

Future Arrangements for System Services

Non-Reserve Services Consultation Paper

April 2026



Executive Summary

The current DS3 (Delivering a Secure, Sustainable Electricity System) System Services Regulated Arrangements have been operational since 2016. They were designed to facilitate new and existing technologies to provide the services required to maintain power system resilience. These arrangements facilitated operation up to a 40% renewable target, and a 75% System Non-Synchronous Penetration (SNSP) limit.

To ensure sufficient provision of system services to deliver 2030 Renewable Energy Source (RES) targets and align with EU requirements, the SEM Committee (SEMC) outlined its High Level Design Decision on the System Services Future Arrangements¹ in 2022. This decision sets out the need to move to a day-ahead auction-based procurement of appropriate system services. In this decision paper, the SEMC also indicated that a period of transition will be required whereby a suite of products will be procured through longer-term contracts or tariffs.

As set out in the respective SEMC Decisions, only reserve services will be included in the Day-Ahead System Services Auction (DASSA). Non-reserve services will transition from tariff-based procurement to competitive arrangements in a phased approach thereafter. These non-reserve services are: Steady State Reactive Power (SSRP), Synchronous Inertial Response (SIR), and Ramping Margins (RMX). Two other services, Dynamic Reactive Response (DRR) and Fast Post-Fault Active Power Recovery (FPFAPR), are not currently procured and are therefore excluded from this transition until a later stage, pending further evaluation of system need.

This consultation sets out the TSOs' evaluation of non-reserve services' product design, locational methodology and volume forecasting methodology. The paper accounts for changes such as the introduction of Low Carbon Inertia Services (LCIS), new HVDC interconnectors, new Renewable Energy Sources (RES) and new Battery Energy Storage Systems (BESS). Based on these findings, we assess the feasibility of implementing market-based procurement mechanisms for SSRP, SIR and RMX. Additionally, the consultation is published alongside an independent economic analysis commissioned by the TSOs. This evaluation focusses on the cost implications of retaining existing non-reserve DS3 arrangements, relative to scenarios in which DS3 is removed.

The key outcomes this assessment are:

- The TSOs intend on delivering upon their obligations, as per relevant EU legislation and SEMC Decisions, by implementing competitive arrangements for the procurement of non-reserve services. To do this in a timely manner whilst ensuring system security is maintained, this transition must be informed by an evaluation of the system need. This assessment will inform the appropriate product redesign required, to both ensure the sufficient provision of non-reserves capability in the future and to enable the introduction of suitable procurement mechanisms. We propose these arrangements will be implemented on a product-by-product basis, rolled out from 2028 onwards.

¹ [SEM-22-012 System Services Future Arrangements High-Level Design Decision Paper \(semcommittee.com\)](https://www.semcommittee.com)

- The TSOs are implementing competitive arrangements in a phased approach, as per the FASS High-level Design. Competitive procurement is already in place for the Low Carbon Inertia Services (LCIS) framework which will deliver a bundle of services that include inertia and reactive power. At FASS Go-live in May 2027, the TSOs propose that the competitive procurement of reserve services will follow with the implementation of the DASSA, while non-reserve services will be procured via tariff arrangements for an interim period. Non-reserves will transition competitive or volume-based procurement following this transitional period, maintaining secure system operation throughout.
- Non-reserve services, as products currently defined within the DS3 Regulated Arrangements, are not suitable for volume-based competitive procurement (via the DASSA, Layered Procurement Framework or Fixed-term Contracts) by FASS Go-live. This reflects system security obligations, and the need to maintain existing operational system service capabilities. These capabilities are necessary to operate the power system at higher levels of SNSP. In addition, the timelines required to complete detailed design and full implementation of alternative product definitions, and procurement mechanisms are not feasible prior to FASS Go Live.
- The TSOs therefore propose that tariff-based procurement for non-reserves continues beyond FASS Go-live for an interim period. However, this would not be an extension of DS3, rather the TSOs will implement a new interim tariff-based arrangement. The details of these arrangements would be subject to input from the RAs and implementation must follow industry consultation on the procurement methodology and contractual arrangements according to the timelines set out in the forthcoming PIR v4.0.
- An indicative timeline for the transition to competitive procurement of non-reserve services is presented below. Note that this timeline is illustrative, and delivery timelines are ultimately subject to the Programme Go-live Assessment as denoted within the plan. However, the TSOs propose that by Q1 2027, following completion of the prerequisite design activities, an economic analysis and joint RA-TSO workshops on product re-definition, the newly defined products will be agreed between the RAs and TSOs. This approach ensures that non-reserves would enable competitive procurement while continuing to meet the operational requirements of the power system.

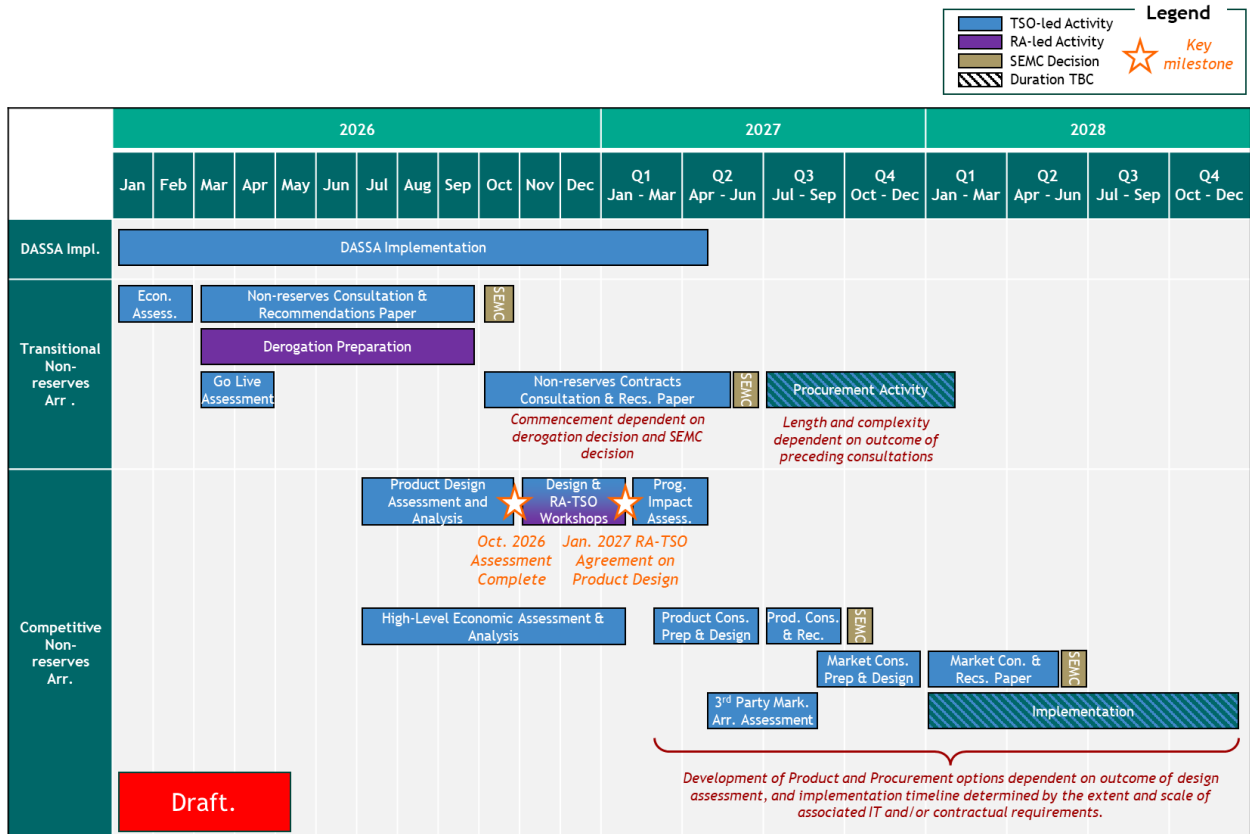


Figure 1-1: Proposed Implementation Timeline for Competitive Procurement of Non-reserves²

Further detail on the rationale for these proposals can be found in the relevant chapters of this paper. In this consultation we are seeking stakeholders’ views on this proposal and have set out a series of questions to frame the responses. The feedback received will then be used to inform a recommendation paper that will be submitted to the SEMC for its consideration and decision. Responses to the questions set out in this paper should be submitted through either the EirGrid or SONI consultation portals before 22nd May 2026.

² Within the Programme Go-live Assessment, the TSOs will undertake a replanning exercise, based on the updated non-reserves timeline represented above, to determine a feasible and appropriate Go-live date for the transitional non-reserves arrangements in the context of the broader FASS Programme delivery schedule.

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Glossary of Terms

Acronym	Meaning
AGU	Aggregated Generator Unit
AVR	Automatic Voltage Regulation
BESS	Battery Energy Storage Systems
BM	Balancing Market
DAM	Day-Ahead Market
DASSA	Day-Ahead System Services Auction
DPOR	Dynamic Primary Operating Reserve
DRR	Dynamic Reactive Response
DS3	Delivering a Secure, Sustainable Electricity System
DSO	Distribution System Operator
DSU	Demand Side Unit. One of more individual demand sites
FASS	Future Arrangements for System Services
FFR	Fast Frequency Response
GFM	Grid Forming
LEU	Large Energy User
LPF	Layered Procurement Framework
LSI	Largest Single Infeed
LSO	Largest Single Outfeed
MMS	Market Management System
MUON	Minimum Units Online
NEA	Non-Energy Action
OSS	Operating Security Standards
PIR	Phased Implementation Roadmap
POR	Primary Operating Reserve
PPM	Power Park modules
RA	Regulatory Authority
RES	Renewable Energy Sources
RMX	Ramping margins 1,3 and 8
RoCoF	Rate of Change of Frequency
RRD	Replacement Reserve Desynchronised
RRS	Replacement Reserve Synchronised
SEM	Single Electricity Market

SEMC	SEM Committee
SIR	Synchronous Inertial response
SNSP	System Non-Synchronous Penetration
SOEF	Shaping our Electricity Future
SOR	Secondary Operating Reserve
SSRP	Steady State Reactive Power
SVC	Static Var Compensators
TCG	Transmission Constraint Group
TOR	Tertiary Operating Reserve
TSO	Transmission System Operator. (SONI for Northern Ireland and EirGrid for Ireland)
TSS	Temporal Scarcity Scalar

1. Introduction

1.1. Background

EirGrid plc is the licenced electricity Transmission System Operator (TSO) in Ireland, and SONI Ltd is the licensed TSO in Northern Ireland. It is the TSO's job to manage the electricity supply and the flow of power from generators to consumers. Electricity is generated from gas, coal and renewable sources (such as wind, solar and hydro power) at sites across Ireland. The high voltage transmission network then transports electricity to high demand centres, such as cities, towns and industrial sites.

EirGrid and SONI have a responsibility to facilitate connections to the power system, including increased levels of renewable sources to generate on the power system, while continuing to ensure that the system operates securely and efficiently. The respective TSO licences include a requirement for the relevant TSO to contract for the provision of System Services.

The DS3 System Services arrangements were designed to facilitate new and existing technologies and participants to provide the System Services required to maintain a resilient power system up to 75% System Non-Synchronous Penetration (SNSP). As part of our Shaping Our Electricity Future Roadmap, the procurement of new system service capabilities from low carbon sources has been identified as essential. This is required to address the technical and operational challenges arising from the need to operate with SNSP levels up to 95% by 2030, supporting renewable targets in Ireland and Northern Ireland.

1.2. System Services Future Arrangements

The System Services Future Arrangements (SSFA) programme was officially launched by the SEM Committee (SEMC) in July 2020 with the publication of a Scoping Paper (SEM-20-044)³ for public consultation.

As set out in the SEMC's SSFA Decision Paper 1 (SEM-21-021)⁴, the objective of the programme is:

“to deliver a competitive framework for the procurement of system services, that ensures secure operation of the electricity system with higher levels of non-synchronous generation.”

1.3. Regulatory Framework for Non-Reserve Services Procurement

The procurement of non-reserve services by TSOs is governed by a series of key regulatory frameworks and policy directives aimed at ensuring consistency, transparency, cost-efficiency, and system security. This includes the System Operation Guideline (SOGL) and the Electricity Directive (2019/944). Together with decisions from the SEMC, these instruments form the

³ [SEM-20-044 System Services Future Arrangements Scoping Paper \(semcommittee.com\)](https://www.semcommittee.com/SEM-20-044-System-Services-Future-Arrangements-Scoping-Paper)

⁴ [SEM-21-021 System Services Future Arrangements Decision Paper 1 \(semcommittee.com\)](https://www.semcommittee.com/SEM-21-021-System-Services-Future-Arrangements-Decision-Paper-1)

foundation for how TSOs operate within the broader European regulatory context, supporting the evolution toward more competitive and inclusive electricity markets.

1.3.1. System Operation Guideline (2017/1485)

The SOGL, particularly Article 108 of Commission Regulation (EU) 2017/1485, provides clear direction regarding the procurement of ancillary services. It states:

“[Regarding ancillary services] TSOs shall ... use all available economically efficient and feasible means to procure the necessary level of ancillary services.”⁵

This clause underscores the obligation on TSOs to prioritise economic efficiency and feasibility when securing system services. It implies that procurement mechanisms should aim to balance cost-effectiveness with the need to maintain system reliability and operational stability. In other words, TSOs must be proactive in enabling economically efficient procurement processes while ensuring access to the relevant ancillary services.

1.3.2. Electricity Directive (2019/944)

The Electricity Directive⁶ further reinforces the EU’s commitment to competitive, non-discriminatory procurement. Article 40 is especially relevant in this regard.

Under paragraph 4, it mandates that:

“TSOs must procure balancing services through transparent, fair, and market-based processes, allowing participation from all qualified entities, including those providing renewable energy, demand response, energy storage, and aggregation services.”⁷

This provision highlights the Directive’s strong preference for inclusive, market-based procurement, ensuring fair access for a wide range of participants. Notably, it aims to accommodate technologies such as demand-side response, energy storage, and aggregation, crucial enablers of a flexible, low-carbon power system.

Paragraph 5 of Article 40 expands the scope of these provisions to non-frequency ancillary services. It specifies:

“Paragraph 4 shall apply to the provision of non-frequency ancillary services by transmission system operators, unless the regulatory authority has assessed that the market-based provision ... is economically not efficient and has granted a derogation.”⁹

This clause makes it clear that non-frequency ancillary services (e.g., voltage control, inertia, reactive power) should also be subject to competitive procurement, unless an exemption is explicitly granted by the regulatory authority. It further stipulates that TSOs must be able to source such services from providers engaged in demand response or energy storage, where such services cost-effectively avoiding unnecessary infrastructure investments and enhancing overall system efficiency.

⁵ [Regulation - 2017/1485 - EN - EUR-Lex](#)

⁶ Some parts of this directive apply in NI under the Protocol on Ireland and Northern Ireland. The DfE has responsibility for transposing the aspects that it judges appropriate.

⁷ [Directive - 2019/944 - EN - EUR-Lex](#)

1.3.3. SEMC Decisions

In April 2022, the SEMC published the SSFA High-Level Design (HLD) Decision (SEM-22-012)⁸. The HLD set out a framework for the competitive procurement of system services, consisting of the following:

1. **Daily Auction Framework** for the procurement of some of the system services through a daily spot market
2. **Layered Procurement Framework (LPF)** comprising contracts with a term of more than a day and up to 12 months.
3. The existing **Fixed Contract Framework** to continue to be used to remove barriers to entry for new technologies with the use of more long-term contracts and ensure sufficient volumes of system services, as required.

Additionally, in SEM-22-012, the SEMC decided that a phased introduction of the procurement mechanisms set out under the HLD can be adopted. The decision reflects the SEMC’s recognition of a transitional period to ensure a stable and secure shift from existing arrangements to market-based procurement:

“...the SEM Committee considers that a period of transition will be required whereby a suite of products will be procured through longer-term contracts or tariffs.”

“...the SEM Committee has decided to implement a transition period and phase the introduction of the full set of System Services Future Arrangements.”

In December 2023, the SEMC published its SSFA Phase III: Detailed Design & Implementation Decision Paper (SEM-23-103)⁹, in which it decided that the commercial arrangements as described in the HLD should be progressed by the TSOs.

In September 2024, the SEMC published its Future Arrangements for System Services DASSA Market Design Decision Paper (SEM-24-066)¹⁰ with respect to the TSOs’ recommended design for the Day-Ahead System Services Auction (DASSA)¹¹ that was submitted to the SEMC in July 2024. In this paper, the SEMC provided further clarity on the transition of non-reserve services to market-based arrangements. The SEMC reiterate the sentiment expressed in SEM-22-012 that a transitional period will be required (i.e., the DASSA to accommodate non-reserve services *in the future*) and that for any services to remain on tariff-based procurement, the RAs must determine that procurement through alternative, competitive means is not economically efficient and grant a formal derogation.

“The design of the auction will allow for the procurement of non-reserve services in the future.”

“The SEM Committee considers that non-reserve services should be procured competitively, in line with the Article 40(5) of Directive 944/2019 from the European Commission, which sets out that all non-frequency ancillary services must be procured

⁸ [SEM-22-012 System Services Future Arrangements High-Level Design Decision Paper \(semcommittee.com\)](#)

⁹ [SEM-23-103 System Service Future Arrangement Phase III: Detailed Design & Implementation Decision Paper \(semcommitte.com\)](#)

¹⁰ [SEM-24-066 Future Arrangements for System Services DASSA Market Design Decision Paper \(semcommittee.com\)](#)

¹¹ [DASSA Design Recommendations Paper \(EirGrid\)](#); [DASSA Design Recommendations Paper \(SONI\)](#)

through market-based means unless the relevant regulatory authority has determined that it is not economically efficient to do so and grants a derogation.”

A subsequent SEMC decision that is relevant for this consultation is the System Services Regulated Arrangements to FASS - The Gap Decision Paper (SEM-25-031)¹². In this paper the SEMC decided to extend the DS3 Regulated Arrangements contracts for all System Services products until the earlier of FASS Go-live or the long-stop date of 30th September 2027. This decision paper also clarified that any products which are not procured through the DASSA initially (non-reserve services) will continue on tariffs until the long-stop date.

1.3.4. Phased Implementation Roadmap

The TSOs acknowledge the necessity of providing clear timelines to industry to facilitate their own programme deliveries. In this regard, the FASS Programme workstreams and projected timelines are detailed in the Phased Implementation Roadmap, which is revised biannually to reflect changes to programme scope or schedule.

As per the TSOs' Phased Implementation Roadmap¹³, and as agreed with the Regulatory Authorities, the TSOs are required to consult on and submit a recommendation paper to the SEMC on the procurement mechanism, products, volumes and locational methodology arrangements for non-reserve services post-FASS Go-live.

¹² [SEM-25-031: Section 3.1 \(semcommittee.com\)](#)

¹³ [Phased Implementation Roadmap \(EirGrid\)](#); [Phased Implementation Roadmap \(SONI\)](#)

1.4. Purpose of the Paper

The purpose of this consultation paper is to set out the TSOs' evaluation of the non-reserve services' product design, locational methodology and volume forecasting methodology, and proposals for the procurement mechanisms.

1.5. Structure of Paper

This paper is broken down into the following sections:

- Section 1: Introduction
- Section 2: Current Procurement Arrangements
- Section 3: Proposals for Non-Reserve Procurement
- Section 4: Evaluating Competitive Procurement Suitability
- Section 5: Steady State Reactive Power (SSRP)
- Section 6: Synchronous Inertial Response (SIR)
- Section 7: Ramping Margin Requirements (RMx)
- Section 8: Independent Technical and Economic Analysis
- Section 9: Summary of Consultation Questions
- Section 10: Next Steps
- Section 11: Appendices

1.6. Next Steps

This consultation will be open for seven weeks, closing on **22nd May 2026**. Responses to the consultation should be submitted to the EirGrid ([link](#)) or SONI ([link](#)) consultation portals.

Should stakeholders have any questions or comments during the consultation period these can be submitted to FASS@Eirgrid.com or FASSProgramme@soni.ltd.uk.

An industry workshop, at which the TSOs will present these proposals and facilitate a Q&A for interested parties, will be scheduled (the date and location are to be confirmed and will be communicated to customers and stakeholders in due course).

Following this consultation, the TSOs will submit a recommendations paper to the SEMC for decision, timelines will be confirmed in the next iteration of the Phased Implementation Roadmap (PIR).

2. Current Procurement Arrangements

2.1. DS3 Regulated Arrangements

All system services are currently procured under the DS3 System Services Regulated Arrangements (DS3 Regulated Arrangements hereafter). These arrangements were designed to meet 2020 government targets by facilitating new and existing technologies to provide services required to maintain a resilient power system when up to 75% of demand is met by non-synchronous technologies. The arrangements have been successful in providing a transparent and stable framework signalling future system requirements necessary for the renewable transition to 2020 and have successfully facilitated SNSP operational levels of 75%.

The DS3 Regulated Arrangements comprise the procurement mechanisms, standard contractual provisions, system service schedules, and payments and incentives in place for 14 system services (12 of which are currently procured), and are commonly understood by the RAs, TSOs and service providers.

In addition to the DS3 System Services Tariff Arrangements (i.e., Volume Uncapped), a subset of system services have been procured under Fixed Contract arrangements (i.e. Volume Capped). These services were procured competitively through an auction process to ensure adequate provision of high availability reserve services to the system. At present, Volume Capped Arrangements are in place for energy storage units whose requirements are to be available for 97% of the time, calculated on a rolling basis looking at the previous 12 months availability data. The expenditure associated with these arrangements is only a small fraction (~1% of DS3 expenditure for 23/24 tariff year) of that associated with the Volume Uncapped arrangements.

Type	Service Name	Abbv.	Unit	Short Description	Procurement Method
Reserve	Fast Frequency Response	FFR	MWh	MW delivered between 2 and 10 seconds	Volume Uncapped Volume Capped
Reserve	Primary Operating Reserve	POR	MWh	MW delivered between 5 and 15 seconds	Volume Uncapped Volume Capped
Reserve	Secondary Operating Reserve	SOR	MWh	MW delivered between 15 to 90 seconds	Volume Uncapped Volume Capped
Reserve	Tertiary Operating Reserve 1	TOR1	MWh	MW delivered between 90 seconds to 5 minutes	Volume Uncapped Volume Capped
Reserve	Tertiary Operating Reserve 2	TOR2	MWh	MW delivered between 5 minutes to 20 minutes	Volume Uncapped Volume Capped
Reserve	Replacement Reserve - Synchronised	RRS	MWh	MW delivered between 20 minutes to 1 hour	Volume Uncapped
Reserve	Replacement Reserve - Desynchronised	RRD	MWh	MW delivered between 20 minutes to 1 hour	Volume Uncapped
Non-reserve	Synchronous Inertial Response	SIR	MWs²h	(Stored kinetic energy) * (SIR Factor - 15)	Volume Uncapped
Non-reserve	Ramping Margin 1	RM1	MWh	Increased MW output deliverable with high certainty for the given time horizon	Volume Uncapped
Non-reserve	Ramping Margin 3	RM3	MWh		Volume Uncapped
Non-reserve	Ramping Margin 8	RM8	MWh		Volume Uncapped
Non-reserve	Steady State Reactive Power	SSRP	MVarh	(MVar capability) * (% of capacity that MVar capability is achievable)	Volume Uncapped
Non-reserve	Fast Post Fault Active Power Recovery	FFPAPR	MWh	Active power (MW) >90% within 250ms of voltage >90%	Not currently procured
Non-reserve	Dynamic Reactive Response	DRR	MWh	MVar capability during large (>30%) voltage dips	Not currently procured

Figure 2-1: System Services Procured under the DS3 Framework

2.2. Low Carbon Inertia Services (LCIS)

In SEM-21-021¹⁴, the SEMC requested that the TSOs carry out an evaluation and bring forward proposals for a fixed term procurement in relation to LCIS. The aim of the procurement was to reach renewable targets and enable a greater amount of renewable generation onto the system, through procuring services, traditionally provided by thermal units, such as inertia, from low carbon sources. The TSOs conducted a consultation on the procurement of LCIS and based on responses to this consultation, submitted a recommendation paper to the RAs on LCIS procurement. In response to this paper the SEMC published a Decision paper (SEM-23-002)¹⁵ on the procurement of LCIS in September 2023.

Low Carbon Inertia Services (LCIS) are critical for reducing the minimum number of conventional units (MUON) and enabling higher levels of SNSP. These services will increase renewables integration and reduce carbon emissions, enhance security of supply and reduce electricity production costs. The LCIS will cater to technology types, such as synchronous condensers that can provide inertia, reactive power and short circuit capability.¹⁶

2.2.1. Phase 1

Currently, LCIS is being procured competitively through a phased approach in which participants submit a tender and those that are successful are awarded a fixed-term contract, with a duration of approximately 6 years. The LCIS phase 1 targets a total volume of 4,000 MVA's, in Northern Ireland and 6,000 MVA's, in Ireland, to meet 2026 requirements. Three zones were defined and incentivised via locational scalars, although procurement and tendering outside these zones is also possible. The contracts award completed in April 2024 in Northern Ireland and in July 2024 in Ireland and target Go-Live date in October and December 2027.¹⁶

LCIS 1 Phase procurement successfully contracted 10,963 MVA.s in total, with 6,963 MVA.s in Ireland and 4,000 MVA.s in Northern Ireland. This equates to approximately 45% of the system's current inertia floor requirement and represents a substantial achievement in lowering carbon emissions from the electricity system, in both Ireland and Northern Ireland. Six contracts were executed, with four in Ireland and two in Northern Ireland. Importantly, five out of six of the contracted assets are located within the three incentivised zones, thus fulfilling the procurements locational requirements.¹⁶

2.2.2. Phase 2

The TSOs have published a consultation paper on Phase 2 of the LCIS Procurement in July 2025.

The Phase 2 proposal builds upon the experience of the first procurement round, targeting the procurement of 10,000 MVA.s (Max 12,000 MVA.s) in Ireland and 4,000 MVA.s (Max 6,000 MVA.s) in Northern Ireland. The TSOs propose to continue with a zonal procurement strategy, targeting development in specific regions to support local system needs

A key change in phase 2 is the broader scope of eligible technologies. While Phase 1 focussed mainly on synchronous condenser technologies, the next phase is expected to open

¹⁴ [SEM-21-021 System Services Future Arrangements Decision Paper \(semcommittee.com\)](#)

¹⁵ [SEM-23-002 Procurement of Low Carbon Inertia Services \(LCIS\) Decision Paper \(semcommittee.com\)](#)

¹⁶ [SEM-24-074 Low Carbon Inertia Services Phase 1 Procurement Information Note \(semcommittee.com\)](#)

participation to a wider pool of low carbon technologies (grid-forming inverters) capable of providing offering inertia, reactive power and short circuit capability services.

To enable this wider participation, updates to the contractual arrangements were proposed such as the removal of the product scalar, which will aim to allow these new suppliers to participate effectively while maintaining system security.

Finally, a timeline is outlined where a structured procurement process will begin once regulatory approval is secured. Furthermore, contracts will be awarded to successful suppliers ahead of 2030 to provide sufficient time for development.

3. Proposals for Non-Reserve Procurement

This section provides an overview of the TSOs' assessment of the suitability of the current product design of non-reserve services for competitive volume-based procurement. It then sets out the TSOs' proposal for the future design and procurement of non-reserve services under FASS.

3.1. Summary of Outcomes

The TSOs have assessed the readiness of the existing non-reserve products for transition to competitive procurement in alignment with SEM-24-066 and Article 40(5):

- **Synchronous Inertia Response (SIR)** is an incentive-based product and encourages a reduction of P_{min} for conventional units. This incentive nature creates inherent challenges such as the inability to forecast service volumes (as the system need is defined as inertia volume, not as SIR volume), codify its contribution into an objective function or mitigate market power risks. These characteristics make SIR structurally incompatible with competitive procurement at this stage.

However, a large share of the system need for inertia will be contracted by the LCIS phase 1 and phase 2 tenders, which will start to come online from 2027 onwards. For any residual need, a standalone inertia product may be developed with defined requirements. This would enable more flexible, market-based procurement opportunities. As part of the upcoming Product Design Assessment and Analysis work package in Q3 2026, one suggestion could be to incorporate inertia into the DASSA. This would complement LCIS volumes while providing a mechanism to address any shortfalls or disruptions.

- **Steady-State Reactive Power (SSRP)** is similarly incentive-based and encourages generators to make their reactive power capability available even at low / zero active power output. SSRP is not a suitably defined product that can transition to a competitive design. Future TSO requirements for voltage control support will need to be defined carefully. This must ensure capability to manage a more dynamic system while recognising the locational nature of reactive power provision.

Future need for reactive power capability results from long-term multi-year voltage studies. These studies determine areas with additional need for reactive power compensation capability, on top of the mandatory capability of generation units and PPMs, to which the TSOs' access shall remain. Therefore, a future evolution of SSRP into a reactive power product may, where feasible, support transition to a more competitive or tender based procurement, similar to the approaches adopted in Great Britain. However, any such development here would require detailed analysis, consideration of locational market power aspects and interactions with evolving DSO contracted services.

- **Ramping Margin (RMX)** provides remuneration to market participants for ensuring sufficient ramping capacity is available to the TSOs, enabling them to manage forecast

errors and net demand fluctuations. As embedded generation increases and conventional units decline, alongside integration with EU Day-ahead, intraday, and XBID continuous trading, system complexity rises. This, coupled with interconnector scheduling moving closer to real time, is expected to drive evolving ramping requirements.

Moreover, EU obligations for coordinated TSO-DSO flexibility assessments will necessitate deeper investigation. Robust assessment of all products, supported by detailed modelling, will be critical to determine the appropriate future RM products and procurement approaches. Therefore, continued analysis is essential as we transition to higher levels of SNSP and RES.

3.2. Transition to Competition

3.2.1. Stage 1 - Transitional Arrangements

As described above, the current definitions of non-reserve services mean they are not suitable for volume-based competitive procurement. Further, the design and implementation of appropriate alternative definitions and market-based mechanisms cannot be completed by the long-stop date in September 2027. The TSOs therefore propose that following this date, the existing suite of non-reserve services (SSRP, SIR, RMX) will be procured via a new set of tariff-based arrangements for an interim period while the reserve products transition to the DASSA. The details of these arrangements will be subject to RA input and industry consultation, and the applicable tariff rates will undergo periodic reviews to reflect price trends in other services and long-term contracts, such as LCIS, to ensure alignment with evolving system needs and capabilities.

The TSOs consider this phased approach as the most pragmatic way to meet both the TSOs' system security obligations and enable the timely and stable transition to a competitive framework. Expediting the transition of non-reserves would leave the TSOs without a mechanism to incentivise and compensate non-reserve service providers. The TSOs consider this to be a substantial risk to system security, particularly at current SNSP levels. The TSOs further consider that allowing a phased transition of the non-reserve services reduces disruption to Industry at FASS Go-live.

This phased approach ensures sufficient provision of non-reserve services' capability on an interim basis while the TSOs' progress the preparatory activities for the introduction of the enduring procurement arrangements in parallel. This phased approach ensures compliance with Article 40(4)-(6) and alignment with SEMC High-Level Design, which states:

“The SEM Committee recognises that a transition period may be required to implement the new arrangements and that during this period, tariff-based procurement may continue to be used for certain services.”

The TSOs are committed to engaging with industry throughout the transition to FASS, and have scoped a comprehensive readiness workstream¹⁷. The TSOs' readiness effort will support service providers to adopt and integrate changes driven by the introduction of the new arrangements

¹⁷ [High-Level Readiness Scope \(EirGrid\)](#); [High-Level Readiness Scope \(SONI\)](#)

at FASS Go-live and ensure that service providers are fully aligned, prepared and ready for a successful implementation both for the transitional and the enduring non-reserve arrangements.

In summary, the TSOs view a continuation of tariff-based procurement as a necessary and prudent method to support system reliability, minimise implementation risk, and facilitate a structured evolution towards a competitive framework for non-reserve services.

3.2.2. Stage 2 - Enduring Arrangements

During the transitional period described above, the TSOs will advance the development of the enduring competitive arrangements for non-reserve services. This will include developing new non-reserve products to ensure the sufficient technical availability of inertia, reactive power, and ramping capability to meet the operational requirements of the power system.

To develop the new non-reserves products, the TSOs will undertake detailed analysis to inform future product design for reactive power, inertia and ramping services in July 2026. This analysis will aim to identify the specific product refinements required to deliver system security and enable the transition to competitive procurement, forming the basis for subsequent implementation activities

Subject to the confirmation of a suitable product definition for each service, preparatory activities to introduce new competitive arrangements can commence. The complexity of the transition will require an iterative, collaborative development process between the TSOs, the RAs and industry stakeholders. The TSOs therefore propose that by conclusion of the Product and Market Arrangement consultative processes in 2028 (see Figure 3-1), a procurement plan for the enduring arrangements for each service will be agreed with the RAs, which will include:

- The procurement method, including the proposed service(s) to be procured; the methodology to determine the volumes required, procurement frequency (e.g., day-ahead, year ahead, etc.) and remuneration structure.
- Principles to guide the procurement approach, ensuring it delivers value for consumers while maintaining overall system security and reliability.
- Implementation timelines and programme requirements, with delivery dependent on sufficient uplift in programme funding.

Following the successful closure of the above design activities, the transitional tariff-based arrangements will conclude, and the newly defined services can move to competitive procurement, where appropriate, on a per-product basis. It is important to note, however, that introducing the enduring arrangements will demand considerable effort and should be considered a significant undertaking regardless of final product design. Depending on the competitive procurement route ultimately approved by the SEMC, a new procurement process may be required. This includes, but is not limited to, modifications to the System Services Code and Grid Code to reflect future product definitions, development of new IT systems and vendor contracting where necessary and the design and implementation of both qualification and performance monitoring processes. These activities are heavily dependent on the final product design and associated procurement mechanism which limits the TSOs' ability to commit to

detailed timelines. However, an indicative timeline for our proposals for non-reserves is included below:

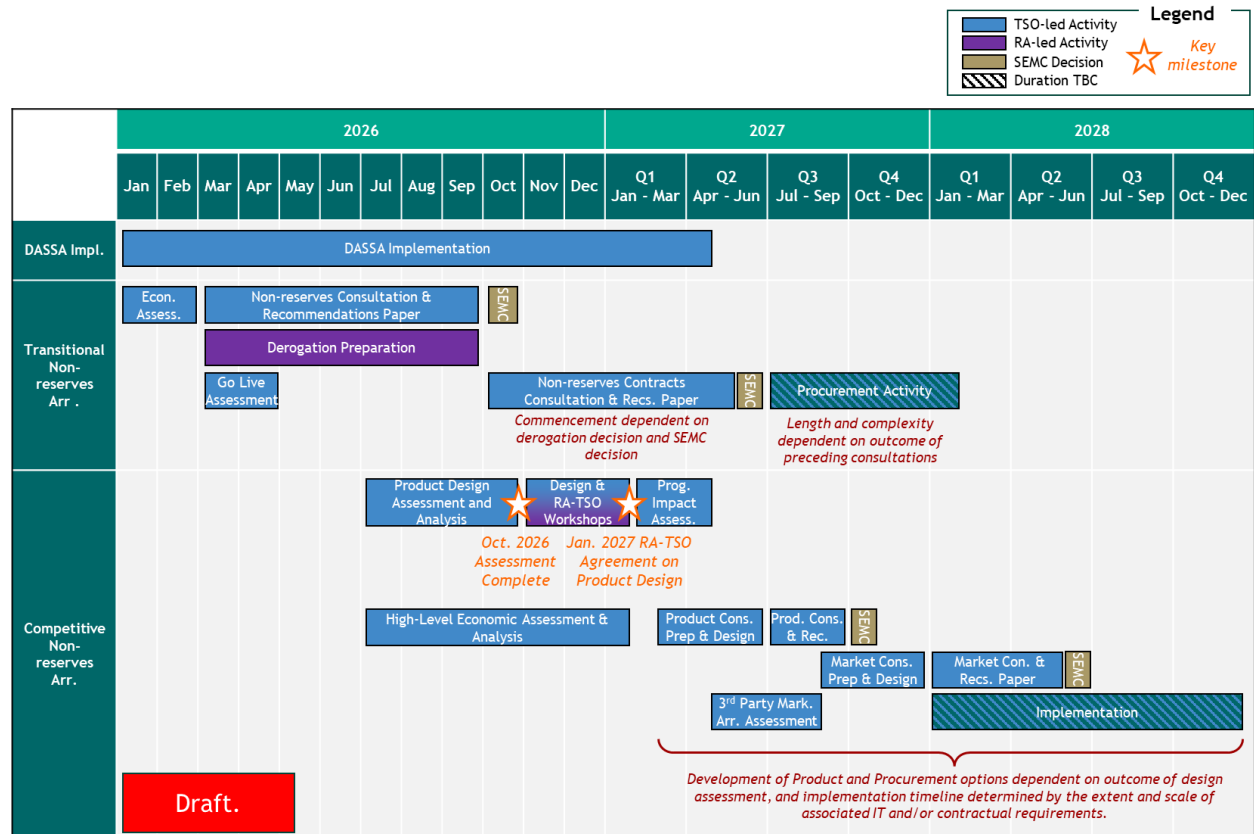


Figure 3-1: Proposed implementation timeline for competitive procurement of non-reserves.

Question #1: Do you have any comments on the TSOs’ proposal to maintain tariff-based procurement for a transitional period post-DASSA Go-live?

Question #2: Do you have any comments on the TSOs’ proposed approach for implementing competitive procurement for non-reserve services under the enduring FASS arrangements?

