NORTHERN IRELAND: **FLEXIBILITY NEEDS ASSESSMENT - 2026**

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Utility Regulator

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To protect the short and long-term interests of consumers of electricity, gas and water.

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ACCOUNTABLE: We take ownership of our actions.

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COLLABORATIVE: Connecting and working with others for a shared purpose.

DILIGENT: Working with care and rigour.

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ABSTRACT

This report presents Northern Ireland's first Flexibility Needs Assessment (FNA), prepared in accordance with European electricity market requirements. The assessment examines the flexibility needed to support increasing levels of renewable electricity generation while maintaining a secure, reliable and affordable electricity system. It considers the roles of electricity networks, energy storage, demand-side response, aggregation, interconnection and digitalisation. The report finds that network constraints remain a significant driver of renewable curtailment and highlights the importance of network reinforcement, alongside greater deployment of non-fossil flexibility resources to support Northern Ireland's transition to a low-carbon electricity system.

AUDIENCE

This report will be of interest to electricity and gas licensees, energy industry participants, flexibility service providers, professional bodies, government departments, other regulatory bodies, community and voluntary sector organisations, organisations representing consumer interests and other stakeholders with an interest in electricity system development, renewable energy integration and the transition to a low-carbon energy system in Northern Ireland.

CONSUMER IMPACT

The FNA is expected to deliver positive long-term benefits for consumers by helping to identify the network developments, operational improvements and flexibility solutions required to support greater integration of renewable electricity. Over time, these measures can improve system efficiency, reduce renewable energy curtailment, support the delivery of climate targets, enhance security of supply and help minimise the overall cost of the energy transition, while maintaining a reliable and resilient electricity system for consumers.[1]

1 Copies of all documents can be made available in large print, Braille, audio cassette and a variety of relevant minority languages if required

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Table of acronyms

Acronyms	Meaning
ACER	Agency for the Cooperation of Energy Regulators
AGU	Aggregated Generating Unit
AIRAA	All-Island Resource Adequacy Assessment
APFC	Automatic power factor correction
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CCA	Climate Change Act (Northern Ireland) 2022
CDA	Central Design Authority
CEC	Citizen Energy Communities
CRU	Commission for Regulation of Utilities
DfE	Department for the Economy
DLR	Dynamic Line Rating
DNDP	Distribution Network Development Plan
DSO	Distribution System Operator
DSR	Demand-side Response
DSU	Demand Side Unit
ECP	Enduring Connection Policy
ED	Economic Dispatch
END	Energy not Delivered
ENS	Energy not Served
ENTSO-E	European Network for Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
ESS	Energy Storage System
EU DSO Entity	European Distribution System Operators Entity
EV	Electric Vehicle
EVA	Economic Viability Assessment
EWIC	East-West Interconnector
FASS	Future Arrangements for System Services
FCR	Frequency Containment Reserve
FNA	Flexibility Needs Assessment

Acronyms	Meaning
FNAM	Flexibility Needs Assessment methodology
FRR	Frequency Restoration Reserve
GWh	Gigawatt Hour
IC	Interconnector
ISP	Imbalance Settlement Period
LCTs	Low-carbon Technologies
LDES	Long-Duration Energy Storage
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MIP	Mixed Integer Programming
MT	Market Time
MTU	Market Time Unit
MW	Megawatt
MWh	Megawatt Hour
NECP	National Energy and Climate Plan
NIEN	Northern Ireland Electricity Networks
NISRA	Northern Ireland Statistics and Research Agency
NRAA	National Resource Adequacy Assessment
OTCE	Operational Tools and Capability Enhancement
PEMMDB	Pan-European Market Modelling Database
PIMB	Imbalance settlement price
PPA	Power Purchase Agreement
REC	Renewable Energy Communities
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources-Electricity
RP	Replacement Reserve
RPG	Reserve Providing Groups
RPU	Reserve Providing Units
SDES	Short-Duration Energy Storage
SDP	Scheduling and Dispatch Programme
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator

Acronyms	Meaning
SEMOpx	Single Electricity Market Operator Power Exchange
SNSP	System Non-Synchronous Penetration
STFlex	Short-term Flexibility
ToU	Time-of-Use
TSC	Trading and Settlement Code
TSO	Transmission System Operator
UR	Utility Regulator
VO&M	Variable Operation and Maintenance
VRES	Variable Renewable Energy Sources

Table of terms

Term	Definition
Climate Change Act (Northern Ireland) 2022	Northern Ireland's climate legislation, which sets legally binding targets, including at least an 80% renewable electricity consumption target by 2030 and net zero greenhouse gas emissions by 2050.
Congestion	a situation in which the electric current flow through a physical asset exceeds operational limits.
D-1	the latest forecast reported at, in local time of the bidding zone, 12:00 the day before real-time observation in the same bidding zone.
Daily timeframe	a timeframe for the characterisation of flexibility needs which occur at the level of a single day of the year. Depending on the specific indicator, daily values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs.
Demand	the total instantaneous electricity consumption observed in the transmission and distribution systems, including the network losses.
Designated entity	the regulatory authority or another authority or entity designated by a Member State to receive the data and analysis submitted by TSOs and DSOs pursuant to Article 19e(3) and adopt the FNA report pursuant to Article 19e(1) of the Electricity Regulation.

Term	Definition
Dispatchable	assets (as individual units or aggregated) which are controllable by market participants or system operators to manage system or network needs.
Distribution Network Development Plan (DNDP)	NIEN's plan for developing the distribution network, setting out forecast constraints, capacity needs and network reinforcement measures over the next ten years.
Downward flexibility	a solution with the ability to either decrease injection into the network or increase demand from the network.
Economic dispatch (ED)	a mathematical optimisation model as described in Article 7 of the ERAA methodology.
Economic viability assessment (EVA)	a model assessing the profitability of capacity resources, informing decisions on retirement, mothballing and re-entry, renewal/prolongation and new build of a capacity resource as described in Article 6 of the ERAA methodology.
Energy not delivered (END)	the energy which is not supplied due to network constraints.
Energy not served (ENS)	the energy which is not supplied due to insufficient capacity resources to meet the demand.
European Resource Adequacy Assessment (ERAA)	the most recent ERAA conducted by ENTSO-E pursuant to Article 23 and approved by ACER pursuant to Article 27 of the Electricity Regulation.
European Resource Adequacy Assessment methodology	the methodology for the European Resource Adequacy Assessment developed by ENTSO-E pursuant to Article 23(3) of the Electricity Regulation.
Fast flexibility	the capacity able to react to aggregated D-1 or shorter error variations (15 to 60 minutes before real-time).
FNA Methodology (FNAM)	the ACER-approved methodology that standardises how TSOs and DSOs assess, quantify and report future electricity system and network flexibility needs across Member States.
FNA report	a report on the estimated flexibility needs for two target years within a period of at least the next 5 to 10 years adopted at national level pursuant to Article 19e(1) of the Electricity Regulation.
Hourly timeframe	a timeframe for the characterisation of flexibility needs which occur at the level of the single hour of the year. Depending on the specific indicator, hourly values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs.

Term	Definition
Local service	energy or capacity procured by a TSO or DSO to solve congestion or voltage issues they have identified in their systems.
Local value	the flexibility (expressed in MW) needed to solve a congestion or voltage issue on a given asset during a given time block.
National climate target	The targets outlined by the Climate Change (Northern Ireland) 2022 Act are referred to as the national climate target throughout this report.
National Energy and Climate Plan (NECP)	an integrated NECP pursuant to Regulation (EU) 2018/1999. To note, where the FNAM refers to NECP targets, the equivalent targets set out in the CCA (Northern Ireland) 2022 have been applied for the Northern Ireland assessment.
Network flexibility needs	the flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues, across relevant timeframe.
Non-dispatchable generation	assets which are constrained in controllability of injections following weather or other conditions such as wind, solar and run-of-river hydro generation.
National Resource Adequacy Assessment (NRAA)	the most recent national resource adequacy assessment pursuant to Article 24 of the Electricity Regulation. If an NRAA is subject to ACER's opinion pursuant to Article 24(3) of the Electricity Regulation, it shall only be considered for the purposes of the FNA methodology once it is amended in accordance with ACER's opinion or accompanied by a report detailing the reasons for not fully incorporating ACER's opinion.
Ramping needs	to needs associated with hourly variations of the residual load[2] assuming perfect forecast conditions.
RES curtailment	limiting the generation or transmission of renewable power for system operational reasons or grid-capacity reasons.
Renewable Energy Sources-Electricity (RES-E) targets	refers specifically to targets for the share of electricity generated from RES within the overall electricity mix.
RES integration needs	the quantity of flexibility required for the Member State to achieve its annual RES integration target.

2 Throughout the analysis, residual load is defined as total local electricity demand minus generation from wind and solar. Generation subject to must-run conditions is not subtracted from this calculation

Term	Definition
RES integration target	the maximum RES curtailment amount or share compatible with the RES target for the Member State. It is expressed either as a maximum RES curtailment in absolute terms, or as a maximum RES curtailment in relative terms to the total RES generation or to the total local electricity demand, or symmetrically as the minimum effectively integrated (i.e., non-curtailed) RES generation in absolute terms or in relative terms to the total RES generation or to the total local electricity demand.
RES target	the national target for RES in the electricity sector of the most recent NECP or from another relevant official national document[3] consistent with the most recent NECP. It is either expressed as a RES volume in absolute terms or as a share of RES production in relative terms to the total local electricity demand.
Seasonal timeframe	a timeframe for the characterisation of flexibility needs which occur at the level of a single month of the year. Depending on the specific indicator, monthly values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs.
Short-term flexibility needs	needs associated with unexpected variations of the residual load such as forced outage of assets or errors in wind, solar and load forecasts during the intra-day or balancing timeframe.
Slow flexibility	the capacity able to react to aggregated D-1 or shorter horizons forecast error (60 minutes to 24 hours before real-time).
System flexibility needs	the flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframe.
Target year	a year for which data and analysis are provided within the framework of the FNA methodology.
Uncovered flexibility needs	the additional flexibility needs identified by the FNAM, not expected to be met by new or existing resources based on ERAA or NRAA inputs.
Upward flexibility	solution with the ability to either increase injection into the network or decrease demand from the network.
Voltage issue	a situation when voltage levels are not within the operational limits.
Very fast flexibility	capacity able to react to aggregated D-1 or shorter horizon's forecast error variations (5 to 15 minutes before real-time).

3 Targets for 2030 are based on the CCA (Northern Ireland) 2022. The 2033 RES-E target (86.9%) was interpolated using the CCA (Northern Ireland) 2022 targets and an assumed 2040 target aligned with Ireland's NECP, as no 2040 target is specified in the Act

Executive Summary

Overview

This report presents the first FNA for Northern Ireland, undertaken in accordance with Article 19e of Regulation (EU) 2019/943 (henceforth referenced as the Electricity Regulation) on the internal market for electricity (recast), as amended by Regulation (EU) 2024/1747. The standardised Flexibility Needs Assessment methodology[4] (FNAM) was developed by the European Network for Transmission System Operators for Electricity (ENTSO-E) and the European Distribution System Operators Entity (EU DSO Entity) to support a harmonised approach to assessing flexibility needs across Member States and was approved by the Agency for the Cooperation of Energy Regulators (ACER) on 25 July 2025.

The FNAM requires Member States to assess both system-wide and network-related flexibility needs over a five to ten-year horizon, while ensuring alignment with wider planning and climate policy objectives. The Northern Ireland assessment focuses on 2030 and 2033 as the target years and examines the role of non-fossil flexibility resources in supporting renewable energy integration, secure system operation and the transition towards a more decarbonised electricity system. To ensure a robust and representative assessment, three weather scenarios from the All-Island Resource Adequacy Assessment (AIRAA) process were selected to capture a range of system conditions.

To implement the FNAM in Northern Ireland, the assessment was adapted to reflect the characteristics of the Single Electricity Market (SEM) and the integrated all-island power system. The system-level analysis is based on detailed modelling of the all-island electricity system, using the latest available assumptions on electricity demand, generation, network infrastructure and system operation. The FNA model is aligned with the generation capacity and demand projections used in the Northern Ireland AIRAA 2026-2035[5] and is further supplemented by inputs from the Enduring Connection Policy (ECP) model[6]. Analysis was also undertaken to ensure that both system-wide and network-related flexibility needs were appropriately captured.

The Utility Regulator (UR) acted as the designated entity for the assessment, with responsibility for overseeing the provision of data and analysis by the System Operator for Northern Ireland (SONI) and Northern Ireland Electricity Networks (NIEN), coordinating the overall assessment process and preparing the final FNA report for submission to ACER and the European Commission. SONI, the

4 ACER, Decision No 05/2025 on the Flexibility Needs Assessment Methodology (FNAM), Annex I- Type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis in accordance with Article 19e(4) of Regulation (EU) 2019/943, 25 July 2025, available at: ACER Decision 05/2025 FNAM Annex I

5 SONI AIRAA Main Report 2026-2035 | SONI

6 2024-Batch-ECP-2.5-ECP-2.5.1-Results-JSO-Publication-May-2025.pdf

Transmission System Operator (TSO) for Northern Ireland, and EirGrid, the TSO for Ireland, have undertaken the FNA modelling and analysis on an all-island basis. This approach supports the use of consistent assumptions and a coordinated methodology across both jurisdictions. However, as required by the updated Electricity Regulation, the interpretation of the FNA results is presented in separate national reports. In parallel, NIEN, as the Distribution System Operator (DSO) for Northern Ireland, assessed distribution-level flexibility needs in accordance with the requirements of the FNAM. Additionally, the UR engaged with the Department for the Economy (DfE) throughout this process. The findings of the assessment will be used to inform the setting of indicative national objectives for non-fossil flexibility by the Member State in January 2027, in accordance with Article 19f of the Electricity Regulation.

As the first application of the FNAM in Northern Ireland, the assessment is subject to methodological limitations, including the assumption that sufficient renewable generation capacity is available to achieve policy objectives before flexibility needs are assessed. Future iterations of the FNAM may provide opportunities to address such challenges and better reflect local circumstances.

This executive summary outlines the key findings of the assessment, their interpretation, and the identified barriers to flexibility, together with associated regulatory recommendations and proposed actions to support the delivery of non-fossil flexibility and higher levels of renewable energy integration in Northern Ireland.

Background

From April 2025 to March 2026, renewable generation (4,264 Gigawatt hours (GWh)) was equivalent to 48% of Gross Final Electricity Consumption (8,818 GWh), according to the Northern Ireland Statistics and Research Agency (NISRA)[7]. This demonstrates that renewable energy provides a substantial share of Northern Ireland's present electricity supply and reflects continued progress towards the target to achieve 80% renewable electricity consumption by 2030, as outlined in the Climate Change Act (Northern Ireland) 2022[8] (CCA).

As renewable generation has increased, so too have periods where available renewable electricity cannot be fully utilised due to a combination of system, operational and network limitations[9]. This is reflected in increasing levels of

7 NISRA Electricity Consumption and Renewable Generation Report (rolling 12-month average). Note: NISRA's renewable generation statistics include bioenergy and hydropower, whereas the FNA focuses only on the curtailment of variable renewable generation (wind and solar)

8 CCA (Northern Ireland) 2022. Available at: https://www.legislation.gov.uk/nia/2022/31/contents

9 In the FNA, surplus is used to describe excess renewable generation, operational constraints as a synonym for curtailment (system-wide limitations) and network constraints as a synonym for transmission or distribution network limitations

renewable curtailment (dispatch down[10]) observed on the power system. In 2025, as published by SONI, approximately 19% of available renewable electricity in Northern Ireland was curtailed, including 22% of available wind generation[11], highlighting the challenges associated with integrating increasing volumes of renewable generation.

These challenges are recognised within the DfE's Path to Net Zero Energy Strategy[12], which provides the framework for Northern Ireland's transition to a secure, affordable and low-carbon energy system.

As renewable generation grows, greater flexibility is needed to manage renewable output. In this context, the FNA supports progress towards Northern Ireland's climate objectives by assessing future flexibility needs and identifying the flexibility, network and operational measures that may be required to enable higher levels of renewable energy integration, while maintaining system security and reliability.

Key Messages

Under the FNAM, no uncovered system flexibility needs are identified in the Base scenario. This outcome reflects a limitation of the current FNAM framework, which assumes renewable deployment consistent with policy targets when assessing flexibility needs. In Northern Ireland, projected renewable capacity remains below the level required to achieve these targets, meaning that no uncovered flexibility need is identified, as renewable deployment, rather than flexibility, is the limiting factor. Future iterations may provide opportunities to address these limitations and better capture local system challenges to provide a more refined assessment of Northern Ireland's needs.

The assessment identifies the key factors influencing Northern Ireland's flexibility needs, which may support more strategic and efficient planning for renewable energy integration. These include:

- **Timely network delivery.** As Northern Ireland's System Operator, SONI is responsible for operating the electricity system securely while planning for future energy needs. The FNA identified network constraints as the primary

10 In line with the FNAM terminology, curtailment in Northern Ireland's FNA report is defined as "*limiting the generation or transmission of renewable power for system operational reasons or grid-capacity reasons*", capturing both system-wide operational limitations and local network constraints. This differs from the conventional use of the term curtailment in Northern Ireland, which has generally been applied to the dispatch-down of wind and solar generation for system-wide operational reasons, where a reduction in output from any or all wind and solar generators would help alleviate the underlying issue, as outlined in the SEM Committee SEM-24-044 paper

11 EirGrid and SONI, Annual Renewable Energy Constraint and Curtailment Report 2025, May 2026. Available at: [Annual Renewable Energy Constraint and Curtailment Report 2025]

12 DfE, Energy Strategy- Path to Net Zero Energy (2021). Available at: [Energy Strategy - Path to Net Zero Energy]

driver of renewable curtailment, highlighting the need to deliver key network infrastructure at pace. Achieving national targets will require a reinforced and more flexible network to integrate higher levels of renewable generation, reduce constraints, maximise the use of renewable energy, support decarbonisation goals and minimise costs for consumers.

- **The rate of renewable build-out.** Northern Ireland at present experiences high levels of renewable curtailment, whilst demand has decreased in the past 10 years[13]. The FNA tested projected renewable build-out based on the Northern Ireland input to the AIRAA 2026-2035. The results of the FNA highlight the potential for increased renewable curtailment as intermittent renewable deployment grows.

- **Cost-benefit and renewable targets.** Meeting Northern Ireland's renewable energy ambitions must be balanced with maintaining affordable electricity costs for consumers. As Northern Ireland works towards the targets outlined in the CCA, understanding the impacts of renewable curtailment will be important to identifying pathways that support decarbonisation while delivering value for consumers.

Key findings

The FNAM distinguishes between two main types of flexibility needs:

- **Network flexibility** reflects the flexibility needed to adjust for grid availability;

- **System flexibility** refers to the ability of the electricity system to respond to changes in supply and demand across different timescales.

The assessment examined network and system needs for the target years under two scenarios: a Base scenario aligned with the renewable integration assumptions set out in the AIRAA 2026-2035, and a High-Renewable Energy Sources (RES) scenario, reflecting a higher level of intermittent renewable deployment consistent with climate target ambitions. The findings are as follows:

1. **Network Needs**

- Persistent network constraints across the assessed target years indicate that network enhancements may be required, alongside flexibility measures, to support the efficient integration of renewable energy.

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- The timely delivery of key infrastructure projects is important to address existing network and operational constraints.

2. System Needs

- The FNA results suggest that higher levels of intermittent renewable deployment could increase flexibility requirements. This is illustrated by the High-RES scenario, which includes 1,000 Megawatts (MW) of offshore wind from 2030 and is associated with higher levels of renewable curtailment relative to the Base scenario.

- System flexibility needs are projected to increase at a faster rate than network flexibility needs, suggesting that flexibility solutions may play an increasingly important role as renewable capacity grows. SONI have suggested an initial flexibility requirement of approximately 4,800 Megawatt-hours (MWh)/day in Northern Ireland from 2030, approximately 20% of within-day flexibility[14]. However, further analysis will be required before an indicative national objective for non-fossil flexibility can be defined.

- The FNA highlights the potential value of long-duration flexibility resources in supporting the integration of renewable generation onto the electricity system. Further procurement may be needed to facilitate their deployment, subject to future system needs and market developments.

- While additional flexibility can reduce renewable curtailment levels and deliver important system benefits, the analysis shows that eliminating curtailment entirely would require volumes of flexibility beyond what is currently considered feasible from available technologies. This highlights the need to consider a broader range of solutions alongside flexibility deployment.

Table 1 presents the results of SONI's analysis, illustrating the impact of different storage configurations on both operationally constrained and transmission-constrained curtailment, relative to the Expected Case under the Base and High-RES scenarios in 2030 and 2033 respectively.

14 This figure is informed by, and should be interpreted in conjunction with, the additional analysis presented in Section 4

Table 1: Article 16.6- Impact of varying storage durations on RES curtailment in Base and High-RES scenarios (WS28 2030 and 2033)

	Base				
WS28, 2030	**Expected Case**	**SDES**	**LDES (8-hour)[15]**	**LDES (20-hour)**	**SDES & LDES**
Storage Capacity (MW)	241	482	482	482	723
Storage Capacity (MWh)	222	444	2,151	5,044	2,373
Annual Surplus + Operationally Constrained Curtailment (%)	9.1	7.4	4.8	3.7	4.2
Annual ECP Transmission Constraint Curtailment (%)	20.8	20.8	20.8	20.8	20.8
Annual Total Curtailment (%)	**30.0**	**28.2**	**25.6**	**24.5**	**25.0**
Annual Surplus + Operationally Constrained Curtailment (GWh)	465.29	377.7	242.41	185.81	215.25
	High-RES				
WS28, 2033	**Expected Case**	**SDES**	**LDES (8-hour)**	**LDES (20-hour)**	**SDES & LDES**
Storage Capacity (MW)	241	482	482	482	723
Storage Capacity (MWh)	222	444	2,151	5,044	2,373
Annual Surplus + Operationally Constrained Curtailment (%)	31.2	28.2	25.4	23.5	24.9
Annual ECP Transmission Constraint Curtailment (%)	18.6	18.6	18.6	18.6	18.6
Annual Total Curtailment (%)	**49.8**	**46.8**	**44.0**	**42.1**	**43.4**
Annual Surplus + Operationally Constrained Curtailment (GWh)	2,894.2	2,615.6	2,358.8	2,181.2	2,306.0

Interpretation of key findings

A central conclusion of the assessment is that Northern Ireland's flexibility challenge reflects the interaction of multiple system characteristics, rather than a single binding constraint. Key drivers, noting the overlap between respective

15 The storage capacities presented for LDES (8-hour and 20-hour) in the scenarios represent total installed storage capacity, including the storage assumptions already incorporated within the Expected Case

constraints, include limited intermittent renewable deployment relative to policy targets in the Base scenario, transmission-related curtailment, operational and stability constraints, forecast uncertainty and evolving net demand patterns.

In line with the FNAM, SONI's analysis indicates that neither flexibility nor renewable capacity alone is sufficient to achieve national renewable integration targets. Flexibility cannot compensate for insufficient intermittent renewable deployment, while increased renewable capacity must be supported by network reinforcement, operational improvements and the deployment of long-duration flexibility.

Transmission constraints emerge as the dominant driver of curtailment. The findings indicate that the most significant reductions are achieved through transmission reinforcement and the reduction of operational constraints, with flexibility measures playing a complementary role. In this context, the commissioning of key infrastructure projects could contribute to reducing curtailment.

Hourly ramping and short-term flexibility needs are incorporated within the modelling framework but do not emerge as uncovered needs. This indicates that existing system resources and reserve arrangements are sufficient to meet such requirements, and that their contribution to overall flexibility needs is limited relative to transmission-related constraints.

The application of the guiding criteria in the FNAM confirms that the importance of flexibility increases under higher renewable penetration and over time. Non-fossil flexibility resources, including energy storage, demand-side response (DSR) and aggregation, could play an important role in meeting future needs at both transmission and distribution levels.

Interconnection is identified as an important enabler of flexibility, supporting cross-border balancing and helping to reduce renewable curtailment. Digitalisation can further enhance system flexibility by improving forecasting, system visibility and operational decision-making.

Flexibility solutions

The assessment remains technology-neutral and expresses requirements in terms of flexibility volumes rather than specific technologies. Energy storage was used as the primary modelling proxy due to its ability to quantify flexibility requirements consistently; however, the identified flexibility could potentially be delivered through a range of technologies and services.

The results suggest that a combination of energy storage, demand-side flexibility and aggregation, smart meters, flexible tariffs, operational improvements, interconnection and transmission and distribution network reinforcement may be required to facilitate higher levels of renewable energy integration and reduce curtailment over time.

Barriers to flexibility, regulatory recommendations and actions

The FNAM also required an assessment of market barriers to flexibility in Northern Ireland, based on the barriers identified in the ACER Recommendation No 01/2026[16]. The assessment suggests that a range of regulatory, market and operational factors may limit the participation of flexibility resources.

- **Market barriers:** Potential barriers identified include challenges for new and smaller participants, limited smart metering and data access, weak flexibility signals, barriers to participation in system services and limited incentives to consider flexibility alongside network reinforcement.
- **Ongoing actions:** A number of measures are already underway, including Future Arrangements for System Services (FASS), the transition to 15-minute market and settlement intervals, planned smart meter deployment and ongoing DSO flexibility initiatives, which may improve opportunities for flexibility participation over time.
- **Actions to 2030:** Priorities may include improving access to market arrangements, strengthening tariff signals, supporting market access and providing clearer incentives for flexibility procurement and digitalisation.
- **Longer term:** Beyond 2030, further development of flexibility frameworks may be required, including enhanced market arrangements, improved TSO-DSO coordination, stronger locational considerations and continued digitalisation of network operation.

Conclusion

Overall, the assessment highlights the potential scale of flexibility required to support Northern Ireland's transition to a low-carbon electricity system. While no uncovered flexibility needs arise under the current FNAM, flexibility requirements are evident and increase significantly under higher intermittent renewable deployment pathways. The findings indicate that flexibility and network

16 ACER, Recommendation No 01/2026 on Barriers to Non-Fossil Flexibility (2026). Available at: ACER Recommendation 01/2026

reinforcement are likely to play complementary roles in supporting future system needs.

This assessment marks the first FNA completed under the Electricity Regulation and forms part of a biennial assessment cycle. Given that this is the first FNA cycle, several methodological limitations have been identified, as detailed in Section 2. These findings, together with feedback from ACER expected in 2027, stakeholder engagement and lessons learned will help inform the next assessment which is due to be completed by July 2028.

1. Introduction

This section outlines the purpose and scope of the FNA, the legal and regulatory framework under which it has been prepared and the respective roles of the parties involved in its development. The FNA is intended to determine and evaluate the flexibility requirements of the power system over the assessment horizon, in accordance with applicable European requirements and national policy objectives. It also sets out the governance arrangements supporting the assessment, including the roles and responsibilities of the UR, DfE, SONI and NIEN.

1.1 Purpose and scope of the national report

The FNA has been developed to identify and quantify the flexibility requirements of the Northern Ireland electricity system over the next five to ten-year horizon, in line with the requirements of the ACER FNAM and as per Article 19e of the Electricity Regulation[17]. The FNAM combines system-wide and network-specific needs to provide a holistic view of flexibility requirements across multiple timeframes, thereby capturing both short-term operational requirements and longer-term structural needs associated with system development.

The primary purpose of the FNA is to assess the extent to which existing and planned flexibility resources are sufficient to support the efficient integration of RES, ensure secure system operation and inform the development of future market and policy frameworks, including the setting of national non-fossil flexibility targets.

The scope of the assessment includes:

- **System-wide flexibility needs** including RES integration, hourly ramping and short-term flexibility requirements;
- **Transmission and distribution network flexibility needs** including congestion management and voltage support;
- **The role of non-fossil flexibility resources** including the role of non-fossil flexibility resources, expressed as technologically agnostic flexibility requirement; and
- **The identification of covered and uncovered flexibility needs** alongside an assessment of potential solutions.

Northern Ireland has selected 2030 and 2033 as the target years for the assessment, within the required five to ten-year horizon as in line with the FNAM.

