DEPARTMENT FOR THE ECONOMY

IMPLEMENTATION PLAN FOR NORTHERN IRELAND

With reference to the recast Electricity Regulation (2019/943)

DECEMBER 20, 2019

DEPARTMENT FOR THE ECONOMY

Implementation Plan

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Glossary of Terms

BM – Balancing Market

BRPs – Balancing Responsible Parties

BSPs – Balancing Service Providers

CACM - Capacity Allocation and Congestion Management

CRM – Capacity Remuneration Mechanism

DAM – Day Ahead Market

DS3 - Delivering a Secure, Sustainable Electricity System

DSU - Demand Side Unit

EWIC – East West Interconnector

IDM – Intra-Day Market

I-SEM - Integrated Single Electricity Market

SEM - Single Electricity Market

SEMC - – Single Electricity Market Committee

SEMO – Single Electricity Market Operator

SONI – System Operator for Northern Ireland

TSO – Transmission System Operator

1. Introduction – The purpose of this paper

This paper is intended to outline how Northern Ireland proposes to give effect to Article 20(3) of the recast Electricity Regulation[1] on the internal market for electricity. This provides that a Member State with identified resource adequacy concerns shall develop and publish an implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failure as part of the State Aid process.

1.1 Northern Ireland

Northern Ireland is one of the devolved administrations of the United Kingdom and energy policy is a devolved competency. Northern Ireland operates a joint wholesale electricity market with Ireland, known as the Single Electricity Market (SEM). This market has been in place since November 2007, and has a total annual value of more than €2 billion.

The Northern Ireland retail market is one of the smallest in Europe, with approximately 812,000 domestic and 74,000 Industrial and Commercial (I&C) customers. Over 99% of the connections in the I&C sector are comprised of small and medium sized enterprises.

Northern Ireland currently has around 4040MW of generating capacity of which 1,788MW is provided by three thermal power stations; 106MW from small conventional generators; and 1,598MW is from renewable sources, predominantly wind[2]. Demand Side Units make a small but growing contribution to overall capacity, with 98MW currently registered in Northern Ireland.

Northern Ireland has 450MW of interconnection with the Great Britain market through the Moyle Interconnector. Northern Ireland also has interconnection with Ireland and is progressing arrangements for further interconnection by way of a second North/South Interconnector. This project is a designated EU Project of Common Interest (PCI).

Analysis completed by the Transmission System Operator (TSO) in 2016 flagged longer term security of supply concerns and recommended the need for a Capacity Remuneration Mechanism (CRM) as part of new market arrangements to address the EU Target model.

[1] Commission Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity (OJ L 158, 14.6.2019, P,54

[2] http://www.soni.ltd.uk/media/documents/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

The SEM has undergone extensive reform to improve liquidity and provide the electricity sector with more stable and effective market arrangements.

The reforms under the Integrated Single Electricity Market (I-SEM) programme went live on 1 October 2018. These changes brought the SEM in line with the IEM requirements under the EU Target Model and in accordance with state aid rules. Work on these reforms had been under way since 2013.

1.2 The Clean Energy Package

The EU has agreed a comprehensive update of its energy policy framework to facilitate the transition from fossil fuels towards cleaner energy and to deliver on the EU's Paris Agreement commitments for reducing greenhouse gas emissions. The completion of this new energy rulebook – called the **Clean Energy for all Europeans package** - marks a significant step towards the implementation of the energy union strategy, adopted in 2015.

1.3 Electricity Market Design

Part of the package seeks to establish a modern design for the EU electricity market, adapted to the new realities of the market – more flexible, more market-oriented and better placed to integrate a greater share of renewables. The electricity market design elements consist of four dossiers - a new electricity regulation, and amending electricity directive, a risk preparedness regulation and a regulation outlining a stronger role for the Agency for the Cooperation of Energy Regulators (ACER).

1.4 The Electricity Regulation

Article 20 of the Electricity Regulation requires those Member States with a resource adequacy concern to develop and implement a plan with a timeline for adopting measures to eliminate identified regulatory distortions or market failures. Northern Ireland already has an approved Capacity Remuneration Mechanism (CRM) scheme in place as part of the new Integrated Single Electricity Market (I-SEM) following a formal State Aid notification process which concluded in November 2017 with the Commission granting State Aid approval of the CRM.

Annual capacity auctions for the SEM have been held since December 2017 and the first T-4 auction was held in March 2019. Capacity Auctions have sent entry and exit signals to the market where appropriate. Under the previous electricity market arrangements, all available generators benefited from capacity payments. This is no longer the case and some generators, including

NI generators, were not successful in the capacity market auction held in December 2018.

Article 22(4) (b) of the Electricity Regulation stipulates that from 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO_2 of fossil fuel origin per kWh of electricity and more than 350 kg CO_2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism. It is anticipated that this will directly affect some generators in Northern Ireland and could potentially contribute to security of supply concerns.

1.5 I-SEM Market Reform

The new Single Electricity Market (SEM) launched successfully on 1 October 2018. The upgrades to the SEM brought it into line with the European Target Model, as outlined in IME3 – the third package of European legislation and regulations launched in 2009. The new SEM design allows for cross-border trading and allows the SEM access to Europe's Internal Energy Market for the first time, making optimal use of cross-border transmission assets. It is designed to ensure greater competition and to put downward pressure on wholesale prices.

A key feature of the new I-SEM project was the introduction of a new State Aid compliant Capacity Remuneration Mechanism (CRM) for the SEM. This was necessary to ensure adequate levels of generation and long term security of supply, which can be particularly challenging for isolated island markets with large volumes of intermittent generation, such as the SEM.

The Commission's State Aid approval in November 2017 recognised the appropriateness of introducing a new SEM CRM in parallel with the restructuring of the island of Ireland's wholesale market. The Commission therefore expressly recognised that the SEM CRM is designed to support and complement the ongoing reform of the Integrated Single Electricity Market, the goal of which is to ensure compatibility with the EU internal energy market legislation.

1.6 Northern Ireland's and Ireland's Implementation Plans

Although Northern Ireland and Ireland are submitting separate Implementation Plans they are effectively measures for the same market but with certain jurisdictional differences. Both plans highlight the continued necessity for the SEM CRM that received State Aid approval for a period of ten years from the European Commission in November 2017. Northern Ireland and Ireland have cooperated in preparation of their respective notifications and we therefore ask the Commission to consider both documents in parallel.

2. General Wholesale Market Conditions

2.1 The Single Electricity Market

The Single Electricity Market (SEM) is underpinned by an international agreement between the UK and RoI Governments and by parallel, complementary primary legislation in both jurisdictions. The SEM is a physically synchronised electricity system with a fully integrated institutional and regulatory system, underpinned by parallel domestic legislation in both jurisdictions. Northern Ireland and Ireland generators compete against each other to be called on to generate to meet the demand across the island of Ireland. Although electricity flows between NI and IE this is not a trading relationship (e.g. in the way that Great Britain trades with continental Europe), it is instead part of the integrated network (in the same way that electricity flows between Scotland and England).

The SEM operates within not only the parallel domestic legislative framework referred to above, but also the wider framework of common rules on electricity markets and linked governance arrangements and structures.

2.2 I-SEM Reforms

The new Single Electricity Market (SEM) came into operation on 1 October 2018. Because the new I-SEM design facilitates trading across borders and making best use of the power available from all sources on the island of Ireland, this helps to alleviate security of supply concerns. It is a more competitive market than the previous iteration of the SEM and sends the correct signals for entering and exiting the market. Consumers benefit from a more competitive process for setting prices, including the use of capacity auctions.

2.3 Prices in the wholesale markets

The new Market does include a generator price cap reflecting the Europe wide caps in Euphemia, which is currently 3,000 EUR/MWh in the SEM Day Ahead and 9,999 EUR/MWh for the Intra-Day Markets. There are price floors of -500EUR/MWh in the Day Ahead Market and -9,999 EUR/MWh in the Intra-Day Market. The price caps are largely for practical system reasons and are set as part of an All-Island Regulatory Authority process. In future, it is expected that decisions on such caps will be taken by ACER as part of the revised process provided for by the Recast Electricity Regulation (2019/943).

The balancing market operates with a technical price cap based on value of lost load and is just over 11,000EUR/MWh (based on €/MW/h set in 2007 and adjusted for inflation), which has never been reached and a floor of -1,000 EUR/MWh. This is required for reasons related to the Balancing Market Operator’s systems. On 24 January 2019 the imbalance price rose to 3,774 EUR/MWh, the highest since I-SEM Go-Live and a level that would not have been permitted under the pre I-SEM market. This happened when an amber alert was issued for Northern Ireland and plant outages (planned and unplanned) coupled with low wind in Northern Ireland and full exports on the Moyle Interconnector meant the system became highly constrained. As a result, some 5 minute prices exceeded the strike price of €500. The lowest price observed has been -€281.16 and the highest price €3,773.69 (24th Jan) or €1,453.09 (excluding 24th Jan).

Following Go-Live, the performance of the balancing market in the new SEM was a focus of attention, especially on whether the level of price volatility appropriately reflected market fundamentals. The very high prices on 24 January 2019 was an example of balancing market outcomes that gave rise to some concern. The SEM Committee consequently decided to direct SEMO to raise an urgent modification to the SEM Trading & Settlement Code to remove a number of System Operator Flags in the imbalance pricing algorithm.

In addition, the SEM Committee issued a public consultation on further changes to the flagging and tagging approach being used in the balancing market and the removal of difference charges where operational constraints are binding. Taking account of the comments received to the consultation, and actions already taken to remove a number of flags, the SEM Committee concluded to keep this matter under ongoing review. Taking account of this and out-turn prices in the balancing market over the coming winter 2019/20, the SEM Committee may review this matter again in 2020.

Apart from the technical caps set out above for the balancing wholesale market, there is a price cap which is formally defined as 10,000€/MWh set in 2007 and adjusted for inflation (this means that the current Price Cap is set to 11,128.26€/MWh), and there is a price floor of -€1,000. These limits apply to all prices submitted in the balancing market.

