CONSULTATION PAPER - FIRM ACCESS

Public Consultation on Firm Access Arrangements in Northern Ireland

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Utility Regulator

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ABSTRACT

This Consultation Paper seeks views on the future treatment of firm access for renewable generators in Northern Ireland. It outlines how firm access is presently allocated to renewable generators in Northern Ireland and how it operates across the system with the level of constraints that are experienced now. It also includes a section on the potential costs of extending firm access to generators that presently do not have firm access, and analyses how firm access and relevant policies are treated elsewhere, including recent changes made to firm access policy in Ireland. The Paper is concluded by laying out future options for progress, and posing questions to respondents.

AUDIENCE

This Information Paper will be of interest to relevant Government departments, SONI, renewable Generators and their representative organisations, and organisations representing consumer interests and other stakeholders.

CONSUMER IMPACT

This Consultation includes questions on policies relevant to how firm access is granted to Generators, and the management of constraints. Any changes to how firm access is allocated, and how this interacts with Dispatch Down due to Constraints, has the potential to pass on significant costs to consumers, making this of potentially significant impact.

Contents Page

Executive Summary 5

Acronyms Used 7

1. Introduction 9

UR Scoping Exercise on Firm Access 9

2. Firm Access and Dispatch Down 11

Concept of Firm Access 11

Dispatch Down in Northern Ireland 13

Firm and Non-Firm Generators 15

System Demand 16

Cost of Compensation Payments 17

Consumers 19

Other External Factors 19

3. International Approaches 21

Northern Ireland Specific Issues 25

4. Initial Conclusions 27

5. Consultation Questions 30

6. Next Steps 32

Executive Summary

This Consultation Paper seeks views on the future treatment of firm access for renewable generators in Northern Ireland. Firm access determines whether a generator is entitled to compensation when instructed to reduce output (known as "dispatch down") because of local network constraints. Non-firm connections allow generators to connect and earn revenue before the necessary network reinforcement is completed.

Dispatch down due to constraints has increased materially, from approximately 10% of renewable generation in 2018 to 25.5% in 2024. Although the level reduced to 19% in 2025, it stood at 20.6% for the period to June 2026. Almost all generators experienced dispatch down above 7% in January 2025 (see Figure 3). Due to current network reinforcement dates, many generators may remain non-firm until the 2030s. Delays to major transmission projects, and additional connecting generation, along with reducing demand levels, and a high level of electricity imports, create challenges to reducing dispatch down swiftly.

The consultation considers whether Northern Ireland should adopt an approach similar to Ireland, under which generators may obtain firm access if specified network reinforcements are not completed within an established timeframe. However, Northern Ireland's higher constraint levels mean this could create financial firm access without the corresponding physical network capacity. Making all non-firm generators firm could result in additional constraint compensation costs, of tens of millions of pounds annually. These costs would ultimately be borne by consumers and be subject to considerable uncertainty.

The underlying problem is the high level of dispatch down, rather than firm-access status alone. Priority should therefore be given to reducing constraints, accelerating necessary network development and making better use of available renewable generation. The paper proposes three broad policy options:

1. **Do nothing,** retaining the current arrangements. This would avoid immediate additional consumer costs but would not change the present allocation of risk or provide a defined review timetable.

2. **Align with the 2023 Ireland firm-access decision**, linking firm access to committed reinforcement dates. This could improve accountability and risk sharing but may expose consumers to substantial and uncertain compensation costs while physical constraints remain unresolved.

3. **Pursue a Northern Ireland-specific approach**, (a preferred basis for moving forward) focused on reducing constraints and improving risk sharing. Potential measures include performance indicators for SONI and NIE Networks in relation to network development, encouraging large demand connections in highly constrained areas, considering targeted

treatment for non-firm generators not receiving Renewable Obligation Certificates, and setting a clear timetable for a future policy review.

Acronyms Used

ACM – Authority for Consumers and Markets in the Netherlands.

ATR – Associated Transmission Reinforcements. Projects to build new transmission infrastructure, or upgrade transmission infrastructure, that are identified as necessary before FAQ can increase.

CEP – Clean Energy Package, set of rules passed by the European Union in 2019, to facilitate a move from fossil fuels to cleaner energy.

CRU – Commission for the Regulation of Utilities – the energy regulator in Ireland

DAM - Day Ahead Market, part of SEM Market for short term trading of electricity

EBIT - Earnings Before Interest and Taxes, measure of a company's operating profitability.

CECJ - Court of Justice of the European Union

ERCOT – Electric Reliability Council of Texas, Texas's System Operator.

FCA - Flexible Connection Agreement, These allow connection to a congested network by giving the operator the right to limit electricity flow under specific conditions. The term "flexible" is equivalent to the term "non-firm" that is used throughout this document.

FAQ – Firm Access Quantity.

FNA – Flexibility Needs Assessment. Conducted by UR, as part of a requirement set out in Regulation (EU) 2019/943.

QABNFLF - Accepted Bid Quantities of Non-Firm Generators, Adjusted Loss Factor.

MEC – Maximum Export Capacity, Units' maximum installed generation capacity.

NESO - National Energy System Operator, Britain's electricity system operator

NSI – North South Interconnector.

SEM - Single Electricity Market, Ireland's Wholesale electricity market

REPG – Renewable Electricity Price Guarantee, part of the Renewable Electricity Generation Bill, which aims to financially incentivise more renewable generation.

ROCs – Renewable Obligation Certificates, in Renewables Obligation Scheme.

ROE - Return on Equity, Compares net income generated by capital utilised.

SEMC - Single Electricity Market Committee, Regulatory body overseeing SEM

SEMO - Single Electricity Market Operator

SONI - System Operator for Northern Ireland

TDPNI - Transmission Development Plan for Northern Ireland, outlines the plans, timetables and budgets for upgrades to the Network for the next ten years.

1. Introduction

UR Scoping Exercise on Firm Access

1.1 In May 2026, UR published an Information Paper as part of its 2025/26 Forward Work Plan project, *Preparation for a Potential Firm Access Review in 2026/27*. The Information Paper indicated that UR would build on the findings of the scoping exercise and progress a further Forward Work Plan action. This consultation seeks stakeholders' views on a range of policy options developed through the scoping exercise and subsequent detailed analysis.

1.2 This workstream has arisen in response to requests from non-firm generators following Ireland's change in firm access policy and high levels of dispatch down due to constraints. Unlike firm generators, non-firm generators receive no compensation when they are instructed not to generate due to network constraints,

1.3 UR has built a knowledge base concerning:

1. Numbers of generators with and without firm access to the network.
2. The location of these generators, their Maximum Export Capacity (MEC), and the constraints experienced by them, since 2020.
3. Compensation cost projections if generators without firm access were to be made firm.
4. The number of generators which receive Renewable Obligation Certificates (ROCs) and resulting compensation.
5. International approaches to allocating firm access to renewable generators, and other relevant issues such as managing constraints, and network planning and development.

