Operational Policy Roadmap 2022-2023

June 2022

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Background and Context

Introduction

Shaping our Electricity Future

EirGrid and SONI are securely operating the all-island system with world-leading renewables penetration, primarily from wind energy. In 2020, 43% of energy used on the island came from renewable resources.

In 2022, the all-island system can accommodate up to 75% of instantaneous generation from non-synchronous resources (mainly wind and HVDC interconnection).

However, while these achievements are leading the way worldwide, to meet evermore ambitious decarbonisation targets in the years ahead, the electricity system will need to accommodate greater amount of renewable energy. This means that the operational constraints will need to be relaxed to facilitate up to 95% of generation from non-synchronous resources by 2030.

The governments of Ireland and Northern Ireland have recently introduced legislation relating to climate action, with specific targets to achieve net zero for carbon by 2050. Energy and electricity usage will be core elements of the climate action legislation and implementation plans. In 2021 EirGrid and SONI delivered the Shaping Our Electricity Future roadmap – to allow EirGrid and SONI to enhance their capability in markets, networks and operations. One of the key commitments in the Shaping Our Electricity Future roadmap was to develop an Operational Policy Roadmap. This roadmap outlines the key actions in the operational policy space that will be required to deliver on the climate action targets while continuing to securely operate the electricity system.

How We Get There

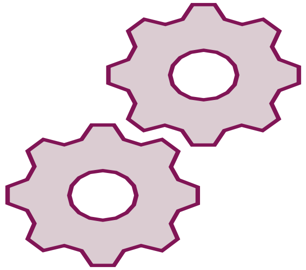
The roadmap is structured in two phases:

- **The first phase to the end of 2023, which is the scope of this document.**
- The second phase covers the period from 2024 to 2030, which will be delivered by the end of 2022.

The system will undergo radical transformation between 2022 and 2030, including the connection of two new HVDC interconnectors (to Great Britain and France), large offshore wind farms and solar generation connections, hydrogen energy production, demand response and energy storage innovations, coupling to European markets and anticipated market evolvement, major growth in demand driven by electrification of society and large electricity users. The roadmaps will aim to plan a pathway for the evolution of operational policy to facilitate these radical transformations while maintaining and enhancing security of supply, reliability and resiliency for customers on the island of Ireland.

Operational Policy Framework

EirGrid and SONI operational policies are grouped into five key operational focus areas: Dynamic Stability, Frequency, Voltage, Thermal, and Short Circuit. These areas are aligned with the EirGrid and SONI *Operating Security Standards.* System operation with high renewable penetration is more complex, with greater inter-dependency between the systems' parameters and metrics, making it difficult to clearly separate the policy areas into distinct entities. However, this aggregation into focus areas allows the information and roadmap actions to be grouped for further detailed analysis and action planning.

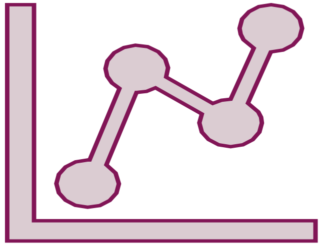


Dynamic Stability

- Minimum Number of Conventional Generation Units
- System Non-Synchronous Penetration
- Inertia
- Rate of Change of Frequency

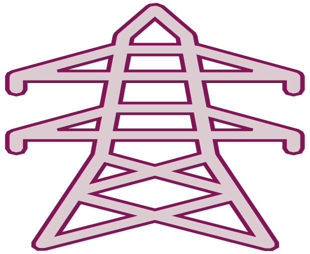
Frequency

- Positive Reserves
- Negative Reserves
- Frequency Regulation
- Ramping Margin
- Interconnector Ramping Rate



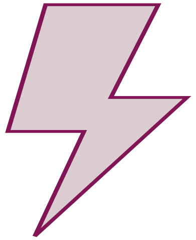
Voltage

- Steady state voltage management
- Post contingency voltage management
- Voltage stability