Question #3: Do you have a view on whether there are suitable procurement methods that should be considered in the upcoming 2026 Product Design Assessment?

TSO Proposal:

Non-reserve services, as currently defined, cannot feasibly enable volume-based competitive procurement, and the design and implementation of appropriate alternative definitions and market-based mechanisms cannot be completed by the Long Stop Date in September 2027. Therefore, the TSOs propose the following:

- **Transitional Arrangements:** Non-reserve services will be procured via a new tariff-based mechanism beyond the long-stop date for an interim, transitional period. This will not be an extension of DS3; rather, the TSOs will design and implement new interim tariff-based arrangements.
- **Enduring Arrangements:** During this interim period, it is the TSOs intention to replace or refine non-reserve products to establish enduring competitive procurement, while ensuring system security is maintained. Each service would then transition to competitive frameworks, where appropriate, on a per-product basis.

4. Evaluating Competitive Procurement Suitability

4.1. Introduction

The procurement of system services plays a vital role in maintaining market efficiency and ensuring grid reliability in modern electricity systems. As grid technologies and operational needs evolve, it is increasingly important for the TSOs to rigorously assess the suitability of market-based procurement approaches. This section outlines the structured approach adopted to assess the feasibility of transitioning non-reserve services into competitive procurement frameworks.

4.2. Benefits of Competitive Procurement

Competitive procurement is central to the efficient and effective operation of electricity markets. Suppliers competing for contracts have strong incentives to innovate, reduce costs, and improve operational efficiency, thereby delivering value through lower market prices.

Transparent and clearly defined procurement processes also ensure accurate identification of system requirements, reducing the potential for excessive procurement and associated expenditure. Furthermore, competitive procurement sends clear price signals, encouraging new market entrants and stimulating innovation.

Collectively, these benefits contribute to a resilient, transparent, and efficient electricity market, capable of adapting to changing conditions and consistently delivering value to consumers.

4.3. Conditions for Effective Competitive Procurement

Competitive procurement processes, can drive efficiency, reduce costs and enhance market performance, provided they are implemented under the correct conditions. However, the extent to which these benefits are realised depends critically on the presence of the following enabling factors within the market environment.

- **Market Power**
Without sufficient competition, suppliers have limited incentives to reduce costs and reflect these savings through competitive pricing, potentially leading to inefficiencies and higher costs for consumers.
- **System requirements are known prior to real time**
If system requirements are clearly defined ahead of real-time, this allows TSOs to establish precise volume requirements for competitive procurement without necessitating frequent adjustments. Clear and predictable requirements contribute to supplier certainty, enabling more efficient planning and bidding.
- **Suppliers have some ability to commit ahead**

If suppliers have some capability to commit their volumes in advance, this enables the market operator to procure volumes effectively ahead of real-time requirements. This advance commitment is crucial in ensuring security of supply, market stability, and reliable grid operation. Suppliers' willingness and ability to commit is linked directly to clear and attractive incentives provided by the procurement mechanism, ensuring that commitments align closely with system needs.

When suppliers have limited or no control over their volume provision, market incentives may not adequately encourage competitive behaviour or volume commitments. Benefits from competition in such scenarios only materialise if new entrants or existing suppliers have sufficient incentive, capability, and resources to commit volumes ahead of real-time requirements. A lack of adequate incentives or capabilities may reduce competitive pressures and potentially result in less efficient outcomes.

- **New entry is a real possibility over a reasonable timeframe**

If new market entry is feasible over a realistic timeframe, this may potentially enhance competition and drive innovation. New entrants may introduce downward pressure on prices, stimulates efficiency, and reduces risks associated with inefficient procurement practices, benefiting end-users and overall market health.

- **Existing suppliers can be incentivised to make efficiency improvements**

If existing suppliers can be effectively incentivised to enhance efficiency, this may lower costs and increase the competitiveness of their offers. Mechanisms that reward improved performance, innovation, and cost management contribute to continuous improvements and greater overall efficiency within the market.

When these conditions are sufficiently met, competitive procurement can deliver meaningful market efficiencies, cost savings and enhanced system reliability.

4.4. Approach for Competitive Feasibility Assessment

In the 'Analysis of Non-Reserve Procurement' workstream which commenced in October 2024, the TSOs developed a framework to assess the feasibility of competitively procuring existing non-reserve products. These include ramping margins (1, 3, and 8), steady-state reactive power, and synchronous inertial response. As outlined in Section 2.1, DRR and FPFAPR are categorised as non-reserve products; however, they fall outside the scope of this assessment as they have not been procured to date and are not considered critical at this time. We have however provided context on the establishment of the DRR and FPFAPR products and have outlined relevant future considerations on these technical needs in Appendix A and B, respectively. The framework was developed based on the conditions required for competitive procurement, as set out above, and was used to evaluate the suitability of each product for transition to a competitive approach. In addition to assessing feasibility, it also identified the key challenges associated with moving away from existing procurement arrangements. The framework is outlined below in Error! Reference source not found..

Considerations	Description
Are volume requirements known prior to real time?	If volume requirements are unclear, participants don't have sufficient information to inform bidding strategies and clearing the market becomes difficult.
Can system requirements be codified into an objective function?	If the product requirements are too complex, clearing the market on time becomes a significant challenge.
Can participants commit to supply ahead of Gate Closure (GC)?	Enabling participants to bid into the market ahead of gate closure fosters competition, encourages new market entrants, may reduce costs and promotes the adoption of modern technologies.
Do participants have adequate time to plan their supply?	If participants need more certainty than a single day-ahead signal provides, they might under-supply or over-supply.
Is there no strong market power for the service?	If there is limited competition, this may create an environment for market power which could withhold volume to push prices up.

Table 4-1: Framework exploring non-reserve competitive transition concerns

This framework was applied to each of the existing non-reserve products to consider the complexity of setting requirements for these products and the potential for suppliers to commit to supply ahead of real time. This framework is needed to justify moving to competitive procurement if the TSOs can see that competition will materialise, lead to lower prices, help reduce TSOs over-procurement and provide appropriate price signals. If these advantages do not materialise, there is no benefit to offset the costs and risks of changing the procurement framework.

Question #4: Do you have any comments on the framework employed by the TSO to assess the feasibility of competitive procurement?

4.5. Considered Competitive Procurement Options

As part of the transition analysis, the TSOs explored multiple procurement methods. The options included the Day-Ahead System Services Auction (DASSA), a Layered Procurement Framework (LPF), Fixed Contracts, and a Regulated Pricing approach. While each method presents distinct advantages such as flexibility, predictability, or simplicity they also come with trade-offs in terms of market complexity, real-time responsiveness, regulatory requirements, and potential impacts on supplier participation. The procurement methods below were considered as part of the options assessment conducted by the TSOs, covering a broad range of approaches.

Procurement options	Details
<p style="text-align: center;">DASSA</p>	<p>Description: A day-ahead procurement process, in which services are competitively procured daily, based on forecasted system conditions.</p> <p>Benefits:</p> <ul style="list-style-type: none"> • Enables participation from providers whose availability and cost profiles are uncertain until close to delivery, including variable renewables and demand-side units • Facilitates more accurate volume-setting by the TSO, as procurement occurs close to real-time conditions. • Supports efficient dispatch by aligning procurement with latest operational data. <p>Challenges:</p> <ul style="list-style-type: none"> • Represents a relatively new procurement mechanism still undergoing development and refinement, which may pose design and implementation risks.
<p style="text-align: center;">LPF</p>	<p>Description: Procurement conducted on a weekly, monthly or yearly basis, designed to strike a balance between long-term cost efficiency and near-term operational flexibility.</p> <p>Benefits:</p> <ul style="list-style-type: none"> • Provides a mechanism to adjust procurement volumes more frequently than long-term contracts, offering flexibility to respond to changing system conditions. • Suitable for providers with relatively predictable availability on a short- to medium-term basis. <p>Challenges:</p> <ul style="list-style-type: none"> • May not fully capture rapid, short-term changes in availability or system needs, leading to inefficiencies. • Not ideal for participants whose availability is only known closer to delivery, such as some renewable or demand-side providers.
<p style="text-align: center;">Fixed Contracts</p>	<p>Description: Procurement of services through fixed-price contracts with a defined volume and duration, typically lasting six months, one year, or extending over longer multi-year durations. These contracts will be awarded via competitive tender.</p> <p>Benefits:</p> <ul style="list-style-type: none"> • Offers revenue certainty and planning stability for providers. • Enables the TSO to secure essential services in advance, support system security • Simplifies administrative process compared to more dynamic procurement models <p>Challenge:</p> <ul style="list-style-type: none"> • Less flexible in responding to short term changes in system needs or provider availability • May lead to inefficiencies if forecasted service requirements differ from actual conditions • Less suitable for participants with variable or short-notice availability such as renewables and DSUs.
<p style="text-align: center;">Regulated Pricing</p>	<p>Description: A non-competitive procurement model where services are remunerated through scalars and predefined rates. These rates are derived from outputs of the DASSA and LCIS. The rates will subject to periodic review every two years.</p> <p>Benefits:</p> <ul style="list-style-type: none"> • Provides pricing certainty for providers and administrative simplicity for the TSOs • Supports service availability where competitive procurement is not yet feasible • Low implementation burden for both TSO and participants

	<ul style="list-style-type: none"> Reduces exposure to market power where competition is limited <p>Challenges:</p> <ul style="list-style-type: none"> Requires derogation from Regulating authorities as stated in SEM 24-066. Prices may not reflect true market value
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Table 4-2: Summary of Feasible Procurement Options for Non-Reserve Services

4.6. Procurement Approach Assessment

The TSOs developed an assessment criteria alongside the RAs during the real time security arrangements workstream as part of the DASSA Top Up Mechanism Consultation¹⁸. This assessment criteria were used to determine the suitability of a list of procurement methods under the criteria of consumer value, system needs, compliance, deliverability and investment. For each of the non-reserve products, these assessment criteria were applied to the potential procurement mechanisms discussed in Table . This assessment was used to compare these four procurement mechanisms under these common criteria highlighting which was the most suitable given current non-reserve product definitions. Each of the assessment criteria are described below:

Criteria	Description
Consumer Value	The mechanism aims to deliver consumer value by keeping prices market-based and ensure appropriate alignment between the markets in energy, capacity and System Services, along with all other relevant revenue streams, to ensure an efficient overall outcome for consumers.
System Needs	The mechanism aims to operate in a manner that ensures that the needs of the system (including security of supply) are met.
Compliance	The mechanism aims to comply with relevant legislation, including the Directive on common rules for the internal market for electricity (EU/2019/944) as part of the Clean Energy Package (CEP), System Operation Guideline (SOGL) Network Code 2017/1485.
Deliverability	The mechanism should be deliverable for DS3 Long stop date in September 2027 to align with SEM-25-031
Investment	The arrangements will be clear in terms of how auctions will operate, in order to give reasonable clarity to developers in terms of financing and shall be transparent in regard to making information accessible and simplistic to understand

Table 4-3: Summary of Assessment Criteria Used on the Procurement Options

Question #5: Do you have any observations regarding the foundations and criteria upon which these evaluations were conducted?

¹⁸ [DASSA Top-up Mechanism Consultation Paper \(EirGrid\)](#); [DASSA Top-up Mechanism Consultation Paper \(SONI\)](#)

5. Steady State Reactive Power (SSRP)

5.1. Current situation

5.1.1. Background

Messages in this section:

- Reactive power compensation relates to voltage stability and is key to ensure system security.
- Ensuring voltage stability requires reactive power compensation of the reactive power absorption or production of consumers and network assets.
- Reactive power compensation exists in two directions: absorbing (leading) and producing (lagging).
- Reactive power shall be compensated locally.
- The unit of reactive power is MVAR.

An important part of system operation (and as required under TSO licence conditions) is ensuring voltage stability, which requires the TSOs to ensure sufficient support mechanisms are in place, including reactive power compensation. Reactive power is an important phenomenon in the electricity networks as operated by EirGrid, SONI and the DSOs. Reactive power relates to voltage and shall be managed correctly to ensure system security. Reactive power is typically indicated by 'Q' and its unit is 'VAR', or 'MVAR' as typically used in transmission grids.

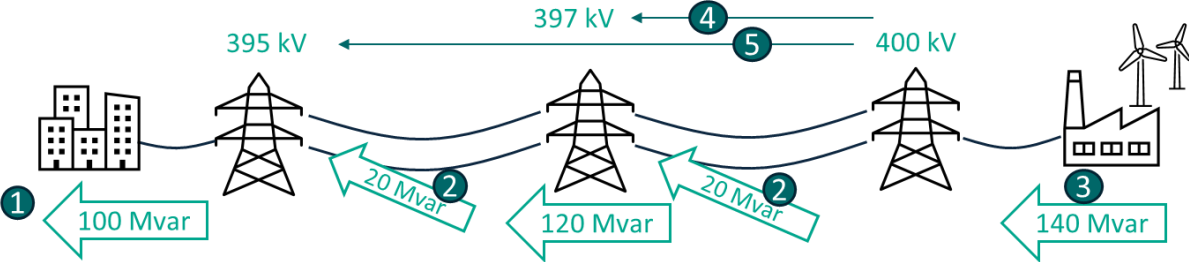


Figure 5-1: Illustrative example of Reactive Power and Voltage in Power Networks

Figure 5-1 provides a brief description on the objective of reactive power compensation in power grids: Many electricity consuming equipment absorbs reactive power (1), e.g. motors, pumps, air conditioners¹⁹. Also grid components absorb or produce reactive power (2). Generation units and certain grid components are able to compensate the reactive power (3) (see section 5.1.2). However, transport of reactive power results in voltage differences between infeed and outfeed (4). The longer the line, the higher the voltage drop (5). In line with meeting voltage requirements as defined in the Grid Code and Operating Security

¹⁹ Demand customers shall adhere to reactive power requirements outlined in the respective Distribution Codes and Grid Codes.

Standards (OSS) (see *Table 5-3*), network operators have to continuously manage reactive power balances at each node in their grid to make sure that the voltage levels remain secure.

Reactive Power compensation is required in two directions which are typically indicated as providing (or lagging) and absorbing (or leading). Typically, low-voltage situations require provision of reactive power by reactive power providers, while high-voltage situations require absorption of reactive power.

As illustrated in *Figure 5-1*, an important aspect of reactive power is that reactive power transport results in a loss of voltage. As voltage shall stay within specified limits, reactive power transported will be limited. Consequently, reactive power compensation needs to be done locally.

5.1.2. Providers of Reactive Power Compensation

Messages in this section:

- Providers of reactive power compensation only support the local need. Providers include:
 - *Transmission system connected generation units and PPMs*: The Grid Code specifies their mandatory reactive power compensation capability. Some providers (wind, BESS) may be able to provide in excess of their mandatory requirements, most notably providing Wattless provision, compensating at 0 MW.
 - *Assets owned by the TAO and operated by the TSOs*, including shunt reactors, capacitor banks, Statcoms).
 - *Synchronous condenser*.
 - *Distribution system connected assets such as wind farms and BESS* may provide compensation to the transmission system if they are located close to the transmission system.

Overview Reactive Power capability

Figure 5-2 provides an overview of potential providers of reactive power compensation in the greater Dublin region. Notably this area, like the other areas marked on the map in the figure, reflects generic study areas and transmission planning database models, which do not necessarily represent the zones representing the local need for reactive power.

Additionally, the figure shows that most components are able to compensate in both absorbing and producing direction (e.g. conventional generation units, synchronous condensers, hydro plant, wind farms, solar, interconnectors, BESS, Statcoms). However, some specific components can only absorb reactive power (like shunt reactors), while some can only provide reactive power (like capacitor banks).

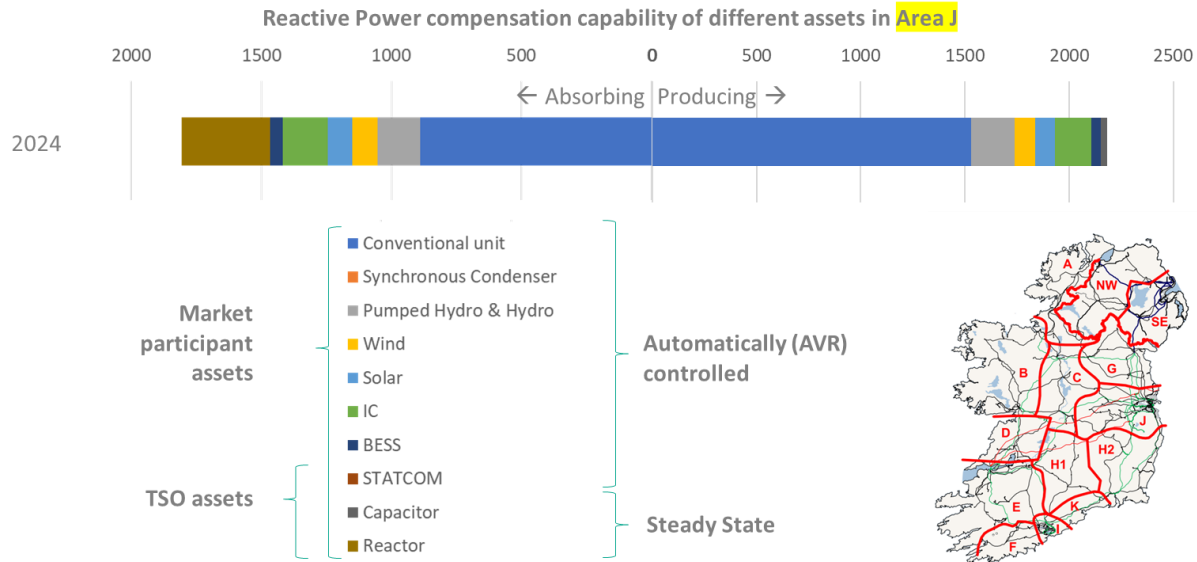


Figure 5-2: Overview of Reactive Power compensation capability in Area J (Greater Dublin region)²⁰

Figure 5-2 also shows that both third party generation/market participant assets and the TSO operated assets are able to compensate reactive power. Typically, TSOs invest in reactive power compensation equipment if the reactive power compensation capability in a particular location is forecasted to be insufficient to manage the voltage in a certain part of the network (see section 5.1.3).

Furthermore, most reactive power compensation assets are automatically controlled by AVR, which means that they continuously adapt their reactive power compensation level to the system needs. Other components are static, which means that they can only be controlled to fixed compensation levels.

Locational supply aspects

Figure 5-2 does not provide an overview of the compensation capability for the entire Irish power system, but only in one area and only for transmission connected assets. As indicated in Section 5.1.1, reactive power is a locational phenomenon and shall be compensated locally. Consequently, the reactive power capability of connected assets shall be reviewed regionally.

Distribution connected assets

The transmission and distribution system operators are responsible for maintaining the voltage within statutory limits in their own networks. Accordingly, these operators are in principle also responsible for the reactive power compensation in their networks.

An increasing number of relatively large wind farms, solar farms and BESS are being physically connected to the Irish distribution grids but are electrically very close to the transmission grid,

²⁰ Figures reflect full declared capability for conventional units and mandatory capability for PPMs. It has to be noted that this area, like the other areas marked on the map in this diagram reflect the study areas as per [Shaping Our Electricity Future studies](#) (figure 14) and transmission planning database models, which do not necessarily represent the zones representing the local need for reactive power.

this a trend that is expected to grow. Consequently, these assets can more efficiently support reactive power compensation in the transmission grid than in the distribution network. The TSOs consider there is significant potential in accessing reactive power support from distribution system connected assets and coordinate closely with both DSOs (NIE Networks and ESB Networks) on reactive power interactions.

Capability: Mandatory Grid Code requirements²¹

As per requirement in the Grid Code, generation assets connected to the transmission grid shall meet mandatory reactive power compensation requirements. The TSOs' Grid Codes specify mandatory ranges for reactive power compensation, both for conventional generation units²² and for controllable Power Park modules²³ (PPMs)²⁴, such as wind farms. Figure 5-3 shows that if the MW output of conventional generators and PPMs is above a certain threshold, they shall be able to absorb (leading) and producing (lagging) reactive power.

It is important to note that within the operational range of generation units and PPMs, the units shall be capable to compensate reactive power over a large range. As shown in *Figure 5-3*, for generation units the mandatory reactive power compensation range slightly shifts towards absorbing for higher active power (MW) setpoints. For PPMs, the mandatory reactive power compensation range is constant between 12% and 100% of the registered capacity.

Furthermore, the Grid Code requires that all generation units shall provide AVR capability²⁵ and that controllable PPMs shall have a voltage regulation system with similar response characteristics to a conventional AVR²⁶.

²¹ In this document we focus on Grid Code requirements. We note that Distribution Code requirements for reactive power are also in place.

²² [EirGrid Grid Code](#), CC.7.3.6

²³ 'PPM' is defined by the [Grid Code](#) as 'a Generation Unit or ensemble of Generation Units generating electricity which; • Is connected to the Network non-synchronously or through power electronics; • Has a single Connection Point to a Transmission System, Distribution System or HVDC System.'

'Controllable PPM' is defined by the Grid Code as 'A site containing at least one PPM can automatically act upon a remote signal from the TSO to change its Active Power output'

²⁴ [EirGrid Grid Code](#), PPM 1.6.3. It needs to be noted that controllable PPMs that have a single connection point on an offshore platform to the transmission system are exempted from these mandatory requirements and shall maintain a unity power factor or as agreed with the TSO.

²⁵ [EirGrid Grid Code](#), CC.7.3.8

²⁶ [EirGrid Grid Code](#), PPM 1.6.2

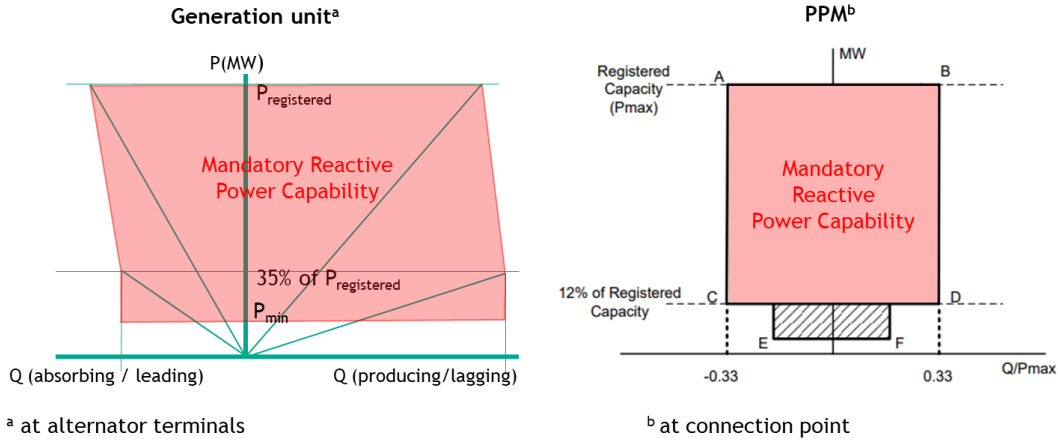


Figure 5-3: Mandatory Requirement for Reactive Power Capability for ‘Generation units’ (left, source: EirGrid Grid Code, CC.7.3.6) and transmission connected PPMs (right, source: EirGrid Grid Code PPM 1.6.3.1)

Non-mandatory capability: Capability in excess of Mandatory Grid Code requirements

Some providers are capable of providing more than the mandatory Grid Code requirements ((1) in Figure 5-4). Furthermore, certain units (including some BESS and wind farms) are able to provide reactive power compensation if their MW output is 0 MW, which is called ‘Wattless’ provision ((2) in Figure 5-4). Currently, some wind farms can provide Wattless reactive power compensation if there is no wind, and this characteristic is currently used in the operation of the grid.

It is noted that non-mandatory capability is not fully standardised. For example, different implementations of e.g. ‘Wattless’ provision exist. i.e. some wind farms can provide reactive power compensation completely independent from wind availability while others require a minimum wind speed to be able to provide reactive power compensation.

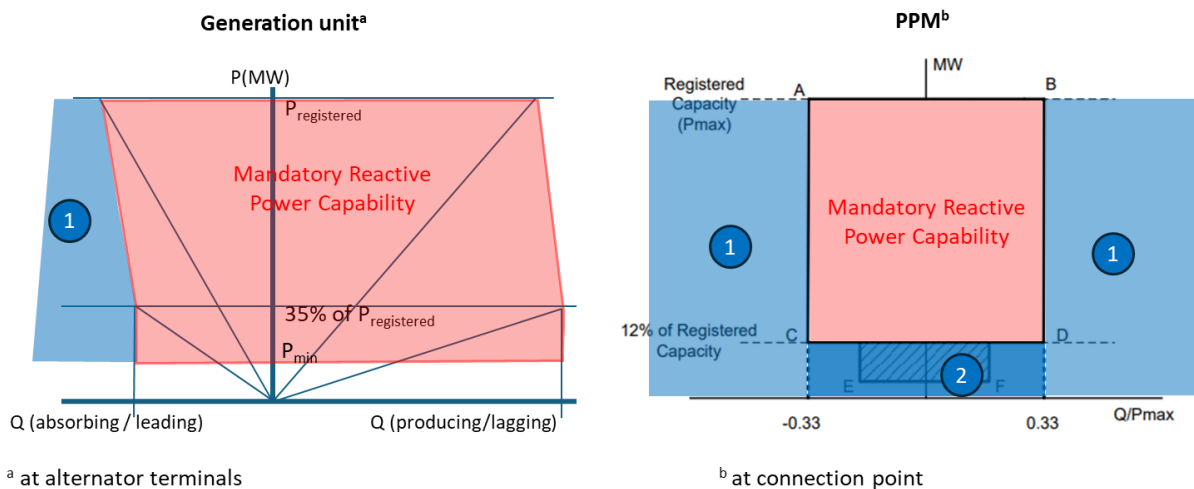


Figure 5-4: Examples of non-mandatory Reactive Power compensation capability: (1) excess of mandatory reactive power compensation (Q)-range; (2) Low load or Wattless provision.

5.1.3. How is reactive power planned?

Messages in this section:

- Voltage/Reactive power studies determine if the mandatory capability of generation units and PPMs and the TAO owned/TSO operated voltage compensation assets are sufficient to ensure voltage stability in each part of the power system.
- If insufficient reactive power compensation capability is available, this may result in new investments in reactive power compensation equipment.

Regularly, the TSOs perform voltage studies to ensure that the reactive power compensation capability is sufficient to meet their needs at each location in their network. If insufficient, the TSOs will determine the need for investment in reactive power compensation equipment, such as shunt reactors, capacitor banks, Static Var Compensators (SVCs) or Statcoms²⁷. For example, *Box 5-1* provides an example that shows that as a result of voltage studies new Statcoms in Ballynahulla and Ballyvouskill substations and shunt reactors in Knockanure have been installed mitigating the impact of both ‘high wind / low voltage’ and ‘low wind / high voltage’ scenarios.

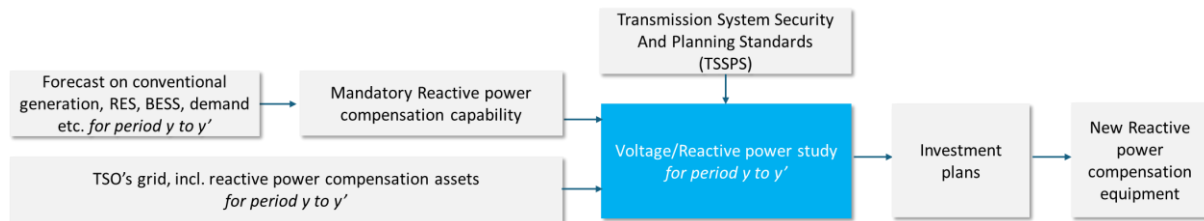


Figure 5-5: Schematic process leading-up to new investments in TSOs' reactive power compensation equipment

Figure 5-5 shows the process resulting in new investments in reactive power compensation equipment: voltage studies determine if sufficient reactive power compensation capability is available to keep the voltages on all nodes within the limits determined in the Transmission System Security and Planning Standards²⁸. If deficiencies in reactive power compensation capability are noted in certain areas, the studies determine what additional reactive power compensation equipment is needed, which may result in new investments in reactive power compensation equipment.

The TSOs undertake detailed assessments to identify locational reactive power support needs and follow a structured approach to investment decision making, with strong oversight and governance processes in place. Timelines from initial identification of the required infrastructure investments to energisation can take five years or more approximately, depending on the technology required, essential permitting processes and equipment availability etc.

²⁷ Investments are ultimately owned by the Transmission Asset Owners (TAOs), but the need for transmission investments is determined by the TSOs and the assets are operated by the TSOs.

²⁸ [TSSPS EirGrid](#); [TSSPS SONI 2023](#)

5.1.4. How is reactive power guaranteed/activated close to/in real-time?

Messages in this section:

- Activation of reactive power compensation varies throughout the day and over the seasons, dependent on the load and system situation.
- Reactive power compensation capability shall be sufficient to meet not only normal situations, but also post contingency, emergency and restoration situations.
- Specified constraints to the scheduling and dispatch process ensure that local needs for reactive power compensation are fulfilled.
- These constraints may result in the need to replace less expensive/low emission generation (RES) by more expensive generation/higher emission generation (conventional), which results in less efficient dispatch and higher emissions.

Reactive power compensation needs largely depend on the system situation and continuously change. Figure 5-6 shows a real-world example of the reactive power compensation by a single plant for one day. As expected, the figure shows that there is reactive power absorption during periods of low load, hence during the night and reactive power production at periods of high load, during the day.

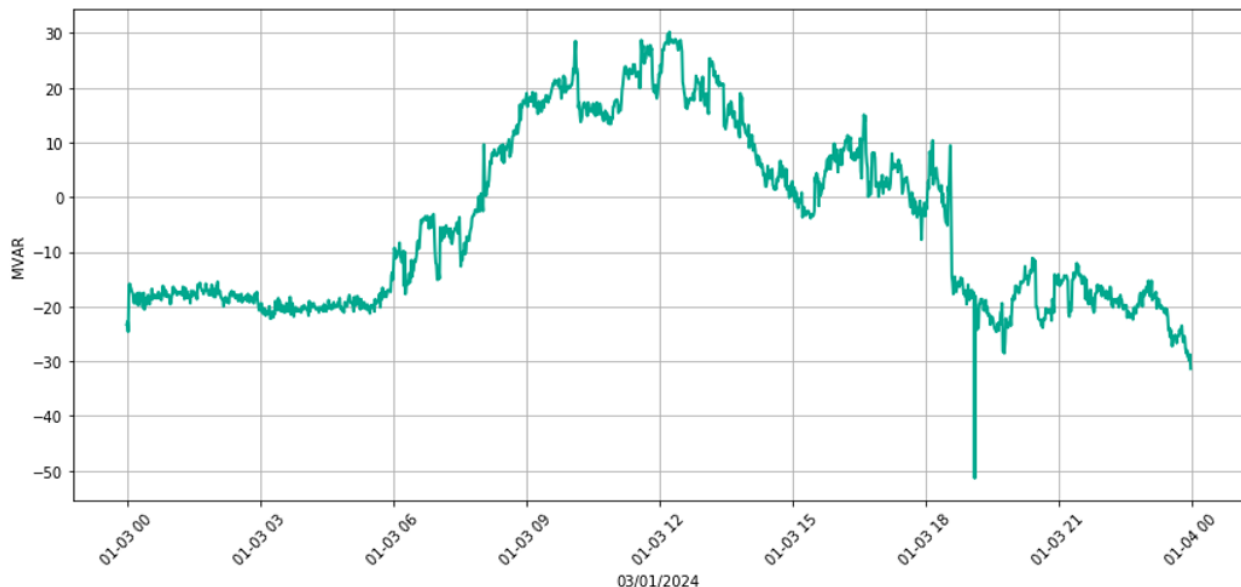


Figure 5-6: Example of Reactive Power compensation volatility for one day for a single plant.

Considering the constant variation in reactive power need, the TSO control centre staff continuously take action in managing the voltage and the reactive power balance, by a) operating transmission assets (shunt reactors, capacitor banks, tap changers) and b) instructing new reactive power setpoints of third-party connected assets²⁹. A new reactive power setpoint shall be implemented by operators of such assets within minutes ((1) in Figure 5-7). After

²⁹ Setpoints may take different forms, such as a targeted voltage, a targeted power factor or a targeted reactive power exchange.

implementing the new setpoint, the AVR continuously performs the fine tuning ((2) in *Figure 5-7*).

To assist the control centre staff with the increasing voltage control/reactive power challenges, the TSOs are developing and testing the Voltage Trajectory Tool (VTT)³⁰. This decision support tool proposes optimal reactive power/voltage control actions for keeping the voltage within the (OSS) standards in the next 10 hours. The VTT aims for minimising control actions and prioritises local control actions which implicitly minimises network losses. Hence, the VTT assists the TSO in real-time with guaranteeing efficient voltage control/reactive power activation under normal operating conditions, as well as during and after disturbances.

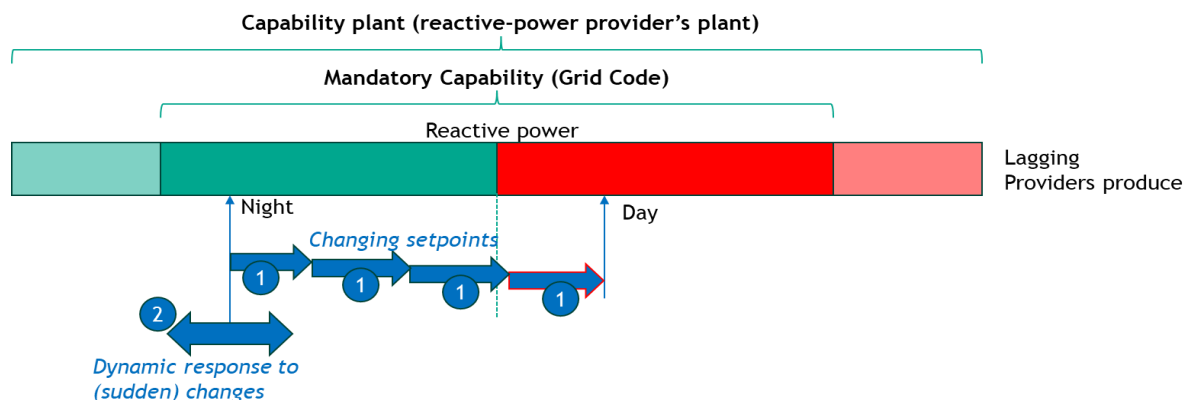


Figure 5-7: Reactive power operation: based on instructions by the System Operator, the asset owner changes the reactive power setpoint. From these setpoints, AVR continuously adapts the reactive power compensation.

It is noted that *Figure 5-6* shows the continuously changing reactive power exchange of a power plant during normal situations with a secure network. This is not the most demanding situation for which the TSOs need to ensure sufficient reactive power capability. Before real-time, the TSOs shall therefore make sure that sufficient reactive power capability is available for managing the voltage in the following situations (see for more detail section 5.2.1):

- *Normal situation with all network components available.*
- *Contingency situations.*
- *Emergency and restoration situations.*

Considering this, the reactive power compensation need depends largely on situations that hardly happen, such as certain contingencies, emergencies or restoration situations. For these situations, it is important that the TSOs have access to the full mandatory capability of reactive power providers.

As indicated above, the mandatory requirements for generators and PPMs ensure that reactive power can be compensated by transmission grid connected assets. However, these requirements only apply if the active power generation is larger than P_{min} . This means that the unit needs to be dispatched to be able to provide reactive compensation services, at least at P_{min} . If the unit is dispatched, typically the full mandatory range will be available.

³⁰ For more detail, please refer to paper [Development of Look Ahead Reactive Power Resource Optimisation Tool for Voltage Security in IBR Dominated Systems](#)

Hence, for areas where the TSOs require reactive power compensation capability provided by market participants in real-time, the TSOs' Scheduling and Dispatch process needs to ensure that sufficient units with that capability are dispatched. Within the Scheduling and Dispatch process this is managed by fulfilling the constraints for voltage. These constraints are included in the Weekly Constraint Updates. *Table 5-1* shows an example which states that, for voltage reasons, at least two large generators shall run in the Dublin area.

Active Ireland Constraints

Name	TCG Type	Limit Type	Limit	Resources	Description
Dublin Generation	NB	N:>=	1 Unit	DB1, HNC, HN2	There must be at least 1 large generator on-load at all times in the Dublin area. Required for voltage control
Dublin Generation	NB	N:>=	2 Units	DB1, HNC, HN2, PBA, PBB	There must be at least 2 large generators on-load at all times in the Dublin area. Required for voltage control. This assumes EWIC is operational. Note that during an outage of EWIC there must be at least 3 large generators on-load at all times in the Dublin area.

Table 5-1: Example constraint for Voltage/Reactive Power reasons (Source: [Wk8_2026_Weekly_Operational_Constraints_Update_0.pdf](#))

If ex-ante market outcomes result in market participants that indicate there will be no or not sufficient large conventional units in the Dublin area, the TSOs will (aligned with current operational constraints) need to redispatch one of these units to generate at its min stable generation level at least. Thereby the new schedule disturbs the SEM's MW system balance. This means that other units may need to be dispatched down, probably RES, like wind generation. Consequently, less expensive generation (RES) is replaced by more expensive generation (conventional). This results in less efficient dispatch. Moreover, generation with lower emissions (RES) is replaced by generation with higher emissions (conventional units).

Accordingly, operational constraints which result in must run requirements for TCGs shall be mitigated and/or the impact of the constraints shall be minimised.