1.4 We summarise our information and analysis in chapter 2 followed by a review of the themes arising from international approaches in chapter 3.

1.5 Chapter 4 presents our initial conclusions, outlines potential policy options, and introduces the consultation questions set out in chapter 5. Chapter 6 then outlines the proposed next steps.

1.6 We have set some principles to guide our assessment of the policy options and ensure that we balance consumer protection with the need to incentivise renewable generation. Our statutory framework, as outlined in the Energy (NI) Order 2003, Article 12(1) and 12(2) requires a balanced regulatory judgment over this issue, which would take into

account the interests of consumers and developers of renewable generation. These principles align with our statutory objectives:

A. Any change in approach should demonstrate that it is in long-term interests of consumers, by minimising unnecessary additional costs in the short term and ensuring long-term growth in renewable energy.

B. Network operators should ensure that network development meets timescales unless there are exceptional reasons.

C. There should be appropriate sharing of the risks of higher constraint levels between non-firm generators (who have invested in renewable technologies), consumers (who pay for any compensation for constraints) and network operators (who control network development timescales)

D. Any decision should set out a timescale for review.

2. Firm Access and Dispatch Down

Concept of Firm Access

2.1 Firm Access is a market concept in the Single Electricity Market (SEM), relating to the Transmission capacity available to Transmission or Distribution connected Generators. At present, firm access is allocated via SONI's Firm Access Quantity (FAQ) Methodology, applying to Generators with a Maximum Export Capacity (MEC) of 5MW or above. [1]

2.2 A Generator granted firm access is guaranteed access to the electricity network, or, when this becomes unavailable, due to the Generator having to be dispatched down due to 'localised' constraints, it is then entitled to compensation payments, set out in the Trading and Settlement Code.[2]

2.3 SONI's Firm Access Methodology was consulted upon in 2011 and last updated in 2013. SONI has launched a consultation on the Methodology in August 2026, which we will explore in more detail later in this section. The methodology applies data on transfer capacity and the likelihood of output reductions, to calculate if the connection can be awarded a Firm Access Quantity (FAQ).

2.4 Under the 2013 Methodology, SONI provides a calculated FAQ alongside the Connection Offer. This FAQ reflects the level of firm access that can be accommodated on the existing transmission network. Where appropriate, an Associated Transmission Reinforcement (ATR) report will detail which network reinforcement projects need to be completed before a generator with no (or partial) firm access, can be awarded full firm access, along with a planned timeline for the completion of these projects.[3]

2.5 Prior to 2011, connection applicants had to wait until network reinforcements had been completed, and firm access was available, before their connection could proceed. The Firm Access Methodology introduced greater flexibility by allowing applicants to connect on a non-firm basis ahead of network reinforcement works. While non-firm generators are not entitled to compensation for constraint-related dispatch down, earlier connection enables them to begin generating electricity and earning revenue sooner.

[1] SONI, 'Generator Connection Process: Allocation of Transmission FAQ In N Ireland and ITC Methodology to Determine FAQs: Decision Paper', 22 July 2013.
[2] SEMO, 'Trading and Settlement Code.'
[3] SONI and NIE, Generator Connection Process: Revised Connection Process, 22 July 2013.

2.6 At present, the Northern Ireland grid is split into five different groups for dispatch[4] . The West has the highest levels of renewable generation, with lower demand. The Eastern regions have lower installed renewable capacity, but the highest share of demand[5].

2.7 While dispatch groups form the basis for managing network constraints, neither the dispatch groups themselves nor the level of constraint influences the prioritisation of connection applications or the charge for connection. The ability to export power from the West (where most renewable generation is located) to East (where most demand is), can create constraint bottlenecks.

2.8 In August 2026, SONI published a Consultation Paper concerning a review of its FAQ Methodology[6]. SONI does not propose fundamental change to the firm access principles, that all generators have a path towards full firm access and that firm access should not be withdrawn once granted. However, proposed changes to dispatch and ATR procedures would make some difference to how the FAQ Methodology would work in practice. An annual update of firm access status is proposed to be published, which could give more clarity to generators.

2.9 In the Consultation Paper SONI outlines that the current approach to dispatching renewable generators makes no distinction between firm and non-firm generation, and both are constrained pro rata in line with SEM-13-012, which includes no constraint groups within Northern Ireland and does not align with the constraint groups SONI uses in the Wind Dispatch Tool. SEMC Decision SEM-11-105 only allows for differentiation between firm and non-firm generators which are within SEMC defined constraint groups, which SONI states limits their flexibility in dispatch.

2.10 SONI states it will engage with UR and SEMC on updating the SEMC constraint groups to allow for differentiation in dispatch between firm and non-firm generators at a node, and *"significantly reduce the need for constraint payments."* SONI provided a 2028 projection that savings of c. £8.6 million a year in constraint payments are possible using different methods of dispatch.

2.11 SONI has also proposed potential changes to the ATRs which non-firm generators are linked to, and which are detailed in Paragraph 2.23.

[4] Wind-Dispatch-Tool-Constraint-Group-Overview.docx - NW Northern, NW Southern, Omagh – Dromore, Kells – Rasharkin and All NI

[5] SONI/EirGrid, 'Wind Dispatch Tool Constraint Group Overview', February 2024. – 73%.

[6] SONI FAQ Methodology Consultation Paper 2026.pdf.

Dispatch Down in Northern Ireland

2.12 Dispatch down due to constraints has increased sharply in the last few years. It increased from around 10% of generation in 2018 to a peak of 25.5% in 2024 [7][8], as shown in Figure 1. While UR notes that constraint levels decreased to 19% in 2025 and, as of June 2026, stands at 20.6% in the year to date,[9] we remain concerned at the high levels of dispatch down and consider that all measures are explored to reduce these levels. UR continues to work with SONI as a member of the Dispatch Down Working Group.

2.13 Electricity prices in the Single Electricity Market (SEM) have, in the main, been higher than those in Great Britain. This has been one contributing factor to how, even during periods of high wind generation, imports from Scotland via the Moyle Interconnector have been scheduled by the Transmission System Operator (TSO) ahead of locally generated electricity in line with the priority dispatch hierarchy.