17 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

The inclusion of 2030 ensures alignment with the common European benchmark year, while the adoption of 2033 provides a further forward-looking assessment reflecting national planning considerations and system evolution. This approach supports consistency with broader European frameworks while allowing for region-specific analysis of longer-term flexibility needs.

1.2 Legal and regulatory context

This assessment has been prepared in accordance with the Electricity Regulation, in particular Article 19e as introduced by Regulation (EU) 2024/1747. This provision requires Member States to assess their system flexibility needs, including the potential contribution of non-fossil flexibility resources.

The FNAM sets out a harmonised framework for the identification, quantification and reporting of flexibility needs across European electricity systems. In this context, the FNA supports progress towards broader policy objectives, including the national renewable energy targets outlined in the CCA. This includes a requirement for at least 80% of electricity consumption to be met from renewable sources by 2030, alongside targets to achieve net-zero emissions by 2050.

The assessment is also designed to align, where relevant, with parallel European and national processes, including the European Resource Adequacy Assessment (ERAA), the National Resource Adequacy Assessment (NRAA) and network development planning processes. In the context of the SEM, which operates as an all-island bidding zone, the analysis reflects the interconnected and integrated nature of the electricity system across Northern Ireland and Ireland.

1.3 Governance: designated bodies involved in the FNA report

The DfE selected the UR as the Designated Entity for the FNA. In this role, the UR was responsible for receiving data and analysis from SONI and NIEN, coordinating the overall process and preparing the Northern Ireland FNA report in accordance with Article 19e of the Electricity Regulation and the relevant provisions of the FNAM.

NIEN, as the DSO, was responsible for evaluating distribution network flexibility needs and provided the relevant data and analysis for inclusion in the FNA report. This included the identification of local network needs arising from congestion and voltage issues, the application of relevant distribution planning assumptions and scenarios, and outlining the nature, location and characteristics of those needs. NIEN carried out its responsibilities directly and provided the outputs to the UR for inclusion in the final report.

SONI, as the TSO, was responsible for providing the system-level data and analysis underpinning the FNA, including the assessment of flexibility needs related to RES integration, ramping and short-term system operation. SONI also identified transmission network constraints, associated flexibility requirements, and provided an assessment of the capability of different flexibility sources.

Given the integrated nature of the SEM, SONI worked closely with EirGrid, the TSO for Ireland, to support a consistent all-island modelling approach (as further detailed in Section 2). This included collaboration on shared modelling inputs, assumptions and analytical methodologies, including the use of the AIRAA model, thereby supporting alignment between the Northern Ireland and Ireland assessments where appropriate, while maintaining separate national submissions.

The UR, SONI and NIEN worked collaboratively under an agreed governance framework, establishing the scope, timelines and analytical approach. SONI and NIEN submitted their analysis to the UR, which subsequently incorporated these inputs into the final report. Throughout the process, the parties engaged regularly to ensure that the submitted analysis was clearly understood, consistently interpreted and accurately reflected in the report. Data exchange and reporting were carried out in accordance with the agreed timeline, with the scope finalised in November 2025, data provided in May 2026 and subsequently submitted to ACER and the EU Commission.

Stakeholder engagement included coordination meetings and technical discussions between the designated bodies, supporting the alignment of assumptions, clarification of methodological interpretation and resolution of jurisdiction-specific issues. In addition, the UR published an Information Note[18] in May 2026, setting out the legislative context, roles, scope and timeline. Stakeholder input was sought in relation to market and regulatory barriers to non-fossil flexibility and the role of digitalisation. Responses were considered and reflected in Annex C of the report.

The UR also recognised the importance of cross-jurisdictional coordination given the interdependencies between Northern Ireland's and Ireland's electricity systems. As Ireland undertook its own FNA, the UR engaged with the Commission for Regulation of Utilities (CRU) to support alignment and a shared understanding of flexibility needs across the all-island electricity system.

As this is the first iteration of the FNA, a number of difficulties arose during the process. These included challenges in interpreting certain aspects of the FNAM, agreeing approaches to implementation and addressing issues where data availability, modelling capability or the practical application of certain requirements were not fully clear. There were also challenges associated with applying a new European methodology in the context of the SEM and ensuring that national reporting requirements remained consistent with the realities of an

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integrated all-island market. These issues were managed through collaboration between the UR, SONI, NIEN and, where relevant, engagement with counterparts in Ireland. No formal dispute resolution process under Article 4(7) was required; instead, issues were resolved through discussion and coordination among the relevant parties.

All parties complied with the confidentiality requirements set out in Article 5 of the FNAM in relation to the exchange, handling and use of information and data during the preparation of the report.

2. Methodological aspects

This chapter sets out the methodological framework underpinning the FNA, ensuring alignment with the FNAM. It identifies the principal data sources used to form the main dataset, the target years selected for analysis and the modelling approach applied to assess flexibility needs. It also describes the treatment of network needs and the fine-tuning approach adopted. Together, these elements provide the basis for assessing national flexibility requirements.

2.1 Data sources

NIEN and SONI used the following data sources:

Table 2: DSO and TSO data sources

	Data Source	Reasoning
NIEN	Distribution Network Planning Scenarios for NIEN	The scenarios provide a structured and forward-looking representation of expected demand, generation and network conditions, ensuring that distribution-level flexibility needs are assessed using robust and internally consistent inputs.
	NIEN - Historical Substation Trend data	Historical substation trending data provides an evidence-based view of network utilisation over time, enabling validation of constraint severity, identification of temporal demand patterns, and more accurate targeting of flexibility services.
	NIEN - Substation Load Indices	Load Indices (LI1-LI5) provide a standardised, peak-loading-based classification of substations, enabling consistent identification and prioritisation of network constraints.
SONI	AIRAA 2026-2035 Inputs and Assumptions for Northern Ireland	Analysis primarily based on the latest AIRAA model (including capacity auctions held up to 2030, with additional auctions expected thereafter) The AIRAA model was further developed and supplemented using additional data sources, including the following:

	Data Source	Reasoning
	ENTSO-E System Operation Guidelines- Frequency Containment Reserve (FCR) related provisions	*To incorporate reserve characteristics into the modelling framework.*
	Pan-European Market Modelling Database (PEMMDB) datasets for Northern Ireland and Ireland (originally sourced via Single Electricity Market Operator (SEMO))	*To align with the ERAA scenario and the requirements set out in Annex 1 of the FNAM and model France and Great Britain.*
	Generic ERAA modelling data, including "General Information - Common Data" (ERAA modelling dataset)	*To address data gaps in the PEMMDB datasets in line with Annex 1 requirements.*
	The Operational Policy Roadmap	*To inform key system constraints, including minimum unit requirements, System Non-Synchronous Penetration (SNSP) limits, inertia levels and Dublin voltage constraints.*
	Historical forecast error data for demand, wind and solar generation, sourced from EirGrid	*To support modelling of short-term flexibility requirements.*
	Updated wind generation profiles developed by SONI using quantile mapping techniques	*To ensure capacity factors and variation are represented for Flexibility Needs Studies.*
	The EirGrid ECP- 2.5 model	*To inform transmission network constraints, including limitations on North-South interconnection (existing North-South tie-line and the North-South Interconnector).*

2.2 Target years considered

At least two target years must be included within a ten-year study horizon, with a requirement to expand the number of target years in subsequent iterations. ENTSO-E and the DSO Entity agreed a common target year of 2030 to be applied consistently across all countries. For the second target year, TSOs and DSOs aligned with the DNDP, ERAA study year and relevant EU climate policy milestones, selecting 2033. These represent the required target years for the current assessment.

For Ireland, target years of 2028 and 2030 were selected. This reflects a minor divergence in implementation between national submissions and does not materially affect the overall FNAM, given the use of a common modelling framework across both jurisdictions.

2.3 Modelling approach

2.3.1 Model design and scenarios

The methodology for the 2026 FNA was developed in line with relevant European regulatory guidance, including the ACER-approved FNAM which was adjusted to reflect the characteristics of the all-island power system. While the original scope set out a comprehensive assessment framework, the final FNAM defined a pragmatic application, taking account of data availability, model capability and alignment with parallel system studies.

Although the FNA is a national requirement, it was agreed that EirGrid and SONI would adopt a shared modelling and analytical approach. This included aligned assumptions, common inputs and coordinated processes, while maintaining separate data processing and reporting outputs for each jurisdiction. This approach was underpinned by several key considerations:

- The economic dispatch results forming the core input to the FNA are based on wholesale market simulations within the SEM. Given that the SEM operates on an all-island basis, an all-island modelling approach ensures consistent inputs and produces aligned and comparable outputs across jurisdictions;
- While the FNA reports are produced at the national level, Article 1(3) requires that flexibility needs are assessed at bidding-zone level. As Northern Ireland and Ireland comprise a single SEM bidding zone, a coordinated modelling approach supports alignment with this requirement;
- Market arrangements relevant to enabling flexibility are largely designed and implemented on an all-island basis. Consistent modelling inputs therefore support a more coherent assessment of market barriers and potential solutions;
- The AIRAA model and its underlying processes are already developed and operated on an all-island basis, with established collaboration between SONI and EirGrid. Therefore, using this shared framework supports consistency, improves representativeness and reduces delivery risk in the first iteration of the FNA by building on existing expertise and resources;

- Key system constraints required to be modelled under the FNAM, such as SNSP, apply at the SEM-wide level, further supporting the use of a coordinated approach.

A series of workshops were held between the relevant modelling teams to identify the most appropriate modelling framework. In all cases, the NRAA approach was preferred to ERAA, reflecting its greater relevance to SEM system conditions and the established experience of SONI and EirGrid in its application.

Two principal modelling options were considered:

- **The AIRAA model**, which is aligned with the requirements of the NRAA as defined in the FNAM. However, it simplifies the transmission network to a single node per jurisdiction;

- **The ECP model**[19], iteration 2.5, which refers to the final batch of projects processed under Stage 2 of the ECP. The model was developed by EirGrid and includes the transmission network, however, the input data was not initially aligned with the NRAA. As a result, a significant amount of further work was required to establish consistency between the two modelling approaches.

Following this assessment, the AIRAA model was selected as the starting point for analysing system flexibility needs, given its closer alignment with the FNAM, particularly Article 7(3). Early-stage testing was undertaken to assess the representativeness of results and a number of enhancements were introduced to incorporate key elements of the ECP model, including additional operational constraints and generator characteristics. The ECP model was used separately to assess the transmission network flexibility needs. Both models were implemented using the Plexos modelling platform.

These enhancements required additional economic dispatch simulations to be rerun. It was also determined that assessing the impacts of additional flexibility resources would be most accurately achieved by incorporating these capabilities directly within the economic dispatch simulations, thereby capturing their effects on overall system dynamics, rather than relying on simplified post-processing approaches based on residual load.

2.3.2 Model modifications

A number of modifications were made to the AIRAA model. These include:

19 The ECP 2.5 is the fifth batch of connection offers planned under ECP-2 by the CRU to facilitate opportunities for connections of RES on to the Irish electricity network. https://cms.eirgrid.ie/sites/default/files/publications/ECP-2.5%20Assumptions%20Document.pdf

- Alignment with the ECP model by increasing variable cost of thermal and VRES generators to reflect gas transportation costs and align import/export ratio to expectation and align to ECP model;

- Limitations on the North-South Interconnector were added from the ECP model to align, so that no double counting or missing of transmission constraints/interconnection constraints occurred. Note that the FNA model has no intraregional transmission constraints, but does have constraints on the existing North-South tie-line, North-South Interconnector and other interconnections;

- Adding generator operational parameters from PEMMDBs (SEMO) and, in cases where data were missing, from generic ERAA data. Representations of generator parameters such as but not limited to ramp rates, cold/warm start times, shutdown times, and minimum stable level were added to generators to better represent unit commitment and economic dispatch, as per Annex 1 in the FNAM;

- Higher detailed modelling of flexibility available and limitations, which is relevant for the FNA but not adequacy, including interconnector ramp rates and removal of time-of-day operating limits on selected thermal generators;

- Incorporating the structure of operational constraints from the ECP model and ensuring their values are in line with the Operational Policy Roadmap, such as system inertia floor, SNSP, system/regional operational constraints related to the minimum number of units on-load, which were incorporated into the model to account for operational considerations not pertinent to resource adequacy studies in AIRAA;

- Developing reserves modelling to incorporate timeframe and duration properties as per ENTSO-E data. This enabled Battery Energy Storage System (BESS) and generator ramp rates to be relevant and work properly with the reserve requirements;

- Adjusting reserve penalty price to limit unserved energy from occurring due to prioritising reserve provision;

- Rescaling onshore and offshore wind profiles using quantile scaling methodology and substituting these for profiles used in the AIRAA study to better reflect the range of wind output;

- Model settings and simulation properties, including problem formulation (Mixed Integer Programming (MIP) vs linear), objective function scalar, MIP gap and market time (MT) schedule accuracy, were adjusted to improve model performance and align with study objectives, to ensure the same or better fidelity but with a quicker run-time. This was done to ensure ending with a practical run-time especially after adding details to the model which slow the run-time down;

- Reserve objects were added to approximate redispatch in real-time due to load and wind and solar power forecast errors, in line with Article 10 (short-term flexibility requirements).

2.3.3 Consideration of cross-border flexibility

Cross-border flexibility was considered in line with Article 19e(1) of the Electricity Regulation through the use of an all-island economic dispatch framework reflecting the SEM. Interconnector flows, exchange capacity and associated operational constraints were explicitly represented within the model, allowing cross-border exchanges to contribute to the computation of flexibility needs, including ramping and short-term requirements under Articles 9(3)(c) and 10(3)(c) of the FNAM. This approach captures the extent to which cross-border capability can offset domestic flexibility requirements. However, the optional assessment of exchange schedules under conditions of market liquidity constraints was not undertaken; consequently, no separate quantification of any resulting reduction in such periods is provided.

2.3.4 RES integration, ramping and short-term flexibility needs

In accordance with Article 7(3) of the FNAM, the approach set out in subparagraph (b) was adopted. This involved the use of an economic dispatch simulation based on NRAA assumptions (as required under subparagraph (i)), with ramping and short-term flexibility needs explicitly integrated into the model (as required under subparagraph (ii)). These elements were incorporated into the economic dispatch model as follows:

- **Ramping needs:** Generator characteristics relevant to flexibility were represented, including parameters such as upward and downward ramp rates, cold and warm start-up times, shutdown times, minimum on/off times, and minimum stable generation levels.

- **Short-term needs:** Reserve objects were introduced within the Plexos model to represent the impact of day-ahead forecast errors, based on historical discrepancies between forecast and actual residual load components (wind, solar and demand), with separate representations for upward and downward deviations. Parameters were derived from available data for 2024 and 2025; however, due to limitations in data availability, a complete dataset was not available and gaps were addressed using suitable proxy values, such as comparable periods for demand and adjacent timeframes for renewable generation. Day-ahead forecast data were only available for demand, while wind and solar forecasts were approximated using the latest available forecasts approximately six hours ahead of real time. Short-term flexibility needs associated with forced outages were represented through FCR and Frequency Restoration Reserve (FRR) reserves, which act as primary and secondary responses to cover the largest potential loss and were already included within the AIRAA model. Certain aspects of real-world reserve provision were not explicitly captured, including the potential contribution of renewable generation to reserve provision, both upward (when curtailed) and downward (when available).

Under Article 7(4)(i), the scope of analysis is limited to assessing RES integration needs pursuant to Article 8. This is because the impacts of ramping and short-term flexibility needs are already implicitly captured within the RES curtailment results derived from the economic dispatch model described above, in line with the requirements of the FNAM. As a result, the intermediate analytical steps set out in Articles 9 and 10- up to paragraph 9(6) for ramping needs and paragraph 10(5) for short-term needs- are not required, as their outcomes are inherently reflected in the Article 8 assessment.

Article 7(4)(i) should also be read in conjunction with the final provisions of Articles 9(11) and 10(10), which clarify that, where an economic dispatch approach is used, the analysis is limited to extracting uncovered needs directly from the model or by comparing metrics such as ENS or RES curtailment with and without relevant constraints. In this case, the model results show no ENS and no uncovered ramping or short-term flexibility needs. This reflects the underlying model assumptions, whereby capacity adequacy is already satisfied (consistent with the AIRAA-based framework), and the available resources are sufficient to meet both ramping and short-term requirements. Consequently, no further analysis under Articles 9 and 10 is required.

To comply with Article 16(10), additional scenarios were undertaken in which ramping inputs, short-term flexibility inputs and operational constraints were selectively removed. This enabled an assessment of the interdependencies between these factors by comparing the resulting RES curtailment profiles with the base case. These comparisons provide the required indicators for ramping and short-term flexibility needs, as set out in Articles 9(11) and 10(10), alongside indicators for operational and transmission constraint impacts.

In summary, the RES curtailment time series produced under the Article 8 analysis inherently captures the effects of ramping and short-term flexibility needs and therefore satisfies the requirements of Article 7(4)(i), including Articles 9(6) and 10(5). The additional scenario analysis carried out under Article 16(10) provides disaggregated indicators of these effects, which combined with further analysis to evaluate the impact of Articles 9 and 10 by assessment of downward ramping foot-room and shortage of short-term flexibility respectively (which concluded that their impacts on RES curtailment were negligible), allow the requirements of Articles 9(11) and 10(10) to be met. Collectively, this approach ensures that all relevant requirements relating to RES integration, ramping and short-term flexibility needs have been addressed.

The following are some additional specific optional aspects outlined for consideration in the FNAM:

- The optional approach of assessing the impact of exchange schedules under market liquidity constraints in extreme price conditions was not adopted.
- The assessment did not include the optional differentiation of residual load variations into very fast, fast and slow categories.
- Given the design of the SEM, including mandatory participation in the balancing market, no additional analysis was required to assess the ability of units to meet balancing energy product requirements.

2.3.5 Consideration of network needs

DSO flexibility needs analysis methodology

This section outlines the methodology used to identify network constraints and quantify the flexibility volumes required to address them. The assessment is aligned with the assumptions, scenarios and methodological approach set out in the DNDP.

The current analysis focuses on constraints at the primary (33 kV) network level, assessing network capacity and determining demand headroom relative to forecast load.

At present, the identified flexibility needs are limited to upward flexibility. The potential role of downward flexibility is under review and may be incorporated in future assessments where such requirements are identified.

DSO methodological approach

NIEN determines peak demand by considering both measured and latent demand, applying historical trends and expected future developments to project demand across the forecast horizon. The anticipated uptake of low-carbon technologies (LCTs), based on the Distribution Network Planning Scenarios, is then incorporated to assess their impact on peak demand over time.

This analysis produces Load Indices (LI1-LI5) for assets across the primary network, with classifications based on peak loading. In line with a flexibility-first approach, locations forecast to reach LI4 or LI5 are assessed for suitability for customer flexibility, taking account of technical constraints and load profile characteristics. For suitable locations, forecast load profiles are analysed to determine the timing, power and energy requirements associated with addressing projected overloads.

Identified flexibility needs are then signalled to the market up to three years in advance through a dynamic procurement process, alongside longer-term visibility of potential future opportunities. During procurement, available flexibility is assessed against technical criteria to ensure system security and is subject to cost-benefit analysis to determine whether flexibility offers a viable alternative to network reinforcement. Where flexibility is not considered suitable, projects progress to conventional investment planning.

For the target years assessed, NIEN identified locations expected to reach LI4 or LI5 and applied a screening process to exclude sites where flexibility would not be appropriate due to technical or demand-related factors. As these target years extend beyond the current regulatory period, the forecasts are subject to uncertainty and will be refined over time. The resulting flexibility requirements are contingent on the availability of technically compliant and cost-effective services at the specified locations.

TSO methodological approach

Transmission network flexibility needs were assessed using the ECP-2.5 model, which provides a full nodal representation of the transmission system across Northern Ireland and Ireland and therefore captures the spatial distribution of transmission constraints explicitly, unlike the AIRAA model. The analysis was undertaken for the relevant target years using closely aligned input assumptions and operational constraints, with model outputs assessed on a time-resolved basis to identify periods in which transmission constraints resulted in RES redispatch or curtailment. These results were used to quantify the impact of transmission constraints on RES integration and to determine whether the threshold for fine-tuning under the FNAM had been exceeded.

The ECP model was first run without transmission constraints to capture the RES curtailment that results from oversupply and operational constraints. The remaining quantity of RES available was input into the model which was run again this time with transmission constraints. The resulting hourly timeseries of RES curtailment was taken as due to transmission constraints and was added to the RES curtailment timeseries from the FNA model. Note that in this context, transmission constraints refer specifically to intra-regional constraints within Northern Ireland, with interconnection assets, including the North-South Interconnector and Moyle Interconnector, represented within both the runs with and without transmission constraints (and also represented within the FNA model). Methods of applying scalars or creating a function for curtailment relating to other timeseries were tested, and due to the difference in curtailment from system constraints between the models alongside the lack of correlation between curtailment and other inputs which would have enabled an accurate curtailment function, it was deemed best to add the timeseries together.

To reduce misalignment between the ECP and FNA models, the ECP scenario most closely aligned with the NRAA/FNA scenario was selected in each case to keep RES capacities similar and align with the interconnection available. This achieved a close match in overall generation capacity and peak and overall demand assumptions, including approximately 99% alignment for wind capacity, 95% for solar capacity and 95% for demand. Scenarios for higher RES capacities were taken from the ECP results for the High-RES scenario modelled in Article 16. The High-RES scenario was derived from the AIRAA model, in which RES capacity is sufficient to exceed RES targets in the absence of curtailment. 2030 and 2035 were run in the ECP model. Transmission constraint values for 2030 were taken from the 2030 output, and transmission constraint values for 2033 were interpolated between the 2030 and 2035 results. To avoid a potential situation where the RES curtailment from the ECP and FNA models would add up to greater than 100%, the largest hourly curtailment value was taken from the ECP model in each case and the final RES curtailment timeseries had each hour capped to the corresponding value.

2.3.6 Fine-tuning approach

Analysis of constraint results from the ECP model indicates that the level of RES redispatch arising from transmission network constraints exceeds the threshold specified in Article 14(3)(a), namely where constraints in MWh exceed 10% of the total annual RES curtailment. Accordingly, a fine-tuning process was applied to incorporate TSO network flexibility needs into the assessment of RES integration needs.

The following aspects were considered in relation to the inclusion of DSO results within the TSO fine-tuning process:

- The relevance of the fine-tuning process is first assessed by determining whether the relevant mechanisms apply in the local context (e.g. where the TSO or DSO has identified network flexibility needs or implemented related constraints). Where applicable, a quantitative threshold is then applied, with impacts evaluated against a 10% threshold of the relevant metric. If the impact falls below this threshold, the mechanism is not considered material and is therefore excluded from the fine-tuning process.

- For downward distribution network needs, engagement with the DSO confirmed that no volumes exceeded the 10% threshold specified in the FNAM; accordingly, fine-tuning was not required for this aspect.

- In relation to Article 13 at the distribution level, no significant increase in unavailability is anticipated as a result of grid prequalification or temporary limits. Minor uncertainties are already mitigated through a modest over-procurement margin within NIEN's flexibility procurement strategy. Accordingly, NIEN considers the volume of flexible resources affected by these processes to be negligible and has set this value to zero for the purposes of the FNA.

As the impact did not exceed the 10% threshold specified in Article 14(3)(b), it was not considered material for the purposes of fine-tuning. Accordingly, no fine-tuning was applied in respect of DSO-related aspects and the process was limited to TSO network flexibility needs.

2.3.7 Caveats relating to the methodology approach

General

The FNA represents a new process, and as such, uncertainty has arisen during the development and application of the modelling framework, particularly in identifying the most appropriate modelling approach. While the FNAM highlights the potential relevance of the economic viability assessment (EVA) from the ERAA framework, several elements of the FNAM require outputs that provide limited value in terms of actionable insights and interpretation of results. Although some flexibility exists to supplement the required outputs with additional analysis, future iterations of the FNAM could benefit from allowing TSOs greater discretion to tailor analysis to local requirements. This would better support its primary objective of setting the targets for non-fossil flexibility.

In addition, there is a lack of clarity regarding scenario requirements. The FNAM requests the use of multiple weather scenarios, similar to those applied in the NRAA, where 36 scenarios are typically considered. In this assessment, three representative scenarios, consistent with the AIRAA 2026-2035 process, were selected. This approach reflects a practical balance, as modelling all 36 scenarios would be impractical due to processing time, while reliance on a single scenario would risk insufficient representation. However, this reduced set increased modelling time, data processing and reporting effort, limiting the ability to explore alternative analyses, such as additional flexibility scenarios, varying VRES deployments or sensitivities relating to interconnector flows. Furthermore, the FNAM does not clearly specify whether additional analyses, including those referenced in Articles 16(5), 16(6), and 16(10), are required across all weather scenarios and target years or only for selected cases. Providing clearer guidance on the expected number and scope of scenarios would improve consistency and transparency for future iterations.

There is also a risk of misalignment between input data sources. In particular, for RES integration flexibility needs, the methodology refers to the use of NECP targets or closest national document, for which the CCA was selected; however, the dataset applied in this assessment is aligned with the AIRAA median forecast which falls short of climate target. Adopting input assumptions aligned with trajectories consistent with achieving the national climate target outlined in the CCA and ultimately net-zero, would provide a more meaningful assessment of the flexibility required under policy-driven scenarios, rather than focusing on flexibility needs associated with more conservative or adequacy-driven futures. This could be incorporated either as a replacement for, or a complement to, the current FNAM through additional scenario design. In this context, exploring a range of VRES deployment scenarios is likely to provide more insight into flexibility requirements than expanding the number of weather scenarios alone.

Finally, careful consideration is required in the interpretation of terminology and definitions. Differences exist between the terminology adopted in the EU FNAM and that used within local SEM arrangements. For example, the FNAM uses the term “curtailment” broadly to describe any forced reduction in renewable output, including actions taken for system operation or network constraints. In contrast, SEM terminology distinguishes between dispatch down of VRES due to “curtailment” (system-wide operational constraints), “constraint” (local network limitations) and “surplus” (excess generation relative to demand and export capacity). For consistency, the results presented in this report apply the definitions used within the EU FNAM, while recognising the need for continued work to further align and clarify terminology across frameworks.

Suitability of modelling approach

In future iterations, it is intended that the FNA analysis will be conducted using a fully nodal model, allowing for a more detailed representation of the system, capturing VRES curtailment resulting from transmission constraints and being able to better understand the interaction between non-transmission and transmission flexibility solutions.

Short-term and ramping flexibility needs

For short-term flexibility needs, the format of forecast data specified in the FNAM did not align with the data available within TSO systems. For example, it was not possible to obtain renewable generation forecasts at 12:00 D-1, and, due to system access and data retention constraints, the most recent two years of historical data were not available. In addition, the FNAM requires the estimation of 99.9th and 0.1th percentile forecast errors, which would typically rely on forecasting ensembles that are not currently available, as well as assumptions regarding potential future improvements in forecasting capability, which remain uncertain. As a result, the modelling approach adopted in this assessment utilised the best available data to provide an evaluation of short-term flexibility needs.

For ramping flexibility needs, the modelling results indicate negligible uncovered needs, with a correspondingly minimal impact on RES curtailment as assessed under Article 10(10). However, this outcome should be interpreted with caution. The hourly data available in the Plexos model is insufficient to catch the short-term ramping issues that are typically experienced. Further, the definition of "ramping" within the FNA framework differs from its application within SONI's operational and planning processes. In particular, SONI's consideration of ramping margin incorporates both ramping capability and the assessment of required margins, reflecting system-specific operational requirements. Consequently, the outcomes of the FNA analysis in relation to ramping should not be interpreted as directly informing, or replacing, existing assessments of ramping margin within the SEM.

In the FNAM, the following definitions and calculations are used to consider ramping flexibility needs:

- **Article 2(2)(y):** 'ramping needs' refer to needs associated with variations of the residual load assuming perfect forecast conditions;
- **Article 9(1):** for each MTU and weather scenario for each target year, the TSOs shall extract the residual load from economic dispatch results pursuant to Article 7(3). The TSOs shall calculate the variations of this residual load, i.e. the changes in the level of the residual load between consecutive MTUs.