5.1.5. Steady State Reactive Power (SSRP) Procurement

Messages in this section:

- The SSRP product serves the following objectives:
 - o Incentivising availability of (mandatory and non-mandatory) Reactive Power compensation capability.
 - o Incentivising provision of Reactive Power compensation capability ranges on top of the mandatory requirements, especially related to the non-mandatory Wattless provision.
 - o Lowering P_{\min} of conventional generation in order to reduce the need to replace less expensive/low emission generation (RES) by more expensive generation/higher emission generation (conventional).
- The SSRP product provides incentives to the providers to:
 - o Keeping Reactive Power providing units available.
 - o Increase their reactive power compensation capability range.
 - o Reduce minimum generation P_{\min} at which reactive power compensation can be provided.
 - o Provide reactive power compensation without exchanging active power (MW), i.e. Wattless provision.
- The volume of the SSRP product (in MVAR) does not directly reflect the reactive power capability of the providing units as its determination includes a factor dependent on P_{\min} .
- The SSRP product does not distinguish between absorbing and producing and does not reflect the location of the providing unit.

There are three attributes that may reduce the impact of the constraints described in the previous section:

- 1) *Increase of reactive power compensation capability range*: The more reactive power individual units may compensate, the less redispatch should be required.
- 2) *Reduction of minimum generation at which reactive power compensation can be provided*: By reducing the minimum generation, the amount of generation redispatch from RES to conventional generation can be minimised.
- 3) *Wattless provision*: If units are capable of providing reactive power compensation without exchanging active power (MW) with the grid, it would prevent the need for redispatch

These attributes are currently incentivised by the SSRP product for which the available volume of a providing unit in a trading period is equal to^{31,32}:

$$SSRP_{Available\ Volume} = SSRP_{range} \cdot RP_{factor} \cdot Unit_{status}$$

Formula 5-1

Where,

- $SSRP_{range}$ is equal to the sum of the declared reactive power (leading) and declared reactive power (lagging) for any trading period (see Figure 5-8).
- $RP_{factor} = \frac{P_{reg} - SSRP_{MinGen}}{P_{reg}}$ (for generation units)
- $RP_{factor} = 1$ (for providing unit not operating as a generation unit, e.g. for dispatchable synchronous condensers and dispatchable loads)
- P_{reg} is the registered capacity of generation units. It is defined in the Grid Code and for all other providing units as the maximum capacity, expressed in whole MW, that a providing unit can deliver on a sustained basis, without accelerated loss of equipment life, at the connection point.
- $SSRP_{MinGen}$ means the time-weighted average of the minimum MW output a providing unit can maintain on a continuous basis whilst providing reactive power control during that trading period as notified by the service provider to the TSO in accordance with a process specified by the TSO.

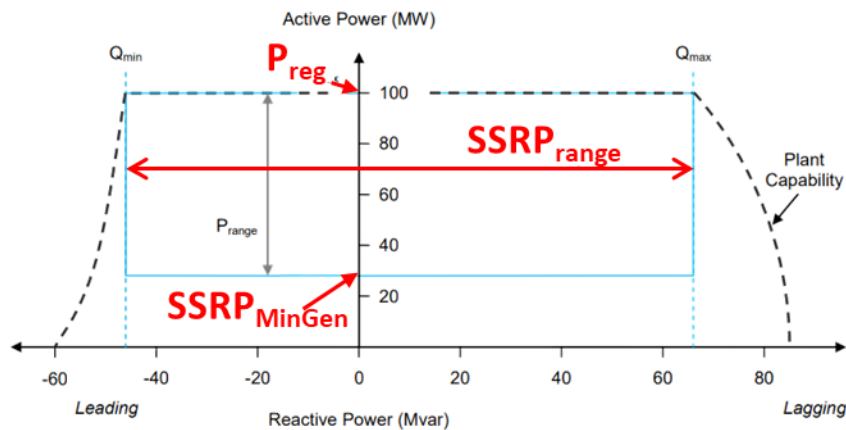


Figure 5-8: Reactive Power provision of a unit and parameters of formula 5-1

- $Unit_{status}$ is percentage of the trading period during which the providing unit is synchronised or connected to the power system and capable of providing reactive power control.

Accordingly, SSRP providers are incentivised to provide a large *reactive power compensation capability range*, as this linearly increases their calculated SSRP volume ($SSRP_{range}$). A larger reactive power range may reduce the number of conventional units that need to be constrained

³¹ [DS3 System Services Agreement](#)

³² It is noted that generation units such as CCGTs may operate in different modes and accordingly have different (SSRP) characteristics for the different modes.

on and accordingly reduce redispatch. A similar impact is achieved by the incentive to reduce $SSRP_{MinGen}$ which does not reduce the number of the units, but the active power production of the SSRP providing units that are dispatched on. Consequently, the amount of generation redispatch from RES to conventional generation can be reduced. Hence, the SSRP product serves three objectives: 1) incentivising an increase of reactive capability ranges; 2) keeping SSRP providing units available and 3) ensuring more efficient dispatch with less emission.

As discussed, suppliers that provide SSRP are remunerated for their service, with the SSRP payment which is described below:

$SSRP_{TradingPeriodPayment} = SSRP_{AvailableVolume} \cdot SSRP_{PaymentRate} \cdot SSRP_{ScalingFactor} \cdot Trading\ Period\ Duration$
--

Formula 5-2

Where

- **$SSRP_{Payment\ Rate}$** is the Payment Rate (expressed in €/MVarh) applicable to SSRP;
- **$SSRP_{Scaling\ Factor} = SSRP_{Performance\ Scalar} \cdot SSRP_{Product\ Scalar} \cdot SSRP_{Wattless\ Scalar} \cdot SSRP_{Locational\ Scalar} \cdot SSRP_{Temporal\ Scarcity\ Scalar}$**
- **$SSRP_{Performance\ Scalar}$** is determined based on whether the result of the performance assessment is a pass or fail.
- **$SSRP_{Product\ Scalar}$** is calculated on a time-weighted average basis is an amount equal to:
 - 2, where the providing unit has declared that it is capable of providing AVR during the trading period; and
 - 1, where the providing unit has declared that it is not capable of providing AVR during the trading period, as notified by the service provider to the TSO in accordance with a process specified by the TSO.
- **$SSRP_{Wattless\ Scalar}$** is an amount equal to:
 - 2, in the event that the Providing Unit has been instructed by the TSO to provide reactive power control at a zero MW output level; or
 - 1, otherwise.
- ***Trading Period Duration*** is the Trading Period Duration (expressed in hours).
- For **$SSRP_{Locational\ Scalar}$** and **$SSRP_{Temporal\ Scarcity\ Scalar}$** we refer to the DS3 System Services Agreement.

The formula for remunerating SSRP suppliers contains two additional incentives. The first incentive is referred to as the ‘wattless’ scalar. If a supplier can provide reactive power control at 0 MW output level (Wattless), the supplier can have its settlement doubled. The second incentive is for the provision of AVR, also doubling the remuneration of the supplier.

		Unit A	Unit B	Unit C	Unit D (Wattless)	Unit E (synchronou s condenser)
(1)	Registered Capacity	400 MW	400 MW	400 MW	400 MW	
(2)	<i>SSRP-range</i>	<i>200 MVar</i>	<i>200 MVar</i>	<i>200 MVar</i>	<i>200 MVar</i>	<i>200 MVar</i>

(3)	SSRP _{MinGen}	200 MW	200 MW	100 MW		
(4)	RP factor (3)/(1)	0.5	0.5	0.75	1	1
(5)	SSRP Available Volume (2)*(4)	100 MVar	100 MVar	150 MVar	200 MVar	200 MVar
(6)	AVR	No (=1)	Yes (=2)	Yes (=2)	Yes (=2)	Yes (=2)
(7)	Wattless	No (=1)	No (=1)	No (=1)	Yes (=2)	Yes (=2)
(8)	Basis for payment³³ (5)*(6)*(7)	100 MVar	200 MVar	300 MVar	800 MVar	800 MVar

Table 5-2: Illustrative example of SSRP Available Volume and the Basis for payment.

Table 5-2 provides a worked example demonstrating that the SSRP volume and the SSRP basis for payment differ for each of the corresponding reactive power suppliers. This divergence occurs despite all suppliers being capable of 200 MVar of reactive power compensation and possessing a 400 MW registered capacity (except for unit E).

Although the capability to compensate reactive power (the SSRP-range) of all units is the same, the SSRP-volume differs from 100 to 200 MVar, resulting from varying SSRP_{MinGen} across the suppliers. Moreover, the basis for SSRP payments ranges from 100 to 800 MVar, as it has a dependency on AVR availability and Wattless provision. It should therefore be noted that the SSRP Volume may diverge from the physical reactive power compensation range.

Accordingly, it can be concluded that the SSRP volume does not one-to-one reflect the system need for reactive power compensation for the following reasons:

- SSRP volume formula results in a difference between SSRP volume and the actual reactive power range, dependent on P_{min}.
- SSRP volume does not directly address specific locational needs but provides the same incentives for reactive power providers.

SSRP volume does not differentiate between absorbing reactive power compensation capability and producing reactive power compensation capability.

5.2. System Need

5.2.1. Objectives

Messages in this section:

- Reactive Power compensation capability is required to meet voltage requirements in RA approved regulations and standards, including EirGrid and SONI OSS and Grid Codes, which implement EU Network Code SOGL.

³³ $SSRP_{Available\ Volume} \cdot SSRP_{Scaling\ Factor}$

- Reactive Power compensation capability is required to ensure operation in emergency and restoration situations, as per RA approved System defence plan and system restoration plan which implement EU Network Code Emergency and Restoration (ER).

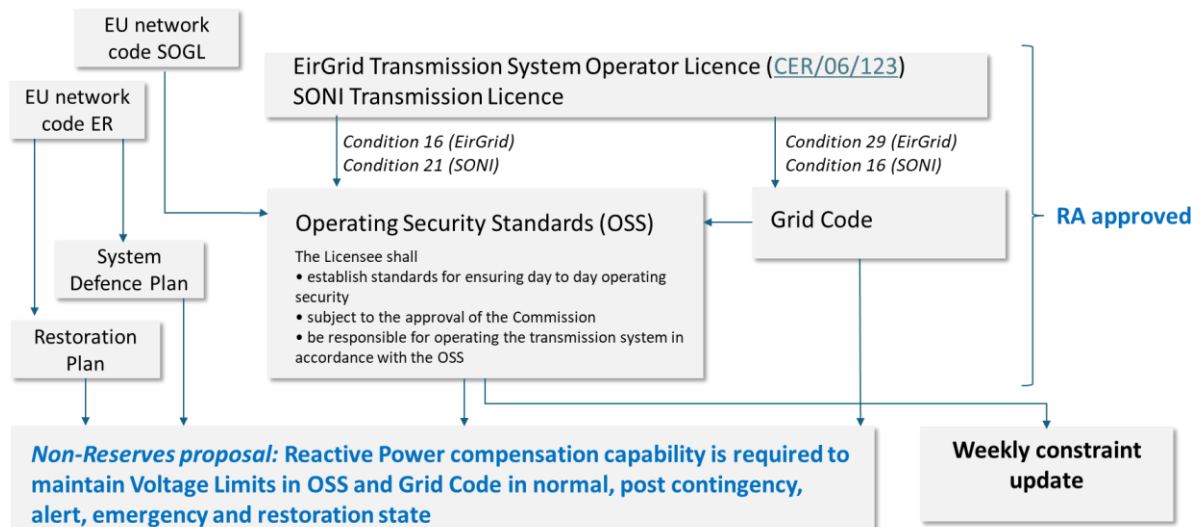


Figure 5-9: Regulatory context of proposals for Reactive Power need

The objective of reactive power compensation is to keep the voltage in the system within secure limits, in all situations, including:

- **Normal state without contingencies:** Table 5-3 shows the voltage ranges specified in EirGrid’s and SONI’s OSS and Grid Codes within which their transmission networks shall operate. The voltage levels measured in the network and at the connection points shall be within this voltage range for a situation without contingencies. In addition to the voltage ranges, EirGrid’s OSS requires that ‘the maximum voltage step change for operational switching [...] shall not exceed 10%’. Similarly, SONI OSS only allows voltage steps up to $\pm 3\%$ ³⁴.
- **Post contingency:** Table 5-3 also shows the post-contingency voltage ranges specified in EirGrid’s and SONI’s OSS within which their transmission networks shall operate. This means that after a contingency, the steady state voltage shall return to the specified range, potentially after mitigation measures, such as switching reactive power compensation or instructing reserve providers to change their reactive power setpoints. In addition to the voltage ranges, EirGrid’s OSS defines that ‘the maximum voltage step change for [...] ordinary contingencies shall not exceed 10%’. SONI OSS requires the voltage step to be below 6% following the loss of single circuit or not exceeding -10%/+6% following the loss of double circuit overhead line.
- **Alert State, Emergency state and System Restoration:** In situations not foreseen in the OSS, reactive power compensation plays a crucial role for returning to the normal

³⁴ For ‘operational switching less frequent than specified in ER P28’ and ‘in accordance with ER P28’ otherwise.

state. As these states are highly unpredictable, the TSOs shall have access to all available reactive power compensation capability, either from dispatched units or non-dispatched units.

	The transmission system shall operate within the voltage ranges	
Nominal voltage	Normal state range	Post-contingency range
400 kV (IE)	370 - 410 kV (92.5 - 102.5%)	360 ³⁵ - 420 kV (90 - 105%)
275 kV (NI)	247.5 - 302.5 (90 - 110%) ^a	
275 kV (IE)	260 - 300 kV (94.5 - 109.1%)	250 - 303 kV (90.9 - 110.2%)
220 kV (IE)	210 - 240 kV (95.5 - 109.1%)	200 - 245 kV (90.9 - 111.4%)
110 kV (IE)	105 - 120 kV (95.5 - 109.1%)	99 - 123 kV (90.0 - 111.8%)
110 kV (NI)	99 ^a - 121 kV (90 - 110%)	
^a Where possible, the steady state pre-fault voltage on the transmission system will be no lower than 95% of nominal.		

Table 5-3 Voltage range in accordance with EirGrid and SONI OSS and Grid Codes³⁶

5.2.2. Future need for Reactive power close to/in real time

Messages in this section:

- Voltage control by reactive power compensation will become more and more volatile, particularly due to the volatile nature of RES.
- In all areas of the grid, the TSOs shall be able to control the voltage continuously by making use of sufficient reactive power compensation capability.

Increasing RES and other future developments will impact the need for reactive power compensation in Ireland and Northern Ireland. One main characteristic is that the reactive power compensation need will be more flexible because of the volatile nature of most RES, i.e. wind farms and solar. Accordingly, the TSOs shall be able to continuously control the voltage by making use of the reactive power compensation capability.

As voltage is a local phenomenon in power grids, the need for reactive power compensation capability will vary across different locations in Ireland and Northern Ireland. *Box 5-1* provides an example for South West Region of Ireland and *Box 5-2* provides an example for the East of Northern Ireland. Similar to today's process (as described in section 5.1.3), results of voltage studies will be used for identifying the need for specific TSO investments in reactive power compensation equipment, the potential location of new synchronous condensers (LCIS) or future provision by market participants (e.g. BESS or PPM), either based on their mandatory

³⁵ 350 kV in EirGrid Grid Code.

³⁶ Sources: [EirGrid OSS](#), [SONI OSS](#), [EirGrid Grid Code](#) CC.8.3, [SONI Grid Code](#) CC5.4.

requirements (Grid Code) or additional capabilities, such as compensation at 0 MW output (Wattless provision).

Box 5-1: Example Reactive Power compensation needs in South West Region of Ireland

Because of the large increase of wind generation in the South West region, EirGrid carried out a series of studies investigating the impact of this new generation on the voltage stability in the region. These studies concluded that there is a requirement for both capacitive and inductive reactive support, as seen under two separate scenarios described, namely a high wind / low voltage scenario and low wind / high voltage scenario:

High Wind / Low Voltage Scenario:

The 220 kV network in the South West is essentially a single circuit path from north Kerry to east Cork, with intermediate 220 kV stations which act as collection points for the wind generation. The worst single contingency for voltage stability in the South West occurs for a trip of the Ballyvouskill - Clashavoon 220 kV circuit (1) and forces all the wind connected into Knockanure, Ballynahulla and Ballyvouskill 220 kV stations to flow north towards Moneypoint (2). This event also cuts off the reactive support to the South West region from the conventional generators located in Cork (3). While the power flow levels seen do not cause thermal overloads on transmission circuits, they absorb more reactive power³⁷ which causes the voltage to decline which may even lead to voltage collapse. For mitigating this risk, 200 MVar of producing dynamic voltage support (capacitive, lagging) nature must therefore be located in the region(4) .

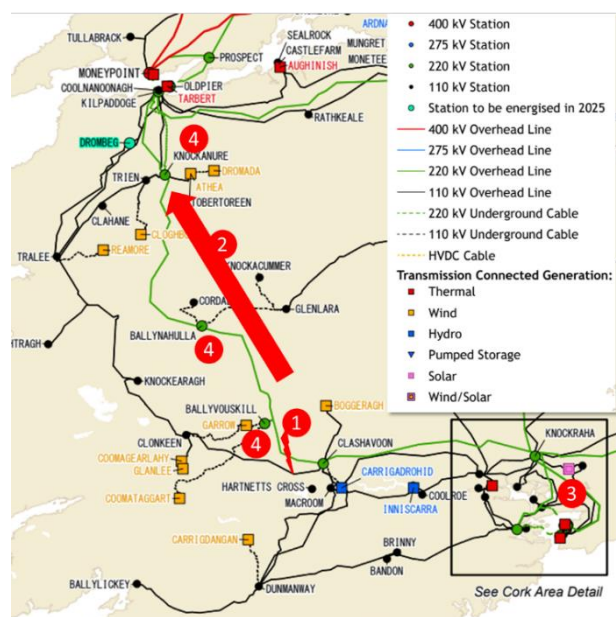


Figure 5-10: Need for low voltage support in South/West Ireland

Low Wind / High Voltage Scenario:

In the South West region there is a significant concentration of underground cable which produce reactive power causing a voltage rise in the network, both under intact and single contingency conditions. During certain low or no wind generation scenarios the network is lightly loaded and the worst single contingency (a trip of the Ballyvouskill - Clashavoon 220 kV circuit) may cause severe high voltages (up to 120% of the nominal voltage, well outside the planning standards). For mitigating this risk, 250 MVar of absorbing dynamic voltage support (inductive, leading) nature must therefore be located in the region.

Investments

³⁷ The flows are larger than the surge impedance loading (SIL) of the circuits, which means that the lines will absorb reactive power.

In order to mitigate both issues above, the TSO has installed ± 100 Mvar Statcoms in the Ballynahulla and Ballyvouskill 220 kV stations (both energised in 2023) and 50 Mvar of shunt reactors in the Knockanure 220 kV station (energised in 2021).

Box 5-2: Example Reactive Power compensation needs in the East of Northern Ireland

In the East of Northern Ireland near Belfast system voltages during normal operation can be as high as 1.06 per unit on the 110 kV system, particularly during the night when the system demand is significantly lower. This area of the transmission system has a greater portion of underground cable. Also due to the lower system demand the lightly loaded 275 kV system acts like a capacitor, producing MVars.

SONI use a variety of methods to reduce high system voltages, including the dispatch of shunt reactors. These shunt reactors are used operationally every day, with all available reactors in service throughout the night. Currently there are seven shunt reactors available connected at Castlereagh, Hannahstown, Kells and Tandragee. In 2019 SONI received Utility Regulator (UR) approval to add four additional shunt reactors to the transmission system - connected at Castlereagh, Tamnamore and Tandragee GSPs. NIE Networks has installed two of these new reactors to the system, while also carrying out asset replacement of some of the existing seven reactors.

With these works progressing concurrently the existing fleet of shunt reactors has not increased in number, and voltage control remains a concern for the control room. Very often this results in thermal generation operating with leading power factors to absorb system MVars. Reactive support available from transmission wind farms and batteries connected to the 110 kV system is helping to bridge the gap and provide some support to the shunt reactors on the system. Studies show that for the trip of any thermal generator in NI (see figure 5-11), the response from this transmission connected wind and batteries (along with support from available shunt reactors) will help to keep system voltages from exceeding statutory limits and cascading into voltage runaway.



Figure 5-11 -High voltage issues in the East of Northern Ireland

Future studies show that with the procurement of LCIS (synchronous compensators) and the completion of the shunt reactor project more options will be available to the control room to manage system voltages. Until then, the procurement of reactive power support from generation remains significantly important to the control room and must remain to prevent further voltage control issues.

5.2.3. How to forecast the needs for Reactive Power compensation?

Messages in this section:

- Reactive power needs are a result of local developments in the grid, such as new generation and demand, and new transmission lines which can have lead times of 5-10 + years.
- Hence, considering the timescales involved in procuring and commissioning reactive support equipment, a meaningful needs assessment for reactive power compensation requirements may focus on local system needs looking 3-10 years ahead.
- Closer to real-time, the availability and the commitment of the unit determine the availability of the reactive power compensation capability.

Years ahead

As discussed in section 5.2.1, reactive power compensation capability needs shall be available for managing different system conditions: fully available system, single contingencies, alert and emergency states and restoration situations. To manage these situations, the TSOs shall be able to access at least the mandatory reactive power capability available in the system. If not sufficient, the TSOs may also require their own assets and/or benefit from the non-mandatory capability of reserve providers, including Wattless provision. As described in section 5.1.3, the TSOs assess these needs as part of the Transmission Planning process.

Accordingly, the reactive power compensation needs result from long-term voltage studies which may trigger investment decisions by the TSOs. Alternatively, market participants may make available additional non-mandatory reactive power compensation capability, including Wattless compensation capability.

Reactive power needs are a result of other developments in the grid, such as new generation and demand, and new transmission lines. Accordingly, reactive power planning needs to be undertaken in a manner that accounts for expected generation and network upgrades (which can have lead times of 5-10 + years) while also cognisant of the timescales involved in procuring and commissioning reactive support equipment. Hence, a meaningful needs assessment for reactive power compensation requirements may focus on system needs looking 3-10 years ahead, identifying both mid- and long-term needs. The TSOs will then determine the appropriate technology investments to meet such requirements.

Year ahead - real time

Year ahead to real-time, it shall be ensured that in real-time sufficient reactive power compensation capability is available. Up to day-ahead, this requires considerations on e.g. maintenance planning. Closer to real-time the unit commitment determines the availability of reactive power compensation capability. Accordingly, in scheduling and dispatch processes, unit commitment constraints may apply if a minimum number of units are required within a certain zone for voltage control. These constraints are currently managed in a TCG (as discussed in Section 5.1.4) and are continuously under review³⁸.

³⁸ See [EirGrid-SONI-Operational-Policy-Roadmap-2025-2035.pdf](#)

5.2.4. Future system need for reactive power compensation

Based on the previous sections, the TSOs conclude with respect to the future system need for reactive power compensation, that:

- Traditionally conventional generators have been providing the majority of reactive power compensation, moving away from this dependency requires other technologies to provide compensation.
- Compensation of reactive power will be different per area, but in general be more volatile and increasing because of increased RES.
- TSO investments can be reduced if capability of market participants can be used. This applies to both the mandatory compensation range, and to capabilities in excess of the mandatory range (non-mandatory), especially with respect to compensation at 0 MW.

5.3. Service Providers

Messages in this section:

- In the coming years, the TSOs expect the connection of substantial offshore wind farms which will provide reactive power support at their onshore connection points.

Figure 5-12 provides a comparison between the 2024 reactive power compensation capability in the greater Dublin area and the forecasted capability for 2030, based on the forecast of conventional generation, RES, BESS etc. for 2030. The figure shows that - in this area - the total reactive power compensation will increase, both on the absorbing and on the producing side. This is mainly due to increasing conventional and wind generation and a new STATCOM this area.

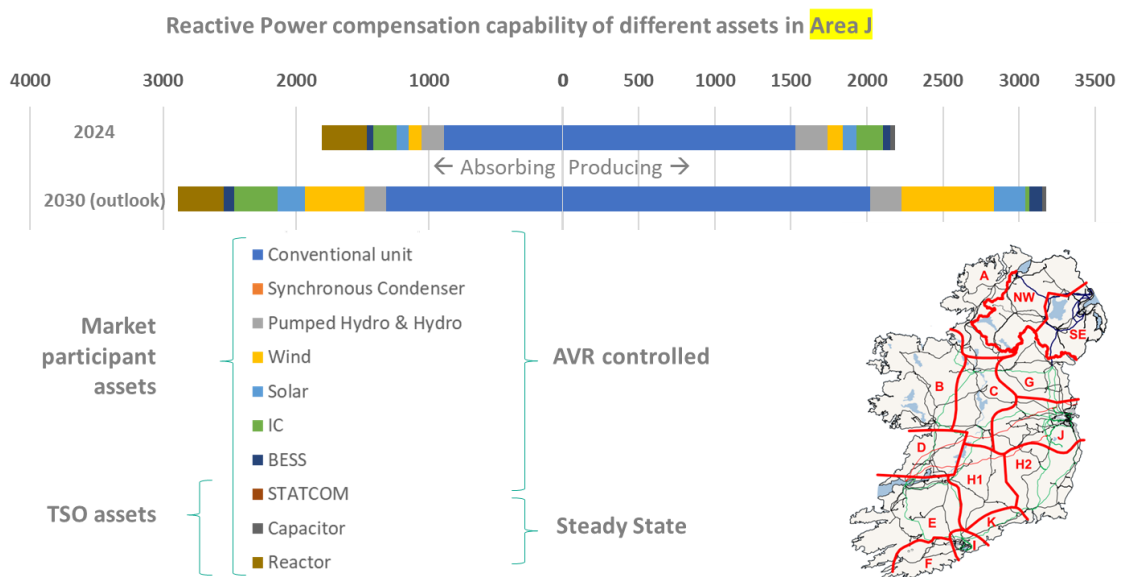


Figure 5-12: Overview of Reactive Power compensation capability in 2024 and an outlook for 2030 for Area J (greater Dublin region)³⁹

In the coming years, the TSOs expect the connection of substantial offshore wind farms which will provide reactive power support at their onshore connection points. As this may be done by means of Statcoms, these wind farms may be able to provide the reactive power compensation Wattless. Also, BESS are able to provide reactive power without exporting or importing to the Grid.

In addition, as discussed in section 5.1.2, distribution connected assets may well support the voltage control in the transmission grid. Similarly, new HVDC interconnectors may add reactive power compensation capability to the grid.

Figure 5-13 provides an overview of the SSRP procurement as per 2024/Q4. The first part of this figure shows the contracted SSRP available volume in MVar. As described in section 5.1.5, the MVar values in this figure are not comparable with the MVar in *Figure 5-12* because the SSRP volumes have been multiplied with the RP-factor, which is dependent on the minimum active power generation (MW) of the providing plant. Furthermore, SSRP does not distinguish between reactive power production and absorption capability and geographical location. The second graph shows the provided SSRP volumes for 2024/Q4 while the third graph shows the actual payments.

³⁹ Figures are illustrative and may contain some inaccuracies.

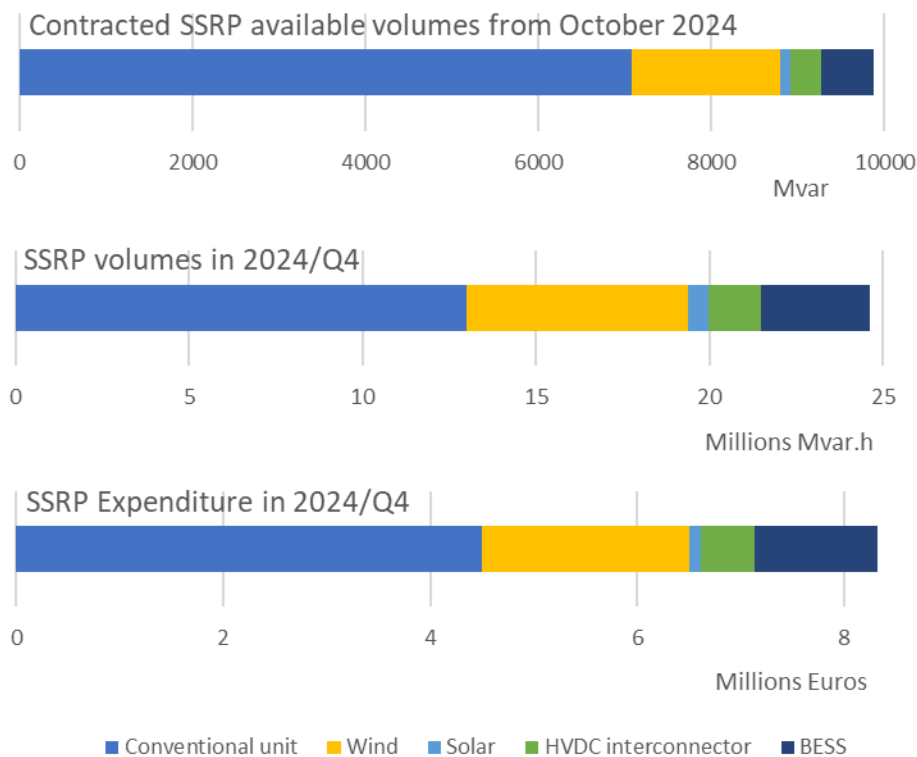


Figure 5-13: SSRP contracted volumes (after Gate 11), SSRP volumes for 2024/Q4 and SSRP expenditure for 2024/Q4, shown for different categories of SSRP providers

5.4. International experience

Messages in this section:

- Most TSOs apply mandatory provision of reactive power compensation, some with and some without a compensation payment for activation.
- Some TSOs (in GB, BE, NL) procure their reactive power compensation needs based on tenders with a contract term of one up to 10 years, resulting in bilateral contracts. This may cover part of their need on top of the mandatory Grid Code requirement (GB) or the full need (BE, NL).
- Short term markets have been studied (GB, ES), but are not implemented.



Figure 5-14: Voltage control procurement scheme in EU countries in 2021 (Source: [ENTSO-E](#))⁴⁰

As shown in *Figure 5-14*, in 2022 most European countries relied on mandatory provision of voltage control/reactive power compensation services. In some of these countries TSOs pay a compensation payment for activation, while in other countries reactive power compensation needs to be provided for free.

Many TSOs recognise trends towards increasing need for intervention to manage voltage which may result in increasing synchronisation cost and utilisation cost and more often fossil fuel generation instructed to manage the voltage. At the same time, it is recognised that RES and BESS could provide voltage support. In this changing environment and urged by the EU Directive 2019/944⁴¹, TSOs are studying how to obtain full capability from new providers (in excess of their mandatory requirements) and if this can be done by competitive arrangements. Below and in *Table 5-4* we describe three countries with experience in procuring reactive power services, all of them using of tenders and long-term contracts.

⁴⁰ It shall be noted that this overview may not be completely up to date as EU TSOs are currently working on the implementation of market-based procurement on non-reserves, as EU Directive 2019/944.

⁴¹ Article 40(5), stating that market-based procurement is applied to non-frequency ancillary services unless the regulatory authority has assessed it to be economically inefficient and has granted a derogation.

		Great Britain	Netherlands	Belgium
Mandatory service	Product	<i>Obligatory reactive power service (ORPS) for transmission connected generators</i>	<i>Dynamic (AVR) response as per Grid Code requirement</i>	<i>Mandatory annual tendering for eligible units ≥ 110 kV</i>
	Procurement	None	None	annual tendering
	Contract	Mandatory Services Agreement (MSA)	None	Individual negotiated bilateral contracts
	Payment	Fixed regulated tariff for the use/activation (4.57 £/MVAh in October '25)	No compensation payment	Prices subject to RA's reasonability check. 8 different prices for activation possible.
Non-mandatory service	Product	Long term Tenders for new emission free reactive power compensation.	<i>Stationary Reactive Power ('stationair blindvermogen')</i>	<i>Voluntary for units without mandatory requirement</i>
	Procurement	Incidental tenders initiated on locational need basis, TSOs/TAOs may participate	Annual Tender	Annual Tender
	Contract	Typically, 9-10 years contracts with 4 years lead time.	Individual negotiated bilateral contracts	Individual negotiated bilateral contracts
	Payment	Price may be for available capability	Price as per bilateral contract	8 different prices for activation possible. Prices subject to RA's reasonability check.

Table 5-4: Comparison of reactive power procurement from third-party connected assets⁴²

Great Britain

In GB, NESO pays a fixed regulated tariff (4.57 £/MVAh in October 2025⁴³) for the use/activation of the Obligatory Reactive Power Service (ORPS) to all generators covered by the mandatory reactive power capability requirements in the Grid Code⁴⁴. This payment is historically based on cost for gas-fired units and may need to be reconsidered because of the changing generation mix.

Aiming for new emission free reactive power compensation capability, around 2020 NESO started tendering for long-term contracts with a duration of typically 9-10 years, after a lead time (for constructing new assets) of 4 years. The tender procedure is initiated occasionally

⁴² Based on [NESO](#), [NESO ORPS](#), [NESO Grid Code](#), [NESO payment rates](#), [NESO ERPS](#), [NESO CUSC](#), [NL Grid Code](#), [TenneT Reactive Power procurement](#), [Eliä T&C Voltage Service Providers](#), [CREG](#), [ELIA Proposal for 2025-2026](#)

⁴³ Source: [NESO](#)

⁴⁴ Which is for *Synchronous units (above 50 MW in England and Wales and 10-30 MW in Scotland)*: 0.85 (lag)-0.95 (lead) and for *Non-Synchronous units*: 0.95 (lag)-0.95 (lead) (source: [NESO](#))

triggered by voltage studies determining the need for additional voltage support in certain areas. The tendered reactive power capability is accordingly locational and characteristics (static and/or dynamic, absorption and/or production, Wattless) are tailored to the specific local need. Typically, the payments are based on availability (per settlement period, based on pay-as-bid), and ORPS payments do not apply to units owning a long-term contract. It shall be noted that also the TSOs/TAOs can participate in the tender.

Until now (after the first tender provides the service), NESO has positive experience with these long-term tenders. Feedback from industry indicates a wish for combining different products in single tender procedures: voltage support, system stability and e.g. restoration services

Currently, the introduction of a Medium term market is being discussed. This market should aim for catering for needs due to e.g. outages, using existing capability not under ORPS. The contract duration will be 1 year or bespoke to need, with a lead time of a year or less⁴⁵.

A detailed review into future reactive power services concluded in 2022, where it was determined that a combination of a long-term and a short-term market for reactive power *‘services gives the best balance between system security and cost efficiency, while increasing consumer value by promoting competition from a wider range of technologies.’* Short-term markets alone were considered not viable because of the limited incentives for new investments and the risk exposed to the system. Long-term markets alone were not preferred because of the unpredictability of demand, resulting in over procurement or risks. Furthermore, long-term markets would create *‘high barriers for entry for some technologies.’* NESO still studies the possibilities of short-term markets for reactive power but is currently not planning to implement these.

However, NESO considers the acceleration of Grid Code changes to mandate reactive power provision from existing and new Inverter-Based Resources, also at low generation levels. Furthermore, NESO plans closer coordination with the DSOs and (preparation for) own investments.

Netherlands

Since the beginning of this century, Dutch TSO TenneT procures steady-state reactive power from generators. This is done via annual tenders resulting in bilaterally negotiated contracts. The contracting focuses on ‘steady state’ reactive power, with a response time of 15 minutes after TenneT’s instruction. It is noted that the automatic response around this setpoint shall be provided as per Grid Code requirement.

Belgium

In Belgium, for eligible units connected to 110 kV networks or above it is mandatory to participate in annual tenders for steady state reactive power services⁴⁶. For other units, participation is voluntary.

⁴⁵ Until approximately 15 years ago (but officially still in place), NESO contracted Enhanced Reactive Power Service (ERPS), which was covering reactive power compensation capability over and above the Grid Code requirements. The ERPS procurement was organised through bi-annual tenders and agreements are termed for 12, 18, 24 months and so on. The agreements could include prices for available capability, synchronised capacity and utilisation. NESO is considering removing or revising this mechanism.

⁴⁶ The TSO’s instructions to change the reactive power setpoint shall be implemented within 5 minutes.

The contracts resulting from the tender include prices (EUR/MVArh) based on use/activation of the services. These prices can be separately defined for production and absorption, injection/off-take mode (active power) and compensator mode. The contracts require approval - including a price reasonability check by the federal RA.

5.5. Conclusion SSRP product review

Messages in this section:

- The TSOs conclude that the SSRP product provides incentives reflecting system needs, while including incentives for increasing the efficiency of the dispatch.

Table 5-5 summarises the two objectives of the SSRP product. Firstly, by remunerating the SSRP-range, the SSRP product provides an incentive for SSRP providers to make reactive power compensation capability available. Secondly, by incentivising that reactive power compensation capability can be provided at a low or even zero MW output, the SSRP product facilitates more efficient (re)-dispatch.

	Mandatory Capability (as per Grid Code)	Non-Mandatory Capability
System Need - reactive power compensation capability	TSOs require full access to mandatory reactive power capability to control voltage in all circumstances	In locations where voltage studies show that there is an additional need for voltage control, TSOs may need access to non-mandatory reactive power capability
Efficient Dispatch	Lower P_{min} reduces dispatch down of RES	Lower P_{min} or Wattless compensation capability reduces dispatch down of RES

Table 5-5: Overview of System Need and Efficiency needs for both mandatory and non-mandatory capability of reactive power compensation capability

The SSRP product remunerates reactive power compensation capability that is mandated by the Grid Code, based on the availability of their service, hence the SSRP product incentivises the availability of the mandatory capability. In addition, the shaded cells in the table show the features for which SSRP product has a larger incentive element. These include incentives to invest in non-mandatory capability and making more available to the TSOs and increase the efficiency of operating by lowering P_{min} and Wattless provision.

