Balancing Market Principles Statement

A Guide to Scheduling and Dispatch in the Single Electricity Market

Version 6

29 July 2022

Version No.	Date	Notes
1.0	8 September 2017	First version.
1.1	6 March 2018	Version for consultation on proposed revisions.
2.0	11 April 2018	Revised version.
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5.0	28 April 2021	Revised version.
5.1	8 April 2022	Version for consultation on proposed revisions.
6.0	29 July 2022	Revised version.

IMPORTANT INFORMATION

This Balancing Market Principles Statement (BMPS) has been prepared by EirGrid and SONI in accordance with their respective Transmission System Operator Licence obligations (Condition 22B of SONI's TSO licence, Condition 10B of EirGrid's TSO licence) and SEM Committee decision SEM-16-058 dated 7 October 2016 entitled 'Balancing Market Principles Statement Terms of Reference'.

This BMPS refers to EU and national legislation and statutory licences in effect and applicable to EirGrid and SONI as of April 2022. The applicable licences and codes are listed below.

Licence / Code	Applicable Version
EirGrid Transmission System Operator Licence	10 March 2017
SONI Transmission System Operator Licence	26 January 2022
EirGrid Grid Code	Version 10, 15 December 2021
SONI Grid Code	8 October 2020
Trading and Settlement Code Part B	Version 25.0, 9 November 2021

We will review the BMPS on an ongoing basis, and in any event at least once a year, to ensure that this BMPS continues to be accurate and up to date. For example, in the event that any relevant provisions of EU and national legislation, statutory licences, the Grid Codes or the Trading and Settlement Code are amended, it may become necessary for EirGrid and SONI to amend this BMPS (subject to and in accordance with the applicable licence condition in their respective Transmission System Operator Licences) to ensure that the BMPS remains consistent with the applicable obligations framework.

All amendments to the BMPS must be submitted by EirGrid to the Commission for Regulation of Utilities and by SONI to the Utility Regulator in accordance with the process and the timeline set out in each TSO Licence.

In the event of an inconsistency between the applicable legislation, licences, Grid Codes and the Trading and Settlement Code on the one hand, and the BMPS on the other, the inconsistency shall be resolved as follows: first, the relevant statutory obligation will prevail; second, the relevant licence obligation; third, the relevant provision of the Grid Codes; and fourth, the relevant provisions of the Trading and Settlement Code. The BMPS describes how the obligations contained in these documents are interpreted and implemented; it does not create any new obligations.

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TERMS AND DEFINITIONS

In this BMPS, the following terms shall have the following meanings, unless the context requires otherwise.

Term	Definition
BMI	Balancing Market Interface – the interface between Participants and the Market Management System (MMS).
CBB	Cross-Border Balancing – one of the services in place between the TSOs and GB TSO to manage cross-zonal interconnector schedules.
CHP	Combined Heat and Power plant – a unit that produces both electricity and heat.
COD	Commercial Offer Data, within the meaning given to that term in the TSC.
Dispatch Instruction	An instruction issued by a TSO to a unit to change output, fuel or mode of operation.
DNO	Distribution Network Operator – the operator of the distribution network in Northern Ireland (being, as at the date hereof, Northern Ireland Electricity Networks Limited).
DS3	The TSOs' programme for 'Delivering a Secure, Sustainable Electricity System' to meet the challenges of operating the electricity system in a secure manner while achieving renewable electricity targets.
DSO	Distribution System Operator – the operator of the distribution system in Ireland (being, as at the date hereof, ESB Networks DAC).
EA	Emergency Assistance - one of the emergency services in place between the TSOs and GB TSO to manage cross-zonal interconnector schedules.
EBGL	Electricity Balancing Guideline
EDIL	The TSOs' Electronic Dispatch Instruction Logger that is used to issue dispatch instructions to units and as the tool for managing real-time declarations of availabilities including System Services.
EI	Emergency Instruction - one of the emergency services in place between the TSOs and GB TSO to manage cross-zonal interconnector schedules.
EirGrid	EirGrid plc
EMS	The TSOs' Energy Management System which provides real-time indication and control of the power system.
ENTSO-E	European Network of Transmission System Operators for Electricity.
GB TSO	National Grid Electricity System Operator
GPI	Generator Performance Incentive
Grid Code	EirGrid Grid Code and SONI Grid Code

ICO	Interconnector Owner – the owner of the Moyle and East-West HVDC interconnectors being Mutual Energy Limited and EirGrid Interconnector Designated Activity Company.
ICRP	Interconnector Reference Programme – the physical schedule for an interconnector which respects the operational ramp limit for such interconnector.
Imbalance Settlement Period	Means a thirty-minute period beginning on each hour and half hour.
IOS	Indicative Operations Schedule
LFCAOA	Load Frequency Control Area Operational Agreement
LFCBOA	Load Frequency Control Block Operational Agreement
LNAF	Long-Notice Adjustment Factor
LSI	Largest Single Infeed
LSO	Largest Single Outfeed
LTS	Long-Term Scheduling - the TSOs' software used to provide indicative commitment decisions (i.e. which units should be on-line or off-line) up to the end of the Trading Day or the next Trading Day depending on the timing of the LTS run.
Maximum Available Capacity	The long-term maximum capacity allowed to flow on Moyle or EWIC.
Maximum Transfer Capacity	The maximum capacity that can flow on Moyle or EWIC that ensures SONI or EirGrid do not enter Alert state.
MMS	Market Management System – The TSOs' market systems which include the scheduling and dispatch tools.
MW	MegaWatt, being the unit of measurement for the instantaneous power production or consumption level of a unit.
NCER	Network Code on Emergency Restoration
Net Transfer Capacity	The capacity made available for transfer at the operational reference point as defined by ENTSO-E.
Operating Reserve Requirement Quantity	The operating reserve requirements used to determine the most recent Indicative Operations Schedule.
Participant	A party with units registered in the market.
PN	A Physical Notification reflecting a Participant's intended MW output or demand for each of its units, excluding Accepted Offers and Accepted Bids, during each Imbalance Settlement Period.
Previous Market Arrangements	The Single Electricity Market arrangements prior to go-live of the Revised SEM arrangements on 1st October 2018.

PPMs	Power Park Modules–A generation unit or ensemble of generation units generating electricity which is connected to the network non-synchronously or through power electronics.
RAs or the Regulatory Authorities	Means the Commission for Regulation of Utilities and the Utility Regulator.
Reference Incident	This is referred to as the imbalance that may arise from the loss of the largest single infeed or outfeed when determining the requirements for reserve scheduling
Revised SEM arrangements	Has the meaning given to that expression in each of the TSO Licences.
RTC	Real Time Commitment - the TSOs' software used to provide indicative commitment decisions (i.e. which units should be on-line or off-line) close to real time.
RTD	Real Time Dispatch - the TSOs' software used to provide indicative incremental and decremental dispatch decisions close to real-time for units which are on-line or scheduled to be on-line.
SAOA	Synchronous Area Operational Agreement
Short Term Reserve Quantity	The available operating reserves and reserves capable of replacing operating reserves within one hour in the most recent Indicative Operations Schedule.
SIFF	System Imbalance Flattening Factor
SCADA	Supervisory Control and Data Acquisition – the TSOs system for gathering real-time data from the power system and controlling items on the power system via the EMS interface.
SCED	Security Constrained Economic Dispatch – the algorithms that provide indicative dispatch schedules.
SCUC	Security Constrained Unit Commitment - the algorithms that provide indicative unit commitment (on-off status of units) schedules.
SONI	SONI (System Operator Northern Ireland) Limited
SOGL	System Operator Guideline
SSII	System Shortfall Imbalance Index
System Services	The 'non-energy' services provided by units and interconnectors that support the secure operation of the power system. Includes DS3 System Services, System Support Services and Ancillary Services.
TCA	The EU-UK Trade and Cooperation Agreement
TOD	Technical Offer Data with the meaning given to that term in the TSC.
Trading Day	means the period commencing at 23:00 each day and ending at 23:00 the next day.

Transmission Constraint	To enable the efficient and secure operation of the power system, units are scheduled and dispatched to certain levels to prevent equipment overloading, voltages outside limits or system instability.
TSC	The Trading and Settlement Code for the Single Electricity Market.
TSO	Transmission System Operator – the operator of the transmission system in (as applicable) Northern Ireland (being SONI as at the date hereof) and Ireland (being EirGrid as at the date hereof), and the term TSOs shall be construed accordingly.
TSO Licences or Licences	EirGrid's TSO licence and SONI's TSO licence
Units	Includes Generator Units (as defined in the TSC), Generation Units (as defined in the Grid Codes), demand side units and System Service providers that form part of the scheduling and dispatch process.

1. OBJECTIVES OF THE BMPS

Our objective in publishing the BMPS is to set out in a clear and comprehensible manner how we fulfil the statutory obligations that govern our scheduling and dispatch process in the SEM. Under the Transmission System Operator Licence obligations (Condition 22B of SONI's TSO licence, Condition 10B of EirGrid's TSO licence) the '*Balancing Market Principles Statement is as accurate and up-to-date a description of the scheduling and dispatch process as is practicable*.'

The scheduling and dispatch process incorporates a range of activities associated with the close to real-time planning and the real-time operation of the power system. It is a continuous '24/7' process managed in a coordinated manner from our control centres in Dublin and Belfast using a range of common operational systems and processes.

The scheduling and dispatch process is built around the SEM Balancing Market. Utilisation of the balancing market offers and bids provided by Participants is the main mechanism by which we dispatch units to manage operational security constraints, (including the provision of System Services), maximise priority dispatch generation and efficiently operate the balancing market.

This BMPS describes the scheduling and dispatch process under the following headings:

Section 2 – Obligations: This section sets out the obligations framework (at both a European and national level) that applies to us in respect of our scheduling and dispatch activities, and also explains the interaction between these objectives.

Section 3 – Inputs: This section sets out the market and technical inputs to the process.

Section 4 – The Scheduling and Dispatch Process: This section sets out the process for production of Indicative Operations Schedules, the issuing of Dispatch Instructions, the provision of data to pricing and settlement systems and information to support various reporting mechanisms and publications.

Section 5 – Exceptions: This section sets out the abnormal events that can arise outside of the normal scheduling and dispatch process and the associated reporting mechanisms in respect of these events.

Section 6 – Publications: This section sets out the publications supported by the scheduling and dispatch process.

In addition, there are two appendices:

Appendix 1 – Obligations Framework: This appendix provides references to the statutory obligations under which our scheduling and dispatch process operates.

Appendix 2 – Scheduling and Dispatch Process: This appendix provides details of the scheduling and dispatch activities that we undertake and provides an example of this process.

2. OBLIGATIONS

The principles under which we operate the scheduling and dispatch process stem from European and National (Ireland and Northern Ireland) policy decisions. These decisions are transcribed into the statutory obligations (such as our TSO Licences) under which we operate. This section sets out these statutory obligations. We also set out how these obligations interact and how we manage competing obligations. The practical implementation of the obligations within the scheduling and dispatch process is presented in section 4.

The scheduling and dispatch process operates within an obligations framework that extends from European regulations through to the Trading and Settlement Code and Grid Codes. The source of these obligations and their hierarchy of implementation in the scheduling and dispatch process are illustrated in Figure 1 below.[1]

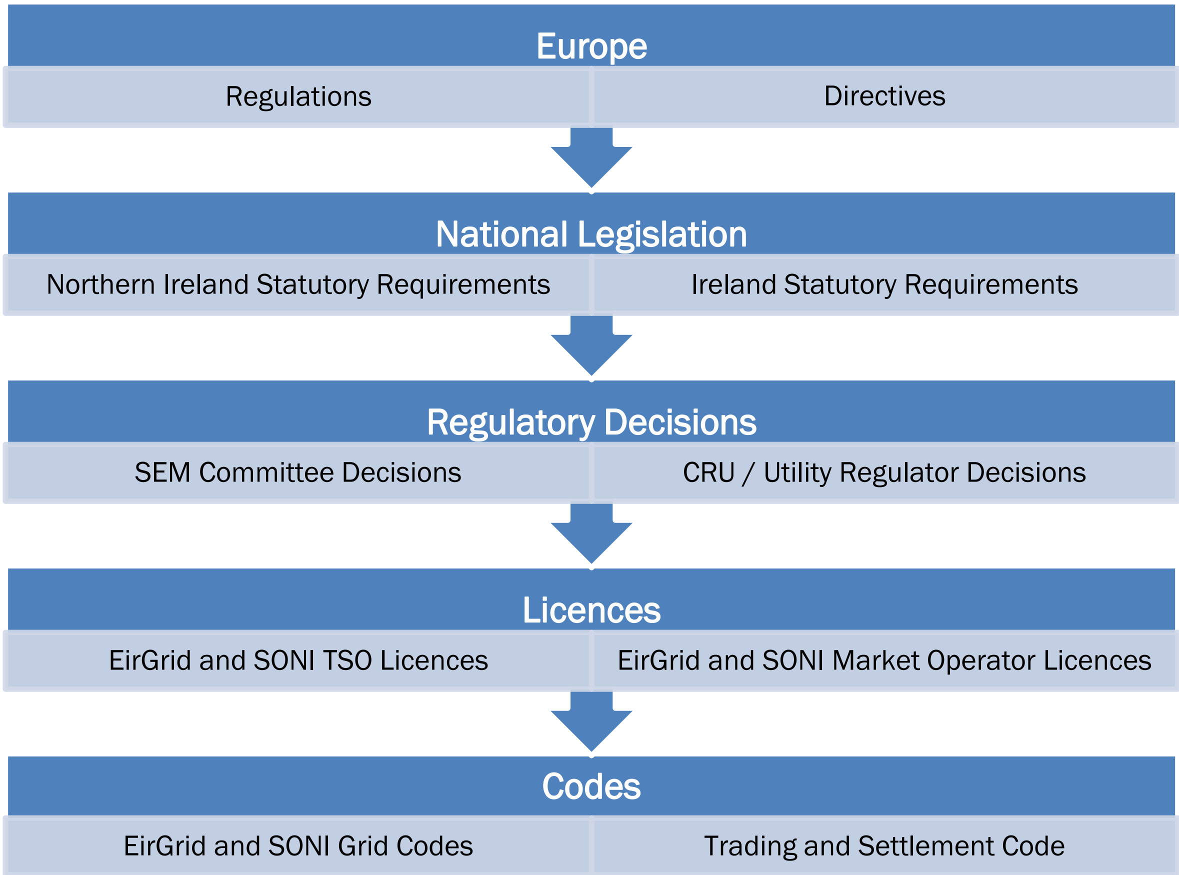

Figure 1: Obligations Framework

Our TSO Licences impose an obligation on each TSO, in conjunction with the other TSO, to schedule units and ensure direct instructions for the dispatch of units. This obligation must be carried out in accordance with the rest of the terms of each TSO Licence and the Grid

[1] Regulations and Directives only applicable to NI if within the scope of the Northern Ireland Protocol. See note in Appendix 1 for more detail.

Codes. This specific obligation to schedule and dispatch units is driven by our overall obligations under the broad obligations framework illustrated above.
Appendix 1 contains a more detailed list of the obligations that govern our scheduling and dispatch process.

In order to clearly explain our obligations, and how they interact, we have categorised them under four main headings as illustrated in Figure 2 below and described in the following sections.