There are two sets of prices submitted for the market: Complex Bid Offer Data (£/MWh price quantity pairs, per-start start-up costs, and per-hour no load costs) which has a Balancing Market Principles Code of Practice (BMPCOP) applied to it so that it should strictly reflect a unit’s Short Run Marginal Costs as outlined in that Code; and Simple Bid Offer Data (only £/MWh price quantity pairs) which does not have these requirements applied and can be freely traded. The Complex prices are used in pricing and settlement for long-notice actions, and are used in settlement (not pricing) for non-energy actions.

The Simple prices are used in pricing for short notice actions, and in settlement for short notice energy actions.

There are also a small number of price requirements for specific unit types depending on their particular attributes: priority dispatch units which are non-dispatchable (unable to dispatch up or down to follow a set point) but which can be controlled (i.e. their output can be limited downwards to manage congestion or system stability issues), with zero marginal costs (such as wind and solar) cannot submit Commercial Offer Data, but are included in pricing and settlement assuming they have bid a price of zero despite not being able to bid, because their dispatch is based on priority order, not on economic merit order; storage units cannot submit fixed cost elements under their Complex submission and must incorporate all costs into the price element; Demand Side Units cannot submit the per-hour cost element under their Complex submission.

In Central Dispatch Systems such as those run by the SEM TSOs – reserves are not procured ahead of time to be held out of the market until real-time, rather participants are free to trade and the TSOs monitor the provision of reserve margin over time, dispatching units away from their traded position if needed to maintain the reserve margin in real-time, this is a co-optimised schedule alongside energy balancing.

2.4 Capacity Remuneration Mechanism Overview

The Capacity Remuneration Mechanism (CRM) is based on the auctioning of Reliability Options. The CRM pays for the capacity to produce electrical energy through the I-SEM on a de-rated “per MW” basis. This means that, typically, Capacity Providers have three income streams:

- A (per MW) capacity payment or “option fee” for being *available* to produce electrical energy;
- A (per MWh) payment for selling energy through one of the Day Ahead, Intraday or Balancing markets; and
- A (per MWh) payment for system support under DS3 auctions.

The arrangements for the CRM are implemented through market codes and other contracts. These set out the detailed rules covering registration, participation, pricing and settlement of contract payments and charges and are overseen and approved by the SEM Committee. Detailed, codified rules are underpinned, as appropriate, through existing or modified licence arrangements in both jurisdictions.

The detailed rules for the remuneration of capacity providers that have been successful in capacity auctions and the associated rules for capacity charges on suppliers are set out in the Trading and Settlement Code (TSC). A set of rules covering procedures for participating in the capacity auctions and in prequalification arrangements is contained in the Capacity Market Code.

As mentioned in section 1.4 Article 22(4) (b) affects the capacity mechanism in that the introduction of new emission limits will impact capacity payments for fossil fuel generators. From 1 July 2025 such generators will no longer receive capacity mechanism payments. The withdrawal of these older fossil fuel generators from the market could possibly lead to security of supply issues for Northern Ireland unless there are new entrants to the market using up to date generation technologies.

2.5 Capacity Concerns

The European Commission has articulated the view that capacity adequacy concerns are largely a result of market failures and regulatory barriers, but it could be argued that in a system with very significant levels of zero-marginal cost generation, an energy only market would not ensure capacity adequacy and this is why a CRM is necessary to deal with issues such as the “missing money problem”. This may occur when the lack of price responsiveness from demand leads to a failure of the energy markets to remunerate capacity sufficiently to meet the target reliability standard and ensure capacity adequacy.

2.6 Missing Money Problem

To remain in the market, an operational generator needs to recover its avoidable fixed costs on top of its variable costs of production. In order to enter a market, a plant needs to expect to also be able to recover its investment costs, on top of its variable and fixed costs. In the energy-only market, the net revenue that is required to ensure investment costs and avoidable fixed costs are covered come from two sources:

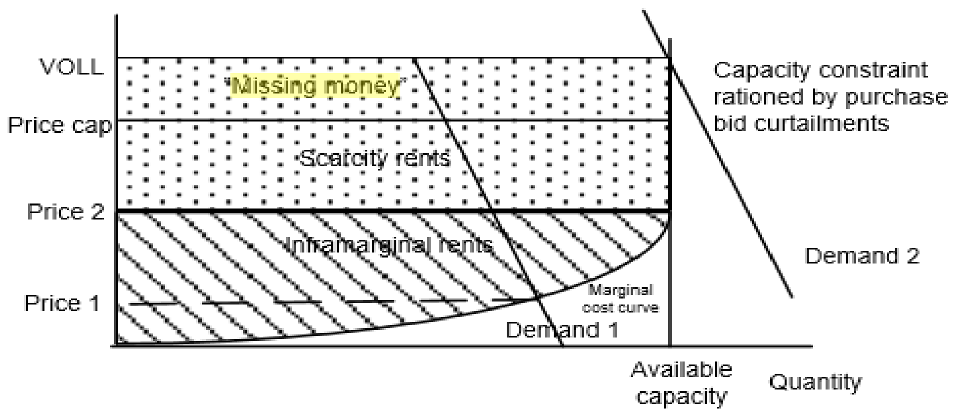
Infra-marginal rent (IMR), which is captured by operating at greater cost efficiency than the price-setting (marginal) plant, which is relatively predictable in other countries. In Northern Ireland however, increasing levels of zero marginal cost renewable generation are leading to downward pressure on infra-marginal rent and making it less predictable.

Scarcity rent[3], which is captured through price spikes at times of relative system scarcity, which may be relatively unpredictable.

[3] Cramton and Stoft (2006): ‘The Convergence of Market Designs for Adequate Generating Capacity’

In an energy-only market, energy prices must be allowed to rise at times to levels that allow for sufficient amounts of scarcity rent to be recovered to ensure that enough plants are on the system to deliver the required level of reliability. These price levels will be significantly above the short run marginal cost of the least efficient plant on the system at the time, and arguably can go as high as the value of lost load (VoLL) in the absence of a price cap.

Figure 1: Electricity pricing and "missing-money problem"



Source: adapted from Joskow, 2006

In order to give the market the best opportunity to reflect the real time value of electricity, Regulators need to ensure that there are no administrative price caps. Price caps should only be put in place for technical reasons and these should be justified and explained. The new Market does include a generator price cap reflecting the Europe wide caps in Euphemia, which is currently 3,000 EUR/MWh in the SEM Day Ahead and 9,999 EUR/MWh for the Intra-Day Markets. There are price floors of -500EUR/MWh in the Day Ahead Market and -9,999 EUR/MWh in the Intra-Day Market. The price caps are largely for practical system reasons and are set as part of an All-Island Regulatory Authority process. In future, decisions on such caps will be taken by ACER as part of the revised process provided for by the Recast Electricity Regulation (2019/943).

The balancing market operates with a technical price cap based on value of lost load and is just over 11,000EUR/MWh (based on €/MW/h set in 2007 and adjusted for inflation), which has never been reached and a floor of -1,000 EUR/MWh. This is required for reasons related to the Balancing Market Operator's systems. As the real time scarcity value of electricity is best reflected in the balancing market, by having a PCAP that represents the value of lost load to consumers, the SEM has chosen to set its PCAP to VOLL in the balancing market.

In the DAM and the IDM there are no bidding controls at all. 96% of the total traded volumes are transacted through these markets. In the Balancing Market there are some rules around mitigating local market power issues which arise due to the constrained nature of the system. All generators must submit a set of commercial offer data that is reflective of their short run marginal cost. This pricing information is only used for settlement purposes when a generator is deemed to have been needed for some “system” reason. As part of the recast Electricity Regulation and EBGL, these prices are not used to set the energy balancing price.

In addition to this measure the SEM Regulatory Authorities have, as part of the introduction of the CRM, introduced an Administrative Scarcity Pricing approach which ensures that the price is a minimum of 3,000EUR/MWh at times when there is a shortage of reserve scarcity. Importantly, this is a price floor so there is no obstacle to the price increasing above this level should generators with prices above the price floor get dispatched to provide balancing energy.

Also the SEM Regulatory Authorities will be implementing the Balancing Guidelines in the coming years making changes to both how the balancing energy price is calculated and how cross-border balancing services are procured. The Regulatory Authorities will also be implementing the measures required by DG COMP in the State Aid decision designed to increase Demand Response participation in energy markets by normalising their participation in line with other forms of participation in the capacity mechanism.

A lack of sufficiently active demand side means that market prices are more likely to rise to higher levels at times of scarcity. In addition, the inelasticity of electricity demand can encourage gaming in the energy market and difficulties in differentiation. Therefore the Regulatory Authorities are working to maximise the role of demand side response in the energy market by implementing a number of measures to ensure DSUs are treated on an equal and transparent basis with other technology types.

These market failures illustrate why energy only markets fail to deliver an optimal level of generation adequacy. However, there is not a generally applicable “best” method to solve this issue. The optimal solution to this problem depends on many factors such as the past, current and future scenarios of the relevant electricity market and the social and economic development status of the country or region concerned.

Based on evidence from the SEM Committee it is felt that these market failures are more acute for a small island system with a high penetration of variable renewable generation. The high penetration of renewable energy sources magnifies the “missing money” problem. This coupled with the size of the generating units on the island means that although measures addressing these problems are being pursued (e.g. treatment of DSUs as mentioned above) they are not expected to ensure an adequate level of generation capacity in the short or medium term. A competitive and non-distortionary

CRM is required in conjunction with those other measures identified in the Guidelines on State Aid for environmental protection and energy 2014-2020 to ensure the island of Ireland has adequate generation in the future.

2.7 Post I-SEM Performance

All indications to date are that that the market is operating as expected, with trading volumes in the Day Ahead, Intra-Day and Balancing markets matching expectations. The efficiency of the flows across the Moyle and East West (EWIC) interconnectors has greatly improved.

The first T-4 auction, conducted by the Single Market Operator (SEMO) took place on 28 March 2019 and will deliver capacity from October 2022 to September 2023. There will still be annual, transitional T-1 auctions for the next few years but ultimately the pattern will be that a T-4 auction and a T-1 auction will be held each year. Once these yearly T-4 auctions start delivering capacity the annual T-1 auctions will switch to become smaller top-up auctions for the delivery year ahead (October to September).

The SEMC decided to run both a T-1 and a T-2 auction this year to ease the administrative burden on market participants.