Thermal

- Steady state thermal loading on transmission plant
- Post contingency thermal loading on transmission plant



Short Circuit

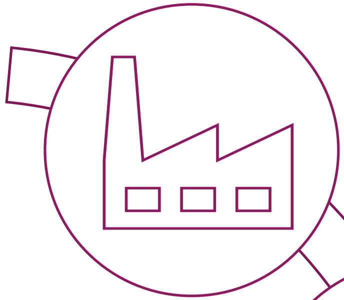
- Short circuit level
- Fault ride through capability
- Protection operation
- Weak and strong grids

Current Operational Policy Framework Definitions and Requirements

Policy	Operational Policy Constraint	Definition	Current Requirements 2022
Dynamic Stability	Rate of Change of Frequency	How fast the frequency moves when subjected to an event that results in a mismatch between generation and demand.	1 Hz/s (under operational trial)
	Minimum Number of Conventional Units	Constraint on the system that specifies a minimum number of conventional thermal units required to be synchronised in Ireland and Northern Ireland.	8 (3 NI/5 IE)
	Inertia Floor	The minimum level of kinetic energy stored in rotating plant operating on the system. Inertia comes from synchronous generation, motor load and transmission assets (synchronous condensers).	23 GWs
	System Non-Synchronous Penetration	A measure of the non-synchronous generation on the system at an instant in time. It is the ratio of the real-time MW contribution from non-synchronous generation and net HVDC imports to demand and net HVDC exports.	75 %
Frequency	Positive Reserves	The quantity of contingency reserve to mitigate low frequency events, such as loss of generation or HVDC import. This is split into defined response tranches across different timescales: FFR/POR/SOR/TOR1/TOR2.	FFR POR SOR TOR1 TOR2 TBD 75 75 100 100 (%LSI)
	Negative Reserves	The quantity of contingency reserve to mitigate high frequency events such as large loss of demand or HVDC export.	50 MW Negative Reserve on Conventional Units in NI
	Regulating Reserve	Reserve carried on synchronous units with +/-15 mHz frequency deadbands that assist in regulating system frequency within the normal operating range (49.8 Hz to 50.2 Hz).	50 MW (NI)/75 MW (IE)
	Ramping Margin	The level of dispatchable generation/demand available to mitigate forecast errors. There are 1, 3 and 8 hour ramping system services.	Explicitly Scheduled
	Interconnector Ramping Rate	The rate of change of HVDC interconnector active power flow. This is an all-island measure and includes the ramp rates for Moyle in NI and EWIC in IE.	10 MW/min across all-island
Voltage	Voltage Management	The ability to securely operate the system by controlling the voltage, within a specified range, pre and post contingency.	Policy & Operating Security Standards
Thermal	Thermal Plant Security Management	The ability to securely operate the system by controlling the pre and post contingency thermal loading within the ratings of the transmission system plant.	Policy & Operating Security Standards
Short Circuit	Short Circuit Plant Security Management	Assessment of equipment duty performed to ensure all plant is within its making, breaking and withstand ratings for the prospective short circuit current calculated.	Policy & Operating Security Standards

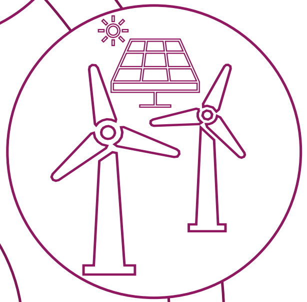
Drivers for Change and Operational Challenges to 2023

Drivers for Change to 2023



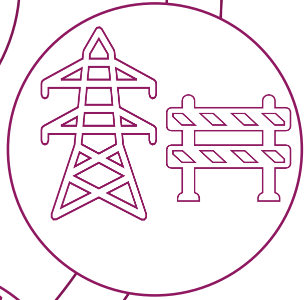
Increased and Flexible Demand

- Anticipated increase in large electricity user demand, particularly in the Dublin region.
- Expected new large battery connections.