Accordingly, the TSOs conclude that the SSRP product provides incentives reflecting system needs, while including incentives for increasing the efficiency of the dispatch.

5.6. Volume forecast methodology

Messages in this section:

- Currently, the required SSRP Volumes are not defined.

- Defining the required SSRP Volumes is challenging because the SSRP volumes:
 - o Do not one-to-one reflect the reactive power compensation capability of the plant.
 - o Do not reflect absorbing or producing direction.
 - o Do not include a locational element.

Currently, the required SSRP Volumes are not defined. The following challenges appear when intending to develop a volume forecast methodology for SSRP:

- The SSRP volumes do not one-to-one reflect the reactive power compensation capability of the plant as the SSRP volume formula (Formula 5-1) includes the RP-factor, which results in different SSRP volumes for providing units with the same reactive power compensation range. Accordingly, an actual reactive power compensation capability need cannot be translated precisely in an SSRP volume.
- While reactive power compensation need is specifically in absorbing or producing direction, SSRP volumes do not distinguish between absorbing direction and producing direction.
- Reactive power needs are local, subject to regular changes reflecting new lines, and development in generation (e.g. more RES, less conventional), BESS and demand.
- The SSRP product remunerates the entire reactive power capability of the providing units, including both the mandatory and non-mandatory part. In the TSO transmission planning studies, the focus is on identifying the areas where additional voltage support is required, over and above the assumed capabilities. For these areas, additional needs are specified.

5.7. Procurement Approach

Messages in this section:

- SSRP does not differentiate between absorption and production of reactive power and is paid independent from the location. To maintain system stability, reactive power compensation capability is required locally. This gives rise to market power risk which require further assessment.
- SSRP procurement results in a non-linear relationship between reactive power volume and SSRP volumes. This makes the forecasting of volume requirements ahead of real-time very difficult.
- Exploring an alternative product for procuring reactive power is not deliverable for day 1 implementation given the significant redesign, analysis, operational and IT frameworks required to transition to a new product.
- At present, the benefits of competitively procuring SSRP via the DASSA, LPF or Fixed Contracts are limited for both TSOs and consumers, given the locational requirements for reactive power, the difficulty in forecasting SSRP volumes and the FASS Go-live timelines.

5.7.1. Feasibility of Competitive procurement

To assess the feasibility of competitive procurement, the suite of non-reserve services were assessed against a matrix of considerations to identify the key challenges that would arise when transitioning from regulated arrangements to a competitive procurement model. This section focuses specifically on SSRP and the market integration barriers SSRP faces given its operational characteristics and system-critical function.

5.7.2. Nature of the Product

Reliable reactive power compensation is essential for maintaining system stability. As noted in Section 5.1, SSRP is defined for conventional generators as the dispatchable reactive power range that can be provided across their full active power output range (i.e., from minimum to maximum generation).

SSRP incentivises all qualified market participants, including conventional generators, wind, BESS, etc. to maintain reactive power capability across their full operational envelope. This reduces unnecessary curtailment of RES solely for reactive power provision, thereby improving system efficiency and supporting sustainability goals.

As illustrated in Section 5.1.1, the transport of reactive power is challenging, as many grid components absorb reactive power, resulting in voltage differences and potential system instability.

Consequently, locational requirements can vary significantly and may evolve frequently based on the generation mix. For example, areas with high renewable penetration may face both high and low voltage events depending on RES output, requiring different reactive power support at different times.

5.7.3. Challenges to Market Integration

The SSRP product presents unique design considerations due to the voltage losses incurred in the transportation of reactive power. Due to this, volume requirements are incredibly difficult to forecast ahead of real time and its inherently locational nature complicates the management of reactive power across the network.

The feasibility of competitive procurement assessment set out in Chapter 4.4 was used to determine the three primary challenges to consider with the integration of SSRP into a competitive market.

1. Are volume requirements known prior to real time?

The precise volume requirements for SSRP cannot be accurately quantified ahead of time due to its incentive-based procurement structure. SSRP encourages units to provide reactive power capability independently of active power generation, including scenarios where no active generation occurs (“wattless” operation), and incentives conventional units to reduce their minimum generation levels, P_{\min} .

The SSRP volume formula described in Section 5.1.5 - Formula 5-1 incorporates a metric known as the “RP Factor” which incentivises reductions in P_{\min} in conventional units. This factor varies

based on supplier technology, for example in the case of synchronous condensers this term equates to one.

Section 5.1.5 Table 5-2 illustrates a worked example of the SSRP volume calculation. While all the units share the same reactive power capabilities (the SSRP-range) the SSRP-volumes can vary (100 to 200 MVar) across suppliers, due to their registered P_{\min} in addition to one unit being a Synchronous condenser. This SSRP volume variance needs to be considered when envisioning SSRP in a competitive auction.

This incentive-based approach results in unpredictable and variable reactive power provision, making definitive volume quantification difficult. Ensuring that providers maintain reactive power capabilities across varying operational scenarios thus becomes the critical procurement objective, rather than targeting fixed reactive power volumes. In summary the incentive elements in SSRP creates inherent uncertainty around product volume, and therefore around what is being competitively procured.

Conclusion: As a result of SSRP incentive elements the relationship between SSRP and reactive power is nonlinear, this makes predicting the amount of SSRP needed impossible

2. Can system requirements be codified into an objective function?

Codifying SSRP requirements into a precise and transparent objective function is inherently challenging for two primary reasons. First, the incentive-based nature of SSRP results in variable and potentially unpredictable provision levels from participants. Providers are encouraged to maximise their reactive power capabilities, which vary based on operational circumstances and economic considerations.

Second, as SSRP is a non-location specific product, incorporating locational-specific requirements into a mathematical or optimisation function introduces additional complexity, particularly given the need for precise, dynamic locational signals. The application of locational scalars, therefore, becomes complex and may result in additional market intricacies and unintended operational or market outcomes.

Conclusion: It is not possible to define SSRP volume requirements in advance with the level of accuracy that would be required to support a meaningful competitive procurement. The TSOs require broad capability across the network to support voltage level where and when needed, as set out in our system defence plan.

3. Is there significant market power risk?

Reactive power compensation needs are inherently dynamic, highly localised, and vary significantly across different operational scenarios and geographic locations. A multizonal approach (which would necessitate a new reactive power product to be designed) to enable localised procurement of reactive power requirements, would inevitably reduce competition within individual zones. Given that SSRP resources in one zone cannot effectively substitute for those in another, market competition is limited to providers operating within specific geographic areas. Consequently, this zonal delineation may create scenarios where a limited number of providers dominate specific zones, increasing the risk of market power exploitation.

Conclusion: The TSOs publish substantial volumes of transparency information that would allow providers to predict when they are likely to have significant local market power.

Therefore, there is a very high risk of market distortion. This market power risk would require Ras to assess multiple locations for market power risk. Locations with limited supply may have suppliers inflating prices to the price cap, with the results resembling current tariff arrangements.

5.7.4. of SSRP Competitive Feasibility Assessment

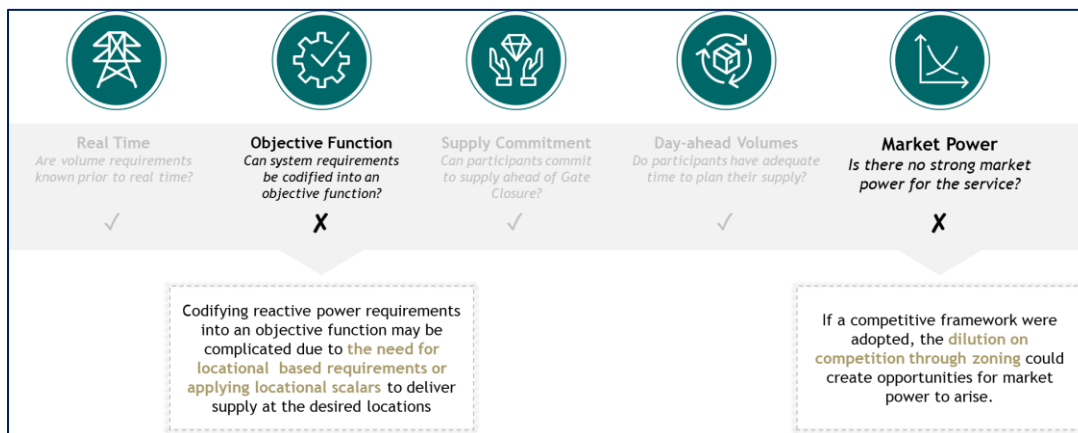


Figure 5-15 - Provides a summary of some of the considerations that would need to be taken for a reactive power product

It is important to note that the transition to competitive procurement for SSRP is constrained by the issues highlighted above. If a new reactive power product was developed, it could create opportunities for market-based procurement and with a defined volume, competitive mechanisms could be explored.

Some of the key challenges regarding reactive power will still exist regardless of any changes to the product as these challenges are inherent features of reactive power. These challenges include the dilution of competition caused by zoning, which arises from the complexity of transporting reactive power and how to codify reactive power requirements to consider multiple locational requirements. At present, the benefits of competitively procuring SSRP are limited for both TSOs and consumers, given the fundamental system constraints associated with reactive power and the current SSRP product definition.

5.7.5. Procurement Approach Considerations

Following on from the feasibility of competitive procurement assessment, the TSOs considered the most suitable procurement method for non-reserve services from the four procurement mechanisms, detailed in Chapter 4: DASSA, LPF, Fixed Contract and Regulated Price. A major consideration for this analysis was that the procurement options need to be deliverable by FASS Go-live. Each procurement method was analysed under five criteria: Consumer Value, System Needs, Compliance, Deliverability and Investment. These topics were used to highlight the most efficient procurement strategy for non-reserve services.

Analysis Outcomes

This section presents findings of this analysis and sets out both the rationale for the TSOs position and the TSOs recommended procurement approach for SSRP.

The TSOs evaluated the suitability of each of the procurement methods and the challenges of implementing the procurement methods for SSRP:

DASSA

Implementing the DASSA framework for SSRP poses fundamental compatibility issues. SSRP is designed primarily as an incentive mechanism to encourage market participants to provide reactive power independently of active power generation, including scenarios where no active power is generated (“wattless” operation). Due to this incentive-based characteristic, SSRP volumes cannot be predefined or accurately quantified ahead of time, which is an essential requirement for effective market operations under DASSA.

Consequently, the intrinsic nature of SSRP as an incentive-driven, non-volume-specific product makes it inherently incompatible with procurement processes like DASSA that rely on predetermined volume commitments and with predefined zones identified for where locational needs are necessary.

SSRP is not designed as a location specific product. A new product would need to be defined to enable such procurement. The localised nature of reactive power requirements and lack of ability to substitute provision between zones will complicate the DASSA clearing optimisation problem, risking delays. This is because the objective function would have to consider not just two zones such as the case of the reserves but multiple nodes significantly complicating the design.

SSRP capability is currently being sourced from units such as RES, DSUs and BESS. Article 40 paragraph 4 of the EU directive 2019/944⁴⁷ states that the TSOs and Ras shall establish technical requirements to ensure all units can participate in the market. This adds complexity for procurement of SSRP in the DASSA as it may be difficult for RES, DSUs and BESS facilities to bid into the DASSA and not be exposed to the auction’s embedded performance incentives as they will not be able to commit to supply day ahead.

Moreover, even setting aside the issue of defining volume requirements, integrating SSRP within existing FASS arrangements parallel to the implementation of DASSA introduces significant practical complexities. This integration would demand comprehensive redesign and restructuring of existing operational frameworks, potentially delaying key project delivery dates and increasing operational uncertainty (see Appendix 11.3). Additionally, extensive analytical and regulatory efforts would be necessary to establish suitable market safeguards, to address market power concerns that may persist in multiple zones

Component	Description
<p>Consumer Value</p>	<p>SSRP volumes are not easily quantified, making it difficult for a mechanism like DASSA, which requires volume commitment, to determine future need and forecast accurately. This will lead to over procurement and high costs for consumers. There are strong market power risks with SSRP due to the product being inherently localised as discussed in Section 5.7.3, With lack of control over cost or volumes, consumer value will diminish.</p>

⁴⁷ [Directive - 2019/944 - EN - EUR-Lex](#)

System Need	SSRP is a non-volume specific product making it inherently incompatible with procurement processes like DASSA that rely on predetermined volume commitments and with predefined zones identified for where locational needs are necessary.
Compliance	SSRP has been explicitly excluded from the initial DASSA framework (SEMC-24-066). In addition to this policy decision, its implementation within DASSA is not technically feasible, due to the absence of dispatchability or measurable volumes.
Deliverability	SSRP transitioning to DASSA is fundamentally incompatible with the operational and IT frameworks underpinning FASS Go-live. Implementing it would require significant redesign and analysis that cannot be completed within current timelines.
Investment	SSRP is not feasible under the DASSA framework, as it lacks a defined product, dispatchability, or forecastable volume. There is no route to market, and no basis for investor confidence under this arrangement.

Table 5-6: Testing DASSA framework as potential procurement mechanism for SSRP

LPF

Applying the LPF procurement mechanism to the SSRP product, in this case a weekly, monthly, or yearly auction, we see many of the same challenges identified for DASSA. SSRP provides reactive power as an incentive-based service, often delivered without the simultaneous generation of active power. As a result, the required volumes of reactive power cannot be accurately determined in advance. This makes it incompatible with procurement mechanisms like LPF that rely on predetermined, locational volume quantities.

As outlined in the DASSA framework, SSRP can be provided by renewable resources, DSUs, and energy storage. However, introducing SSRP through an LPF-based procurement mechanism introduces significant complexity, particularly regarding unit commitment timing, as auctions may occur one week to a year before delivery.

Additionally, the multizonal nature of reactive power further complicates the application of LPF, raising similar concerns about potential market power as previously identified within the broader DASSA framework.

Proceeding with this integration, despite clear compatibility challenges, would necessitate extensive redesign of the current FASS strategy. TSOs would be required to perform detailed additional analyses, such as identifying technical requirements, defining zonal clearing prices, and implementing an appropriate IT framework. Conducting these tasks concurrently with transitioning reserve products into DASSA could significantly risk delays to the current scope of the FASS design. See Appendix (11.3)

Component	Description
Consumer Value	SSRP volumes are difficult to quantify, making it unsuitable for a mechanism like LPF, which conducts a weekly, monthly, or yearly auction, to determine future need and forecast accurately. This may lead to over procurement and potential cost hikes for consumers. Similar to the case of

	DASSA, market power is a real possibility in the application of LPF to SSRP, threatening consumer value
System Need	SSRP volumes cannot be defined making it inherently incompatible with procurement processes like LPF that rely on predetermined volume commitments. Additionally, LPF does nothing to support SSRPs inherent highly localised nature, resulting in multiple location requirements being considered
Compliance	The LPF supports the regulator’s competitive procurement goal. However, due to the incentive-driven, non-locational, non-volume-specific nature of the current SSRP product, it is incompatible with LPF.
Deliverability	SSRP cannot feasibility transition to LPF due to misalignment with the operational and IT frameworks underpinning the FASS Go-live. Significant redesign and implementation effort would be required, which is not achievable within current timelines
Investment	For the reasons discussed in section 5.7, SSRP is incompatible with LPF. Without a route to market providers of SSRP have no means of monetising their capability, offering no basis for investment.

Table 5-7: Testing LPF framework as potential procurement mechanism for SSRP

Fixed Contracts

Procuring SSRP through fixed-term contracts, including yearly, six month or longer-term arrangements presents similar limitations. Because SSRP incentivises providers to make reactive power capability available even when not generating active power it is inherently passive and unpredictable. This renders it fundamentally incompatible with traditional fixed contract models, which require clearly defined, enforceable volume obligations.

Since SSRP volumes cannot be predetermined or dispatched in a conventional sense, applying fixed volume thresholds or caps is not viable. Furthermore, introducing fixed contracts for SSRP may amplify concerns around market power concentration, particularly in zones where provider options are limited. Locking in providers through fixed agreements could grant certain parties influence over SSRP provision in specific areas.

As discussed in the case of LPF, a fixed contract mechanism would exaggerate the technological hurdle anticipated for renewables and DSUs as it would require these units to bid far in advance of delivery.

Similarly to the case of DASSA and LPF, implementing such an option for FASS Go-live would require further analysis, in addition to delivering on the existing plan to transition the reserve products to DASSA.

Setting aside the difficulty in forecasting and setting SSRP volume requirements, this decision would necessitate additional analysis alongside current arrangements, including technical needs, the definition of zones, determining adequate zonal pricing, and IT implementation.

Introducing these additional workstream streams and consulting on them could compromise the FASS Go-live date and even risk premature implementation. For these reasons, fixed contracts are not an appropriate mechanism for SSRP procurement, nor is the option in the scope for implementation for the September 2027 long stop date. See Appendix item (11.3)

Component	Description
Consumer Value	SSRP volumes are not easily quantified or forecasted. This makes it difficult for fixed contracts which require clearly defined volume obligations. As discussed in the case of LPF this may lead to inflated costs and procurement inefficiencies. Additionally inherent location considerations risk market power risk, impacting consumer values
System Need	SSRP volumes cannot be ascertained making it inherently incompatible with Fixed Contracts that rely on predetermined volume commitments. As with other procurement methods locational requirements of multiple areas must be considered in the solution here complicating the design.
Compliance	While fixed contracts align with the regulatory objective of promoting competition, SSRP's non-locational and non-volume-based design makes it incompatible with this model.
Deliverability	Moving SSRP to a fixed contract model would conflict with the operational and IT structures supporting FASS Go-live. Delivering this shift would require major redesigns and cannot be achieved within current timelines.
Investment	Fixed contracts are not a viable approach for SSRP, which lacks a defined product structure or forecastable volume. There is no clear market route or basis for investor confidence under this model

Table 5-8: Testing Fixed Contracts framework as potential procurement mechanism for SSRP

Regulated Pricing

Given the unique characteristics of the SSRP product, regulated pricing emerges as the only viable mechanism for effective procurement. From a system design and implementation perspective, regulated pricing provides a stable and administratively manageable framework to incentivise reactive power provision. It ensures flexible providers get fair compensation based on their demonstrated capabilities, rather than on uncertain or speculative volume commitments. It is a procurement mechanism which is immediately deliverable and is known well to participants.

Economically, regulated pricing also offers significant benefits to consumers. It protects against potential market power abuse, particularly in zones with limited provider competition, a safeguard that alternative competitive procurement mechanisms are unable to guarantee. Additionally, it delivers certainty to investors by offering predictable revenue streams, encouraging the development and retention of critical voltage support capability.

Component	Description
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Consumer Value	Consumers are protected from market power risks, as pricing is predetermined and not subject to strategic bidding. This structure also supports system stability without exposing consumers to volatile pricing.
System Need	Regulated pricing ensures reliable delivery of system needs, as it builds on proven operational arrangements (e.g. must-run commitments). Inertia provision is ensured through continued synchronous operation, which this arrangement supports effectively.
Compliance	Use of regulated tariffs may require a derogation or exemption from standard market-based procurement expectations ⁴⁸ . However, if necessary, this can be managed through formal regulatory processes.
Deliverability	This approach is immediately deployable using existing infrastructure and commercial agreements. It avoids the need for new IT systems or auction platforms, making it the most viable near-term solution for FASS Go-live.
Investment	Regulated pricing provides clarity and income certainty, which supports investment in flexible synchronous capacity. Investors benefit from predictable returns and the ability to plan around a known tariff structure.

Table 5-9: Testing Regulated Pricing framework as potential procurement mechanism for SSRP

Conclusion of Procurement Consideration Analysis

It is critical that the TSOs continue to procure SSRP for system stability and voltage control. The TSOs conducted an in-depth analysis of the suitability of the four procurement mechanisms detailed above.

Given that the chosen procurement option needs to be deliverable for FASS Go-live, the locational constraints of SSRP and the difficulty in forecasting SSRP volume requirements, the TSOs consider Regulated Pricing the only suitable SSRP procurement method. The risks of significant market power for SSRP, the difficulty determining an objective function and the difficulty in forecasting volume requirements of SSRP make it incompatible with any other procurement method.

One potential pathway could be a transition from SSRP toward a reactive power product. Such an approach would create avenues for competitive procurement to be explored in the future. This would yield greater flexibility in procurement design, open participation to a wider set of

⁴⁸ Subject to the approach to transposition of Article 40 of Directive 2019/944 in each country

technologies, and align with the long-term trajectory of moving into competitive procurement while maintaining system security.

However, challenges remain. Market power consideration would need to be carefully assessed given the inherently locational nature of reactive power and the potential concentration of providers in key grid areas. Mechanisms would need to be considered mitigate these risks of dominance by a small number of providers would be essential.

Looking ahead, this could open the door to considering procurement approaches discussed in the international analysis in Section 5.4. such as those adopted in Great Britian, where longer-term tenders are being used to support investment in reactive power. Lessons learned from their design and operation could help inform the development of an enduring competitive procurement pathway for reactive power in Ireland and Northern Ireland.

TSO Proposal:

It is the proposal of the TSOs' to continue with regulated pricing for the procurement of SSRP. The results of the feasibility of competitive procurement assessment indicated that regulated pricing is the only viable SSRP procurement option for FASS Go-live, given that:

- SSRP is an incentive product which results in a non-linear relationship between reactive power and SSRP volumes.
- SSRP does not differentiate between absorption and production of reactive power and is paid independent from the location. To maintain system stability, reactive power compensation capability is required locally.
- At present, the benefits of competitively procuring SSRP are limited for both TSOs and consumers, given the locational requirements for reactive power and the difficulty in forecasting SSRP volumes.
- Finally, exploring an alternative product for procuring reactive power is not deliverable for day 1 implementation given the significant redesign, analysis, operational and IT frameworks required to transition to a new product.

Question #6: Do you have any comments regarding our proposal to maintain tariff-based procurement of SSRP for a transitional period?

6. Synchronous Inertia Response (SIR)

6.1. Current Situation

6.1.1. Why is Inertia required?

Oxford languages⁴⁹ defines inertia as the ‘*resistance to change in some other physical property*’ and provides the following example: ‘*the thermal inertia of the oceans will delay the full rise in temperature for a few decades*’. Similarly, the inertia of a power system (as stored kinetic energy) damps the deviations in system frequency caused by demand and generation (RES) deviation or trips of (large) generators or interconnectors. A system with more inertia is more robust and less vulnerable to sudden changes in frequency. A minimum level of Inertia is therefore required to keep the system frequency and rate of change of frequency (RoCoF) within the frequency quality standards, both continuously, and during incidents.

As a reference, *Box 5-1* provides a more detailed technical description of Inertia, RoCoF and related metrics. For understanding of this consultation paper, it is most important to consider the following characteristics of Inertia:

- A minimum level of inertia (currently set at 23,000 MVA.s) in the IE/NI synchronous area is required to keep the system frequency and RoCoF within their statutory limits (see section 6.2).
- Within a synchronous area, there is - in principle - no need for geographical distribution of inertia⁵⁰.
- The unit of inertia is MVA.s, but also MW.s is or has been used by TSOs and in referenced documents. In this document we apply MVA.s.

⁴⁹ Source: [Oxford Languages](#)

⁵⁰ The LCIS phase 1 studies revealed that in some situations RoCoFs may be different dependent on the location in the grid and could be impacted by the distribution of inertia-resources. This issue is not considered in this paper.

Inertia

The inertia of the power system refers to the ability of the system to oppose changes in system frequency due to the resistance imposed by the large rotating masses of the synchronous machines. The inertial energy has an important role in the frequency control process. The natural resistance of the synchronous machines to a change in speed assists with keeping the power system frequency close to its nominal frequency of 50 Hz.

$$H = \frac{1}{2} \frac{J\omega_o^2}{S_n}$$

J is the total moment of inertia
 ω_o is the angular frequency
 S_n is the total power

RoCoF

The Rate of Change of Frequency (RoCoF) is a measure of how fast the frequency moves when the system is subjected to an event that results in a mismatch between generation and demand. RoCoF is inversely proportional to the system inertia; the lower the inertia, the higher the RoCoF.

$$RoCoF = \frac{f * Power Loss}{2(H_{total} - H_{power loss})}$$

f is the frequency
 H_{total} is total system inertia
 $H_{power loss}$ is lost inertia due to power loss

Note: This calculation method is instantaneous, not average RoCoF. It does not consider the effect of fast frequency response from IBR or the inherent response from frequency and voltage dependent load.

SNSP

The System Non-Synchronous Penetration (SNSP) and the Minimum Number of Conventional Units On (MUON) are system constraints introduced to ensure enough synchronous machine capacity is maintained to a level that guarantees a secure and safe system operation. SNSP metric was introduced following analysis performed as part of Facilitation of Renewables (FoR) studies in 2011 and has been regularly refined. It refers to the ratio of non-synchronous supply infeed on the grid at any given time.

$$SNSP [\%] = \frac{non-synchronous\ generation + net\ imports}{demand + net\ exports} \times 100$$

MUON

The minimum number of conventional units on (MUON) constraint was introduced to ensure enough large synchronous units are operating to preserve the voltage control capability and maintain a minimum level of system inertia, this is independent of the inertia constraint.

Currently, the constraint is set to a minimum of 4 large conventional units in Ireland and 3 in Northern Ireland to satisfy this constraint (from a selected list of generators considered large), while trials are being considered to reduce this number.

Box 6-1: Dynamic Stability Metrics relevant to Inertia⁵¹

6.1.2. Providers of Inertia

Messages in this section:

- Inertia is an intrinsic characteristic that is mainly provided by conventional generators, but also by synchronous condensers and motor loads connected throughout the power systems. Their inertia becomes automatically fully available when a unit connects to the grid.
- Non-synchronous units (such as most wind farms, solar PV, BESS) do not inherently provide inertia at the moment, but certain technologies can be programmed to provide an inertia-like response.
- There are no mandatory requirements for inertia in the Grid Code.

Current providers

Currently, in most power systems - including the IE/NI system - inertia is mainly provided by conventional synchronous⁵² generators. These units provide inertia due to the kinetic energy of the rotating mass of turbines and generators.

Figure 6-1 provides an overview of the inertia volume in the IE/NI synchronous area throughout 2023, which is for the vast majority available from dispatched conventional generators. In addition, the synchronous condenser at Moneypoint makes 4000 MVA.s available when dispatched. The figure shows that the available inertia varied between the set inertia floor of 23,000 MVA.s (see section 6.1.3) and 49,000 MVA.s. This variation is due to the dispatch of

⁵¹ Source: [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

⁵² Synchronous means that rotors of these units rotate in line with the rotating magnetic field of the stator, and therefore the rotational speed of the machine and the system frequency are synchronised.

generation units. Hence, when many conventional generation units are dispatched, the inertia will be high.

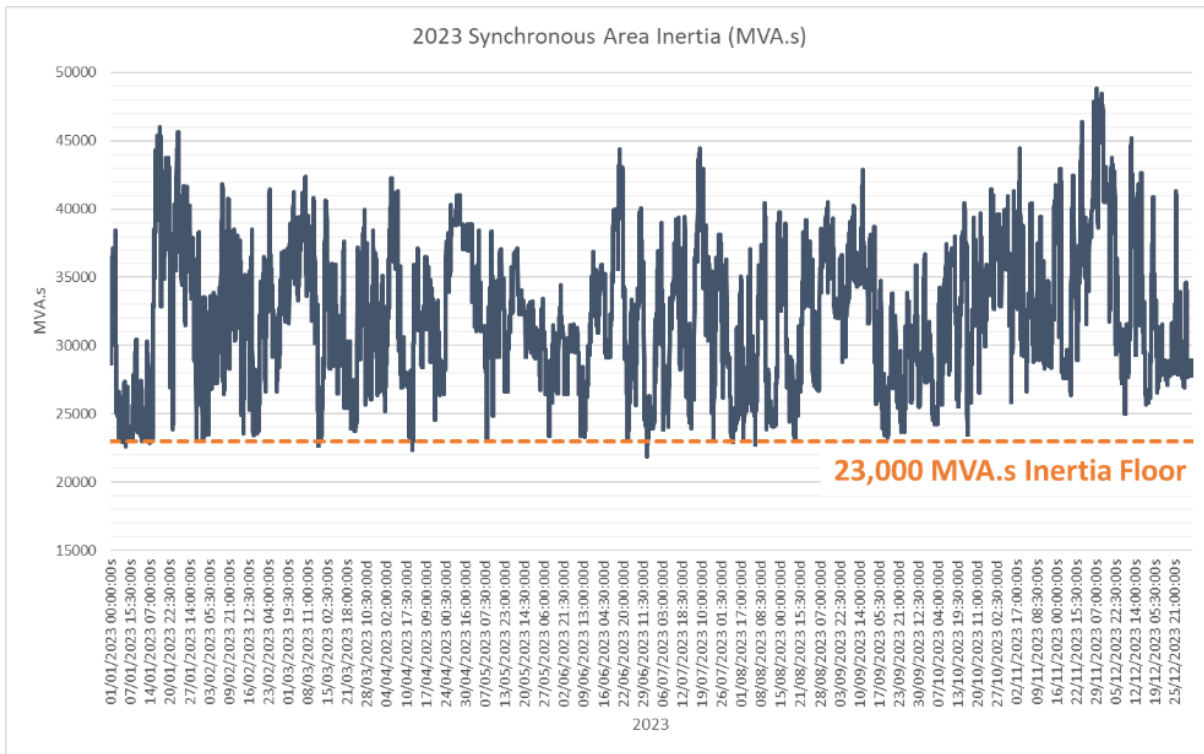


Figure 6-1: synchronous inertia in the IE/NI synchronous area in 2023

Capability: Grid Code requirements and intrinsic characteristics

There are no Grid Code requirements for inertia provision. Hence, inertia is an intrinsic characteristic of synchronous generation as well as various motor loads connected across the system. The volume of inertia provided by a generation unit or motor depends on the build of the unit and could be considered fixed by design.

Inertia becomes automatically fully available when a unit connects and synchronises to the grid. The available inertia of the unit does not change with active or reactive power provision or consumption. The inertia response of a synchronised unit happens automatically and immediately in case of a change in system frequency. Such response is inherent and cannot be controlled.

Non-synchronous units (such as most wind farms, solar PV, BESS) do not inherently provide inertia. However, as part of Grid-Forming (GFM) capabilities which may be implemented in these units, they may provide artificial inertia-like response in the future (see section 6.3).

Locational supply aspects

Within a synchronous area (like the IE/NI synchronous area), inertia in principle does not have a locational aspect. Hence, service providers in IE provide inertia for the entire IE/NI synchronous system, and service providers in NI do the same.

It needs to be noted that in case of a system split, e.g. by a double circuit trip of the North-South tie-line between Ireland and Northern Ireland, the IE/NI synchronous area is split in two synchronous areas: IE and NI. In that situation, inertia providers in IE will only provide inertia to IE, and inertia providers in NI only provide inertia to NI.

Distribution connected assets

Both transmission and distribution connected assets provide inertia to the entire synchronous system, independent from the voltage level to which they are connected. Hence, distribution connected synchronous generators and motors also contribute to provision of inertia.

6.1.3. How is inertia planned?

Messages in this section:

- The main drivers for the need for inertia are the largest single incident in both infeed (LSI) and outfeed (LSO) direction. If this incident takes place, the system shall stay within the limits for system frequency and rate of change of frequency (RoCoF)
- Detailed system studies determine the need for minimum requirement for inertia, given the LSI, LSO, consequential losses and the volume and speed of the fastest reserves (FFR and POR)

The TSOs currently operate the IE/NI synchronous area with a fixed inertia floor of 23,000 MVA.s. This value is based on detailed system studies that determine this floor, considering that even with the tripping of the largest single infeed (LSI) and outfeed (LSO), the reserves (such as FFR and POR) shall be able to keep the system frequency and RoCoF within the statutory limits (see section 6.2). Although there is a relationship between inertia volume and fast acting reserves such as FFR, the latter cannot fully replace inertia. For this reason, the TSOs apply a fixed inertia floor to prevent RoCoF exceeding operational limits and determine reserve requirements based on actual system conditions, including the LSI and LSO.

6.1.4. How is inertia activated in real-time?

Messages in this section:

- Inertia reacts automatically/instantaneously on a frequency change, this is a physical process. Hence, Inertia does not require a real-time controller or manual activation.

Inertia starts being available when the synchronous generator, motor or condenser is connected (synchronised) to the power system. When the circuit breaker (switch) to the network is opened, the inertia provision stops. The unit provides inertia on a single level, independent from its active or reactive power setpoint.

Inertia response provides energy instantaneously following a frequency change. This is a physical process that happens fully automatically. Hence, inertia does not require a real-time controller or (manual) activation.

6.1.5. How is inertia guaranteed in real-time?

Messages in this section:

- A minimum operational limit for Inertia to the TSOs' Scheduling and Dispatch process ensures that sufficient inertia providing units are dispatched.
- If the ex-ante market outcomes result in schedules ((F)PNs) with a total all island inertia of less than the minimum operational limit (currently 23,000 MVA.s), the TSOs need to dispatch additional providers of inertia, typically conventional units. This results in less efficient dispatch and higher emissions.
- Minimum Units On Line (MUON) constraints for both jurisdictions ensure that both Ireland and Northern Ireland have a certain inertia volume to reduce the impact of a double circuit trip of the North-South tie-line.

As indicated above, synchronous generators, condensers and electrical motors automatically provide inertia response to a frequency change inherently if they are connected to the system. This means that the unit needs to be dispatched to be able to provide inertia services, at least at its minimum stable generation. If the unit is dispatched, the full inertia contribution of the unit will be available, as this is independent from its active power (MW) or reactive power (MVar) setpoint.

Hence, to make sure that the system need is fulfilled, the TSOs' Scheduling and Dispatch process needs to ensure that sufficient inertia providing units are dispatched. Within the Scheduling and Dispatch process this is managed by fulfilling the operational limit for inertia. This limit is included in the Weekly Constraint Updates as an 'active system wide constraint'. *Table 6-1* shows an example which states that the Inertia in the all-island power system shall be at least 23,000 MVA.s.

Active System Wide Constraints

Name	TCG Type	Limit Type	Limit	Resources	Description
Operational Limit for Inertia		N:>	23,000 MVA.s	Ireland and Northern Ireland Power Systems	Ensures that all island Inertia does not fall below 23,000 MVA.s

Table 6-1: Example of System Wide constraint for inertia (Source: [Wk8_2026_Weekly_Operational_Constraints_Update_0.pdf](#))

In addition to the system wide constraint, *Table 6-2* shows that for both jurisdictions Minimum Units On Line (MUON) constraints are implemented. These constraints ensure that both Ireland and Northern Ireland have a certain inertia volume to reduce the impact of a double circuit trip of the North-South tie-line.

Active Northern Ireland Constraints

Name	TCG Type	Limit Type	Limit	Resources	Description
System Stability	NB	N:>=	2 Units at all times	B31, B32, C30, KGT6, KGT7	There must be at least 2 machines on-load at all times in Northern Ireland. Required for dynamic stability

Active Ireland Constraints

Name	TCG Type	Limit Type	Limit	Resources	Description
System Stability	NB	N:>=	4 Units	AD2, DB1, GI4, HNC, HN2, PBA, PBB, TYC, WG1	There must be at least 4 machines on-load at all times in Ireland. Required for dynamic stability

Table 6-2: Example of Jurisdictional constraints for MUON (Source: [Wk8_2026_Weekly_Operational_Constraints_Update_0.pdf](#))

Meeting these constraints is managed by the Scheduling and Dispatch process. I.e. if the ex-ante market outcomes result in schedules ((F)PNs) with a total all island inertia of less than 23,000 MVA.s, the TSOs need to dispatch additional providers of inertia, typically conventional units. As these units need to be dispatched at least at their ‘declared minimum generation’, the new schedule disturbs the SEM’s MW system balance. This means that other forms of generation may need to be dispatched down, which typically means wind farms. Consequently, less expensive generation (RES) is replaced by more expensive generation (conventional). This results in less efficient dispatch. Moreover, generation with lower emissions (RES) is replaced by generation with higher emissions (conventional units). As these are unwanted effects, operational constraints which result running out-of-the-market conventional generators shall be mitigated and/or the impact of the constraints shall be minimised. This is done by SIR procurement, as described in the next section.

6.1.6. Synchronous Inertial Response (SIR) Procurement

Messages in this section:

- SIR provides incentives to:
 - o Keep inertia providing units available.
 - o Operate on lower declared minimum generation levels (which reduces dispatch-down) and therefore reduce the impact of redispatch resulting

from conventional generators that must run to meet the minimum inertia constraints.

- The SIR-factor (SIRF) in the SIR volume formula drives the second incentive by increasing the SIR volume for units with a lower declared minimum generation.
- Accordingly, units that provide the same amount of inertia may have a very different SIR volume.
- Inertia needs can therefore not be translated in SIR levels.
- The unit of Inertia is MVA.s, while unit of SIR is MWs².

The impact of the constraints described in the previous section may be limited by reducing the ‘declared minimum generation’ of conventional units. By reducing the declared minimum generation, the amount of generation redispatch from RES to conventional generation can be minimised.