- **Article 9(2):** For each MTU and weather scenario for each target year, pursuant to Article 6(1), the TSOs shall extract from the economic dispatch results pursuant to Article 7(3) the dispatch of flexible resources (generation, storage and demand units), as well as the schedules of exchanges. The dispatches and schedules are used to calculate the ramping residual margins on the generation, storage, demand assets and exchange capacities by means of all the following:

  a) the difference between the dispatched power production and the minimum and maximum power of the generation assets (on unit or aggregated level), including renewables;

  b) the difference between the dispatched off-take and the minimum and maximum power of the demand and storage assets (on unit or aggregated level);

  c) the difference between the scheduled import and export and the available exchange capacity.

Ramping Margin in the SEM is defined as the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration as follows:

- **Ramping Margin 1** is defined as the increase in MW output, or reduction in demand, that a unit can deliver within one hour of receiving a dispatch instruction, and sustain for an additional two hours thereafter.

- **Ramping Margin 3** is defined as the increase in MW output, or reduction in demand, that a unit can deliver within three hours of receiving a dispatch instruction, and sustain for a further five hours thereafter.

- **Ramping Margin 8** is defined as the increase in MW output, or reduction in demand, that a unit can deliver within eight hours of receiving a dispatch instruction, and sustain for a further eight hours thereafter.

The detailed calculation of SEM Ramping Margin requirements is set out in the following document: Ramping Margin Requirements in Scheduling[20]. This highlights that the requirements account for key sources of uncertainty, including renewable generation forecasts, demand variability and interconnector and tie-line flows.

20 EirGrid and SONI, Ramping Margin Requirements in Scheduling, 22 September 2021, available at: SEMO- Ramping Margin Requirements in Scheduling

2.4 Additional data and analysis

Additional modelling runs were undertaken using a High-RES scenario derived from the AIRAA model, in which RES capacity is sufficient to exceed RES targets in the absence of curtailment. This analysis, enabled under Article 16(11) and conducted in conjunction with the assessment under Article 16(6), was used to examine the impact of higher RES penetration on the base case results reported under articles 8 and 16.

In addition, modelling was performed incorporating a 20-hour energy storage system (ESS), alongside a series of incremental 10-hour BESS configurations, to support a more detailed evaluation of the additional 4,800 MWh of flexibility identified for Northern Ireland by SONI beyond the existing development plan.

Lastly, alignment with the FNAM may understate the impact and value of the North-South Interconnector. Additional model analysis has therefore been carried out to better reflect the interconnector and its role in alleviating the All-Island Min Sets constraint. Under the FNAM, operational constraints must align with the Operational Policy Roadmap. As the analysis uses transmission constraint values from the ECP model, the commissioning date of the North-South Interconnector is also aligned with that model. However, this approach relaxes operational constraints before the interconnector is commissioned, which does not reflect real-world operation. In practice, the North-South Interconnector is needed to reduce the Min Sets constraint to an all-island value of 3, as set out in the Operational Policy Roadmap for 2030. Article 16(10) also identifies reducing operational constraints as a key driver of curtailment reduction. In addition, the FNAM must align with the latest AIRAA model assumptions, including reserve requirements. These requirements do not change after the North-South Interconnector is commissioned, although the interconnector is expected to reduce reserve requirements in practice. Consequently, the FNAM results may not fully capture the wider system benefits associated with the North-South Interconnector and could therefore understate its overall value.

3. Scenarios and assumptions description

This chapter sets out the scenarios, targets and key assumptions underpinning the FNA. Building on the methodological framework described in Section 2, it defines the inputs applied to the analysis. Collectively, these elements provide a basis for understanding the conditions and main drivers shaping the results, highlighting import and export quantities as a key influence.

3.1 Scenarios used to assess system and network needs

3.1.1 Scenarios for system needs

For the assessment of system flexibility needs, the AIRAA 2026-2035 model was selected, applying an economic dispatch simulation approach in line with FNAM Article 7(3)(b). Under this modelling framework, it is necessary to represent short-term and/or ramping flexibility needs within the analysis. To enhance the accuracy of the results, both short-term and ramping flexibility needs were incorporated.

In addition, the analysis was undertaken using a subset of weather scenarios derived from the AIRAA modelling. In line with the FNAM, Weather Scenarios 4, 28 and 34 were selected for assessment, where they were identified as providing a representative spread of resource adequacy outcomes. These scenarios capture a range of wind, solar and demand conditions, supporting a more comprehensive assessment of flexibility needs.

3.1.2 Scenarios for network needs

Scenarios for DSO data

The distribution network FNA is based on the most recent DNDP, scheduled for publication in 2026, in accordance with FNAM Article 6(6) of the FNAM. The DNDP considers a range of distribution-level flexibility needs, including the management of local network constraints, thermal overloads and voltage limitations, where flexibility solutions may defer or complement traditional network reinforcement. These needs are assessed using forecast demand growth trajectories and projected uptake of LCTs, as set out in the Distribution Network Planning Scenarios report. The analysis incorporates key assumptions relating to peak demand, LCT deployment and network capacity and is underpinned by scenario-based projections that reflect differing levels of demand growth and technology uptake. The modelling approach and analytical framework applied in this report are consistent with those adopted in the DNDP, ensuring alignment between the FNA assessment and established distribution network planning methodologies.

Scenarios for TSO data

Transmission network needs were derived from the ECP model maintained by EirGrid. The ECP model includes a detailed representation of the transmission network and associated reinforcement requirements, making it an appropriate source for assessing future network needs. However, as the ECP study scenarios did not align exactly with the renewable generation capacities adopted in the FNA, the AIRAA model was used as the primary source for system modelling, as it more closely reflected the required technology capacities and assumptions. To ensure consistency with the FNA scenarios, network reinforcement needs were therefore extracted from ECP model runs with VRES capacities closest to those used in the assessment, together with a higher-VRES scenario representing the High-RES case. Both scenarios were available for the 2030 and 2035 study years. The transmission network requirements for 2030 were taken directly from the corresponding ECP outputs, while 2033 values were estimated through interpolation between the 2030 and 2035 results.

Base and High-RES scenarios

The assessment considers two scenarios (outlined in Table 3):

1. **Base Scenario-** aligned with the median assumptions from the AIRAA 2026-2035 assessment;

2. **High-RES Scenario-** aligned with the higher intermittent renewable deployment trajectory from AIRAA 2026-2035.

The Base and High-RES scenarios share the same assumptions for demand, conventional generation, operational constraints, network development and interconnection and interconnector modelling. The principal distinction is the renewable generation mix, with the High-RES scenario adopting a higher renewable energy trajectory than the median forecast used in the Base scenario. This enables the assessment of flexibility needs under increased renewable penetration while holding all other system assumptions constant.

Table 3: Input assumptions for Base and High-RES scenarios

	Base scenarios		High-RES scenarios	
Input Parameters	**2030**	**2033**	**2030**	**2033**
Demand	AIRAA 2026-2035: Median Best Estimate	AIRAA 2026-2035: Median Best Estimate	Same as Base	Same as Base
Generation: Conventional	AIRAA 2026-2035: Plant Successful in Capacity Auction	AIRAA 2026-2035: Plant Successful in Capacity Auction	Same as Base	Same as Base
Generation: RES	AIRAA 2026-2035: Median forecast aligned with figures from internal modelling	AIRAA 2026-2035: Median forecast aligned with figures from internal modelling	AIRAA 2026-2035: Higher renewable trajectory relative to the median trajectory	AIRAA 2026-2035: Higher renewable trajectory relative to the median trajectory
Operational Constraints: No. of Min Sets	All-island 3 sets	All-island 2 sets	Same as Base	Same as Base
Operational Constraints: Non-Synchronous Generation	95% SNSP	Linear interpolation between 95% (2030)- 100% (2035)	Same as Base	Same as Base
Network Developments	ECP 2.5 (NDP Q3 2025)	ECP 2.5 (NDP Q3 2025)	Same as Base	Same as Base
Interconnection	North South, Moyle, East–West Interconnector (EWIC), Greenlink, Celtic	North South, Moyle, EWIC, Greenlink, Celtic, North South 2	Same as Base	Same as Base
Interconnector Modelling	Price model for the IC's reflects the regional price differentials currently observed in the SEM, France and GB markets	Price model for the IC's reflects the regional price differentials currently observed in the SEM, France and GB markets	Same as Base	Same as Base

Table 4: Northern Ireland RES generation capacity assumptions aligned with AIRAA (2026-2035)[21]

		Northern Ireland RES generation trajectory: Base v High-RES scenarios (MW)									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	**Offshore wind**	0	0	0	0	0	0	0	0	0	500
	Onshore wind	1410	1470	1550	1700	1850	2000	2150	2300	2450	2600
	Solar	270	300	350	410	480	550	620	690	760	830
High-RES	**Offshore wind**	0	0	0	0	1000	1000	1000	1000	1000	1000
	Onshore wind	1420	1490	1590	1780	1970	2160	2340	2530	2720	2910
	Solar	280	310	380	450	540	630	710	800	890	980

3.2 Target for RES integration

In accordance with FNAM Article 8(7), renewable energy targets for the assessment were derived from relevant national policy commitments. For Northern Ireland, the assessment adopts the target set out in the CCA that "at least 80% of electricity consumption is from renewable sources by 2030", which serves as the primary reference point for the analysis. As no equivalent statutory target is defined for 2033, an intermediate RES-E target of 86.9%[22] was assumed by SONI for the purposes of the assessment, providing a continuous trajectory of renewable electricity deployment across the study period in line with Articles 8(7) and 8(8) of the FNAM.

The targets adopted reflect established national policy objectives and are aligned with the assumptions underpinning system planning and modelling exercises undertaken by the TSO and DSO. Their selection ensures consistency with both regulatory frameworks and broader decarbonisation ambitions, providing an appropriate basis for assessing flexibility needs within the FNA.

21 SONI AIRAA Main Report 2026-2035 | SONI

22 To note, the 2033 RES-E target (86.9%) was interpolated by SONI using the CCA targets and an assumed 2040 target aligned with Ireland's NECP, as no 2040 target is specified in the CCA

3.3 Portfolio of flexibility resources available

3.3.1 Transmission level

At the transmission level, the model incorporates the following sources of non-fossil flexibility in Northern Ireland as outlined in the AIRAA report and data workbook:

- **Demand-side units:** 61.1 MW, with an associated marginal cost of €505/MWh[23].
- **BESS:** 241.1 MW of capacity, with an energy storage volume of 221.9 MWh is modelled for 2030 and 2033.
- **Interconnection capacity:**
  - **Existing North-South tie-line:** 300 MW export to Ireland and 200 MW import from Ireland.
  - **North-South Interconnector:** 900 MW export to Ireland and 950 MW import from Ireland, commissioning from 1 October 2031.
  - **Moyle Interconnector:** 500 MW capacity in both directions.

3.3.2 Distribution level

At the distribution level, the following resources are connected to the distribution network and have the potential to contribute to meeting flexibility needs, subject to technical compliance and cost-effectiveness. Total figures reflect the overall capacity available.

- DSR: 14.85 MW, including demand turn-down response and non-fossil generation currently registered on the Piclo platform.

3.4 Other assumptions

All assumptions applied in the FNA model are derived from the latest AIRAA model, subject to a number of adjustments to better reflect the requirements of the FNAM. For example, BESS are assumed to operate with a constant efficiency of 80%, with degradation not taken into account and with maximum and minimum state-of-charge limits of 90% and 10% respectively.

The principal changes made to the input assumptions were as follows:

23 AIRAA-2026-2035_DataWorkbook.xlsx

- **Reserve provision:** In the AIRAA model, FCR and FRR were provided only by BESS and generators respectively. In the FNA model, both generators and BESS can provide either service. Additional parameters relating to response time and delivery duration were also introduced to ensure a more realistic optimisation of reserve provision, based on the operational characteristics of each resource according to ENTSO-E[24], including ramp rates and available energy. Specifically, FCR and FRR were modelled with durations of 15 minutes and 30 minutes, respectively. Consistent with the ENTSO-E System Operation Guideline, FCR was assumed to respond within 30 seconds, while FRR was assumed to be fully activated within 15 minutes.

- **Value of reserve shortfall:** The value of reserve shortfall was reduced to €3,750/MWh, below the value of lost load, to ensure that the model prioritises serving demand over meeting reserve requirements.

- **Generator parameters:** Generator characteristics, including but not limited to ramp rates, start-up and shutdown times, and minimum up and down times, were updated using PEMMDB and ERAA data (see Section 2).

- **Operational limits:** Operational limits on generators KGT6 and KGT7 were removed.

- **Interconnector ramp rates:** The ramp rate for the Celtic Interconnector was limited to 400 MW/hour, while the combined ramp rate for the GB interconnectors was limited to 300 MW/hour.

- **Operational Policy Roadmap[25] constraints:** Additional operational constraints were introduced in line with the Operational Policy Roadmap, including:
    - an inertia constraint requiring a minimum of 23,000 MWs across the SEM;
    - SNSP targets of 85% for 2027-2028, 90% for 2029, 95% for 2030, and 100% for 2035, with linear interpolation between 2030 and 2035 resulting in a value of 98% for 2033; and
    - minimum-units-running constraints for Northern Ireland and Ireland, together with voltage constraints for Dublin. The Operational Policy Roadmap specifies all-island minimum-units-running values of 5 for 2028, 3 for 2030, 2 for 2032 and 0 from 2035 onwards.

24 Response times and durations were derived from the ENTSO-E System Operation Guideline (Commission Regulation (EU) 2017/1485). FCR is required to be fully activated within 30 seconds (Article 154), with a full activation period of 15 minutes (Article 156), while FRR is required to be activated within 15 minutes (Articles 157 and 158, including Table 2) and sustained for 30 minutes. Available at: ENTSO-E System Operation Guideline

25 SONI and EirGrid, Operational Policy Roadmap 2025-2035, March 2025, available at: Operational Policy Roadmap 2025–2035

- **Alignment with the ECP model:** To improve consistency with the ECP model:
    - the variable operation and maintenance (VO&M) costs of thermal generation were increased using the “EVA” scenario within the AIRAA model to better align expected import and export flows;
    - the VO&M costs of wind and solar generation in the SEM were increased from €0/MWh to €1/MWh for the same purpose; and
    - North-South transfer capability was restricted to 300 MW export to Ireland and 200 MW import from Ireland.
- **Short-term flexibility representation:** Additional reserve objects were introduced to approximate real-time redispatch arising from load and wind/solar forecast errors, consistent with the requirements of Article 10 relating to short-term flexibility needs.

4. Results of Flexibility Needs Assessment

This chapter presents the results of the FNA undertaken in accordance with Articles 8-12 and 16 of the FNAM. It assesses system-wide and network flexibility needs across relevant timescales and considers the role of non-fossil flexibility resources in supporting renewable integration.

All figures presented in this report are specific to Northern Ireland and do not represent all-island results. The figures present curtailment as a percentage of available VRES generation rather than installed capacity. Consequently, a higher curtailment percentage in a given month does not necessarily imply a higher quantity of curtailed energy, but rather that a larger share of the renewable generation available during that month is curtailed.

It should be noted that curtailment is affected by net interchange between Northern Ireland and neighbouring jurisdictions. Since net interchange is influenced by relative market prices, periods of net import may be associated with higher curtailment levels, particularly during times of elevated VRES output. While interconnection is broadly considered beneficial to system operation, the extent of any curtailment reduction may depend on future price differentials between Northern Ireland and neighbouring markets.

4.1 System-wide flexibility needs

Flexibility needs depend on the rate of renewable build-out, timely network delivery and balancing costs against renewable targets. Uncovered needs are clear when national perspectives on climate targets are included in complement to the ACER base methodology. Low-carbon flexibility has the potential to reduce reliance on fossil-fuelled generation while supporting system security. SONI suggests that Northern Ireland's first FNA identifies a flexibility requirement of approximately 4,800 MWh from 2030, approximately 20% within-day flexibility.

The assessment of system-wide flexibility needs across hourly, daily and seasonal timeframes indicates that, under the FNAM, the identified needs are covered and no uncovered system-wide flexibility needs arise in the Base scenario. This outcome reflects that RES availability penetration in the Base scenario remains below the national climate target and therefore does not result in an uncovered flexibility gap, as defined by the FNAM.

However, the temporal analysis shows that flexibility requirements are nonetheless significant across all relevant timeframes. Curtailment and residual load variation are more volatile at shorter time intervals, while longer timeframes exhibit lower variation but larger cumulative energy volumes, implying a need for resources capable of addressing both power and energy requirements.

In summary:

- Curtailment associated with surplus VRES and operational constraints occurs for 1,176-1,434 hours across weather scenarios in 2030, increasing to 1,835-2,209 hours in 2033.

- All weather scenarios exhibit curtailment in every month of the year, indicating that curtailment is not limited to specific seasonal conditions.

- Curtailment volumes from surplus VRES and operational constraints increase over time from approximately 463-534 GWh in 2030 to 947-1,152 GWh in 2033.

- These results suggest that flexibility plays an increasingly important role in reducing curtailment and maximising renewable energy utilisation as renewable penetration increases.

- In 2030, transmission constraints are the primary driver of curtailment, highlighting the importance of network reinforcement and expansion.

- When all sources of curtailment, including transmission constraints, are considered, curtailment occurs for 4,358-4,475 hours in 2030, rising to 5,872-6,035 hours in 2033 across weather scenarios.

- Total curtailed energy volumes increase from approximately 1,175-1,299 GWh in 2030 to 1,813-2,093 GWh in 2033.

Overall, the results indicate that major drivers of curtailment surplus and operational constraints are increasing between 2030 and 2033, reinforcing the importance of additional flexibility to facilitate higher levels of renewable generation. Network reinforcement remains a main driver of curtailment in both 2030 and 2033.

4.1.1 RES Integration

The assessment of RES integration needs in the Base scenario, as shown in Table 5, indicates that Northern Ireland does not have uncovered RES integration needs, as defined by the FNAM. This reflects that available VRES penetration remains below the national climate target in the absence of curtailment. In 2030, the available VRES as a share of total generation in the Base scenario ranges from 56.8% to 57.9%, against an 80% target.

In 2033, the equivalent range is 64.2% to 65.7%, against an 86.9% target. By contrast, the High-RES scenario shows available VRES penetration of 101.6% to 103.0% in 2030 and 108.1% to 110.0% in 2033, indicating that sufficient renewable capacity would enable the target to be exceeded, assuming sufficient reduction in curtailment could be achieved.

Table 5: Article 16.6.2- Available VRES % penetration of total electricity requirement in Base and High-RES scenarios

	Available RES, % of Total Electricity Requirement, RES Gen / (Total Gen + Import - Export) (assuming no curtailment)		
Scenario	**NI Base**	**NI High-RES**	**RES Target**
2030, WS 4	57.9	103.0	80
2030, WS 28	56.8	101.6	80
2030, WS 34	57.7	102.8	80
2033, WS 4	65.7	110.0	86.9
2033, WS 28	64.2	108.1	86.9
2033, WS 34	65.4	109.7	86.9

Characterisation of residual load time series

The residual load indicators, as presented in Table 6, show that variability persists across hourly, daily and seasonal timeframes, however, the nature of the flexibility requirement evolves with increasing duration. The FNAM defines residual load indicators as follows:

- **Hourly Indicator:** indicates how much residual load variation is expected between the next hour and the hourly average of the past day, calculated as the sum of absolute variations between the hourly residual load and its daily average.
- **Daily Indicator:** indicates how much residual load variation is expected between the next day and the daily average of the past week, calculated as the sum of absolute variations between the daily residual load and the weekly average.
- **Seasonal Indicator:** indicates how much residual load variation is expected between the next month and the monthly average of the past year calculated as the sum of absolute variations between the monthly residual load and the annual average:
    - In WS28 2030, the residual load indicators are 1,917 GWh on an hourly basis, 1,687 GWh on a daily basis and 1,005 GWh on a seasonal basis.

- In WS28 2033, the corresponding indicators are 1,744 GWh, 1,805 GWh and 1,037 GWh. The average variation metrics likewise indicate continuing system variability across all timeframes.

These results suggest that shorter time periods are associated with greater variation, whereas longer periods show smoother profiles but larger cumulative energy requirements over the duration of the event. Accordingly, the flexibility challenge is not limited to short-duration balancing but also includes sustained energy-shifting requirements over longer periods.

Table 6: Article 8.5.2- Residual load time series: hourly, daily and seasonal indicators

Scenario	Indicator	Sum (GWh)
WS28, 2030	Hourly	1,917
	Daily	1,687
	Seasonal	1,005
WS28, 2033	Hourly	1,744
	Daily	1,805
	Seasonal	1,037

Table 7 presents the residual load variation indicators, showing average hourly, daily and seasonal variability. These indicators illustrate the expected change in residual load over different time horizons.

An hourly average indicator value of 0.22 GWh indicates that, on average, the residual load in the next hour is expected to deviate by approximately 0.22 GWh from the average hourly residual load of the preceding day. By comparison, the seasonal average indicator value of 83.79 GWh demonstrates that although seasonal variability occurs less frequently (with a seasonal indicator value of 1,005 compared to an hourly indicator value of 1,917), the magnitude of the variation is significantly greater. Consequently, a substantially larger volume of storage is required to manage seasonal variability due to the longer timescales over which these fluctuations occur.

Table 7: Article 8.5.3- Residual load variation as an average: hourly, daily and seasonal indicators

Scenario	Indicator	Sum (GWh)
WS28, 2030	Hourly average of hourly indicator	0.22
	Daily average of daily indicator	4.62
	Seasonal average of seasonal indicator	83.79
WS28, 2033	Hourly average of hourly indicator	0.2
	Daily average of daily indicator	4.9
	Seasonal average of seasonal indicator	86.40

Characterisation of RES generation curtailment

Annual hourly RES curtailment profile

The RES curtailment analysis illustrated in Figure 1 and Figure 2 indicates that curtailment varies significantly by week and month, making it difficult for any single flexibility solution to achieve high utilisation consistently throughout the year. Curtailment is often observed at levels exceeding 50%, especially between October and March, when curtailment is consistently positive for many days at a time, indicating a greater requirement for energy flexibility. Even within months of less curtailment, high levels of instantaneous curtailment are reached, suggesting that power flexibility will always be required.

Further, curtailment worsens over time, with total curtailment increasing in the Base Scenario from approximately 29.8-31.2% in 2030 to 34.7-37.9% in 2033 across the modelled weather scenarios.

The figures presented throughout this chapter are based on the WS28, providing a consistent basis for comparison. However, the results were broadly similar across the three weather scenarios, with only limited variation.

Figure 1: Article 8.1.1- RES generation curtailment time series, hourly percentage throughout the year (WS28, 2030)

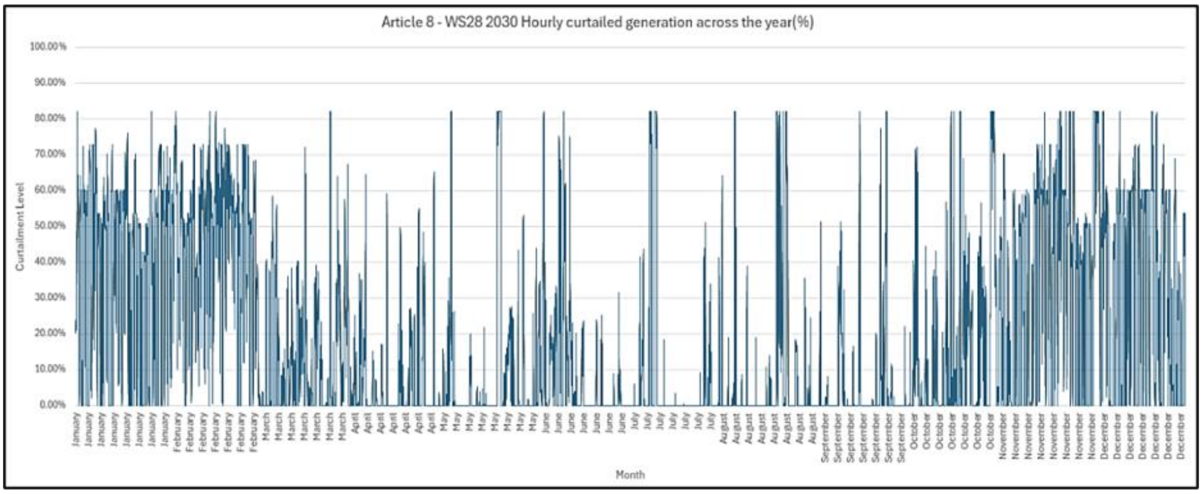
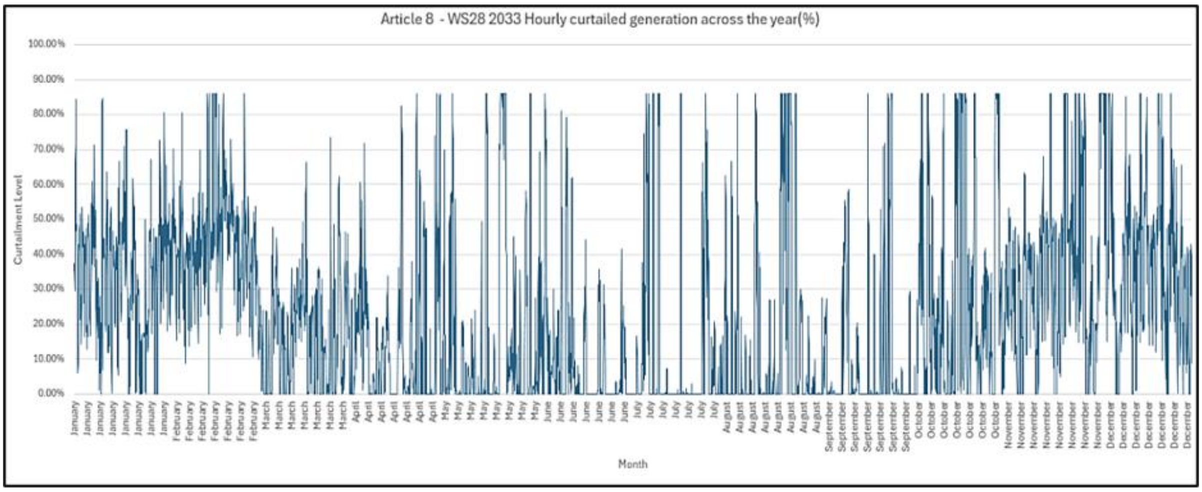


Figure 2: Article 8.1.1- RES generation curtailment time series, hourly percentage throughout the year (WS28, 2033)



RES generation actual curtailment distribution

Figure 3 and Figure 4 illustrate the distribution of hourly curtailment percentages, as requested under the FNAM. They show that a large proportion of hours fall within the 0-1% curtailment range. This suggests that, during many hours of the year, a storage asset dedicated solely to reducing curtailment would have little or no charging requirement. The results therefore highlight that storage can provide value beyond curtailment reduction and may be available to support a range of other system services for much of the time.