While insufficient time has passed for a full appraisal of the new market, initial signs are that the changes have been positive. There is now a more competitive market with greater integration, reduced curtailment of variable generation as well as more efficient flows across the interconnectors, which are dictated by price signals. Initial indications are that the new wholesale market is delivering more competition and more efficient prices than would have been the case under the old market.

3. Balancing Markets – Introduction

3.1 How it works

The Balancing Market (BM) reflects actions taken by the TSO to keep the system balanced. For example, differences between the market schedule and actual system demand. It determines the imbalance settlement price for settlement of these balancing actions. This includes any uninstructed deviations from a participant's notified ex ante position.

3.2 Energy balancing services

Energy balancing services are offered into the Balancing Market by generators and suppliers. The TSO then determine the use of these services. For example, they might instruct a generator to increase its output to meet demand. The generator is then paid through the BM for the extra energy used to balance the grid. The TSO can also call on non-energy balancing services. These might include voltage regulation or energy reserves. A participant's net energy position is the accumulated volume of its trades in the ex ante markets and any balancing actions.

3.3 Market timeline

The BM trading day is divided into 48 (30-minute) imbalance settlement periods. These align with the IDM trading periods. Within each imbalance settlement period there are six (5-minute) imbalance pricing periods. The submission window for market data opens 19 days ahead of the trading day (D-19). It closes 1 hour before the start of each 30-minute imbalance settlement period (t-1).

3.4 Who can participate?

Participation is mandatory for generators with an export capacity above the minimum threshold. It is voluntary for dispatchable generators below that threshold, 10 MW.[4]

[4] https://www.sem-o.com/markets/balancing-market-overview/

Role	Description	Markets
Generator	Generators supply energy to the grid.	All
Supplier	Suppliers take energy from the grid for consumption.	All
Assetless Trader	Assetless Traders take positions in the ex-ante markets but have no physical assets.	BM, DAM and IDM
Interconnector	Interconnectors offer capacity in the Capacity Market (CM) and Financial Transmission Rights (FTRs) in FTR auctions. They do not trade energy in markets but they can have exposure in settlement of the BM for differences between dispatched and delivered positions.	CM, BM, FTR auctions
Capacity Market Unit (CMU)	Interconnectors and large generators are represented in the Capacity Market as CMUs. Small or intermittent generators can be aggregated.	CM

Imbalance Settlement

3.5 Incentives for Balancing Responsible Parties to reduce their imbalance

Balancing Responsible Parties (BRPs) are subject to financial settlement of imbalance volumes times the imbalance settlement price which reflects the real-time value of the balancing energy required to correct the imbalance. Also for Balancing Service Providers (BSPs) they are subject to additional incentive charges, where if their level of provision of energy deviates from the level to which they were dispatched by the TSOs, outside of a certain tolerance, then an “uninstructed imbalance charge” of 20% of the market price they are being settled at (either Bid Offer Price or Imbalance Price) will be applied to them for the deviated volume outside of tolerance. The tolerance is calculated for over generation and under generation in a way that the tolerance is larger in the direction which would have been helpful for the frequency (and therefore system balance), and therefore reducing the volume on which this additional charge would apply and meaning no additional charge would apply if the deviated volume was entirely within the increased tolerance.

In general all market participants are exposed to the TSO’s imbalance settlement rules. There are a small number of scenarios in which imbalance settlement is applied differently due to particular attributes: when a Pumped Storage Unit is in pump mode, it is assumed to be dispatched to its metered quantity so that it is not subject to uninstructed imbalances; Demand Side Units have their metered position assumed to be equal to their dispatched position due to not having a methodology for calculating the settlement-standard delivered reduction in demand, and any energy revenue received by the unit at the imbalance price is removed from the unit, in order to not double-count the energy reduction which would also arise on a supplier meter and be settled at the imbalance price on that supplier.

3.6 Imbalance Settlement Price

At a high level, the Imbalance Settlement Price is a single price for all imbalances and balancing energy settlement, set based on the principle that they are based on the actions taken by the TSO to balance the system, and should be based on the marginal energy action to meet the Net Imbalance Volume. This is done by calculating the volumes and prices associated with dispatching units to deviate from their Physical Notifications, including all of those quantities in a ranked set based on economic merit order, and using a set of rules following a Flagging and Tagging approach to determine which actions are energy/non-energy and which actions meet the NIV. In this way the imbalance settlement price is intended to reflect the real-time value and cost of energy balancing actions, such that any BSP action in-merit would be settled at the price of the marginal energy balancing action, and BRPs would be subject to imbalance settlement at that price, reflecting the real-time value of balancing energy.

However there are some costs which are not covered through the imbalance settlement price. The costs for non-energy balancing actions which are out of merit are not settled through the imbalance price, which is intended to reflect the cost of energy actions. There are premium and discount payments for when a BSP’s Bid Offer Price is out of merit and therefore more advantageous to be settled at than the central balancing energy/imbalance price.

Depending on the extent to which recovery of fixed costs has been built into Simple Bid Offer Data, the extent to which the orders containing that data set the Imbalance Price, and the extent to which units are seen as being used for energy or non-energy purposes over the course of the time it is dispatched on, there may be additional fixed cost payments which need to be made whole based on units being settled on their cost-based Complex Bid Offer Data and where the settlement at the imbalance price and premiums and discounts are insufficient to recover these costs.

If prices are reduced from the pure marginal energy action level through in-particular the Price Average Reference element of the Flagging and Tagging process, then some energy balancing costs may be made out-of-merit and need to be made-whole through premium or discount payments on top of settlement at the imbalance price.

There are cases where the volumes of balancing actions and imbalances do not completely align and therefore the cost cannot be completely attributed to the BRPs. This happens due to errors in volumes for reasons such as the actual losses on the transmission system being different to those modelled in the market, theft, differences between actual physical consumption and the profiled consumption calculated for non-interval meters, etc.

The costs caused by all of these additional items are estimated ex-ante (and calculated ex-post) in order to socialise the cost across consumers through tariffs applied to Supplier Units, with different tariffs for different cost causes.

3.7 Administrative Scarcity Pricing Mechanism

There is an administrative scarcity pricing mechanism currently in operation as referred to in Article 44(3) of EBGL. This administered price sets the Price Floor at times of system stress (for example, reserve shortfall or load-shedding) to a much higher price than would normally be expected in the balancing market, while allowing for prices to be set higher than this administered level if market bidding reflects this, but which should guarantee prices at least at the administered level reflective of the cost of scarcity in such times. The main input for determining the price at times that the functionality is triggered is an RA determined Reserve Scarcity Curve, which reflects what the price should be at different levels of reserve scarcity. Reserve scarcity is where the volume of short term reserves actually being provided is less than the volume required for them. The Full Administered Scarcity Price (PFAS) can be triggered for Demand Control triggered in either Ireland or Northern Ireland jurisdictions. However to ensure that it is only triggered for system-wide events rather than local jurisdiction events, there is a “double-lock”, where this approach only applies when there is both Demand Control / a frequency event in either jurisdiction, and a system-wide reserve scarcity event.

3.8 Value of lost load

Value of Lost Load is formally defined as 10,000€/MWh set in 2007 and adjusted for inflation (this means that the current value is set to 11,128.26€/MWh), the study to determine this value is as follows: AIP-SEM-

07-484 The Value of Lost Load, the Market Price Cap and the Market Price floor: A Response and Decision Paper published 18th September 2007[5]

3.9 Procurement of ancillary services – The DS3 Programme

SONI/Eirgrid have been developing a programme of work entitled "Delivering a Secure, Sustainable Electricity System" (better known as DS3) and is a further piece of work to complement the I-SEM. A core part of that work is increasing the System Non-Synchronous Power (SNSP) level of the grid to 75%. It is currently at 65% and the Regulatory Authorities in both Northern Ireland and Ireland will report on their work to increase it.

The DS3 project aims to maximise the use of renewable sources of electricity by taking technical steps to improve the ability of the power network on the island of Ireland to accommodate generation from renewables. Renewable generation has a zero fuel cost and is therefore the lowest cost generation to produce in the market.

The acquisition of system services is a key pillar of the DS3 programme. There are 14 services that can be secured across a range of areas. Subject to the agreement of the Regulatory Authorities, the fixed contracts will be available to high availability providers (i.e. those who can guarantee a high percentage of renewable power); they will be let via auction; the volumes of capacity will be capped; and the revenue rate will be guaranteed for 6 years.

Set out below is a list of the ancillary services

- POR Primary Operating Reserve
- SOR Secondary Operating Reserve
- TOR1 Tertiary 1 Operating Reserve
- TOR2 Tertiary 2 Operating Reserve
- RRD Replacement Reserve (Desynchronised)
- RRS Replacement Reserve (Synchronised)
- SSRP Steady State Reactive Power
- SIR Synchronous Inertial Response
- RM1 Ramping Margin 1 Hour
- RM3 Ramping Margin 3 Hour
- RM8 Ramping Margin 8 Hour
- FFR Fast Frequency Response
- FPFAPR Fast Post Fault Active Power Recovery
- DRR Dynamic Reactive Response

[5] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/AIP-SEM-07-484%20VOLL%20.PCAP_.PFLOOR%20Decision%20Paper%2018%2009%2007.pdf

These ancillary services are procured through a competitive process and the link to the website provided in footnote 6 below[6] provides more detail. Footnote 7[7] provides a link to previously awarded DS3 contracts in Northern Ireland.

In both Northern Ireland and Ireland a no-commitment (non-firm) based model is used for procurement of these System Services under a tariff based framework. Service providers qualify onto a framework that has a 12 month period which defines the characteristics and maximum quantities of making such services available. This qualification process follows a competitive tender approach. For more detail please follow website link provided in footnote 4.

Therefore these System Services do not correspond to the concept of procurement of Balancing Capacity under EBGL, given providers are not obligated to hold any reserves, may trade freely in the wholesale electricity markets, and may determine their own availability. There is no step in advance of real-time operations of ex-ante procurement of reserve capacities to be physically held by units. The System Services payments are related to availability to provide a service, as opposed to the actual provision of a firm volume as per the model considered under EB GL. The SEM approach differs in that the margin for reserves is not procured ex-ante, but is rather co-optimised along with all other reserve margins, non-energy requirements, and energy balancing requirements, as part of the Integrated Scheduling Process to be held across the units available to provide the service in a least cost manner based on their Integrated Scheduling Process Bids, technical capabilities, and overall system minimum margin requirements. A list of previously awarded System Services contracts (in Northern Ireland) can be found by following the website link provided in footnote 7 below.