2.14 High constraint levels seen in Northern Ireland can also be compounded by the lack of interconnection to Ireland which limits exports. Available generation from imports through the Moyle Interconnector, plus Northern Ireland renewables, exceeded NI demand 23% of the time in 2024, while a limited amount of Northern Ireland renewables can flow to Ireland through the North South Tie Line.[10]

2.15 SONI publishes regular reports and Data relating to system and renewable energy use. They include reports on, Renewable Energy, System and Renewable Data Reports, Renewable Connections and Forecasting and Renewable Dispatch-Down (Constraint and Curtailment)[11][12]. The following graph summarises the key data and shows the upward trend of dispatch down:

[7] SONI, 'Annual Renewable Dispatch-Down Report'.
[8] Northern Ireland Constraints Report 2023.
[9] Figures up to and including June 2026 – Dispatch Down Summary Report.
[10] Aurora, 'Wasted Potential: Dispatch Down of Renewables in the I-SEM'.
[11] SONI, 'System and Renewable Data Reports'.
[12] SONI, Historical Dispatch Down Rates.

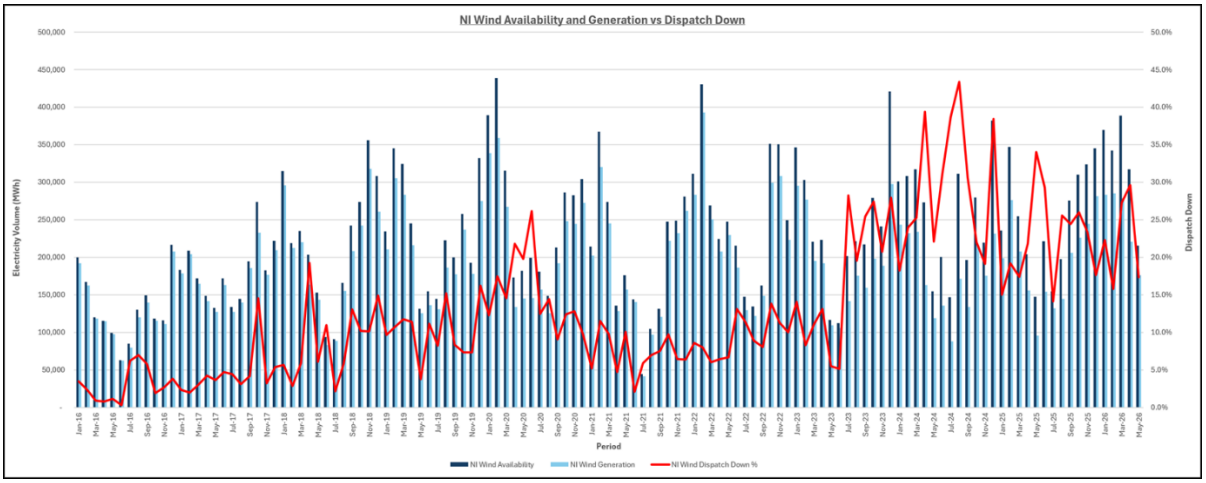


Figure 1 - Wind Availability, Generation and Dispatch Down Rates in Northern Ireland, 2016 to 2026[13]

2.16 SONI had projected, in 2023, levels of dispatch down due to constraints would reduce to just over 5%, on average, by 2030. However, due to delays to the second NSI[14], and import levels on the Moyle Interconnector, dispatch down levels are anticipated to continue at a higher rate. SONI is implementing the actions set out in its Dispatch Down Action Plan[15], which is designed to mitigate and reduce levels of dispatch down across the power system.

2.17 UR's Flexibility Needs Assessment (FNA)[16] examined network level flexibility needs, constraint levels, and where flexibility could provide effective solutions to reduce constraints. The FNA forecasts that relatively high constraint rates would continue until 2033, driven by a combination of network constraints, operational limits and evolving system conditions.

2.18 We further note that approximately 410MW of renewable generation is due to connect to the system in the next four years. This could exacerbate relatively high constraints, if other actions are not taken[17].

2.19 Network development can naturally lag behind the deployment of renewable generation, as transmission infrastructure projects typically require longer lead times to plan, approve and deliver[18]. However, a review of the Transmission Development Plans for Northern Ireland (TDPNIs),

[13] Dispatch Down Summary Report.

[14] This is one of the projects proposed in the TDPNI, which would construct a new Interconnector/400 kV circuit, connecting Woodland Substation in Couty Meath to Turleenan in County Tyrone. This would be the second source of interconnection between Northern Ireland and ROI, and could assist relieving some dispatch down due to constraints in Northern Ireland.

[15] Draft Dispatch Down Action Plan - System Operator for Northern Ireland - December 2024.pdf

[16] Utility Regulator, 'Northern Ireland: Flexibility Needs Assessment – 2026'.

[17] SONI, 'Connections Register'.

[18] Redispatch and congestion management - Publications Office of the EU.

shows that several key network development projects have experienced significant delays. For example, between the 2021 and 2025 TDPNIs, the projected completion date for the Mid Antrim Upgrade changed from 2026 to 2030, the NW of Northern Ireland 110kV Reinforcement was deferred from 2029 to 2037, and the NSI from 2025 to 2031.[19]

Firm and Non-Firm Generators

2.20 Analysis of all renewable generators shows that 675MW of generation, across 36 Generators, is firm. Further to that, 68MW, across six generators, is partially firm, and 437MW, across 25 generators, is non-firm.

2.21 UR analysis indicates, that, based on current dispatch-down levels, all Northern Ireland firm and non-firm generators exceed the 2% threshold used as an initial screening criterion in Ireland. The figures below illustrate the geographic distribution of renewable generators in Northern Ireland and their respective levels of dispatch down for single months (January 2021 and January 2025), in three bands of dispatch down; less than 2%, between 2% and 7% and greater than 7%. The vast majority of generators experienced dispatch down above 7% in January 2025.

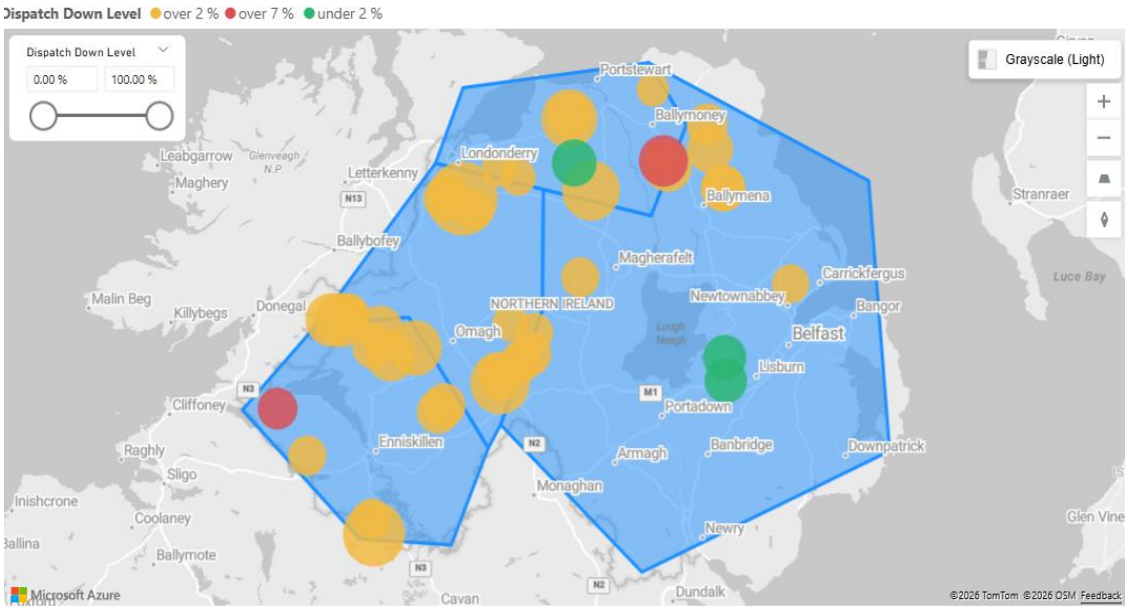


Figure 2 – Dispatch Down Level of Renewable Generators, January 2021[20]