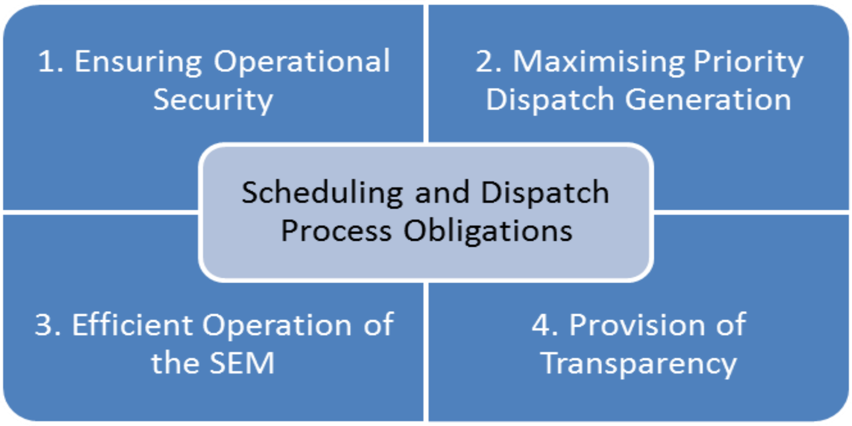

Figure 2: Scheduling and Dispatch Process Obligations

2.1. ENSURING OPERATIONAL SECURITY

We are responsible under Article 40 of Directive (EU) 2019/944[2] of the European Parliament and of the Council of 5 June 2019 concerning common rules for the internal market in electricity and amending Directive 2012/27/EU (**Recast Internal Electricity Market Directive**[3]) for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity, operating, maintaining and developing under economic conditions secure, reliable and efficient transmission systems with due regard to the environment, in close cooperation with neighbouring transmission system operators and distribution system operators, contributing to security of supply through adequate transmission capacity and system reliability, and ensuring a secure, reliable and efficient electricity system.

The European Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation (SOGL) sets out minimum requirements for transmission system operation and cross-border cooperation between TSOs. Among other things it includes detailed guidelines on requirements and principles concerning operational security

[2] In NI, some of these duties are shared with NIE Networks, the Transmission Asset Owner, while maintenance of the transmission network in NI is fully the responsibility of NIE Networks.
[3] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

and rules on operational security analysis, including regional operational security coordination and appointment of regional security coordinators.

In addition, the European Commission Regulation (EU) 2017/2196 establishing a network code on emergency and restoration (NCER) sets out rules relating to the management of the electricity transmission system in the alert, emergency, blackout and restoration states with the main objective of a reliable, efficient and fast restoration of the transmission system back to its normal state.

The responsibility to ensure operational security is also provided for in national legislation, namely: (for Ireland) Regulation 8 of S.I. No 445/2000 European Communities (Internal Market in Electricity) Regulation 2000 (as amended); and (for Northern Ireland) Article 12 of the Electricity (Northern Ireland) Order 1992 (as amended).

Our obligations in respect of ensuring operational security are further defined in our Licences, the TSC and the Grid Codes, and therefore form a key part of the scheduling and dispatch process.

Appendix 1.2 contains a table setting out our obligations to ensure operational security.

2.2. MAXIMISING PRIORITY DISPATCH GENERATION

Our obligations to provide priority dispatch to certain classes of generators are reflected in EU and national legislation, our Licences and the Grid Codes, and form a key part of the scheduling and dispatch process.

Article 16 of Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (the RES Directive) provides that Member States are required to ensure that when dispatching electricity generating installations, TSOs shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria.

Article 12 of Regulation (EU) 2019/943 (the **Internal Electricity Market Regulation**) amends this such that renewable generators with an output greater than 400kW and renewable generators that have been commissioned after July 4th, 2019 are (subject to certain limited exceptions) no longer treated as “priority dispatch”. Renewable generators commissioned before that date or with output less than 400kW are still given priority in dispatching of the system; however, this may be voluntarily given up by the relevant participant or it may be removed if the renewable generator becomes subject to significant modifications. Article 13 of the Internal Electricity Market Regulation, however, requires a redispatch down hierarchy for non-market based circumstances that consider all power-generating facilities using renewable energy sources equally. Note that implementation of Article 12 and 13 is subject to ongoing industry and regulatory engagement with the latest SEM proposed decision papers, SEM-21-027 and SEM-21-

026, outlining that the treatment and participation of such units is unlikely to change markedly until any associated system changes are complete.

Article 15 of Directive 2012/27/EU of the European Parliament and of the Council on energy efficiency provides that Member States are required to ensure that, subject to requirements relating to the maintenance of the reliability and safety of the grid, based on transparent and non-discriminatory criteria set by the national regulatory authorities, TSOs when they are dispatching electricity generating installations, provide priority dispatch of electricity from high-efficiency cogeneration in so far as the secure operation of the national electricity system permits. This has been similarly updated with the publication of the Internal Electricity Market Regulation which provides that high-efficiency cogeneration generators commissioned after July 4th, 2019 are (subject to certain limited exceptions) no longer treated as "priority dispatch". The high-efficiency cogeneration generators connected before July 4th, 2019, under the new Internal Electricity Market Regulation, can continue to benefit from "priority dispatch" or can revoke this benefit if requested by the generator. Note that implementation of the priority dispatch changes to high-efficiency cogeneration generators, as outlined above, are also subject to ongoing industry and regulatory engagement. However, since the 4th July 2019 there have been no new high-efficiency CHP generators added to the SEM, and there have been no significant modifications to the connections of pre-existing high-efficiency CHP generators.

In Northern Ireland, the priority dispatch provisions of the RES Directive were transposed into Northern Irish law through, among other things, a new condition in SONI's TSO Licence (Condition 9A). Certain provisions of the Internal Electricity Market Regulation were transposed into Northern Irish law on 4 December 2020 through the Electricity (Priority Dispatch) Regulations (Northern Ireland) 2020, prior to the end of the **Brexit** transition period. In addition, under the Northern Ireland Protocol, the Internal Electricity Market Regulation remains applicable in respect of Northern Ireland (subject to certain conditions) following the UK's exit from the European Union. However, amendments to SONI's TSO Licence to update Condition 9A in light of The Electricity (Priority Dispatch) Regulations (Northern Ireland) 2020 and the Internal Electricity Market Regulation are still to be put into place.

The obligation to provide priority dispatch to certain classes of generators is also provided for in national legislation, namely: (for Ireland) Section 21 of S.I. No. 217/2002 - Electricity Regulation Act 1999 (Public Service Obligations) Order 2002 (as amended); and (for Northern Ireland) Article 11AB of the Electricity (Northern Ireland) Order 1992, as amended, including by virtue of The Electricity (Priority Dispatch) Regulations (Northern Ireland) 2020.

Appendix 1.3 contains a table illustrating how our obligations in respect of priority dispatch have been implemented in each jurisdiction.

2.3. EFFICIENT OPERATION OF THE SEM

We are responsible under Article 40 of the Recast Internal Electricity Market Directive for ensuring a secure, reliable and efficient electricity system.

We are also responsible under Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management ("CACM") for facilitating access to cross-zonal (cross-border) exchanges of electricity and to avoid any unnecessary restriction of cross-zonal capacities. With effect from 1 January 2021, CACM no longer applies on the SEM / Great Britain border and, as such, the practical application of CACM, with respect to cross border transfer in the SEM, is suspended until the SEM is reconnected to the EU internal energy market with the completion of the proposed Celtic Interconnector. In the meantime, as provided for under the Trade and Cooperation Agreement, SONI is engaging with other UK transmission system operators to develop a new day-ahead capacity calculation methodology and EirGrid is engaging with EU transmission system operators similarly.

Under the Trade and Cooperation Agreement - Article 311 (1), to ensure efficient use of interconnectors and reducing barriers to trade between SEM and GB, EirGrid is required to ensure that the maximum level of capacity of electricity interconnectors is made available to (b)(i) ensure secure system operation and (b)(ii) efficient use of systems. Also, under Article 311(1)(c), EirGrid are to ensure the electricity interconnector capacity is only curtailed in emergency situations and this curtailment must take place in a non-discriminatory manner.

Commission Regulation (EU) 2017/1485 establishing a guideline on system operation (SOGL) requires the establishment of common principles for secure system operation, which includes, the establishment of load frequency control and synchronous areas, prequalification procedures for units providing reserves and ancillary services, dimensioning procedures to be used by TSOs to determine the volumes of services needed and exchanging and sharing of reserves within and between synchronous areas.

The Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (EBGL) includes the establishment of common principles for the procurement and settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for the activation of frequency restoration reserves and replacement reserves. The practical application of EBGL in the SEM is suspended pending reconnection of the SEM to the EU internal energy market with the completion of the proposed Celtic Interconnector.

Under Regulation 8 of S.I. No 445/2000 European Communities (Internal Market in Electricity) Regulation 2000 (as amended), EirGrid is obliged, in discharging its functions as transmission system operator, to take into account the objective of minimising the overall costs of the generation, transmission, distribution and supply of electricity to final customers.

In addition, we have an obligation under our Licences to establish and operate a merit order system for the Balancing Market which will take account of the objectives set out in each Licence. Our Licences (Condition 10A of EirGrid's TSO Licence and Condition 22A of SONI's TSO Licence) require us to take into account the following objectives:

- minimising the cost of diverging from physical notifications;
- as far as practical, enabling the Ex-Ante Market to resolve energy imbalances; and
- as far as practical, minimising the cost of non-energy actions.

Appendix 1.4 contains a table setting out our obligations with respect to ensuring a secure, reliable and efficient electricity system.

2.4. PROVISION OF TRANSPARENCY

We have a number of reporting and monitoring obligations under Regulation (EU) No 1227 / 2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT) and the Commission Implementing Regulation No. 1348 / 2014 on data reporting implementing Article 8(2) and Article 8(6) of REMIT (the Implementing Regulation). The goal of REMIT and the Implementing Regulation is to increase integrity and transparency of wholesale energy markets in order to foster open and fair competition in wholesale energy markets for the benefit of final consumers of energy.

We are obliged to comply with the transparency requirements in Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation. In addition, we are obliged to comply with other transparency measures under the Recast Internal Electricity Market Directive, Council Regulation (EU) 543 of 2013 on submission and publication of data in electricity markets and amending Annex 1 to Regulation (EC) No 714 / 2009 of the European Parliament and of the Council, the TSO Licences, the Grid Codes and the TSC. For example, we are required to submit reports to the SEM Committee's Market Monitoring Unit.

Section 6, Publications, provides a reference point for these and other publications.

Appendix 1.5 contains a table setting out our obligations with respect to increasing the integrity and transparency of the SEM.

2.5. IMPLEMENTATION OF OBLIGATIONS

These obligations provide the framework within which the scheduling and dispatch process operates. They determine the overall design of the processes that we follow; from the inputs that we feed into this process to the functionality of the tools that we use.

In some instances, the implementation of specific obligations is bound by the practicalities of the process such as the necessity to produce and update schedules in a timely manner. The distinction between energy and non-energy actions is not made in the scheduling and dispatch process for example. This distinction is made in the ex-post imbalance pricing process as described in our 'Methodology for System Operator and Non-Marginal Flagging'.

The obligations also interact and at times compete. Given the continuous, real-time nature of the scheduling and dispatch process, there must be a clear approach to prioritising these obligations to ensure that a technically feasible and consistent scheduling and dispatch solution is achieved to the maximum extent possible

Based on the hierarchy of obligations outlined in Figure 1 we prioritise these scheduling and dispatch process obligations in the following order:

1. Ensuring operational security;
2. Maximising priority dispatch generation; and
3. Efficient operation of the SEM.

Security is placed first as without a secure system the other obligations could not be met. This is consistent with the intentions set out in Article 13(5) of the Internal Electricity Market Regulation. Priority dispatch is placed second, ahead of efficient operation of the SEM, on the basis of SEMC decision SEM-11-062 'Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code'. This decision states that we must adhere to an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations. At times this will result in dispatch being economically less efficient to avoid curtailment of priority dispatch generation.

Within each of these three high-level obligations, further ranking or weighting of obligations is required. Examples include the sub-categorisation of priority dispatch units as described in section 3.1.1 and the weighting of economic objectives as described in section 3.1.2.

The practical implementation of these obligations and their hierarchy within the scheduling and dispatch process is set out in section 4.

The requirement to provide transparency is an overarching obligation. We support the transparency objective through the design of our process and tools to feed a wide range of publications as described in section 6.

Where clarification of the implementation of these obligations is required, we will seek guidance from the RAs. Any update to the implementation of these obligations within our scheduling and dispatch process will be reflected in the BMPS in line with the requirements in our Licences to keep the BMPS up to date.

3. INPUTS

This section describes the data inputs to the scheduling and dispatch process including the source of the data and how it is used.

There are thousands of data items that form inputs to the scheduling and dispatch process. These can be categorised as commercial data (the cost of energy from each unit), technical data (the capability of each unit) as well as parameters used to implement the objectives of the process (weighting policy objectives). The data comes from various sources (from Participants and System Operators) over varying timeframes (once a day to every second) and through different interfaces (energy market and power system). The data items, grouped by source, are summarised in Figure 3 below.

The inputs we have described in this section are associated with scheduling and dispatch under typical operational circumstances. Abnormal events can arise whereby different inputs are taken into account and where different scheduling and dispatch processes apply. These events are described in section 5 ‘Exceptions’.

Policy Objectives

- Priority Dispatch categorisation
- Scheduling and Dispatch Policy Parameters

Participants / System Service Providers

- Technical Data - energy market and System Services
- Commercial Data - energy market
- Physical Notifications
- Availability / System Service Capability Declarations
- Unit Under Test
- New Technologies

Ex Ante IntraDay Markets

- Interconnector Schedules*

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Figure 3: Inputs to the Scheduling and Dispatch Process

*Note: Section 3.3 below outlines the changes to the interconnector schedules as a result of the UK leaving the EU and the interim workaround currently in place.

The following sections describe each of these inputs and, where defined, provides relevant references to the obligations under which each is provided.

3.1. INPUTS REFLECTING POLICY OBJECTIVES

Inputs reflecting European / Ireland / Northern Ireland policy objectives are set out below.

3.1.1. PRIORITY DISPATCH

We give priority to the dispatch of certain generation types as required by European, Ireland and Northern Ireland legislation (see Appendix 1.3). The output of these units is maximised as far as technically feasible. Within this categorisation there is a hierarchy of units, this is defined in SEM Committee decision SEM-11-062 with the subsequent inclusion of Solar and Tidal generation on an interim basis as referenced in the SEM Committee's letter to us on 24 March 2017[4], and as illustrated in Figure 4 below. Note that this hierarchy sits within other dispatch requirements related to hydro stations during flood risk situations, the treatment of interconnector schedules (avoiding curtailment of market schedules), other units (non-priority dispatch) and TSO-led Cross-Zonal Actions over the interconnectors.