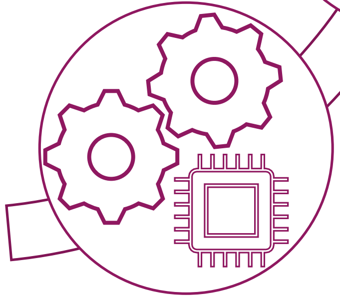
New Generation Connections

- New onshore wind and solar connections connected at transmission and distribution level throughout the island.
- Small-scale generation connections at residential level.



System Constraints

- System constrained during high demand and/or high wind periods. Outages of generation and transmission plant can be challenging to accommodate, wind can be constrained at times during these periods.



New Transmission Grid Technology

- Envisaged connections of new synchronous condensers and STATCOM devices.

Operational Challenges

- **Dynamic Stability**
  - Conventional generation and SNSP constraints act to limit renewable generation during certain periods.
  - Shifting from well-known response and behavior of conventional generation to a system dominated by the IBR customised response.
- **Frequency**
  - Challenges with generation availability, margin and security of supply.
  - Aging fleet of conventional generation (reliability issues, slow ramping).
  - Managing large quantities of batteries for reserve and starting trials for energy use.
  - Capability to respond to fast changes in the output of generation, demand and interconnector transfers.
  - Frequency moving faster and outside the operational ranges more often.
  - Small-scale residential generation impacting demand forecast accuracy, visibility and controllability.
- **Voltage**
  - High voltage around Dublin, limited dynamic support in remote areas with large wind penetration.
  - Small-scale resources further reducing the transmission level demand and exacerbating voltage control challenges.
- **Thermal**
  - Transmission loading constraints on the transmission system in certain areas intensified by transmission outages.
- **Short Circuit**
  - Risk of system strength reducing below what was considered when IBR controls were first set.
  - Risk of converter interaction, oscillations - power system swings, commutation failure/blocking, harmonic distortion levels, voltage unbalance.
  - Higher than anticipated fault levels in some areas, lower than required in other (weaker grid) areas.

Roadmap to 2023

EIRGRID SONI

Key Operational Policy Objectives to the End of 2023

Between 2022 and the end of 2023, EirGrid and SONI will continue to operate the system securely while also aiming to:

1. Reduce the required minimum number of conventional units on the island from **8 to 7.**
2. Reduce the minimum inertia limit on the island from **23 GWs to 20 GWs**.
3. Reduce the negative reserve requirement on conventional units in Northern Ireland from **50 MW to 0 MW.**

Dynamic Stability - Minimum Required Number of Conventional Units

Objective 1

Operate the all-island system securely with a reduced number of large conventional generation units from 8 to 7, to maximise renewables penetration

Why?

- To maintain a safe and secure system operation there's a constraint on the minimum number of units required in service. Large conventional generation units provide:
  - 'system strength' (inertia and fault current contribution),
  - system services (frequency and voltage regulation, restoration capability)
  - assist maintaining the system's power quality within limits (acting as a sink for harmonic distortion and limiting voltage unbalance).
- Securely reducing the minimum number of conventional thermal units should allow more renewable energy to be used on the system as the energy from these units may be replaced by curtailed energy from renewables.

What?

- In 2022 there is a standing market constraint to have a minimum of 8 large conventional units synchronised. This requirement is split regionally to 5 units in Ireland and 3 in Northern Ireland. The market allocates which of the large conventional generation units are running, based on cost optimisation (currently most of these units are fossil fuel-fired).
- The 'must-run' conventional units and the minimum inertia limits are intertwined, since the large generators are providing the bulk of the current system inertia. The assessment for changing both these limits is going to be coordinated.
- The constraint is entered in the market and usually becomes active during periods of low demand and/or high renewable generation.
- It is envisaged that changing the constraint could introduce system operation challenges (voltage and frequency control, fault ride-through, generation stability).