[19] SONI, 'Transmission Development Plan Northern Ireland: 2021 - 2030', SONI, Draft Transmission Development Plan Northern Ireland: 2025-2034'.

[20] Data supplied by SONI.

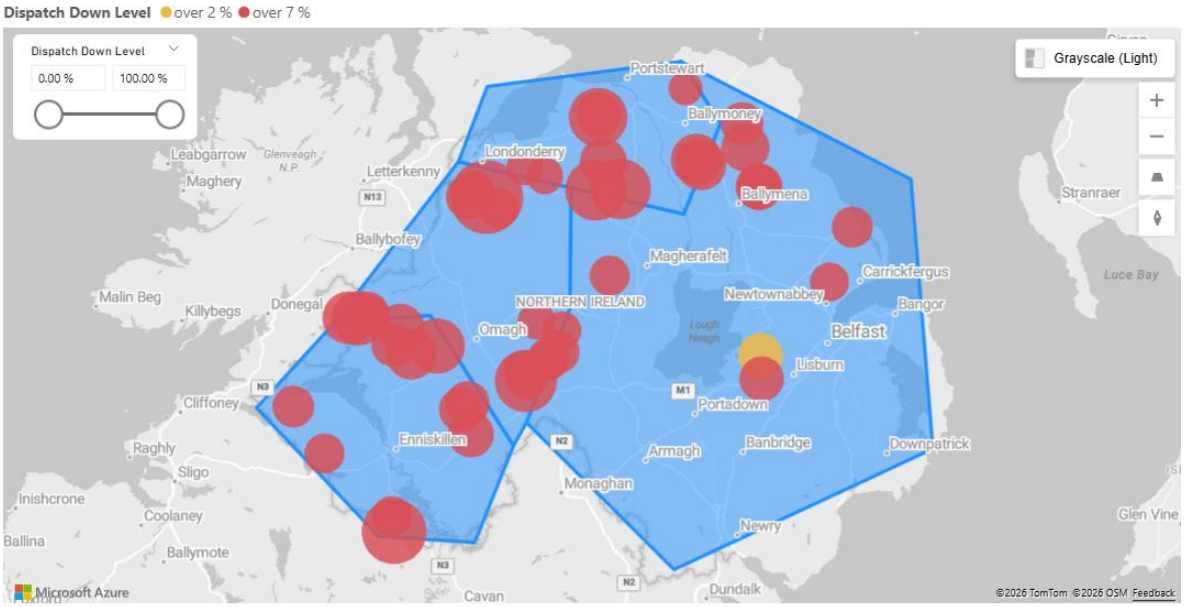


Figure 3 - Dispatch Down Level of Renewable Generators, January 2025[21]

2.22 As outlined in paragraph 2.4, non-firm connections were provided with an indicative timeline for the ATRs required before they could be made firm. For the 31 generators which are non-firm or partially firm, we can see that all of them require the NSI and most require the Mid Antrim upgrade. The timescales for those two network development projects were pushed back by a number of years. We note that the estimated completion dates have remained unchanged through a number of quarterly updates.

2.23 In the August 2026 FAQ Consultation, SONI proposes that, once Synchronous Condensers at Coolkeeragh and Coleraine come online in 2027, SONI would be able to remove 400MW of non-firm Wind and all non-firm solar from the NSI ATR. However, because of other ATRs, and newly linked ATRs, there would be projected to be no major change in FAQ levels before 2031.

System Demand

2.24 System demand has steadily fallen in recent years, for a variety of reasons. Lower demand has been a contributory factor to dispatch down levels.

[21] Data supplied by SONI.

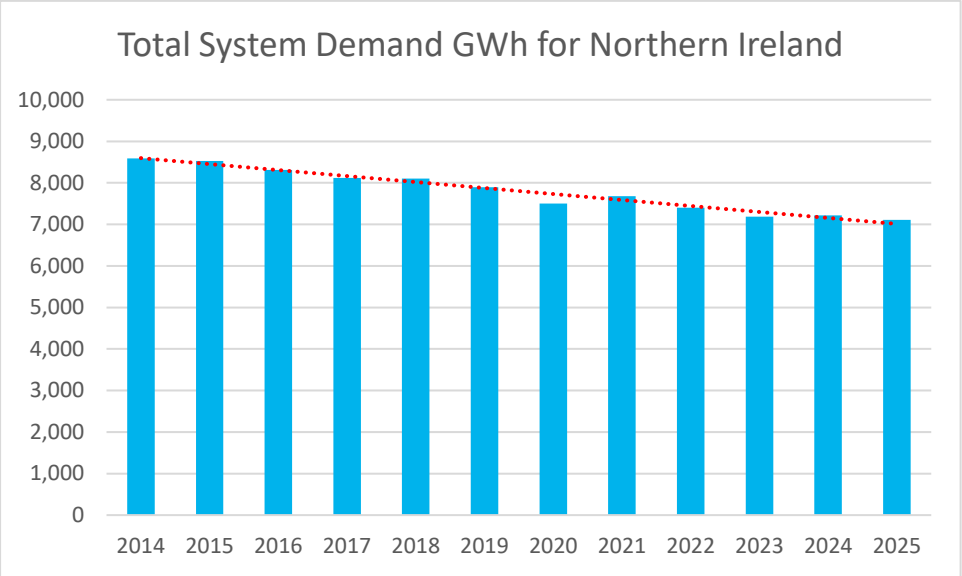


Figure 4 - System Demand for Northern Ireland[22]

2.25 Changes to demand, such as increasing electrification of heat and transport, as well as potential data centres, may reverse this trend.

2.26 Incentivising new demand connections, for example data centres, close to areas of high constraint could be an effective way to use more of the available renewable electricity.

Cost of Compensation Payments

2.27 UR has explored approximate compensation costs, if all non-firm dispatch down volumes for SEM-participant NI generators had been deemed firm and compensated at the Day Ahead Market (DAM) Price. We would note that nothing in this section should be construed as implying that any particular compensation should be applicable.