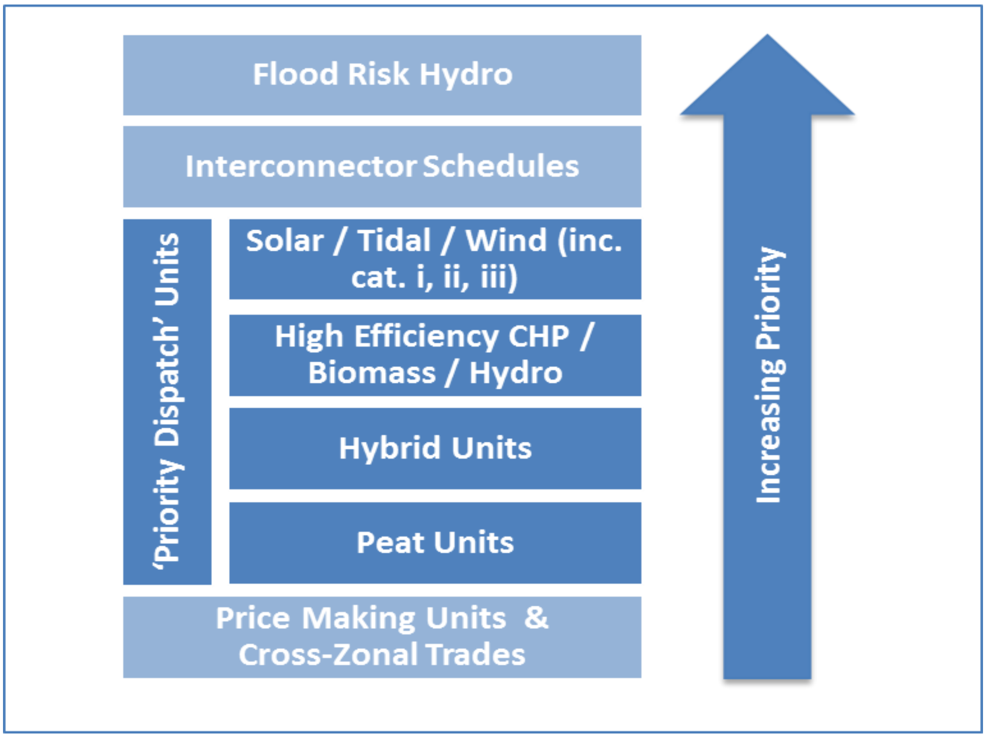

Figure 4: Priority Dispatch Order from SEM-11-062

Note that within the solar, tidal and wind category there are sub-categories reflecting the controllability of Power Park Modules (PPMs) (per SEM-11-062 wind farms that are controllable are given priority over wind farms that should be, but are not, controllable). We have published a document describing how this categorisation is determined and managed 'Wind Farm Controllability Categorisation Policy' – this is referenced in section 6, Publications. Based on the guidance provided by the SEM Committee on the 24th of March

4 Letter from SEM Committee to TSOs, dated 24 March 2017, 'Re: TSOs Priority Dispatch Review: Inclusion of Solar and Tidal'. SEMC Ref D/17/5471

2017, we have updated our systems and processes to accommodate Solar and Tidal units within the priority dispatch hierarchy[5].

We implement priority dispatch policy, and the associated hierarchy, by the application of a range of negative decremental prices to units classified as priority dispatch. This implementation is discussed in Section 4, The Scheduling and Dispatch Process.

3.1.2. SCHEDULING AND DISPATCH POLICY PARAMETERS

Under our Licences we are required to apply policy parameters in our scheduling and dispatch process to give effect to RA policy.

The RA determined scheduling and dispatch policy parameters are:

- The Long Notice Adjustment Factors (LNAF) relative to unit Notification Times;
- The System Imbalance Flattening Factors (SIFF) relative to the System Shortfall Imbalance Index (SSII); and
- The Daily Time for fixing the SSII/SIFF for a Trading Day.

These parameters are designed to reduce the propensity for starting-up long-notice units over shorter notice units in our scheduling process. Along with other aspects of the scheduling and dispatch processes, this outcome is designed to contribute towards the objective of enabling ex-ante markets to resolve energy imbalances.

The scheduling process objective is to minimise the cost of diverging from Participants' PNs. To achieve this and meet the other objectives of satisfying security constraints and maximising priority dispatch, the optimisation will at times schedule long-notice units over short-notice units based on cost. To counter this, and account for the objective of allowing Participants resolve energy imbalances, parameters can be applied within the optimisation to weight scheduling decisions towards shorter notice units. This is achieved by applying multipliers to the start-up costs of off-line, long notice units. This will reduce the propensity for starting-up long-notice units where shorter notice units can be utilised and where the objective of satisfying operational security constraints and maximising priority dispatch can still be achieved.

Per SEMC decision SEM-21-088 on 18 November 2021, the SEM Committee has decided that LNAF and SIFF will be set at zero for the period 1st January to 31st December 2022. A consultation may be carried out in August 2022 to determine the values to apply from January 2023.

[5] Document on controllability status update of PPMs: http://www.eirgridgroup.com/site-files/library/EirGrid/2020-01-January-Controllability-status-update.pdf

As these parameters are zero, they currently have no impact on the scheduling and dispatch process. We have however described the parameters in more detail below given that they may be applicable at a future date.

3.1.2.1. LONG NOTICE ADJUSTMENT FACTORS

The TSOs will determine a table of LNAF per Notification Time interval values in line with an RA approved methodology. As Notification Time increases so will the LNAF associated with that Notification Time. As each unit can have a Notification Time associated with each of its three Warmth States (hot, warm and cold as defined in the TSC and Grid Codes), each unit will have an LNAF per associated Warmth State. Below a certain Notification Time threshold, the LNAF will be set to zero meaning that no adjustment of the start-up cost will apply to those units.

3.1.2.2. SYSTEM IMBALANCE FLATTENING FACTORS / SYSTEM SHORTFALL IMBALANCE INDEX

Energy actions should only arise when there is an energy imbalance. If the imbalance is zero, all actions should be constraint (non-energy) actions and the LNAF would not be required as the schedule should seek to resolve constraint (non-energy) actions at least cost. The TSOs will therefore implement a SIFF based on a SSII that will also act on the start-up cost of a unit. When the system imbalance is high there will be a high SIFF when system imbalance is low there will be a smaller SIFF. This will allow targeting of the LNAF and SIFF at times when early energy actions are more likely and dampen or remove their effect when not required. As these parameters are currently zero, they have no impact on the scheduling and dispatch process.

3.1.2.3. THE DAILY TIME FOR FIXING THE SSII/SIFF

The SSII, and resulting SIFF, is a calculated value which is fixed for each trading day at a pre-determined time each day. This time will be determined in line with the parameter setting methodology approved by the RAs.

While these parameters are currently set to zero, and therefore not impact on the scheduling process, our overall scheduling and dispatch process is still designed to account for our obligation of enabling ex-ante markets to resolve energy imbalances (as described in section 4.5).

3.2. PARTICIPANT AND SYSTEM SERVICE PROVIDER INPUTS

The following section describes Inputs provided by Participants and System Service providers.

3.2.1. UNIT TECHNICAL DATA

There are two main sources of unit technical data utilised in the scheduling and dispatch process: Technical Offer Data (TOD) and System Services capabilities.

TOD includes maximum and minimum output capabilities, ramp rates and notification times of units and is fundamental to the process of scheduling and dispatching units. Through the selection of predefined TOD sets, a participant can also determine their mode of operation (e.g. CCGT or OCGT mode) and/or fuel (subject to system security requirements). The requirements for this data are set out in the Grid Codes SDC1 (Scheduling and Dispatch Code), TSC Part B D.3 (Timing of Data Submission), D.5 (Technical Offer Data), Appendix H (Data Requirements for Registration) and Appendix I (Offer Data).

System Services data (which incorporate DS3 System Services and other System Support Services and Ancillary Services) includes operating reserve capability curves, reactive power capabilities and inertia. This data, along with TOD, is used to ensure that sufficient System Services are scheduled to meet the security requirements of the power system. The requirements for this data are set out in the Grid Codes (SDC1) and the relevant DS3 System Services agreement (Schedule 9 – Operating Parameters). This data is managed through the relevant System Services agreement and submitted via real-time declarations in our Electronic Dispatch Instruction Logger (EDIL) or by other means, as specified in the DS3 System Services contractual documents.

Unit technical data is used to perform validation of PNs (see section 3.2.3 on PNs), to develop schedules of units that utilise their technical capability to meet security and other requirements and to ensure that the dispatch of units is within their technical characteristics. We validate unit technical data through unit testing and on-going monitoring. To qualify to provide a System Service a unit’s capability is proven and monitored for that service. To qualify to provide DS3 System Services, units must satisfy a suite of specific DS3 System Services tests which assess their capabilities and determine relevant unit technical data.

3.2.2. UNIT COMMERCIAL DATA

The requirements for submission of Balancing Market commercial offer data submissions are set out in Grid Codes SDC1, TSC Part B sections D.3 (Timing of Data Submissions), D.4 (Commercial Offer Data) and Appendix I (Offer Data). This commercial offer data takes two forms:

- Complex Bid Offer Data: 3-part offer data comprising start-up, no-load and incremental and decremental price quantity pairs; and

- Simple Bid Offer Data: Incremental and decremental price quantity pairs.

We do not make any adjustment to Participants' submitted commercial offer data even if there is a known error in this data. We do not make any adjustments in the scheduling and dispatch process for such errors. It is the responsibility of the Participant to update their commercial offer data in line with TSC rules.

Commercial data associated with the provision of System Services does not currently form an input to the scheduling and dispatch process as each System Service considered in the scheduling and dispatch process is remunerated using common tariffs (i.e. a fixed payment rate per service is applied to each service provider). System Service providers are therefore selected based on their Balancing Market commercial offer data (where applicable) and their technical capability to provide a service.

We select the appropriate commercial data set (complex or simple) for use in the scheduling and dispatch process as set out in appendix 2.1. The objective of the scheduling and dispatch process is to minimise the cost of diverging from participants' Physical Notifications. Unit commercial data forms the basis of determining this cost.

3.2.3. PHYSICAL NOTIFICATIONS

Physical Notifications (PNs) are submitted by Participants as their intended output excluding any accepted offers and bids (i.e. the PN does not reflect any balancing action that we take on the unit). It is Participants' responsibility to ensure that their PNs are consistent with the Technical Offer Data for their units.

All dispatchable Participants are required to submit PNs. Non-dispatchable Participants will not be obliged to submit PNs (even if they have traded or expect to trade in the markets) but may elect to do so for information purposes. We use our own forecasts of their output as an implicit PN for these non-dispatchable units.

The requirements for submission of PNs are set out in Grid Code SDC1, TSC Part B sections D.3 (Timing of Data Submission), D.7 (Physical Notification Data) and Appendix I (Offer Data).

A unit's PN is used along with its incremental and decremental cost curves to form a composite cost curve that is used within the scheduling and dispatch process. PNs for units under test are also flagged to ensure that the PN is prioritised within the scheduling and dispatch process. These items are discussed further in section 4.

3.2.4. AVAILABILITY AND SYSTEM SERVICES CAPABILITY DECLARATIONS

Participants are required to submit and maintain forecast active power (MW) availability for their units with real-time updates provided as this information changes. Updates to System Service capabilities are also required from System Service providers.

Forecast availabilities submitted by Participants via the BMI are:

- a Forecast Availability Profile;

- a Forecast Minimum Output Profile; and
- a Forecast Minimum Stable Generation Profile

Requirements for these submissions are set out in Grid Codes SDC1 and TSC Part B section D.6.3 (Availability, Minimum Stable Generation and Minimum Output).

Real-time availability declarations are also provided by Participants via EDIL interface with the TSOs. Requirements for real-time availability declarations are set out in Grid Codes SDC1.

It is the responsibility of Participants to ensure that forecast availability aligns with real-time availability declarations in EDIL. For example, if a unit trips, the Participant will re-declare its availability to zero in EDIL and update the forecast availability via the BMI in line with the allowed forecast availability submission window.

Non-dispatchable wind units provide a real-time availability signal via our Energy Management System (EMS). Forecast availability for non-dispatchable wind comes from our wind forecast[6].

For dispatchable units, real-time System Services declarations such as reactive power or operating reserve capabilities are made in real-time via EDIL. Requirements for the declaration of System Services are set out in Grid Codes SDC1. Any longer-term changes to System Service capability are managed through the respective System Services agreement in place with each System Service provider.

We select the appropriate availability data (forecast or real-time) for use in the scheduling and dispatch process as set out in appendix 2.1. Unit availability data determines the technical capability range available to be utilised in the scheduling and dispatch process.

3.2.5. UNIT UNDER TEST NOTIFICATION

To facilitate unit testing which requires a specific running profile, Participants submit PNs via the BMI specifying the period that the unit is requested to be under test with a test flag. Any PN submission that includes a PN with a test flag will require manual approval by the TSO before it is accepted into the scheduling and dispatch systems. Any subsequent modifications to a test PN, including cancellation is also subject to our approval.

The type of test being requested by a unit will determine the notification time required by us to assess and approve a test and incorporate into the scheduling and dispatch process. The Grid Codes set out definitions for the categorisation of tests as either a Significant Test or a Minor Test (OC8 in the EirGrid Grid Code, and OC10 and OC11 in the SONI Grid Code).

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[6] The approach for solar generation follows the wind model. Further information is available in the document entitled 'Wind and Solar Forecasting Methodology for Scheduling and Dispatch' published on the TSO Responsibilities page of www.SEM-O.com.

We prioritise a unit under test in the scheduling and dispatch process so that its PN is respected as far as technically feasible.

Participants should refer to our published *Unit Under Test Guidelines for Market Participants* which describes the arrangements for progressing a test.

3.3. EX-ANTE MARKET INTERCONNECTOR SCHEDULES

Interconnector schedules are an output of from the IDA1 and IDA2 ex ante intraday markets. These are notified to us following completion of the first intraday market (IDA1) at ~18:00 on day D-1 and the second intraday market (IDA2) at ~08:30 on Day D.

Interconnector schedules are represented as fixed demand and/or generation profiles within the scheduling and dispatch process. However we may amend these profiles using Cross-Zonal Actions as described in section 3.4.6.

As noted previously, since the UK has left the EU, we do not have ex ante day ahead interconnector schedules. Under the Trade and Cooperation Agreement (TCA), SONI is engaging with UK TSOs to develop a proposal for a new day ahead capacity calculation between SEM and GB. EirGrid is also engaging with EU TSOs on the same.

3.4. SYSTEM OPERATOR INPUTS

System operators referred to in this section are: the Distribution System Operator (DSO) in Ireland (ESB Networks Designated Activity Company) and the Distribution Network Operator (DNO) in Northern Ireland (Northern Ireland Electricity Networks Limited), the GB TSO (National Grid ESO), the Interconnector Owners ICOs (Mutual Energy Limited and EirGrid Interconnector Designated Activity Company) and the TSOs in Ireland and Northern Ireland (EirGrid and SONI).

3.4.1. DEMAND FORECAST

We produce demand forecasts representing the predicted electricity production required to meet demand including system losses but net of unit demand requirements (‘house-load’).

The forecasts are based on historical jurisdictional data for total generation (conventional, wind and solar). The total generation is used as a proxy for the total demand. The forecasts for each jurisdiction are calculated separately due to the different demand profiles in Ireland and Northern Ireland, and to reflect the differences in some bank holidays and special days. The forecast only reflects the generation visible to us via SCADA; however, we have to also consider deeply embedded generation or micro-generation as part of the forecast process. The forecasts themselves are produced using a proprietary software package. The algorithm learns the relationship between the system demand and a set of predictor variables (day of week, time of day, week of year, special days, average hourly temperature) based on historical data. It then creates a prediction for each half hour of the forecast period.

We prepare and publish a 4-day demand forecast at half-hour resolution on a daily basis. We then update this forecast on a continuous basis to account for actual demand conditions and interpolate the forecast to a 1-minute resolution for use in the scheduling and dispatch process.

Demand forecasts are produced in line with Grid Code obligations - OC1.6 in the EirGrid Grid Code and OC1.5 in the SONI Grid Code.

In our scheduling process we develop plans that schedule sufficient generation to meet our demand forecast.

Further detail on demand forecasting is available in a separate document entitled 'Short-term Demand Forecasting Methodology for Scheduling and Dispatch' and in the BP_SO_4.2_Demand Forecasting for Scheduling and Dispatch business process.