Both Aggregators (DSUs and AGUs) and Energy storage Units (Batteries) can provide ancillary services to the TSO.

[6] http://www.eirgridgroup.com/site-files/library/EirGrid/Volume_Uncapped_Bidders_Conference_Slide_Deck_11042019_Final_Published.pdf

[7] http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-contract-awards-SONI.pdf

3.10 Pricing in the balancing market

With regard to energy prices on the balancing market a marginal pricing approach is explicitly incorporated into the pricing design and work is planned to assess if it is compliant under Article 30(1)(a) of the EBGL.

For the balancing wholesale market, there is a price cap based on the Value of Lost Load which is formally defined as 10,000€/MWh set in 2007 and adjusted for inflation (this means that the current Price Cap is set to 11,128.26€/MWh), and there is a price floor of -€1,000. These limits apply to all prices submitted in the balancing market. The following are the reference documents: AIP-SEM-07-484 - The Value of Lost Load, the Market Price Cap and the Market Price floor: A Response and Decision Paper published 18th September 2007[8] and SEM-17-071 Trading and Settlement Code Policy Parameters 2018 Decision Paper published 14th September 2017[9]

There are two sets of prices submitted for the market: Complex Bid Offer Data (£/MWh price quantity pairs, per-start start-up costs, and per-hour no load costs) which has a Balancing Market Principles Code of Practice (BMPCOP) applied to it so that it should strictly reflect a unit's Short Run Marginal Costs as outlined in that Code; and Simple Bid Offer Data (only £/MWh price quantity pairs) which does not have these requirements applied and can be freely traded. The Complex prices are used in pricing and settlement for long-notice actions, and are used in settlement (not pricing) for non-energy actions. The Simple prices are used in pricing for short notice actions, and in settlement for short notice energy actions. This footnote provides a link to information on the BMCPOP[10]

There are also a small number of price requirements in the SEM Trading and Settlement Code for specific unit types depending on their particular attributes: priority dispatch units which are non-dispatchable (unable to

[8] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/AIP-SEM-07-484%20VOLL%20.PCAP_.PFLOOR%20Decision%20Paper%2018%2009%2007.pdf

[9] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-071%20TSC%20Policy%20Parameters%202018%20Decision%20%20Paper.pdf

[10] https://www.semcommittee.com/news-centre/i-sem-balancing-market-principles-code-practice-decision-paper-0

dispatch up or down to follow a set point) but which can be controlled (i.e. their output can be limited downwards to manage congestion or system stability issues), with zero marginal costs (such as wind and solar) cannot submit Commercial Offer Data, but are included in pricing and settlement assuming they have bid a price of zero despite not being able to bid, because their dispatch is based on priority order, not on economic merit order; storage units cannot submit fixed cost elements under their Complex submission and must incorporate all costs into the price element; Demand Side Units cannot submit the per-hour cost element under their Complex submission. Balancing service providers are allowed to submit or update their bids until the energy balance gate closure time as provided for in Article 24(3) of EBGL.

Remuneration of balancing service providers

There is no explicit Balancing Energy remuneration for availability in the Balancing Market – remuneration in this market is based on imbalance of physical provision of energy versus the traded position of the unit, and on the delivered balancing actions. Ancillary Services payments are based on the availability to provide a service.

Meeting 2020 renewable electricity targets

The 2020 renewable electricity target means that we are in the process of increasing the amount of non-synchronous generation on the island's power system in a safe and secure manner. The aim of the DS3 Programme is to meet this challenge. So far the DS3 programme has enabled SONI to increase levels of renewable generation on the system <u>from 50% to 65%</u>. The aim is to increase this gradually to 75% over the coming years.

4 Demand Side Response

A Demand Side Unit (DSU) consists of one or more individual demand sites that can be dispatched as if it was a generator. An individual demand site is typically a medium to large industrial premises. A DSU Aggregator may contract with the individual demand sites and aggregate them together to operate as a single DSU. Aggregated Generator Units (AGUs) and Demand Side Units (DSUs) require regulatory approval to operate in the Single Electricity Market (SEM). Demand Side Response is eligible to participate in day ahead and intraday markets as well as the balancing/ancillary services market. DSR can be represented both individually and via aggregators but with some size restrictions on how large an individual site within a demand-side response unit aggregation can be (currently 10MW restriction as all dispatchable units above 10MW must register individually).

4.1 Demand Side Response in Northern Ireland

Dispatchable Aggregated Generating Units (AGU) operate in Northern Ireland, which consist of a number of individual diesel generators grouping together to make available their combined capacity to the market. An AGU capacity of 76 MW and a DSU capacity of 98 MW were successful in the T-1 Capacity Market auction held in December 2018.

DSR is currently treated differently to other market participants. The main way in which it is treated differently is that Demand Side Units have their metered position assumed to be equal to their dispatched position due to not having a methodology for calculating the settlement-standard delivered reduction in demand, and any energy revenue received by the unit at the imbalance price is removed from the unit, in order to not double-count the energy reduction which would also arise on a supplier meter and be settled at the imbalance price on that supplier. They are also not exposed to some of the incentive charges under the capacity market, and have some greater flexibility in the level to which they are obliged to offer in the capacity market auctions due to how their underlying physical provision can change differently to other participants.

However there has been a regulatory decision that developments will be made, with interim and enduring solutions, to have DSR treated the same as other market participants in terms of capacity market related charges and energy revenues. Please see link to SEM Committee Decision Paper below.[11]

[11] https://www.semcommittee.com/sites/semc/files/media-files/SEM-19-029%20-%20DSU%20State%20aid%20compliance%20-%20Decision%20paper_0.pdf

4.2 Exemptions from network or energy related costs for specific classes of consumers

There are not any exemptions on these costs by class of consumer. A reduction of demand settled through a change in the meter quantity of the Supplier Unit to whom the relevant Demand Side Response site is associated would reduce the charge which is applied through a tariff on the metered quantity. This benefit is not currently seen by the relevant Demand Side Unit, but is seen by the Supplier Unit, and therefore the incentive created may be that Suppliers are more likely to allow their customers to sign up with Demand Side Units.

Demand for use in generating energy (e.g. such as house load for generation stations) is not subject to tariffs to the extent that the provision of energy from the generation site exceeds the demand – i.e. the demand is netted off the generation, so that it is almost seen as "self-supply" without being subject to tariffs. However this should not have much influence on Demand Side Response.

4.3 Smart Meters

The Strategic Energy Framework (SEF) 2010-2020 which set out the strategic direction for Northern Ireland's energy strategy from 2010 is nearing the end of its lifespan and a new Energy Strategy is under development. This will set out the direction for the Northern Ireland energy sector in the period from 2020 to 2050, i.e. from expiry of the SEF to the date by which the UK government has legislated for net-zero carbon emissions. The issue of smart meters will be considered as part of the development of the new Energy Strategy.

5 Retail Markets: Regulated Prices

5.1 Introduction

Power NI as the former incumbent electricity supplier in Northern Ireland, remains subject to a regulated tariff regime as it retains dominant market share in the domestic and small business sectors. Its regulated margin (the profits margin it is allowed to take) is 2.2%.

A price control was applied for domestic and business customers in the early years as Power NI had significant market power in both sectors. The price control is now only applicable on the domestic market as Power NI is no longer dominant in the non-domestic market. Power NI is "selected" to provide regulated prices in the domestic market because it still has unique market power as a supplier in this sector.

5.2 Background

At present in Northern Ireland the percentage of total demand supplied under the regulated tariff regime is circa 20% and is only available to domestic customers. There are four alternative domestic suppliers who compete with Power NI for customers and they do have special offers with fixed terms during which the price is discounted and is typically lower than the regulated tariff. On the flip side the standard tariffs offered by some of these competitor suppliers can be higher than the regulated tariff.

Since the Northern Ireland electricity market was privatised and opened up to competition there has been significant switching from Power NI. As the former incumbent supplier it has 56.1% of the domestic market and the remaining 43.9% is held by the other 4 competitor suppliers.[12] The continued growth of the new entrants in the domestic market is clear, given that the non-incumbents now represent 43.9% of total domestic connections in NI (an increase from 42.8% in the same period last year).

The regulated tariff is above cost and is set on a cost plus margin basis and has no effect in terms of discriminating against other suppliers. There is no direct cross-subsidisation between customers supplied at free market prices and those supplied at regulated prices. The electricity that is sourced from generators to supply regulated customers is purchased in exactly the same

[12] https://www.uregni.gov.uk/sites/uregni/files/media-files/2019-11-14%20Transparency%20Report%20Q3%202019%20FINAL.pdf

way and from the same market as other electricity that is destined to supply non-regulated customers.

The Utility Regulator continuously monitors the domestic market for its competitiveness looking at market shares, prices and switching data. At present there is no timeline for price deregulation in Northern Ireland but this issue will be considered as part of the work involved in transposing the recast Electricity Directive. Article 5 of the Directive allows Member States to apply regulated priced to vulnerable customers. It also allows price setting for other household customers and micro enterprises for a transitional period in order to establish effective competition between suppliers and to achieve fully effective market based retail pricing of electricity.

Regarding measures to help energy poor and energy vulnerable customers the Utility Regulator (UR) is currently implementing a three year Consumer Protection Programme (CPP) which was launched in April 2019. This programme has a suite of specifically designed projects aimed at enhancing protections for vulnerable domestic electricity, gas and water consumers. These projects are grouped under the four objectives of affordability, equal access, empowerment through education and transparency, and leadership and engagement. Energy efficiency and fuel poverty (energy poor) measures are addressed and co-ordinated by the Department for Communities through their Affordable Warmth Scheme.

Assessment of the progress towards achieving the measures outlined will be both internal and external. Internally the UR provides bi-monthly progress updates to the UR board on each of the projects included in Consumer Protection Programme (CPP). Externally UR has a stakeholder group (with a membership of consumer representative bodies and statutory partner organisations) which is independently chaired and monitors implementation progress of the CPP. This group provides independent reports to UR board on progress that has been delivered. With regard to social tariffs there are currently no social tariffs available in Northern Ireland for any domestic electricity consumer grouping.