2.28 To do this we needed access to external data sources, specifically from the Single Electricity Market Operator (SEMO). Data requested included all Loss Adjusted Bid Quantities (QABNFLF) for Northern Ireland Generators, and the Day Ahead Market (DAM) price. The QABNFLF is a SEM variable, as defined in the Trading and Settlement Code[23] .

2.29 We used this data to calculate a weighted average DAM price for each year, weighted by the level of QABNFLF in each Imbalance Settlement Period. We used these volumes and prices to explore the potential historic and future costs of compensation for foregone market revenues for dispatch down of non-firm volumes.

[22] SONI, 'System and Renewable Data Summary Report'.
[23] Balancing Market Rules | Rules and Modifications | SEMO.

2.30 We applied a weighted average price for non-firm generators, derived from Market outcomes, to estimate the payments these generators would have received during 2020-2025 (as part of Dispatch Balancing Costs) to compensate for generation dispatched down because of constraints, in a scenario where these generators would have held firm access.

2.31 By combining the QABNFLF for each individual generator with the volume weighted DAM price for each year, we then received a robust value for the compensation that would have been paid to non-firm generators during the time period 2020-2025, if they had been firm.

2.32 We found that the potential cost of compensating non-firm dispatch down volumes by deeming them firm in future could be significant. Increases in dispatch down volumes and market and support rates could also exacerbate this. Our analysis indicates that such compensation costs could be in the order of tens of millions annually in future. We also would note that there is significant uncertainty in relation to what compensation will be applicable and as such it is not possible to know with certainty what these costs will be.

2.33 Some aspects potentially impacting compensation costs (e.g. those arising from foregone revenues associated with power purchase agreements, or under the new Renewable Electricity Price Guarantee (REPG) support scheme, or future market design changes to introduce nonpriority dispatch renewable generators) are also unknown and have therefore not been included in our analysis of these costs.

2.34 The potential extent of these compensation costs appears to be dependent on multiple factors. One is how they are affected by constraints - in this case these were rising through the period of the analysis. The other was changes in the DAM price. Both these factors could affect the potential compensation value. The amount of future renewable generation added to the network, and future demand levels, are also factors that could influence potential compensation costs.

2.35 In addition, some generators receive revenue from Renewable Obligation Certificates (ROCs). We analysed Ofgem data on the ROCs price, ROCs recycle value, and number of ROCs held by each relevant individual generator, from 2020 to September 2025. However, our main focus was on the revenue generators *without* firm access might have received, if they had firm status.

2.36 Of the 25 Generators without firm access, 14 hold ROCs certificates. Our calculations indicated a significant increase to potential compensation if non-firm volumes outside of the ROCs scheme were compensated.

2.37 Our analysis of generator finances[24] demonstrated that most generators, both firm and non-firm, were profitable. The analysis also suggested a tentative relationship between firm access and profitability, as well as between firm access and future investment decisions. In particular, many generators had proceeded with investment despite initially holding non-firm access rights.

2.38 Although profitability is likely to have been influenced by a number of factors, our analysis found that generators that were not Earnings Before Interest and Taxes (EBIT) positive generally neither held firm access rights nor benefited from Renewable Obligation Certificates (ROCs). While other factors may also have influenced profitability, we observed that generators that were not profitable generally did not have firm access and did not hold ROCs.

2.39 Following the publication of our Information Paper in May 2026, UR received correspondence from generators highlighting the financial impacts associated with what they described as above-average dispatch down rates, the absence of firm access rights, and the loss of ROC income. Generators stated that these factors were adversely affecting project revenues and, consequently, the financeability of generation assets.

Consumers

2.40 We are mindful of the importance of ensuring long term value for consumers and avoiding significant price increases where possible. This is even more relevant, given Northern Ireland is the region with the lowest annual average household discretionary income in the UK,[25] and 2024 modelling from the Northern Ireland Housing Executive has estimated that 27% of households are in fuel poverty.

2.41 Consumers in Vulnerable Circumstances are spending more on their monthly energy bills and are more likely to be struggling to pay them.[26]

Other External Factors

2.42 There are also potential developments that could change the context relating to the situation around non-firm generators.

2.43 The Renewable Energy Generation Bill (previously known as Renewable Energy Price Guarantee or REPG) was placed before the NI Assembly in

[24] Note this included analysis, where accounts were available, for Earnings Before Interest and Taxes (EBIT) Margin and Return on Equity.
[25] ASDA Income Tracker - July 2026.
[26] Utility Regulator, 'Domestic Consumer Insight Tracker Survey', July 2026.

June 2026[27], following the Final Scheme Design in September 2025, with contract awards planned to commence in 2027.

2.44 The final Scheme Design referred to 'extremely high' constraint rates potentially deterring investment and thus increasing auction prices. Compensation at strike price "for all constraints and curtailment events," unless already compensated, was proposed. This would be temporary, until "long term remedial activities" could be implemented.[28] This could negatively affect existing non-firm generators, who may experience higher future levels of dispatch down, due to increased generation in their area.

2.45 Article 13(7) of Regulation 2019/943, part of the Clean Energy Package (CEP), requires that System Operators compensate renewable generators with firm access, in the event of non-market based dispatch down. This compensation is related to net revenues from the sale of electricity on the day-ahead market including associated financial support.

2.46 Interpretation of Article 13 (7), through SEM Decision SEM-22-009[29] and a pending modification to the Trading and Settlement Code[30] has now progressed to the European Court of Justice (CECJ). One open question concerns compensation for revenue lost from dispatch down, including foregone financial support, and what type of generators this applies to. [31]

2.47 If Article 13(7) is upheld, this may render TSOs liable for several hundred million pounds in compensation, potentially dating back from 2020. This would significantly increase future compensation payments, on an already constrained all-island system, and could impact consumer bills.

2.48 Decision could be taken in late 2026 or later, with the Irish Supreme Court obliged to implement the CECJ's ruling with no scope for appeal.

[27] Archibald introduces landmark Renewable Electricity Generation Bill | Department for the Economy.
[28] Department for the Economy, 'Final Scheme Design For A Renewable Electricity Support Scheme for Northern Ireland'.
[29] SEM-22-009, 'Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019943.'
[30] SEMO, 'Modification Proposal Form (Mod_05_23)'.
[31] Energia Group Holdings (ROI) DAC & ors v The Commission for Regulation of Utilities GR Windfarms 1 Ltd & ors v Commission for Regulation of Utilities (Approved) [2025] IESC 1 (21 January 2025) – note the reference in Article 13 to excluding 'unjustifiably' low or high compensation.

3. International Approaches

3.1 Our research reflects different approaches to allocating firm access and reducing constraints. Most measures apply to new connections rather than existing connections.