3.4.2. RENEWABLES FORECASTS

We procure wind and solar power forecasts from two independent forecast providers. These forecasts include the forecast power output from each wind farm and solar farm with a Maximum Export Capacity (MEC) greater than or equal to 5 MW along with the total aggregate forecast power production and an uncertainty of the aggregate power forecast in the form of confidence bands around the forecast. Standing data, such as location, turbine number, type and model and hub height, for each wind farm is provided to the wind forecast providers. In addition, meteorological measurements, outage information and SCADA from each site (where available) are sent to the providers on an ongoing basis. This information is used by the wind forecast providers to develop and train models for each wind farm. Numerical Weather Predication models along with the developed wind power prediction models are then used to produce the wind power forecasts.

Each forecast provider provides us with a raw (not accounting for outages) forecast every 6 hours, at 15-minute resolution for the next 4.5days. We then adjust the forecasts to take wind farm outages into account, merge these forecasts and blend them with current wind conditions on a continuous basis and interpolate to a 1-minute resolution for use in the scheduling and dispatch process.

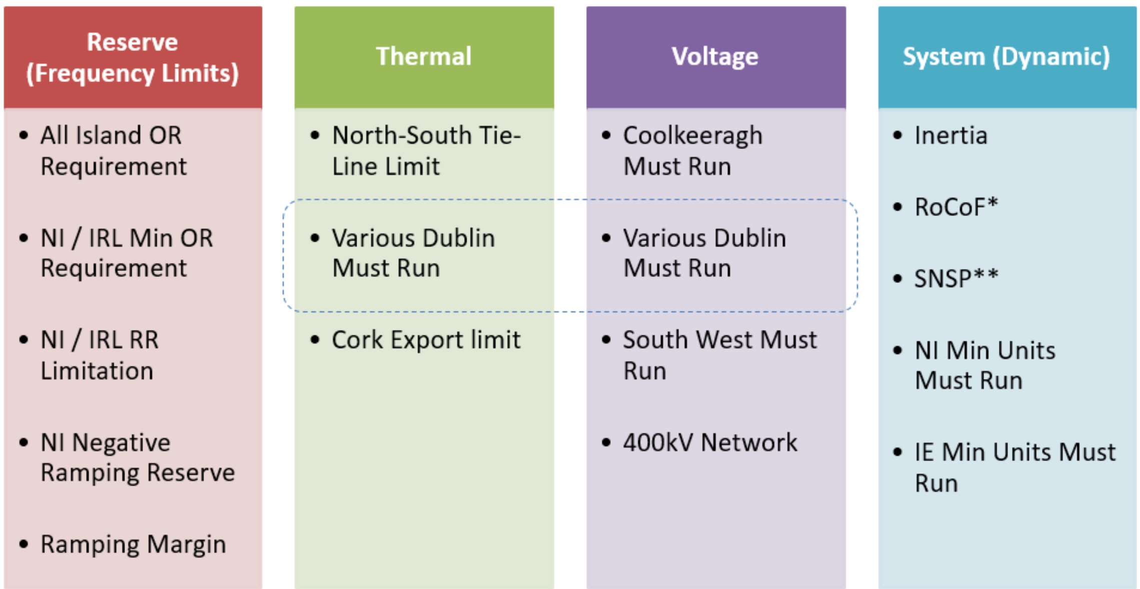
Wind forecasts do not include curtailment forecast as these are only implemented in real-time operation.

Note that while wind participants may submit physical notifications (PN) representing their forecast production, these are not used in the scheduling and dispatch process. Rather we develop schedules that utilise our own forecast of renewables. This approach is driven by the priority dispatch categorisation of renewable generation.

The impact of solar generation is becoming increasingly significant on the operation of the power system. Forecasting for solar farms has been in place since Q2 2017. Standing data is provided to the Forecast Providers for each site and revised as updates are made. Further information on wind and solar forecasting is published in a separate document entitled 'Wind and Solar Forecasting Methodology for Scheduling and Dispatch' and in Business Process BP_SO_4.3_Wind Forecasting.

3.4.3. CONSTRAINTS

Constraints impose limits on the physical operation of units in order to maintain operational security requirements under normal and contingency (failure of an item of equipment, e.g. transmission line or unit) conditions. An illustration of some of the constraints on the Ireland and Northern Ireland power system is provided in Figure 5 below. There are also additional constraint categories which are related to maintaining security of supply, hydro management and the environment.



*RoCoF: Rate of Change of Frequency
**SNSP: System Non-Synchronous Penetration

Figure 5 Illustration of Power System Constraints

We determine constraints through planning studies, real-time analysis and monitoring of the power system. The majority of constraints are known in advance and are modelled in the scheduling tools to ensure that the resulting schedule respects known requirements. Other constraints may arise through real-time analysis and monitoring and are managed in real-time operation.

Our Transmission Outage Planning function determines the sequencing of transmission outages during the outage season. In the course of this analysis, significant transmission constraints are identified, such as the necessity for must-run units, or restrictions on the running of certain units or groups of units. Each week, additional constraints analysis is carried out for the following week, based on expected transmission and unit outages and forecast demand conditions. This analysis is undertaken using models of the power system and proprietary power system analysis tools to model particular system conditions and contingencies.

In real-time operation of the power system there is a need to respond to forced outages (such as a transmission line tripping) or unexpected constraints (such as higher than expected wind generation levels) as it is not possible for all scenarios to be covered in the weekly look-ahead analysis. We perform security analysis every five minutes which considers circuit loadings, system voltages and transient stability for a range of contingencies. This real-time analysis runs in parallel with the scheduling and dispatch and may result in constraints arising that are not reflected in the schedules. We manage such scenarios through their real-time dispatch decisions as set out in section 4.

Constraints may also arise on distribution network connected units. Where such constraints impact on our ability to dispatch/control units, the relevant DSO/DNO will inform us so that the constraint is reflected in the scheduling and dispatch process.

Participants' PNs are not required to respect these constraints (only the physical constraints of the units themselves) so a key aspect of the scheduling and dispatch process is the application of these constraints to the PNs to produce a schedule and dispatch that is physically secure. Constraints modelled in the scheduling tools also form a key input to the Imbalance Pricing process through the setting of System Operator Flags as referenced in section 4.6 and the publication of our 'Methodology for System Operator and Non-Marginal Flagging' as referenced in section 6 Publications[7].

We publish a description of the constraint types and details on each transmission constraint in our Operational Constraints Update document – see section 6, Publications. Currently this document is updated on a weekly basis and is complemented with an ad-hoc reporting of any amended or new constraints that are not captured in the weekly updates e.g. in response to a forced outage.

3.4.4. SYSTEM SERVICE REQUIREMENTS

The provision of System Services (such as operating reserves and reactive power) from service providers is required to support the secure operation of the power system. We specify the requirement for System Services in a number of ways:

- 'must run' requirements to support the provision of reactive power from units in particular locations on the power system,
- relatively static system requirements such as the minimum system inertia level,
- dynamic requirements for operating reserves which must be sufficient to cover the largest imbalance that may arise from the loss of the Reference Incident, in both the

[7] See also Information Note on the flagging process associated with inter-area flow constraints https://www.sem-o.com/documents/general-publications/Information_Note_on_Inter-Area_Flow_Constraints.pdf

positive (to cover the loss of the LSI) and negative (to cover the loss of the LSO) directions.

We publish requirements for the System Services modelled in the scheduling and dispatch process in our Operational Constraints Update - see section 6, Publications.

3.4.5. INTERCONNECTOR TECHNICAL DATA

The ability to transfer power over the interconnectors (Moyle and EWIC HVDC interconnectors) is a function of the capacity of the interconnectors and the capacity of the transmission systems on either side. We co-ordinate the setting of the interconnection capacities with the ICOs and GB TSO. These capacities feed into the ex ante intra day markets and the scheduling and dispatch process[8]. Under Article 311(1)(b) within the Trade and Cooperation Agreement, SEM and GB must ensure the maximum level of capacity of electricity interconnectors is made available to ensure secure system operation and efficient use of systems. Also, under Article 311(1)(c), the interconnector capacities may only be curtailed in emergency situations and this curtailment must be non-discriminatory.

The determined capacities are provided to the ex ante intra day markets as the limits to allowable cross-zonal (between SEM and BETTA) exchanges of power. We also use these capacities in the scheduling and dispatch process to determine available capacity for Cross-Zonal Actions. Cross-Zonal Actions are discussed in section 3.4.6.

We set the operational ramp rate applied to each interconnector in accordance with the methodology set out in the Load Frequency Control Block Operational Agreement article 3. This is a MW/min ramp rate that is applied in the physical dispatch of each interconnector.

The interconnectors can also provide a number of System Services. These capabilities are as agreed in the relevant System Services agreements that we have in place with the ICOs.

3.4.6. PRICES AND VOLUMES FOR CROSS-ZONAL ACTIONS

While interconnector (Moyle and EWIC HVDC interconnectors) schedules are determined by the ex ante intra day markets, they can, under defined circumstances, be adjusted by us through Cross-Zonal Actions. Cross-Zonal Actions is the collective name for a number of services that are available to us to reduce or increase imports or exports on the interconnectors for limited and specific reasons. Among the Cross-Zonal Actions two trading options are implemented: Co-ordinated Third-Party Trading (CTPT) and Cross Border Balancing (CBB). CBB and a service similar to CTPT existed in the Previous Market Arrangements.

[8] The SEM-GB Joint Implementation Group's 'Interim Cross Zonal TSO Arrangements for GB-ISEM go live' sets out the interim approach: www.sem-o.com/documents/general-publications/Interim-Cross-Zonal-TSO-Arrangements-for-GB-ISEM-go-live-Publication.pdf

CTPT and CBB will only be used to facilitate priority dispatch and / or system security. We also may set down the Maximum Transfer Capacity on the interconnectors for system security reasons. To resolve system security issues, we will first look to take 'local' actions within the SEM. From a priority dispatch perspective, we also look to take 'local' SEM actions first (such as reducing the output of conventional generation to make room for wind). If these actions are insufficient, we will then look to Interconnector trading. Trades only happen after the closure of the respective intra-day markets so do not impact on participants in those markets. SONI and EirGrid are currently engaging with the GB TSO to improve the cross-zonal actions currently available.

System security reasons may be short term decisions or could be longer term implementations such as the management of operating hours on generators. Each proposed trade must be agreed with the GB TSO. The GB TSO will have the right to reject the proposed trade where it is deemed to have a negative impact on secure, efficient, and economical system operation.

The table below describes the Cross Zonal Actions which were agreed for go-live of the revised SEM arrangements. The table below also includes any Cross-Zonal Actions that have been introduced following go-live. At go-live Co-ordinated Third Party Trading (CTPT) was not finalised, however it is now finalised and operational. Further information is available in the SEM-GB Joint Implementation Group's paper on 'Interim Cross Zonal Arrangements for GB-ISEM Go-live'[8].

Cross-Zonal Action	Description
Co-ordinated Third Party Trading - CTPT	For periods for which the cross border intraday auctions have completed and <u>subject to the agreement of the GB TSO</u>, we contract with a third-party to trade in the GB intraday market so as to alter the cross-zonal flow. CTPT volumes are limited to the capacities of the interconnectors. These trades are only entered into for system security (including congestion management) and/or priority dispatch. The advantages of this type of trading over Cross Border Balancing (CBB) (described below) include potentially greater liquidity, more competitive prices and greater flexibility.
Cross-Border Balancing – CBB	We have trading arrangements in place with the GB TSO. We exchange offers and bids for volumes of energy and prices on a daily basis. CBB volumes are normally capped at 200 MW (200MW can be exceeded with agreement between SONI/EirGrid and the GB TSO) in both directions for each interconnector in accordance with operating protocols agreed between us, the ICO and the GB TSO. Trades initiated by us are priced by the GB TSO in accordance with their internal procedures. Trades initiated by the GB TSO are priced by us daily based on surplus capacity available at short notice across the trading day. In accordance with the operating protocols and the GB TSO's obligations under the GB Market Rules, the GB

Cross-Zonal Action	Description
	TSO will publish on the GB market Information website (www.bmreports.com) both the prices the GB TSO provide to us and the prices we provide to the GB TSO. The service is only available on a rolling 1 to 2-hour timescale from real-time (post BETTA Balancing Market gate closure). These trades are only entered into for system security (including congestion management) and/or priority dispatch. Each instance of CBB is subject to the agreement of the GB TSO. Given the tighter timescales of this service and the availability of the existing Trading Partner arrangements, this CBB mechanism was not frequently used by us in the Previous Market Arrangements or by the GB TSO.
Setting Down of interconnector maximum transfer capacities	We may set down the Maximum Transfer Capacity on the interconnectors to avoid the transmission system(s) entering alert states.[9]
Emergency Assistance - EA	We have an Emergency Assistance arrangement in place with the GB TSO. This service is an emergency service that allows either party to request emergency cross-zonal assistance from the other party. The service would be utilised during capacity shortfall scenarios. A fixed price is agreed by us in advance (although any higher CBB price would apply if the service was activated) and a fixed volume is made available.[9]
Emergency Instruction - EI	We have an Emergency Instruction arrangement in place with the GB TSO. This service is an emergency service that allows either party to instruct a reduction in interconnector flow towards zero. The service would be utilised during an operational security event such as a circuit overloading and results in the application of a reduced Net Transfer Capacity (NTC) on the interconnector. The price for Emergency Instruction is calculated post event.
Frequency Deviation Cross-Zonal Flow	This is an automatic response (for high or low frequency) through which either or both interconnectors can provide reserve. The response is generally short lived. The provision of this service can be by either what is termed 'static response' or 'dynamic response'. Static response is provided in pre-defined block of MWs at a pre-

[9] The difference between reducing the Interconnector Transfer Capacity values in the '*Emergency Instruction-EI'* and 'Setting Down of interconnector maximum transfer capacities*' actions,* as outlined in the table above, is the timeframe of these actions. The setting down of interconnector maximum transfer capacities is to prevent entering system alert/emergency states whereas the emergency instruction to reduce interconnector transfer capacities is carried out following an operational security event.

Cross-Zonal Action	Description
	defined frequency setting. Dynamic response is also referred to as frequency response. The activation of these services is treated as a CBB trade.
Interconnector Under Test	An interconnector can request to go under test for a number of imbalance settlement periods or a full trading day. Testing can be classified as either significant or minor based on the impact on the power system and market. Testing can include commissioning, testing following refurbishment, grid code testing, modification to control systems or other tests that pose an additional risk of tripping.

Any utilisation of Cross-Zonal Actions takes place after closure of the cross-zonal markets.

When trading takes place the prices and volumes of energy offered as part of the non-emergency actions will form an input to the scheduling and dispatch process.

We have published a number of operational process documents which present in more detail how cross-zonal actions are implemented. These include *BP_SO_11.1 Calculation of CBB Trade Prices and Volumes; BP_SO_11.2 CBB Trading between EirGrid/SONI and NGET; BP_SO_11.3 Interconnector Emergency Actions* and *BP_SO_11.4 Coordinated Third-Party Trading.*

3.4.7. REAL-TIME SYSTEM CONDITIONS

We collect information on the real-time status of the power system via our Energy Management System (EMS) and Supervisory Control and Data Acquisition (SCADA) system. This information includes:

- the status of transmission circuits being in or out of service;
- the status of units (on/off);
- power-flows on circuits and interconnectors;
- real-time demand;
- real-time wind output;
- system voltages;
- system frequency; and
- real-time contingency analysis results.

Our scheduling process takes ‘snapshots’ of the real-time status of the power system so that the most up-to-date system conditions, along with forecast conditions, are modelled in our scheduling systems. This information can change on a second-by-second basis so forms a key input to the real-time dispatch decisions and control actions that we take.