Figure 3: Article 8.1.3- RES generation actual curtailment distribution chart (WS28, 2030)

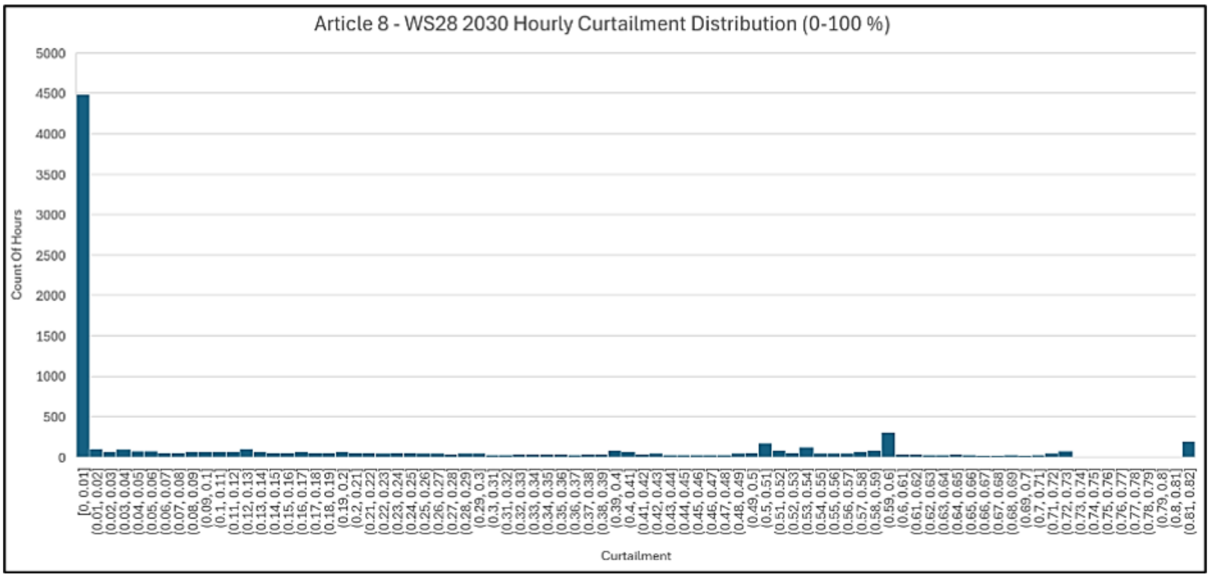
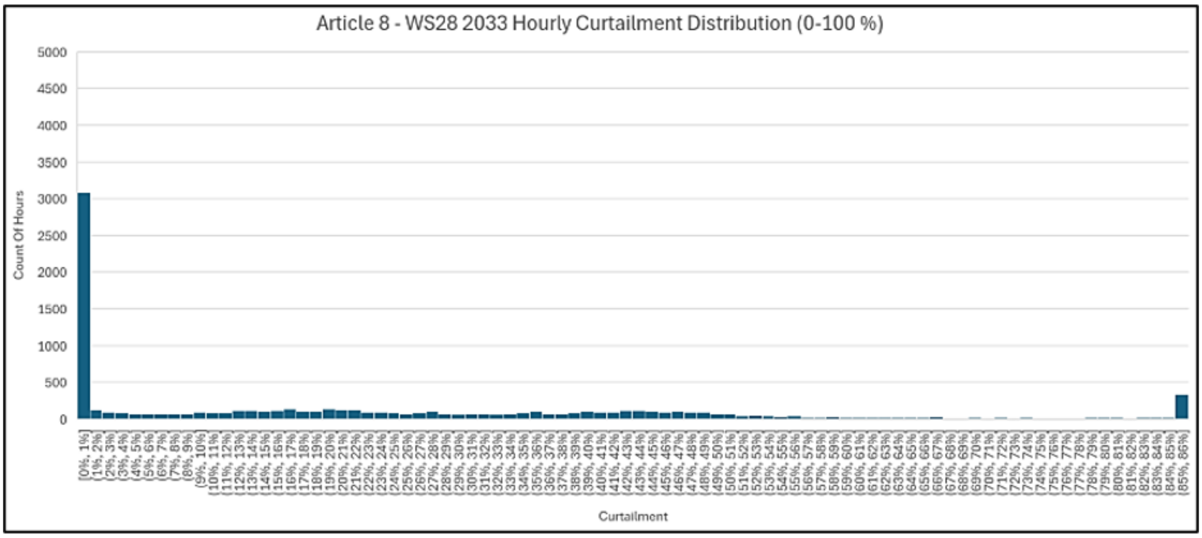


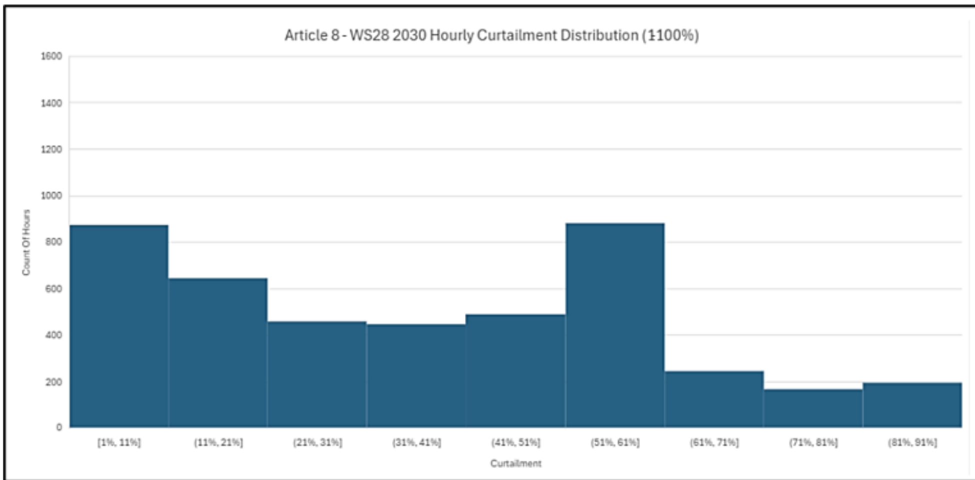
Figure 4: Article 8.1.3- RES generation actual curtailment distribution chart (WS28, 2033)



RES generation curtailment distribution

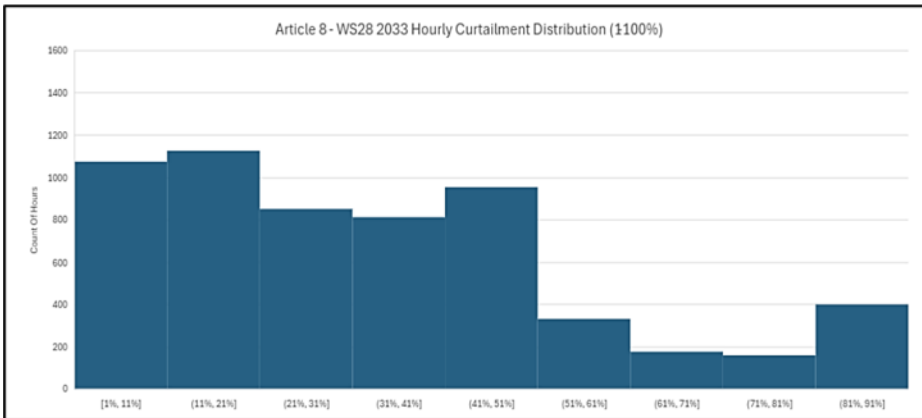
Figure 5 and Figure 6 present the distribution of curtailment after excluding the 0-1% curtailment bin, enabling a clearer view of the hours in which curtailment occurs. The charts show the proportion of time that curtailment falls within different percentage ranges, providing insight into both the frequency and magnitude of curtailment events. This helps illustrate how often a storage asset dedicated to reducing curtailment could be utilised and the scale of curtailment it would be required to address.

Figure 5: Article 8.1.2a- RES generation curtailment distribution chart (hourly) (WS28, 2030)



Curtailment	Probability
<1%	49.6%
1%-11%	10.0%
11%-20%	7.4%
20%-30%	5.3%
30%-40%	5.1%
40%-49%	5.6%
50%-100%	17.1%

Figure 6: Article 8.1.2a- RES generation curtailment distribution chart hourly (WS28, 2033)



Curtailment	Probability
<1%	32.6%
1%-11%	12.3%
11%-20%	12.9%
20%-30%	9.7%
30%-40%	9.3%
40%-49%	10.9%
50%-100%	12.2%

Weekly, monthly and annual RES curtailment

Figure 7 and Figure 8 show limited variation between the modelled weather scenarios. Curtailment occurs throughout the year, with all scenarios exhibiting curtailment in each month, though it is most pronounced during the winter and shoulder months (spring and autumn). This reflects periods when renewable generation is high relative to demand and highlights the need for flexibility solutions capable of addressing both short-term power imbalances and larger, sustained energy surpluses.

Figure 7 and Figure 8 illustrate how curtailment varies across different timescales. The solid lines show the proportion of available renewable generation that is curtailed over weekly and monthly periods. For example, the monthly series indicates that some curtailment occurs in every month, while the weekly series shows that only two weeks in 2030 experience no curtailment. Weekly curtailment can also reach approximately 50% of available VRES output, implying a requirement for significant energy flexibility. This variation in curtailment over time presents a challenge and may benefit from long-duration weekly/seasonal flexibility.

The dashed lines represent maximum curtailment levels and provide an indication of the power capacity required from flexibility resources. These peaks vary considerably over time, highlighting that both the energy and power requirements of flexibility are likely to fluctuate throughout the year.

In summary, these charts illustrate both the duration and scale of future flexibility needs relative to available renewable generation. By 2033, both the volume and variability of curtailment increase, suggesting a growing need for greater flexibility.

Figure 7: Article 8.4.1- Weekly, monthly and annual curtailment generation (average, maximum and minimum values) (WS28, 2030)

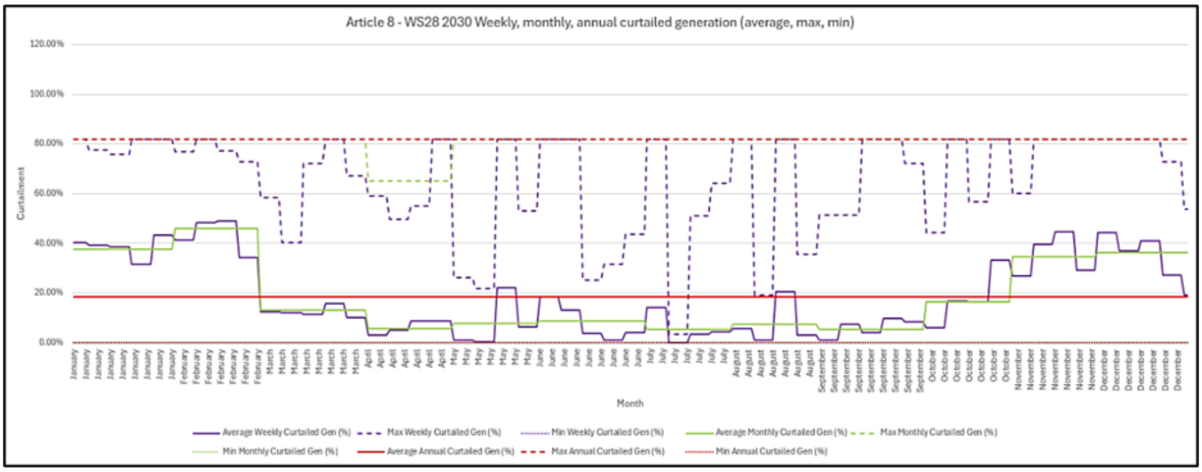
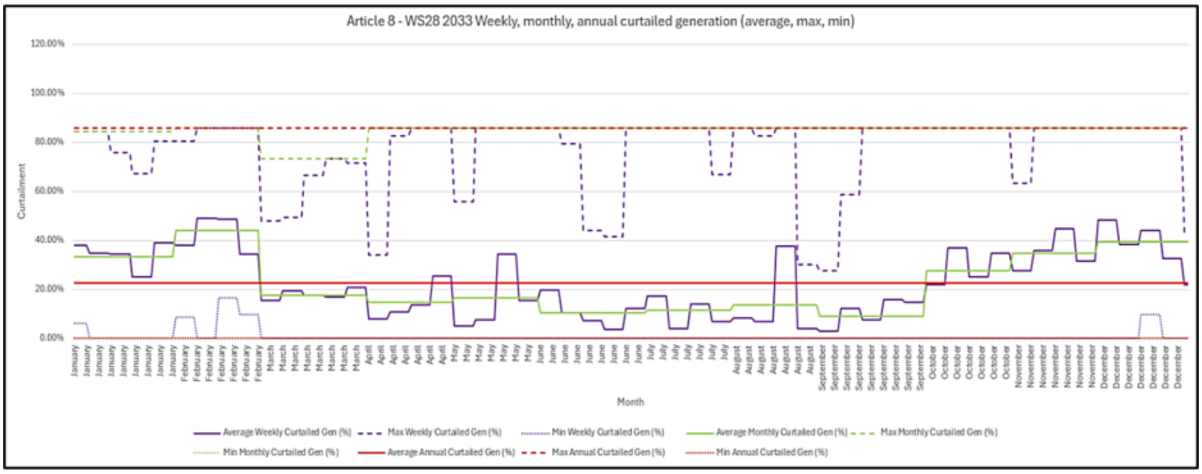


Figure 8: Article 8.4.1- Weekly, monthly and annual curtailment generation (average, maximum and minimum values) (WS28, 2033)



Average hourly RES curtailment

The average hourly curtailment profile exhibits a dual-peaking pattern and is partially inversely correlated with residual load. Figure 9 and Figure 10 show that the overall shape of the curtailment profile remains broadly consistent over time; however, the 2033 profile is significantly elevated, indicating higher levels of curtailment throughout the year. This suggests that increases in wind and solar generation, together with growing demand, largely preserve the underlying temporal pattern of curtailment, while the greater volume of renewable generation results in larger quantities of curtailed energy.

Figure 9: Article 8.4.2- Average hourly curtailment for the year (WS28, 2030)

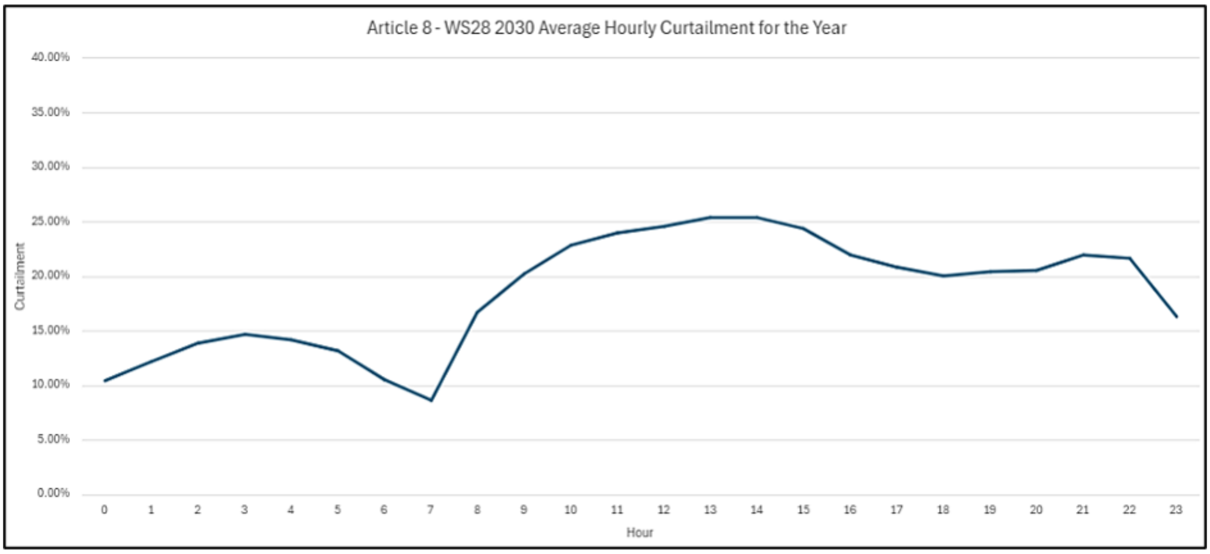
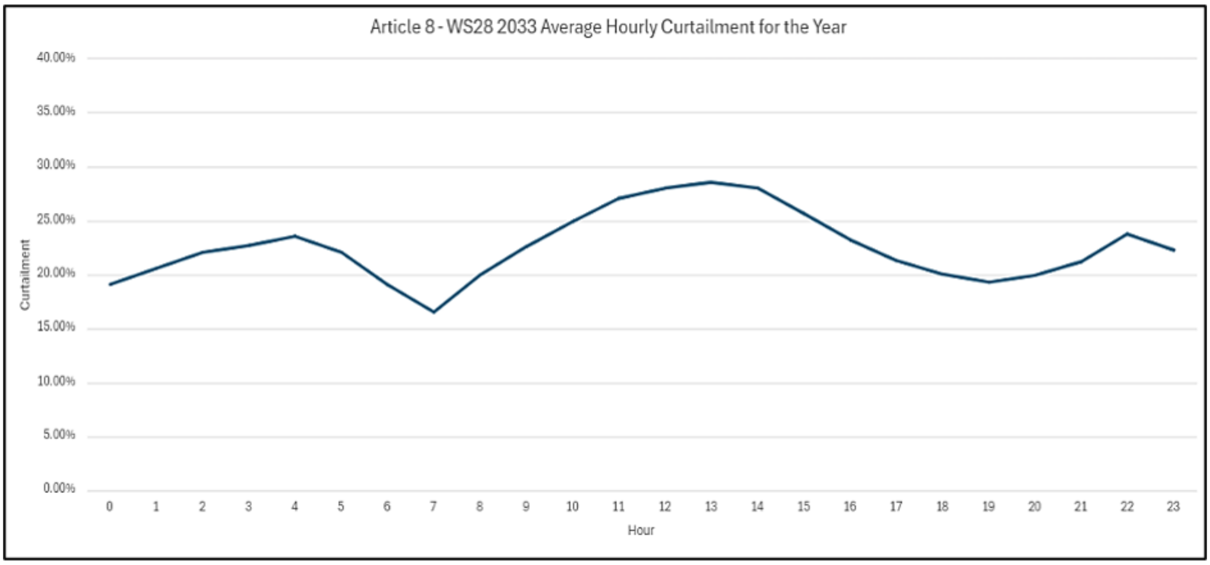


Figure 10: Article 8.4.2- Average hourly curtailment for the year (WS28, 2033)



Seasonal profile of RES curtailment

Figure 11 and Figure 12 show that, in 2030, curtailment during the winter months is concentrated within a relatively flat period spanning the afternoon and evening hours. By 2033, however, curtailment is more evenly distributed across the full 24-hour period. This illustrates how the temporal profile of curtailment evolves over time and varies by month as the generation mix and system conditions change.

These charts further illustrate the challenge of addressing curtailment using flexibility technologies that are primarily suited to within-day energy shifting. First, they highlight the significant variation in total curtailment between months, consistent with the patterns observed in Figure 7 and Figure 8, suggesting a need for flexibility solutions capable of shifting energy across longer timescales. Second, they show that the hourly profile of curtailment varies considerably by month and evolves over time, potentially affecting the utilisation and value of within-day storage technologies.

February and September 2030 provide a useful illustration. In February, both the quantity and day-to-day variability of curtailment are relatively high, suggesting that within-day storage technologies, such as four-hour BESS, would not saturate and have value in arbitrage. In contrast, September exhibits lower levels of curtailment and less variability, indicating more limited opportunities for within-day flexibility.

By 2033, while total curtailment in February remains elevated, the average daily curtailment profile becomes flatter. This suggests that a greater proportion of curtailment occurs over extended periods, potentially reducing the relative contribution of within-day flexibility solutions alone. In summary, monthly flexibility will be important to reduce curtailment.

Figure 11: Article 8.4.3- Average hourly curtailment per month (WS28, 2030)

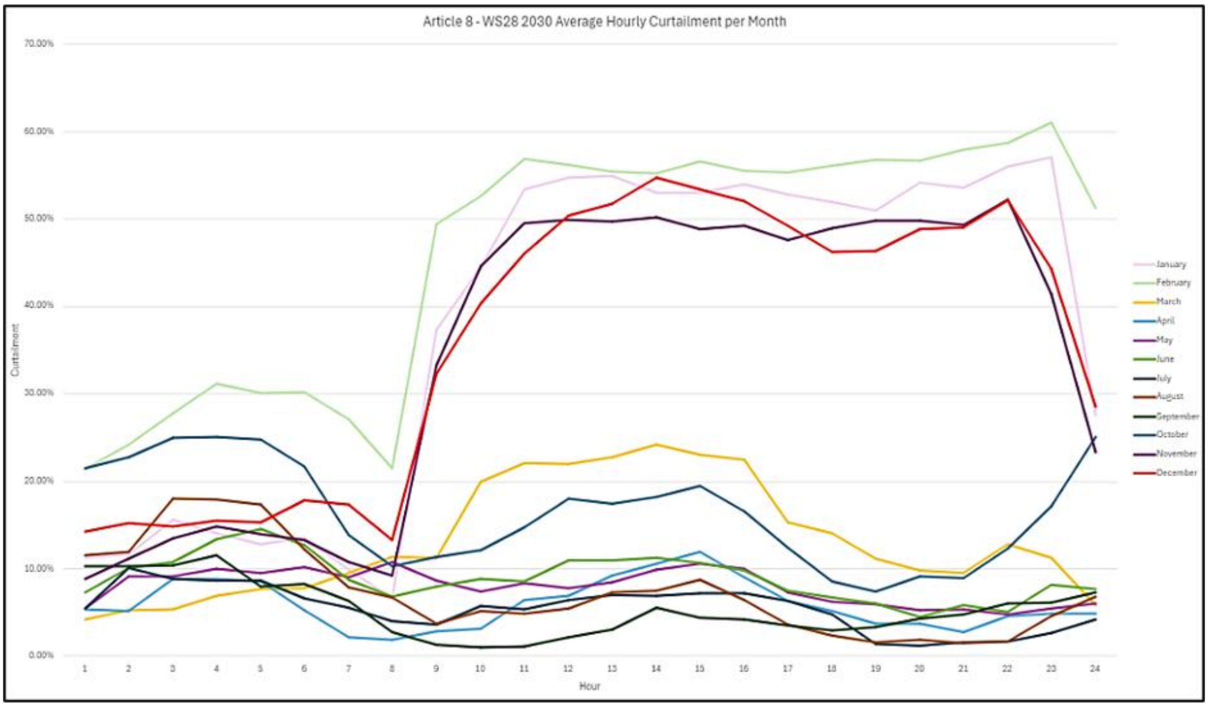
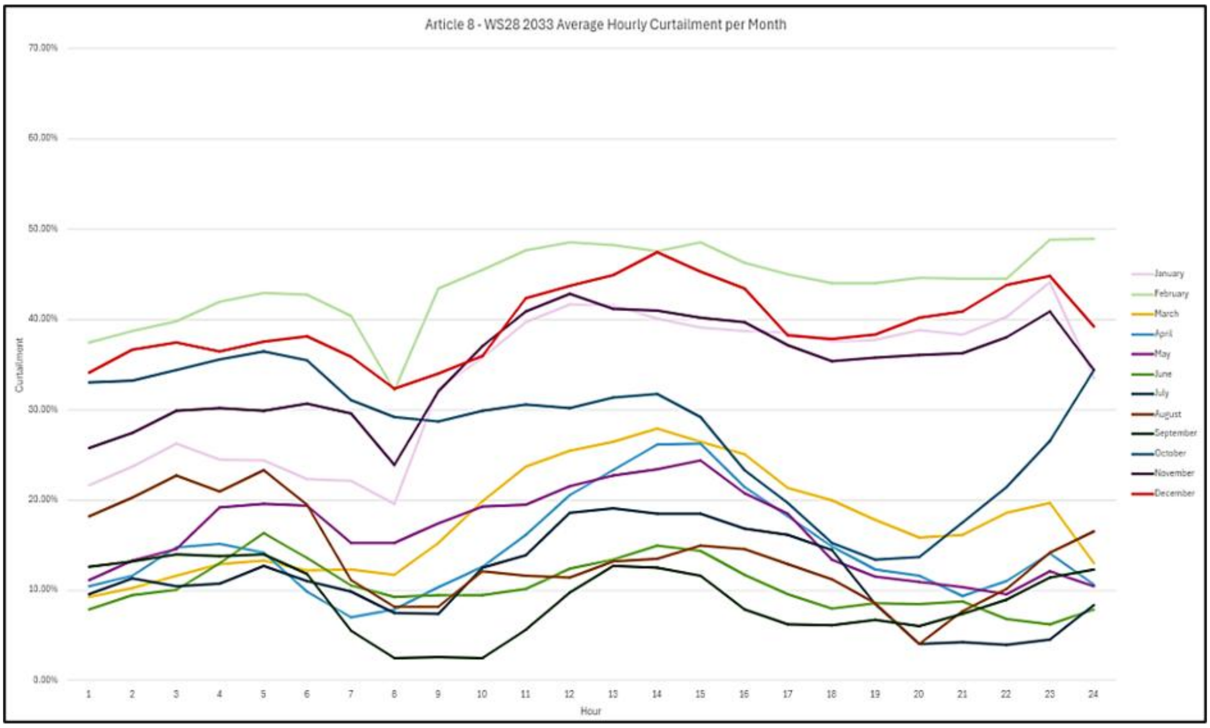


Figure 12: Article 8.4.3- Average hourly curtailment per month (WS28, 2033)



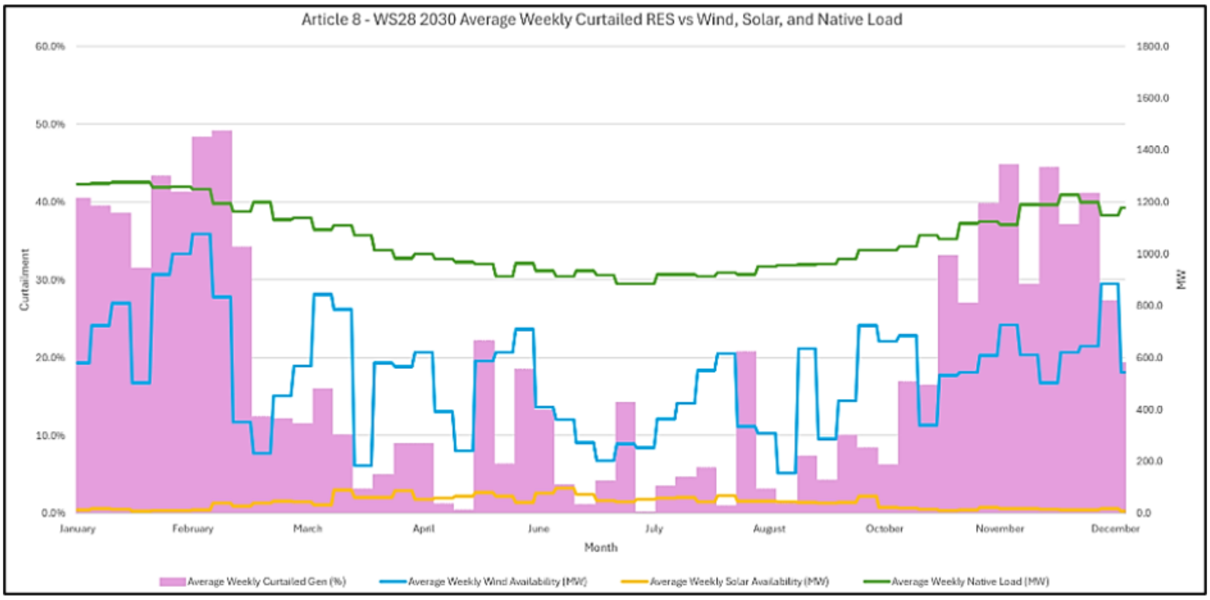
Correlation between weekly RES curtailment, wind, solar and native load

Figure 13 does not indicate a clear visual correlation between curtailment and demand, wind generation or solar generation. Wind generation accounts for the majority of renewable output, while solar generation is relatively small in comparison. As a result, total renewable output remains highly variable across the year, largely reflecting changes in wind generation.

In the Base case for 2030, a large proportion of curtailment arises from transmission constraints, the extent of which is strongly influenced by transmission outages. During outage periods, renewable generation in affected areas may be curtailed for prolonged durations. As these events are location-specific, the resulting curtailment is not necessarily correlated with system-wide variables such as wind generation, solar generation or load.

Curtailment is also influenced by net interchange between Northern Ireland and neighbouring jurisdictions, particularly during periods of high VRES output. Net interchange is driven by relative market prices, which determine the extent to which surplus renewable generation can be exported. Consequently, when wind and solar generation are high in Northern Ireland, curtailment levels may be sensitive to price differentials with neighbouring markets. Higher renewable output in neighbouring jurisdictions can reduce export opportunities and increase the likelihood of curtailment occurring within Northern Ireland.

Figure 13: Article 8.4.4- Average weekly curtailed RES vs wind, solar, native load (WS28, 2030)



Correlation distribution- wind, solar, native load and curtailed generation

Figure 14 to Figure 17 examine the relationship between curtailment and wind generation, solar generation and load. The analysis was repeated excluding hours with zero curtailment, allowing the distribution of positive curtailment events to be assessed more clearly. This highlights trends that are less apparent when all hours are included.