Approaches to Managing Existing Connections

Changes in Ireland

3.2 Recent changes to how firm access is allocated in Ireland have potentially facilitated new generators being awarded firm access:

3.3 On the first run of the new methodology, if constraints are 2% or below in a node, a generator is awarded firm access ('Firm Threshold'). If above 2%, no award is made, with further examination of partial firm access and required network reinforcements. This exercise is repeated periodically.

3.4 For those who are not determined to be firm, the generator is told what network reinforcement is required, and the planned completion date. Unlike in Northern Ireland, if network reinforcement is not completed within a stated timescale, the generator will now nevertheless be awarded firm access.

3.5 In 2025 and 2026, EirGrid's firm access reviews considered the firm access status of 124 generators (7.8GW), via the new methodology. In 2025, around a third of wind and half of solar generators were granted firm access, conditional on reinforcement, and around 5% of wind and 15% of solar became firm without further reinforcement [32] [33]. In 2026, the numbers made firm, for onshore wind, in particular, sharply reduced[34].

3.6 We note that it was stated in SEM-23-004 that, if related network re-enforcements were not completed by the allocated FAQ date, then any compensation from granting associated generator FAQs would be moved to a separate jurisdictional TSO cost recovery, paid for by consumers in Ireland. When the relevant reinforcements were completed, the unit's FAQ would be moved back into the existing all-island settlement. None of

[32] EirGrid, 'Firm Access 2025 Review Report: Final Technical Report', May 2025.

[33] In the Firm Access Review three 'lenses' are listed - 'Does the decision on generator firm access protect the end consumer from unreasonably high constraint payments?'; 'Does the decision on generator firm access provide an appropriate locational signal for whether generation should connect?'; 'Is a specific constraint or group of constraints in an area sufficient justification for a specific reinforcement?'

[34] EirGrid, Firm Access April 2026 Run Review Report: Final Technical Report', April 2026. - 40MW of capacity available for new onshore wind in unreinforced system.

the measures proposed in this consultation would affect these arrangements.

Proactive Constraint Management

3.7 Some regions have integrated the management of constraints into market arrangements or dispatch processes. In Great Britain, the Constraints Collaboration Project, identified the potential for short- and long-term constraint management markets[35] . The Megawatt Dispatch Project uses Balancing Market actions, and new Transmission Constraint Management services, to manage the system to reduce constraints [36] .

Approaches to New Connections

Locational Signals for New Connections

3.8 In some regions, renewable generators can be encouraged to locate in lower constraint areas, placing less strain on the network. Texas' ERCOT programme identifies high value renewable zones, via constraints studies, to direct development[37]. In Denmark, differentiated connection charges for 'production' and 'consumption' dominated areas apply, with higher tariffs for production areas.[38] There are plans in Germany to implement dynamic grid fees by 2030, that would be location variable, could be positive or negative, and would reward grid friendly behaviour.[39] The CRU has also focused on facilitating hybrid connections, through MEC sharing, behind a single connection point [40].

3.9 Incentives to demand users (especially large demand users) can encourage location in high constraints zones, to utilise 'excess' renewable generation. The Dutch ACM's prioritisation framework, instead of a 'first come first served' approach, sets out three priority categories for electricity capacity requests, including 'congestion relievers'[41]. This includes flexible industrial users, Data Centres, storage, or electrolysers [42].

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[35] TEL, 'Exploring Options for Constraint management in the GB Electricity System: The Potential for Constraint Management Markets', January 2024.

[36] NESO, 'MW Dispatch Service Details Including Visibility and Control Requirements'.

[37] Heesun Jang, 'Market Impacts of a Transmission Investment: Evidence from the ERCOT Competitive Renewable Energy Zones Project', *Energies*, 13(2), 2020.

[38] ACER, 'Getting the Signals Right: Electricity Network Tariff Methodologies in Europe: ACER Report on Network Tariff Practices', March 2025. – In the production area, high amounts of renewable energy are produced, and the consumption area where high amounts are consumed.

[39] Cameron Murray, Germany: BNetzA's Post-2029 Dynamic Grid Fees to Reward Grid-Friendly Behaviour, But More Clarity Needed', *Energy Storage News*.

[40] CRU, 'Consultation on Sharing of Maximum Export Capacity (MEC) Behind a Single Connection Point,' March 2026.

[41] Defined by the ACM as an area where current or forecast power flows exceed capacity limits.

[42] ACM, 'Draft Code Decision Prioritisation Space for Transport Requests 2025', June 2025.

3.10 The Demand for Constraints service proposed in Great Britain identifies similar technologies. A ten-year ancillary service contract would offer reduced electricity costs, for increased consumption during constraints [43].

Increased Flexibility of Connections

3.11 European Directive 2024/1711[44] states a framework should be developed to offer Flexible Connection Agreements (FCAs), but this should not delay network reinforcements. Flexible (which is equivalent to non-firm) connections should be converted to firm, once the network is developed sufficiently, but where it is identified network development is not the most efficient solution, a permanent non-firm connection could be offered (these are not offered in NI).

3.12 In Norway, FCAs can be offered with conditions, being permanent (to avoid grid development costs) or temporary (until development is completed). In return, faster grid connection is delivered[45]. In Finland, the flexible connection framework includes distinction between temporary and permanent FCAs, with permanent FCAs in areas where network development is deemed to not be efficient[46].

3.13 In Denmark, limited grid access can happen beside a reduced connection fee, for new connections not triggering grid reinforcements. The grid operator can disconnect/dispatch down the generator over constraints[47].

3.14 In the Netherlands, FCAs are only available in network areas defined as congested. Tariffs are calculated on the highest demand reached during a month, not a contracted amount of capacity. Timeslots are available, where capacity is only available during contracted (offpeak) timeslots[48].

3.15 There are active proposals to design flexible/'non-firm' contracts, and hybrid connections, for Large Energy User demand connections, to maximise utilisation of renewables, in Ireland. It is stated this will benefit efficiency and optimise the use of grid infrastructure, by large demand users, including data centres, can increase demand when there is a

[43] TEL, 'Exploring Options for Constraint management in the GB Electricity System: The Potential for Constraint Management Markets', January 2024. – this includes electrolysers, industrial demand and process, district heating, commercial demand, and aggregated demand.
[44] Directive (EU) 2024/1711 of the European Parliament and of the Council of 13 June 2024 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market Design Text with EEA relevance.
[45] Eurelectric, 'From Backlog to Breakthrough: Managing Connection Queues in Distribution Networks,' June 2025.
[46] CEER, Grid Connection Challenges', June 2026.
[47] THEMA, 'Conditional Grid Connections: A Literature Review'.
[48] ACM, 'Codebesluit Non-Firm ATO', January 2024.

surplus of renewables, and reduce demand when the grid is constrained[49].