5.3 Price comparisons for the 5 domestic suppliers of electricity

Prices and Annual Bills as at 29 November 2018

Supplier	Standing Charge	p/KWh (inc. VAT)	Typical annual bill (inc. VAT) (3,100KWh)
Budget Energy	8.008	17.86	£582.80
Click Energy		16.99	£526.69
Electric Ireland		16.99	£526.69
Power NI (REGULATED)		16.60	£543.83
SSE Airtricity		18.67	£578.77

6. Interconnection

As stated earlier in this paper Northern Ireland has 450MW of interconnection with the Great Britain market through the Moyle Interconnector. Northern Ireland has an existing tie-line with Ireland and are progressing arrangements for further interconnection by way of a 2nd tie-line (referred to as the North/South Interconnector – although it will be treated as a piece of transmission infrastructure, not an interconnector). This project is a designated EU Project of Common Interest (PCI). There is also some potential for an additional interconnector between Northern Ireland and Great Britain.

6.1 North-South Interconnector

As the second high capacity transmission link between Ireland and Northern Ireland is it is hoped that this will be commissioned by the target date of 2023. Prior to the completion of this second North-South Interconnector project, the existing interconnector arrangement between the two regions creates a physical constraint that affects the level of support that can be provided by each system to the other. On this basis each TSO is obliged to help the other in times of shortfall. With this joint operational approach to capacity shortfalls, the TSOs agreed that the level of capacity reliance would be maintained by modifying interconnector flows. Reductions in reserve would be followed by load shedding by both parties as a final step to maintaining system integrity. [13] [14]

Generation adequacy assessments for each region are carried out with an assumed degree of capacity interdependence from the other region. This is an interim arrangement until the additional interconnector removes this physical constraint. The capacity reliance values used for the adequacy studies are shown in the table below.

	North to South	South to North
Capacity Resilience	100MW	200MW

During real time operations, flows in excess of the capacity reliance can sometimes take place if required. As it is within the all-island market, the interconnection between Ireland and Northern Ireland is treated as an element of the transmission system, rather than an interconnector to facilitate cross-

[13] https://www.sem-o.com/documents/general-publications/Information_Note_on_Inter-Area_Flow_Constraints.pdf

[14] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_82_May_2019.pdf

border trading. As such, it is a different case compared to how the East-West (EWIC) and Moyle interconnectors are considered.

6.2 Current status of proposed North-South Interconnector

In January 2018, the Department for Infrastructure (DfI) granted full planning approval for construction of the interconnector. However, following initiation of a judicial review, DfI requested that the Court quash the decision. On 9 August 2019, DfI advertised and sought views on further environmental information that had been received in relation to the planning application. The process for decision making in respect of the Interconnector will depend on the administrative context (e.g. if a DfI Minister is in office).

PCI Status

The North South Interconnector has (EU) Project of Common Interest (PCI) status, which means that it is entitled to accelerated planning and permit granting.

6.3 Generation Available in Great Britain

When assessing the contribution of an interconnector to generation adequacy, we need to consider the availability of generation at the other side, as well as the availability of the interconnector itself. In order to improve our understanding of how interconnection can provide benefit, we look to our European neighbours. ENTSO-E, in collaboration with EirGrid, SONI and other TSOs, has recently improved its adequacy assessment methodology with a special emphasis on harmonised inputs, system flexibility and interconnection assessments. The Mid-Term Adequacy Forecast (MAF[15]) uses probabilistic methods to take into account the intermittency of the growing renewable generation sector.

6.4 Moyle Interconnector between Northern Ireland and Scotland

The Moyle Interconnector is a dual monopole HVDC link with two coaxial undersea cables from Ballycronan More (Islandmagee) to Auchencrosh (Ayrshire). The transfer capacity of the Moyle Interconnector for the trading of electricity between the electricity markets of Ireland and Great Britain varies[16] as shown in the table below.

[15] https://www.entsoe.eu/outlooks/midterm/

[16] http://www.mutual-energy.com/trading-across-the-moyle-interconnector-isem/

Direction	Dates	Combined Capacity (MW)	Additional Capacity Potentially Available (MW)	Potential Total Capacity Allocation (MW)
West to East	10 November 2017 to 30 November 2019	80	420	500
	1 December 2019 to 31 May 2020	307	193	500
	1 June 2020 to 31 October 2021	250	250	500
	1 November 2021 to 31 March 2022	160	340	500
	1 April 2022 onwards	500	0	500
East to West		450	-	450

It is difficult to predict whether or not imports for the full capacity will be available at all times. For the purposes of adequacy studies, the Moyle interconnector is treated with a 60% External market derating factor (270 MW) used in the SEM Capacity Market, and appropriate availability statistics.

6.5 Import/Export of Electricity

There is currently a restriction on firm (export) capacity from Northern Ireland to Scotland due to transmission constraints. This varies on a daily basis depending on conditions in the GB system.[17]

As well as importing electricity for commercial/trading purposes interconnectors are used to import electricity to maintain security of supply. In addition the TSO is entitled to use interconnector capacity for countertrading or redispatching.

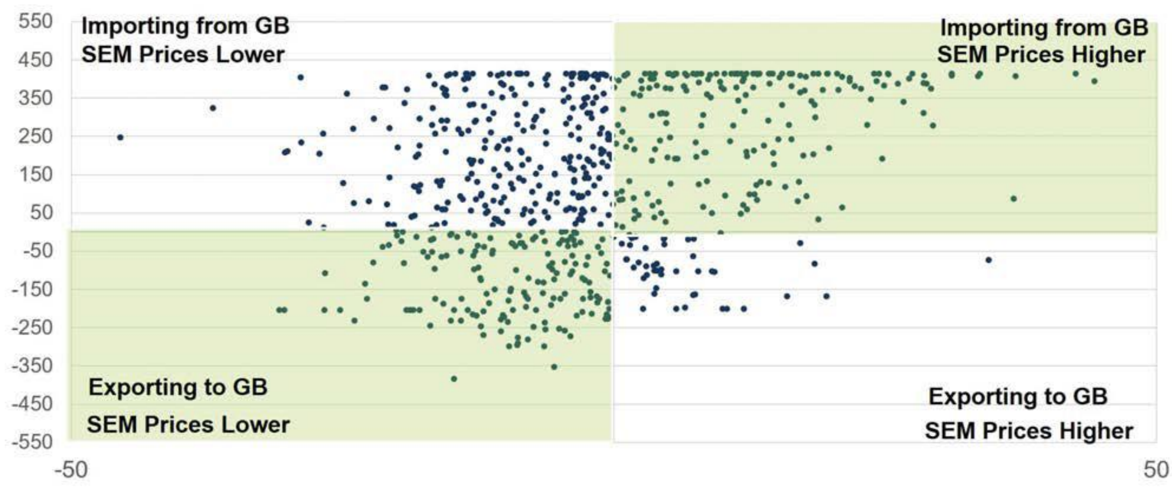
6.6 I-SEM Reform – Improved Interconnector Flows

It is important to note the improved efficiency in interconnector flows that has taken place following the introduction of the I-SEM reforms with both interconnectors now forming an integral component of the SEM rather than as a separate add-on to the market. The integrity of Moyle and EWIC is highlighted by the full capacity utilisation of both interconnectors. It is through

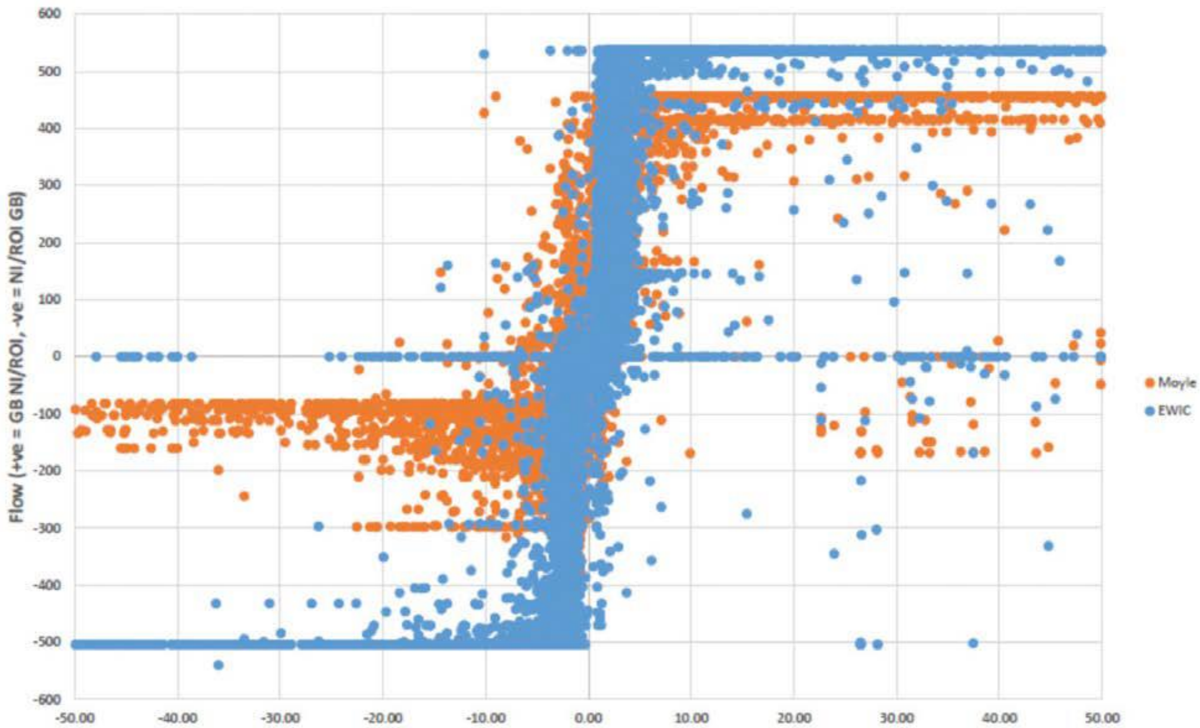
[17] http://www.mutual-energy.com/trading-across-the-moyle-interconnector-isem/

EWIC and Moyle that the SEM is directly linked and market coupled through the Day Ahead Market to the EU Internal Energy Market, via Great Britain, with electricity interconnection continuing to perform a vital role in maintaining security of supply. As well as their energy market role both interconnectors can provide ancillary services, including frequency response and reactive power, which are paramount to power generation decarbonisation within an isolated Island system with exceptionally high volumes of intermittent wind generation.