The graphs indicate that curtailment is more strongly correlated with wind generation than with solar generation, suggesting that variations in wind output are a more significant driver of annual curtailment levels. However, when the analysis is restricted to periods in which curtailment occurs, the correlation between solar generation and curtailment increases substantially. This indicates that, during a day when curtailment will occur, the hourly curtailment is more likely to coincide with periods of solar generation, even though solar output is a less significant driver of overall curtailment across the year.

- **Wind and curtailed generation**

Wind generation, solar generation and load are all forecast for system management. Examining the correlation between these variables and curtailment provides an indication of the extent to which curtailment may be explained, and potentially anticipated, by underlying system conditions. For example, a strong positive correlation between wind generation and curtailment would suggest that periods of higher wind output are generally associated with higher levels of curtailment.

The correlation coefficient ranges from -1 to 1, where:

- **-1** indicates a perfect negative correlation, meaning that as one variable increases, the other decreases (e.g. higher demand is always associated with lower curtailment).
- **0** indicates no correlation, meaning there is no consistent relationship between the variables (e.g. solar generation provides no indication of the level of curtailment).
- **1** indicates a perfect positive correlation, meaning that both variables move together (e.g. higher wind generation is always associated with higher curtailment).

Figure 14 illustrates that the relationship between wind generation and curtailment is relatively weak for much of the year. For just over 70 days, the correlation between the two variables is close to zero, indicating that wind output provides little information on the level of curtailment expected. In contrast, only around 50 days exhibit a strong positive correlation (greater than 0.83), where higher wind generation is consistently associated with higher levels of curtailment.

This result is largely driven by the significant contribution of transmission-related curtailment in 2030. Curtailment associated with transmission outages can persist for extended periods and is determined primarily by local network conditions rather than system-wide variables such as wind generation, solar generation or demand. As a result, a substantial proportion of curtailment in 2030 is not strongly linked to wind output.

By contrast, curtailment arising from renewable energy surpluses or system constraints is more likely to be positively correlated with wind generation. This effect becomes more apparent in 2033, when curtailment associated with transmission constraints remains broadly unchanged while curtailment driven by renewable energy surpluses and system constraints increases. Consequently, the results presented in Figure 15 show a stronger relationship between wind generation and curtailment than those in Figure 14.

This reflects the increasing influence of wind output on curtailment as renewable penetration grows. The trend is consistent with expectations as additional renewable capacity is connected to the system and would be expected to become more pronounced under higher intermittent renewable deployment scenarios.

Figure 14: Article 8.4.5a- Correlation distribution wind vs curtailed generation (WS28, 2030)

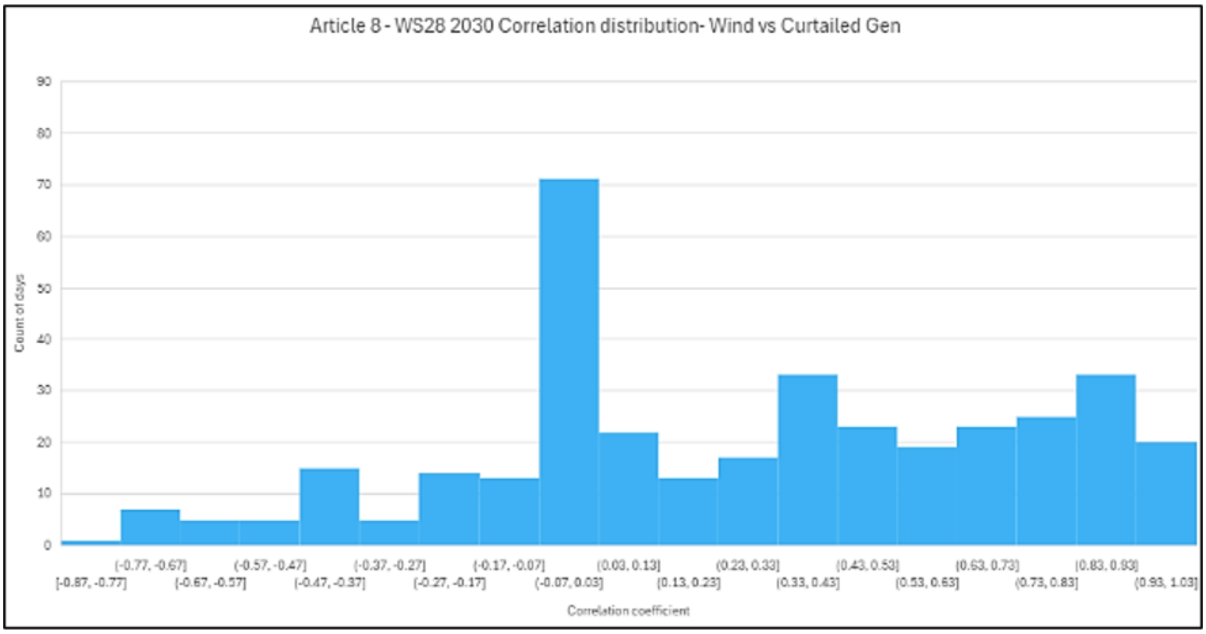
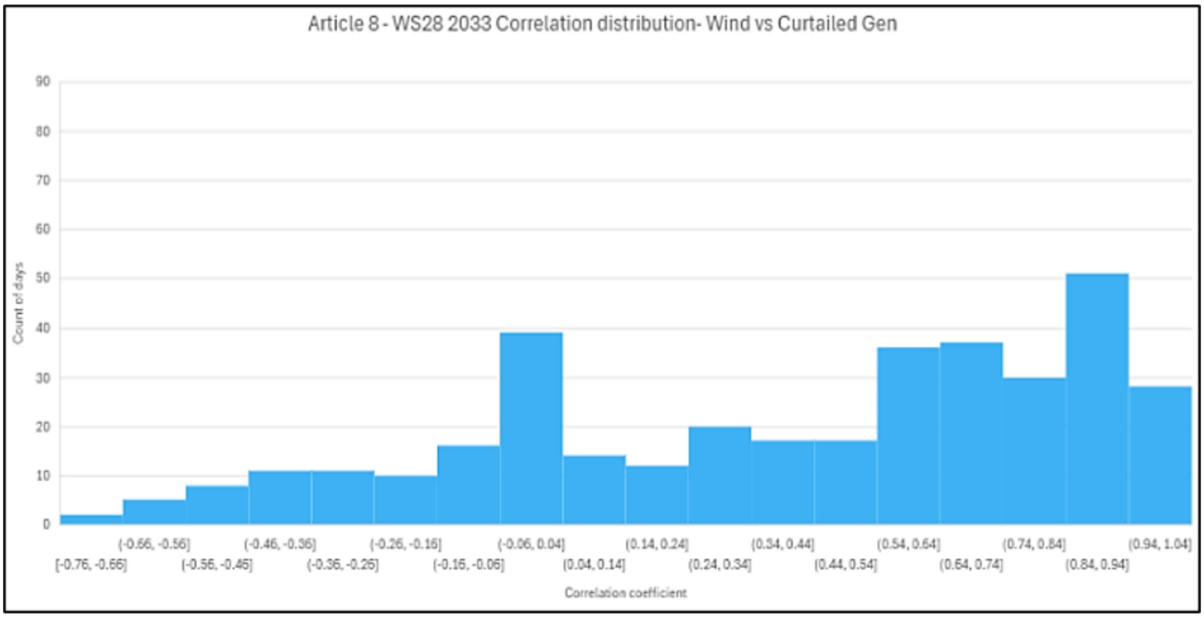


Figure 15: Article 8.4.5a- Correlation distribution wind vs curtailed generation (WS28, 2033)

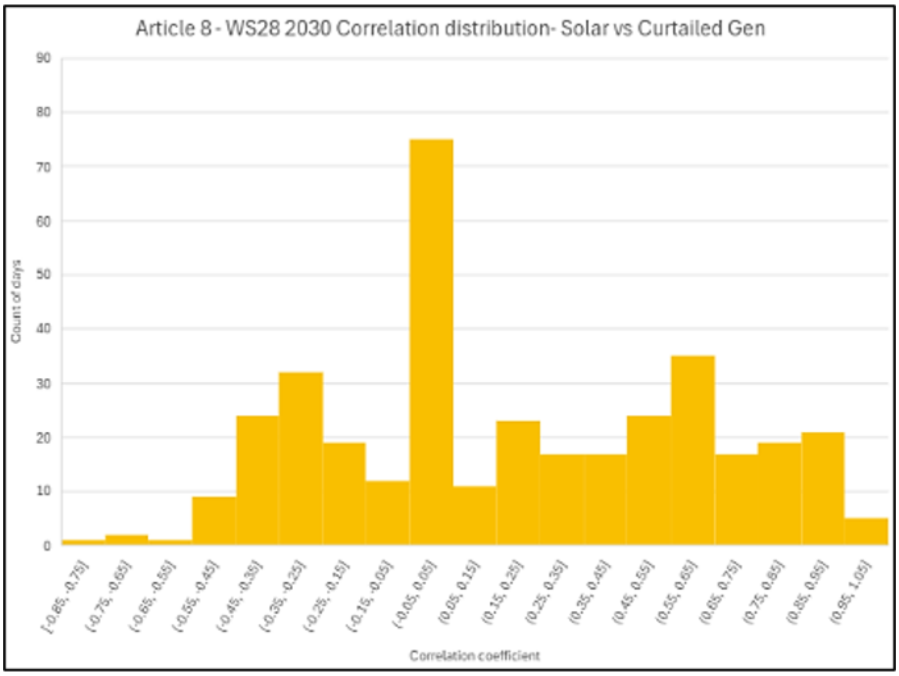


- **Solar and curtailed generation**

The relationship between solar generation and curtailment is shown in Figure 16. Compared with wind generation, there are fewer days with a strong positive correlation between solar output and curtailment. This is expected given that wind generation represents a substantially larger share of renewable generation in Northern Ireland than solar generation.

The results for 2033 are broadly similar, indicating that solar generation remains a relatively weak predictor of curtailment. This suggests that forecasts of solar output alone are unlikely to provide a reliable indication of expected curtailment levels.

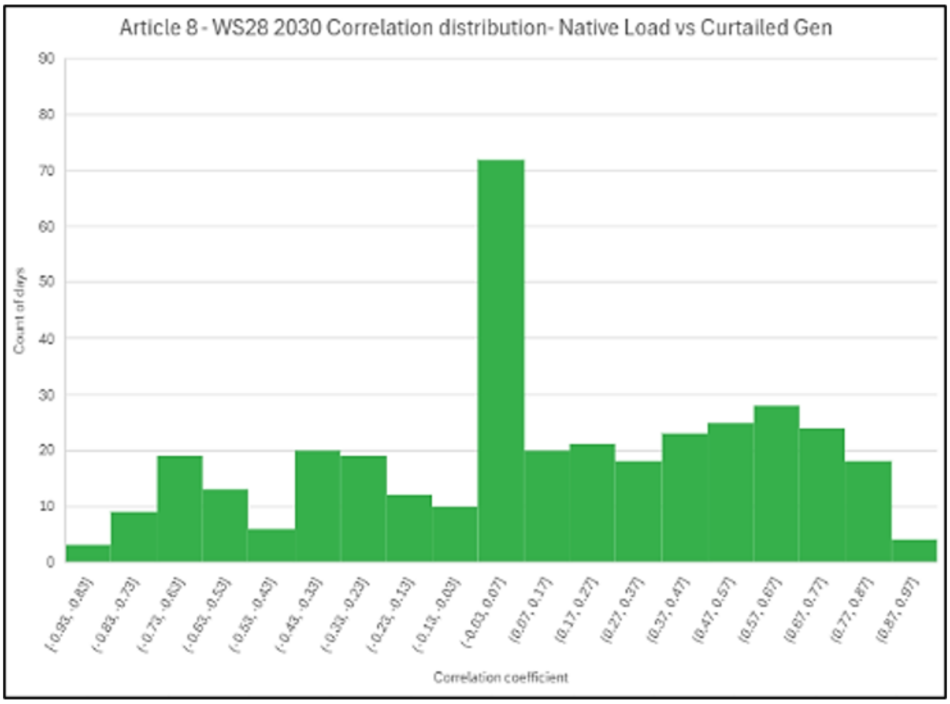
Figure 16: Article 8.4.5b- Solar vs curtailed generation



- **Native load and curtailed generation**

Figure 17 suggests a limited relationship between load and curtailed generation. As a result, load forecasts may have limited value in predicting the level of curtailment that will occur.

Figure 17: Article 8.4.5c- Native load vs curtailed generation



In summary, the results suggest that curtailment is influenced by a range of factors beyond wind generation, solar generation and load. As such, accurately forecasting curtailment is likely to require a more sophisticated approach to capture the range of factors influencing curtailment.

Residual Load Time Series

The FNAM-requested correlation metrics outlined in Table 8 should be interpreted with caution, as the large number of hours with zero curtailment can mask relationships that are evident only during curtailment events. For example, in 2030, native load shows a positive correlation with curtailment when all hours are included, suggesting that higher-load days are associated with higher overall curtailment levels. When the analysis is restricted to periods in which curtailment occurs, however, the relationship becomes negative, indicating that curtailment events tend to coincide with lower-load conditions, consistent with the trends shown in Figure 9 and Figure 10.

Wind generation exhibits a stronger positive correlation with curtailed generation than either solar generation or native load across all timescales and in both study years, indicating that increases in wind output are more likely to contribute to overall curtailment volumes. Wind generation also remains strongly correlated with both the occurrence and magnitude of curtailment, reflecting its significant contribution to renewable surplus conditions throughout the year. However, this should not be interpreted as implying that additional wind generation is less effective than solar generation in contributing towards the national climate target. The relative value of different renewable technologies depends on a range of factors, including generation costs, output profiles and the availability of supporting flexibility resources. Consequently, higher levels of curtailment associated with wind generation do not necessarily imply lower system value, particularly where lower-cost wind deployment enables greater renewable penetration and complementary flexibility investment within the same overall expenditure.

For solar generation, correlations strengthen considerably during curtailment periods. This suggests that high solar output does not necessarily result in curtailment; however, when system conditions give rise to curtailment, the highest levels of curtailment are more likely to coincide with periods of stronger solar generation.

The specific system conditions leading to curtailment were not assessed as part of this correlation analysis and therefore cannot be determined directly from these results. Nevertheless, curtailment is likely influenced by a combination of operational and network factors, including transmission constraints and interconnector flows, with modelling observations indicating that periods of high imports are often associated with increased curtailment.

Table 8: Article 8.5.1- Correlation coefficient- daily, weekly and monthly (WS28, 2030 and 2033)

	2030			2033		
Variable	**Annual average of daily correlation coefficient**	**Annual average of weekly correlation coefficient**	**Annual average of monthly correlation coefficient**	**Annual average of daily correlation coefficient**	**Annual average of weekly correlation coefficient**	**Annual average of monthly correlation coefficient**
Wind vs curtailed generation	0.66	0.54	0.58	0.75	0.67	0.70
Solar vs curtailed generation	-0.02	0.15	0.14	0.03	0.16	0.15
Native load vs curtailed generation	0.30	0.05	0.04	0.17	-0.02	-0.03

Uncovered needs

As illustrated in Table 5, there are no uncovered RES integration needs in the Base scenario. Under Article 8 of the FNAM, an uncovered RES integration need is identified only where RES curtailment exceeds the maximum level compatible with the renewable energy target and sufficient RES capacity is available to meet the target.

However, this should not be interpreted as meaning that flexibility is unnecessary. The High-RES results show that, where sufficient renewable capacity is assumed, curtailment becomes even larger, indicating that available renewable energy cannot always be fully utilised by the system. High levels of curtailment are a clear signal of the need for additional flexibility, as they reflect periods when renewable generation exceeds the system's ability to absorb or use it effectively.

Flexibility resources, such as energy storage and DSR, can help reduce curtailment by shifting energy across time and increasing the utilisation of renewable generation. As intermittent renewable deployment increases, flexibility therefore becomes increasingly important in minimising curtailment, maximising the value of renewable energy and supporting the efficient integration of higher levels of RES onto the system.

Flexible resources

As no uncovered RES integration needs arise in the Base scenario due to insufficient projected RES capacity to meet targets, no additional flexibility resources are required to meet uncovered needs as defined by the FNAM, and consequently the Article 8 analysis does not quantify further flexibility requirements under Articles 8(11) and 8(12). The supplementary High-RES and Article 16 analyses provide additional insight into potential flexibility requirements under higher intermittent renewable deployment pathways.

Table 1 is divided into two sections. The upper table presents the impact of additional BESS under the Base scenario using AIRAA renewable capacity projections, while the lower table presents the equivalent analysis under the High-RES scenario. The “Expected Case” column represents the expected level of curtailment based on the quantity of BESS assumed within each scenario. It should be noted that additional storage is only used to reduce surplus and operationally constrained curtailment and does not address curtailment arising from transmission constraints.

The benefit of additional storage can be quantified by comparing each scenario against the corresponding Expected case scenario. Within the Base scenario, Short-Duration Energy Storage (SDES) reduces curtailment by 1.7%. Long-Duration Energy Storage (LDES) (8-hour) introduces the same additional power capacity as SDES but provides greater energy capacity, resulting in a larger reduction in curtailment of 4.3%. The LDES (20-hour) scenario adds the same power capacity as the SDES and LDES (8-hour) cases but with further energy capacity, achieving the largest reduction in curtailment analysed, at 5.4%.

The lower table presents the same analysis using the High-RES renewable capacity projections. The overall trends and conclusions remain consistent with those observed in the Base scenario, although the reductions in curtailment are greater. This suggests that higher levels of wind and solar deployment could increase both flexibility requirements and the potential value of additional storage in reducing curtailment. The results also indicate that long-duration flexibility may play an increasingly important role as renewable capacity expands and RES integration targets are approached.

The largest storage configuration assessed was a 20-hour duration system providing 5,044 MWh of flexibility. While this reduced surplus generation and operationally constrained curtailment more effectively than the 8-hour storage case, it did not eliminate surplus generation or operationally constrained curtailment under either the Base or High-RES scenarios.

Table 1 *(reproduced from Executive Summary):* Article 16.6- Impact of varying storage durations on RES curtailment in Base and High-RES scenarios (WS28, 2030 and 2033)

	Base				
WS28, 2030	**Expected Case**	**SDES**	**LDES (8-hour)[26]**	**LDES (20-hour)**	**SDES & LDES**
Storage Capacity (MW)	241	482	482	482	723
Storage Capacity (MWh)	222	444	2,151	5,044	2,373
Annual Surplus + Operationally Constrained Curtailment (%)	9.1	7.4	4.8	3.7	4.2
Annual ECP Transmission Constraint Curtailment (%)	20.8	20.8	20.8	20.8	20.8
Annual Total Curtailment (%)	**30.0**	**28.2**	**25.6**	**24.5**	**25.0**
Annual Surplus + Operationally Constrained Curtailment (GWh)	465.29	377.7	242.41	185.81	215.25
	High-RES				
WS28, 2033	**Expected Case**	**SDES**	**LDES (8-hour)**	**LDES (20-hour)**	**SDES & LDES**
Storage Capacity (MW)	241	482	482	482	723
Storage Capacity (MWh)	222	444	2,151	5,044	2,373
Annual Surplus + Operationally Constrained Curtailment (%)	31.2	28.2	25.4	23.5	24.9
Annual ECP Transmission Constraint Curtailment (%)	18.6	18.6	18.6	18.6	18.6
Annual Total Curtailment (%)	**49.8**	**46.8**	**44.0**	**42.1**	**43.4**
Annual Surplus + Operationally Constrained Curtailment (GWh)	2,894.2	2,615.6	2,358.8	2,181.2	2,306.0

4.1.2 Ramping needs and Short-term flexibility needs

Hourly ramping requirements and short-term flexibility needs, as defined in Articles 9 and 10, were represented within the modelling framework. The results

26 The storage capacities presented for LDES (8-hour and 20-hour) in the scenarios represent total installed storage capacity, including the storage assumptions already incorporated within the Expected Case

indicate that both requirements are adequately met and have a negligible impact on overall system flexibility needs.

No hours of unserved energy were identified, indicating that upward ramping requirements were satisfied throughout the assessment period. In the worst-case scenario (WS34, 2030), only around 2.5% of VRES curtailment could potentially be attributed to insufficient downward ramping flexibility.

Similarly, instances of uncovered short-term flexibility needs were rare, occurring in less than 0.1% of hours in the worst-case scenario (WS28, 2033). Furthermore, the reported reserve 'shortages' represent reductions in reserved capacity rather than complete reserve depletion. Consequently, no additional standalone analysis was undertaken under Articles 9 and 10, as the model outputs demonstrate that these requirements do not materially influence the flexibility needs identified in this assessment.

4.2 Network flexibility needs

This section outlines the assessment of network flexibility needs at both distribution and transmission levels, in line with Articles 11 and 12 of the FNAM. The following sections assess the impact of network limitations on RES curtailment and examine the extent to which transmission network reinforcement could reduce curtailment levels.

4.2.1 DSO network needs

The distribution-level network flexibility needs identified are summarised in Table 14 (Annex B) and presented in accordance with Article 11(2) of the FNAM and the reporting requirements outlined in Annex 2. The analysis identifies upward flexibility needs only, reflecting requirements to alleviate network constraints at the primary (33 kV) level across a number of locations, including Ballynahinch, Drumnakelly, Enniskillen, Newry, Omagh, Waringstown, and Lisaghmore. These needs are defined in terms of both energy (MWh) and power (MW) over the applicable time horizon (2030 and 2033) and relate to two principal use cases: (i) investment deferral, where flexibility is used to manage sustained loading and defer network reinforcement, and (ii) operational constraints, where flexibility is required to manage shorter-term overloads. The spatial granularity is defined at the transmission-distribution interface to provide consistency with TSO analysis, noting that multiple downstream flexibility locations may exist within each reported area. Downward flexibility needs have not been assessed in this iteration, however, this will be considered in future assessments as the FNAM and data availability continue to develop.

Flexibility is expected to be accessed through local service procurement mechanisms in line with Article 11(6), with services procured on a technology-agnostic basis from technically compliant and cost-effective providers, including generation, storage, and demand-side resources. The identified needs are based on forecast network conditions and have undergone an initial triage to confirm their potential suitability for flexible solutions.

No material divergence has been identified between the detailed distribution-level network flexibility needs and the DSO indicators developed pursuant to Article 16(4). Furthermore, as flexibility procurement at the distribution level in Northern Ireland remains at an early stage of development and is undertaken in advance of constraints materialising, it is not yet possible to determine whether any portion of the identified needs will remain uncovered. Accordingly, all identified needs are treated as potentially addressable through market-based procurement, with the extent of coverage to be determined through the ongoing development and testing of flexibility markets.

4.2.2 TSO network needs

Article 14(3)(a) specifies that a fine-tuning assessment should be undertaken where RES curtailment attributable to transmission network constraints exceeds 10% of total annual RES curtailment (MWh). The analysis indicated that this threshold was exceeded by a significant margin across all scenarios, and therefore the transmission-constraint analysis was undertaken as part of the Article 8 assessment.

For example, in 2030, Table 9 shows that transmission constraints account for 64% of the increase in curtailment, substantially exceeding the 10% threshold. These results indicate that transmission constraints are a key driver of curtailment, representing a significantly larger contribution than other sources of curtailment.

Table 9: Article 8.13- Curtailment including and excluding transmission constraints (WS28, 2030 and 2033)

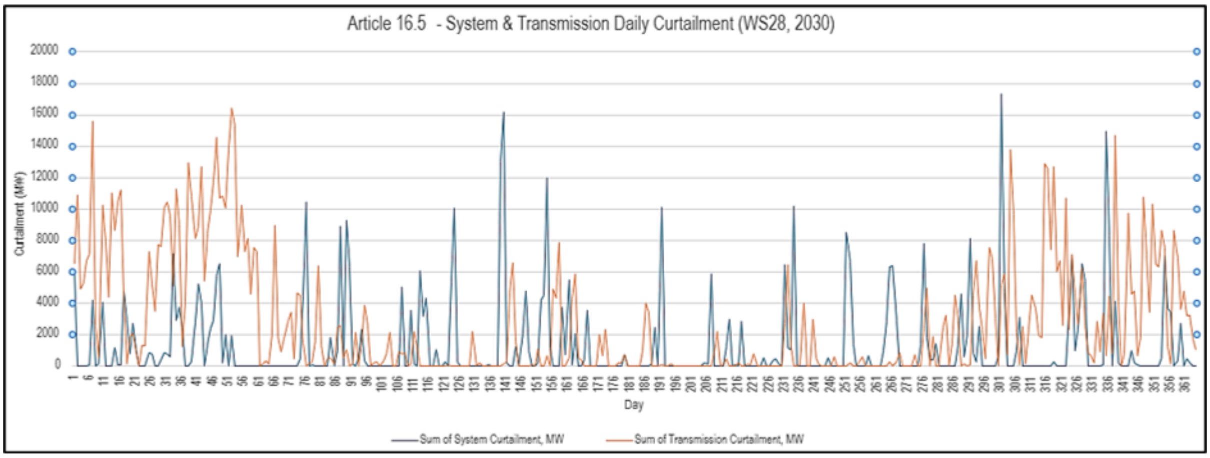
	2030	2033
Curtailment **without** transmission constraints (MWh)	465,289	1,067,024
Curtailment **with** transmission constraints (MWh)	1,288,002	2,051,080
Difference (MWh)	822,713	984,056
Curtailment due to transmission constraints (%)	64	48

Analysis undertaken in both the Base and High-RES scenarios shows that transmission-related curtailment is a primary driver of renewable energy losses. This suggests that, while flexibility can help reduce curtailment, a substantial proportion can only be addressed through network-focused measures, including transmission reinforcement and technologies such as dynamic line ratings (DLR), that increase network utilisation and transfer capability.

Daily Curtailment from System and Transmission Constraints

Figure 18 compares curtailment arising from system limitations ("surplus + curtailment" in SEM terminology) with curtailment arising from transmission constraints ("constraint" in SEM terminology). Transmission-related curtailment generally persists for longer durations, often extending over several weeks, whereas system-related curtailment typically occurs over periods of several days. This suggests that the two forms of curtailment may require different mitigation approaches: flexibility resources can help reduce curtailment associated with system limitations, while transmission network reinforcement is more effective in addressing curtailment resulting from transmission constraints. While system-related curtailment generally occurs over shorter durations, the results suggest that further reductions may require storage durations substantially beyond those widely deployed on the system today.

Figure 18: Article 16.5.2- System and transmission curtailment



4.3 Synthesis- Guiding criteria application outcomes

This section synthesises the findings from Sections 4.1 and 4.2, applying the guiding criteria set out in Article 16 of the FNAM to identify flexibility resources. The guiding criteria have been applied to the assessed system needs, taking account of the interaction between system-wide and network constraints. While no uncovered flexibility needs are identified in the Base scenario due to insufficient projected RES capacity, the analysis highlights the increasing importance of flexibility in supporting the continued expansion of renewable energy capacity.

The quantities presented in this assessment represent energy flexibility requirements (MWh) rather than a prescriptive technology choice. BESS was used as the primary proxy for flexibility within the modelling due to its ability to represent and quantify these requirements consistently. However, the assessment remains technology-neutral, and the identified flexibility could potentially be delivered through a range of solutions, including demand-side flexibility, LDES or other emerging flexibility resources.

This assessment considers energy storage as a flexibility solution and finds that increasing storage deployment can reduce curtailment, with increases in energy capacity (MWh) generally delivering greater benefits than increases in power capacity (MW) alone. However, the benefits of additional storage are subject to diminishing returns as curtailment levels reduce and deployment volumes increase.

As outlined in Section 4.2, the analysis also indicates that network-related constraints make a material contribution to curtailment, and the Article 16(10) assessment suggests that reducing operational constraints through planned transmission reinforcements, including North-South Interconnector, could provide additional benefits.