Prioritising and Driving Network Development

3.16 In Great Britain, connection queue reform prioritises projects aligned with system needs, that pass strategic alignment tests. NESO can designate individual projects as strategically important, where they provide system/economic benefits. NESO says it only intends to designate projects materially reducing constraints or using new technologies[50] .

3.17 The Networks Options Assessment[51] directly compares costs of managing system constraints against the cost of network reinforcement, feeding into Holistic Network Planning. The Strategic Spatial Energy Plan sets out optimal energy infrastructure required to meet future demand, guiding the use of strategic alignment criteria for connecting to the grid[52] .

3.18 In planning, the provision of nationally significant low carbon infrastructure has been designated a Critical National Priority [53], and the National Planning Policy Framework includes a section on supporting the development of energy infrastructure aligning with net zero[54].

Overall Themes

3.19 Review of international approaches has reflected a variety of approaches to firm access allocation and other relevant issues. Some approaches, such as Ireland's new allocation system, theoretically allow for more allocation of firm access than the Northern Ireland system.

3.20 Other proposals, including enhanced constraint mapping, the integration of constraints into network planning and dispatch decisions, and incentives to influence the location of generation and demand, could affect the level of constraints experienced by generators and, consequently, the need for firm access.

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[49] Government of Ireland, 'Large Energy User Action Plan', note that Directive 2024/1711 allows for Flexible Connection Arrangements to be a permanent solution, if network development is not the most efficient solution, however, if the network is developed the connection should be made firm, and FCAs by themselves should not deter network development - CEER, Grid Connection Challenges', June 2026.

[50] HSFK, 'Clean Power 2030: Connections reform - 'First Ready and Needed, First Connected, January 2025.'

[51] National Grid, 'Network Options Assessment 2021/22 Refresh,' July 2022.

[52] NESO, 'Strategic Spatial Energy Planning (SSEP)' .

[53] UK Government, Overarching National Policy Statement for Energy (EN-1), December 2025.

[54] Ministry of Housing, Communities and Local Government, 'National Planning Policy Framework: Plan – Making and National Decision-Making Policies', December 2025.

3.21 Some of these considerations are relevant to Northern Ireland. We will consider whether there are issues with these ideas being applied here.

Northern Ireland Specific Issues

3.22 The higher level of constraints in Northern Ireland creates difficulties in following approaches used elsewhere. The below graph highlights the higher rate of dispatch down in Northern Ireland compared to regions in Ireland:

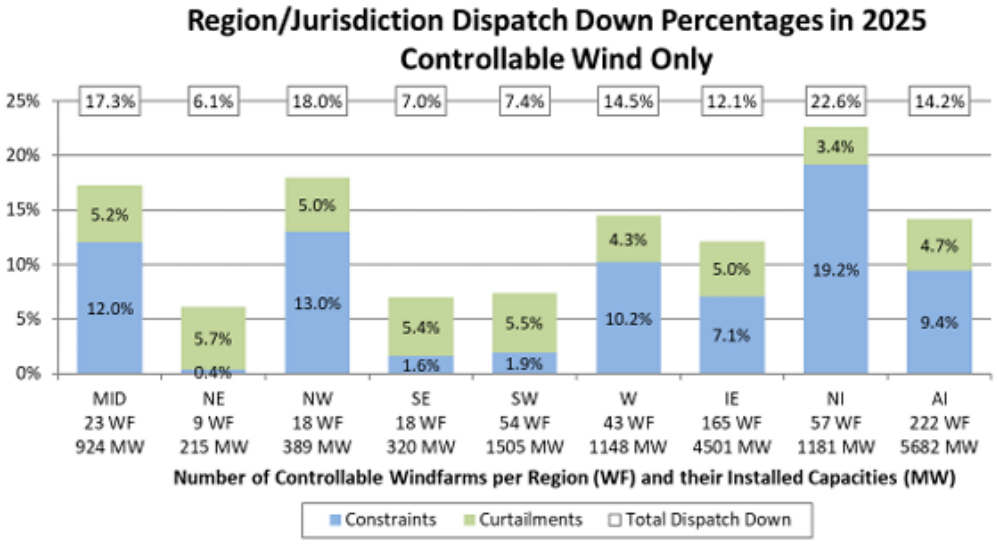


Figure 2 - All-Island Dispatch Down Percentages by Region (2025)

3.23 Considering the 2% Firm threshold approach used in Ireland, very few non-firm generators in Northern Ireland would qualify.

3.24 Looking at the expected completion dates of ATRs, all non-firm generators would stay non-firm until at least 2031, if current estimated completion dates are met. Granting firm access to more generators sooner than 2031 could lead to 'financial' firm access, not a 'physical' one where most of the energy transmitted can be consumed.

3.25 Non-firmness creates an issue for affected generators, particularly where the required ATRs have been delayed and they are financially impacted. This may get worse if dispatch down levels remain high and new generators access the Renewable Energy Generation scheme and make local constraints worse. This may create an apparent two-tier system. It is also worth noting that the treatment of constraints and curtailment under the Renewable Energy Generation Scheme means that the issue of firmness will not apply to new generation capacity procured through the scheme.

3.26 If firm access policy was revised to target this issue, it could transfer the burden solely onto consumers. More compensation costs may also embed expectations of permanent firm access, encouraging generation to be sited suboptimally, *vis-á-vis* constraints. It could also reduce incentives to collaborate with network operators to minimise dispatch down.

3.27 We note the matter in hand is not the level of firmness, but the level of dispatch down. If this was reduced, non-firm generators would be paid for generation on the same basis as firm generators.

3.28 Reducing dispatch down due to constraints appears to be a more immediate and feasible way to tackle the underlying issues applying to these generators. This could be looked at through the lens of increasing demand, through network build or development of storage and flexibility services.

4. Initial Conclusions

4.1 It is clear that dispatch down has been high over last three years and is unlikely to return to pre-2023 levels in the short term. Planned network development has been consistently delayed and will take some time to complete. Most non-firm generators are linked to two or more ATR projects [55].

4.2 Non-firm connection agreements provide developers with the opportunity to connect ahead of network development and begin to generate revenue, in areas of constrained capacity. If only firm connection agreements were available, then developers would have to wait until the network development has been completed.

4.3 We understand and accept that non-firm generators would have based their business cases on expectations of becoming firm, using the ATR dates in the connection agreement. Some non-firm generators tell us their revenue is impacted, due to the combination of long term delays to network development, lower system demand, and higher dispatch down levels than anticipated, shifting the risk of delayed network development to them, rather than network operators.

4.4 The principles that we outlined in paragraph 1.6, repeated below, have informed the policy options proposed in this chapter, over which we will take a balanced regulatory judgment, factoring into account the interests of consumers and developers:

A. Any changed approach should be in the long-term interests of consumers, by minimising short term unnecessary additional costs and ensuring long-term growth in low carbon technologies.