4. THE SCHEDULING AND DISPATCH PROCESS

Our scheduling and dispatch process incorporates a range of activities associated with managing the close to real-time planning and operation of the power system.

This process is designed to implement European and jurisdictional policy objectives (see section 2 Obligations) based on a range of commercial and technical inputs (e.g. prices, forecasts and constraints as set out in section 3 Inputs). The outputs of the process are: the production of Indicative Operations Schedules; the issuing of dispatch instructions; the provision of data to pricing and settlement systems and information to support various reporting mechanisms and publications as illustrated below.

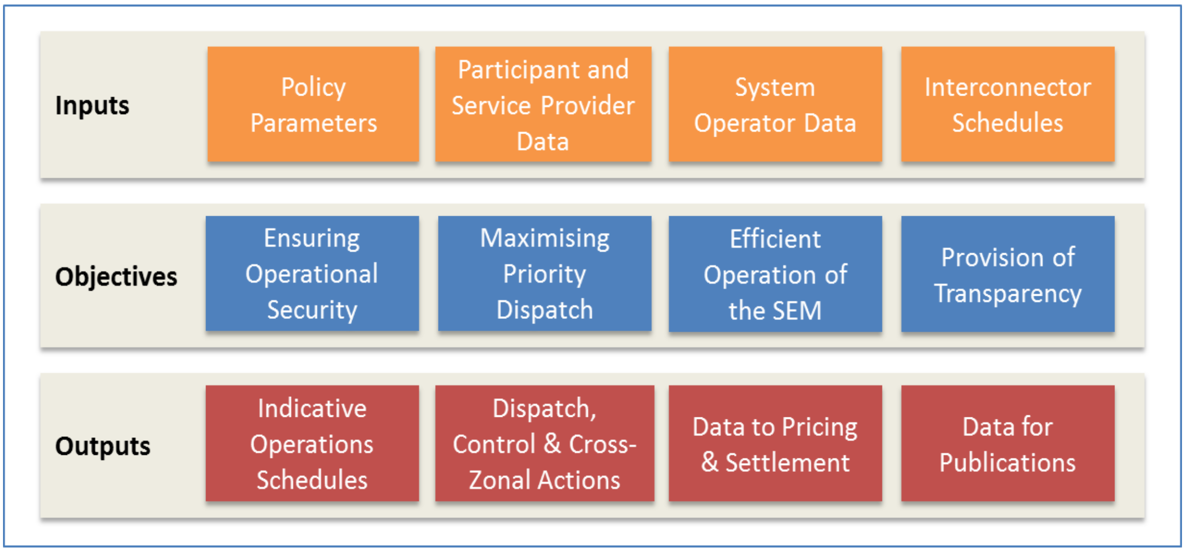


Figure 6 Overview of Inputs, Objectives and Outputs of the Scheduling and Dispatch Process

This section describes how these policy objectives are achieved within the scheduling and dispatch process and the outputs of this process. This section describes this process under typical operational conditions. Abnormal events can arise whereby different processes apply. These events are described in section 5 'Exceptions'.

4.1. PROCESS OVERVIEW

The scheduling and dispatch process is built around the Balancing Market. This is the sole mechanism by which we schedule and dispatch units to manage operational security constraints (including the provision of System Services), maximise priority dispatch generation and efficiently operate the balancing market.

The Balancing Market requires, for dispatchable units, Participants to submit PNs with COD, representing their incremental and decremental costs to move from this position, by Gate Closure of the Trading Day (13:30 day-ahead). Participants can update their PNs and COD after this time and up to Gate Closure of the Imbalance Settlement Period to reflect their intraday trading activity or any update to their balancing offers and bids.

Conditions on the power system can change from what was forecast (demand and wind variations), and transmission circuit and unit availability can change in an unplanned manner. In order to fulfil the objectives described in section 2, we operate a continuous scheduling process to ensure the latest market and system information feeds into the actual dispatch. The continuous nature of the process means that whenever a dispatch instruction is issued, it will be on the basis of the latest market positions, the latest notification of unit capabilities and the latest actual and forecast power system conditions.

The scheduling and dispatch process consists of three main activities:

- Input data processing: the data inputs described in section 3 are processed to present them in a form that is appropriate for each of the scheduling timeframes;
- Scheduling: the production of Indicative Operations Schedules (IOSs) over the short, medium and long term; and
- Dispatch: the issue of dispatch instructions and other control actions to Participants and System Service Providers.

The following sections describe these three main parts of the process. It should be noted that our processes and tools remain under review. These processes are therefore subject to change.

4.2. INPUT DATA PROCESSING

Section 3 lists the types and sources of inputs to the scheduling and dispatch process. Selection of the appropriate input data is required given that the scheduling process operates over a range of market timescales. In some cases, the input data is interpolated to allow scheduling at the appropriate resolution. In other cases, input data is adjusted or substituted to give effect to policy objectives. Examples of this input data processing are as follows:

- Application of negative decremental prices to priority dispatch units – we apply a range of negative decremental prices to priority dispatch units to give effect to the policy objective of maximising the output of priority dispatch generation up to their PN. The prices applied replace any decremental prices offered by a unit for the purposes of scheduling and dispatch.
- Demand forecast interpolation – our long-term demand forecast is produced at 30-minute resolution. In order to be capable of scheduling at 5-minute resolution (see next section) we interpolate the demand forecast to produce a 1-minute resolution forecast in the short term. A similar process applies to the wind forecast.
- Demand forecast blending – forecasting uncertainty means that real-time system demand will generally not match the long-term forecast. In order to produce a realistic

short-term forecast of demand we adjust the first part of the long-term forecast, so that it aligns with real-time demand, but blend it back to the long-term forecast. A similar process applies to the wind forecast.

- **Selection of commercial offer data and unit availability** – we select the appropriate Participant data to use in each of the scheduling horizons. In the short term (RTD) we use simple commercial offer data and real-time availability declarations. In the longer term (LTS and RTC) we use complex commercial offer data and forecast availability.
- **Creation of Composite Cost Curves** – based on the commercial offer data and PNs submitted by participants in the required timeframes, we create a single composite cost curve for each scheduling interval.
- **Production of the Interconnector Reference Programme** – we adjust the interconnector schedule to account for the operational ramp rate applied to each interconnector.
- **Treatment of Battery Energy Storage Power Station (ESPS) Units**– Our market systems have known limitations related to the scheduling, dispatch, pricing and settlement of Battery ESPS Units in the balancing market. To resolve these limitations, the current market systems require a major upgrade. An interim solution has been developed as a means of enabling Battery ESPS Units to participate in the balancing market prior to this major market system upgrade. The interim solution requires Battery ESPS Units to register and operate battery units as a "Multi-fuel" generator type in market systems, with some refinements and specific approaches in certain areas, such as charging the Battery ESPS Units and settlement. Currently we predominately use these Battery ESPS Units in our scheduling and dispatch processes as sources of operating reserve in the interim while we develop our market systems and processes to avail of other uses of these resources. A Battery Unit Guidance Note detailing the interim solution will be published this calendar year.
- **Treatment of Energy Limited Generator Units** – Hydro-electric units are defined as Energy Limited Generator Units in the Trading and Settlement Code. We schedule hydro-electric units to follow their PN to facilitate constraints related to hydro management and associated environmental considerations, and to give effect to the policy objective of maximising the output of priority dispatch generation up to their PN. We may deviate from these schedules during dispatch in real-time when we take into account the unit availabilities and constraints, the economic merit order and the effective management of remaining energy limits to balance the power system over the trading day.

Appendix 2.1 provides more details on each of these input data processing steps.

4.3. SCHEDULING

Scheduling is the process of planning the dispatch instructions that we issue based on the inputs described above. Our scheduling process operates from close to real-time through to the next Trading Day. Given the volume of inputs to the process and the complex nature of the process itself, it is split into a number of timeframes that allow for short-term analysis to be performed quickly and regularly while longer term analysis, which takes more time to process, is performed less frequently. The aim is to achieve a rolling, integrated and current plan of 'unit commitment' and 'economic dispatch' actions.

4.3.1. UNIT COMMITMENT AND ECONOMIC DISPATCH

These actions are determined using either a Security Constrained Unit Commitment (SCUC) or a Security Constrained Economic Dispatch (SCED) optimisation programme. These are complex mathematical programmes that employ optimisation techniques to simplify the scheduling problem so that it is determined within the time restrictions of real-time operations. This is because, with the scale of the problems to be solved, "brute force enumeration", where every possible outcome is tested, is not feasible.

The purpose of SCUC is to determine the commitment status of units, i.e. whether or not a unit is on (synchronised) or off (de-synchronised) and the schedules of units, i.e. their indicative MW output level at instances in time, at least cost of diverging from participant's Physical Notifications while respecting technical constraints and other policy objectives.

SCED does not make unit commitment decisions (it takes these from SCUC) but optimises the MW schedules of units already committed or scheduled to be committed. Like SCUC, its objective is to schedule at least cost of diverging from participant's Physical Notifications while respecting technical constraints.

4.3.2. RAMPING MARGIN TOOL

Scheduling is assisted by a Ramping Margin Tool. This tool enables Grid Controllers to accurately schedule and dispatch the Ramping Margin services and manage changing demand and generation profiles with increased wind integration. The tool calculates the total Ramping Margin reserve required (additional capability available to be deployed), and the system and jurisdictional expected ramping duties (sum of the changes in production schedules across all units). The sum of the Ramping Margin reserve requirement and the expected ramping duty is submitted to the schedulers and are applied as a form of constraint known as the Ramping Margin demand.

The Ramping Margin constraints went live on September 8th 2020[10].

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[10] See Information Note on Ramping Margin Constraints on the SEMO website: https://www.sem-o.com/documents/general-publications/Ramping_Margin_Requirements_in_Scheduling.pdf

4.3.3. SCHEDULING RUN TYPES: LTS, RTC AND RTD

We apply these optimisation programmes in three instances of scheduling run types which each consider different scheduling timeframes. These scheduling run types are:

- **Long-Term Schedule (LTS)** - uses a SCUC optimisation to produce unit commitment advice from two hours ahead (three hours for the first day-ahead run) for a schedule up to 30 hours. The horizon of the LTS reduces as the time between the run and the end of the trading day for which day-ahead market results are available reduces. LTS is initiated manually and the exact timing of each run can vary due to the dependence on the availability of key inputs. The below table sets out the timing and rationale for the timing of each LTS run as well as the maximum horizon for which each run can produce results.

LTS Run Initiation[11]	**Rationale for Timing**	**Maximum Horizon**
After 14:00	Day-Ahead Market results received; Updated renewables forecast available.	Up to 22:30 on the next trading day.
After 18:00[12]	IDA1 European Market results received; Updated renewables forecast available.	
After 22:00	Preparation for night valley.	
After 00:00[10]	Confirmation of night load valley and morning load rise; Updated renewables forecast available.	Up to 22:30 on the same trading day.
After 06:00[10]	Updated renewables forecast available.	
After 08:30	IDA2 European Market results received.	

[11] All times are approximate as the initiation of the run is dependent on the availability of data from external sources including forecast providers and market results.
[12] +1 hour during Daylight Saving Time (Irish Standard Time) as renewable forecasting does not observe Daylight Saving Time.

Note that Day-Ahead Markets running since 31 December 2020 do not include any SEM-GB interconnection capacity so the resulting interconnector schedules will be artificial for the first day-ahead run to ensure that we can continue to operate securely given the later notice of actual interconnector schedules. They may initially be set to zero but in some cases, the interconnector schedules may vary from zero to reflect more realistic estimates of the interconnector schedules[13]. Interconnector capacity will continue to be allocated in the intraday auctions so the market will still be capable of producing non-zero interconnector schedules. As a consequence, we do not have day-ahead interconnector schedules until 18:10 each day. **Real-Time Commitment (RTC)** – uses a SCUC optimisation to produce unit commitment advice from close to real-time (from 30 minutes) to four hours ahead (producing a schedule which covers 3.5 hours).

- **Real-Time Dispatch (RTD)** – uses a SCED optimisation to produce MW dispatch advice based on real-time system conditions and forecasts for an hour from close to real-time (10 minutes).

The sequencing of these scheduling runs is illustrated in Figure 7 below.

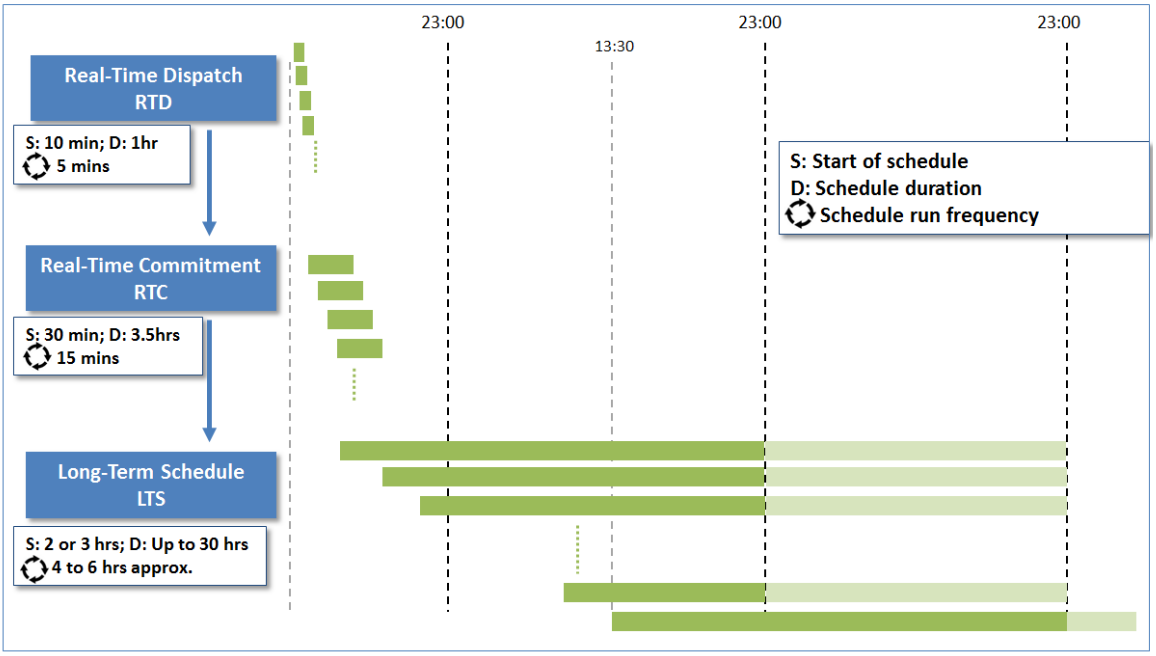


Figure 7 Illustrative Scheduling Run Sequence

13 For the vast majority of the time there is very limited knowledge by the schedulers of what the interconnector schedules will be until IDA1 files arrive. For the first LTS run the interconnector files come through as zero. If LTS produces insecure schedules with the interconnector files at zero, controllers move away from a zero profile up to an extent that LTS can produce secure schedules.

4.3.4. SCHEDULING OUTPUTS

The output of each of these scheduling runs is an Indicative Operations Schedule (IOS). This IOS provides:

- **unit commitment status**: the on/off status of each unit in each scheduling interval; and
- **production and consumption[14] levels**: MW levels per scheduling interval.

IOSs will also indicate any proposed implementation of a Cross-Zonal Action. Further information on the scheduling of Cross-Zonal Actions is provided in Section 3.4.6.

