for a price cap is a key consideration required for the economic dispatch for the EVA and can dramatically influence the electricity market revenues of units and is therefore a very sensitive input.

This methodology implements the price caps from the ERAA 2024 modelling as a baseline assumption. The price caps from ERAA 2024 are based on ACER's decision 2023/01[18]. According to ACER, if the clearing price exceeds 70% of the maximum clearing price for the day-ahead during at least two days in a 30-day rolling period, then the maximum clearing price will be increased by 500 €/MWh the next day.

In modelling terms it is technically challenging to model dynamic price caps according to ACER's decision 2023/01. ERAA 2024 took an approach of building a broad set of weather scenarios and forced outage patterns for each study year and then analysed hourly prices applying ACER's rules for price caps. The result is a mean price cap value for each year of the study horizon which will be used for the purpose of this methodology.

Other price caps may be implemented in additional EVA scenarios.

### 6.3.2. Uplift

An uplift above the short run marginal cost of the marginal generator is included which would reflect generator's bidding behaviour above that of the short run marginal cost during periods of scarcity.

### 6.3.3. Outages

A range of outage patterns is simulated, using the same forced and maintenance scheduling outage simulation process as is implemented for the adequacy modelling. This means that for each weather scenario, a range of plant availability conditions is simulated.

## 6.4. Assess economic viability of units

The economic viability is computed using the methodology described below for all units.

[18] https://eepublicdownloads.entsoe.eu/clean-documents/nc-tasks/ACER%20Decision%2001-2023%20on%20HMMCP%20SDAC%20-%20Annex%201.pdf

### 6.4.1. Economic Viability

The economic viability of a unit is determined using the average cashflows across all modelled weather scenarios for the entire lifetime of the unit (where the revenue for each weather scenario is the average of the different outage patterns simulated as discussed in the section above) to calculate net present value (NPV). A unit is considered to be economically viable if the unit's net present value is positive, i.e. the net present value of the revenues is greater than the net present value of the costs[19].

The cashflow $C_t$ in year $t$ is defined as the sum of all costs (negative value) and revenues (positive values) for that year. The costs include capex, fixed costs, and other costs if applicable. The revenues include the ancillary service revenue assumptions and the modelled inframarginal rent which is defined as the difference between the modelled clearing price and the variable cost of the unit across all modelled hours and weather scenarios in the economic dispatch.

The equation below shows how the net present value (NPV) is calculated. The NPV is the sum of the cashflows $C$ over the economic lifetime $T$ discounted by the hurdle rate. If the economic lifetime of an EVA resource extends beyond the last year of the modelling horizon, then the cashflow will be assumed to remain constant using the last modelled year's values.

$$NPV = \sum_{t=0}^{T} \frac{C_t}{(1 + Hurdle\ Rate)^t}$$

The hurdle rate is defined as the weighted average cost of capital (WACC) plus a hurdle rate premium. The WACC is a jurisdiction-wide assumption, whereas the hurdle rate premium varies based on technology class depending on the associated risk of a technology class, for example the uncertainty of revenue distribution. The assumptions for the WACC and hurdle premium are defined in the inputs and assumptions document.

During this stage, Annual Run Hour Limited units are monitored to ensure compliance with their limit.

### 6.4.2. Resource scope

There are two types of units considered in the EVA: existing units and new units.

- Existing units are resources which are in the initial pre-EVA portfolio, these are only assessed once their capacity market contract ends (see section 6.4.3).
- New units are resources which are not in the initial pre-EVA portfolio but could be included if assessed to be economically viable.

According to Article 23(5)(b) of EU Regulation 2019/943, the EVA shall assess the likelihood of retirement, mothballing, and new-build of units. The methodology considers the units and decision variables according to **Error! Reference source not found.** below.

| Technologies | Decommissioning | Commissioning | Life Extension | Mothballing |
|---|---|---|---|---|
| **Gas (OCGT/CCGT)** | ✓ | ✓ | ✓ | ✓ |
| **Oil** | ✓ | ✓ | ✓ | ✓ |
| **Battery** | | ✓ | | |

*Table 11 - EVA resources and decision variables*

Note, as renewable generation is assumed to be driven by policy, these are not considered within the scope of the EVA.

[19] With the net present value being discounted by the unit's hurdle rate.