This reduction is currently incentivised through the SIR service, with the available volume for a providing unit in trading period T defined as in *Formula 6-1*:

$$SIR_{Available\ Volume_T} = Kinetic\ Energy_T \cdot (SIRF_T - 15) \cdot Unit_status_T$$

Formula 6-1

Where,

- ***Kinetic Energy_T*** is the Contracted Kinetic Energy of the Providing Unit for Trading Period T.
- ***SIRF_T*** = $\frac{Kinetic\ Energy_T}{Declared\ MinGen_T}$ (for a synchronised providing unit operating as a Generation Unit)
- ***SIRF_T*** = 45 s (for synchronised providing unit operating as a Synchronous Compensator or Synchronous Motor)
- ***Declared MinGen_T*** means the Time-Weighted Average of Minimum Generation in a Trading Period as notified by the Service Provider in accordance with the Grid Code or in such other manner as stipulated by the Company as appropriate.
- ***Unit_status_T*** is percentage of the trading period during which the providing unit is synchronised or connected to the power system and capable of providing reactive power control.

As the Kinetic Energy of a unit is not influenceable, SIR providers are only incentivised to increase their availability and to reduce their declared minimum generation. A lower declared minimum generation reduces the active power production of the SIR providing units that are dispatched on. Consequently, for situations in which conventional units are constrained on for meeting operational inertia limits, the amount of generation redispatch from RES to conventional generation can be reduced. Hence, the SIR product serves two objectives: 1) keeping SIR providing units available and 2) ensuring more efficient dispatch with less emission.

In addition, the SIR providers are remunerated for each MWs^2 , in accordance with *Formula 6-2*:

$$SIR_{Trading\ Period\ Payment} = SIR_{Available\ Volume} \cdot SIR_{Payment\ Rate} \cdot Trading\ Period\ Duration$$

Formula 6-2

Where,

- *SIR_{Payment Rate}* is the Payment Rate (expressed in €/MWh) applicable to SIR.
- *Trading Period Duration* is the Trading Period Duration (expressed in hours).

Table 6-3 demonstrates that SIR volumes differ significantly between service providers. These divergences exist despite each of the suppliers being contracted at 2,000 MVA.s of kinetic energy and 250 MW of registered capacity (except for the synchronous condenser). Regardless of these similarities the determined SIR available volume differs from 10,000 to 50,000 MWs^2 , resulting from a different declared minimum generation.

		Generation Unit A	Generation Unit B	Synchronous Condenser
(1)	Registered Capacity	250 MW	250 MW	
(2)	<i>Kinetic Energy</i>	<i>2,000 MVA.s</i>	<i>2,000 MVA.s</i>	<i>2,000 MVA.s</i>
(3)	Declared minimum generation	100 MW	50 MW	
(4)	SIRF [$15 \leq SIRF \leq 45s$]	20s	40s	45s
(5)	SIR Available Volume	10,000 MWs^2	50,000 MWs^2	60,000 MWs^2

Table 6-3: Illustrative example of determination of SIR Available Volume for three distinct units all with convergent contracted kinetic energy values.

It can be concluded that the SIR volume does not directly reflect the system need for inertia. This is evident when comparing their units: inertia is measured in MVA.s, whereas SIR is measured in MWs^2 . As a result, units that provide the same amount of inertia may correspond to very different SIR volumes. Accordingly, inertia system needs cannot be directly translated into SIR levels. The SIR product instead provides incentives for units to operate at a lower declared minimum generation.

Figure 6-2 provides the contracted SIR volumes for the IE/NI synchronous area for both conventional generation units and synchronous condensers. As said, these numbers could not be linked directly to the existing minimum inertia floor of 23,000 MVA.s.

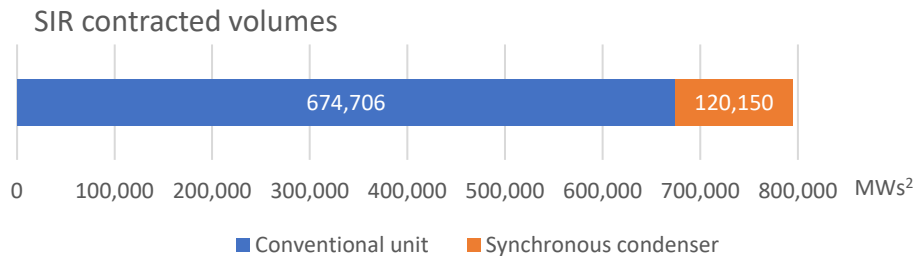


Figure 6-2 SIR Contracted Volumes for October 2024

6.2. System Need

6.2.1. Objectives

Messages in this section:

- Inertia is required to meet the system requirements stated in RA approved regulations and standards, including EirGrid and SONI OSS, Grid Code, SAOA, all of which implement EU Network Code SOGL.

Requirements in Codes, Standards, Agreements and Licenses

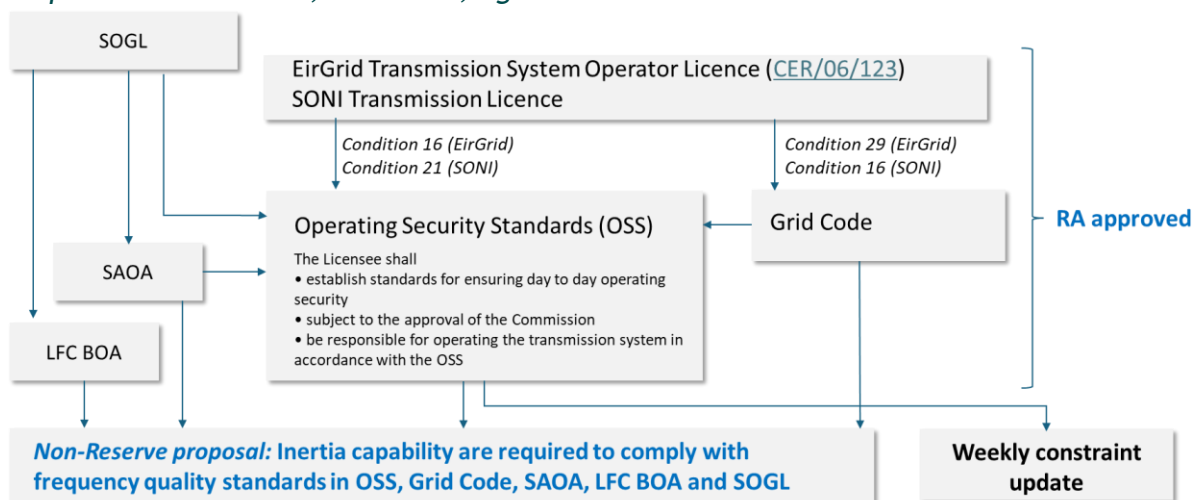


Figure 6-3: Regulatory context of proposals for inertia

Figure 6-3 shows the agreements, standards, codes and licenses that stipulate the requirements that indirectly define system need for inertia and the required volume. In short, the objective of inertia is to keep the system frequency and RoCoF in the system within secure limits, in all situations, including:

- ‘Normal’ frequency regulation, i.e. maintaining the system frequency within the standard frequency range: 49.8 to 50.2 Hz⁵³.
- Mitigating the impact of contingencies (e.g. trip of the LSI) to avoid^{54 55}:
 - o A maximum instantaneous frequency deviation larger than 1000 mHz from the nominal frequency of 50 Hz (i.e. the system frequency shall not go below 49.0 Hz or above 51.0 Hz).
 - o A RoCoF larger than +/- 1 Hz/s measured over 500 ms.

In accordance with Article 39(2) of the SOGL, the TSOs are required to periodically (every two years) review the need for establishing a minimum required inertia. If a need is identified, the TSOs shall define the minimum inertia required to maintain operational security and to prevent violation of stability limits. The Ras approved the TSOs’ submission under this article in December 2022⁵⁶, which referred to several studies into the need for inertia.

Operational Policy Roadmap 2025-2035

The requirements in codes, standards, agreements and licenses as described above are implemented in operational policies including several system constraints. As outlined in the EirGrid and SONI Operational Policy Roadmap 2025-2035⁵⁷ (published in March 2025), these system constraints must evolve to accommodate more Renewable Energy Sources (RES) on the system. *Table 6-4* shows how EirGrid and SONI are aiming to gradually relax the key operational constraints.

	2025	2029	2030	2032	2035
MUON	7	4 or less	3 or less	2 or less	0
SNSP	75%	90%	95%	95%	100%

Table 6-4: Key operational constraints related to inertia and their Milestones and Timelines⁵⁸

6.2.2. Required volume

Messages in this section:

- Up to 2027 the inertia floor shall be 23,000 MVA.s. The largest uncertainty in forecasting future system need for inertia services is related to fault ride through capability (FRT) of Large demand facilities.
- The TSOs procured synchronous inertia-services as part of long-term LCIS contracts and a second phase of procurement is currently being prepared.

⁵³ As per [System Operations Guideline](#) and [Synchronous Area Operational Agreement](#).

⁵⁴ As per EirGrid OSS, SONI OSS, [System Operations Guideline](#) and [Synchronous Area Operational Agreement](#).

⁵⁵ [Grid Code Version 14 \(eirgrid.ie\)](#) and [SONI-Grid-Code_Apr_2024.pdf](#)

⁵⁶ Source: [CRU \(ref. 2022988\)](#) and [UR \(Ref: NET/E/TH/614\)](#), the TSOs have submitted to the RAs in April 2025.

⁵⁷ [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

⁵⁸ [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

- If not solved in another way, limited FRT capability of large demand facilities may increase the system need for inertia significantly above the volumes procured in the LCIS phase 1 and phase 2 procurement schemes.

In order to meet the objectives described in section 6.2.1, the power system requires a minimum volume of inertia and a minimum volume of fast reserves, such as FFR. The Operational Policy Roadmap 2025-2035 defines that up to 2027 the inertia floor shall be 23,000 MVA.s⁵⁹. This level of inertia is the starting point for the approved Volume Forecasting Methodology (VFM) for reserves products⁶⁰. Hence, the required volumes of reserves (mainly FFR) will be defined based on the rather static inertia floor on the one hand, and more volatile system conditions such as the largest possible loss of infeed or outfeed.

As further discussed in section 6.3, the TSOs procured synchronous inertia-services as part of long-term LCIS contracts. A second phase of procurement is currently being prepared. For the purpose of defining the volume of inertia services to be procured as part of LCIS phase 2, the TSOs have performed detailed studies for year 2028 in which no conventional units are assumed (MUON = 0), except for the hydro storage units at Turlough Hills. The analysis concluded that in the LCIS phase 2, 14,000 to 18,000 MVA.s need to be contracted in addition to the 11,000 MVA.s already procured in LCIS phase 1. This analysis identified a number of uncertainties, most importantly the limited Fault Ride Through (FRT) capability of large demand facilities, which may significantly increase the inertia floor and accordingly result in a need of inertia services on top of the inertia volumes contracted in LCIS phase 1 and phase 2. Hence, the inertia need may become larger than the inertia volume contracted by LCIS phase 1 and phase 2, which may be the outcome of further studies including updated assumptions for 2030 and beyond.

Please refer to the LCIS phase 2 consultation document, for the details on this study.

6.2.3. Jurisdictional requirements for inertia

Messages in this section:

- To mitigate the risk of a double circuit trip of the North-South tie-line when reducing the minimum number of large conventional units, the TSOs will introduce jurisdictional requirements for inertia.

In principle, inertia response reacts to a change in frequency which is the same⁶¹ in the entire synchronous area. This would mean that a single requirement for the IE/NI synchronous area would be sufficient. However, to mitigate the risk of a double circuit trip of the North-South tie-line, the TSOs currently distribute inertia over the two jurisdictions by requiring a minimum number of large conventional units to be dispatched (MUON) in both jurisdictions (see section 6.1.5). As discussed in the Operational Policy Roadmap 2025-2035⁶², the TSOs will move to a model that applies regional inertia floors, considering the planned go-live of the second North-

⁵⁹ For the years after 2027, the inertia policy is to be reviewed based on system needs.

⁶⁰ [SEM-25-011 Future Arrangements for System Services - DASSA Volume Forecasting Methodology Decision Paper](#)

⁶¹ Previous studies indicated that transient differences in frequency between locations may appear.

⁶² [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

South interconnector in 2031. This change, and the delivery of the LCIS programme, will enable reducing MUON constraints across Ireland and Northern Ireland while ensuring dynamic stability and operational security for the loss of the tie-line. This approach will be re-assessed post connection of the second North-South interconnector and should be informed by experience of operating the system with low inertia floor levels.

6.2.4. How to forecast needs for Inertia?

Messages in this section:

- The inertia floor is considered fixed, stable and based on detailed studies.

As explained in section 6.2.2, the inertia floor is considered fixed and based on detailed studies. Consequently, the need for inertia is currently considered stable. However, it is to be noted that part of the inertia need will be covered by long-term LCIS contracts with fixed amounts of inertia.

6.3. Service Providers

Messages in this section:

- Until completion of LCIS phase 1 and phase 2 (target 2030), a significant share of the inertia needs to be provided by conventional units and the existing synchronous condenser.
- After completion, LCIS phase 1 and phase 2 may cover a significant share of the system need. The remainder may need to be provided by conventional units and the existing synchronous condenser.

This section describes the future providers of inertia: LCIS, conventional units, (non-LCIS) synchronous condensers and GFM technology.

LCIS phase 1 and LCIS phase 2

Following the SEM-21-021 Decision⁶³ on the System Services Future Arrangements, the TSOs developed a project which resulted in awarding fixed term contracts for the provision of Low Carbon Inertia Service (LCIS), which include synchronous inertia, reactive power and short circuit contribution capability. In 2024, EirGrid and SONI published Contract Award Notices for LCIS phase 1, awarding four contracts for a total volume of 10,963 MVA.s. of LCIS, of which 4000 MVA.s in Northern Ireland and 6,963 MVA.s in Ireland. The go-live dates of these contracts are in 2027.

At the moment, LCIS phase 2 is being developed, and a consultation paper has been published. The TSOs will target the procurement of 10,000 MVA.s (Max 12,000 MVA.s) in Ireland and 4,000 MVA.s (Max 6,000 MVA.s) for Northern Ireland.

Beyond LCIS Phase 2 and referring to section 6.2.2, additional procurement phases may be required subject to further analysis and SEMC approval.

⁶³[SEM-21-021 System Services Future Arrangements - Decision Paper 1 | The Single Electricity Market Committee](#)

Conventional units

Until go-live of LCIS phase 2 (target: 2030), the inertia floor will not be fully met by LCIS contracts. Consequently, the power system still needs to rely on synchronous inertia to be provided by conventional units, including both the thermal power plants and the hydro storage units.

Even after go-live of LCIS phase 2, the analysis referred to in section 6.2.2 may indicate that the inertia provided by the LCIS phase 1 and phase 2 contracts will not be sufficient to meet the inertia needs for the power system. Hence, inertia provision by conventional units may also be required after go-live of LCIS phase 2.

Synchronous condenser

Similar to the conventional units, synchronous condensers connected to the Irish system may well provide a useful contribution to the power system.

Grid Forming technology

As described in the LCIS phase 2 consultation paper, EirGrid and SONI acknowledge that technologies providing inertia from non-synchronous sources, particularly GFM technology, have become more advanced, with projects emerging worldwide. However, there is no well-established industry definition for the GFM concept. Therefore, until further progress is made, the TSOs propose that LCIS Phase 2 shall focus on the procurement of inertia from synchronous sources as for LCIS Phase 1. We refer to the LCIS phase 2 consultation paper for a description of the TSOs activities related to inertia provision by GFM technology.

6.4. International experience

Messages in this section:

- Traditionally, inertia services were typically not procured or paid for because sufficient inertia was historically inherently provided by conventional units.
- In some countries, long-term contracts for inertia procurement are currently being concluded, prepared for or being studied. In addition, day-ahead procurement is of interest.

Considering that inertia was historically inherently provided by conventional units, inertia services were typically not procured or paid for. Also, in large synchronous power systems and systems with a limited share of non-synchronous production units (RES), conventional units still provide sufficient inertia services. However, especially in smaller systems with a large share of non-synchronous production, the inherently available inertia may become insufficient. Accordingly, inertia needs to be managed, and additional sources of inertia may be required, as for Ireland described in the sections above.

Below, we provide a short overview of inertia procurement that is currently undertaken, prepared for or is being studied in Australia and GB. It is noted that in both countries procurement of inertia is being developed. Hence, similar to EirGrid and SONI, NESO concluded long-term contracts for synchronous condensers for providing low carbon inertia services and is preparing for future long-term contracts. On the other hand, although day-ahead procurement is of interest in both countries, there are no day-ahead markets for inertia yet.

Great Britain

The current inertia requirement in the GB system is 120,000 MVA.s. However, NESO studies the feasibility of a reduction to 102,000 MVA.s. This value is based on the largest incident in the system (future largest loss of 1800 MW) and the requirement that the RoCoF remains within 0.5 Hz/s which would result in an inertia need of 90,000 MVA.s. Assuming a loss of 12,000 MVA.s from the 1800 MW unit, the pre-fault minimum inertia requirement would be 102,000 MVA.s⁶⁴.

To enable NESO's ambition for zero-carbon operation, under the first phase of their Stability Pathfinders program 12 synchronous condensers have been contracted, which are operational now and deliver inertia to the network. These units are expected to deliver up to £128 million in consumer savings over their lifetime and to reduce CO2 emissions by around 6 million tonnes⁶⁵.

NESO further anticipates on a deficit of inertia and considers the acceleration of Grid Code changes to mandate GFM capabilities of new PPMs. Furthermore, NESO is currently implementing markets for stability services (which include inertia) across several timescales⁶⁶:

- *Long-term (Y-4)*: First time in 2025, NESO launched its first tender for delivery in 2029.
- *Mid-term (Y-1)*: First time in 2023-2025, for delivery year 2025/2026.
- *Short-term (D-1)*: NESO announces that 'Further information will be provided on the development of the short-term (D-1) market at a later date'.

Australia

The Australian Energy Market Commission (AEMC) issued directions paper⁶⁷, which outlines analysis on whether inertia exhibits the necessary economic characteristics to justify implementing an operational procurement mechanism, such as a spot market. "The key findings include:

- *for minimum inertia, a medium to long-term contracting framework likely remains the most effective market structure at present;*
- *for additional inertia, operational procurement may deliver benefits to consumers. However, the choice of procurement mechanism and its detailed design should be guided by practical considerations, including further technical detail and whether the expected benefits can exceed the implementation and operational costs.*
- *early estimated potential benefits of operational procurement for additional inertia in the NEM range from \$7.7 million to \$30 million per year - this estimate may need to be revisited based on stakeholder feedback and further work on the detailed design and practical considerations."*

The Directions Paper was published for consultation and stakeholders were invited to respond by 5 February 2025⁶⁸. The timeline for a draft determination has been extended to 27 June

⁶⁴ Source: [NESO, Frequency Risk and Control Report](#)

⁶⁵ Source: [NESO](#)

⁶⁶ Source: [NESO](#)

⁶⁷ Source: [AEMC](#)

⁶⁸ Source: [AEMC](#)

2025, considering “the complexities associated with the proposed operational procurement of inertia, including understanding power system needs and technological capabilities”.

6.5. Conclusion SIR product review

Messages in this section:

- The TSOs conclude that the SIR product provides incentives reflecting system needs, while providing strong incentives for increasing the efficiency of the dispatch.

Table 6-5 summarises the two objectives of the SIR product. Firstly, by remunerating the availability of inherent kinetic energy (the inertia) provided by a unit, the SIR product provides an incentive to keep the inertia providing units available, including both synchronous generation units and synchronous condensers without an LCIS contract. Secondly, by incentivising a low ‘declared minimum generation’, the SIR product facilitates more efficient (re)-dispatch.

	Inherent Capability Generation units	Synchronous condensers
System Need - inertia (MVA.s)	To be able to meet the system needs for inertia, the TSOs require availability of synchronous/inertia providing generating units	To be able to meet the system needs for inertia, the TSOs require availability of synchronous condensers (inertia providers)
Efficient Dispatch	Lower Declared minimum generation reduces dispatch down of RES	Dispatch of Synchronous Condensers does not require redispach of RES

Table 6-5: Overview of System Need and Efficiency needs for inertia

Accordingly, the TSOs conclude that the SIR product provides incentives reflecting system needs, while providing strong incentives for increasing the efficiency of the dispatch.

6.6. Volume forecast methodology

Messages in this section:

- Currently, the required SIR Volumes are not defined.
- The need for inertia provided by conventional units will still be significant at least until the LCIS units are delivered to operation.
- Defining the required SIR Volumes is challenging because the SIR volumes of a plant do not reflect the inertia provision of the plant.

Figure 6-4 provides an illustrative example of the how the LCIS phase 1 and phase 2 cover the all-island inertia need. The figure shows that after commissioning of the LCIS contracted units,

the remaining need for inertia may be limited, in line with the LCIS objective to reduce the minimum conventional units on-line (MUON).

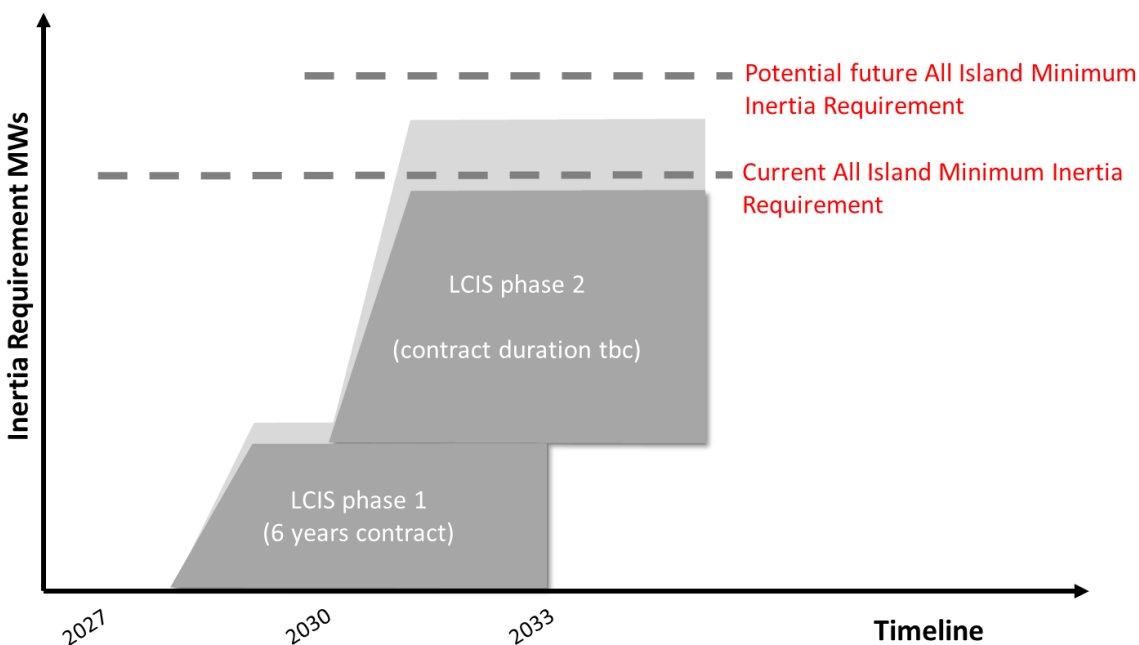


Figure 6-4: Illustrative example of how the LCIS phase 1 and phase 2 cover the system inertia need

Consequently, while until 2030, the need for inertia provided by conventional units may still be significant, it will reduce gradually when the LCIS units are delivered to operation. The total need for inertia services may be affected though because of the impact of limited FRT capability of large demand facilities and RES.

The minimum system needs for inertia (in MVA.s) are and will be defined (e.g. currently 23,000 MVA.s). After commissioning of LCIS phase 1 and phase 2, (at least) part of this volume will be provided by LCIS contracts. E.g. if the total need is 23,000 MVA.s and the LCIS contracts provide 10,000 MVAs, the remaining need for inertia will be 13,000 MVA.s, which clearly shows the system need. However, this value cannot be translated in the required SIR Volumes (in MWs²) as SIR volumes of a plant do not reflect the inertia provision of the plant (see section 6.1.6). Accordingly, the need for inertia cannot be translated into a SIR volume.

6.7. Procurement Approach

Messages in this section:

- SIR provides inertia as a byproduct of synchronous operation and cannot be dispatched or forecasted in a way that supports competitive procurement.
- The non-linear relationship between SIR and system inertia makes it unsuitable for inclusion in market-clearing processes or fixed-volume contracts.
- Market power risks further limit the feasibility of DASSA, LPF, or Fixed Contracts.

- Lastly, the significant uplift required to introduce an alternative product definition means it cannot be delivered for FASS Go-live
- As a result, none of the competitive procurement strategies suggested (DASSA, LPF, Fixed Contracts) would be feasible for the procurement of a SIR product. The most appropriate procurement model that remains is that regulated pricing arrangement.

This section builds upon the Analysis of Non-Reserve Services Project (December 2024) and extends the analytical framework introduced in Chapter 4. The goal is to conduct a detailed evaluation of potential procurement strategies for SIR. Drawing from system need assessments, the provider landscape, and international benchmarks, this chapter outlines a recommended strategy that enables both a viable Day 1 implementation and lays the foundation for a resilient long-term procurement model.

SIR represents a system-critical capability that operates differently from traditional ancillary services. As power systems become more reliant on non-synchronous sources such as wind and solar, maintaining system stability through inertia becomes increasingly challenging. The procurement framework for SIR must, therefore, recognise the unique technical and operational nature of this product and align with its real-world constraints and performance characteristics.

6.7.1. Feasibility of Competitive procurement for Synchronous Inertia Response

As discussed in Chapter 4, each of the identified system services was assessed against a matrix of considerations to identify the key challenges that would arise when transitioning from a regulated to a competitive procurement model. This section focuses specifically on SIR and outlines the barriers to market integration given its operational characteristics and system-critical function.

6.7.2. Nature of the Product

As outlined in Section 6.1.6, SIR produces inertia as a byproduct of its use by definition, SIR reflects the kinetic energy (at 50Hz) of a Centrally Dispatched Synchronous Providing Unit, scaled by the SIR Factor (SIRF) and measured in MWs^2 . Synchronous generators and condensers inherently provide inertia when synchronised at 50Hz via their rotating mass, which helps resist rapid frequency changes by opposing the RoCoF.

The SIR Factor is an embedded incentive mechanism designed to lower the minimum stable load of synchronous units, enabling them to provide inertia even at lower output levels. This supports system stability by keeping rotating mass online, particularly during periods of high non-synchronous generation.

6.7.3. Challenges to Market integration

Three primary challenges arise when considering the integration of SIR into a competitive market:

1. Is the service volume known ahead of time?

Inertia is a system need. The SIR product contributes to meeting this requirement, However the actual amount of inertia provided depends on the physical characteristics of each unit (e.g. Rotating mass and operating capacity) and the number of such units online at any given moment. The relationship to these physical characteristics is demonstrated in SIR volume formula described below in Section 6.1.6, Formula 6-1.

The formula demonstrates that the unit for SIR (MWs^2) is distinct from that of inertia ($MVA.s$) indicating they represent different physical quantities. Moreover, the relationship between SIR and Inertia is non-linear, as the SIR volume is dependent on the physical characteristics of the synchronised unit, its contracted kinetic energy (inertia) and the declared P_{min} consequently, two units that can provide the same level of inertia may exhibit differing SIR volumes.

For example, as shown in Section 6.1.6 *Table* , three units with a Contracted Kinetic Energy of 2000 $MVA.s$ will have SIR available volumes ranging from 10,000 MWs^2 to 60,000 MWs^2 . This divergence between the two terms is sourced from the differing declared minimum generation, P_{min} .

This makes the prospective procurement of SIR in a forward-looking competitive market difficult. The TSOs cannot quantify how much inertia will be produced by SIR until dispatch decisions have been made. This creates inherent uncertainty around product volume, and therefore around what is being competitively procured.

Conclusion: The TSOs cannot predict the volume of SIR that would be required to ensure system stability during any given day with enough accuracy to be able to define a meaningful procurement volume ahead of time.

2. Can system requirements be codified into an objective function?

SIR inherently provides inertia but with attached incentives for units to provide it at a lower MW output, codifying its value and a required volume in an objective function (such as in a market-clearing algorithm) presents a challenge. Inertia is not dispatched, and its contribution is not additive in a linear sense that would allow for easy optimisation or auctioning.

For this reason, SIR remains structurally incompatible with market constructs that require standardisation, granular volume forecasting, and price discovery based on marginal value.

However, inertia requirements can be quantified at a system level based on stability studies. Should the procurement framework evolve to target inertia as a standalone product, it may be possible to codify those requirements into a defined service offering. However, such a service would be distinct from SIR and would require the development of clear, measurable delivery obligations, such as those under emerging Low Carbon Inertia Services (LCIS) tenders.⁶⁹

Conclusion: The complex formula that is used to calculate SIR is not suitable for inclusion in a market clearing algorithm.

3. Is there significant market power risk?

While SIR is a system-wide service, the set of providers capable of delivering it can be limited, especially under conditions of high renewable output. This introduces the risk of market concentration and potential exercise of market power. For example, in periods where inertia

³ [LCIS Recommendations Paper on the Contractual Arrangements .pdf](#)

is scarce, a small number of synchronous units (particularly in certain locations) may become essential for system stability. These units could therefore exert significant influence over the price of SIR or inertia, particularly if no alternative providers are available.

This risk is especially pronounced in the north-south interconnector corridor, where transmission constraints can exacerbate dependency on specific units. In such scenarios, system operators may be required to commit units out of merit for system security, further distorting market outcomes. These conditions suggest that inertia-related services, including SIR, will need to take this challenge into consideration when undergoing analysis into the compatibility with a range of competitive procurement methods.

Conclusion: there is significant risk of market power being exerted with respect to the provision of SIR

6.7.4. Conclusion of SIR Competitive Feasibility

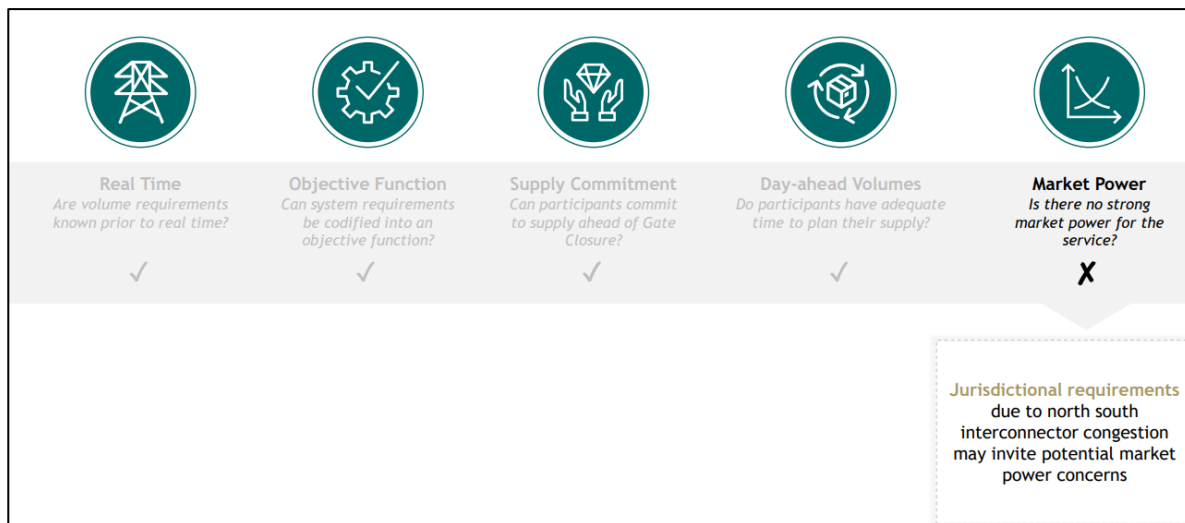


Figure 6-5: Demonstrates the challenges that have arisen when consider a pure inertia product

It is important to note that if the competitive framework were applied directly to a pure inertia product, rather than SIR, many of the above challenges could be partially mitigated. A standalone inertia product could be designed with specific volume and performance criteria (e.g., GVA-s capacity), enabling clearer codification and procurement. However, even in that scenario, market power issues would remain, particularly given the current concentration of providers and the operational imperative to always maintain inertia.

As such, the unique nature of SIR, as a passive, enabling mechanism that supports inertia provision, makes it inherently difficult to integrate into a market-based structure. Any future evolution toward competitive procurement must account for these fundamental limitations and weigh them against the critical system value that SIR continues to provide.

6.7.5. Procurement Option Consideration Analysis

As outlined in Chapter 4, the TSO adopted a prudent and structured approach to identifying a suitable procurement mechanism. The analysis considered a range of options, beginning with

the DASSA, followed by the LPF, fixed term contracting and concluding with an evaluation of regulated pricing arrangements.

This section presents findings of that assessment, as detailed in chapter 4, and sets out both the rationale for the TSOs position and the recommended procurement approach for SIR.

Analysis Outcomes

The TSOs evaluated the success and challenges of each of the procurement methods:

DASSA

The DASSA is a day-ahead procurement process where services are procured daily based on forecasted supply and demand conditions. From a high-level perspective, DASSA enables participation from suppliers whose availability is only fully known closer to gate closure. Additionally, it allows the TSOs to accurately align their requirements in real-time.

When applying this framework to SIR, the challenges outlined in section Feasibility of Competitive Procurement (6.7.3) become immediately apparent. SIR is fundamentally incompatible with such an arrangement.

To successfully clear a market like DASSA, the TSO must identify a clear and firm volume requirement in advance. This is not possible for SIR, which provides inertia as a byproduct of its utilisation. This core characteristic makes it wholly unsuited to a procurement mechanism that depends on predefined quantities.

Moreover, even setting aside the volume issue, incorporating a SIR product into DASSA would require significant additional work on top of the existing analysis and workstreams already supporting the FASS Go-live and its overall design. This could potentially jeopardise the go-live timeline by triggering a fundamental redesign of current workstreams and projects, increasing the risk of delays and introducing operational uncertainty (see Appendix 11.3). This is before even accounting for the further analytical work required to design market safeguards and address potential market power concerns.

Component	Description
<p>Consumer Value</p>	<p>SIR contains incentive elements that are incompatible with frameworks requiring a defined volume requirement such as the DASSA. There is a risk of market power where “must-run” units may have substantial influence, that has the potential to constrict consumer benefit. Without the ability to set caps or volumes, the outcome would mirror current arrangements with no guarantee of consumer value.</p>
<p>System Need</p>	<p>SIR only provides inertia as a by-product of synchronous generation, not as a direct service. This makes it impossible to define or forecast a required volume, which is a core requirement for DASSA procurement.</p>

Compliance	SIR has been explicitly excluded from the initial DASSA framework (SEMC 024/066). In addition to this policy decision, its implementation within DASSA is not technically feasible , due to the absence of dispatchability or measurable volumes.
Deliverability	SIR transitioning to DASSA is fundamentally incompatible with the operational and IT frameworks underpinning FASS Go-live. Implementing it would require significant redesign and analysis that cannot be completed within current timelines.
Investment	SIR is not feasible under the DASSA framework, as it lacks a defined product, dispatchability, or forecastable volume. There is no route to market , and no basis for investor confidence under this arrangement.

Table 6-6: Testing DASSA framework as potential procurement mechanism for SIR

LPF

The LPF is a procurement method primarily focused on yearly, monthly or weekly auctions, designed to balance long-term stability with short-term flexibility. Generally, the LPF facilitates improved planning and coordination; however, it may create difficulties for participants who cannot reliably determine their real-time availability, particularly those involving RES. Additionally, due to its broader procurement horizon compared to DASSA, LPF may not adequately address real-time requirements, potentially leading to inefficiencies.

In terms of applying the LPF to the SIR product, the identified challenges align closely with those observed under the DASSA framework. Specifically, the LPF approach does not sufficiently resolve concerns related to market power nor does it clarify the complexities involved in determining required volumes of SIR.

Furthermore, adopting this procurement option for SIR is beyond the implementation scope intended for the September 2027 long stop date. Consequently, consideration of LPF at this stage would not only be incompatible but could also introduce a significant risk of delay to existing FASS arrangements (See Appendix 11.3).

Component	Description
Consumer Value	SIR is not a dispatchable or clearly quantifiable product, making it incompatible with auction-based frameworks like LPF that rely on predefined volume requirements. LPF, like DASSA, lacks any mechanism to address market power from “must-run” units. Without control over volumes or costs, consumer value cannot be guaranteed
System Need	SIR only produces inertia as a passive by-product of synchronous generation, not as an active service, this makes it impossible to set a firm

	volume requirement , which is essential for the forward planning nature of auctions under LPF ,which can span up to 1 year
Compliance	While LPF aligns with the regulator’s objective for a competitive procurement mechanism . SIR is technically incompatible with this model. SIR cannot be expressed as a schedulable, measurable product suitable for competitive clearing or auctioning under current LPF structures
Deliverability	SIR is structurally incompatible with LPF due to its lack of dispatchability, defined volumes, or ability to be competitively cleared. Even if the product were redefined to fit structurally, the necessary analytical work and IT system development could not be completed in time for LPF go-live
Investment	SIR is not a market-compatible product under LPF and therefore cannot be competitively procured . As a result, there is no applicable investment case —no price signal, no route to market, and no commercial framework to support supplier entry or participation

Table 6-7: Testing LPF framework as potential procurement mechanism for SIR

Fixed Contract

The fixed contract arrangement represents a procurement agreement between market participants and the TSO, aiming to secure service volumes and stable pricing over an extended horizon. In the context of this analysis, the considered timeframe ranges from 6 months to one year, while allowing for longer durations where appropriate. Such arrangements provide revenue certainty, particularly advantageous for new entrants. However, they may compromise the flexibility required by the system if operational conditions change.