B. Network operators should ensure that network development meets timescales unless there are exceptional reasons.

C. There should be appropriate sharing of the risks of higher constraint levels between non-firm generators (who have invested in renewable technologies), consumers (who pay for any compensation for firm constraints) and network operators (who control network development timescales).

D. Any decision should set out a timescale for review.

4.5 We propose the following policy options which we consider against the principles

[55] Aside from one partially firm generator.

1. Do Nothing.

   This would mean retaining the current arrangements. It would avoid immediate additional consumer costs but would not change the present allocation of risk or provide a defined review timetable.

   It does not meet principle C – ensuring appropriate risk sharing of higher constraints, and principle D – a timescale for review.

2. Align with the 2023 Ireland firm access decision[56].

   This would link firm access to committed reinforcement dates. This could improve accountability and risk sharing but may expose consumers to substantial and uncertain compensation costs while physical constraints remain unresolved.

   This puts the focus on principle B of ensuring network development meets timescales and would demonstrate a risk-sharing approach to meet principle C.

   If all non-firm generators were granted firm access rights, our analysis indicates that this could result in additional compensation payments of potentially tens of millions of pounds annually for constraint-related dispatch down. The core problems of high constraint levels and delayed network development would also remain. This option would not meet principle A, as it would commit consumers to future unknown costs.

3. Pursue a Northern Ireland-specific approach.

   This option is focussed on reducing constraints and improving risk sharing, by pursuing a number of measures, which might include the following:

   (i) KPIs on SONI and NIE Networks for network development timescales. It is imperative SONI and NIE Networks meet the timescales in the TDPNI, and SONI continues to implement measures in the Dispatch Down Action Plan. We will explore the feasibility of whether incentives or penalties could be applied to System Operators, for actions within their control.

   (ii) Encouraging demand connections in high constraint areas.

   (iii) Consideration on whether we can pursue a different approach for non-firm generators, not in receipt of ROCs.

[56] CRU, 'Firm Access – Detailed Methodology, November 2023.

(iv) Encouraging and facilitating changes that would enable hybrid connections, such as the ability for two or more generation or storage technologies to share Maximum Export Capacity (MEC) at a single connection point.

(v) Set a timescale for the next review of the firm access policy.

This option proposes no significant changes to how firm access is allocated, beyond any procedural changes that may be made by SONI as part of their FAQ review.

We consider that this policy option meets each of the Principles and allows for measures to mitigate the core problem of constraints. We ask a question in chapter 5 on what further measures should be included within policy option three, including suggestions on co-operation with other bodies.

This option is UR's preferred basis for moving forward.

4.6 We are seeking views on the proposed options from market participants, SEM stakeholders and consumers. We will continue to engage with the Commission for Regulation of Utilities (CRU) and consumer views will also be sought through engagement with CCNI and UR's Domestic Consumer Advisory Forum and Non-Domestic Consumer Advisory Forum.

5. Consultation Questions

5.1 The consultation questions are informed by the analysis of the current situation in Northern Ireland and approaches adopted in other jurisdictions. They also reflect the need to explore solutions that could help manage and reduce constraints.

Views on Policy Options

5.2 **Question 1-** What are your views on the merits of the three policy options detailed in this consultation paper? Are there further measures you would suggest could be included, especially in policy option three, that would ensure we meet our four principles? On what timescale do you think these options could be progressed?

Treatment of Selected Generators

5.3 **Question 2-** Do you think any action could be taken to manage the risk of increased dispatch down for non-firm generators, due to new connections? If so, what can be done?

5.4 **Question 3-** Financial accounts show that some generators could be more negatively impacted than others. Is it appropriate to take a different approach in a firm access policy for those generators who are more negatively impacted? How could this be done?

Existing Generators Repowering

5.5 **Question 4–** Could firm access rights be tied to an asset or a project or for a specific time period, as opposed to being considered as permanent as set out in SONI FAQ Methodology?

5.6 **Question 5–** Give your views on how/ whether firm access should be assessed at the point of repowering/renewal of equipment. For example, should another, existing non-firm generator, at the same node be allocated that firm access, instead of it being maintained with the existing generator?

Demand Utilisation

5.7 **Question 6-** Would a Demand for Constraints service (like available in GB) be useful in Northern Ireland, if it incentivised large demand users to increase their consumption at times of high renewable generation?

Locational Preferences for Demand

5.8 The demand connections queue is also not aligned with the level of constraints within dispatch zones, despite the potential benefits of

incentivising large demand users to locate in constrained areas. As has been demonstrated in other jurisdictions, this can help utilise generation that would otherwise be constrained due to network limitations preventing its transmission to other locations.

5.9 **Question 7-** Should large demand users, like data centres, be incentivised to connect in high constraint areas and what form might the incentive take? Would priority in the connection queue be a sufficient incentive?

Prioritising and Driving Network Development

5.10 **Question 8-** Please give your views on progressing key network development projects? Do you have any views on where improvements could be made to speed up network development?

5.11 **Question 9–** Are there specific incentives that the UR should consider placing on Network operators and owners?

6. Next Steps

Task	Date
UR initial engagement with SEM Committee	September 2026
Issue of Consultation	6 October 2026
End of consultation	22 January 2027
Review of Consultation responses	Q1 2027
Engagement with SEMC on Consultation responses and detail of proposed decision	Q1 2027
Engagement with UR Board on Consultation responses and detail of proposed decision	Q1 2027
UR publishes decision	2027
UR implements decision	To be confirmed

Table 1 - Dates for next steps

2.1 The deadline for responses to this consultation is 22 January 2027. Responses should be sent to:

Ben Harris
Utility Regulator
Millennium House
Great Victoria St
Belfast
BT2 7AQ
Ben.Harris@uregni.gov.uk and
Electricity_Networks_Responses@uregni.gov.uk

6.1 The Utility Regulator's preference would be for responses to be submitted by e-mail to the above email addresses.

6.2 Note that the Utility Regulator intend to share any responses received with the SEM Committee and the CRU.

6.3 If you want other information that you provide to be treated as confidential, please be aware that, under the Freedom of Information Act 2000, there is a statutory Code of Practice with which public authorities must comply and which deals, amongst other things, with obligations of confidence. In view of this, it would be helpful if you could explain to us why you regard the information you have provided as confidential.

6.4 Information provided in response to this consultation, including personal information, may be subject to publication or disclosure in accordance with the access to information regimes (these are primarily the Freedom of Information Act 2000 and the Data Protection Act 2018.

6.5 As stated in the GDPR Privacy Statement for consumers and stakeholders, any personal data contained within your response will be deleted once the matter being consulted on has been concluded though the substance of the response may be retained.

6.6 This paper is available in alternative formats such as audio, Braille etc. If an alternative format is required, please contact us and we will be happy to assist.