In the SEM, physical flows on Moyle and EWIC Interconnectors are linked to the SEM Day Ahead market and the price difference between it and the DAM price in GB. Where the DAM price in the SEM is higher than in GB, the interconnectors will import power into the SEM. Where the SEM price is lower, for example because there are high levels of wind on the island, the interconnectors will export power to GB A common means of graphing this relationship is presented in Figures 10 and 11 which chart the interconnector flows before and after the introduction of the new market arrangements. The X-axis shows the difference in DAM prices between the SEM and GB so that the positive price difference on the right of the graph is when the SEM price is higher than the GB price and the Interconnector should be importing. The negative values on the left of the graph is when the SEM price is lower and the interconnectors should be exporting. The Y-axis shows the volume of the flow and its direction so that in the upper half of the graph, in which values are positive, the Interconnectors are importing into the SEM from GB. In the lower half the negative values indicate an export.



Interconnector flows prior to the introduction of I-SEM reforms



Interconnector flows post I-SEM reform

For there to be evidence of efficient trading the scatter graph should show the periods of flow in the upper right of the graph and bottom left. In the upper right quadrant the SEM price is higher than the GB price and the Interconnectors are importing. In the bottom left quadrant the SEM price is lower than the GB price and the interconnectors are exporting. Efficient flows on the Interconnectors were a key objective of the SEM market design and the pattern shown in the post I-SEM reform figure shows that flows on Moyle (red) and EWIC (blue) across the year flowed overwhelmingly in the correct direction with only a few exceptions. Ramping constraints, which limit the speed of change in the direction of flow, have not so far resulted in significant flows in the wrong direction and market coupling has been successful in ensuring efficient interconnection between the SEM and GB markets. This has resulted in reduced prices when the price level is higher in the SEM than in GB and higher exports and use of wind power when prices in the SEM are lower than in GB.[18]

6.7 Interconnection Targets

On the Island of Ireland, various interconnection projects are being developed; Greenlink (IE-UK) has recently signed a connection agreement and the Celtic Interconnector (IE-FR) is in the planning phase. The North-

[18] https://www.semcommittee.com/publications/sem-19-071-sem-annual-report-october-2018-september-2019

South Interconnector between Ireland and Northern Ireland is also currently under the planning process.

Point (d) of Article 4 of Regulation 2018/1999 requires Member States to implement an electricity interconnection of 10% for 2020 and 15% for 2030. The indicators related to this concern the price differentials in the wholesale market, nominal transmission capacity of interconnectors in relation to peak load and installed renewable generation capacity, The SEM currently has approximately 9.8GW of dispatchable generation and interconnection capacity and approximately 4.4GW of installed renewable generation. Interconnection capacity accounts for approximately 1000MW, however there are technical limits on this.

6.8 Phasing out of certain generation technologies

Coal and peat fired power stations will be phased out and the introduction of new emissions limits in the capacity market (as provided for in Article 22(4) of the Electricity Regulation), is likely to reduce high carbon emitting generation further.

7. Conclusion

7.1 Changes to Conventional Generation in Northern Ireland

This section describes changes in fully dispatchable plant capacities in Northern Ireland. Information on known plant additions and closures are documented. For the purposes of adequacy studies, all existing plant that entered the T-4 2022/23 auction are included, not just the capacity that was successful in the auction. This amounts to 2.4 GW of de-rated dispatchable plant in Northern Ireland. Ballylumford (units B4 and B5) closed at the end of 2018, having received a Grid Code derogation from the Utility Regulator to close earlier than required as per the Grid Code.

Assumptions for plant changes in Northern Ireland

Plant	Export Capacity (MW)	Expected closure date	Comment
Kilroot ST1	238	End of 2024	Owner indicated that it will reduce to 199MW from mid-2020 Assumed to be not available after 2024 due to restrictions on coal-firing
Kilroot ST2	238	End of 2024	As above

A Selective Non-Catalytic Reduction system is in place at ST1 and ST2 to reduce emissions. The system has been fully available in 2016, 2017 and 2018 and there is also potential to purchase some additional emission allowances in the UK NOx trading scheme. It is understood both can be fully available under this arrangement until the end of June 2020.

Emission restrictions become tighter in July 2020 when the Transitional National Plan ends and the units on oil firing could be limited to a rolling annual average of 1500 stack hours. In 2021 revised Best Available Techniques Reference Document restrictions will apply, so limits will further tighten. However, there is potential to further reduce NOx emissions and they could be fully available until the end of 2024. This solution would only apply to the coal rating of 398 MW.

On 23 April 2019 AES announced that it had sold all generation located at the Ballylumford and Kilroot sites to EP UK Investments Ltd, which is part of Energetický a Průmyslový Holding (EPH) company.

7.2 Demand

As already mentioned the closure of the Kilroot generators known as ST1 and ST2 could possibly lead to security of supply issues. In their Al-Island Capacity Generation Statement 2019-2028[19] SONI states that the Total Electricity Requirement (TER) has been relatively flat for the past number of years with the expectation that electricity demand will remain fairly stable in the near future. However, there have been some enquiries and a connection application related to a possible new Data Centre demand.

SONI use three demand scenarios – low, median and high. In the median demand scenario Northern Ireland is within the adequacy standard until 2025 when it drops below standard. This is due to the closure of the Kilroot coal units. For Northern Ireland, the standard is 4.9 hours Loss of Load Expectation (LOLE) and assumes a 200 MW capacity reliance on Ireland – see Table below.

Scenario	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Median Demand	360	350	310	300	280	270	-70	-90	-100	-110
Low Demand	390	390	360	360	360	360	50	50	50	50
High Demand	310	310	260	230	220	190	-160	-180	-220	-230

Results of adequacy studies for Northern Ireland, given in MW of surplus plant (+) or deficit (-)

7.3 Adequacy Results for Northern Ireland

Using the median demand scenario not much change is expected in the demand forecast or in the plant portfolio until 2025 when Northern Ireland goes into deficit in the median and high demand scenarios due to the unavailability of the Kilroot coal units. As mentioned previously this could possibly lead to security of supply issues.

7.4 Internal Network Congestion

There are significant internal network congestions on the island as a whole. The annual cost of these was forecast at €271m for the 2019-20 tariff year. Network reinforcement measures are planned, including construction of a second interconnector between Northern Ireland and the Republic of Ireland which if built will be expected to materially reduce the annual cost of congestion.

7.5 Looking forward

In purely Northern Ireland terms the best solution to any resource adequacy concerns is for the proposed second North-South Interconnector to clear any remaining legal and regulatory hurdles and be commissioned by the target date of 2023. In addition there is the proposal to develop a 480 MW Belfast Power Station which would make a valuable contribution to security of supply in Northern Ireland. The flexible nature of its generation (able to ramp from zero to full power in 50 minutes) would also make it a useful source for ancillary services.

But it has to be borne in mind that as both Northern Ireland and Ireland are part of the same market then adequacy concerns for the island of Ireland need to be taken into account. At present the all-Island Generation Capacity Statement 2019-2028 assumes that second North-South Interconnector will be commissioned in 2023.

In the all-island case, the surplus for any particular year is greater than the sum of the two separate jurisdictional studies. This capacity benefit demonstrates some of the advantages of the second North South Interconnector.

All-island adequacy results for different scenarios are initially in surplus. This surplus drops over time, due to demand increasing and the assumed plant closures. If capacity unsuccessful in the future SEM capacity auctions, or any other plant becomes unavailable then further deficits could occur.

ANNEX: QUESTIONNAIRE ON POSSIBLE REGULATORY DISTORTIONS AND MARKET FAILURES

Section 1 – General wholesale market conditions

1. With regards to day-ahead and intraday electricity prices, are there any formal or informal price limits other than those currently applied within European single day-ahead and intraday coupling as set out in Article 41(1) and 54(1) of CACM?

The new Market does include a generator price cap reflecting the Europe wide caps in Euphemia, which is currently 3,000 EUR/MWh in the SEM Day Ahead and 9,999 EUR/MWh for the Intra-Day Markets. There are price floors of -500EUR/MWh in the Day Ahead Market and -9,999 EUR/MWh in the Intra-Day Market. The price caps are largely for practical system reasons and are set as part of an All-Island Regulatory Authority process. In future, decisions on such caps will be taken by ACER as part of the revised process provided for by the Recast Electricity Regulation (2019/943).

The balancing market operates with a technical price cap based on value of lost load and is just over 11,000EUR/MWh (based on €/MW/h set in 2007 and adjusted for inflation), which has never been reached and a floor of -1,000 EUR/MWh. This is required for reasons related to the Balancing Market Operator's systems. On 24 January 2019 the imbalance price rose to 3,774 EUR/MWh, the highest since I-SEM Go-Live and a level that would not have been permitted under the pre I-SEM market.

2. Are there any formal or informal rules or requirements that limit generators' ability to freely price their offers in wholesale markets?

Please refer to the technical caps as set out in Question 1.

In addition, for the balancing wholesale market, there is a price cap which is formally defined as 10,000€/MWh set in 2007 and adjusted for inflation (this means that the current Price Cap is set to 11,128.26€/MWh), and there is a price floor of -€1,000/MWh. These limits apply to all prices submitted in the balancing market.

There are two sets of prices submitted for the market: Complex Bid Offer Data (£/MWh price quantity pairs, per-start start-up costs, and per-hour no load costs) which has a Balancing Market Principles Code of Practice (BMPCOP) applied to it so that it should strictly reflect a unit's Short Run Marginal Costs as outlined in that Code; and Simple Bid Offer Data (only £/MWh price quantity pairs) which does not have these requirements applied and can be freely traded. The Complex prices are used in pricing and settlement for long-notice actions, and are used in settlement (not pricing) for non-energy actions. The Simple prices are used in pricing for short notice actions, and in settlement for short notice energy actions.