In addition to the production of IOSs, the scheduling process produces merit orders of available actions that we can take to increment / start-up units or decrement / shut-down units in response to changing system conditions that may not have been factored into the IOS (e.g. a deviation from forecast wind levels or a unit trip that requires fast start units to be started up).

The continuous nature of the scheduling process in accounting for the latest inputs means that the IOSs will be a good indication of expected commitment and dispatch levels. However, the IOSs are always indicative until we issue a dispatch instruction or take a control action, as discussed in the next section.

Appendix 2.2 provides more detail on the scheduling run process. We publish IOSs as described in section 6, Publications.

4.4. DISPATCH AND CONTROL ACTIONS

Based on the IOSs and taking real-time system conditions into account (such as system frequency, voltage, thermal circuit loadings and dynamic stability), dispatch instructions and other control actions are determined and issued by us to individual dispatchable and controllable units. Any required deviation from the IOS will be taken in line with a merit order of available actions (to increment or decrement units) taking into account real-time unit operating levels, unit response characteristics and operational security requirements.

4.4.1. REQUIREMENT TO FOLLOW INSTRUCTIONS

All units must follow the dispatch instructions that we issue. All controllable wind farms are controlled directly by us. No unit should synchronise, intentionally desynchronise or change output (other than for automatic frequency response) without a dispatch instruction from us.

[14] Consumption of storage units and demand side units.

4.4.2.TYPES OF INSTRUCTIONS

The following dispatch instructions / control actions are taken based on the IOSs:

- Commit – connect (synchronise) to the power system;
- De-commit – disconnect (de-synchronise) from the power system;
- MW Level – the active power MW level to which the unit should operate;
- Wind farm / solar unit Active Power Control – MW active power control set-points;
- Cross-Zonal Action – implementation of a change to an ICRP to implement a Cross-Zonal Action.

In addition to these instructions based on the IOSs, other control actions on units and interconnectors are taken to provide System Services such as reactive power and, for example, change Operating Modes. A description of the dispatch instructions and control actions that we can take is set out in Appendix 2.3. A full list of instruction types is contained in the Grid Codes – SDC2.4.2.4.

4.4.3.TIMEFRAMES

We issue dispatch instructions and control actions over a range of timescales reflecting the technical characteristics of units. These instructions can be categorised as long-notice (instructions that take effect prior to Balancing Market Gate Closure) and short-notice (instructions that take effect after Balancing Market Gate Closure):

- Long notice actions: Instructions to synchronise can take a number of hours to implement and are issued in line with the notification time required by the unit to start-up which, for many thermal units, is ahead of Balancing Market Gate Closure. These longer notice instructions relate to managing operational security constraints such as deployment of sufficient capability to provide operating reserves and constraining on units to provide voltage support. They can also be taken to ensure sufficient headroom is made available, and System Services provided, to facilitate priority dispatch generation. On some units, the de-synchronisation process may take longer than one hour, i.e. the time from a unit being told to shut-down until it actually disconnects from the power system.
- Short notice actions: Instructions associated with real-time balancing of supply and demand, optimisation of security constraints and priority dispatch levels ('MW' dispatch instructions and wind farm / solar unit active power control). These instructions are issued after Balancing Market gate closure in real-time taking into account the ramp rates of units that are already on. Units with short notification times can also be instructed to synchronise/de-synchronise in this timeframe. Delivery of System Services such as reactive power is also instructed in real-time taking into account the unit's control system response characteristics.

We may issue dispatch instructions at any time and for any quantity so long as it respects the technical characteristics of units (other than for the maximisation and emergency type instructions described in Appendix 2.3). So, while dispatch instructions should generally align with the latest IOS, they do not have to exactly coincide with the IOS's scheduling interval or scheduled quantity. For example, an IOS with the following schedule for a unit 14:00 100 MW, 14:05 110 MW, 14:10 120 MW, could result in an actual dispatch instruction issued at 14:02 of 130 MW.

The timing and magnitude of actual instructions that we issue and variations between them and the IOS will take into account the real-time conditions of the power system (a sample of which is listed in section 3.4.7). For example, we will delay or bring forward a dispatch decision for a unit to change output based on actual system frequency. If system frequency is low, indicating a negative imbalance, we may advance an instruction to increment a unit or delay the decrement of a unit. Other causes of variation include load forecast error, renewables forecast error, technical performance of units and system constraints.

We issue unit commitment instructions in line with unit notification times subject to system security requirements.

4.4.4. PRIORITY DISPATCH

Priority dispatch generation is comprised of dispatchable units (e.g. peat, hydro, CHP) and non-dispatchable (but generally controllable) units (wind and solar).

Dispatchable units must submit PNs and their priority dispatch status will apply to their PN'd quantities as far as the secure operation of the power system allows. Any availability above the PN'd quantity will not be treated as priority dispatch but in normal economic order.

Non-dispatchable units may submit PNs however they will run to their actual availability subject only to operational security constraints.

In the event of curtailment or constraint of non-dispatchable units being required, we issue control set-points to these units on a pro-rata basis – to all units for global system curtailment events or to a subset of units within a constraint group[15].

Appendix 2.3 provides more detail on the dispatch and control actions that we take. We publish dispatch instructions as described in section 6, Publications.

[15] See Information Note on Wind Dispatch Tool Constraint Groups on the EirGrid website: https://www.eirgridgroup.com/site-files/library/EirGrid/Wind-Dispatch-Tool-Constraint-Groups.pdf

4.5. MEETING OUR OBLIGATIONS

The objective of this scheduling and dispatch process is to allow us to fulfil the obligations set out in section 2. These are:

- ensuring operational security;
- maximising priority dispatch generation;
- efficient operation of the SEM; and
- provision of transparency.

The following sections set out how we practically implement these obligations within the scheduling and dispatch process. This implementation is illustrated in Figure 8 below.

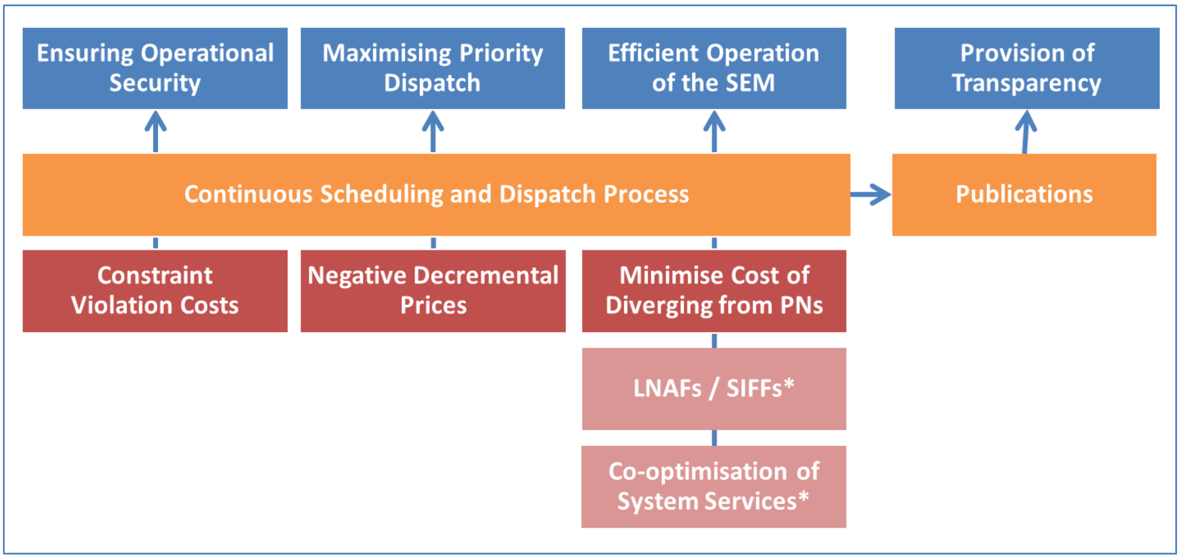


Figure 8 Implementation of Objectives

(*LNAF and SIFF currently set to zero per SEM-21-088. Refer to Section 3.1.2 for further information on these parameters.)

4.5.1. ENSURING OPERATIONAL SECURITY

Through analysis of forecast conditions and scenarios we define system security constraints that set limits within the scheduling process. Each constraint type is assigned a constraint violation cost which is incurred if the constraint is breached within the scheduling optimisation. This cost deters the optimisation from breaching a constraint as to do so would result in a higher apparent cost within the optimisation. These constraint violation costs are parameters within the optimisation that we tune to give effect to each constraint. In principle all constraints are absolute requirements which must be respected.

This process captures the majority of power system security issues and ensures our schedules are secure. However, to account for real-time system conditions we also continuously monitor the status of the system to determine other potential security issues (e.g. that might arise following the trip of a unit or transmission circuit). Our real-time dispatch therefore takes into account this real-time security assessment to ensure that operational security is maintained.

4.5.2. MAXIMISING PRIORITY DISPATCH GENERATION

We assign priority dispatch status in the scheduling and dispatch process by allocating a range of pre-determined negative decremental prices to the units defined as priority dispatch (see Inputs section). These prices reflect their relative position in the priority dispatch hierarchy – the higher the priority the more negative the decremental price. These negative decremental prices are tuned to account for potential conflicts with other constraints or the prices of other units.

Any submitted decremental price is substituted by this predefined priority dispatch price for the purpose of the optimisation however this replacement price does not feed into pricing or settlement. The purpose of MOD_10_19 was to ensure the submitted decremental price from priority dispatch generators did not set the imbalance price and were only used for settlement purposes. MOD_10_19 and the necessary change requests to implement this modification in the MMS were approved. However, due to a market participant challenge, this modification is on hold with no current timeline for its implementation.

The intent of these negative decremental prices is to have the optimisation engine avoid these actions as they would result in a high cost (the optimiser is trying to minimise cost). However, these units can still be decremented in order to avoid violation of any operational security constraints (which have a higher violation cost).

We develop the schedule to ensure that sufficient 'room' is made available to accommodate priority dispatch generation (i.e. non-priority dispatch units will have their output reduced or they may even be de-committed) and that sufficient System Services are scheduled to support system operation (such as the scheduling of sufficient inertia on the system to support the operation of the system during high wind conditions).

Our dispatch objective is then to minimise any operational security-related constraint or curtailment of priority dispatch sources.

4.5.3. EFFICIENT OPERATION OF THE SEM

The specific obligations set out in our Licences related to the economic aspect of the scheduling and dispatch process are:

- minimising the cost of diverging from physical notifications;
- as far as practical, enabling the Ex-Ante Market to resolve energy imbalances; and
- as far as practical, minimising the cost of non-energy actions.

We implement these obligations through the overall design of the scheduling and dispatch process and through the specific treatment of commercial data within the process as described in the following sections.

4.5.3.1. PROCESS DESIGN

These objectives are in part met by the overall design of the scheduling and dispatch process as one which uses the latest information available to continuously update schedules and determine dispatch. Ex-ante market activity is facilitated by:

- Exclusive use of the balancing market arrangements as the mechanism for taking all unit dispatch actions. We do not participate in the day-ahead or intraday markets and we do not have 'out of market' contractual arrangements to manage unit participation in these markets;
- Implementation of a continuous scheduling process that accounts for the latest ex-ante market information provided by Participants. As Participants can update their costs and PNs up to one hour ahead of real-time, our schedules are updated on a more regular basis to ensure that we are also operating off the latest commercial positions;
- Issuing unit commitment instructions in line with notification times (subject to system security requirements) thus allowing Participants time to resolve energy imbalances through the ex-ante markets; and
- Providing Participants with transparency of our processes and publication of information such as forecast energy imbalances, Indicative Operations Schedules and dispatch instructions.

4.5.3.2. COST MINIMISATION

Two of our Licence obligations relate to minimising cost – minimising the cost of diverging from PNs and minimising the cost of non-energy actions.

In the scheduling and dispatch process we do not distinguish between energy and non-energy actions but rather minimise the cost of all actions with respect to the cost of diverging from PNs. This distinction is not made in the scheduling and dispatch process as each action can have both an energy and non-energy component. The distinction is however made ex-post through the application of flagging rules as described in our 'Methodology for System Operator and Non-Marginal Flagging' (referenced in sections 4.6 and 6.4).

We implement a cost minimisation objective through the creation of composite cost curves based on the commercial offer data and PNs submitted by Participants (as referenced in section 4.2 and in more detail in Appendix 2.1). The optimisation then minimises the cost of diverging from PNs (based on the composite cost curve) of the schedule while meeting system security requirements and maximising priority dispatch generation.

Any deviation from the optimised schedule is made in line with a merit order of actions (to increment/start-up units or decrement/shut-down units) taking into account real-time unit operating levels, unit response characteristics and operational security requirements.

4.5.3.3. WEIGHTING TOWARDS SHORTER NOTICE ACTIONS

In addition to the process design features set out above, scheduling and dispatch policy parameters (as discussed in section 3.1.2) have been designed to contribute to the obligation of allowing ex-ante markets resolve energy imbalances. As noted in this section, these parameters are currently set to zero so have no impact on the scheduling and dispatch process at this time. We have however described the implementation of the parameters here as it is intended to re-evaluate their application in time for implementation from January 2023

Where a forecast energy imbalance exists, the scheduling process will resolve this imbalance as energy balance is a key system security constraint. The scheduling and dispatch policy parameters (LNAFs and SIFFs) are designed to weight the scheduling process towards shorter notice actions in achieving this energy balance by making longer notice actions appear more costly. This affords Participants more time to resolve the energy imbalance in the ex-ante markets.

The start-up cost for each unit is adjusted by the unit specific LNAF (related to unit notification time) and SIFF (related to the forecast system shortfall) as follows:

$$\text{Start-up cost in scheduling run} = \text{Submitted Start-up cost} * [1 + (\text{LNAF} * \text{SIFF})]$$

While the application of these factors is intended to weight the schedule towards shorter notice actions, this would not occur if it were to result in priority dispatch curtailment or violation of a security constraint as these have higher costs within the optimisation.

Again, as these parameters are currently set to zero, they have no impact on the scheduling and dispatch process.

4.5.3.4. SYSTEM SERVICES CO-OPTIMISATION

As noted in section 3.2.2 we do not account for the cost of System Services in the scheduling and dispatch process so we are currently not co-optimising energy market and System Services costs. The objective of minimising the cost of diverging from PNs is purely related to the balancing market commercial data submitted by Participants.

This position will be reviewed with further development of the commercial arrangements for System Services.

4.5.4. PROVISION OF TRANSPARENCY

In order to provide transparency of the scheduling and dispatch process we publish documents that describe the process (such as this BMPS and our Operational Processes), its inputs (such as demand and wind forecasts) and its outputs (Indicative Operations Schedules and dispatch instructions).

Further information on our publications is set out in section 6, Publications.

4.6. DATA TO PRICING AND SETTLEMENT SYSTEMS

The dispatch instructions issued and actions that we take result in the delivery of balancing energy and System Services. Data from the scheduling and dispatch process feeds the respective settlement systems so that Participants and System Service providers are settled appropriately. There are also charges related to the performance of units such as Other System Charges and Generator Performance Incentives (GPIs) and outputs of the process that relate to Capacity Market settlement.

The table below illustrates the range of scheduling and dispatch process outputs used in pricing and settlement systems. Note that there are additional data inputs to each system such as COD, TOD and market metering that are not included in this illustration.