As a result, curtailment reduction is likely to require a combination of flexibility resources and network investment. While flexibility can help reduce surplus generation and operationally driven curtailment, transmission reinforcement is likely to represent the more practical long-term solution for addressing persistent network-related constraints. Under higher intermittent renewable deployment pathways, both the need for flexibility and the potential value it can provide increase over time.

Table 10: Article 16- Additional analysis showing extent of curtailment

Scenario	Peak surplus and curtailment (MW)	Largest block of surplus and operationally constrained curtailment (HRs)	Largest block average surplus and operationally constrained curtailment (MW)	MW of 4-hour BESS required to supply largest block	MW of 20-hour BESS required to supply largest block	Hours of storage at peak MW required to supply largest block
Base-WS28, 2030	1,570	42	540	5,670	1,134	14
Base-WS28, 2033	1,910	64	917	14,672	2,934	31
High-RES-WS28, 2033	3,063	108	1,349	36,423	7,285	48

As illustrated in Table 10, the magnitude of potential requirements suggests that fully meeting future flexibility needs will be challenging. This will likely require consideration of a coordinated approach combining flexibility resources, transmission investment, operational improvements and future deployment of renewable generation.

SONI's Further Assessment

SONI has proposed a flexibility need of 4,800 MWh, derived from its modelling analysis and qualitative assessment of future system requirements. A sensitivity analysis tested flexibility levels ranging from 240 MWh to 12,000 MWh and showed system benefits up to around 4,800 MWh. The results of SONI's assessment, examining the impact of incremental 10-hour storage capacities on curtailment, are presented in Table 11.

Table 11: Article 16- Additional analysis assessing the impact of incremental storage capacities on curtailment

	Increments of additional 241MW 10-hour storage				
Base- WS28, 2033	**241 MW, 10-hour**	**482 MW, 10-hour**	**723 MW, 10-hour**	**964 MW, 10-hour**	**1,205 MW, 10-hour**
Annual Surplus + Operationally Constrained Curtailment (%)	11	9	8	7	6
Annual ECP Transmission Constraint Curtailment (%)	20	20	20	20	20
Annual Total Curtailment (%)	31	29	28	27	26
Annual Surplus + Operationally Constrained Curtailment (GWh)	709	576	509	458	409
High-RES- WS28, 2033	**241 MW, 10-hour**	**482 MW, 10-hour**	**723 MW, 10-hour**	**964 MW, 10-hour**	**1,205 MW, 10-hour**
Annual Surplus + Operationally Constrained Curtailment (%)	32	30	28	27	26
Annual ECP Transmission Constraint Curtailment (%)	19	19	19	19	19
Annual Total Curtailment (%)	51	49	47	46	46
Annual Surplus + Operationally Constrained Curtailment (GWh)	3,452	3,231	3,081	2,962	2,875

The assessment also identifies additional scenario analysis, as outlined in Table 12. The scenario terminologies are explained below:

- **Base:** The factual scenario.
- **No STFlex:** Short-term flexibility requirements, as in Article 10, have been removed. This includes removal of FCR and FRR reserve requirements, and the reserve requirements added to represent changes in real-time due to day-ahead error in wind power, solar power, and load forecasts.
- **No Ramp:** All thermal generator constraints on flexibility are removed, including ramp rates and startup and shutdown times.

- **No Op Constraints:** All operational constraints have been removed. These include inertia, SNSP, min sets, and Dublin voltage constraints.

Table 12: Article 16.10.4- Analysis of upward needs arising from network and system needs (WS28, 2030)

Scenario	Surplus + Operationally Constrained Curtailment, %	ECP Transmission Constraint Curtailment, %	Total Curtailment, %
Base	9.2	20.8	30.0
No STFlex	6.3	20.8	27.1
No Ramp	7.4	20.8	28.2
No Ramp or STFlex	6.4	20.8	27.2
No Op Constraints	5.8	20.8	26.6
No Op Constraints or STFlex	2.6	20.8	23.4
No Op Constraints or Ramp	4.0	20.8	24.9
No Op Constraints or Ramp or STFlex	2.6	20.8	23.4
No Tx Constraints	9.2	0	9.2
No STFlex or Tx Constraints	6.3	0	6.3
No Ramp Tx Constraints	7.4	0	7.4
No Ramp or STFlex or Tx Constraints	6.4	0	6.4
No Op Constraints or Tx Constraints	5.8	0	5.8
No Op Constraints or STFlex or Tx Constraints	2.6	0	2.6
No Op Constraints or Ramp or Tx Constraints	4.0	0	4.0
No Op Constraints or Ramp or STFlex or Tx Constraints	2.6	0	2.6

SONI anticipates that interconnection developments, particularly the North-South Interconnector, could deliver benefits through reduced curtailment, lower operational constraints and more efficient all-island balancing. However, these benefits are not fully reflected in the modelling. In line with the FNAM, operational constraints are reduced in accordance with the Operational Policy Roadmap before the commissioning of the North-South Interconnector, despite these reductions being dependent on its delivery in practice. In addition, AIRAA reserve assumptions were retained, meaning potential reductions in all-island FCR and FRR requirements are not captured. Consequently, the model results may understate the full benefits of the interconnector.

The future role of flexibility technologies remains uncertain and dependent on future developments in their maturity, scalability and costs. However, as these technologies evolve, greater certainty is expected regarding their deployment potential, while maintaining opportunities for additional demand and renewable generation.

SONI note that current market signals may not provide sufficient certainty to support the scale of investment required in long-duration storage, given the associated capital costs, development timescales and revenue uncertainty. While some deployment of short-duration storage has occurred, the analysis indicates that future system needs may increasingly require flexibility capable of managing variability over longer timescales. Consequently, further consideration of policy, regulatory and market arrangements may be required to support the efficient delivery of flexibility resources and network investments aligned with future system needs.

5. Barriers for flexibility and contribution of digitalisation

5.1 Barriers, mitigation measures and incentives

This section sets out the UR's findings for Northern Ireland in relation to the regulatory and market design barriers and associated indicators outlined in Section 1 of the Annex to the ACER Recommendation No 01/2026. The evaluation was informed by responses from subject matter experts across the relevant organisations, including the UR, NIEN and SONI, drawing on both jurisdictional and all-island perspectives where appropriate. In addition, an Information Paper was published by UR to seek stakeholder views on the barriers identified by ACER. The responses received have been considered as part of the evaluation and are summarised in Annex C.

5.1.1 Barrier 1: Lack of proper legal framework for market access to new entrants and small actors

Indicator 1.1: Main roles and responsibilities of new actors not fully defined

The Electricity Directive requires Member States to establish an appropriate regulatory framework for active customers, market participants engaged in aggregation, Renewable Energy Communities (RECs) and Citizen Energy Communities (CECs) to enable the active participation of flexibility.

Assessment against this indicator indicates that Northern Ireland has implemented many of the key regulatory and legislative foundations required to support new market participants in flexibility markets. These arrangements build on the framework established through the Electricity (Northern Ireland) Order 1992[27] and the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007[28], which provide the basis for participation in electricity generation, supply, aggregation and wholesale electricity markets.

Active customers are granted most rights in line with EU requirements, including the ability to sell self-generated electricity through Power Purchase Agreements (PPAs), generate, consume and store electricity within their own premises, and participate in aggregation without being subject to undue payments, penalties or contractual restrictions imposed by suppliers. While the sharing of electricity between separate premises requires a supply licence or exemption, the existing legislative framework provides clear routes for participation. Under Article 10 of the

27 The Electricity (Northern Ireland) Order 1992, Article 10, establishes the requirement for a licence to generate, transmit, distribute or supply electricity in Northern Ireland, subject to specified exemptions. Available at: legislation.gov.uk

28 The SEM was established under the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007. Available at: The Electricity (Single Wholesale Market) (Northern Ireland) Order 2007

Electricity (Northern Ireland) Order 1992, active customers must be licensed unless they meet the criteria set out in the Electricity (Class Exemptions from the Requirement for a Licence) Order (Northern Ireland) 2013[29] .

Aggregation activities are permitted, and independent aggregators can access the market without requiring supplier consent. The SEM framework, established under the 2007 Order, provides recognised pathways for participation through balancing responsibility arrangements, the Trading and Settlement Code (TSC), SEM market rules, licensing requirements (including Demand Side Units (DSUs) and Aggregated Generating Units (AGUs)), relevant TSO requirements and compliance with the Distribution and Grid Codes. Collectively, these arrangements support market integrity while enabling aggregators to participate in flexibility services.

Aggregation is already facilitated through established SEM structures. All units participate as individually registered market units and are settled under a single Balance Responsible Party (BRP). DSUs, AGUs (Northern Ireland only) and Aggregated Generators (Ireland only) can aggregate physical assets behind unit identifiers and participate within the market framework. While aggregation models involving multiple BRPs at a single connection point are not currently implemented, the existing arrangements provide practical and well-established routes for aggregation participation. Similarly, although the term "aggregator" is not explicitly defined in SEM legislation, existing definitions for DSUs, AGUs and ASUs provide recognised mechanisms for aggregation participation. Future alignment with evolving EU terminology could further enhance consistency across jurisdictions.

Legislative frameworks are also in place to support RECs. While a fully explicit domestic framework for CECs has not yet been established, many of the underlying principles are already reflected through existing SEM arrangements, providing a foundation on which future developments can build.

Energy storage facilities can be co-located with renewable generation facilities and electric vehicle (EV) charging infrastructure, supporting the deployment of flexible technologies and facilitating greater integration of renewable energy resources.

Overall, Northern Ireland has implemented most of the key requirements needed to enable new actors to participate in flexibility markets. The combination of the Electricity (Northern Ireland) Order 1992, the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 and subsequent market and licensing arrangements provides a strong foundation for active customer participation, aggregation, RECs and energy storage. As flexibility markets continue to evolve,

29 The Electricity (Class Exemptions from the Requirement for a Licence) Order (Northern Ireland) 2013 provides exemptions from electricity licensing requirements for specified classes of persons and activities under the Electricity (Northern Ireland) Order 1992. Available at: legislation.gov.uk

further refinement of certain arrangements could build on this and support even broader participation by a diverse range of market actors.

Indicator 1.2: Market access restricted due to lack of legal eligibility

Member States are required to ensure non-discriminatory access to wholesale electricity markets for all market participants, either individually or through aggregation, including resources such as variable renewable generation, demand response and energy storage. To achieve this, national frameworks should provide pathways for a broad range of energy resources to participate in electricity markets.

In Northern Ireland, the legislative and regulatory framework established through the Electricity (Northern Ireland) Order 1992 and the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 provides the foundation for market participation across the electricity sector. Within the SEM, market participants engaged in aggregation, including independent aggregators, are legally eligible to participate in wholesale markets provided the relevant parties and units are appropriately registered with SEMO. Participation opportunities are available across the Day-Ahead Market, Intraday Market, Balancing Market, and system services arrangements, with the Balancing Market being mandatory only for units above the de minimis threshold of 10 MW export capacity. Participation in system services, including services equivalent to FCR is open to technically qualified units, ensuring that services can be delivered securely and efficiently.

The current framework does not explicitly prohibit any actor category, including household customers, commercial customers, industrial customers, renewable generators, energy storage operators, RECs or CECs, from participating in wholesale markets or system services. Rather, participation is facilitated through established licensing, registration, balancing responsibility and technical qualification arrangements that support the efficient operation of the electricity system and wholesale market.

In practice, the framework provides multiple routes to market participation. Generators, storage operators and qualified aggregated units can participate directly in relevant markets, while smaller consumers, households, energy communities and other distributed resources can engage through suppliers, aggregators or other market intermediaries. This approach helps enable participation by a wide range of market actors while maintaining market integrity and system reliability.

Overall, the SEM framework supports broad market participation and is largely aligned with the objective of enabling flexibility resources to contribute to wholesale markets and system services.

Indicator 1.3: Unclear framework for access to final customer data

The Electricity Directive requires Member States to establish rules governing access to final customer data by eligible parties. This includes metering and consumption data, as well as the information necessary to facilitate customer switching, demand response, self-consumption, electromobility and other energy services.

Assessment against this indicator suggests that Northern Ireland has established important legislative and regulatory frameworks for the electricity sector through the Electricity (Northern Ireland) Order 1992 and the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007, while further development of customer data access arrangements is planned as part of the wider digitalisation of the energy system. The DfE has committed to a successful smart meter rollout, including collaboration with the UR and NIEN on detailed project plans, the development of a Data Access Code and the specification of the future smart metering system. As outlined in the DfE's Design Plan for the Roll-Out of Smart Electricity Meters[30], the deployment of smart meters is scheduled to commence in early 2028, which is expected to facilitate enhanced access to consumer energy data.

The ongoing development of smart metering infrastructure presents an opportunity to establish a more structured and standardised approach to customer data access. As these arrangements are implemented, greater clarity around roles, responsibilities and data exchange processes could support wider participation in flexibility markets and facilitate access to the information required to deliver innovative energy services. This is expected to be particularly beneficial for emerging market participants, including aggregators, demand response providers and other flexibility service providers.

The introduction of interoperable systems and clearly defined data-sharing arrangements has the potential to enhance market transparency, improve customer engagement and support confidence among both existing and prospective market participants. In turn, this could strengthen the ability of flexibility providers to develop new services and business models while supporting a more efficient and responsive electricity system.

The reference model for metering and consumption data access set out in Article 3 of Commission Implementing Regulation (EU) 2023/1162[31] could provide a useful framework for the continued development of Northern Ireland's data access arrangements, supporting interoperability, transparency and non-discriminatory access for eligible parties.

30 DfE (2026), Design Plan for the Roll-Out of Smart Electricity Meters, available at: https://www.economy-ni.gov.uk/publications/design-plan-roll-out-smart-electricity-meters

31 Commission Implementing Regulation (EU) 2023/1162 of 6 June 2023, available at: EUR-Lex

Overall, Northern Ireland has a clear pathway towards enhancing customer data accessibility through the planned smart meter rollout and associated governance arrangements. Building on the principles established by the 1992 Electricity Order, the 2007 SEM Order and ongoing smart metering initiatives, future developments could further support innovation, demand-side participation, flexibility services and consumer empowerment across the electricity sector.

Indicator 1.4: Ownership restrictions for energy storage and electro-mobility

The Electricity Directive requires DSOs and TSOs to act as neutral market facilitators and, in general, not own, develop, manage or operate energy storage facilities or EV charging infrastructure unless specific conditions are met. These provisions are intended to support competitive, market-based investment in flexibility resources, while allowing for carefully targeted derogations where necessary to maintain system security, reliability and efficient network operation.

In Northern Ireland, the framework established through the Electricity (Northern Ireland) Order 1992, the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007, and subsequent regulatory arrangements is aligned with these principles. The regulatory framework supports the separation of system operation functions from competitive market activities, helping to promote a level playing field for market participants while encouraging private-sector investment in flexibility services, energy storage and EV infrastructure.

To date, no derogations have been requested or granted to enable TSOs or DSOs to own, develop, manage, or operate energy storage facilities or EV charging infrastructure. This demonstrates that flexibility services and related infrastructure continue to be provided through market-based mechanisms, supporting competition and facilitating participation by a broad range of commercial providers.

The current approach provides a strong basis for the continued development of competitive flexibility markets while maintaining the option to utilise derogations, where justified, in line with EU requirements. This flexibility could prove valuable in supporting future system needs in circumstances where market-based solutions alone may not be sufficient to deliver required services or infrastructure.

In 2017, the UR issued a Decision paper[32] and published guidance[33] on network code derogations, providing an established precedent for the assessment and governance of derogation requests. Building on this experience, there may be

32 Utility Regulator (2017), Decision Paper on Derogations, setting out the Utility Regulator's decision and approach to the application of derogations from electricity network code requirements in Northern Ireland. Available at: [Utility Regulator Decision Paper on Derogations (February 2017)]

33 Utility Regulator (2017), Guidance Document on Derogations, providing guidance on the application and assessment of derogation requests relating to electricity network codes in Northern Ireland. Available at: [Utility Regulator- Guidance Document on Derogations (February 2017)]

opportunities to develop further guidance relating to derogations for energy storage and EV charging infrastructure. Such arrangements could provide additional clarity and transparency for stakeholders while ensuring that any future derogations are applied in a proportionate manner.

Overall, Northern Ireland's framework supports the EU objective of fostering competitive and market-led flexibility solutions while retaining mechanisms to address exceptional circumstances where necessary.

Indicator 1.5: Restrictions on trade in day-ahead and intraday markets

The SEM framework provides accessible and well-established routes for participation in the Day-Ahead and Intraday Markets, supporting a wide range of market participants and flexibility resources. The legislative framework established by the Electricity (Northern Ireland) Order 1992 and the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 provides the basis for participation in the SEM. Detailed trading arrangements, including the minimum bid size of 0.1 MW in the Day-Ahead and Intraday Markets, are established through Single Electricity Market Operator Power Exchange (SEMOpx) market rules and operating procedures. In addition, participants can trade energy in time intervals aligned with the current Imbalance Settlement Period (ISP) of 30 minutes.

While the SEM currently operates with a 30-minute ISP, compared to the 15-minute settlement period required by EU legislation, the existing arrangements provide a stable and established framework for market operation and flexibility participation. The SEM Committee previously granted an exemption from the 15-minute ISP requirement in 2021, enabling a managed approach to market development while the implications of shorter settlement periods continue to be assessed.

The current settlement arrangements already support participation from renewable generation, storage, and demand-side resources, while ongoing consideration of shorter settlement periods presents an opportunity to further enhance market efficiency and flexibility. A move towards a 15-minute ISP could provide more granular market signals and support increased participation from fast-acting technologies, such as BESS.

Reflecting this opportunity, the UR and the CRU have written to SONI and EirGrid requesting formal submissions to initiate a project to implement a 15-minute Market Time Unit (MTU) and 15-minute ISP in accordance with Article 53 of Commission Regulation (EU) 2017/2195[34] and Article 8(2) of the Electricity Regulation respectively. This demonstrates continued regulatory commitment to the evolution of the SEM and alignment with wider European market developments.

34 Article 53 of Commission Regulation (EU) 2017/2195 (Electricity Balancing Guideline) requires ISPs to be 15 minutes in all scheduling areas unless a regulatory authority grants a derogation. Available at: https://eur-lex.europa.eu/eli/reg/2017/2195/oj

SONI is currently assessing the feasibility and implications of implementing a 15-minute ISP. Subject to the outcome of this work, shorter settlement intervals could further strengthen market signals, support increased participation by flexibility providers and enhance the efficiency of market and system operation.

Overall, the SEM framework supports flexibility through accessible Day-Ahead and Intraday markets, established trading arrangements and ongoing market reforms, helping to facilitate participation by storage, demand response and renewable resources.

5.1.2 Barrier 2: Lack of Enablers and Incentives to Provide Flexibility

Indicator 2.1: Lack of adequate metering systems

The assessment highlights smart meter deployment as an opportunity to further enhance flexibility across Northern Ireland's electricity system, supporting greater participation from both household and non-household consumers.

The assessment found that submetering does not constitute a barrier to market participation in Northern Ireland. Customers, aggregators and other market participants can utilise submetering systems for internal monitoring, verification and cost allocation purposes, while NIEN accepts metering at either grid connection or asset level, subject to applicable technical requirements. This provides flexibility in metering arrangements while maintaining established settlement and billing processes.

The existing framework therefore supports the development of innovative flexibility solutions and enables a range of metering approaches to address different customer and market participant needs.

Looking ahead, smart metering represents a key enabler of future flexibility services. Increased deployment is expected to improve the availability of granular consumption and generation data, supporting demand response, aggregation, consumer engagement and broader participation in flexibility markets. Enhanced data availability could also help unlock new value streams for consumers while facilitating more efficient system operation.

As set out in the DfE's Design Plan for the Roll-Out of Smart Electricity Meters, Northern Ireland's smart meter deployment is scheduled to commence in early 2028 and is expected to be completed over a three-year period. This programme represents an important step in the continued digitalisation of the electricity sector and will allow for a wider range of flexibility services and market innovations in the years ahead.

Overall, the current metering framework supports flexibility participation, while DfE’s planned rollout of smart meters from 2028 is expected to further enable demand response, aggregation, consumer engagement and broader access to flexibility markets.

Indicator 2.2: Absence of price signals

The Electricity Regulation encourages Member States to deploy smart metering systems and, where these are in place, to introduce Time-of-Use (ToU) network tariffs that reflect network usage in a transparent, cost-efficient and predictable manner. Such pricing arrangements can support more active consumer participation in electricity markets and help unlock additional flexibility from demand-side resources and distributed energy technologies.

Assessment against this indicator indicates that Northern Ireland has established a range of retail electricity tariff offerings within the legislative and regulatory framework. These arrangements promote retail competition and future innovation in tariff design, while ongoing smart metering and tariff reform initiatives are expected to further strengthen opportunities for flexibility participation.

A variety of retail tariff options are already available to consumers, including standard variable tariffs, Economy 7 tariffs, EV tariffs and other specialist products, with approximately 161 tariff offerings currently available across the market. Around 60% of household customers are on tariffs other than standard variable products, demonstrating an existing degree of customer engagement with alternative tariff structures and providing a foundation for further development of time-based pricing arrangements.

While dynamic pricing contracts and time-differentiated network tariffs are not yet widely deployed, the current framework presents a significant opportunity to enhance flexibility incentives as the electricity system continues to evolve. Greater adoption of time-based pricing could provide more granular signals to consumers, encouraging increased participation in demand response, smart charging, energy storage and other flexibility services.

The planned rollout of smart meters is expected to play a central role in this transition. As set out in the DfE's Design Plan for the Roll-Out of Smart Electricity Meters, suppliers will develop new products and services, including ToU and dynamic tariff offerings, supported by customer-facing applications and enhanced billing information. This work will be undertaken through a multi-stakeholder process, while maintaining tariff options that continue to meet the needs of all consumers.

In parallel, the UR has already undertaken a Call for Evidence[35] in 2021 on network tariff reform and is preparing its first consultation under the Multi-Year Network Tariff Structure Reform Project. Together, these initiatives demonstrate an active

35 Utility Regulator (2021), Electricity Tariff Reform: Call for Evidence Responses Report, summarising stakeholder views on electricity tariff reform and the development of future tariff structures to support decarbonisation, consumer engagement and system flexibility in Northern Ireland. Available at: Utility Regulator- Electricity Tariff Reform: Call for Evidence Responses Report

programme of work aimed at modernising pricing arrangements and ensuring that future tariff structures support both consumer choice and system flexibility.

Overall, Northern Ireland's existing tariff framework supports flexibility participation, while smart meter rollout and ongoing tariff reform are expected to strengthen price signals and encourage greater uptake of demand response, storage and other flexibility services.

5.1.3 Barrier 3: Restrictive requirements to provide balancing services

Indicator 3.1: Non-market-based balancing products

The Electricity Balancing Regulation aims at ensuring that the procurement of balancing services (i.e. both balancing energy and balancing capacity) is fair, objective, transparent and market-based, avoids undue barriers to entry for new entrants and fosters the liquidity of balancing markets while preventing undue distortions within the internal market in electricity.

This indicator regarding non-market-based procurement of balancing energy and capacity is currently not applicable in the SEM, given that:

1. TSOs do not procure balancing capacity (as in the reserve volumes term). Instead, reserve volumes are paid for through a regulated tariff payment approach as per the DS3 (Delivering a Secure, Sustainable Electricity System) programme. A procurement/tender-based approach is used for the qualification process to bring resources into the DS3 framework. A regulated tariff payment approach is then applied for the availability of reserve volumes provided by those resources.

2. Balancing energy is procured through the Integrated Scheduling Process, which is market-based.

The FASS programme is currently being developed as the successor framework to the DS3 programme. FASS represents a significant evolution of the all-island System Services framework, with a focus on increasing the use of transparent, competitive and market-based procurement arrangements. The programme is intended to support the continued integration of high levels of renewable generation while ensuring the reliable and secure operation of the power system.

A key objective of FASS is to introduce day-ahead procurement mechanisms for System Services and progressively align procurement arrangements with the standard balancing products and market principles set out in Article 25 of Commission Regulation (EU) 2017/2195 (Electricity Balancing Guideline). The programme is also intended to facilitate greater harmonisation with European electricity market arrangements and reduce reliance on local, non-market-based balancing products over time.

In addition to moving towards more market-based procurement, FASS is expected to broaden opportunities for participation by a wider range of flexibility providers, including battery energy storage, DSR, aggregated resources and other emerging technologies. By enabling greater competition between service providers, the framework is anticipated to support more efficient procurement of system services while providing clearer investment signals for flexibility resources.

The development of FASS also reflects the changing needs of the electricity system as renewable penetration increases. The framework is expected to help ensure that sufficient volumes of the required system services can be procured efficiently to support system stability, manage operational challenges associated with variable renewable generation and facilitate progress towards net zero objectives. Overall, FASS is expected to provide a more enduring, scalable and market-oriented framework for procuring system services as the transition from DS3 progresses.

Overall, the SEM's balancing arrangements support flexibility participation through market-based balancing energy procurement, while the development of FASS is expected to further expand opportunities for flexibility providers by introducing more competitive, transparent and market-oriented procurement of system services.

Indicator 3.2: Restrictions in the prequalification of reserve providing groups

The Electricity Directive requires TSOs to establish prequalification processes for both Reserve Providing Units (RPUs) and Reserve Providing Groups (RPGs), enabling distributed energy resources to participate in balancing services regardless of size. The Directive also promotes the aggregation of different resource types, including generation, demand-side resources and energy storage, within the same reserve providing group.

Assessment against this indicator indicates that the SEM framework provides established and generally accessible pathways for participation in balancing and reserve services. The existing prequalification arrangements are designed to accommodate a broad range of technologies and business models, supporting participation from both individual units and aggregated resources. For balancing energy services, the TSC provides a rolling qualification process that enables RPGs to participate in the market, while allowing combinations of generation, demand and storage resources, subject to standard technical and network requirements such as Maximum Export Capacity (MEC) and Maximum Import Capacity (MIC) limits.

The framework therefore enables flexibility resources to participate based on their ability to meet the relevant technical requirements. For distribution-connected participants, coordination between the TSO and DSO helps ensure that services can be delivered securely while maintaining the reliability of the wider electricity network.

Looking ahead, the FASS programme presents a significant opportunity to further enhance participation in balancing and reserve markets. FASS is being developed to introduce more market-based procurement arrangements and broaden opportunities for flexibility providers. Following FASS go-live, balancing capacity services will be procured as part of the new framework.

For upward reserve services, FASS is expected to build on the existing prequalification approach, providing continuity for participants while supporting a wider, more competitive market for flexibility services. Arrangements for downward reserve services are currently being developed and will further expand the range of services and resources able to participate in future procurement processes.

Overall, the SEM framework provides established routes for a wide range of flexibility resources, including aggregated demand, storage and generation assets, to participate in balancing and reserve services, while the forthcoming FASS programme is expected to further expand participation opportunities through more competitive and market-based procurement arrangements.

Indicator 3.3: Large minimum eligible capacity

Balancing markets, including prequalification processes, should be designed to facilitate non-discriminatory access for all market participants, either individually or through aggregation. This enables a broad range of flexibility resources, including smaller distributed energy resources, to participate in balancing services and contribute to system operation.

Assessment against this indicator indicates that the SEM framework provides accessible participation arrangements that are aligned with European requirements. The current minimum capacity requirement of 1 MW for participation in balancing energy services is consistent with EU standards and there is no maximum capacity restriction for balancing energy participation. This supports the involvement of a diverse range of market participants, including aggregated resources and emerging flexibility technologies.

The existing arrangements provide a clear pathway for balancing market participation and enable aggregators and flexibility providers to combine resources to meet minimum qualification thresholds where appropriate. This helps ensure that balancing services can be delivered by a broad range of technologies while maintaining system reliability and operational efficiency.

While balancing capacity is not currently procured in the SEM, the forthcoming FASS programme is expected to further expand participation opportunities through the introduction of balancing capacity procurement. Under current proposals, service providers will be required to demonstrate a minimum capability of 1 MW for each reserve service in order to participate in the daily auction, maintaining consistency with European market standards.