How?

- As part of the Operation Policy Review Committee (OPRC) process, studies will be carried out to analyse and understand implications of reducing the requirement from 8 to 7. These studies will examine a range of operational scenarios, conditions and contingencies.
- The simulation studies will anticipate the impact on overall system operation (stability, frequency and voltage control, generation margin etc) and assess the risk - using a variety of measurable parameters.
- A well-defined operational trial is anticipated to commence following the studies (indicatively January 2023), during which the parameters will be monitored, and disturbance events studied in detail.

Dynamic Stability - Minimum Inertia Limit

Objective 2

Operate the system securely, maximising renewable generation, with the requirement for a minimum inertia level reducing from 23 GWs to 20 GWs on the island of Ireland.

Why?

- Large conventional generation units provide inertia which is critical for the existing frequency control process. Inverter-based resources (IBR) like wind/solar/storage/HVDC do not inherently provide inertia. IBR can provide fast frequency response and if specially designed and configured can provide inertia (grid forming algorithms with energy storage).
- Certain type of demand, like motor loads also contribute to inertia, although in Ireland this is not significant due to limited heavy industry.
- The minimum inertia level is an all-island constraint (no current jurisdictional split) and is monitored in real time.
- Reducing the minimum inertia requirement should result in a reduction of the minimum number of conventional thermal units on the system which should allow more renewable energy to be used on the system as the energy from these units may be replaced by curtailed energy from renewables.

What?

- The ‘must-run’ conventional units and the minimum inertia limits are intertwined, since the large generators are providing the bulk of the system inertia. The assessment for changing both these limits is going to be coordinated.
- The constraint is entered in the market and usually becomes active during periods of low demand and/or high renewable generation, requiring units to be constrained ‘on’ when they may not otherwise have been.
- Inertia can be provided by other transmission connected resources such as synchronous compensators or IBR with additional energy buffer. There are plans to connect some SCs in the years ahead. This will be independent of the operational trial.

How?

- As part of the OPRC process, studies will be carried out to analyse and understand implications on reducing the inertia floor requirement to 20 GWs. These studies will examine a range of operational scenarios, conditions and contingencies to determine secure operating modes.
- The studies will anticipate the impact on overall system operation (stability, frequency and voltage control, generation margin) and assess the risk using a variety of measurable parameters.
- A well-defined operational trial is anticipated to commence following the studies (indicatively January 2023), during which the parameters will be monitored, and disturbance events studied in detail.

Frequency - Negative Reserve

Objective 3

Operate the system securely at all times with a reduced requirement to carry a portion of spinning negative reserve on conventional units in Northern Ireland.

Why?

- To facilitate renewable energy generation, all conventional thermal units regularly run close to their designed minimum operating limits.
- However, in recent years, some spinning negative reserve (on synchronous generation units) has been required to mitigate over frequency events – which may be caused by the unexpected disconnection of large demand or AC or HVDC interconnectors.
- This negative reserve requirement can be dynamic and static, provided by synchronous or asynchronous resources. It is allocated by the market to minimise costs.
- Some conventional units in Northern Ireland currently have allocated fixed negative reserve minimum thresholds for system operation considerations.

What?

- Negative reserve is required to arrest the frequency deviation following loss of demand/HVDC interconnector exporting in order to avoid the unselective disconnection of generation and/or reduction in transfer of importing interconnectors, in response to over-frequency events.
- The 50 MW negative reserve threshold constraint on conventional units in Northern Ireland is entered as a constraint in the scheduling process.
- If this were reduced or removed, the negative reserve could be provided by wind generation.
- Reduction of periods in which required spinning negative reserve in NI is 50 MW.

How?

- Study the system implications of the removal of the synchronous negative reserve limit on the Northern Ireland units.
- Carry out a well-defined operational trial to assess the impact on key performance metrics and assess the response to system disturbances, if the limit is removed.
- Update definitions and reserve criteria to define the frequency reserve service requirements for negative reserves.
- Negative reserve can be carried on non-synchronous generation, but at times when non-synchronous generation output is low, the negative reserve might be instructed on conventional units.
- Test the provision of negative reserve from IBR.