When evaluating the procurement of SIR through fixed contracts, similar challenges arise as those observed under the LPF. The passive provision of inertia in SIR provision makes it fundamentally incompatible with fixed contract arrangements as the required volumes of inertia from SIR cannot be accurately predetermined, and therefore, it is not realistic to impose caps aligned with accepted contracts. Additionally, adopting this procurement method could exacerbate market power concerns identified within the analysis, potentially granting certain units disproportionate market influence.

Introducing fixed contracts for SIR is beyond the implementation scope intended for the September 2027 long stop date. Implementing an additional workstream and consulting could compromise the FASS Go-live date and even risk premature implementation, increasing the risk of security and stability issues, particularly given the increasing rates of SNSP. For these reasons, fixed contracts are not an appropriate mechanism for SIR procurement, nor is the option in the scope for implementation for FASS Go-live. See Appendix item (11.3).

Component	Description
Consumer Value	SIR cannot be structured as a scheduled, volume-defined service, making it incompatible with fixed contract models that rely on long-term procurement certainty. There’s also no ability to mitigate market power or

	ensure cost control for consumers, so the arrangement offers no guaranteed consumer value.
System Need	SIR only delivers inertia as a by-product of synchronous generation and cannot be forecast or committed to in advance. Fixed contracts require clear, forward-looking volume commitments, which SIR simply cannot provide.
Compliance	While Fixed Contracts offer a competitive procurement route aligned with regulatory intent, SIR is technically incompatible with such mechanisms. It cannot be defined, measured, or cleared in advance to meet the structural and regulatory expectations of fixed-term auctions or tenders.
Deliverability	SIR is structurally incompatible with the fixed contract model due to its passive nature and lack of dispatchability or measurable volumes. Even if structural issues were overcome, the required analysis and system design could not be completed in time to align with existing contract cycles.
Investment	Fixed contracts require products that can be clearly defined, priced, and committed over a term – SIR does not meet any of these criteria. As a result, it is not applicable as a commercial product, and no viable investment signal or market opportunity exists under this framework.

Table 6-8: Testing Fixed Contracts as potential procurement mechanism for SIR

Regulated Pricing

The regulated pricing arrangement represents an extension of current procurement mechanisms, where suppliers are remunerated according to predetermined rates and scalars. The key advantages of this approach include predictable costs for the TSO, mitigation of market power concerns, and proven reliability due to its historical usage. Additionally, regulated pricing presents minimal implementation risks for the FASS Go-live.

Regarding SIR, regulated pricing emerges as the only viable method capable of effectively incentivising provision due to the inherent challenges associated with quantifying and procuring inertia. Economically, it offers significant benefits to consumers by protecting them from potential market power issues, a protection that alternative procurement methods cannot fully guarantee. Furthermore, from an implementation standpoint, regulated pricing is feasible for immediate deployment, providing clarity and security to investors and adequately compensating flexible suppliers based on their demonstrated capabilities.

Component	Description
Consumer Value	Consumers are protected from market power risks, as pricing is predetermined and not subject to strategic bidding. This structure also supports system stability without exposing consumers to volatile pricing.

System Need	Regulated pricing ensures reliable delivery of system needs, as it builds on proven operational arrangements (e.g. must-run commitments). Inertia provision is ensured through continued synchronous operation, which this arrangement supports effectively.
Compliance	Use of regulated tariffs may require a derogation or exemption from standard market-based procurement expectations. However, if necessary, this can be managed through formal regulatory processes.
Deliverability	This approach is immediately deployable using existing infrastructure and commercial agreements. It avoids the need for new IT systems or auction platforms, making it the most viable near-term solution for FASS Go-live.
Investment	Regulated pricing provides clarity and income certainty, which supports investment in flexible synchronous capacity. Investors benefit from predictable returns and the ability to plan around a known tariff structure.

Table 6-9: Testing Regulated Pricing framework as potential procurement mechanism for SIR

Conclusion of Procurement Consideration Analysis

To maintain system reliability and operational stability, the procurement of SIR must continue - and the findings indicate that the only procurement method currently compatible with SIR is the regulated pricing arrangement.

As previously discussed, SIR includes incentive-based elements, which makes it difficult to define clear volume requirements and objective functions. These challenges are particularly relevant when assessing whether SIR can be transitioned into a competitive procurement framework. It is also worth noting that, when considering inertia, the only persisting issue relates to potential market power arising from reliance on the north-south interconnector.

Looking ahead one path could be to procure an explicit inertia product. Unlike SIR, an inertia-focussed product could leverage a defined volume requirement, which in turn may create opportunities for transparent procurement design. However, market power risks arising from the North-South interconnector would remain, as inertia provision is likely to be concentrated among a limited number of providers particularly in Northern Ireland. In addition, the LCIS is expected to procure a substantial share of the grid’s inertia requirement. Any inertia-based solution would need to align closely with LCIS to ensure consistency while remaining flexible enough to meet any short-term discrepancies.

One possible approach would be to incorporate inertia procurement via the DASSA. Further studies would be needed to further explore the ramification of this application however, as inertia requirements are dependent on renewable penetration and fuel mix on the grid, a complimentary daily auction alongside LCIS would likely be beneficial. This would be useful to meet any short comings in LCIS volume, provide TSOs with options in the event of any outages or disturbances and ultimately supporting overall system stability.

TSO Proposal:

It is the proposal of the TSO's to continue with regulated pricing for the procurement of SIR. The results of the feasibility of competitive procurement assessment indicated that regulated pricing is the only viable SIR procurement option, for FASS Go-live, given that:

- SIR is an incentive product that provides inertia as a byproduct. The relationship between SIR and inertia is non-linear, and as a result SIR volumes cannot be translated into inertia system requirements.
- The definition of SIR makes competitive procurement inherently flawed as a grid crucial volume cannot be ascertained and therefore forecasted.
- Congestion on the North- South interconnector may result in market power concerns for any inertia-based product and a solution would need to be understood before progressing
- Finally, exploring an alternative product for procuring inertia is not deliverable for day 1 implementation given the significant redesign, analysis, operational and IT frameworks required to transition to a new product.
- As a result, none of the competitive procurement strategies suggested (DASSA, LPF, Fixed Contracts) would be feasible for the procurement of a SIR product. The most appropriate procurement model that remains is that regulated pricing arrangement.

Question #7: Do you have any comments regarding our proposal to maintain tariff-based procurement of SIR for a transitional period?

7. Ramping Margin Requirements (RMx)

7.1. Current Situation

7.1.1. Why are ramping margin products required

Messages in this section:

- Power system operations require ramping adequacy to ensure sufficient capability to meet net demand requirements 24/7.
- Ramping adequacy is required to meet two elements;
 - o Expected ramping duty which aims to manage expected changes in generation mix and overall load requirements and
 - o Ramping uncertainty which considers potential forecast errors

The TSOs, as prudent system operators (and in line with licence and legislative requirements), aim to ensure that there is sufficient generation to meet load and maintain sufficient volumes of reserve availability. This requires the TSOs to undertake detailed forecasting of changing load and generation conditions from days ahead up to minutes ahead of real time to ensure there is sufficient capability on the system to manage forecasted and regular changes in net load e.g. morning pick up as energy demand increases across the island, and to manage changes in generator output. Net load is the overall demand for electricity on the island that needs to be supplied at any point in time, which is comprised of IC exports, fluctuating consumer demand, and demand interactions of embedded generation (e.g. rooftop PV).

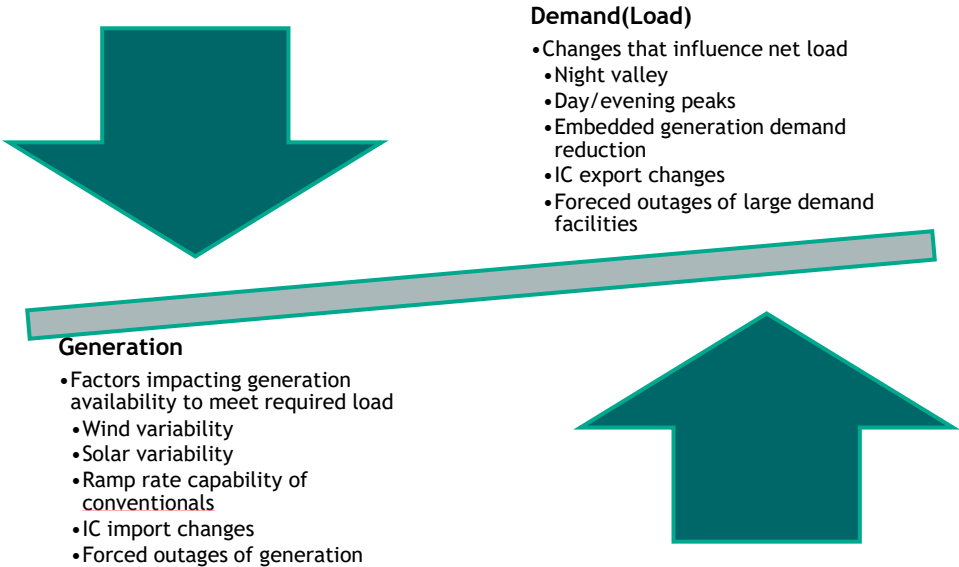


Figure 7-1: Factors influencing net load considerations

Ramping adequacy in the context of power system operation can be defined as ensuring sufficient capacity of responsive generation/demand units to meet net demand (net load)

requirements 24/7. Ramping capability within a power system is a function of the ability of generation and demand units to change their output/input across certain timeframes to manage net load variations. Ramping requirements for a particular power system vary as the generation mix and load profile changes across the day. The DS3 programme identified the need for ramping margin support and specific ramping margin products that could help provide the capability needed to manage ramping requirements. Ramping margin adequacy needs to be sufficient to meet two main considerations;

- *Ramping duty* - to manage changes in generation volumes relative to overall load i.e. managing large, predicted increases or decreases in demand, or changes in generation mix based on forecasts and generator provided information e.g. drop off or pick up in wind/solar production with variable weather conditions.
- *Ramping Margin Uncertainty* - detailed forecasting of both demand and generation is critical to secure system operation and is becoming an increasingly complex task with larger volumes of grid scale and embedded renewables, and dynamic demand considerations. To be able to manage the uncertainty associated with forecasting the TSOs currently schedule sufficient ramping capability to manage potential (and inevitable) forecast errors. In addition, within the current system of incentivised DS3 System services (reserves and non-reserves) the TSOs need to ensure availability of sufficient Replacement Reserve after a credible contingency. This adds a requirement linked to the current replacement reserve volumes and the LSI at any given time.

The overall ramping margin requirement therefore aims to cover both anticipated net load changes- i.e. the expected ramp duty due to variability in anticipated wind/solar generation, daily demand profiles etc and unanticipated changes due to potential forecast errors. Thus, as illustrated in Figure 7-2 below, the ramping margin requirement aims to ensure there is a sufficient level of dispatchable generation and demand that can ramp to manage future predicted net load and any variability of this due to forecasting errors and uncertainties.

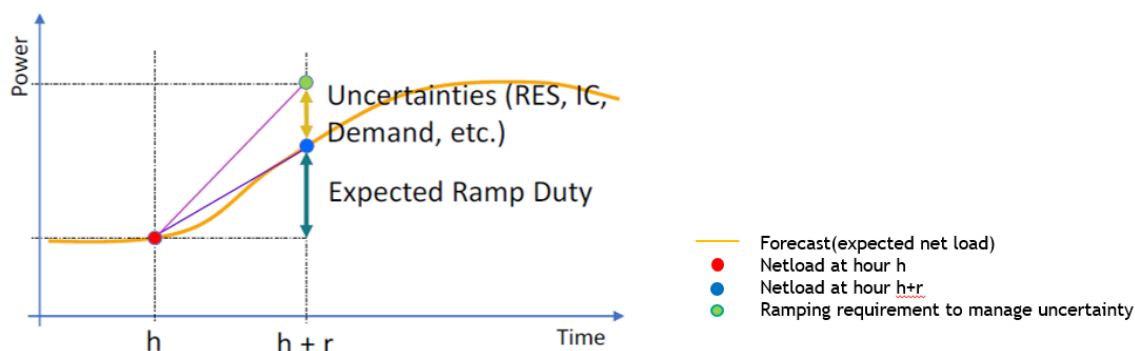


Figure 7-2: Ramping margin requirements are divided into Ramping Duty and Ramping Margin uncertainty

7.1.2. How is ramping margin planned?

Messages in this section:

- Expected ramping duty accounts for RES generation forecasts, Interconnector Schedules and Demand forecasts.

- Ramping uncertainty considers potential forecast errors associated with RES generation forecasts, demand forecasts and IC schedule uncertainty.
- Ramping margin is planned to ensure the system has sufficient flexibility to accommodate fluctuations in demand and generation, particularly as non-synchronous generation increases.

Ramping Duty

Ramping duty requirements are informed by multiple factors related to system operation; e.g. RES generation forecasts, Interconnector schedules and Demand forecasts, we provide a brief overview of some of these below.

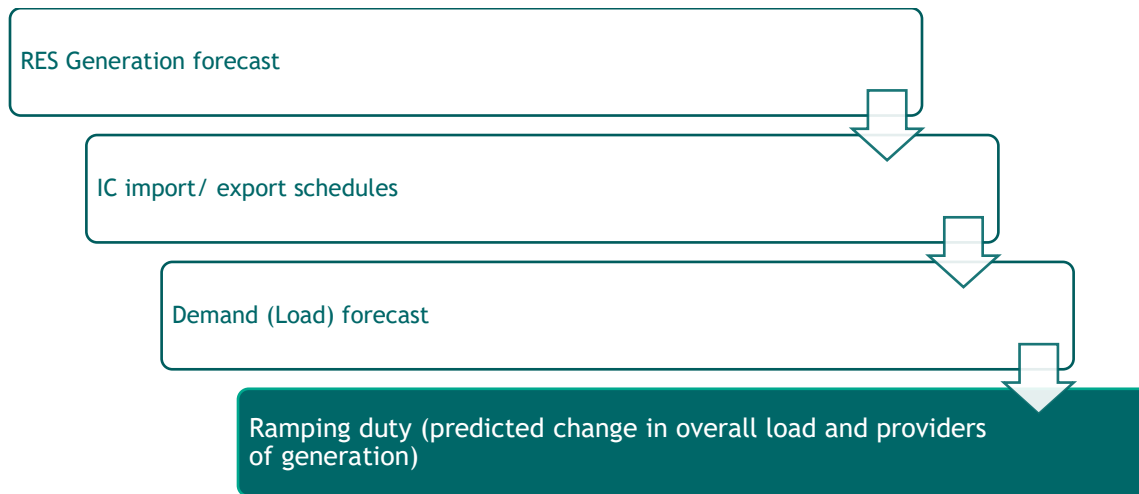


Figure 7-3 Flowchart for Ramping Duty

Demand or Load forecasting is a critical process that ensures the TSOs are well informed to meet actual load requirements at any point in time. As required under OC1 of both Grid Codes the TSOs have to produce demand forecasts ranging from the operational planning phase through to real time operation i.e. scheduling and dispatch.

To produce a demand forecast for the scheduling and dispatch timeframe, the TSOs take into account historical demand curves, the impact of public holidays and weather forecasts - both current and historic. Separate forecasts are created for each jurisdiction due to the different demand profiles in Ireland and Northern Ireland, different usage patterns, industrial customers and to reflect the differences in public/bank holidays in each jurisdiction. The need for jurisdictional forecasts is also driven by the physical limitation on N-S tie-line connecting Ireland and Northern Ireland.

Figure 7-4 gives an overview of the inputs to the load forecasting process and Load Forecast Tool in EMS and the output in terms of load forecasts. These forecasts are then utilised within the Market Management Systems (MMS) and Load predictor tool (LPRED) to inform the Long-Term Scheduling (LTS), Real-Time Commitment (RTC) and Real-Time Dispatch (RTD) processes, ensuring sufficient generation is scheduled to meet forecasted load⁷⁰.

⁷⁰ [Short-term Demand Forecasting Methodology.pdf](#)

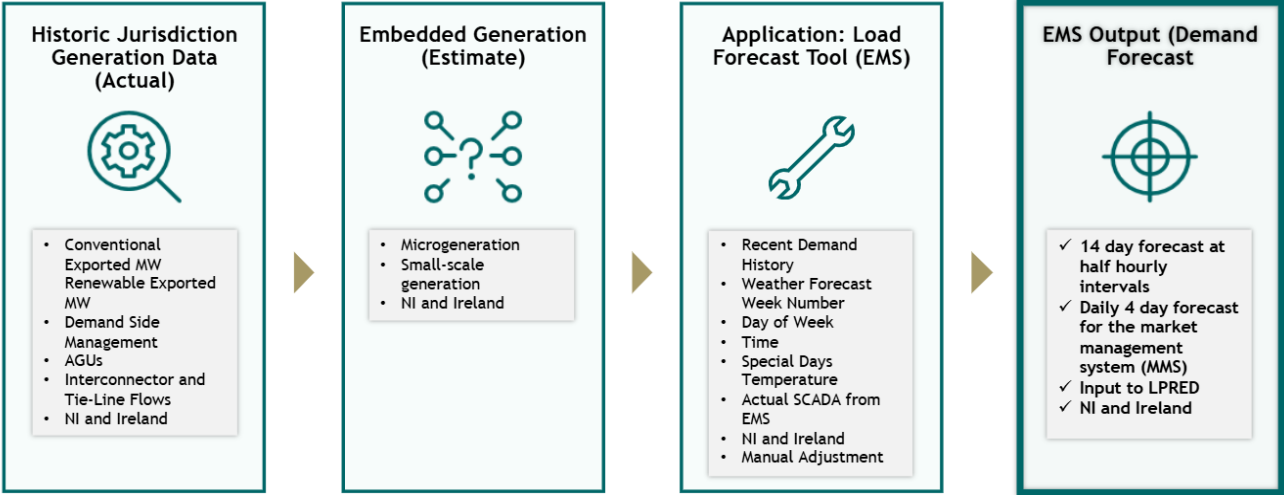


Figure 7-4: Overview of inputs and outputs from Load Forecast tool in EMS

The current level of interconnection and associated potential imports into and exports out from the Island (1500MW comprised of EWIC, Moyle and Greenlink Interconnectors) is important to take into consideration in the ramping duty requirements. Interconnector schedules in future time horizons, e.g. changes in export or import positions will impact the overall demand and generation requirements on the island.

RES Forecasts are important considerations for ramping duty predictions - as changes in wind or solar availability can reduce RES generation considerably. This means that other generation must be available to ramp up to replace wind, or vice versa if RES availability is increasing other generation may need to ramp down to accommodate increasing RES contribution to overall demand.

To help illustrate the challenge of predicting ramping duty requirements that are influenced by RES generation output and can manage forecast uncertainty this we provide an example of considerations from a passing high wind weather system in October 2023.

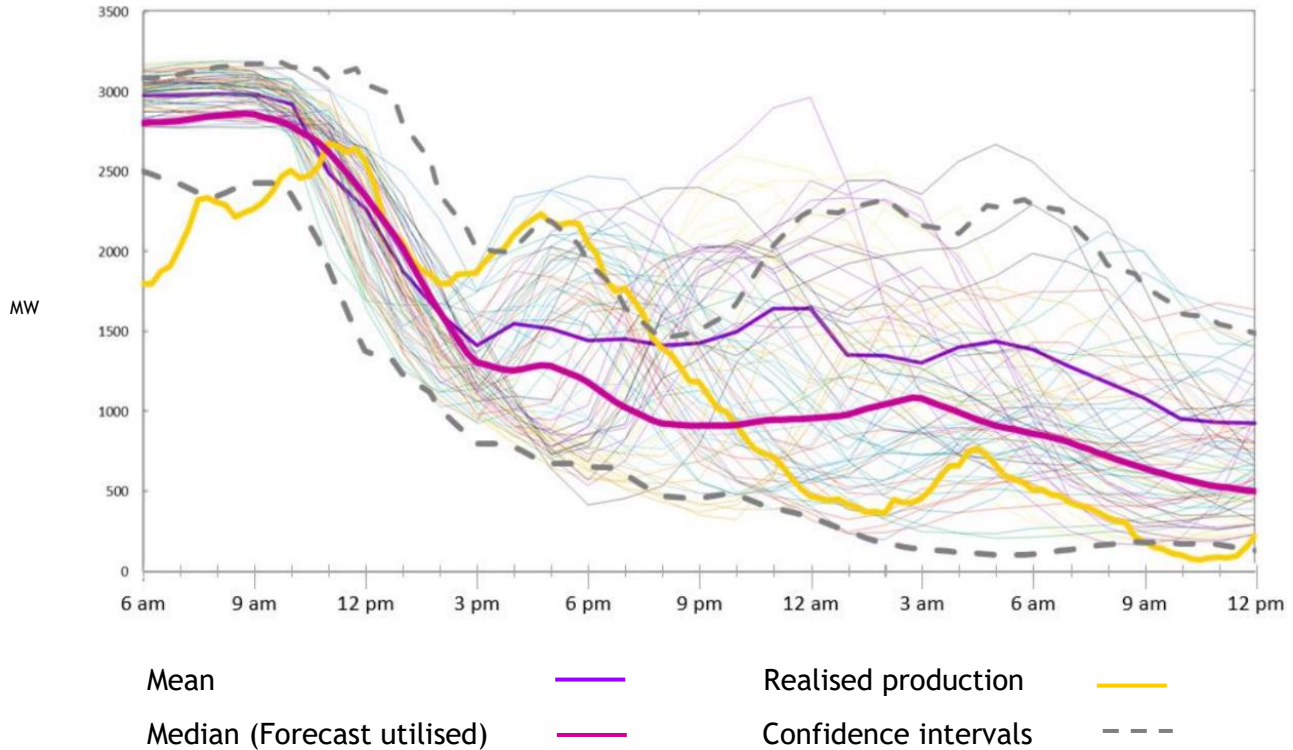


Figure 7-5 Outline of wind forecast variability

Two vendors for RES forecasting are utilised by the TSOs, and confidence intervals of 90% are generally utilised. In this example, which outlines a variable wind forecast for a 30-hour period, the vendor provided mean forecast (purple line) is shown along with ensemble of forecasts that the mean is derived from.

EirGrid & SONI utilise the median production forecast (pink line). The bounds of possible forecasts are shown in the confidence interval lines. Actual wind generation is shown in yellow to help illustrate the wide variation in wind output compared to available forecasts.

The TSOs need to be able to ensure that sufficient generation is available at all times, which includes active power output reduction from certain sources (e.g. wind as per above example) and active power input increases from others (conventional sources to replace reduction in wind generation). The MMS works to ensure sufficient generation (with minimal cost of deviation from submitted PNs) to meet forecasted ramping duty. t

Ramping Uncertainty

Ramping uncertainty is comprised of several components including RES forecast uncertainty, interconnector flow uncertainty and load forecast error.

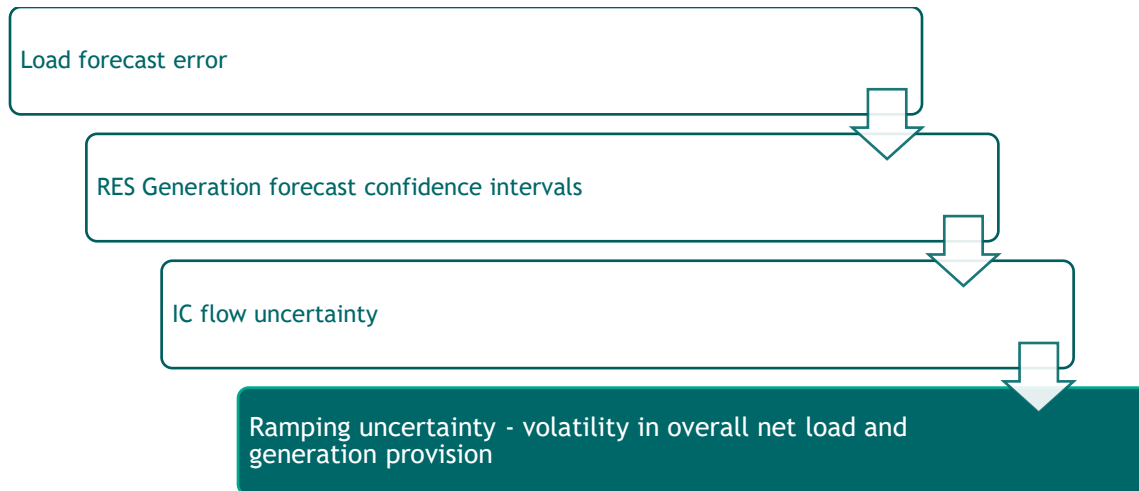


Figure 7-6 Flowchart for Ramping Uncertainty

Ensuring accuracy when forecasting storm events can be difficult, as not only are the TSOs relying on forecasting of highly volatile weather systems but are also trying to understand the potential volume of high wind speed turbine shutdown (a protection mechanism to prevent wind turbine damage). The following example of Storm Isha during January 2024 helps exemplify this by demonstrating the differences between the two vendor forecasts and the actual wind availability signals received at the control centre directly from the wind farms. EirGrid and SONI receive forecasts from their vendors on a rolling 6-hour basis starting at 00:00, so receive updated forecasts at 6:00am, 12:00, 18:00 and again at 00:00, for each 15-minute forecast interval of the next 120 hours.

The level of under or over forecast MW that relate to inaccuracy of forecasts can be significant during storm conditions, as **Error! Reference source not found.** demonstrates. Using information gathered during Storm Isha in January 2024, values of almost -2500W of inaccurate forecasting occurred, requiring the TSOs to take action to ensure sufficient alternative generation is available. Some of the high levels of error can be explained by turbine shutdown (a protective measure whereby turbines turn out of the wind to prevent damage to turbine parts during extremely high wind speeds), however this does not diminish the challenge of ensuring sufficient ramping capability to manage the change of generation availability during such events.

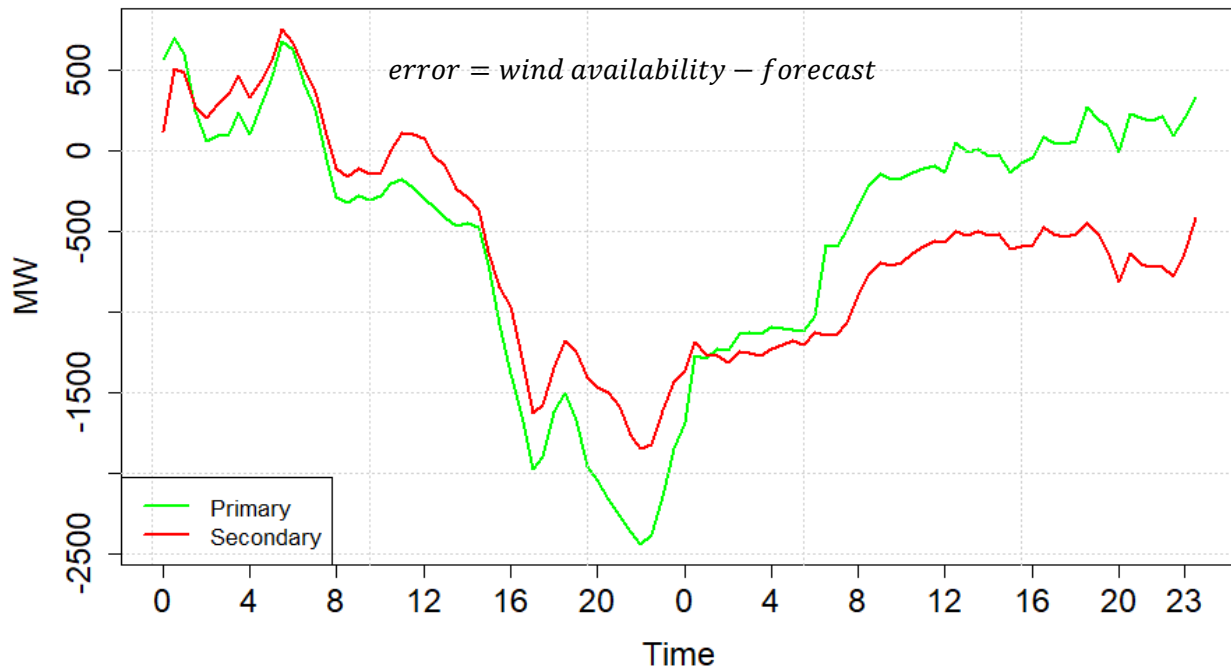


Figure 7-7: Wind forecast error associated with Primary and Secondary Vendor forecasts supplied for Storm Isha period 2024

In addition, the current Ramping margin processes ensure that the TSOs can avail of sufficient headroom to manage all timeframes and requirements even following the occurrence of the largest credible contingency. If a contingency event occurs, for example the loss of an LSI of 500MW, available POR-TOR1 volumes will be activated automatically, and TOR 2 will be activated manually. Sufficient RR will then be required to replace the volumes of POR-TOR2. The TSOs therefore ensure that the LSI and Replacement reserve volumes are accounted for in the current monitoring and scheduling of available ramping margin capability. (See section 7.2.2 for more detail).

7.1.3. Ramping Margin (RMX) Current Products

Messages in this section:

- Currently the TSOs consider three different time horizons for upward ramping requirements i.e. providers shall be able to provide increased MW output or reduction in demand, within one hour (RM1), three hours (RM3) or eight hours (RM8) of receiving a dispatch instruction. The response (MW output) shall be maintained for respectively further two hours (RM1), five hours (RM3) or eight hours (RM8) after the initial response time has been elapsed.
- The DS3 products RM1, RM3 and RM8 provide incentives for keeping ramping margin available to the TSO.

The current suite of ramping market products provides incentives to market participants to make available sufficient upward ramping capability (increase in generation or decrease in demand) to the TSOs to manage ramping requirements.

There are three ramping products, Ramping Margin 1, Ramping Margin 3 and Ramping Margin 8. Each product is comprised of two components a requirement to have the contracted ramping margin (MW) available within a certain period and then sustain that response for a fixed period (x).

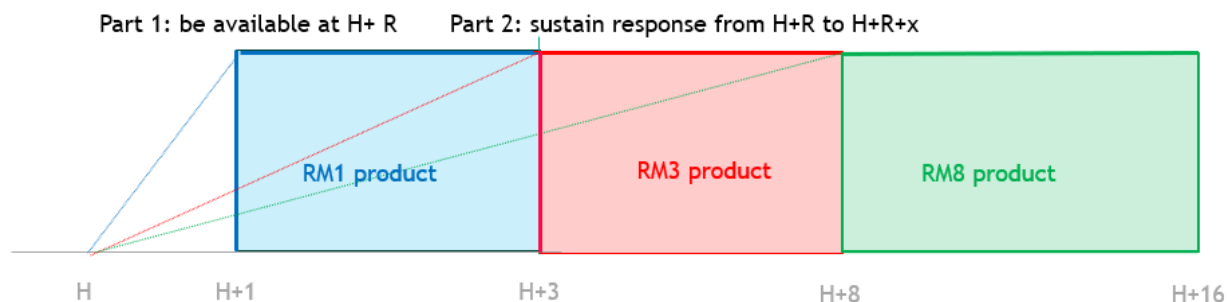


Figure 7-8: RMX Summary of three products

Non-reserve services	Unit	Delivered within	Maintained for	Definitions
RM1 Ramping Margin 1	MWh	1 hour	2 hours	Ramping Margin 1 is the increased MW output or reduction in demand, a unit can provide, within one hour of receiving a dispatch instruction and maintaining that MW output for a further two hours after the one hour period has elapsed.
RM3 Ramping Margin 3	MWh	3 hours	5 hours	Ramping Margin 3 is the increased MW output or reduction in demand, a unit can provide, within three hours of receiving a dispatch instruction and maintaining that MW output for a further five hours after the three hour period has elapsed.
RM8 Ramping Margin 8	MWh	8 hours	8 hours	Ramping Margin 8 is the increased MW output or reduction in demand, a unit can provide, within eight hours of receiving a dispatch instruction and maintaining that MW output for a further eight hours after the eight hour period has elapsed.

Figure 7-9 -Outline of current ramping margin products and components

Ramping capability can vary depending on the type of generator and the generator state: e.g. Online (load cycling) or Offline Hot can generally ramp quickly and are therefore suitable for short term ramping requirements. Offline Warm or Offline Cold cycling states generally require a longer time period to reach their minimum stable power level and ramp up from that level, hence are more suitable for fulfilling long-term ramping requirements.

The current Ramping Margins products are incentivised through DS3 System Services Tariffs paid to all qualified providers. Qualified provider capability is detailed in their specific DS3 System Service contracts with the relevant System Operator and tariff payments are made based on their contracted capability and monitored availability. This incentivised provision of ramping capability ensures the system has sufficient flexibility to accommodate fluctuations in demand and generation, particularly as non-synchronous generation increases.

The general volume ramping margins volume for a trading period, T is defined as⁷¹:

$$RMX_{Available\ Volume_T} = \text{Min}(Ramp_{potential_T}, Ramp_{Declared_T}, Ramp_{Avail_T})$$

Formula 7-1

Where,

- **Ramp_{potential}** is the potential ramping margin, which is defined as highest additional power a unit can provide in one, three and eight hours with respect to RM1, RM3, and RM8. The potential ramping margin will be determined in accordance with the ramp rates set out in the technical offer data (TOD).
- **Ramp_{Declared}** is the lowest value of declared ramping for the trading period, which is derived from EDIL declarations.
- **Ramp_{Avail}** is defined as the difference between the minimum availability from the start of the Trading Period until 3, 8 or 16 hours later (corresponding to RM1, RM3, and RM8), and the average MW output or average MW reduction over that interval

Furthermore, the potential ramping capability will depend on the unit’s thermal state. As specified in the TOD, ramp rates are defined for hot, warm and cold conditions, and appropriate category must be applied in the calculation. For units without defined thermal states (such as hydro), a warm state is assumed as default.

Service providers are remunerated for providing ramping capability using¹⁵ Formula 7-2.

$$RMX_{Trading\ period\ Payment} = RMX_{Available\ Volume} \cdot RMX_{Payment\ Rate} \cdot Trading\ Period\ Duration$$

Formula 7-2

Where,

- **RMX_{Payment Rate}** is the corresponding Payment Rate (expressed in €/MW) applicable to either RM1,3 or 8.
- **Trading Period Duration** is the Trading Period Duration (expressed in hours).

7.1.4. Current ramping margin providers

Messages in this section:

- Current upward RM provision is predominately provided by Conventional units.
- Maximum volume limitations per unit are imposed.

⁷¹ [Ire-DS3-System-Services-Regulated-Arrangements_final.pdf](#)

The current provision of RM contracted capability (via DS3 contracts and remunerated through tariffs based on monitoring service availability) is predominately from Conventional units, with small provision from DSUs, AGUs and Batteries.

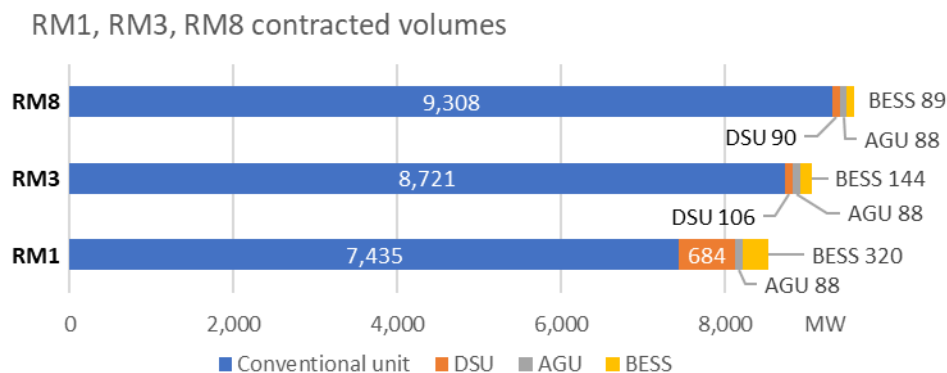


Figure 7-10: DS3 Contracted Capacity for RM1, RM3 and RM8 (MW) - Values as of October 2024

Under DS3 arrangement there is a maximum volume that can be contracted from a single provider, which is set currently at 450MW for RM1, and 500MW for RM3 and RM8⁷².

Service	Max Volume per unit
RM1	450MW
RM3	500MW
RM8	500MW

Table 7-1 Maximum contracted volume from a single provider of RM products

7.2. System need

7.2.1. Objectives

Messages in this section:

- EirGrid and SONI in line with licence requirements and SOGL requirements utilise the current Ramping Margin products, a Ramping Margin tool and operational processes to meet the system need for ramping adequacy.

Currently there are no explicit requirements for ramping capability contained within EU legislation or network codes. However, through both EirGrid and SONI licence conditions 73, 74 and SOGL requirements EirGrid and SONI are required to ensure stable system operation and schedule sufficient generation resources “as will in aggregate be sufficient to match at all

⁷² <https://cms.eirgrid.ie/sites/default/files/publications/DS3-Bidders-Information-Session-8-January-2025.pdf>

⁷³ [Eirgrid-Transmission-System-Operator-March-2017-Licence](#)

⁷⁴ [SONI Consolidated TSO licence](#)

times (to the extent possible having regard to the availability of SEM Generation) demand forecast on the All-Island Networks taking account of information provided by electricity undertakings, together with an appropriate margin of reserve” as per SONI Licence condition 10(4) and EirGrid Licence Condition 22 (4) while accounting for the dynamic operating characteristics of SEM Generation. Additional requirements are listed in EirGrid’s licence conditions 3 and 10 (5), and SONI’s licence conditions 22 (4) and 22(5). The below table outlines relevant requirements from SOGL.