FASS is also expected to provide clear qualification pathways for both upward and downward reserve services. For upward reserve services, the existing prequalification framework will continue to provide an established basis for participation, while arrangements for downward reserve services are being developed as part of the wider programme. Proposed maximum qualification capacities of 75 MW for upward local reserve services and 300 MW for Replacement Reserve (RR) are intended to support efficient market operation while accommodating a range of service providers.

Overall, the SEM framework supports broad and non-discriminatory participation in balancing services by enabling flexibility providers, including aggregators and distributed energy resources, to access markets through proportionate qualification requirements, while FASS is expected to further enhance opportunities through the introduction of balancing capacity procurement.

Indicator 3.4: Unregulated duration or long prequalification process

The Electricity Directive recommends that prequalification processes for balancing services are transparent and efficient, providing prospective Balancing Service Providers (BSPs) with clear pathways to participation. Defined processes can help support investment decisions and facilitate the timely entry of new flexibility resources into the market.

In the SEM, established qualification processes are already in place for participation in balancing and system services. While TSOs do not currently procure balancing capacity, the existing DS3 framework includes regular six-monthly procurement gates that provide opportunities for new entrants, including energy storage and other flexibility providers, to qualify and participate in system services. Participants are required to submit a technical questionnaire by a specified deadline, which is then assessed by the TSO as part of the qualification process.

The current arrangements provide a structured route to market participation and have supported the entry of a diverse range of flexibility providers. As the market continues to evolve, there may be opportunities to further enhance transparency by formalising indicative timelines for intermediate stages of the qualification process, helping participants to plan investment and project delivery with greater certainty.

The development of the FASS programme presents an opportunity to build on existing arrangements and provide further clarity around qualification requirements and processes. In particular, additional guidance on how qualification requirements apply when RPUs or RPGs are modified- for example through changes in asset composition, connection points or capacity- could further support market participants and streamline future participation.

Overall, the SEM framework provides established and transparent qualification pathways for flexibility providers to access balancing and system services, while the development of FASS offers an opportunity to further enhance participation through clearer and more streamlined qualification processes.

Indicator 3.5: Large minimum bid size

The European target model sets out that the minimum bid volume for energy and the bid granularity for standard balancing products shall be 1 MW for all reserve types, thereby facilitating the entry of small distributed flexible resources.

The SEM currently applies a 1 MW minimum participation threshold for balancing energy services. Following FASS go-live, balancing capacity services are expected to apply the same 1 MW qualification threshold. These arrangements are aligned with EU requirements for balancing energy and balancing capacity participation.

Overall, the SEM framework supports participation by smaller and aggregated flexibility resources through a 1 MW minimum qualification threshold.

Indicator 3.6: Long validity period of balancing energy bids

The validity period of balancing energy bids represents the minimum timeframe over which a balancing product is delivered, helping to determine how different resources can participate in balancing markets.

In the SEM, balancing energy is delivered through a central dispatch model, under which TSOs issue dispatch instructions in the form of absolute MW setpoints that remain in place until updated. Balancing energy volumes are then derived from the difference between these dispatch instructions and participants' Physical Notifications[36].

This approach provides TSOs with significant operational flexibility and enables balancing resources to respond dynamically to real-time system needs. Rather than relying on predefined validity periods for balancing energy bids, the central dispatch model allows dispatch instructions to be adjusted as system conditions evolve, supporting efficient system operation and security of supply.

Overall, the SEM's central dispatch model provides flexibility resources with the ability to respond dynamically to real-time system needs, supporting efficient balancing actions and secure system operation.

36 SEMO, Balancing Market Principles Statement (Version 9.0), available at: SEMO Balancing Market Principles Statement

Indicator 3.7: Symmetric balancing capacity products

Symmetric FRR capacity products can be more challenging for some flexibility resources to provide, as renewable generation, demand response and energy storage technologies often have different capabilities in delivering upward and downward services. Product designs that accommodate these characteristics can support broader participation from a diverse range of flexibility providers.

In the SEM, TSOs do not currently procure symmetric balancing capacity products and instead procure upward reserve services through a six-monthly procurement process. This approach supports participation from a wide range of flexibility resources and helps facilitate market access for technologies with differing operational characteristics, including renewable generation, DSR and energy storage.

Overall, the SEM's reserve service arrangements support participation from a broad range of flexibility resources by procuring services based on operational requirements, helping to accommodate the differing capabilities of renewable generation, demand response and energy storage technologies.

Indicator 3.8: Restrictions in price settlement rules of balancing energy

The Electricity Regulation requires balancing energy pricing to be based on a marginal pricing methodology, helping to ensure that balancing prices reflect the value of the marginal balancing action and providing transparent market signals for participants.

In the SEM, balancing energy pricing is based on a single marginal imbalance settlement price (PIMB) for each 30-minute ISP. The price is derived from balancing energy actions identified through a flagging and tagging process, which seeks to minimise the influence of non-energy actions, such as constraint management or system security actions, on price formation.

Balancing actions taken by market participants are settled through the SEM balancing market settlement arrangements. The imbalance settlement price is calculated using accepted bid and offer actions, with flagging and tagging applied to limit the influence of non-energy actions, such as constraint or system-security actions, on imbalance price formation. Where accepted actions are not settled at the imbalance settlement price, settlement arrangements provide for the use of the relevant bid or offer price, including premium and discount components where applicable.

Non-energy balancing actions are therefore generally treated separately for price-formation purposes, while remaining subject to settlement in accordance with the TSC and associated SEM settlement rules. By excluding non-energy actions from price formation, the SEM seeks to ensure that the imbalance settlement price more accurately reflects the marginal cost of balancing energy actions and provides an efficient signal for real-time system balancing.

Overall, the SEM's balancing energy pricing arrangements are designed to provide transparent and efficient market signals by applying a marginal pricing approach that reflects the cost of balancing energy actions, supporting effective participation by flexibility providers in real-time system balancing.

Indicator 3.9: Non-contracted balancing energy bids not allowed

The Electricity Regulation provides BRPs with the ability to submit non-contracted balancing energy bids, promoting competition and enabling a broad range of flexibility providers to participate in balancing markets without requiring a prior balancing capacity contract.

In the SEM, non-contracted balancing energy bids for local, standard and specific aFRR and mFRR services can be submitted without the need for a balancing capacity contract. This is supported by the SEM's central dispatch model, under which available capacity is offered into the balancing market regardless of whether a balancing capacity contract is in place. As a result, the framework facilitates broad participation in balancing energy markets and provides opportunities for a diverse range of resources, including new and emerging flexibility providers, to contribute to system balancing.

Overall, the SEM framework supports broad participation in balancing energy markets by allowing non-contracted balancing energy bids, enabling a diverse range of flexibility providers to offer services without requiring a prior balancing capacity contract.

Indicator 3.10: Too short predefined minimum duration between consecutive activations

The indicator seeks to understand whether balancing energy products allow sufficient operational flexibility for different types of BSPs, including resources that may require recovery time between consecutive activations.

In the SEM, balancing energy is delivered through a central dispatch model under the Integrated Scheduling Process. Rather than defining fixed activation and deactivation periods at the product level, dispatch instructions are issued based on real-time system requirements, providing TSOs with flexibility to respond efficiently to changing system conditions. Operational capabilities and limitations are reflected through unit-specific technical parameters, such as minimum on/off times and other operational constraints submitted by market participants.

This approach provides a flexible and technology-neutral framework for balancing energy provision, allowing system requirements to be met dynamically while accommodating the operational characteristics of participating resources. As the range of flexibility providers continues to expand, there may be opportunities to further consider how evolving balancing market arrangements can support the participation of technologies with specific recovery or cycling requirements, including certain demand response and energy storage applications.

Overall, the SEM's central dispatch model provides a flexible and technology-neutral framework for balancing energy provision, enabling resources to respond according to their operational capabilities while supporting efficient system balancing and participation from a diverse range of flexibility providers.

Indicator 3.11: Long procurement lead time and long duration of balancing capacity contracts

The indicator assesses the lead times and contract durations associated with balancing capacity procurement, recognising that shorter procurement timeframes can broaden participation opportunities for a diverse range of flexibility providers, including distributed energy resources.

The assessment indicates that balancing capacity in the SEM is currently delivered through the DS3 System Services arrangements, which provide established procurement processes and contractual certainty for service providers. Under these arrangements, contracts are typically awarded through six-monthly procurement processes, with contract durations generally ranging from one month to one year. Rather than reserving balancing capacity through dedicated short-term procurement processes, system operators utilise a real-time co-optimised dispatch approach that enables available resources to provide both energy and reserve services efficiently.

These arrangements have successfully supported system security and facilitated the participation of a growing range of flexibility technologies, including demand-side resources and energy storage. The existing framework also provides participants with a degree of revenue certainty through contractual arrangements while allowing system operators to optimise the use of available resources in real time.

Looking ahead, the FASS programme represents a significant evolution of the current framework. FASS is intended to introduce day-ahead procurement of balancing capacity, increasing alignment with European market arrangements and creating additional participation opportunities for flexibility providers. The introduction of shorter procurement timeframes is expected to complement existing arrangements and further support participation by a wider range of technologies and business models.

Overall, the current DS3 arrangements provide established procurement processes and revenue certainty for flexibility providers, while the development of

FASS is expected to improve participation by introducing day-ahead balancing capacity procurement and shorter procurement timeframes aligned with evolving market needs.

5.1.4 Barrier 4: Restrictive requirements to provide congestion management

Indicator 4.1: Unjustified lack of market-based TSO congestion management

Article 13 of the Electricity Regulation requires redispatching to be based on objective, transparent and non-discriminatory criteria and, where possible, to utilise market-based mechanisms.

Within the SEM, redispatch is managed through the market and dispatch arrangements established under the Integrated Scheduling Process. The Integrated Scheduling Process first seeks to optimise dispatch using market-based offers and bids before applying any redispatch actions required to maintain secure system operation. As a result, market-based dispatch principles are embedded at the core of system operation, with redispatch used where necessary to manage operational and network constraints.

The SEM's central dispatch model has been designed to support the secure and efficient operation of an electricity system with a relatively high level of transmission constraints and increasing levels of renewable generation. The SEM Committee[37] has previously concluded that, given the characteristics of the all-island system, there may be limitations to relying solely on market-based redispatch mechanisms, particularly where competition is limited in specific locations or for certain system services. In this context, the current arrangements seek to balance market efficiency, security of supply and effective management of network constraints.

Redispatch arrangements are applied consistently across dispatchable technologies and the wider power system. Certain resource-specific provisions also apply where appropriate, including arrangements for variable renewable generation. These arrangements have enabled the SEM to accommodate increasing levels of renewable generation while maintaining secure system operation.

The governance framework for redispatch is supported by established regulatory and stakeholder engagement processes. The SEM Committee periodically reviews the market design and operational arrangements, with policy developments typically informed by stakeholder consultations, workshops and modification processes. This provides a transparent mechanism for assessing future changes as

37 SEM Committee (2016), Balancing Market Principles Statement Terms of Reference (SEM-16-058). Available at: SEM Committee Decision Paper. [semcommittee.com]

market conditions, system requirements and legislative frameworks continue to evolve.

Additionally, a number of developments are expected to support the continued evolution of dispatch and redispatch arrangements. The Scheduling and Dispatch Programme (SDP) is a programme of market and system changes designed to enhance SEM scheduling and dispatch arrangements, support the integration of increasing volumes of renewable generation and facilitate alignment with evolving European electricity market requirements. In particular, SDP-01 (Non-Priority Dispatch Renewables) is being implemented to facilitate the integration of renewable generation units that do not qualify for priority dispatch. The project is intended to align the treatment of these renewable generators more closely with other dispatchable units within the scheduling and dispatch process, supporting greater consistency across technologies while facilitating the continued growth of renewable generation on the power system.

Overall, the SEM's dispatch and redispatch arrangements are founded on market-based principles and support the efficient integration of renewable generation, while ongoing developments such as the SDP are expected to further enhance flexibility and alignment with evolving market requirements.

Indicator 4.2: Unjustified lack of market-based DSO congestion management

This indicator is driven by Articles 13(1), 13(2) and 13(3) of the Electricity Regulation, which promote the use of objective, transparent and non-discriminatory approaches to redispatch, including market-based solutions where appropriate, and Article 32(1) of the Electricity Directive, which requires Member States to establish frameworks that enable DSOs to procure flexibility services to support the efficient operation and development of distribution networks.

In Northern Ireland, NIEN has established a flexibility services framework that places market-based procurement at the centre of congestion management and network planning. Through its flexibility services programme, customer flexibility is considered alongside traditional network solutions, with flexibility often providing an efficient means of addressing network needs and deferring or avoiding reinforcement where appropriate. Public procurement processes are supported through established procurement arrangements and clearly defined technical and commercial requirements, providing transparent opportunities for participation by flexibility providers.

Flexibility services are procured through competitive market processes that consider both pricing and technical requirements, ensuring that procured services are cost-effective and capable of delivering the required network outcomes.

Procurement activities are carried out in accordance with the Procurement Act 2023[38].

Overall, NIEN's flexibility services framework supports market-based congestion management by procuring flexibility through transparent and competitive processes, enabling customer flexibility to be considered alongside traditional network reinforcement in meeting network needs efficiently.

Indicator 4.3: Constraints in local markets for TSO/DSO congestion management

In addition to Article 13(1) and 13(2) of the Electricity Regulation and Articles 31(8), 32(1) and 32(2) of the Electricity Directive, this indicator assesses whether market arrangements enable broad participation by flexibility providers in local congestion management services and whether any barriers exist within the prequalification process, product design or market structure.

In Northern Ireland, NIEN operates local flexibility markets for congestion management and network support. Flexibility services are procured on a technology-neutral basis, enabling participation from a broad range of resources, including generation, energy storage and demand-side flexibility solutions. The current framework is designed to facilitate participation by both established and emerging technologies and flexibility services have been successfully deployed across a range of asset sizes and technologies.

Participation is based on clearly defined technical and commercial requirements that reflect the operational needs of specific network locations. These requirements are intended to ensure that procured services can reliably deliver the required network outcomes while maintaining security and efficiency. Flexibility services are typically secured in advance of need to support effective network planning and investment deferral, while contract arrangements provide certainty for both flexibility providers and the DSO. Although contracts are generally agreed at fixed prices for a given flexibility season, seasonal procurement cycles provide opportunities for pricing to evolve over time in response to market conditions.

Northern Ireland is also continuing to develop innovative approaches to network access and flexibility. In addition to the existing flexibility services markets, NIEN is progressing work on Flexible Connections, which explores how customers can connect to the network more quickly and efficiently using flexible operational arrangements where appropriate. The Flexible Connections Call for Evidence[39] and subsequent development work, including progression through the Central Design

38 Procurement Act 2023 (UK). Available at: https://www.legislation.gov.uk/ukpga/2023/54/contents
39 NIEN, Flexible Connections Call for Evidence, seeking stakeholder views on the development of flexible connection arrangements to support more efficient access to the electricity network and facilitate the integration of LCTs. Available at: Flexible Connections Call for Evidence

Authority (CDA) process under MRC5010[40]- MIC for Flexible Connections, demonstrate ongoing efforts to expand connection options and support greater participation by flexible technologies and new market entrants.

Procurement by NIEN[41] considers both technical and commercial criteria and is undertaken in accordance with the UK Procurement Act 2023, including the provisions relating to Qualifying Utilities Dynamic Markets. This provides a transparent and competitive framework for the procurement of flexibility services and supports broad market participation.

NIEN continues to monitor market availability and flexibility potential across the network while regularly testing the market for new flexibility solutions. Information on flexibility opportunities is published through established channels, helping to increase awareness and participation among prospective service providers. Further, NIEN continues to explore innovative congestion management solutions through initiatives such as flexibility services procurement, flexible connections, network reconfiguration and other future network projects.

SONI does not currently procure local congestion management services.

Overall, NIEN's local flexibility markets support broad participation by flexibility providers through transparent, technology-neutral and competitive procurement arrangements, while ongoing initiatives such as Flexible Connections are expected to further expand access and support innovative approaches to congestion management.

5.1.5 Barrier 5: Complex, lengthy, and discriminatory administrative requirements

Indicator 5.1: Inefficient grid connection procedures

Driven by Article 16 of Directive (EU) 2018/2001[42], Article 31(3a) of Directive (EU) 2019/944 (henceforth referenced as the Electricity Directive) and paragraphs 3 and 5 of Commission Recommendation (EU) 2024/1343[43], Member States are encouraged to establish grid connection arrangements that are transparent, accessible and efficient, supporting the timely deployment of renewable

40 SEMO CDA, MRC5010- MIC for Flexible Connections, a market change proposal supporting the implementation of flexible connection arrangements within the Single Electricity Market framework. Available via the SEMO market modifications portal: Balancing Market Modifications

41 NIEN, Procurement Statement, setting out the principles, processes and governance arrangements used by NIEN when procuring flexibility and other network services, including compliance with relevant procurement legislation and market engagement requirements. Available at: NIEN Procurement Statement

42 Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources (recast), Articles 16 and 17, which establish requirements relating to permit-granting procedures and simplified connection arrangements for renewable energy projects. Available at: EUR-Lex: Directive (EU) 2018/2001

43 Commission Recommendation (EU) 2024/1343 on speeding up permit-granting procedures and accelerating the rollout of renewable energy and related infrastructure projects. Available at: EUR-Lex: Commission Recommendation (EU) 2024/1343

generation, storage, electrification technologies and consumer-led energy solutions.

In Northern Ireland, established grid connection processes are in place for renewable generation, energy storage, self-consumers, heat pumps and other LCTs connecting to both the distribution and transmission networks. Applicants are able to:

1. Access comprehensive connection information online.

2. Progress through clearly defined stages within established connection processes.

3. Submit applications electronically, with distribution connections facilitated through NIEN's online connections portal[44] and transmission applications submitted directly to SONI.

4. Progress planning and other required consents in parallel with the connection process, helping to streamline overall project development timelines. Planning consent is not required in order to accept a connection offer, although it is typically a condition that must subsequently be satisfied.

NIEN has also implemented streamlined connection pathways for a range of smaller LCTs. Installers can use the Connect Direct[45] platform to submit applications for technologies such as EV chargers, heat pumps, solar PV and battery storage, with application outcomes available rapidly for eligible installations. In addition, the G99/NI Fast Track[46] process provides a simplified and efficient connection route for smaller-scale generation and storage projects below the applicable capacity threshold (13.8kW currently).

In line with Article 17 of the Renewable Energy Directive (RED), NIEN applies simplified connection arrangements where appropriate, supporting efficient customer access to the network.

Transparency is further supported through the publication of network information and capacity data. NIEN makes information on available network capacity publicly available across the distribution system, while SONI publishes a range of network

44 NIEN, Connections Portal, providing an online application and tracking service for distribution network connection applications in Northern Ireland. Available at: NIEN's Connections Portal

45 NIEN, Connect Direct, an online platform enabling installers of LCTs, including EV chargers, solar PV, battery storage and heat pumps, to submit and receive outcomes for eligible connection applications. Available at: ENA Connect Direct

46 NIEN, G99/NI Fast Track Process, which provides a simplified connection route for eligible smaller-scale generation and storage installations. Available at: NIEN G99/NI Fast Track Installations

and generation outlook publications, including forecast information relevant to future demand and generation connections[47].

Northern Ireland is also continuing to develop innovative approaches to network access. Initiatives such as Flexible Connections are exploring opportunities to provide more efficient and flexible routes to network access, helping to facilitate the integration of renewable generation, storage and other flexibility technologies. Ongoing industry work, including the development of MRC5010- MIC for Flexible Connections, demonstrates continued progress in expanding connection options and supporting a wider range of LCTs.

For larger-scale renewable generation, storage projects, self-consumers, RECs and EV infrastructure, connection arrangements continue to evolve alongside broader network, market and policy developments. As increasing volumes of LCTs connect to the network, there may be opportunities to further build on the existing framework through additional streamlined processes and connection solutions, supporting the continued growth of renewables, flexibility and consumer participation in the electricity system.

Overall, Northern Ireland's grid connection framework provides transparent and accessible pathways for renewable generation, storage and other low-carbon technologies, while ongoing initiatives such as Flexible Connections continue to enhance network access and support the growth of flexibility resources.

Indicator 5.2: Disproportionate procedures and requirements for market access

SONI has identified a number of areas where future developments could further support participation by smaller and emerging flexibility providers. DSUs participating in the SEM are required to provide metering, telemetry and operational data to enable the TSO and market operator to carry out scheduling, dispatch and settlement functions. While smart metering has not yet been rolled out widely in Northern Ireland, existing arrangements enable DSUs to participate using established metering, monitoring and settlement processes. The future rollout of smart metering may provide additional opportunities to enhance visibility and support broader participation in demand-side flexibility services.

Current network and market arrangements also continue to evolve to support greater integration of flexible and hybrid technologies. The UR's Decision on Changes to Over Install Policy for Single Technology and Hybrid Co-Located Technology Sites[48] established revised arrangements for over-installation at both

47 SONI, Generation Capacity Statement and associated forecast publications, which provide information on forecast transmission network development, demand and generation capacity requirements, and network capability available to prospective transmission-connected customers. Available at: SONI Generation Capacity Statement and SONI Publications

48 Utility Regulator (2024), Decision on Changes to Over Install Policy for Single Technology and Hybrid Co-Located Technology Sites, setting out revised over-installation arrangements for both single-technology and hybrid co-located projects connected to the distribution and transmission networks in Northern Ireland. Available at: NI Over Install Decision Paper

distribution and transmission-connected sites, providing greater flexibility for renewable generation and hybrid projects. However, dynamic sharing of MEC across multiple units behind a single connection point and energy sharing between co-located technologies are not yet fully implemented in Northern Ireland. As a result, opportunities to optimise connection capacity across portfolios of technologies remain under development. Future arrangements relating to MEC sharing, hybrid connections and integrated hybrid units could further enhance network utilisation, increase operational flexibility and support more efficient use of existing infrastructure.

The current TSO framework provides technology-neutral participation routes, including aggregation through DSUs and other flexibility arrangements, rather than dedicated participation pathways designed specifically for smaller resources. Existing and emerging market developments, including aggregation, flexibility services, hybrid connection arrangements and SDP initiatives, are expected to create further opportunities for smaller and distributed flexibility providers to participate in electricity markets and system services.

Overall, the SEM and wider network framework provide established and technology-neutral routes for flexibility providers to participate in electricity markets and system services, while ongoing developments in smart metering, hybrid connections, MEC sharing and aggregation are expected to further reduce barriers and expand opportunities for smaller and emerging flexibility resources.

5.1.6 Barrier 6: Lack of requirements and incentives for system operators to consider non-wire alternatives

Indicator 6.1: Lack of incentives for system operators to consider non-wire alternatives

Driven by Articles 31(7), 32(1) and 40(5) of the Electricity Directive and Articles 13(1) and 13(2) of the Electricity Regulation, Member States are required to establish regulatory frameworks that enable TSOs and DSOs to procure flexibility services and utilise these services to support efficient network and system operation.

In Northern Ireland, the regulatory framework already provides a strong basis for the procurement of flexibility services. NIEN are able to procure flexibility services, including congestion management services, from a wide range of providers, including generation, demand response and energy storage resources. This has enabled the development of local flexibility markets and supported the increasing role of flexibility in network operation and planning.

At transmission level, SONI currently manages congestion through established balancing market and dispatch arrangements within the SEM framework. These arrangements provide mechanisms for managing system constraints and maintaining security of supply through the balancing mechanism. In parallel, work is ongoing to extend the range of services that can be procured, including the implementation of arrangements to facilitate the procurement of non-frequency ancillary services in the future.

The Northern Ireland framework also supports consideration of flexibility alongside traditional network solutions. Flexibility services are already being utilised in network planning and operation, particularly at distribution level and ongoing policy, regulatory and market developments provide opportunities to further strengthen the role of flexibility as an alternative or complement to conventional network reinforcement where appropriate.

In relation to cost recovery, the existing price control framework enables SONI and NIEN to recover efficiently incurred costs associated with flexibility procurement, digitalisation initiatives and network investment. This includes both operational and capital expenditure related to the delivery of network outputs and innovation programmes. Regulatory oversight by the UR helps ensure that investments deliver value for consumers while supporting network modernisation, digitalisation and flexibility deployment.

Article 18(8) of the Electricity Regulation and Article 32(1) of the Electricity Directive require regulatory frameworks to support efficient alternatives to network reinforcement, including flexibility services, smart grids, digitalisation and other innovative technologies. In Northern Ireland, the existing licence and price control framework provides mechanisms through which incentives and funding can be established to support these activities where they are demonstrated to deliver value for consumers and the electricity system. Through regulatory frameworks such as RP6[49], NIEN has been able to develop flexibility services, innovation programmes, digitalisation initiatives and network transformation projects, while the development of RP7[50] provides a further opportunity to build on this progress and strengthen the role of flexibility, smart networks and innovative solutions in supporting future network needs. The framework therefore provides a basis for flexibility procurement and innovation-led investment, with ongoing regulatory processes determining the specific incentives, outputs and funding arrangements that best support efficient network development and operation.

Further evolution of regulatory and market frameworks may provide additional opportunities to strengthen the use of flexibility services, smart grid technologies and innovative solutions alongside traditional network investment. These developments could help maximise system efficiency, support renewable

49 Utility Regulator, RP6 Final Determination for NIEN (2017-2024), which established the regulatory framework, outputs, incentives and funding arrangements for NIEN, including provisions supporting innovation, network development, digitalisation and flexibility services where they deliver value for consumers and the electricity system. Available at: [RP6 Final Determination]

50 Utility Regulator, RP7 Price Control Programme, which will set the regulatory framework, outputs, incentives and expenditure allowances for NIEN for the next price control period and provides an opportunity to further develop arrangements relating to flexibility procurement, digitalisation, smart networks and innovative solutions. Available at: [NIEN RP7]

integration and enhance the contribution of flexibility resources to the future electricity system.

Overall, the Northern Ireland regulatory framework supports the use of flexibility services as an alternative or complement to traditional network reinforcement, with established arrangements for flexibility procurement, cost recovery and innovation funding, while future regulatory developments such as RP7 provide opportunities to further strengthen the role of flexibility, digitalisation and smart network solutions.

5.2 Retail electricity tariffs

This section provides an overview of retail electricity tariffs, customer exposure to time-based price signals, network tariff structures, balancing service arrangements, prequalification processes and congestion management measures in Northern Ireland. It also considers, in light of ACER's recommendations on network tariff methodologies[51] and barriers to distributed energy resources[52], the extent to which current arrangements support demand response, flexibility services and consumer participation. In particular, the assessment considers:

- The basis on which network tariffs are applied[53].
- The treatment of active and non-active customers within network charging arrangements[54].
- The use of exemptions, discounts and other differentiated tariff treatments[55].

The available information relates to household electricity customers. Information on non-household customer contracts and tariffs was not available as part of this assessment.

A broad range of household electricity tariff options are available in Northern Ireland, including standard variable tariffs, Economy 7 tariffs, Powershift tariffs, EV tariffs and other differentiated products. A total of 161 tariff offerings were identified,

51 Getting the signals right: Electricity network tariffs methodologies in Europe, ACER report on network tariff practices, 2025

52 ACER report on demand response and other distributed energy resources and the barriers that are holding them back, 2023

53 ACER considerations and recommendations, and information specific to this aspect are included in Section 5.2 of ACER 2025 report on network tariff practices and in Sections 11.5 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back

54 ACER considerations and recommendations, and information specific to this aspect are included in Section 5.5.4 of ACER 2025 report on network tariff practices and in Sections 11.1 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back

55 ACER considerations and recommendations, and information specific to this aspect are included in Section 5.5 of ACER 2025 report on network tariff practices and in Sections 11.4 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back

varying across a range of characteristics such as tariff structure, payment method, fixed-term arrangements, standing charges and other commercial features.

The information provided indicates that suppliers offer a variety of tariff options to meet differing customer needs and preferences. Approximately 60% of household customers are currently on tariffs other than standard variable tariffs, demonstrating an existing level of engagement with alternative tariff structures. Standard variable tariffs account for around 40% of the market.