Operational Policy Change Process

The **Operational Policy Review Committee (OPRC)** governs the process of operational policy changes in EirGrid and SONI. The OPRC is formed of members with extensive experience and expert knowledge of system operations. The members will consider the proposed changes, review all related materials, reports and approve or reject the proposed changes based on strict operational criteria.

If the trial period of operation passes without adverse impacts, subject matter experts will study the results of the trial parameters and criteria. An in-depth examination of all events that occurred is carried out and reported on to the OPRC. The conditions and events during the trial are examined to determine if any trial related issues arose. The OPRC reviews the outcome and report and decides whether to either:

1. Cease the trial noting adverse impacts.
2. Continue the trial if there is insufficient evidence. Gather more relevant data points and information to support decisions.
3. Approve the proposed operational policy change as the enduring operational policy.

In the Ongoing Monitoring phase, EirGrid and SONI engineers monitor the system parameters and analyse events and disturbances to assess system performance and generator compliance relative to operational policy parameters and metrics.

During Information Gathering stage the current status of the policy and parameters are assessed and consultation is held with operations specialists on the drivers, requirements and needs for changes.

If the OPRC grant approval, an operational policy trial is commenced with strict operational criteria and parameters to be monitored, including hours of operation.
The trial may be suspended at any time by operations staff if adverse impacts arise during the trial.

At the Analysis/System Studies stage subject matter experts and operations policy specialists study the system under an extensive and detailed range of conditions. They study the impact of the proposed policy change and make recommendations on the conditions of the operational trial.
The OPRC approve or reject the proposed trial, based on the studies and in-depth discussions.

Operational Policy Actions Timeline 2022-2023

Dynamic Stability

- **Rate of Change of Frequency**
  - 2022: Complete operational trial and policy review and update.
  - 2023: Monitor operations events and generator unit compliance.
- **Minimum Number of Conventional Units**
  - 2022: Complete information gathering and studies/analysis.
  - 2023: Begin operational trial in early 2023. Based on the operational trial, review and decide if update to operational policy is required by end of 2023.
- **Inertia Floor**
  - 2022: Complete information gathering and studies/analysis.
  - 2023: Begin operational trial in early 2023. Based on the operational trial, review and decide if update to operational policy is required by end of 2023.
- **System Non-Synchronous Penetration**
  - 2022-2023: No anticipated increase to SNSP to end of 2023. Ongoing monitoring of system parameters and detailed analysis of events and disturbances and market outcomes.