### 6.4.3. Capacity market

When considering the economic viability of existing resources, all existing capacity market contracts up to and including the latest auction at the time of the data freeze date are excluded from the EVA. If an existing resource is without a capacity market contract it is included in the EVA. This methodology is consistent with the ERAA 2024 methodology which assumes no future capacity market auctions in the central reference scenario. This means that resources that have already secured capacity market contracts would only be assessed from the year after their contract ends. The methodology does not simulate potential future capacity auctions.

For simplification in the modelling optimisation, units with a capacity market contract finishing at the end of the capacity year would assume to have the contract until the end of the calendar year, therefore would be assessed from January on the year after their contract ends.

### 6.4.4. Geographical Scope

The scope of modelling includes an economic dispatch of Great Britain, France and the SEM however the methodology does not assess the viability of resources of Great Britain and France. This is assumed appropriate for the purpose of examining economic viability of resources in the SEM. Both Great Britain and France have capacity markets, so it is assumed that these capacity markets achieve the target reliability standard in each region.

## 6.5. Adjust capacities based on economic viability

For each modelled year, the EVA adjusts the capacity based on their economic viability with units being moved into their most economically viable status. The most economically viable status is defined as the status which has the highest NPV. The EVA has three potential statuses:

1. Online – Retained in the portfolio
2. Offline – Removed from portfolio
3. Mothballed – Offline for a number of years then returning to Online

The net present value for all units, for all modelled years, for all statuses is calculated. For each unit the status is changed so that each unit is in its most economically viable status. The changes are made first for the units which are the most economically unviable or the most economically viable.

For example, if the net present value of the unit is most economically viable when the unit is mothballed for 2 years rather than online or offline, the unit is mothballed for 2 years. If for another unit the net present value of its current status of online is negative and the status for mothballing is also negative then the unit will be made offline at this will be the most economically viable status since this net present value will be zero.

## 6.6. Iterate until convergence is achieved

The process of changing the capacities based on the economic viability will be repeated until convergence is reached. Convergence is achieved when all units are in the most economically viable status i.e. they are in the most optimal status (online, offline, or mothballed). This means there are no units online that are not economically viable and vice versa.

Figure 11 below shows a flow chart for the EVA process of iterating based on the units' economic viability.