Standard variable tariffs are periodically updated, typically on a quarterly basis. While dynamic retail pricing products are not yet widely available, the existing range of tariff structures provides a foundation for future tariff innovation and increased consumer participation in flexibility services.

ToU tariffs are already available through products such as Economy 7 and EV tariffs, providing customers with opportunities to shift consumption and benefit from differentiated pricing. More advanced tariff models, including dynamic tariffs and hybrid pricing arrangements, are expected to develop alongside Northern Ireland's smart meter rollout programme. The DfE’s Design Plan for the Roll-Out of Smart Electricity Meters states that suppliers will develop ToU and dynamic tariff offerings, supported by customer applications, enhanced billing information and new service propositions, while maintaining tariff options suitable for a broad range of consumers.

The ongoing development of Flexible Connections arrangements and associated market developments, including MRC5010- MIC for Flexible Connections, further demonstrate the evolution of network access and flexibility frameworks in Northern Ireland. Together, these initiatives provide a foundation for future innovation in customer participation, tariff design and flexibility services.

Based on the information provided, approximately 96.6% of household customers are not currently exposed to ToU or dynamic price signals. The planned smart meter rollout and associated tariff development programme are expected to provide the platform for broader adoption of cost-reflective and flexibility-focused tariff structures over time.

Network tariffs in Northern Ireland recover both transmission and distribution network costs and are primarily applied through supplier arrangements using established flat-rate and capacity-based charging structures. These arrangements provide simplicity and predictability for consumers while supporting efficient cost recovery. As smart metering and tariff reform initiatives progress, there may be opportunities to introduce greater differentiation in tariff structures where this delivers benefits for consumers and the wider electricity system.

The absence of widespread time-differentiated network tariffs at present reflects the current policy, regulatory and infrastructure context. Significant work is already underway through the smart meter programme, tariff reform initiatives and ongoing UR projects, providing a clear pathway for future development should time-based charging arrangements be considered beneficial.

For balancing services, reserve volumes are not currently procured through balancing capacity markets. Instead, providers are remunerated through the DS3 System Services arrangements, which compensate resources based on the provision and availability of required services. These arrangements have played an important role in supporting system reliability and enabling participation from a diverse range of flexibility providers.

FASS is expected to introduce more market-based procurement arrangements, including day-ahead procurement mechanisms, while supporting increased alignment with European balancing market principles and broadening participation opportunities for flexibility providers.

Balancing energy within the SEM is managed through the Integrated Scheduling Process and central dispatch arrangements, which allow available resources to be utilised efficiently in real time based on system requirements. These arrangements support secure system operation while providing opportunities for a range of technologies to contribute balancing and system services.

Since balancing capacity is not currently procured directly, the existing qualification and tender processes primarily serve to assess eligibility, performance and technical capability under the DS3 framework. This provides a structured route to participation and helps ensure that service providers can meet system requirements.

Flexible connection arrangements continue to evolve through policy, regulatory and innovation initiatives. Ongoing work by NIEN, SONI and industry stakeholders is exploring how more flexible connection and access arrangements can support renewable integration, flexibility participation and efficient utilisation of existing network infrastructure. These developments provide a strong foundation for continued innovation in network access, flexibility markets and consumer participation as Northern Ireland's electricity system continues to decarbonise and digitalise.

5.3 Digitalisation

The transition to a more flexible, low-carbon electricity system is increasingly supported by digitalisation initiatives at both national and European levels. These initiatives aim to improve access to energy data, strengthen interoperability between market participants, enhance consumer engagement and support the development of innovative flexibility services. Through improved data governance, system visibility and digital infrastructure, digitalisation can contribute to more efficient system operation while helping to unlock additional sources of flexibility across the electricity sector.

Consistent with the FNAM and Article 19e(2)(d) of the Electricity Regulation, this section considers how digitalisation can facilitate the deployment and utilisation of flexibility resources within Northern Ireland's electricity system. The assessment examines the contribution of digital technologies and grid-enhancing solutions, including active system management, advanced monitoring, observability and DLR, to the integration of renewable generation and the efficient operation of the network. It also reviews key enablers identified through the FNA process, including smart meter deployment, demand-side participation and the regulatory arrangements supporting flexibility services and non-wire alternatives.

Northern Ireland's regulatory framework provides mechanisms for TSOs and DSOs to recover incurred costs associated with flexibility procurement, network innovation and digitalisation through price controls and regulated charges, subject to UR approval, providing a pathway for the continued development of digital capabilities that can support future system flexibility.

5.3.1 Relevant legislation

The digitalisation of the electricity sector in Northern Ireland is supported by a combination of domestic regulatory requirements and wider European legislation. At a local level, the Electricity (Northern Ireland) Order 1992 provides the legal framework for electricity regulation, while the UR's 2025 digitalisation licence modifications[56] require SONI and NIEN to develop and maintain a Digitalisation Strategy and Action Plan focused on data sharing, transparency and innovation. At a European level, the Electricity Directive, the Electricity Regulation, Commission Implementing Regulation (EU) 2023/1162[57] and the Electricity Market Design Reform promote consumer access to energy data, interoperability, demand response, energy storage and active market participation. The proposed EU Network Code on Demand Response[58] aims to establish a harmonised framework for integrating demand-side flexibility into electricity markets and system operation. The code is expected to cover market participation, prequalification and verification requirements, baseline methodologies, aggregator-supplier interactions, TSO-DSO coordination, congestion management services and interoperability between flexibility markets. Further, the code is also intended to support more consistent approaches to the measurement, validation and

56 Utility Regulator, Decision under Article 14(8) of the Electricity (Northern Ireland) Order 1992- Licence Modifications regarding Digitalisation to NIEN Transmission, Distribution and SONI Electricity Licences (April 2025), available at: Utility Regulator Digitalisation Decision Paper

57 Commission Implementing Regulation (EU) 2023/1162 on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data. Available at: EUR-Lex: Commission Implementing Regulation (EU) 2023/1162

58 ACER, Recommendation No. 01/2025 on the Demand Response Network Code (2025). Available at: ACER Demand Response Network Code

settlement of flexibility services across Europe. Together, these frameworks seek to enable a more data-driven, flexible and consumer-focused electricity system.

5.3.2 The Utility Regulator's digitalisation developments

The UR has identified a number of potential areas for future exploration as part of its evolving approach to digitalisation. Building on the recently introduced licence obligations for SONI and NIEN, these areas could include enhanced oversight of digitalisation action plans, the development of a broader UR digitalisation strategy and further consideration of issues such as data governance, smart metering, consumer engagement, interoperability, flexibility markets and TSO-DSO coordination. While these areas remain under development, they have the potential to help address several barriers identified through the FNA by improving access to data, supporting the participation of flexibility resources, enhancing system visibility and coordination and strengthening the evidence base for network and market decision-making.

5.3.3 Smart meter deployment

The DfE's Smart Electricity Meter Design Plan identifies smart metering as a key component of the wider digitalisation agenda and energy transition, with the rollout expected to improve access to more granular, accurate and timely consumption data. Over time, developments in smart metering and energy data frameworks could support capabilities such as near real-time consumption information, historical data access, separate import and export accounting and settlement at imbalance settlement resolution. Together, these developments could enhance system visibility for consumers, NIEN and SONI, support demand-side participation, enable innovative tariff structures and facilitate the integration of LCTs, such as EVs and heat pumps.

5.3.4 Demand-side

The SONI and EirGrid Demand Side Paper[59] highlights that future demand response arrangements may require more advanced measurement, verification and settlement frameworks, including the use of dedicated sub-metering to improve observability and support settlement processes. The paper also identifies reform of DSU energy payment arrangements as an important enabler of demand-side flexibility, with future settlement models potentially based on metered and verified demand response, underpinned by improved baselining and performance assessment. In addition, it notes that separately metered on-site generation can simplify the verification of delivered response, indicating that enhanced metering and monitoring capabilities may become increasingly important as demand-side flexibility markets develop. The proposed EU Network Code on Demand Response

59 EirGrid and SONI, TSO Demand Side White Paper (December 2024), outlining the role of DSR in supporting flexibility, renewable integration, system services and future market development across the island of Ireland. Available at: [TSO Demand Side White Paper]

is also expected to introduce more harmonised arrangements for flexibility participation, measurement and verification, aggregation, settlement and TSO-DSO coordination across European electricity markets.

5.3.5 SONI and NIEN Joint Digitalisation Strategy and Action Plan

The UR's 2025 digitalisation licence modifications require SONI and NIEN to jointly develop plans for digitalising and sharing energy system data, improving transparency and delivering consumer benefits, as further detailed in the UR's Digitalisation Strategy and Action Plan Guidance[60] . These obligations are reflected in Licence Condition Requirement 43 of the SONI and NIEN Transmission Licences and Licence Condition Requirement 46 of the NIEN Distribution Licence, providing the regulatory basis for the Joint Digitalisation Strategy.

The key background is that Northern Ireland's electricity system is becoming more decentralised, more data intensive and increasingly reliant on coordination between transmission and distribution. The strategy notes that, where information is difficult to find, inconsistently described or exchanged through one-off processes, this can slow decision-making, create rework and reduce transparency. It therefore establishes a shared direction for digital, data and technology capabilities, with a focus on making priority datasets easier to access, trust and use; improving coordination across the transmission-distribution boundary; and strengthening public-facing transparency on delivery progress. The four strategic themes are: whole-system data, standards and interoperability; coordinated grid operations and digital control; digital enablement for distributed energy and flexibility; and customer and stakeholder value, transparency and accessibility.

SONI and NIEN are progressing a number of initiatives that are relevant to the FNA, reflecting the priorities identified within their Joint Digitalisation Strategy and the associated Action Plan, which is currently under development and expected to be finalised by March 2027. Under whole-system data, standards and interoperability, the strategy identifies actions such as creating shared definitions, clearer data ownership, a joint data catalogue, a plain-English glossary for priority datasets, clearer guidance on what data can be shared publicly or through controlled access and reusable approaches for data sharing. Under coordinated grid operations and digital control, the strategy focuses on improved operational data sharing between the organisations, secure and monitored transfers, future system integration where appropriate, shared operational visibility at the TSO-DSO boundary and the digitalisation and standardisation of priority cross-boundary workflows. The strategy also highlights the SDP, which is progressing enhancements to the scheduling and dispatch of generation and storage assets, improving the optimisation of battery storage and wind generation and supporting the integration of synchronous condensers into system operations.

60 Utility Regulator, Digitalisation Guidance Paper (14 January 2026), providing guidance on the implementation of digitalisation licence obligations and the development of joint digitalisation strategies by SONI and NIEN. Available at: [Digitalisation Guidance Paper]

Under digital enablement for distributed energy and flexibility, the strategy focuses most directly on the FNA. It aims to improve the shared understanding of distributed energy and flexibility participation, strengthen planning insight across network and system planning, and make connection and flexibility information easier for stakeholders to navigate where it is lawful and appropriate to share. The strategy specifically identifies the FNA as an example of the value of joined-up evidence, noting that it requires consistent transmission and distribution data and assumptions to support decisions based on a shared understanding across both organisations. Under customer and stakeholder value, transparency and accessibility, the strategy includes clearer signposting to authoritative sources, improved cross-boundary customer journeys, coordinated communication during major events, aligned reporting, shared risk tracking, and a joint benefits and KPI catalogue. It also notes that NIEN, through collaboration with SONI, has updated its Network Capacity Map to include Transmission Generation headroom, providing a whole-system view of capacity information in a single tool.

These actions can help address several barriers identified through the FNA process. For the barrier relating to a lack of enablers and incentives to provide flexibility, the strategy supports the development of better data foundations, clearer access routes, improved visibility of system and network information, and more consistent information for flexibility providers and innovators. This is relevant to ACER's focus on adequate metering systems, access to data, price signals and the broader enabling conditions for demand response and flexibility. For the barrier relating to lack of regulatory incentives for system operators to consider non-wire alternatives, the strategy's emphasis on planning insight, transparent reporting, priority datasets, joint governance and benefits tracking can support a stronger evidence base for considering flexibility and other non-wire options where appropriate. More broadly, the strategy can contribute to overcoming data-related market barriers by improving interoperability, data governance, operational coordination and stakeholder access to information, all of which are important foundations for the effective identification, deployment and utilisation of flexibility resources.

5.3.6 Dynamic Line Rating

DLR illustrates the potential contribution of digitalisation to Northern Ireland's evolving electricity system. By combining real-time monitoring, weather information and digital analytics, DLR can provide a more dynamic assessment of network capacity than traditional static ratings. This aligns with the objectives of the SONI and NIEN Joint Digitalisation Strategy, which seeks to improve system visibility, data utilisation and operational coordination across the transmission and distribution networks. While the benefits will depend on implementation and operational requirements, DLR has the potential to support more efficient use of existing network infrastructure, facilitate renewable integration and contribute to the wider digital capabilities that can enable flexibility within the electricity system.

5.3.7 Conclusion

Overall, increased deployment of smart metering, standardised data access arrangements, enhanced system observability and settlement-ready measurement infrastructure are expected to be delivered progressively over the coming years and could help unlock additional flexibility opportunities. As these capabilities mature and become more widely implemented, they have the potential to support greater participation from demand response, distributed energy resources and other non-fossil flexibility providers.

6. Conclusions

This section presents the key findings of the FNA, outlining the main conclusions in relation to identified flexibility needs, their principal drivers and their expected development over time.

6.1 Key findings

The FNA evaluates the flexibility requirements of the Northern Ireland electricity system for 2030 and 2033, in accordance with the FNAM and relevant European and national policy frameworks.

The assessment shows that, under the Base scenario, no uncovered system flexibility needs arise as defined by the FNAM. This outcome reflects that renewable generation capacity remains below the level required to meet the national climate target outlined in the CCA, rather than indicating that flexibility is not required.

Notwithstanding this, the analysis confirms that flexibility requirements are present and are expected to increase over time. Curtailment of renewable generation occurs at significant levels across all scenarios and is projected to increase between 2030 and 2033, driven by a combination of network constraints, operational limits and evolving system conditions.

The key findings of the assessment are as follows:

- Persistent network constraints across the assessed target years indicate that network enhancements may be required, alongside flexibility measures, to support the efficient integration of renewable energy.
- The North-South Interconnector has the potential to help alleviate existing network and operational constraints in Northern Ireland, supporting increased renewable integration and potentially reducing curtailment.
- The FNA results suggest that higher levels of intermittent renewable deployment could increase flexibility requirements. This is illustrated by the High-RES scenario, which includes 1,000 MW of offshore wind from 2030 and is associated with higher levels of renewable curtailment relative to the Base scenario. As a result, flexibility requirements are expected to increase over time.
- System flexibility needs are projected to increase at a faster rate than network flexibility needs, suggesting that flexibility solutions may play an increasingly important role as renewable capacity grows.

- SONI estimates an initial flexibility requirement of approximately 4,800 MWh/day in Northern Ireland from 2030, approximately 20% of within-day flexibility in addition to that already assumed within the AIRAA plan. However, additional analysis will be necessary to build on the findings of this assessment and support the development of an indicative national objective for non-fossil flexibility[61].

- The results suggest that additional long-duration flexibility resources could play an increasing role beyond 2030, with long-duration storage demonstrating the potential to reduce curtailment across the scenarios assessed. Further procurement may be needed to facilitate their deployment, subject to future system needs and market developments.

6.1.1 Summary of flexibility needs

In summary, the flexibility needs identified in this assessment can be characterised as follows:

- **System-wide needs:**
  - No uncovered needs under the Base scenario, as defined by the FNAM due to insufficient projected RES capacity;
  - Material flexibility requirements nonetheless exist, driven by renewable curtailment and residual load variability across hourly, daily and seasonal timescales;
  - Long-duration flexibility is expected to play an important role in managing sustained energy imbalances, particularly under intermittent renewable deployment pathways with sufficient VRES capacity to support the achievement of national climate targets.

- **Transmission network needs:**
  - No quantified flexibility need in the Base scenario due to insufficient projected RES capacity according to the FNAM;
  - Transmission constraints are identified as a key structural driver of curtailment, requiring network reinforcement as a primary solution, with flexibility playing a complementary role;

61 Any future LDES procurement should be supported by a cost-benefit analysis to ensure that procurement volumes and technology requirements deliver value to consumers while meeting system needs

- Curtailment arising from transmission constraints remains relatively consistent between 2030 and 2033 and across the Base and High-RES scenarios. While transmission constraints are the primary driver of curtailment in the Base Scenario, the relative importance of system flexibility increases under the High-RES Scenario as renewable penetration rises.

- **Distribution network needs:**
  - Localised flexibility requirements have been identified at primary network level to address forecast demand growth and network constraints;
  - These needs are expected to be addressed through market-based procurement, subject to availability and cost-effectiveness of flexible services.

Overall, the analysis indicates that the scale and importance of flexibility will increase as intermittent renewable deployment progresses.

6.2 Next steps

6.2.1 Improvements for future iterations

The first iteration of the FNA has provided valuable insights into both flexibility needs and the practical application of the FNAM, highlighting opportunities to further enhance the methodology and strengthen its policy relevance. The assessment demonstrated the importance of considering flexibility needs alongside renewable deployment pathways, network development and operational constraints, while also identifying opportunities to provide a more integrated view of future system requirements.

The process could further benefit from clearer guidance, earlier stakeholder engagement and the ability to reflect jurisdiction-specific circumstances, which could support more consistent, efficient and actionable assessments in future cycles.

Following completion of the first FNA cycle, a lessons learned exercise will be undertaken to capture stakeholder feedback and identify opportunities to enhance future iterations.

6.2.2 Steps following publication

- In accordance with Article 19f of the Electricity Regulation, the next stage following publication of this report is the establishment of an indicative national objective for non-fossil flexibility (the Objective) by 25 January 2027. The Objective must include the respective contributions expected from both demand response and energy storage. The findings of this FNA will subsequently inform the development of that Objective.

- Article 19f further provides that achievement of the Objective may be supported through measures that address barriers to non-fossil flexibility. The market, regulatory and operational barriers identified within this assessment may therefore provide a basis for considering potential actions to facilitate additional flexibility deployment.

- In accordance with Article 19g of the Electricity Regulation, where investment in non-fossil flexibility is considered insufficient to achieve the indicative national objective, Member States may introduce non-fossil flexibility support schemes, subject to the requirements set out in the Regulation.

Annex A - System level analysis: Rationale for articles not undertaken within the Flexibility Needs Assessment

Table 13: Summary of articles not applied within the FNA and the associated rationale.

Article	Requirement	Reason Not Undertaken / Not Applicable
8(10)	In case of positive uncovered RES integration needs, the TSOs shall analyse the benefit of adding new flexibility resources to the system for the target years.	Not applicable, as there are no uncovered RES integration flexibility needs under the FNAM. Separate studies undertaken to support Article 16(6) provide relevant insights on the potential benefits of additional flexibility resources.
8(11)	The TSOs shall quantify additional flexibility resources required to meet the RES integration target.	Not applicable, as there are no uncovered RES integration needs identified under the FNAM.
8(12)	The TSOs shall assess the impact of additional flexibility resources on the RES integration pursuant to paragraphs (6) to (11), either by running an economic dispatch simulation pursuant to Article 7(3)(b), or by reflecting the new flexibility resources in the residual load time series resulting from economic dispatch results pursuant to Article 7(3)(a) and taking into account the contribution of flexible resources and interconnections.	Not applicable, as there are no uncovered RES integration flexibility needs under the FNAM. However, separate studies undertaken for Article 16(6) included economic dispatch simulations incorporating additional flexibility resources consistent with the approach envisaged under this article.
8(14)	To produce fine-tuned results pursuant to Article 14, the TSOs shall repeat the relevant steps described in paragraphs (10) to (12) reflecting the additional RES curtailment and unavailability of flexible resources within either the separate economic dispatch or the ERAA's / NRAA's economic dispatch results.	Not applicable, as there are no uncovered RES integration flexibility needs under the FNAM requiring further fine-tuning analysis.

8(15) & 8(16)	Unavailability of flexible resources is applied in the form of derating factor to the flexible resources considered in the economic dispatch pursuant to Article 7(3), based on the estimation resulting from the application of Article 13 and correlating information via time periods (hour and day of the year) or system operation conditions (renewable and load conditions). The derating factor shall be allocated to hours in which the network could face constraints. The derating of flexible resources pursuant to paragraph (15) shall be reported to the designated authority or entity.	Not applicable, as threshold testing under Articles 13 and 14 determined that relevant flexibility resource unavailability impacts were below the required threshold and therefore did not need to be reflected in the fine-tuning assessment.
8(17)	Whenever accounting for the contribution of flexible resources considered in the inputs of the economic dispatch pursuant to Article 7(3), and whenever additional RES curtailment has been added due to ramping or short-term needs pursuant to paragraph (3), TSOs shall account for flexible resources that were already used in the computation of the flexibility gap for ramping and/or short-term needs.	Not applicable, as ramping and short-term flexibility requirements were already incorporated directly into the model inputs and therefore did not require additional post-processing adjustments.
12(5)	The TSOs shall carry out a cost-benefit analysis to justify the use of flexible solutions as an alternative to grid expansion. In doing so, they shall provide to the designated authority or entity, and where an entity is designated also to the NRA, a description of the method and the calculations they used to make this comparison.	A cost-benefit analysis was not undertaken because transmission reinforcement is first required to reduce the underlying level of renewable curtailment. Following sufficient network development, a more meaningful assessment of the relative benefits of network investment and additional flexibility could be conducted.
16(7)	The TSOs shall assist with further analysis of the assessment of the capability of the different sources of flexibility to meet uncovered upward needs, quantified pursuant to Articles 9, 10 and 12. In particular, the TSOs shall provide: a. Analysis of the technical capability of the different sources of flexibility (e.g., additional flexibility resources - including at local level where relevant, additional reserve capacity, or further participation to balancing) to reduce the uncovered needs. The TSOs shall account for the technical characteristics, sub-indicators	Not applicable, as the FNA identified no uncovered upward flexibility needs relevant to this article. Consequently, no further analysis was required.

	identified in paragraph (5), and cost-efficiency. b. Analysis to verify possible overlaps with the adequacy findings of ERAA or NRAA, starting with the results of the scenarios compliant with Article 3(5)(a) of the ERAA methodology. When analysing the uncovered upward needs quantified pursuant to Articles 9 and 10, the TSOs shall consider reliability standards for the bidding zones, where such standard is defined.	
16(8)	As short-term needs are covered by the FRR capacity in line with Article 157 of Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation, the TSOs shall provide an analysis on how uncovered short-term flexibility needs quantified in Article 10 will first be met using additional reserve capacity or with further participation to balancing.	Not applicable in the SEM context. Under SEM central dispatch, all market participants are registered in and available to the balancing market. In addition, the FNA identified no uncovered short-term flexibility needs.
16(9)	For the identified transmission network needs quantified pursuant to Article 12, the TSOs shall provide an analysis of the capability of grid reinforcements already identified by the most recent published TYNDP or a national development plan to cover these needs.	Not applicable, as planned grid reinforcements from the national development plan are already included within the ECP modelling assumptions. The Article 12 transmission network assessment therefore already reflects these reinforcements, meaning further analysis would not provide additional insight.

Annex B - DSO network needs results table

Table 14: DSO network needs

Line number	Direction of need	Target year	Time block	Spatial granularity	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs	Share of downward flexibility needs pertaining to RES generation curtailment	Expected contractual means to access flexibility
1	Upwards	2030	Entire Year	Ballynahinch Main	33 kV	Total Energy over the period	10.33 MWh	N/A	Local Service
2						Summation of the maximum Power	1.34 MW		
3				Drumnakelly Main		Total Energy over the period	29.43 MWh		
4						Summation of the maximum Power	1.19 MW		
5				Enniskillen Main		Total Energy over the period	1.97 MWh		
6						Summation of the maximum Power	0.36 MW		
7				Newry Main		Total Energy over the period	2.07 MWh		
8						Summation of the maximum Power	0.63 MW		
9				Omagh Main		Total Energy over the period	3.05 MWh		
10						Summation of the maximum Power	0.46 MW		
11				Waringstown Main		Total Energy over the period	7.83 MWh		
12						Summation of the maximum Power	1.03 MW		
13		2033	Entire Year	Ballynahinch Main	33 kV	Total Energy over the period	183.52 MWh	N/A	Local Service
14						Summation of the maximum Power	3.22 MW		
15				Drumnakelly Main		Total Energy over the period	163.00 MWh		
16						Summation of the maximum Power	2.51 MW		
17				Enniskillen Main		Total Energy over the period	32.32 MWh		
18						Summation of the maximum Power	1.09 MW		
19				Lisaghmore Main		Total Energy over the period	0.65 MWh		
20						Summation of the maximum Power	0.58 MW		
21				Newry Main		Total Energy over the period	19.70 MWh		
22						Summation of the maximum Power	1.73 MW		
23				Omagh Main		Total Energy over the period	153.95 MWh		
24						Summation of the maximum Power	1.52 MW		
25				Waringstown Main		Total Energy over the period	112.71 MWh		
26						Summation of the maximum Power	1.93 MW		

Annex C - Stakeholder insights on future flexibility opportunities

The UR published an Information Paper in May 2026 providing information on Northern Ireland's first FNA. The paper outlined the legislative and policy context for the assessment, the roles of key organisations involved and invited stakeholder views on market and regulatory arrangements affecting non-fossil flexibility. The paper received a range of responses, highlighting opportunities to further develop flexibility markets and support the transition to a low-carbon energy system.

A number of common themes emerged across stakeholder submissions:

1. Market signals and investment frameworks

Stakeholders highlighted the importance of continued development of market arrangements and revenue frameworks to support investment in flexibility resources. Respondents recognised the growing role of demand-side flexibility, energy storage and other non-fossil technologies in the future electricity system and identified opportunities to further strengthen investment signals, remuneration mechanisms and long-term market visibility.

2. Demand-side flexibility and flexible demand

Stakeholders identified significant potential for demand-side flexibility to support renewable integration, system efficiency and the management of renewable curtailment. Industrial demand, electrified heat, data centres and aggregated demand-side resources were highlighted as important sources of future flexibility, with respondents recognising the value of enabling both demand reduction and demand increase services.

3. Market access and participation

Responses emphasised the importance of ensuring that flexibility markets remain accessible to a diverse range of participants. Stakeholders highlighted opportunities to streamline qualification processes, telemetry requirements and market arrangements to support broader participation by demand-side resources, aggregators and smaller flexibility providers as markets continue to evolve.

4. Energy storage and long-duration flexibility

Many respondents highlighted the important role that energy storage can play in supporting renewable integration, system balancing and network management. Stakeholders noted the potential benefits of maintaining technology-neutral market arrangements and continuing to consider the contribution of long-duration storage technologies to future flexibility needs.

5. Digitalisation and enabling infrastructure

Digitalisation was consistently identified as a key enabler of future flexibility markets. Stakeholders highlighted the opportunities associated with smart metering, enhanced data access, automated control systems and improved operational visibility. The planned smart meter rollout was widely recognised as an important step towards expanding flexibility participation and enabling new consumer-focused services and tariff arrangements.

6. Network constraints and flexible solutions

Stakeholders recognised the value of flexibility services, energy storage and flexible demand in supporting efficient management of network constraints alongside traditional network reinforcement. Responses highlighted opportunities to further embed flexibility solutions within network planning and investment decision-making alongside traditional network interventions.

7. Consumer participation and accessibility

Respondents emphasised the importance of ensuring that the benefits of flexibility are accessible to a wide range of consumers. Key themes included consumer engagement, awareness of flexibility opportunities, simple participation pathways and ensuring that market developments continue to deliver positive outcomes for all consumer groups.

8. Strategic planning and long-term perspective

Stakeholders highlighted the importance of aligning flexibility planning with longer-term decarbonisation objectives, intermittent energy deployment and wider energy policy developments across the electricity, heat and transport sectors. Respondents noted the value of long-term planning approaches that support coordinated decision-making and investment across the energy system.

Overall, the stakeholder responses provided valuable insights into the future development of flexibility markets in Northern Ireland. The feedback highlights strong interest in expanding the role of non-fossil flexibility resources and will help inform future regulatory, policy and market development activities aimed at supporting participation, innovation and the efficient transition to a more flexible and decarbonised electricity system.