There are also a small number of price requirements for specific unit types depending on their particular attributes: priority dispatch units which are non-dispatchable (can't dispatch up or down to follow a set point) but which can be controlled (i.e. their output can be limited downwards to manage congestion or system stability issues), with zero marginal costs (such as wind and solar) cannot submit Commercial Offer Data, but are included in pricing and settlement assuming they have bid a price of zero despite not being able to bid, because their dispatch is based on priority order, not on economic merit order; storage units cannot submit fixed cost elements under their Complex submission and must incorporate all costs into the price element; Demand Side Units cannot submit the per-hour cost element under their Complex submission.

3. **Are there any rules or provisions which require the TSO to release generation reserves to the market when market prices rise above certain thresholds.**

This is not applicable in Central Dispatch Systems such as those run by the SEM TSOs – reserves are not procured ahead of time to be held out of the market until real-time, rather participants are free to trade and the TSOs monitor the provision of reserve margin over time, dispatching units away from their traded position if needed to maintain the reserve margin in real-time, this is a co-optimised schedule alongside energy balancing.

4. **Are there currently any capacity mechanisms (i.e. in the form of reserves)? If yes, please elaborate on how they work.**

Yes, in the form of Reliability Options. A series of capacity auctions are performed each year. The capacity market ensures that electricity supply in the island of Ireland continues to meet demand, and also meets minimum requirements for capacity in specific locations. The capacity auctions procure capacity on a "de-rated basis" that reflects the marginal contribution of one more unit of that technology maintaining the annual reliability of the power system for the year that the capacity is procured for. The capacity market results in successful participants being awarded "reliability options". In return for a firm payment for their auction capacity, the capacity provider is required to return to wholesale customers (via the market operator) energy revenues (across all markets) earned above a regulatory set strike price (currently about €500/MWh) on their capacity obligations. The capacity obligations vary across time and may equal their auctioned capacity at peak times but will be lower at other times when demand is less. The Capacity Market is funded by suppliers through a capacity charge. In return, the suppliers are hedged against high energy prices above the strike price, funded by the charges on Reliability Option holders for energy revenues above the strike price. Capacity providers can be left financially exposed if not running at the time the imbalance price is above the strike price, being charged for the difference in prices against the volume of the obligations they did not meet and therefore do not have energy revenue to help pay the charge, incentivising them to trade on to meet their obligations at these times to reduce their exposure. The market caps their exposure over time to this uncovered charge to a multiple of their capacity revenue.

Section 2: Balancing markets

Sub-section 2.1: Imbalance settlement

5. What incentives do balancing responsible parties have to reduce their imbalances (or help the overall system to be in balance)?

BRPs are subject to financial settlement of imbalance volumes times the imbalance settlement price which reflects the real-time value of the balancing energy required to correct the imbalance. Also for BSPs they are subject to additional incentive charges, where if their level of provision of energy deviates from the level to which they were dispatched by the TSOs, outside of a certain tolerance, then an "uninstructed imbalance charge" of 20% of the market price they are being settled at (either Bid Offer Price or Imbalance Price) will be applied to them for the deviated volume outside of tolerance. The tolerance is calculated for over generation and under generation in a way that the tolerance is larger in the direction which would have been helpful for the frequency (and therefore system balance), and therefore reducing the volume on which this additional charge would apply and meaning no additional charge would apply if the deviated volume was entirely within the increased tolerance.

6. Are all market participants exposed to the TSO's imbalance settlement rules? Are the terms/rules of the imbalance settlement the same for all balance responsible parties?

In general yes there are no exceptions for units being exposed to imbalance settlement rules. There are a small number of scenarios in which imbalance settlement is applied differently due to particular attributes: when a Pumped Storage Unit is in pump mode, it is assumed to be dispatched to its metered quantity so that it is not subject to uninstructed imbalances; Demand Side Units have their metered position assumed to be equal to their dispatched position due to not having a methodology for calculating the settlement-standard delivered reduction in demand, and any energy revenue received by the unit at the imbalance price is removed from the unit, in order to not double-count the energy reduction which would also arise on a supplier meter and be settled at the imbalance price on that supplier.

7. How are the costs for procuring balancing services translated in imbalance settlement prices?

At a high level, the Imbalance Settlement Price is a single price for all imbalances and balancing energy settlement, set based on the principle that they are based on the actions taken by the TSO to balance the system, and should be based on the marginal energy action to meet the Net Imbalance Volume. This is done by calculating the volumes and prices associated with dispatching units to deviate from their Physical Notifications, including all of those quantities in a ranked set based on economic merit order, and using a set of rules following a Flagging and Tagging approach to determine which actions are energy/non-energy and which actions meet the NIV. In this way the imbalance settlement price is intended to reflect the real-time value and cost of energy balancing actions, such that any BSP action in-merit would be settled at the price of the marginal energy balancing action, and BRPs would be subject to imbalance settlement at that price, reflecting the real-time value of balancing energy.

8. Are the full costs of balancing actions attributed to the balance responsible parties though the imbalance settlement price?

However there are some costs which are not covered through the price. The costs for non-energy balancing actions which are out of merit are not settled through the imbalance price, which is intended to reflect the cost of energy actions. There are premium and discount payments for when a BSP's Bid Offer Price is out of merit and therefore more advantageous to be settled at than the central balancing energy/imbalance price.

Depending on the extent to which recovery of fixed costs has been built into Simple Bid Offer Data, the extent to which the orders containing that data set the Imbalance Price, and the extent to which units are seen as being used for energy or non-energy purposes over the course of the time it is dispatched on, there may be additional fixed cost payments which need to be made whole based on units being settled on their cost-based Complex Bid Offer Data and where the settlement at the imbalance price and premiums and discounts are insufficient to recover these costs.

If prices are reduced from the pure marginal energy action level through in-particular the Price Average Reference element of the Flagging and Tagging process, then some energy balancing costs may be made out-of-merit and need to be made-whole through premium or discount payments on top of settlement at the imbalance price.

There are cases where the volumes of balancing actions and imbalances do not completely align and therefore the cost cannot be completely attributed to the BRPs. This happens due to errors in volumes for reasons such as the actual losses on the transmission system being different to those modelled in the market, theft, differences between actual physical consumption and the profiled consumption calculated for non-interval meters, etc.

The costs caused by all of these additional items are estimated ex-ante (and calculated ex-post) in order to socialise the cost across consumers through tariffs applied to Supplier Units, with different tariffs for different cost causes.

9. **Has the Member State considered introducing an administrative scarcity pricing mechanism as referred to in Article 44(3) of EBGL?**

Yes, there is an administered scarcity pricing mechanism currently implemented. This administered price sets the Price Floor at times of system stress (for example, reserve shortfall or load-shedding) to a much higher price than would normally be expected in the balancing market, while allowing for prices to be set higher than this administered level if market bidding reflects this, but which should guarantee prices at least at the administered level reflective of the cost of scarcity in such times. The main input for determining the price at times that the functionality is triggered is an RA determined Reserve Scarcity Curve, which reflects what the price should be at different levels of reserve scarcity. Reserve scarcity is where the volume of short term reserves actually being provided is less than the volume required for them. The Full Administered Scarcity Price (PFAS) can be triggered for Demand Control triggered in either Ireland or Northern Ireland jurisdictions. However to ensure that it is only triggered for system-wide events rather than local jurisdiction events, there is a "double-lock", where this approach only applies when there is both Demand Control / a frequency event in either jurisdiction, and a system-wide reserve scarcity event.

10. **How is the imbalance settlement price calculated for a balancing period in which the TSO has to disconnect one or more consumers involuntarily?**

As per the normal process just with the administered scarcity pricing mechanism triggered, see the previous answers.

11. **What is the estimated value of lost load in the Member State? Please provide a copy of any study providing a basis for this estimate.**

Value of Lost Load is formally defined as 10,000€/MWh set in 2007 and adjusted for inflation (this means that the current value is set to 11,128.26€/MWh), the study to determine this value is as follows: AIP-SEM-07-484 The Value of Lost Load, the Market Price Cap and the Market Price floor: A Response and Decision Paper published 18th September 2007 (https://www.semcommittee.com/sites/semcommittee.com/files/media-files/AIP-SEM-07-484%20VOLL%20.PCAP_.PFLOOR%20Decision%20Paper%2018%2009%2007.pdf);

Sub-section 2.2: Procurement of ancillary services

12. Are ancillary services procured through a competitive process? Does the TSO procure (a portion of) its balancing reserves close to real time (day-ahead)?

Yes, a competitive tender is performed. Please see here for more detail. A list of previously awarded DS3 contracts (in Northern Ireland) can be found at:

http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-contract-awards-SONI.pdf

In Ireland and Northern Ireland a no-commitment (non-firm) based model is being used for procurement of these System Services under a tariff based framework. Service providers qualify onto a framework that has a 12 month period which defines the characteristics and maximum quantities of making such services available. This qualification process follows a competitive tender approach; see the following link for more detail: http://www.eirgridgroup.com/site-files/library/EirGrid/Volume_Uncapped_Bidders_Conference_Slide_Deck_11042019_Final_Published.pdf
A list of previously awarded System Services contracts (in Northern Ireland) can be found at: http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-contract-awards-SONI.pdf

13. Can demand side participants provide ancillary services to the TSO?

Yes, Aggregators (DSUs and AGUs) and Energy storage Units (Batteries) can provide ancillary services.

14. Are there any formal or informal rules or requirements that limit generators' ability to freely price their offers in balancing markets?

Same answer as previously provided for wholesale markets: "For the balancing wholesale market, there is a price cap is the Value of Lost Load, which is formally defined as 10,000€/MWh set in 2007 and adjusted for inflation (this means that the current Price Cap is set to 11,128.26€/MWh), and there is a price floor of -€1,000. These limits apply to all prices submitted in the balancing market. The following are the reference documents: AIP-SEM-07-484 The Value of Lost Load, the Market Price Cap and the Market Price floor: A Response and Decision Paper published 18th September 2007 (https://www.semcommittee.com/sites/semcommittee.com/files/media-files/AIP-SEM-07-484%20VOLL%20.PCAP_.PFLOOR%20Decision%20Paper%2018%2009%2007.pdf); SEM-17-071 Trading and Settlement Code Policy Parameters 2018 Decision Paper published 14th September 2017 (https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-

071%20TSC%20Policy%20Parameters%202018%20Decision%20%20Paper.pdf).