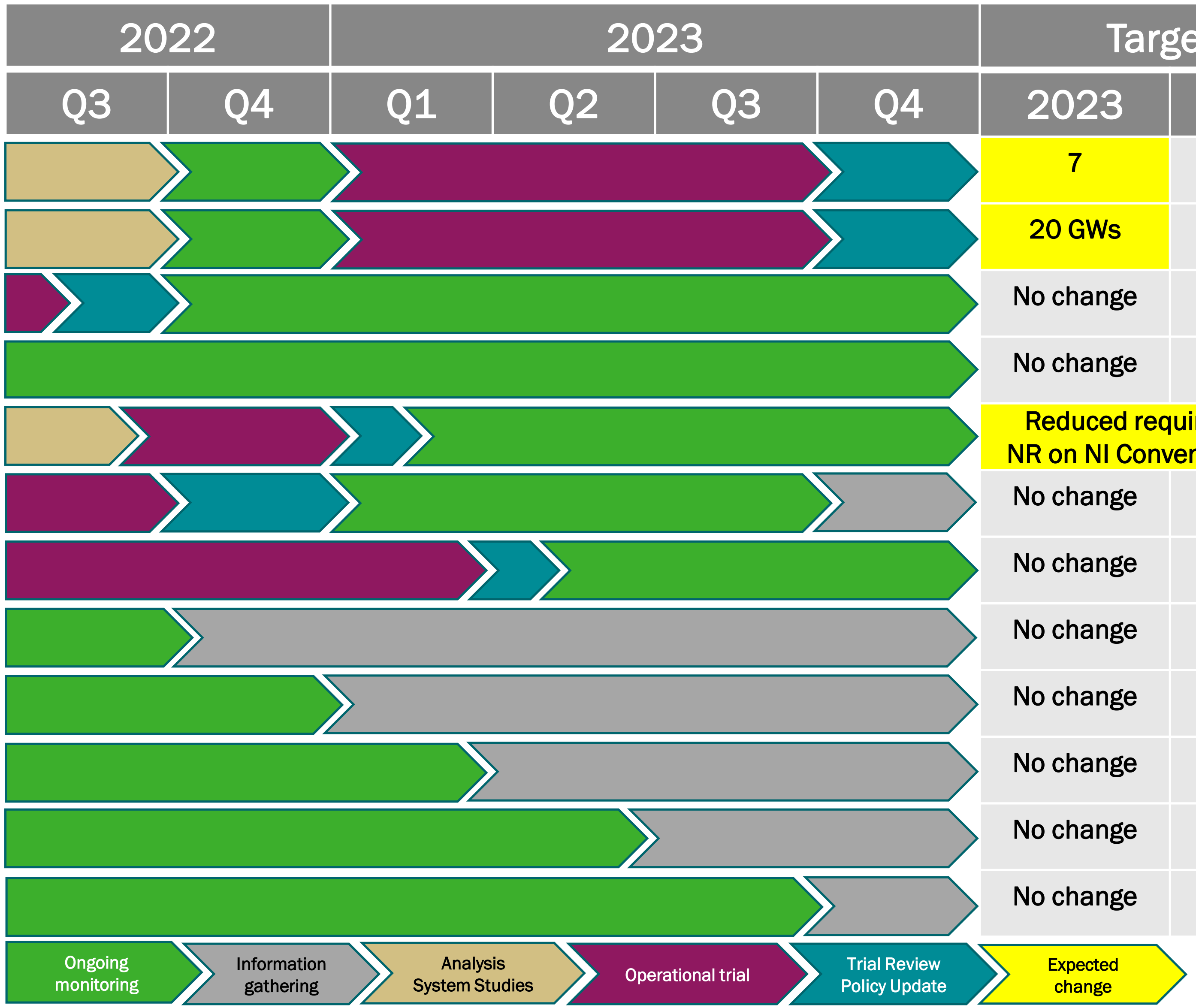
Frequency

- **Positive Reserves**
  - 2022: Trial on battery frequency response modes of operation with possible reserve policy review.
  - 2022: Information gathering to consolidate reserve policies and information. Refine policy on FFR.
  - 2023: Information gathering process for FFR policy development.
- **Negative Reserves**
  - 2022: Begin information gathering and studies/analysis on impact of reducing negative reserve limits on conventional units in NI. Begin operational trial in late 2022.
  - 2023: Based on the operational trial, review and decide if policy update required.
- **Regulating Reserve**
  - 2022: Complete operational trial on minimum synchronous operating reserve requirements.
  - 2023: Based on the operational trial, review and decide if update to operational policy is required in 2023.
- **Ramping Margin**
  - 2022: Review of current ramping margin operational policy.
- **Interconnector Ramping**
  - 2022: Begin early-stage information gathering and assessment on the needs for the interconnector ramping operational policy.

Voltage | Thermal | Short Circuit

- **Voltage Control, Thermal and Short Circuit**
  - 2023: Begin early-stage information gathering and assessment to understand the impact on system operation on voltage control, thermal loading and short circuit levels from relaxing the existing Operational Policy limits on the number of units and inertia.
  - 2022: Implementation of Voltage Trajectory Tool (VTT).
  - Studies and analysis will commence in 2024 and will be documented in the phase 2 operational policy roadmap.