SOGL requirement Article 55	<p>Each TSO shall be responsible for the operational security of its control area and, in particular, it shall:</p> <ul style="list-style-type: none"> a) develop and implement network operation tools that are relevant for its control area and related to real-time operation and operational planning b) develop and deploy tools and solutions for the prevention and remedy of disturbances c) use services provided by third parties, through procurement when applicable, such as redispatching or countertrading, congestion management services, generation reserves and other ancillary services
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Table 7-2: Table outlining SOGL requirements that relate to Ramping margin and Ramping Margin Tool

In line with the above requirements, and as prudent system operators EirGrid and SONI incentivise the provision of ramping margin capability through the RMX products and have developed and maintain the ramping margin tool to ensure sufficient resources are scheduled to manage ramping uncertainty to enable sufficient generation to meet demand on the island.

7.2.2. Current ramping margin products and scheduling requirements

Messages in this section:

- The Ramping Margin tool assess ramping margin requirements and available ramping capability.
- The Ramping Margin tool ensures that sufficient ramping capability is scheduled through the MMS system.

A ramping margin tool has been developed by the TSOs to assist in the identification of upward ramping needs to manage ramping uncertainty and to assist in the forward-looking monitoring of upward ramping capability. The tool utilises D-2, D-1 RES forecasts (updated every 6 hours), and continually updated demand forecasts closer to real time, to forecast RM1, RM3 and RM8 uncertainty requirements. The tool both identifies the ramping margin uncertainty requirements and monitors the availability of ramping capability across all units, heat states and timeframes (i.e. headroom available in RM1, RM3 and RM8 time horizons).

The Ramping Margin Tool outputs are then incorporated into MMS processes, ultimately ensuring that sufficient ramping capability is scheduled and dispatched for both ramping duty and ramping uncertainty requirements.

The current formula utilised within the ramping margin tool determines the upward ramping margin capability to meet uncertainty requirements at time t+R, where t is the current time (scheduling interval) and t+R is the time at a certain ramping margin window from time t. For example, the RM3 requirements at time t=2pm determine the requirements for 5pm (2pm +3 hours), as follows;

$$RM_{Rt}(R) = LSI(t+R) + LFE(t+R) + \max(RR(t+R), Uncertt(R)) + Tie_uncert + IC_Uncertainty(t+R)$$

Formula 7-3

Where,

- R is the ramping margin category interval, (RM1(t+1), RM3 (t+3), RM8 (t+8))
- $RM_{Rt}(R)$ is the Ramping Margin Requirement for interval “t” for ramping margin category interval “R”
- $LSI(t+R)$ is the Largest Single Infeed in scheduling interval “t+R”
- $LFE(t+R)$ is the Load Forecast Error in scheduling interval “t+R”. A 1% LFE error value is used
- $RR(t+R)$ is the Replacement Reserve volume required in each jurisdiction in scheduling interval “t+R”
- $Uncertt$ is the variable generation uncertainty forecasted for each ramping margin category “R” in scheduling interval “t”
- Tie_uncert is the Tie Line (North-South tie line) uncertainty flow, -i.e. % deviation from scheduled (MMS) tie-line flows (currently set at 0%)
- $IC_Uncertainty(t+R)$ is the HVDC cross border interconnector schedule uncertainty, currently where schedules at t+R are uncertain 100MW is added to RM requirements, where IC schedules are certain 0MW is added

The formula above outlines that the TSOs schedule for the largest of either required Replacement reserve volumes or the maximum variable generation uncertainty for the relevant time horizon. This means in practice that if, for example, the forecasted $Uncertt$ (Variable generation forecast uncertainty) for RM3 has a value of 300MW and RR requirements are 450MW then 450MW will be scheduled. Alternatively, if the forecasted $Uncertt$ value is 525MW, and RR requirements are 450MW, then 525MW will be scheduled. This approach aims to ensure that efficient utilisation of Ramping margin volumes are achieved.

Where there are only non-firm Interconnector reference programs (ICRP) in place (e.g. in advance of the current coupled intraday auctions with GB) the interconnector uncertainty value is 100MW. Where firm ICRPs are available this value is set at zero MW.

The following table outlines the SEM-GB interconnector firm and non-firm periods.

	Receive Time	Firm Period	Non Firm Period
Day Ahead	12:00 D-1	N/A	23:00 D to 23:00 D
IDA1	18:00 D-1	23:00 D to 10:59 D	11:00 D to 23:00 D
IDA2	08:00 D	11:00 D to 23:00 D	N/A

Figure 7-11: Table outlining Firm and Non-Firm Interconnector schedule timeframes (SEMO)

To help illustrate the difference between ramping duty and ramping margin we outline an example in the following text.

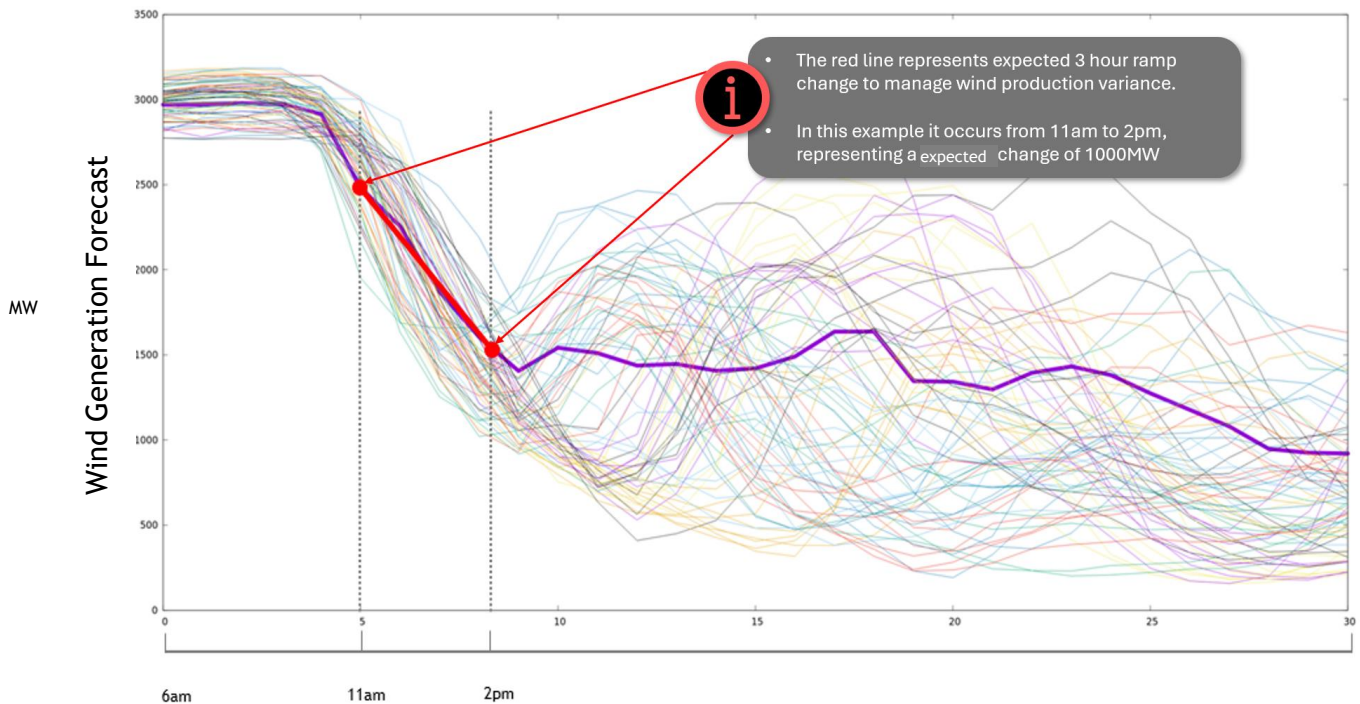


Figure 7-42 Variable generation forecasted ramp example

The largest expected ramp duty requirement resulting from a drop in wind production, utilising the median forecast of wind generation for a particular day (using the latest forecast provided at 6am⁷⁵) from 11am to 2 pm is shown in by the red line - approx.1000MW, necessitating the availability of other generation/demand that can ensure sufficient capacity is available to meet the required net load.

⁷⁵ Updated forecasts are provided on a rolling 6 hour basis

In addition to account for forecast uncertainty the widest possible drop in wind production could equate to approximately 2000MW.

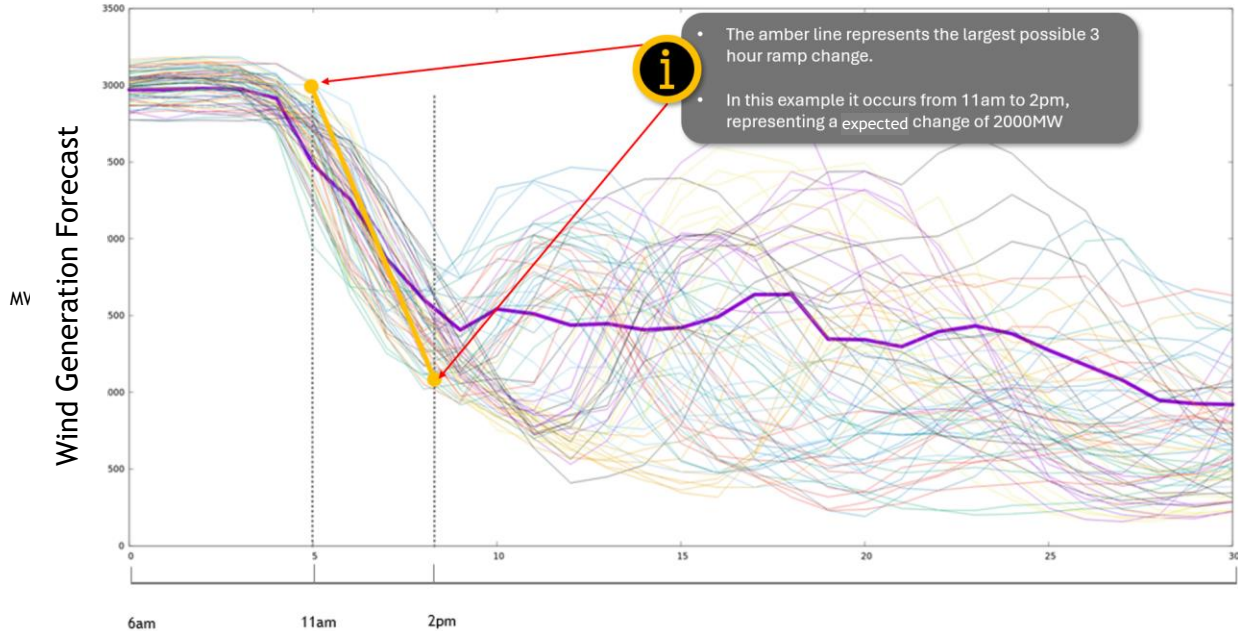


Figure 7-135 Variable generation potential ramp forecast uncertainty

Taken together this would mean that the TSOs would need to ensure MMS schedules deliver against a predicted drop in wind generation of 1000MW and an additional 1000MW for uncertainty in wind forecast accuracy, necessitating in total ramping margin requirement of 2000MW.

The variable generation uncertainty is calculated using the variable generation forecast and the variable generation ramp forecast i.e. as per above the scheduled ramp in wind generation is 1000MW and the possible ramp of generation using the 90th confidence interval

is an additional 1000MW:

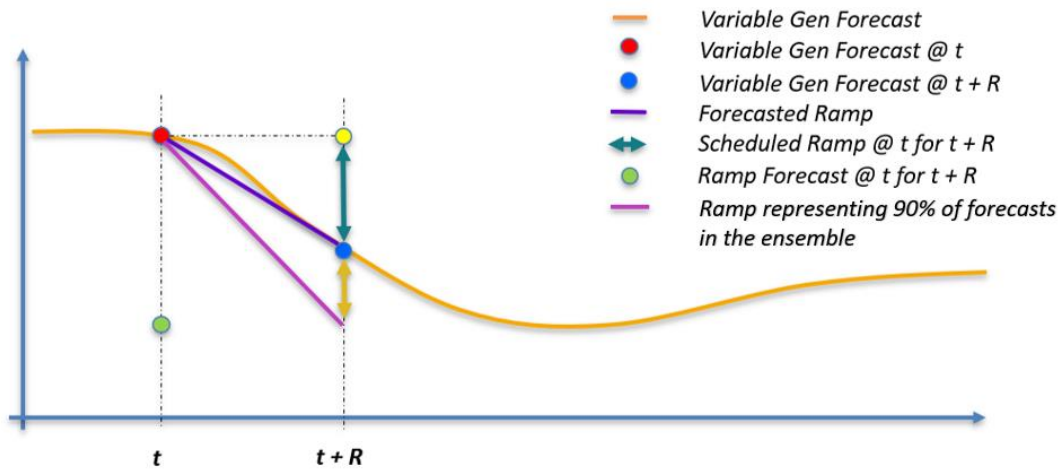


Figure 7-164 Outline of Variable Gen Forecast and Ramp forecast considerations

Currently the DS3 system service programme remunerates units that declare their ramping margin via ensuring EDIL declarations in line with their contracted capability.

Product	EDIL Declaration
Ramping Margin 1	EDIL Declaration RM 1-3 Hours in MW
Ramping Margin 3	EDIL Declaration RM 3-8 Hours in MW
Ramping Margin 8	EDIL Declaration RM 8-16 Hours in MW

Table 7-3: Displays Ramping Margin Total Time horizons

Contracted units are monitored and assessed continuously for their performance in the provision of ramping margin capability. The Performance Assessment of the RM service is based on an evaluation of the Providing Unit’s ability to follow Dispatch Instructions (DI) in a calendar month, for all Providing Units which are not DSUs. For Providing Units which are DSUs, performance will be assessed slightly differently.

Essentially where units are found to deviate from their ramping capability as declared in EDIL or fail to sync their payments will be impacted negatively.

7.2.3. Evolving system characteristics

Messages in this section:

- Forecasting ramping margin requirements is likely to increase in complexity with;
 - o higher levels of TSO and DSO connected RES and embedded RES (e.g. household solar PV),
 - o higher levels of interconnection,
 - o integration into EU intraday markets.

- Ramping margin requirements will need further assessment to ensure sufficient ramping adequacy to meet future system needs.

The TSOs consider that the ramping margin requirements for the All-Island power system will change over time. As the system continues to integrate higher volumes of embedded and grid scale renewables and BESS, increased interconnections to neighbouring power systems and changing demand dynamics, the complexity in forecasting demand and generation will increase. Additionally, while the current RM products and tools focus on ensuring sufficient headroom availability the TSOs consider it will be important to assess the need for downward focused ramping capability in the coming years. Ramping margin supports and product definitions will need to evolve to manage these complexities, following further analysis of all aspects; including those outlined below;

Renewable Generation

A main source of uncertainty in the power system is renewable generation forecasts, which as outlined above can be affected by both the magnitude and timing of forecast errors. During periods of high renewable generation—particularly when forecast uncertainty is high—there is a greater need for Ramping Margin on the all-island system. At the same time, these periods typically see fewer conventional generators online, reducing the availability of traditional ramping capacity. As a result, there will be a growing reliance on alternative sources to provide Ramping Margin. As the volume of embedded and grid scale solar generation increases, the impact of potential shorter-term variations in output (e.g. passing cloud cover) may drive additional or different ramping requirements. Current evidence from recorded fluctuations in solar output illustrate the complexity of forecasting accurate generation profiles, where drops of 60% of output across solar generation sites have occurred within 30 minutes. Currently, the TSOs’ operations and use of the ramping margin tool provides sufficient capability to manage this variability, and as the volume of solar generation increases the somewhat dispersed nature of solar generation sites may facilitate an inherent smoothing of the impact of cloud cover change on overall solar generation volumes. However, as the volume of solar continues to grow, the TSOs consider that there will be a need to better assess the risks associated with this when considering ramping margin capabilities.

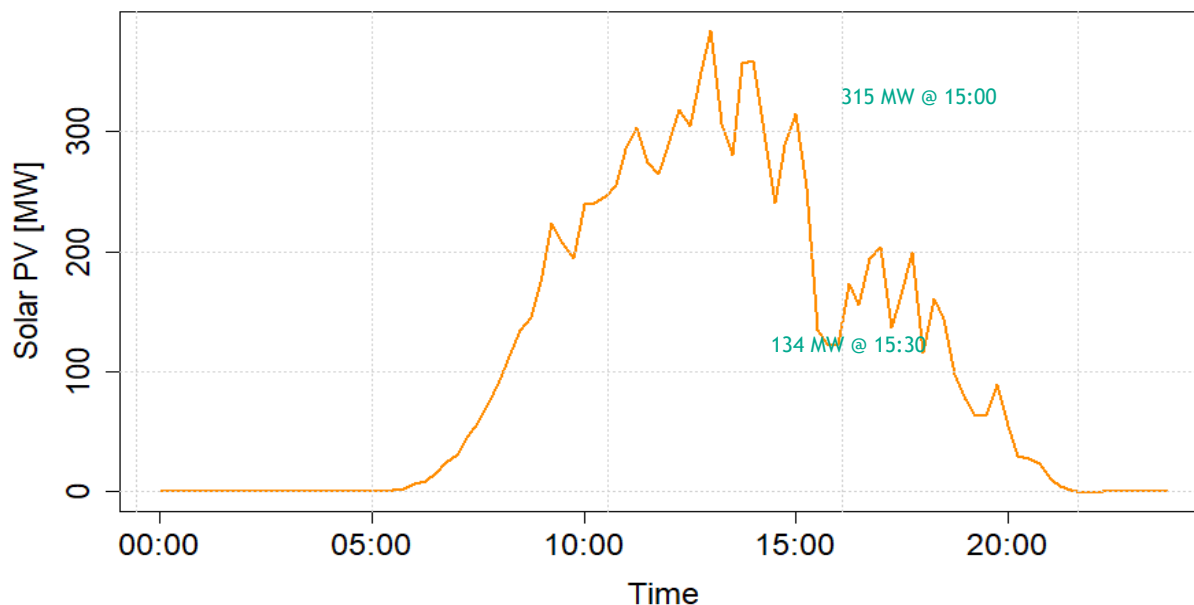


Figure 7-15: Intra hour variations resulting from passing cloud cover across a number of solar generation sites

Improving Forecasting accuracy

Ramping margin uncertainty in future is likely to grow in other areas with greater levels of interconnection, changing ramp rates for interconnectors and dynamic demand e.g. fleet EV charging. Improving forecasting capability in both generation and demand forecasting will be a necessary development for future power system operations and therefore as part of the Operational Tools & Capability Enhancement (OTCE) programme of work⁷⁶ there is a TSO focused workstream on improving forecast accuracy to minimise uncertainty.

Market interactions

As the system progressively incorporates a different energy mix and encounters more challenging operational consideration ensuring appropriate market participant behaviour will become more important. With the advent of the Celtic Interconnector and the implementation of the Strategic Markets Programme (SMP) to enable re-integration into EU Day-Ahead, intraday and balancing markets there is likely to be significant change in how SEM participants trade and interact within each market timeframe. Additionally, as the Celtic interconnector will be closely coupled to the EU intraday markets, Celtic flows may vary more frequently than SEM-GB IC flows. The TSOs are currently assessing how best to cater for such uncertainty in future developments of the Ramping Margin Tool.

In addition, the introduction of DASSA will oblige participants to submit PNs aligned with contracted POR-TOR2 and RR capability, which the Ramping Margin tool will take account of. Operational experience of DASSA and its interaction with Ramping Margin capability will be critical to inform future ramping product design. From a procurement perspective the TSOs consider that further examination of emerging market dynamics will be necessary to fully define

⁷⁶ [SOEF-Advisory-Council-Meeting-9-- OTCE overview](#)

ramping margin requirements and suitable products in the future, and how these should be best procured.

Ensuring appropriate market incentives are in place to enable a more flexible generation and demand mix will also be required as part of the implementation of the revised Electricity Market Directive and Regulation, the Network Code on Demand response and national legislation. Ensuring full participation by market participants in all market timeframes will need to be examined further in terms of appropriate market rulesets and codes of practice.

7.2.4.Future EU assessment requirements

Messages in this section:

- The Flexible Needs assessment that will need to be undertaken by each EU Member state will require analysis of ramping duty and ramping uncertainty.
- The outputs of this assessment process will help inform future ramping requirements.

As part of recent European Electricity Market Design reform legislative changes, TSOs, DSOs and relevant authorities will be obliged to undertake Flexibility Needs assessments, which will include the need to assess ramping margin requirements for both ramping duty and ramping uncertainty.

The approved Flexible Needs Assessment methodology has been published by ACER in July 2025 ⁷⁷ and outlines methodologies to be followed for assessing overall flexibility and breaks this down into different components, which largely reflect both the Ramping Duty and the Ramping Uncertainty.

Term	Definition	Assessment responsible party according to the ACER FNA
System flexibility needs	Flexibility need by electricity system to adjust to variability of generation and consumption across relevant market timeframes: composed of RES integration needs, ramping needs, short term flexibility needs	Assessed by the TSO but associated to the whole electricity system requirements (i.e. transmission and distribution systems)
RES integration needs	“the quantity of flexibility required for the Member State to achieve its annual RES integration target”),	As per above
Ramping Needs	“needs associated with variations of the residual load assuming perfect forecast conditions”	As per above

⁷⁷<https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-flexibility-needs-assessment-methodology-2025.pdf>

Short-term Flexibility Needs	<p>“needs associated with unexpected variations of the residual load or forced outage of assets during the intra-day or balancing timeframe”</p> <p>“TSOs...(may) further distinguish between very fast, fast, and slow short-term residual margins for a target year, for example from 5 to 15 minutes (to calculate very fast short-term residual margins), 15 to 60 minutes (to calculate fast short-term residual margins) and 1 hour to D-1 (to calculate slow short-term residual margins).”</p>	As per above
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Table 7-4: Outline of Flexible Needs Assessment requirements

EirGrid and SONI are working with the DSOs, RAs and relevant Government departments to prepare for and conduct these assessments and will ensure that the determination of future ramping margin requirements align with ACER’s methodology. All relevant EU TSOs and DSOs are obliged to conduct this assessment by May 2026, for submission to the relevant regulatory authority for inclusion in the Member States’ Flexibility Needs Assessment report⁷⁸.

7.3. International experience /comparisons

Messages in this section:

- System Operators in other EU jurisdictions do not apply specific ramping margin focused products.
- Alternatively, these TSOs appear to be able to manage fluctuations utilising a combination of strong balancing incentives, intraday market and balancing market products, interconnected balancing markets and processes.

In an EU context, ramping margin focused products are not explicitly defined, and currently other EU TSOs are operating systems with high levels of variable RES and appear to be able to manage fluctuations utilising a combination of strong balancing incentives, intraday market and balancing market products, interconnected balancing markets and processes. Elia, the Belgian TSO, identified in its [2024-2034 Adequacy and Flexibility study](#) the need for upward and downward flexibility requirements will grow with greater levels of renewables, and identified three main requirements (please note that the term ramping flexibility does not equate to the DS3 ramping products)

- Ramping flexibility i.e. capacity which can be regulated upward or downward in a timeframe of 5 minutes,
- Fast flexibility -i.e. ability to be regulated upward or downward within 5-15 minutes
- Slow flexibility - ability to be regulated upward or downward within in 5 hours

⁷⁸ [ACER Decision 05-2025 - FNAM](#)

Elia expects that the market participants will be able to help resolve the needs for the Slow flexibility requirements through trading in the intraday markets. For the Ramping and Fast flexibility requirements, Elia indicate that they consider these needs cannot be met through the wholesale markets as they are identified after the last intraday market opportunity and will therefore rely on the Frequency restoration reserve (Manual Frequency restoration (mFRR) and automatic Frequency Restoration Reserve (aFRR) balancing products to help resolve the residual load imbalances that will occur as a result of flexibility requirements. It is important to note that Elia operate a self-dispatch system, highly integrated into the Central EU synchronous area, with intraday markets closing close to real time, compared to the central dispatch model and the intraday markets currently utilised in the SEM, with different balancing market arrangements.

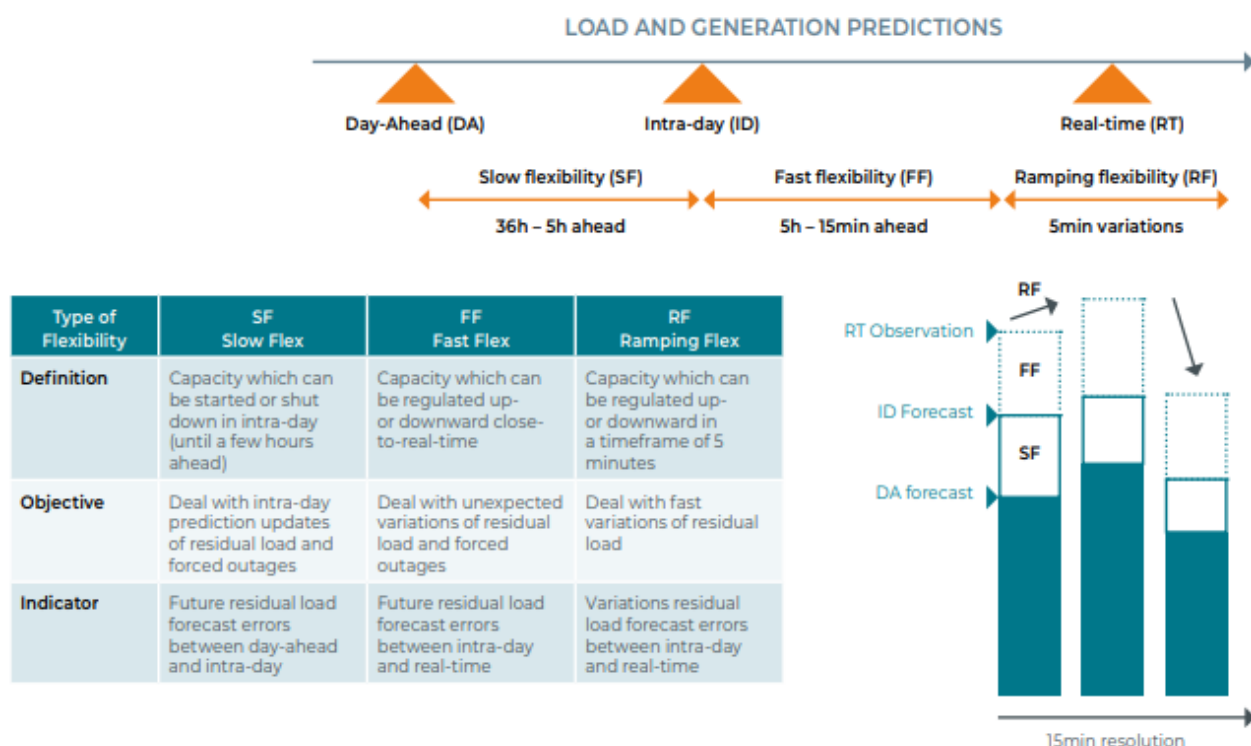


Figure 7-716 Elia flexibility requirements outlined in Elia Adequacy and Flexibility study for 2024-2034⁷⁹

7.4. Procurement Approach

This section of the report draws on the *Analysis of Non-Reserve Services* Project completed in December 2024 and builds on the feasibility of competitive procurement assessment previously introduced in Chapter 4. This assessment was developed to determine the suitability of procurement mechanisms across various system services.

Drawing on the insights from system needs, the potential provider landscape, and international experience, this section outlines a recommended procurement strategy for Ramping Margin.

⁷⁹ [Elia Adequacy & Flexibility Study for Belgium 2024-2034](#)

The aim is to identify a suitable procurement mechanism for FASS Go-live implementation, while also laying the groundwork for a robust and sustainable long-term procurement approach.

Messages in this section:

- Ramping Margins volume requirements are increasingly difficult to accurately forecast ahead of real time due to dependencies on wind and solar/RES generation variability, unknown market outcomes and interconnector flows.
- Exploring an alternative product for procuring Ramping Margins is not deliverable for day 1 implementation given the significant redesign, analysis, operational and IT frameworks required to transition to a new product.
- At present, the benefits of competitively procuring Ramping Margins via the DASSA, LPF or Fixed Contracts are limited for both TSOs and consumers, given the difficulty in forecasting Ramping Margin volumes and FASS Go-live timelines.

7.4.1. Feasibility of Competitive procurement

As discussed in Chapter 4, each of the non-reserve system services were assessed against a matrix of considerations to identify the key challenges that would arise when transitioning from regulated arrangements to a competitive procurement model. This section focuses specifically on Ramping Margin (RMX) and the market integration barriers RMX faces given its operational characteristics and system-critical function.

7.4.2. Nature of the Product

Currently, upward ramping margin is incentivised through DS3 SS tariff-based products and contracts with providers compensated based on their verified capability. This ensures the system has sufficient flexibility to accommodate fluctuations in demand and generation, particularly as non-synchronous generation increases.

As outlined in Section 7.2.2 there are three different Ramping Margin products currently defined with explicit requirements related to ramping margin available within a defined period (1, 3 and 8 hours) and for associated product durations.

Ramping margin products are designed to address demand forecasting errors associated with RES and outages. Under the DS3 program, suppliers are categorised by their operational states (hot, warm, or cold), in order to evaluate their ability to adjust generation output over intervals of one, three, and eight hours.

As outlined in Section 7.2.3, the need for ramping margin is growing due to increasing levels of renewable generation on the all-island system. There are two main drivers of this. First, greater renewable penetration means conventional production must ramp up or down more frequently to balance the system as renewable resource availability changes. Second, the uncertainty of future forecasts may increase the need for ramping margin to be held in reserve⁸⁰.

⁸⁰ [DS3 System Services Current System Services Volume Requirements Information Paper.pdf](#)

7.4.3. Challenges to Market integration

Three primary challenges arise when considering the integration of RMX into a competitive market:

1. Is the service volume known ahead of time?

The volume of Ramping Margin required is not known with certainty ahead of time. Although the ramping duty becomes clearer closer to real-time, it is highly sensitive to short-term fluctuations in both renewable generation and system demand. Forecast errors, particularly during periods of high renewable output, can vary significantly in both magnitude and direction, making it difficult to accurately predict the level of ramping that will be needed.

This uncertainty creates a challenge for market-based procurement. If the required volume cannot be reliably forecast, it is difficult to define the product in a way that enables meaningful competition or pricing. Suppliers would face the risk of being over or under contracted without clear signals in advance.

Moreover, aligning ramping procurement with parallel competitive market timelines, will require extensive analysis to understand. Until the appropriate level of visibility and understanding is achieved, it remains challenging to implement a competitive framework that can confidently and efficiently procure the required ramping volume.

Conclusion: The TSOs cannot predict the short-term needs for ramping with sufficient certainty far enough ahead of time to support efficient procurement or meaningful competition. Ramping requirements measured across a longer horizon will be assessed under an ACER approved methodology as part of the Flexibility Needs Assessment work to be delivered by the two governments.

2. Can participants commit to supply ahead of Gate Closure?

Ramping Margin is defined as the guaranteed margin a unit can provide to the system at a specific point in time, for a defined duration and horizon. The TSOs currently schedule to 1-, 3-, and 8-hour ramping horizons, with associated durations of two, five, and eight hours respectively referred to as RM1, RM3, and RM8.

To avail of RM3 and RM8 remuneration, qualified market participants must understand their availability three hours and eight hours in advance and then maintain that capability over the relevant durations. This requires certainty in unit availability well ahead of a relevant gate closure, limiting flexibility. Given the timing and duration of the ramping products, early commitment under a competitive framework could be difficult.

Additionally, operating within such a framework may be complex, as participants would need to balance RMX commitments with other market obligations, including DAM, IDA, and balancing positions. This would either hinder the imposition of any delivery obligations or result in substantial risk premia being added to bids to reflect this and may also result in sub-optimal outcomes in other markets due to reduced liquidity as the ramping capability is removed from that optimisation. Withholding ramping capability from the DAM, IDA and Balancing Market would make it more difficult for the market to resolve forecasting challenges before they impact real-time dispatch.

Conclusion: Participants cannot commit to supplying ramping capability ahead of gate closure without impacting other markets.

7.4.4. Conclusion of Ramping Margin Competitive Feasibility



Figure 7-87: Summary of Ramping Margin Competitive Feasibility Assessment.

As highlighted above, the key challenge with Ramping Margin is the inability to accurately forecast its requirements ahead of real time due to dependencies on wind and solar/RES generation variability, unknown market outcomes and interconnector flows. Furthermore, the increasing integration of coupled markets (GB and EU once Celtic is operational) is expected to introduce greater uncertainty following the closure of the Local wholesale markets. The introduction of Celtic will bring with it the arrival of new markets coupled with Central Europe (SDAC, EUIDA1, EUIDA2, EUIDA3 and SIDC) which will impact ramping margin requirements on a within day basis, making it difficult to predict ahead of time^{81, 82}.

⁸¹ [SMP - Market Operator Special Topic](#)

⁸² [EirGrid-FPM-Industry-Workshop-September-2024.pdf](#)

Consequently, based on the current product definition, the potential benefits of procuring RMX through competitive tenders are limited for both TSOs and end consumers.

7.4.5. Procurement Approach Considerations

Following on from the feasibility of competitive procurement assessment, the TSOs considered the most suitable procurement method for non-reserve services from the four procurement mechanisms, detailed in Chapter 4; DASSA, LPF, Fixed Contract and Regulated Price. A major consideration for this analysis was that the procurement options need to be deliverable by FASS Go-live. Each procurement method was analysed under five criteria: Consumer Value, System Needs, Compliance, Deliverability and Investment. These topics were used to highlight the most efficient procurement strategy for non-reserve services.

Analysis Outcomes

The TSOs evaluated the suitability of each of the procurement methods and the challenges of implementing the procurement methods for RMX:

DASSA

Implementing the DASSA framework for ramping margin introduces several complex challenges, particularly regarding the determination of required volumes. A more detailed analytical approach would be necessary to assess the impact of broader market dynamics, including increased interconnector flows, evolving ramping behaviours, changing fuel mixes, and the role of DASSA in forecasting and securing sufficient ramping capability.

When applying the existing Ramping Products to DASSA alongside reserves, issues become immediately apparent, for instance consider a CCGT with a 100MW rating bidding into the DAM. While demand follows its expected trajectory the wind forecast for the day anticipates wind ramping at the 12 pm peak. As a result, the CCGT will have been scheduled for 95MW (in DAM) at the start of the day and min gen over the peak (5 MW). They would perhaps bid in 95 MW of ramping in the DASSA over the peak.

If the wind forecast changes closer to real time -e.g. wind peak is 1 hour later than previously anticipated this could result in inefficient market activity to manage net load in all timeframes that are enveloped in the ramping period. It could be argued that an alternative could be to withhold some capacity from ramping, but this means they would have to anticipate wind forecast changes and errors into their intraday bidding significantly complicating trading and anticipating risk.

Another inefficiency stems from bidding in such an arrangement. Conventional and BESS can provide a diverse portfolio of system services including ramping it is possible that suppliers will factor in the potential for lost opportunity of other quicker system services if they were to provide longer ramping services.

For instance, if such a unit was to provide ramping, for example RM3 this is in total a eight-hour product or sixteen periods in DASSA, the subsequent bidding would reflect the risk of lost opportunity of all the products it could have provided in parallel had it not provided ramping. Therefore, it could be argued that this may inflate the price of providing ramping. One could state the unit doesn't have to be fully engaged with providing the full spectrum of ramping only

providing a proportion of its capability. However, the price included will be the diminished profit missed across the range of reserve services.

It stands to question why a supplier would invest a large proportion of its generation volume given these considerations and may find better uses for its capabilities such as diversifying its portfolio across the wholesale energy market and FFR- RR services.

In practise, a ramping market operating under current definitions in the DASSA could face low participation, limited volumes, and disproportionately high prices. The bidding of which would add complexity for suppliers, while offering no clear assurance of improved economic outcomes for consumers. These conflicting obligations introduce a material operational risk and raise questions about the feasibility of aligning market and system requirements. Further analysis would be required to determine a workable solution to these scheduling and compatibility issues, ensuring reliable service delivery without imposing infeasible obligations.

From a consumer perspective, it is important to assess whether current ramping margin arrangements that already consider cost-reflective bidding are more beneficial than transitioning to a DASSA-based approach. Without robust evidence that a market-based mechanism would produce superior outcomes, particularly under the uncertainties of forecasting and dispatch alignment, it is unclear whether moving to DASSA would deliver improved consumer value. Moreover, the inability to define accurate volume requirements at a day-ahead stage with confidence undermines the efficiency and transparency expected of competitive procurement.

Finally, introducing a DASSA-based ramping margin arrangement would not be compatible with a go-live timeline under current system constraints. In addition to the analytical and logistical issues outlined above, there are unresolved questions about early dispatch visibility, bid coordination, and how ramping obligations would be reflected in market positions. Any implementation would require extensive further work, potentially extending well beyond the September 2027 long stop date (see Appendix 11.3).

Component	Description
Consumer Value	The Ramping duty is known ahead of real time; however, there is considerable uncertainty due to RES and demand forecast errors. providing RMX Forecasts for 10:00am D-1 could require inefficient volumes of RM products making it difficult to assess potential cost savings from transferring ramping products to DASSA.
System Need	As discussed in Section 7.2.3, further work needed to accurately forecast and define ramping requirements and capabilities well in advance of market operations to enable appropriate procurement and scheduling. Therefore, transferring ramping products to DASSA would not meet system needs.
Compliance	RMX has been explicitly excluded from the initial DASSA framework (SEMC-24-066). In addition to this policy decision, its implementation within DASSA is not technically feasible.