There are two sets of prices submitted for the market: Complex Bid Offer Data (£/MWh price quantity pairs, per-start start-up costs, and per-hour no load costs) which has a Balancing Market Principles Code of Practice (BMPCOP) applied to it so that it should strictly reflect a unit’s Short Run Marginal Costs as outlined in that Code; and Simple Bid Offer Data (only £/MWh price quantity pairs) which does not have these requirements applied and can be freely traded. The Complex prices are used in pricing and settlement for long-notice actions, and are used in settlement (not pricing) for non-energy actions. The Simple prices are used in pricing for short notice actions, and in settlement for short notice energy actions. The following is a link to information on the BMPCOP: https://www.semcommittee.com/news-centre/i-sem-balancing-market-principles-code-practice-decision-paper-0

There are also a small number price requirements in the SEM Trading and Settlement Code for specific unit types depending on their particular attributes: priority dispatch units which are non-dispatchable (can’t dispatch up or down to follow a set point) but which can be controlled (i.e. their output can be limited downwards to manage congestion or system stability issues), with zero marginal costs (such as wind and solar) cannot submit Commercial Offer Data, but are included in pricing and settlement assuming they have bid a price of zero despite not being able to bid, because their dispatch is based on priority order, not on economic merit order; storage units cannot submit fixed cost elements under their Complex submission and must incorporate all costs into the price element; Demand Side Units cannot submit the per-hour cost element under their Complex submission.”

Section 3: Demand-side response

15. Are all types of demand-side response eligible to participate in the wholesale electricity markets (including day-ahead and intraday) as well as the balancing/ ancillary services markets?

Yes. DSR currently has some differences to other market participants in terms of settlement. The main way in which it is treated differently is that Demand Side Units have their metered position assumed to be equal to their dispatched position due to not having a methodology for calculating the settlement-standard delivered reduction in demand, and any energy revenue received by the unit at the imbalance price is removed from the unit, in order to not double-count the energy reduction which would also arise on a supplier meter and be settled at the imbalance price on that supplier. They are also not exposed to some of the incentive charges under the capacity market, and have some greater flexibility in the level to which they are obliged to offer in the capacity market auctions due to how their underlying physical provision can change differently to other participants.

However there has been a regulatory decision that developments will be made, with interim and enduring solutions, to have DSR treated the same as other market participants in terms of capacity market related charges and energy revenues, see the following link: https://www.semcommittee.com/sites/semc/files/media-files/SEM-19-029%20-%20DSU%20State%20aid%20compliance%20-%20Decision%20paper_0.pdf

16. **Can demand-side response be represented both individually and via aggregators?**

Yes, with some size restrictions on how large an individual site within a demand-side response unit aggregation can be (currently 10MW restriction as all dispatchable units above 10MW must register individually).

17. Are there any exemptions from network or energy-related costs as well as surcharges (RES, CHP, capacity mechanisms, etc.) for specific classes of consumers which might affect demand response incentives?

There aren't exemptions on these costs by class of consumer. A reduction of demand settled through a change in the meter quantity of the Supplier Unit to whom the relevant Demand Side Response site is associated would reduce the charge which is applied through a tariff on the metered quantity. This benefit is not currently seen by the relevant Demand Side Unit, but is seen by the Supplier Unit, and therefore the incentive created may be that Suppliers are more likely to allow their customers to sign up with Demand Side Units.

Demand for use in generating energy (e.g. such as house load for generation stations) is not subject to tariffs to the extent that the provision of energy from the generation site exceeds the demand – i.e. the demand is netted off the generation, so that it is almost seen as “self-supply” without being subject to tariffs. However this should not have much influence on Demand Side Response.

18. What percentage of customers is provided with smart meters (please specify it separately for the following groups of customers: a) households, b) business customers, c) industrial users)

The Strategic Energy Framework (SEF) 2010-2020 which set out the strategic direction for Northern Ireland’s energy strategy from 2010 is due to come to an end shortly and a new Energy Strategy is under development. This will set out the direction for the Northern Ireland energy sector in the period from 2020 to 2050, i.e. from expiry of the SEF to the date by which the UK government has legislated for net-zero carbon emissions. The issue of smart meters will be considered as part of the development of the new Energy Strategy

19. Are all the smart meters capable of metering and transmitting at least hourly metering values and do data management systems enable suppliers to settle customers on the basis of at least hourly metering values (i.e. against at least hourly spot market prices for the purposes of dynamic pricing)?

Not applicable. Please refer to answer to question 18.

20. Do customers in the retail market have access to a dynamic price contract linked to wholesale market spot prices?

Not yet, but suppliers may have plans to offer this in future.

Section 4 – Retail Markets: Regulated prices

21. What is the percentage of total demand supplied under regulated prices?

At present this is approximately. 20%.

22. Which customer groups are eligible for regulated prices?

Only domestic customers can avail of regulated electricity tariffs.

23. What is the percentage of demand per customer group supplied under regulated prices?

As already stipulated in 21 and 22 above only domestic customers can avail of regulated prices and the total demand supplied is c. 20%.

24. Are there market based energy offers which are more attractive than the regulated prices available to all customers, including regulated customers?

Yes – there are special offers with fixed terms during which the price is discounted that are lower than the regulated tariff. On the flip side the standard tariffs offered by some of those same competitor suppliers are higher than the regulated tariff.

a. Are regulated prices set at a level where effective price competition among suppliers can occur?

As above.

b. What were the regulated prices for the different customer groups in 2018 in c/kWh?

Only one customer group with regulated prices i.e. domestic. The price in 2018 was 16.6 p/kWh (inc VAT at 5%)

c .Please provide examples of available competitive prices that compete with the regulated prices and their comparable price level in c/kWh.

See below prices in p/kWh and also typical annual bill figures. The regulated supplier is Power NI and the other are competing against the regulated Power NI prices.

Typical annual bill of standard tariffs (including evergreen DD and online discounts)

Prices and Annual Bills as at 29 November 2018

Supplier	Standing Charge	p/KWh (inc. VAT)	Typical annual bill (inc. VAT) (3,100KWh)
Budget Energy	8.008	17.86	£582.80
Click Energy		16.99	£526.69
Electric Ireland		16.99	£526.69
Power NI (REGULATED)		16.60	£543.83
SSE Airtricity		18.67	£578.77

25. What is the methodology for calculating each of the retail regulated prices currently in place? Who sets the methodology? Who approves the prices?

Prices are set on a cost plus margin basis. The Utility Regulator approves the prices.

26. Has there been any significant switching of regulated customers to alternative suppliers?

Yes. Presently the regulated supplier has 56.1% of the domestic customers and the other 4 alternative domestic suppliers have the remaining 43.9%.

a. Please provide the share of customers under regulated prices in each customer category for the last five years consecutively.

Only one customer category has regulated prices i.e. domestic customers.

27. How are suppliers supplying regulated customers selected? How is non-discrimination in the selection process ensured?

The supplier that supplies regulated prices was the former incumbent monopoly supplier. It had to have a price control for domestic and business customers in the early years as it had significant market power. The price control is now only applicable on the domestic market as Power NI is no longer dominant in the non-domestic market. Power NI is "selected" to provide regulated prices in the domestic market because it is the only supplier in that market with market power.

28. What are the measures planned to fully effective market-based pricing of electricity for all final customers and what is the timeline?

We continuously monitor the domestic market for its competiveness looking at market shares, prices and switching data. There is no definite timeline for when we might move to market based pricing as we are not in a position to know when Power NI market share will have fallen to below 40-50%.

29. What is the timeline for price deregulation? Is it due to happen before the planned introduction of the capacity mechanism?

Both Northern Ireland and Ireland already have a capacity mechanism in place since 2017. In Northern Ireland the timeline for price deregulation will be considered as part of the work involved in transposing the recast Electricity Directive.

Section 5: Interconnection

30. Has the Member State developed interconnection with the view to reaching at least its interconnection targets as referred in point (d) of Article 4 of Regulation (EU) 2018/1999?

On the Island of Ireland, various interconnection projects are being developed; Greenlink (IE-UK) has recently signed a connection agreement and the Celtic Interconnector (IE-FR) is in the planning phase. The North-South Interconnector between Ireland and Northern Ireland is also currently under the planning process.

Point (d) of Article 4 of Regulation 2018/1999 requires Member States to implement an electricity interconnection of 10% for 2020 and 15% for 2030. The indicators related to this concern the price differentials in the wholesale market, nominal transmission capacity of interconnectors in relation to peak load and installed renewable generation capacity, The SEM currently has approximately 9.8GW of dispatchable generation and interconnection capacity and approximately 4.4GW of installed renewable generation. Interconnection capacity accounts for approximately 1000MW, however there are technical limits on this.

31. Please describe the amount of interconnection capacities available for trading from and to the Member State and their current utilization

A schedule of trading capacity is available on the Mutual-energy website: http://www.mutual-energy.com/trading-across-the-moyle-interconnector-isem/

Northern Ireland has 450MW of interconnection with the Great Britain market through the Moyle Interconnector. We have an existing tie-line with Ireland and are progressing arrangements for further interconnection by way of a 2nd tie-line (referred to as the North/South Interconnector – although it will be treated as a piece of transmission infrastructure, not an interconnector). This project is a designated EU Project of Common Interest (PCI)

32. Are there currently administrative import and/or export restrictions on interconnectors limiting trade with neighbouring countries? If yes, please explain what is the impact of such restrictions on the market?

See link above. There is currently a restriction on firm (export) capacity from Northern Ireland to Scotland due to transmission constraints. This varies on a daily basis depending on conditions in the GB system.

33. Are there any internal network congestions? What is the annual cost of redispatching/ countertrading in the Member State? Are there planned or ongoing network reinforcement measures?

Yes, there are significant internal network congestions on the island as a whole. The annual cost of these was forecast at €271m for the 2019-20 tariff year. Network reinforcement measures are planned, including construction of a second interconnector between Northern Ireland and the Republic of Ireland which if built will be expected to materially reduce the annual cost of congestion.