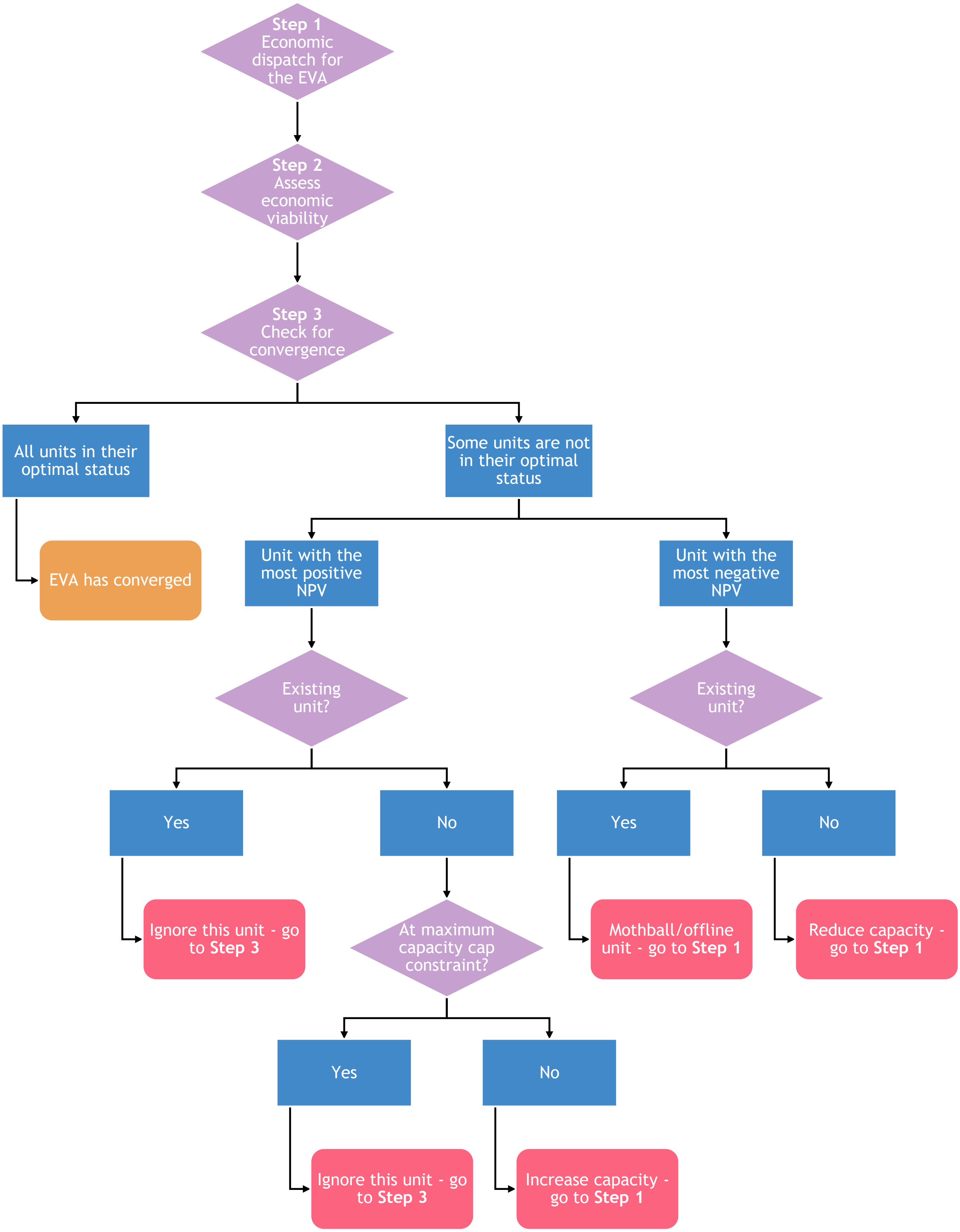


*Figure 11 - Flowchart representation of the iterative process*

## 6.7. Final EVA portfolio

Once convergence has been reached a post-EVA portfolio has been found, the capacity changes resulting from the EVA are provided in terms of +/- MW change for each technology type. Note the results will be for a given technology class, and not on a unit level basis, this is reflective of the intention of this study which is to assess the outcomes of the SEM rather than isolated units.

# 7. Appendix 2: Glossary

| | |
|---|---|
| **ACER** | The European Union Agency for Cooperation of Energy Regulators |
| **AHC** | Advanced Hybrid Coupling |
| **ATC** | Available Transmission Capacity |
| **BESS** | Battery Energy Storage System |
| **BEV** | Battery Electric Vehicles |
| **CCS** | Carbon Capture & Storage |
| **CHP** | Combined Heat & Power |
| **CO2** | Carbon Dioxide |
| **CONE** | Cost Of New Entry |
| **COP** | Coefficient Of Performance |
| **DFT** | Demand Forecasting Tool |
| **DSU** | Demand Side Units |
| **EENS** | Expected Energy Not Served |
| **ENS** | Energy Not Served |
| **ENTSO-E** | European Network of Transmission System Operators for Electricity |
| **ERAA** | European Resource Adequacy Assessment |
| **EU** | European Union |
| **EV** | Electric Vehicles |
| **EVA** | Economic Viability Assessment |
| **FBMC** | Flow Based Market Coupling |
| **FCR** | Frequency Containment Reserve |
| **FOR** | Forced Outage Rate |
| **FR** | France |
| **FRR** | Frequency Restoration Reserves |
| **GB** | Great Britain |
| **GCS** | Generation Capacity Statement |
| **GJ** | Gigajoules |
| **GW** | Gigawatts |
| **IRR** | Internal Rate of Return |
| **LOLD** | Loss Of Load Duration |
| **LOLE** | Loss Of Load Expectation |
| **LOLP** | Loss Of Load Probability |
| **LSI** | Largest Single Infeed |
| **MW** | Megawatt |
| **NCV** | Net Calorific Value |
| **NTC** | Net Transfer Capacities |
| **P2X** | Power-to-X |
| **PEMMDB** | Pan-European Market Database |
| **PHEV** | Plug-in Hybrid Electric Vehicles |
| **PTDF** | Power Transfer Distribution Factor |
| **PV** | Photovoltaics |
| **RES** | Renewable Energy Sources |
| **ROCOF** | Rate-of-Change-of-Frequency |
| **RR** | Replacement Reserves |
| **SEM** | Single Electricity Market |
| **SNSP** | System Non-Synchronous Penetration |
| **SONI** | System Operator for Northern Ireland |
| **SRMC** | Short-Run Marginal Cost |
| **SY** | Submission Year |
| **TSO** | Transmission System Operator |
| **VO&M** | Variable Operations & Maintenance |
| **VOLL** | Value of Lost Load |
| **WACC** | Weighted Average Cost of Capital |