Deliverability	Introducing a DASSA-based RMX arrangement is incompatible with the current go-live timeline due to unresolved issues around early dispatch visibility, bid coordination, market position integration, and other analytical and logistical challenges discussed in Section 7.4.3. Implementation would require extensive further work, likely extending well beyond the planned go live.
Investment	Complexity for providers, trying to balance positions in ex-ante and RM products. Without robust evidence that moving to a DASSA-based ramping margin mechanism would yield better outcomes than existing arrangements (which already incorporate cost-reflective bidding). Additionally, logistical challenges may lead to inefficiencies.

Table 7-5: Testing DASSA framework as potential procurement mechanism for RMX

LPF

The application of the LPF mechanism to ramping margin procurement is fundamentally incompatible with the operational characteristics and forecasting requirements of this service. In this case the LPF, representing a yearly, monthly or weekly auction, is not suited to a system service like ramping margin that is highly time-sensitive and dependent on real-time system conditions.

Ramping margin requirements are determined and refined much closer to real-time, with forecasting accuracy improving significantly from D-2 to actual delivery. Attempting to procure ramping services via fixed-interval auctions beyond D-2 would not align with these evolving needs. It would introduce a high risk of inefficiency, with procured capabilities potentially mismatched to actual system conditions at the time of use.

Moreover, LPF assumes a level of stability and predictability that is inconsistent with the operational volatility of ramping needs. The rigid structure of LPF-based auctions would reduce the TSO's flexibility to respond to near-term changes, undermining system security and the ability to deliver value to consumers.

In addition, a similar analytical pathway discussed for DASSA applies here: any attempt to adapt LPF for ramping margin would require extensive redesign, modelling, and system change, placing it well beyond the timeline for feasible implementation (See Appendix 11.3).

In conclusion, LPF should not be considered a viable or appropriate procurement mechanism for ramping margins. The fundamental incompatibilities between LPF design principles and ramping margin service characteristics make its application incompatible.

Component	Description
Consumer Value	Ramping requirements will be difficult to predict for LPF (D-7 to D-364) timescales, and would likely need to be overestimated to ensure sufficient volumes in all timescales. Because of these uncertainties, it is difficult to determine if there will be any consumer cost savings.

System Need	RMX requirements are only clear closer to real time. Attempting to procure ramping services via fixed-interval auctions covering D-364 or D-7 would not align with these evolving needs. It would introduce a high risk of inefficiency, with procured capabilities potentially mismatched to actual system conditions at the time of use.
Compliance	While the LPF offer a competitive procurement route aligned with regulatory intent, RMX is technically incompatible with this mechanism. RMX forecasts are determined at D-2 a yearly, monthly, or weekly contract may be inefficient.
Deliverability	RMX would necessitate extensive redesign, modelling, and system modifications, making it infeasible to implement within the required timeframe, likely extending well beyond the planned go live.
Investment	Complexity for providers, trying to balance positions in ex-ante and RM products up to 1 year before delivery. Logistical challenges may lead to inefficiencies.

Table 7-6: Testing LPF framework as potential procurement mechanism for RMX

Fixed Contract

Fixed-term contracts, whether annual or semi-annual, are not a suitable mechanism for procuring ramping margin. The nature of ramping requirements which are driven by real-time system conditions and short-term forecast deviations means that flexibility is essential. Fixed contracts, by design, lack the responsiveness needed to meet these evolving needs.

Similar to the LPF mechanism, fixed contracts rely on long lead times and assume stable, predictable requirements. This directly conflicts with the dynamic, time-sensitive characteristics of ramping margin. Attempting to secure capacity months in advance would risk over- or under-procurement and reduce the efficiency of the system.

Finally, pursuing fixed contracts would necessitate a substantial shift in resources and divert time away from the current trajectory for implementing FASS (see Appendix 11.3). Even if compatibility issues were resolved, significant further analysis would be required to thoroughly understand ramping margin products, evaluate critical dependencies—such as the increasing role of interconnectors—and assess how an evolving fuel mix and integration with European-linked markets influence ramping needs. These elements must be thoroughly examined before selecting such a procurement option. Additionally, solutions would need to be developed to manage the logistical complexities arising from interactions between ramping and energy market operations.

Given these fundamental misalignments, fixed contracts should not be considered a viable route for ramping margin procurement under current operational realities or within the FASS implementation timeline (See Appendix 11.3).

Component	Description
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Consumer Value	Ramping requirements will be difficult to predict for fixed contract timescales, and would likely need to be overestimated to ensure sufficient volumes in all timescales. These uncertainties make it difficult to assess consumer cost savings from shifting ramping products to fixed contracts, especially since volumes would need to be forecasted months or years in advance of delivery.
System Need	Ramping margin needs typically become clear only near real time. Procuring capacity months in advance assumes static, predictable needs, which contradicts the dynamic, time-sensitive nature of ramping margin. This misalignment can result in over- or under-procurement, ultimately reducing system efficiency.
Compliance	Although fixed contracts can provide a competitive procurement pathway aligned with regulatory aims, RMX is technically incompatible with this model. Forecasts are determined close to real time, making contracting over longer lead times unfeasible.
Deliverability	Implementing RMX through fixed contracts would require significant redesigns of modelling and operational processes. This added complexity would make delivery within required timelines unfeasible and could cause delays beyond the intended schedule.
Investment	Fixed contracts introduce complexity for providers, who must manage positions across both ex-ante and real-time products up to a year or six months in advance. These logistical challenges are likely to result in inefficiencies for investors.

Table 7-7: Testing Fixed Contract framework as potential procurement mechanism for RMX

Regulated pricing

Regulated pricing is currently the most appropriate and economically efficient option for procuring ramping margins. It aligns with the operational realities of the service, where requirements are only known closer to real time and flexibility is essential.

Alternative approaches, such as auctions or fixed contracts, introduce unnecessary logistical complexity particularly around bidding, unit scheduling, and delivery coordination and are poorly suited to the dynamic nature of ramping needs.

Until further analysis is completed to define and quantify ramping requirements, regulated pricing remains the most effective and least disruptive mechanism. It is also fully deliverable for FASS Go-live, ensuring continuity of service and certainty for participants while longer-term solutions are explored.

Component	Description
Consumer Value	This structure supports system stability without exposing consumers to volatile pricing.

System Need	Regulated pricing ensures reliable delivery of system needs, as it builds on proven operational arrangements (e.g. must-run commitments). RMX aligns with the operational realities of the service, where requirements are only known closer to real time which this arrangement supports effectively.
Compliance	Use of regulated tariffs may require a derogation or exemption from standard market-based procurement expectations. However, if necessary, this can be managed through formal regulatory processes.
Deliverability	This approach is immediately deployable using existing infrastructure and commercial agreements. It avoids the need for new IT systems or auction platforms, making it the most viable near-term solution for FASS Go-live.
Investment	Regulated pricing provides clarity and income certainty, which supports investment in flexible synchronous capacity. Investors benefit from predictable returns and the ability to plan around a known tariff structure.

Table 7-8: Testing Regulated Pricing framework as potential procurement mechanism for RMX

Conclusion of Procurement Consideration Analysis

It is critical that the TSOs continue to remunerate RMX to ensure operational security and stability. The chosen procurement option must be deliverable for FASS Go-live and ramping requirements, driven by real-time system conditions and short-term forecast deviations, demand essential flexibility.

Currently, RMX volume requirements are forecasted on a D-2 basis, any procurement time horizon past this point would make them incompatible with RMX requirements. Additionally, the further integration of RES, including large volumes of embedded RES, the introduction of the Celtic interconnector and subsequent replacement of local markets with EU coupled markets is expected to complicate the forecasting of ramping margin requirements.

Markets such as DASSA provide a practical timeframe for identifying and responding to ramping needs, helping TSOs to manage increasing uncertainty. Nonetheless, the current scale of ramping products raises questions over the economic value such a transition would deliver for consumers, highlighting the importance of future product design and definition.

The move to a more dynamic system with greater availability of shorter notice generation plants, may change the ramping product definitions and requirements. In addition, the introduction of DASSA will oblige participants to submit PNs aligned with contracted POR-TOR2 and RR capability, which the Ramping Margin tool will take account of. Operational experience of DASSA and its interaction with Ramping Margin capability will be critical to inform future ramping product design, and detailed studies and assessment of the mentioned challenges will be essential to more fully understand and define future ramping product requirements. These

challenges will also be considered through the mandatory processes in Ireland and Northern Ireland that we will follow to set non-fossil flexibility targets and deliver the resulting action plan⁸³.

TSO Proposal:

It is the proposal of the TSOs' to continue with regulated pricing for the procurement of Ramping Margins 1,3 and 8. The results of the feasibility of competitive procurement assessment indicated that regulated pricing is the only viable procurement option for RMX that is compatible with FASS Go-live, given that:

- This volume requirement is incredibly difficult to fully predict due to forecasting errors and uncertainties (Section 7.1.1).
- There is an inherent incompatibility between a DASSA based procurement for ramping and scheduled generation particularly when considering opportunity cost, making integration into DASSA unsuitable. The Fixed contracts and LPF are also inherently incompatible with ramping as they both assume a stable forecastable system.

Further detailed analysis and study are needed to define and quantify ramping requirements considering the evolving system, future provider capability and future system requirements.

Question #8: Do you have any comments regarding our proposal to maintain tariff-based procurement of Ramping Margins for a transitional period?

⁸³ Article 19F of Regulation 2019/943 (as updated in July 2024 by Regulation 2024/1747)

8. Independent Technical and Economic Analysis

8.1. Purpose and Scope

EirGrid and SONI commissioned independent technical and economic analysis to examine the interaction between existing DS3 non-reserve tariff and the outcomes in the Day-Ahead Market (DAM).⁸⁴ The purpose of the analysis was to provide an independent third-party perspective of short-run (interim) policy options that could be implemented without changes to existing product definitions. In the short run, current product definitions for SIR and SSRP do not correspond to physically meaningful volumes and are therefore not compatible with competitive, quantity-based procurement.

The analysis focuses on how anticipated DS3 revenues influence energy market bidding behaviour, the resulting delivery of inertia and reactive power through the unconstrained energy market, and the extent to which any resulting shortfalls would need to be addressed through non-energy actions (NEAs). Ramping capability was considered qualitatively only as it depends on units technical characteristics (soak times, ramp rates, warmth states) and operating positions over multiple trading periods, making its interaction with energy market outcomes difficult to quantify in a short run modelling framework.

The full methodology, assumptions and quantitative results are set out in the Procurement of Non-reserve System Services - Assessment of interim options, which accompanies this consultation.

8.2. Overview of modelling approach

The independent analysis compares a status quo scenario, in which DS3 revenues for SIR and SSRP are anticipated and reflected in DAM bids, with counterfactual scenarios in which anticipated DS3 revenues are removed from bids. DAM outcomes are simulated for a set of representative historical days spanning a wide range of system conditions, including varying wind and solar penetration levels and SNSP.

For each scenario, DAM outcomes are first determined. Any shortfall in inertia or reactive power relative to assumed system requirements is then addressed through Non-Energy Actions (NEAs). The resulting impacts on energy prices, energy volumes and NEA costs are assessed to understand the overall system cost implications of removing DS3 payments.

8.3. Key Assumptions and Limitations

The analysis applies a number of simplifying assumptions which should be taken into account when interpreting the results. These include:

- A focus on DAM outcomes and NEAs;

⁸⁴ [DotEcon Economic Assessment \(EirGrid\)](#); [DotEcon Economic Assessment \(SONI\)](#)

- Rational bidding behaviour, whereby market participants anticipate DS3 revenues and reflect these in energy bids;
- Simplified representation of NEA selection and costs, which is likely to be optimistic relative to operational realities;
- No explicit reactive power requirement within the DAM, with any resulting shortfall addressed through NEAs;
- No consideration of the locational needs for reactive power requirements, which in practice increase the cost of NEAs to meet reactive power needs as the pool of suppliers that can be chosen to meet these is narrowed;
- Exclusion of additional operational costs and risks.

8.4. Interaction between DS3 payments and energy market outcomes

Under the modelling assumptions, DS3 payments for SIR and SSRP form part of suppliers' expected revenue streams and therefore influence energy market bidding behaviour. Anticipated DS3 revenues reduce the effective turn-on costs of units capable of providing inertia and reactive power, leading to lower energy bids and affecting the ordering of units in the DAM.

When anticipated DS3 revenues are removed from bids, turn-on prices increase for affected units, altering DAM clearing outcomes. Across the scenarios examined, this results in higher DAM clearing prices, lower traded energy volumes, and reduced delivery of inertia and reactive power through the unconstrained energy market.

This interaction between DS3 tariffs and energy market outcomes is consistent with the original policy intent of the DS3 arrangements, which explicitly recognised that incentives for system services would interact with energy market signals to support system stability.

8.5. Findings

Taken together, the independent analysis indicates that:

- DS3 payments, while small in aggregate, influence energy market outcomes and system service delivery;
- Removing DS3 payments leads to higher energy prices, reduced energy volumes, and increased reliance on NEAs in some trading periods, across a wide range of system conditions;
- The additional costs associated with replacing DAM-delivered inertia and reactive power through NEAs can outweigh the savings from eliminating DS3 payments in most cases;
- While the removal of tariffs can yield a net benefit, these outcomes are not the dominant result in the analysis under the preferred assumptions and feature in only a minority of cases;
- Therefore, taken on balance, there is no consistent evidence that removing SIR or SSRP payments would reduce total system costs to consumers in the short run, whilst it will increase system operation risks;

- In relation to ramping, the analysis indicates that RMX payments may influence commitment and bidding behaviour at the margin; however, these effects are diffuse, depend on achieving compatible operating positions across multiple trading periods, and were not quantified due to their inherent complexity and uncertainty.

The analysis concludes that DS3 payments serve a useful role in modulating energy market outcomes to support non-reserve delivery and that removing them under current product definitions would likely introduce cost and system risk without clear short run benefits.

9. Summary of Consultation Questions

Section	TSOs' Questions
3.2	Question #1: Do you have any comments on the TSOs' proposal to maintain tariff-based procurement for a transitional period post-DASSA Go-live?
3.2	Question #2: Do you have any comments on the TSOs' proposed approach for implementing competitive procurement for non-reserve services under the enduring FASS arrangements?
3.2	Question #3: Do you have a view on whether there are suitable procurement methods that should be considered in the upcoming 2026 Product Design Assessment?
4.4	Question #4: Do you have any comments on the framework employed by the TSOs to assess the feasibility of competitive procurement?
4.6	Question #5: Do you have any observations regarding the foundations and criteria upon which these evaluations were conducted?
5.7	Question #6: Do you have any comments regarding our proposal to maintain tariff-based procurement of SSRP for a transitional period?
6.7	Question #7: Do you have any comments regarding our proposal to maintain tariff-based procurement of SIR for a transitional period?
7.4	Question #8: Do you have any comments regarding our proposal to maintain tariff-based procurement of Ramping Margins for a transitional period?

10. Next Steps

This consultation will be open for seven weeks, closing on **22nd May 2026**. Responses to the consultation should be submitted to the EirGrid ([link](#)) or SONI ([link](#)) consultation portals.

Should stakeholders have any questions or comments during the consultation period these can be submitted to FASS@Eirgrid.com or FASSProgramme@soni.ltd.uk.

An industry workshop, at which the TSOs will present these proposals and facilitate a Q&A for interested parties, will be scheduled (the date and location are to be confirmed and will be communicated to customers and stakeholders in due course).

Following this consultation, the TSOs will submit a recommendations paper to the SEMC for decision, timelines will be confirmed in the next iteration of the Phased Implementation Roadmap (PIR).

11. Appendices

11.1. Appendix A: Dynamic Reactive Response (DRR)

During voltage dips in the transmission systems, generation units support the system by injecting reactive current into the system. This response is an inherent response of conventional synchronous generation units. However, for non-synchronously connected generation units (PPMs) this response is not inherent but can be implemented. For this reason, the Grid Codes currently include a minimum requirement for reactive current injection by PPMs. However, with increasing SNSP and accordingly less conventional synchronous generation units, the reactive current injection available through these standard grid code requirements may not be sufficient, which may harm the stability of the system after a fault. To fill this gap, the TSOs designed the DS3 product Dynamic Reactive Response (DRR). DRR is currently not procured, but there may be a need for DRR within the coming years which is subject to further study by the TSOs.

Note: this issue is related to Fault Ride Through issues which will not be discussed in this section.

11.1.1. Current situation

Reactive current is injected by conventional synchronous generation units immediately after a sudden voltage dip, which may happen after a fault (short-circuit). *Figure 11-1* provides an illustrative example of this response. The figure shows that in case of a sudden voltage drop \odot , the generation unit increases reactive current injection immediately. When the voltage is recovering, the reactive current injection reduces \odot . This response to sudden voltage changes is an inherent characteristic of a conventional synchronous generation unit in line with fundamental physical properties. Accordingly, it happens fully automatically. PPMs (non-synchronously connected units) do not have the same fundamental characteristics.

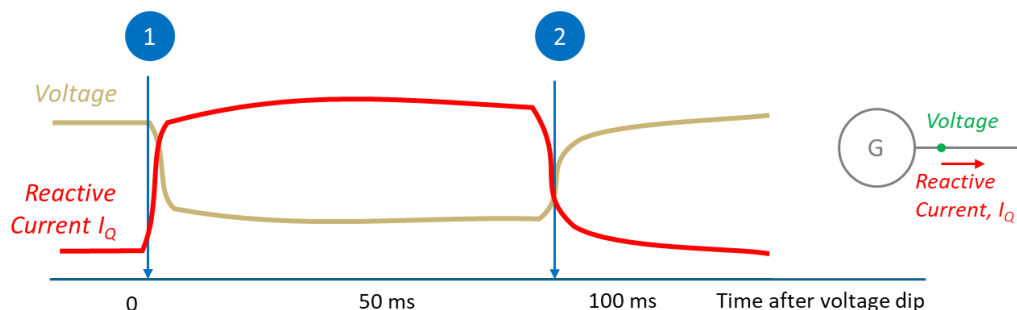


Figure 11-1: Illustrative example of Reactive Current injection of a conventional synchronous generation unit responding to a voltage dip.

The inherent response of conventional synchronous generation units to voltage dips provides essential support to the voltage in the power system and therefore also supports the system (voltage) stability after incidents in the system. In addition to that, the increased current injection is key to the protection of the power system. Hence, the response is essential for ensuring the stability of the power system and the protection of the power system.

As voltage and also the voltage dips are local phenomena in the power system, local assets are required for providing reactive current in response to these local voltage dips. Consequently, reactive current injection capability needs to be sufficiently available across the power system.

11.1.2. Service Providers

Reactive current is injected by conventional generation units in response to voltage dips when dispatched and synchronously connected to the power system. This response is available independent from their active power setpoint. Because the minimum number of dispatched conventional generation units on-line (MUON) will reduce⁸⁵, the reactive current injection into the power system may reduce.

However, the increasing number of synchronous condensers - as contracted by the LCIS phase 1 and phase 2 programs - will also inject reactive current and - at least partly - replace the reducing contribution of the conventional generators.

In addition, PPMs shall inject reactive current in response to voltage dips in accordance with the mandatory requirements stipulated in the TSOs' Grid Codes (which implement EU Network Code RfG⁸⁶). However, different from approaches in GB and the Netherlands, the EirGrid and SONI Grid Codes do not include requirements for responses faster than 100 ms. To be able to fill this gap, the TSOs developed the - to date not procured - DS3 product DRR which requires a response within 40 ms. Table 11-1 shows both the mandatory Grid Code requirements and the characteristics of the DS3 DRR product.

	Grid Code mandatory requirements for PPM ⁸⁷	DS3 Dynamic Reactive Reserves (DRR) ⁸⁸ product (currently not procured)
Voltage dips		> 30%
Response	$I_Q \geq$ proportional to Voltage dip	MVAR \geq 31% at P_{reg} at U_{nom}
Rise time	\leq 100 ms	\leq 40 ms
Settling time (to 90-110%)	\leq 300 ms	\leq 300 ms

Table 1111-1: Mandatory Grid Code requirements for PPM and DS3 DRR product

The DRR product was originally established in 2013⁸⁹ in order to be prepared for the foreseen high levels of SNSPs. The TSOs considered that procurement of this product could start when the system needs appear. A review in 2021 suggested some updates of the definition, including reducing the settling time from 300 ms to 100 ms.

⁸⁵ [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

⁸⁶ Article 20 of the [COMMISSION REGULATION \(EU\) 2016/ 631 - of 14 April 2016 - establishing a network code on requirements for grid connection of generators](#)

⁸⁷ Source: [Eirgrid Grid Code PPM 1.4](#), [SONI Grid Code CC.S2.1](#)

⁸⁸ Source: [DS3 System Services Technical Definitions](#)

⁸⁹ See: [DS3 System Services Technical Definitions Decision Paper SEM-13-098](#)

11.1.3. International experience

In accordance with article 20 of RfG, many TSOs used the right to specify the mandatory capability of a PPM of providing Fast Fault Current, which is the term applied in RfG for reactive current injection by PPMs after a voltage dip (see *Box 11-1*).

Box 11-1: Definition of fast fault current in the Requirements for Generators (RfG)

‘fast fault current’ means a current injected by a power park module or HVDC system during and after a voltage deviation caused by an electrical fault with the aim of identifying a fault by network protection systems at the initial stage of the fault, supporting system voltage retention at a later stage of the fault and system voltage restoration after fault clearance;

Table 11-2 includes an overview of the mandatory characteristics of FFC injection by PPMs in Great Britain, Netherlands, Germany and Belgium. It is apparent that in Great Britain, Netherlands, Germany mandatory requirements for Fast Fault Current provision by PPMs require a rise time which is far shorter than the ≤ 100 ms as required by the EirGrid and SONI Grid Codes. Hence, the mandatory requirements in these countries may be considered similar to the requirements of the defined DS3 market product.

	GB Fast Fault Current Injection (FFCI) ⁹⁰	NL Fast Fault Current (‘snelle foutstroom’) ⁹¹	DE Dynamic Grid Support (‘Dynamische Netzstützung’) ⁹²	BE Fast Fault Current ⁹³
Market or Mandatory	Mandatory	Mandatory for PPMs connected to ≥ 110 kV ¹	Mandatory for PPMs	Mandatory for Type B, C and D
Voltage dips		$\Delta V > 10\%$ of U_{nom}	Connection requirements referring to standard VDE-AR-N 4120/4130 (similar requirements as in NL Grid Code)	To be included in the connection agreement
Response		$(dI_q/I_n)/(dV/V_n) = 2\%$ to 6% (determined by SO)		
Rise time	≤ 60 ms up to 65% of ΔI_R ≤ 120 ms up to 100% of ΔI_R	≤ 30 ms up to 90% of ΔI_R		
Settling time (to 90-110%)		≤ 60 ms (after fault)		

⁹⁰ Source: [GB Grid Code](#)

⁹¹ Source: [Dutch Grid Code](#), art. 3.19

⁹² Source: [TenneT](#), [Amprion](#) connection requirements

⁹³ Source: [Federal Grid Code](#), art. 93, §3

Table 11-2: Overview of characteristics of Fast Fault Current provision by PPMs in other jurisdictions

11.1.4. Future System Need

The system need for DRR is driven by reducing synchronous generation, which may be (partly) compensated by synchronous condensers contracted in the LCIS program and the existing mandatory requirements for PPMs in the Grid Codes. As the system evolves the TSOs consider that further detailed studies are required to confirm⁹⁴:

- if, when and where a DRR product will be required.
- if Grid Code requirements / DRR product requirements need to be defined further.

If the TSOs conclude that there is a need for implementing a DRR service, it shall be carefully evaluated if this need is to be provided as a market product, considering the very specific needs per zone. Alternatively, grid code requirements for reactive current provision by PPMs may be aligned with other jurisdictions. This may be part of the 'review grid code standards for prioritisation of active and reactive power under fault conditions' in 2025-2028 as the TSOs have committed to in the EirGrid and SONI Operational Policy Roadmap 2025-2035⁹⁵.

11.2. Appendix B: Past Post Fault Active Power Recovery (FPFAPR)

11.2.1. Background

The DS3 product Fast Post Fault Active Power Recovery (FPFAPR) was originally established in 2013⁹⁶ in order to mitigate potentially insufficient FRT capability of RES generation alongside an expected reduction of inertia in the power system resulting from the increasing SNSP. FPFAPR has not, to date, been procured through qualification and tariff payments for availability.

11.2.2. Current situation

FRT capability of generation and demand units is their capability to stay connected to the network and to continue stable operation after the power system has been disturbed by faults in the network. For example, a generation unit shall revert to its pre-fault MW output shortly after a fault on a power line has been cleared and the voltage at its terminals returns to normal levels.

FRT capability is important for restoring the power system after a fault. Hence, insufficient FRT capability would mean that after clearance of fault (by isolating the faulted element), generation units would not recover to their pre-fault MW output. Accordingly, a significant power imbalance could occur, potentially resulting in a (severe) frequency incident.

For that reason, the Grid Codes include mandatory FRT requirements for both conventional generation units, HVDC Interconnectors and PPMs (e.g. wind, solar etc). *Figure 11-2* shows the

⁹⁴ Related to this and also subject to these detailed studies are a review of the priority in EirGrid's Grid code for active power response at voltage dip over reactive power response.

⁹⁵ Source: page 36 of [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

⁹⁶ See: DS3 System Services Technical Definitions Decision Paper SEM-13-098

durations and depths of voltage dips that generation units and PPMs shall withstand (please refer to the Grid Codes for more detail).

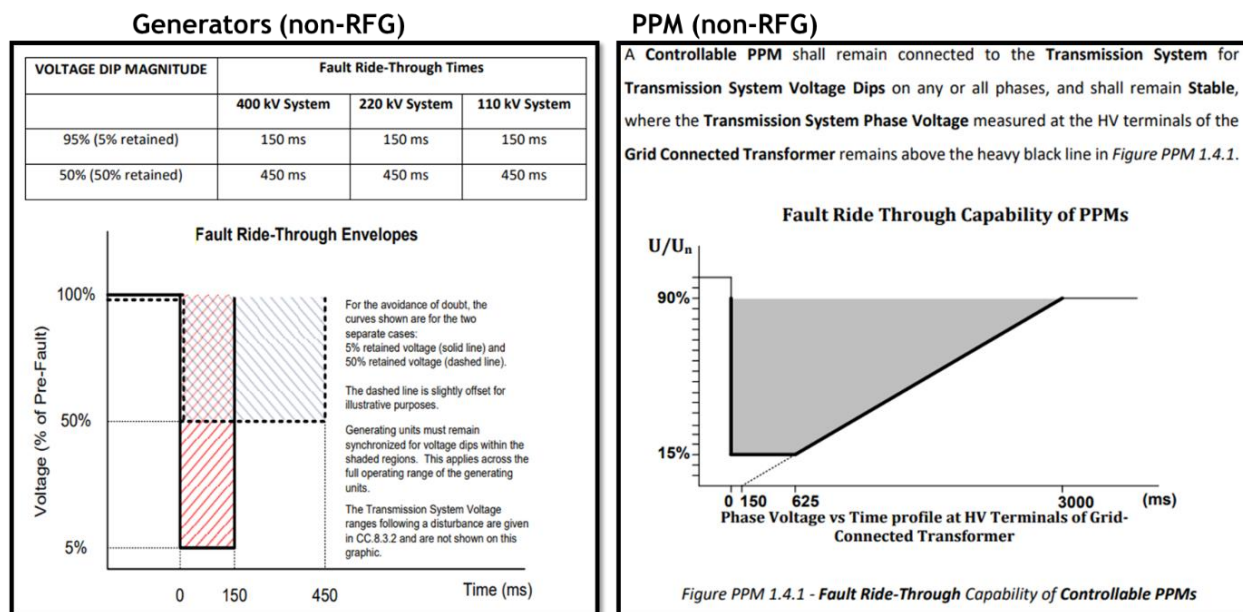


Figure 11-2: Fault Ride Through requirements for Generators (source: EirGrid Grid Code CC 7.3, similar to SONI Grid Code CC.S 1.1) and PPMs (source: EirGrid Grid Code PPM 1.4.1, similar to SONI Grid Code CC.S 2.2)

Additionally, proposals are under development for the incorporation of FRT requirements for large demand facilities, so that there is a requirement for all transmission connected users to have minimum FRT capability. The Grid Codes also include requirements for reverting to the pre-fault active power (MW) output after the fault is cleared. Table 11-3 includes characteristics for PPMs.

	Grid Code mandatory requirements for PPM	
For fault clearance time	≤ 140 ms	> 140 ms
Response time (after recovering to 90% of nominal Voltage)	≤ 500 ms	≤ 1 s
Active Power Recovery to	≥ 90% at MIN($P_{available}$, $P_{setpoint}$)	

Table 11-3: Mandatory Grid Code requirements for PPM (Source: EirGrid Grid Code PPM 1.4, SONI Grid Code CC.S 2.1)

11.2.3. FPFAPR definition

In response to concerns on the impact of potentially reducing FRT capability in the system, the TSOs defined the DS3 product FPFAPR which has been established in 2013⁹⁷, but has, to date, not been procured. The product definition would require qualified providers to meet enhanced standards compared to the grid code standards. A generation unit that provides FPFAPR would need to recover to at least 90% of its pre-fault active power value within 250 ms (see Figure

11-3) which is faster than required the 500 ms or 1 s as required by the Grid Code (see Table 11-3) In addition, an FPFAPR provider shall remain connected for at least 15 minutes.

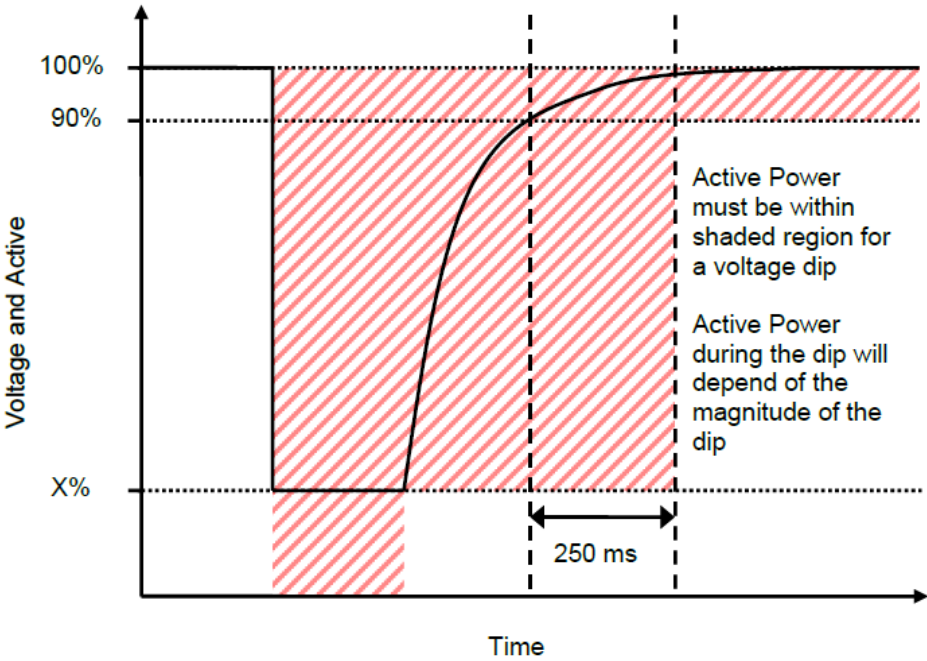


Figure 11-3: FPFAPR definition (source: DS3 System Services Technical Definitions Decision -aper - SEM-13-098, 2013)

11.2.4. Future System Need

A distinct system need for FPFAPR would be driven by a TSO concern of limited FRT capability of connected system users in combination with reducing inertia. Detailed studies need to confirm:

- If and when a FPRAPR product will be required.
- If alternative solutions may mitigate the issue.
- If Grid Code requirements / FPFAPR product requirements are properly defined.

If the TSOs conclude in the proposed studies that there is a need for implementing a FPFAPR service, it shall be carefully evaluated how this capability will be delivered, e.g. by means of a market product or alternatively, grid code requirements. This is related to the ‘review grid code standards for prioritisation of active and reactive power under fault conditions’ in 2025 - 2028 as the TSOs have committed to in the EirGrid and SONI Operational Policy Roadmap 2025-2035⁹⁸.

11.3. Appendix C: Procurement Timelines

This section provides an overview of the activities required for a transition to competitive procurement, noting that each product will require a tailored approach informed by system studies completed across all services to determine the future system need, followed by product-

⁹⁸ Source: page 36 of [EirGrid and SONI Operational Policy Roadmap 2025-2035](#)

specific details and draft implementation timelines (to be confirmed following confirmation of the product design and procurement mechanism).

The TSOs are cognisant of the fact that the existing DS3 Arrangements cannot be extended further - new arrangements for non-reserves must be in place from the long-stop date of 30th September 2027. As such, activities for the development of these arrangements have been reflected in the timelines. The timeline demonstrates that it is not possible to define new products in addition to the design and implementation of a new procurement methodology by the long stop date of September 2027. Therefore, to ensure system security is maintained, while TSOs are seeking to enable competitive procurement, the TSOs must introduce new regulated arrangements.

An estimated ‘time to implement’ of the other alternatives discussed in this paper is shown in Table 11-4. These are illustrative examples of the time frames such an implementation would require, as represented in ‘The Gap’ Recommendations Paper published in June 2025.

Procurement Type	Estimated Time to Implement	IT Changes
Layered Procurement Framework	c. 21 Months	Yes
Fixed Contract	c. 26 Months	Yes

Table 11-4: Table showing the time needed to implement each of the alternative procurement methods suggested in the HLD⁹⁹

Therefore, the only option available to ensure system security in the transitional period between the long stop date and the introduction of competitive arrangement is implementation of new regulated arrangements.

A definitive timeline for the implementation of new procurement methods can only be quantified by detailed programme planning, which will be informed by the outcomes of detailed design, as denoted in the timeline below.

⁹⁹ [EirGrid-June-2025-SOEF-Markets-FASS-DS3-System-Services-Tariffs-to-FASS-The-Gap-Recommendations-Paper.pdf](#)

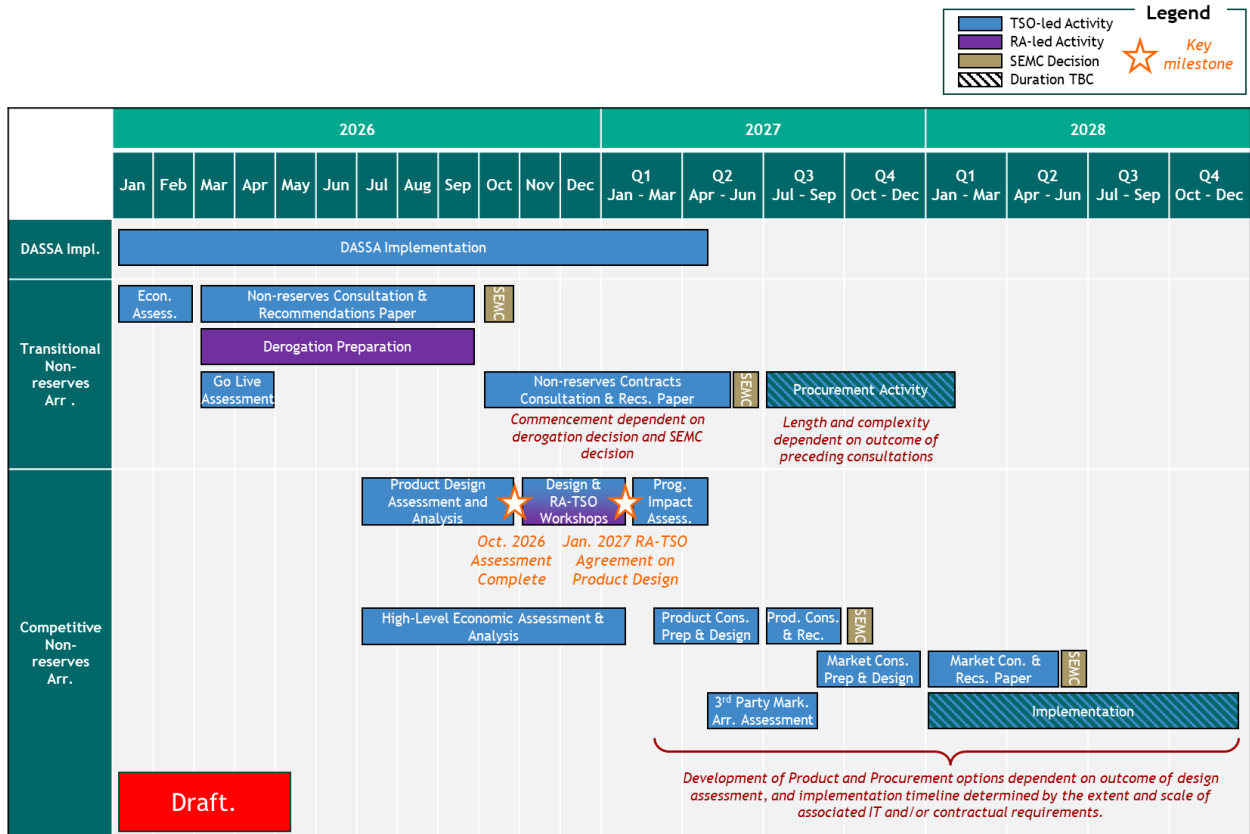


Figure 11-4: The Non-Reserve Timeline.