Scheduling and Dispatch Process Data Item	Imbalance Pricing	Balancing / Capacity Market Settlement	System Services Settlement	Other System Charges & GPIs
Dispatch Instructions	Y	Y	Y	Y
Cross-Zonal Actions	Y	Y	Y	
Real-Time Availabilities	Y	Y	Y	Y
System Operator Flags	Y	Y		
Non-Marginal Flags	Y			
Short Term Reserve Quantity	Y			
Operating Reserve Requirement Quantity	Y			
Quantity of Demand Control	Y			
System Services Flag		Y		
Operational Metering (SCADA)			Y	Y

Data transactions from the System Operator to the Market Operator are defined in TSC Part B Appendix K. These include data items related to Imbalance Pricing. The Imbalance Price for each Imbalance Pricing Period (each 5 min period) is set by the marginal, unconstrained unit in that period. Whether or not a unit is constrained in each 5-minute period is identified within each RTD schedule. This identification process is an automated, rule-based process which is captured in our 'Methodology for System Operator and Non-Marginal Flagging', see section 6, Publications.

Where System Operator flags and Net Imbalance Volume tags are not determined, e.g. during planned or unplanned market system outages, the implication on Balancing Market Settlement is that affected units are settled on simple commercial offer data where they may otherwise have been flagged/tagged and therefore have been settled on complex commercial offer data.

With modification MOD_19_19 to the Trading and Settlement Code, a change request was implemented to introduce additional logic to determine the commercial offer data (i.e. simple or complex) for situations where flags/tags are not available for all Imbalance Pricing Periods (i.e. 5min) within an Imbalance Settlement Period (i.e. 30 min). This means that where System Operator flags and NIV tags are not available for all Imbalance Pricing Periods in an Imbalance Settlement Period (e.g. during planned or unplanned outages), the default logic will be that units are settled on Complex Commercial Offer Data in that Imbalance Settlement Period.

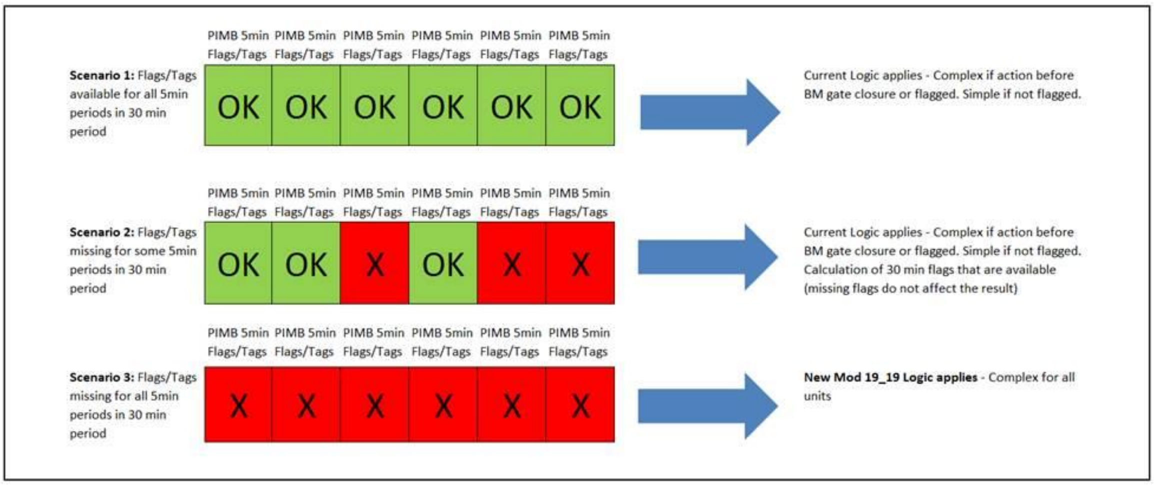


Figure 9 Change in Flagging Logic for Imbalance Pricing COD selection as a result of MOD_19_19

5. EXCEPTIONS

This section of the BMPS sets out the exceptional events that can occur that cause us to deviate from the processes set out in section 4 and describes how these events are reported.

There is no TSC or Grid Code definition for an 'exception'. In order to frame such events, it is necessary to firstly describe typical, everyday operational activity.

5.1. TYPICAL OPERATIONAL ACTIVITY

We take into account uncertainty in forecast demand, renewable generation and contingency events such as changes to unit availability and transmission circuit trips. We schedule reserves and formulate constraints to address these uncertainties and events as far as possible and build these into the IOSs.

Conditions and events can also arise that are not captured in the IOSs. These are due to modelling assumptions within the scheduling and dispatch tools, e.g. models do not capture the very short-term dynamic characteristics of units. Also, the granularity of the IOSs (the RTD IOS is at 5-minute intervals) means that it does not schedule for the intervening minutes where demand or wind could be higher, or lower and unit or interconnector operating levels could be different.

Our aim is to follow the IOSs as closely as possible however actual dispatch instructions will also take into account the real-time feedback from the power system (voltages, frequency, thermal loadings and system stability). Any real-time deviations from the IOS will be based on a merit order of available actions subject to the constraints imposed by operational security requirements and the technical capabilities of units.

We do not consider deviations from the IOS as exceptional but rather part of the normal and necessary real-time operation of a complex, dynamic power system. We publish IOSs, actual dispatch instructions and a range of other reports that reflect this activity (see section 6 Publications).

There are also abnormal events, or 'exceptions', that can arise which lead to operation outside of the processes described in section 4 and Appendix 2, i.e. outside of the IOSs and outside of the merit order/constraint-based adjustments to the IOSs. Such events are not day-to-day occurrences but if they occur, they can cause significant disruption to the operation of the power system and the energy markets.

It is difficult to identify all operating scenarios and prescribe each as 'typical' or 'exceptional'. The table below provides our view of the currently identified events within each category however we recognise that this list of events and their categorisation may evolve in SEM. Further details on exceptions and how these are reported is provided in the next section.

<table>
<tr><th>Typical Activity</th><th>Exceptions</th></tr>
<tr><td>

The start-up or shutdown of units or the adjustment of unit or interconnector outputs to:

maintain system voltages, frequency, thermal circuit loadings and stability within operational limits;
balance supply and demand;
provide reserves in response to a unit or interconnector trip;
respond to transmission circuit trips leading to a requirement to redispatch to manage constraints;
facilitate unit or power system testing; and
deliver non-emergency Cross-Zonal Actions.

Determine the Maximum Transfer Capacity on the interconnectors.

</td><td>

Total or partial system shutdown;
Emergency actions;
Load shedding;
Significant Incidents; and
Fuel Emergencies.

</td></tr>
</table>

5.2. EXCEPTIONS

Exceptions and their associated reporting mechanisms are set out in the table below. These exceptions are mainly based on the definitions of event types from the Grid Codes and are events that materially impact on Participants. We also recognise that there may be other events in this category that may drive the need for additional reporting, this is discussed further below.

Exception	Description	Reporting Mechanism
Total Shutdown (defined in the EirGrid and SONI Grid Codes)	A total black-out of the power system. Rules associated with such an event are contained in the TSC and Grid Codes. From a market perspective an 'Electrical System Collapse' leads to implementation of 'Administered Settlement'. The scheduling and dispatch process during such an event are focused on restoration of the power system using contracted Black Start units and a predefined power system restoration plan.	TSOs issue 'Blackout State[16] Alert' notifying system users of the event. MO notifies Participants that 'Administered Settlement' is being implemented. A public incident report is published by the TSOs. Reported in the annual All-Island Transmission System Performance Report.
Partial Shutdown (defined in the EirGrid and SONI Grid Codes)	A black-out of part of the power system.	As above.
Emergency (defined in EirGrid Grid Code only)	An abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the transmission system.	TSOs issue appropriate alert notifying system users of the event. Supply interruption incidents are reported in the annual All-Island Transmission System Performance Report.

[16] https://www.sem-o.com/documents/general-publications/BP_SO_09.2-Declaration-of-System-Alerts.pdf

Exception	Description	Reporting Mechanism
Emergency Assistance (one of the Cross-Zonal Actions available to the TSOs / GB TSO)	A TSO instruction (initiated by EirGrid, SONI or National Grid) to an interconnector which adjusts the interconnector schedule in either direction depending on the nature of the emergency. Used to manage either a capacity shortfall situation or a system constraint that cannot be addressed through other actions.	Results in a System Operator to System Operator Trade and is published via the BMI report REPT_030 'SO Interconnector Trades Report'
Emergency Instruction (defined in EirGrid Grid Code only. Also refers to one of the Cross-Zonal Actions available to the TSOs / GB TSO)	A TSO dispatch instruction to a unit which may require an action or response which is outside the limits implied by the then current declarations. In the case of interconnectors this is a TSO instruction (initiated by EirGrid, SONI or National Grid) to reduce the interconnector schedule towards zero for operational security reasons.	Currently there is no explicit reporting of Emergency Instructions to units. Should they occur, the TSOs will include Emergency Instructions in an annual report of exceptions. Any Emergency Instruction associated with an interconnector would result in an NTC reduction and would be notified to Participants as part of the normal NTC notification process.
Demand Control / Emergency Manual Disconnection / Planned Manual Disconnection / **Rota Load Shedding / Automatic Load Shedding** (SONI Grid Code OC4)	Reduction in demand carried out when a Regulating Margin cannot otherwise be achieved, or insufficient capacity is available to meet demand.	TSOs issue appropriate alert notifying system users of the event. Demand Control events are notified by the SO to the MO as set out in TSC Part B Appendix K. Supply interruption incidents are reported in the annual All-Island Transmission System Performance Report.

Exception	Description	Reporting Mechanism
Demand Control (EirGrid Grid Code OC5)	All or any of the methods of achieving a Demand reduction or an increase in Demand.	TSOs issue appropriate alert notifying system users of the event. Demand Control events are notified by the SO to the MO as set out in TSC Part B Appendix K. Supply interruption incidents are reported in the annual All-Island Transmission System Performance Report.
Significant Incident (SONI Grid Code definition) **Significant System Incident** (EirGrid Grid Code definition)	Events which have had or might have an operational effect on the transmission system, a user's system or an interconnector owner's system.	TSOs may issue an appropriate alert notifying system users of the event. A written report is provided to/from the TSOs, a system user or external TSO (depending on the nature of the incident) which is shared with impacted parties. Governed under EirGrid Grid Code OC7, SONI Grid Code OC5.
Fuel Security (SONI Grid Code)	Notifications and instructions relating to the Northern Ireland Fuel Security Code.	Relevant Grid Code communications channels apply during any event. Reporting to The Department for the Economy and Northern Ireland Network Emergency Coordinator (NINEC) as required during any event.
Gas Supply Emergency (EirGrid and SONI Grid Codes)	Instructions relating to the gas supply emergencies.	Relevant Grid Code communications channels apply during any event.

By definition, these exceptions reflect anticipated or actual system security events. Our priority in such events, as in normal operation, remains the maintenance of system security.

We recognise that as we gain experience of these arrangements that other materially impacting events might arise which are not captured by either the normal reporting arrangements (as set out in section 6) or by the exceptions reporting arrangements defined here. We will therefore review our event-driven reporting arrangements and update this section of the BMPS as appropriate to reflect any new events that fall into this exception's category. Where appropriate we will use existing communication channels to notify Participants of such events.

5.3. AUDIT

As required by our Licences, our scheduling and dispatch process is subject to a now annual audit. This audit facilitates external, independent assurance of specified elements of the operation and implementation of our scheduling and dispatch process.

The audit potentially offers a mechanism for identifying additional exceptions and reporting on them.

The independent assurance report for the 2020 audit period was published in 2021 and can be found here, 'Independent Assurance Report on compliance with specified elements of the Scheduling and Dispatch process for the 12 month period ended 31 December 2020'.

There were no findings from the 2020 audit, that required Section 5.2 above to be updated. We will update the BMPS to reflect any process impact of an audit.

6. PUBLICATIONS

We support the provision of information to Participants and the wider industry through the publication of operational data, processes, methodologies and reports. This information is key to a well-functioning market and as a transparency measure in assisting understanding of our decision-making processes. It is recognised that the detailed elements of some of our operational processes need to remain agile in the context of service priorities and technical considerations of the new market. Consequently, as operational documents these are subject to change however, we will ensure that process modifications are communicated to participants.

The tables below outline the different types of publications that we support and provide some examples of specific publications and links to documents where available. The source of publications, existing and under development, are also described.

We have published a market website that includes a page for 'TSO Responsibilities'[17]. It is available in the publications section of www.SEM-O.com and will act as a reference point for publications associated with the scheduling and dispatch process. We have maintained the indicative list of publications in this section for illustration purposes.

[17] www.sem-o.com/publications/tso-responsibilities/

6.1. PUBLICATION SOURCES

Sources of publications for operational data are set out in the table below.

Source	Description	Link
ENTSO-E Transparency Platform	European platform for sharing of operational data from power systems around Europe.	https://transparency.entsoe.eu
EirGrid Website	Corporate website providing a mix of operational data and reports.	www.eirgridgroup.com
SONI Website	Corporate website providing a mix of operational data and reports.	www.soni.ltd.uk
SEMO Website	Market website - source of data for Market Participants. Includes the TSO Responsibilities page.	www.sem-o.com
EirGrid Group Smart Grid Dashboard	Web-based application that enables users to view, compare and download key all-island power system information.	http://smartgriddashboard.eirgrid.com
Previous Market Website	Previous market website with pre-go live data and ISEM project documentation.	http://lg.sem-o.com/
Balancing Market Interface (BMI)	The interface between Participants and the TSO' market systems.	Available to Market Participants.
Balancing Mechanism Reporting Service (BMRS)	GB TSO website for providing data relating to the GB Electricity Balancing and Settlement arrangements	https://www.bmreports.com/

6.2. OPERATIONAL DATA

Operational data consists of the inputs to, and outputs from the scheduling and dispatch process. These tend to consist of large volumes of automatically generated reports provided on a regular basis. Some of this data is already provided via the EirGrid, SONI and SEMO website, the ENTSO-E Transparency Platform and new interfaces were developed to support the SEM.

There are over 80 Balancing Market Interface (BMI) reports available to Market Participants. A description of each report is contained in the document 'I-SEM Technical Specification (ITS) Volume C: Balancing Market'. Note that these reports are for registered Participants – some are 'member public' (the report is available to all Participants) others are 'member private' (the report is only available to the specific Participant). There are also a large number of reports available on the ENTSO-E Transparency Platform and the SEMO website. A sample of reports is provided in the table below. Some of these reports are duplicated between the different platforms as they have been developed to meet different requirements such as accessibility versus IT system compatibility.