	Operational Policy Constraint	Current Requirements	Targets 2023	Targets 2030
Stability	Minimum Number of Conventional Units	8	7	≤ 4
Stability	Inertia Floor	23 GWs	20 GWs	17,5 GWs
Stability	RoCoF [3]	1 Hz/s	No change	No change
Stability	SNSP	75%	No change	95 %
Frequency	Negative Reserve (NR)	50 MW on Conventional Units in NI	Reduced requirement for NR on NI Conventional Units	
Frequency	Positive Reserve	FFR POR SOR TOR1 TOR2 TBD 75 75 100 100 (%LSI)	No change	TBD
Frequency	Regulating Reserve	50(NI)/75(IE) MW	No change	TBD
Frequency	Ramping Margin	Explicitly Scheduled	No change	TBD
Frequency	Interconnector Ramping	10 MW/min across all-island	No change	TBD
Plant Limits	Voltage Management	Policy and OSS	No change	TBD
Plant Limits	Thermal Management	Policy and OSS	No change	TBD
Plant Limits	Short-circuit Management	Policy and OSS	No change	TBD



Notes on the Roadmap

1. For definitions refer to page 6 of the report and for acronyms refer to page 19.
2. Policy areas that show no activity in Phase 1 will be assessed and worked on in Phase 2 to 2030.
3. The RoCoF operational trial at 1 Hz/s is still underway as per June 2022 and review period will commence in Q3 2022.
4. Where a policy has TBD the limit will be determined in the Phase 2 of the roadmap or during the OPRC process.
5. Where OSS is referenced, please refer to the EirGrid and SONI Operating Security Standards document for the requirements.
6. This roadmap provides EirGrid and SONI's current view of the scope and timelines for trials of new or updated operational policy. Actual trials may follow different timelines and/or change scope, and new trials may be added as we review priorities and progress through the period.

It is important to note that:

- Operational trials may not proceed as planned if potential system security violations are flagged in the pre-trial study and analysis phase.

- Mitigating actions to manage security of supply issues (for example; capacity adequacy and transmission outage issues), such as the requirement to implement 'must run' constraints, may significantly curtail operational trial objectives (such as reducing the minimum number of units) or make the achievement of the trial conditions infeasible.

Stakeholder Impact

- **Conventional Generators**
  - Some conventional generator units may be run less frequently during periods of high renewable generation and/or low demand during the operational trials, and if the policy update is approved post 2023.
  - Units in Northern Ireland which had not been operating at minimum generation may be moved to minimum generation during the negative reserve trial.
- **Renewable Generators**
  - During the operational trial, renewable (wind) generation is likely to be less curtailed during periods of high wind and/or low demand.
  - Some windfarms in Northern Ireland will be operated in frequency-sensitive mode to provide frequency regulation as part of the negative reserve trial.
- **System Services Providers**
  - Ongoing frequency response tuning of battery energy storage units in response to the changing characteristics of the power system.
- **Demand Users**
  - No significant impact anticipated.
- **Distribution System Operators**
  - No significant impact anticipated.


For Further Information Visit
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Acronyms

FFR – Fast Frequency Response

GWs – Gigawatt seconds

IBR - Inverter Based Resources

IE – Ireland

LSI - Largest System Infeed

MVAR – Megavolt Amp - reactive

MW - Megawatt

NI – Northern Ireland

OSS – Operating Security Standards

POR – Primary Operating Reserve

RoCoF – Rate of Change of Frequency

SC - Synchronous Compensators (Condensers)

SNSP – System Non-Synchronous Penetration

SO – System Operator

SONI – System Operator of Northern Ireland

SOR – Secondary Operating Reserve

TOR – Tertiary Operating Reserve

TOV – Temporary Overvoltage