Sample of Operational Data	Source
Demand Data	
Demand Forecast (ENTSO-E)	ENTSO-E TP
Demand Actual (ENTSO-E)	ENTSO-E TP
Demand Forecast (Market Data Static Report)	SEMO Website
Demand Forecast (Market Data Dynamic Report)	SEMO Website
Demand Actual (Smart Grid Dashboard / System Information)	EirGrid /SONI Websites
Demand Forecast (BMI)	BMI
Wind and Solar Data	
Wind and Solar Forecast (ENTSO-E)	ENTSO-E TP
Wind and Solar Actual (ENTSO-E)	ENTSO-E TP
Wind Forecast (Smart Grid Dashboard / System Information)	EirGrid /SONI Websites
Wind Actual (Smart Grid Dashboard / System Information)	EirGrid /SONI Websites
Aggregated Wind Forecast (Market Data Static Report)	SEMO Website
Aggregated Wind Forecast (Market Data Dynamic Report)	SEMO Website
Aggregated Wind and Solar Forecast (BMI)	BMI
Wind Unit Forecast (BMI)	BMI
Indicative Operations Schedules	
LTS Indicative Operations Schedule (Market Data Static Report)	SEMO Website
RTC Indicative Operations Schedule (Market Data Static Report)	SEMO Website
LTS Indicative Operations Schedule (BMI)	BMI
RTC Indicative Operations Schedule (BMI)	BMI
RTD Indicative Operations Schedule (BMI)	BMI
Information Note on the Indicative Operations Schedules and Dispatch (TSO Responsibilities)	SEMO Website

Sample of Operational Data	Source
Dispatch Instructions	
Hourly Dispatch Instructions (Market Data Static Report)	SEMO Website
Daily Dispatch Instructions D+1 (Market Data Static Report)	SEMO Website
Daily Dispatch Instructions D+4 (Market Data Static Report)	SEMO Website
Hourly Dispatch Instructions (BMI)	BMI
Daily Dispatch Instructions D+1 (BMI)	BMI
Daily Dispatch Instructions D+4 (BMI)	BMI
Outages	
All Island Generation Outage Plan (TSO Responsibilities)	SEMO Website
Daily Generator and DSU Outage Schedules Report (BMI)	BMI
EirGrid Transmission Outage Plans (Outage Information)	EirGrid Website
All-Island Transmission Outage Programme (TSO Responsibilities)	SEMO Website
EirGrid Transmission Outage Plans (TSO Responsibilities)	SEMO Website
SONI Transmission Outage (Outage Information)	SONI Website
Daily Transmission Outage Schedule Report (Market Data Static Report)	SEMO Website
Daily Transmission Outage Schedule Report (BMI)	BMI
Constraint Reports	
Operational Constraints Update - weekly (TSO Responsibilities)	SEMO Website
Operational Constraints Update - ad-hoc (TSO Responsibilities)	SEMO Website
Information Note on Inter-Area Flow Constraints (TSO Responsibilities)	SEMO Website
Information Note on Wind Dispatch Tool Constraint Groups (TSO Responsibilities)	Eirgrid Website
Others	
Scheduling and Dispatch Policy Parameters	SEMO Website
Unit Under Test (Market Data Static and Dynamic Report)	SEMO Website
Unit Under Test (BMI)	BMI
North-South Tie-Line and Moyle Interconnector Data	SONI Website
Cross Border Balancing Prices	BMRS Website

6.3. OPERATIONAL PROCESSES

Operational processes set out our end to end operational activities related to various aspects of the scheduling and dispatch process. These are common EirGrid and SONI processes that describe step-by-step actions taken in the short-term planning and real-time operation of the power system. As operational documents these are subject to change. We continue to develop these documents for application in SEM. We publish up-to-date operational processes on the TSO Responsibilities page of the SEMO website.

6.4. METHODOLOGIES

We publish a number of methodologies related to the scheduling and dispatch process, these are the methodologies for:

Methodology	Source
Determination of Scheduling and Dispatch Policy Parameters	N/A - not currently available.
Short-term Demand Forecasting Methodology	SEMO Website
Wind and Solar Forecasting Methodology	SEMO Website
System Operator and Non-Marginal Flagging	SEMO Website
Interim Cross-Zonal Capacity Calculation	Interim Cross Zonal TSO Arrangements for GB-ISEM go-live
Methodology to Determine the Minimum Provision of Reserve Capacity on FCR in the Synchronous Area	SAOA
Methodology to Determine Limits on the Amount of Exchange and Sharing of FRR Between Synchronous Areas	SAOA
Methodology to Determine Limits on the Amount of Exchange and Sharing of RR Between Synchronous Areas	SAOA
Methodology to Assess the Risk and the Evolution of the Exhaustion of FCR in Synchronous Area IE/NI	SAOA
Methodology to Reduce the Electrical Time Deviation	SAOA
Ramping Restrictions for Active Power Output	LFCBOA

6.5. REPORTS

We publish a number of quarterly and annual reports that provide Participants with information on the outcome of the scheduling and dispatch process.

Report	Source
Quarterly Renewable Dispatch Down (Constraint & Curtailment)	EirGrid / SONI websites and SEMO Website
Annual Renewable Dispatch Down (Constraint & Curtailment)	EirGrid / SONI Websites and SEMO Website
Quarterly Constraint Cost Outturn	EirGrid Website and SEMO Website
Annual All-Island Transmission System Performance Report	EirGrid / SONI Websites and SEMO Website
Scheduling and Dispatch Policy Parameter Performance Report	SEMO Website
Annual Scheduling and Dispatch Process Audit Report	EirGrid / SONI Websites and SEMO Website

APPENDIX 1 OBLIGATIONS FRAMEWORK

This appendix sets out our obligations under European and national legislation, applicable regulation and applicable codes that relate specifically to the scheduling and dispatch process outlined in the Balancing Market Principles Statement.

Important Note: EU legislation is only applicable to Northern Ireland if it is within the scope of the Northern Ireland Protocol. In particular, EU legislation which governs wholesale electricity markets will continue to apply in accordance with Article 9 and Annex 4 of the Northern Ireland Protocol. For example, Directive (EU) 2019/944, Regulation (EU) 2019/943 and Regulation (EU) No 1227 / 2011 continue to apply in respect of Northern Ireland (subject to certain conditions) on this basis.

Certain other provisions of EU legislation which are not explicitly listed in Annex 4 of the Northern Ireland Protocol may also continue to apply in respect of Northern Ireland if those provisions are ones which apply in Ireland and govern wholesale electricity markets and are necessary for the joint operation of the SEM. It is not possible to list all such provisions exhaustively in this Appendix 1.

APPENDIX 1.1 OVERVIEW

The table below sets out the obligations framework that governs our obligations (as TSOs) in respect of the scheduling and dispatch process.

European Legislation	Relevant European legislation includes the following: • Directive 2012/27/EU of the European Parliament and of the Council on energy efficiency, amending Directives 2004/8/EC and 2006/32/EC; • Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources; • Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU[18]; • Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity; • Commission Regulation (EU) 2015 / 1222 establishing a guideline on capacity allocation and congestion management (CACM);

[18] Only the aspects of this directive that are transposed into local law apply in NI.

	• Commission Regulation (EU) 543 / 2013 on submission and publication of data in electricity markets and amending Annex 1 to Regulation (EC) No 714 / 2009 of the European Parliament and of the Council; • Regulation (EU) No 1227 / 2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT); and • Commission Implementing Regulation No. 1348 / 2014 on data reporting implementing Article 8(2) and Article 8(6) of REMIT. • Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation (SOGL); • Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (EBGL); and • Commission Regulation (EU) 2017/2196 establishing a network code on emergency and restoration (NCER). The TSOs will have additional obligations under other EU Regulations or Directives that have not yet been finalised and / or entered into force. This BMPS will be updated from time to time in accordance with our Licences to reflect the TSOs' obligations.
National Legislation	Northern Ireland legislation includes the following: • SI 231 of 1992: The Electricity (Northern Ireland) Order 1992; • SR 198 of 2014: The Energy Efficiency Regulations; and • SR 306 of 2020: Electricity (Priority Dispatch) Regulations. Irish legislation includes the following: • S.I. No. 426/2014 - European Union (Energy Efficiency) Regulations 2014; • S.I. No. 483/2014 - European Union (Renewable Energy) Regulations 2014; • S.I. No. 60/2005 - European Communities (Internal Market in Electricity) Regulations 2005 (as amended); and • S.I. No. 445/2000 - European Communities (Internal Market in Electricity) Regulations, 2000 (as amended).

Regulatory Decisions	Key SEM Committee Decisions include: • SEM-11-105 Treatment of Price Taking Generation in Tie Breaks in Dispatch; • SEM-11-062 Principles of Dispatch and the Design of the Market Schedule; • SEM-15-065 Energy Trading Arrangement Detailed Design Market. • SEM-17-020 Complex Bid Order Controls in the I-SEM Balancing Market; • SEM-20-072 Decision Paper on Eligibility for Priority Dispatch Pursuant to Regulation (EU) 2019/943 • SEM-21-088 I-SEM Policy Parameters and Scheduling and Dispatch Parameters; and • SEM-17-048 Balancing Market Principles Code of Practice Key CRU and Utility Regulator Decisions include: • Decision by the Ireland-and Northern Ireland Regulatory Authorities on the amended Synchronous Area Operational Agreement of Ireland and Northern Ireland and Load-Frequency Control Block Operational Agreement of Ireland and Northern Ireland[19]
Licences	• EirGrid Transmission System Operator Licence; • EirGrid Market Operator Licence; • SONI Transmission System Operator Licence; and • SONI Market Operator Licence.
Codes	• EirGrid Grid Code; • SONI Grid Code; and • Trading and Settlement Code.

[19] https://cru.ie/wp-content/uploads/2019/11/CRU19140a-Joint-Decision-to-approve-Operational-Agreements-SAOA-and-LFCBOA-between-EirGrid-and-SONI-for-Ireland-and-Northern-Ireland.pdf

APPENDIX 1.2 OPERATIONAL SECURITY OBLIGATIONS FRAMEWORK

The obligations framework that governs our obligations (as TSOs) to ensure operational security is presented below.

European Legislation	• Directive (EU) 2019/944 on the internal market in electricity (Article 40)[20]; • Regulation (EU) 2019/943 on the internal market for electricity; • Commission Regulation (EU) 2015 / 1222 establishing a guideline on capacity allocation and congestion management; • Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation; and • Commission Regulation (EU) 2017/2196 establishing a network code on emergency and restoration.
National Legislation	<u>Ireland</u> • European Communities (Internal Market in Electricity) Regulation 2000 (S.I. No 445 / 2000) (as amended) (Regulation 8). <u>Northern Ireland</u> • Electricity (Northern Ireland) Order 1992 (as amended) (Article 12); and Northern Ireland Fuel Security Code.
Regulatory Decisions	• SEM Committee decision: SEM-15-065 Energy Trading Arrangement Detailed Design Market Decision Paper.
Licences	<u>Ireland</u> • Transmission System Operator Licence (Condition 1(8), Condition 3(1), Condition 4(1), Condition 10A (2, 5), Condition 15 and Condition 16). <u>Northern Ireland</u> • Transmission System Operator Licence (Condition 14, Condition 20, Condition 21 and Condition 22A (2, 5)).
Codes	• EirGrid Grid Code (SDC 1 and SDC 2); • SONI Grid Code (SDC 1 and SDC 2); and • Trading and Settlement Code (Part B, A.2.1.4).

[20] Only the aspects of this directive that are transposed into local law apply in NI.

APPENDIX 1.3 PRIORITY DISPATCH OBLIGATIONS FRAMEWORK

The obligations framework that governs our obligations (as TSOs) specifically in respect of the treatment of priority dispatch generation is presented below.

European Legislation	• Directive 2009/28/EC on promotion of the use of energy from renewable sources (Article 16); • Directive 2009/72/EC on the internal market in electricity (Article 14(7)); and Directive 2012/27/EU on energy efficiency, amending Directives 2004/8/EC and 2006/32/EC (Article 15). • Regulation (EU) 2019/943 of the European parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
National Legislation	<u>Ireland</u> • Electricity Regulation Act 1999 (Public Service Obligations) Order 2002 (as amended) (Section 21); • European Communities (Renewable Energy) Regulations 2014 (S.I. No 483/2014) (Regulation 4); and • European Union (Energy Efficiency) Regulations 2014 (S.I. No 426 / 2014) (Regulation 35). <u>Northern Ireland</u> • The Electricity (Northern Ireland) Order 1992 (as amended) (Article 11AB); • Electricity (Priority Dispatch) Regulations (Northern Ireland) 2012 (as amended); and • The Energy Efficiency Regulations (Northern Ireland) 2014 (Section 12) • The Electricity (Priority Dispatch) Regulations (Northern Ireland) 2020
Regulatory Decisions	SEM Committee decisions: • Decision SEM 11-062 (Principles of Dispatch and the Design of the Market Schedule); • Decision SEM-11-105 (Treatment of Price Taking Generation in Tie Breaks in Dispatch); • Decision SEM-13-012 (Constraint Groups Arising from SEM-11-105); and • SEM-20-072 Decision Paper on Eligibility for Priority Dispatch

	Pursuant to Regulation (EU) 2019/943 • Decision SEM-21-088 (I-SEM Policy Parameters and Scheduling and Dispatch Parameters); • Decision SEM-15-064 (Energy Trading Arrangements Detailed Design – Building Blocks Decision Paper)
Licences	Ireland • Transmission System Operator Licence (Condition 10A(5)). Northern Ireland • Transmission System Operator Licence (Condition 9A, Condition 22A(5)).
Codes	• EirGrid Grid Code (SDC 1.4.7.3); and • SONI Grid Code (SDC 1.4.8.3).

APPENDIX 1.4 EFFICIENT OPERATION OF THE SEM OBLIGATIONS FRAMEWORK

The obligations framework that governs our obligations (as TSOs) to ensure a secure, reliable and efficient electricity system is presented below.

European Legislation	• Directive (EU) 2019/944 on the internal market in electricity (Article 40); • Commission Regulation (EU) 2015 / 1222 establishing a guideline on capacity allocation and congestion management; • European Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation (SOGL); and • Commission Regulation (EU) 2017/2196 establishing a network code on emergency and restoration.
National Legislation	Ireland • European Communities (Internal Market in Electricity) Regulation 2000 (S.I. No 445 / 2000) (as amended) (Regulation 8). • European Union (Energy Efficiency) Regulations 2014 (S.I. No 426 / 2014) (Regulation 35). Northern Ireland • Electricity (Northern Ireland) Order 1992 (as amended) (Article 12). • Energy Efficiency Regulations (Northern Ireland) 2014.

<table>
<tr><td>Regulatory Decisions</td><td>SEM Committee decisions:
SEM-11-062 Principles of Dispatch and the Design of the Market Schedule;
SEM-15-065 Energy Trading Arrangement Detailed Design Market Decision Paper; and
SEM-21-088 I-SEM Policy Parameters and Scheduling Dispatch Parameters.</td></tr>
<tr><td>Licences</td><td><u>Ireland</u>
Transmission System Operator Licence (Condition 1(8), Condition 10A and Condition 26).
<u>Northern Ireland</u>
Transmission System Operator Licence (Condition 16 and Condition 22A).</td></tr>
<tr><td>Codes</td><td>EirGrid Grid Code (SDC 1.2, SDC 1.4.7.2, SDC 1.4.7.3);
SONI Grid Code (SDC 1.2, SDC 1.4.8.2, SDC 1.4.8.3); and
Trading and Settlement Code (Part B, A.2.1.4).</td></tr>
</table>

APPENDIX 1.5 TRANSPARENCY OBLIGATIONS FRAMEWORK

The obligations framework that governs our obligations (as TSOs) specifically in respect of increasing the integrity and transparency of the SEM is presented below.

European Legislation	• Regulation (EU) No 1227 / 2011 on wholesale energy market integrity and transparency ("REMIT"); • Commission Implementing Regulation (EU) No 1348 / 2014 on data reporting, implementing Article 8(2) and Article 8(6) of REMIT; and • Commission Regulation (EU) No 543 / 2013 on submission and publication of data in electricity markets. • European Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation (SOGL);
Regulatory Decisions	SEM Committee decisions: • Decision SEM-15-065 Energy Trading Arrangement Detailed Design Market Decision Paper; and • Decision SEM-16-058 I-SEM Energy Trading Arrangements Balancing Market Principles Statement Terms of Reference.
Licences	<u>Ireland</u> • Transmission System Operator Licence (Condition 10A, Condition 10B, Condition 26 and Condition 27). <u>Northern Ireland</u> • Transmission System Operator Licence (Condition 7, Condition 22A and Condition 22B).
Codes	• Trading and Settlement Code (Part B, A.2.1.4).

APPENDIX 2 SCHEDULING AND DISPATCH PROCESS

The following sections provide a description of the scheduling and dispatch process that we follow in SEM. Our processes and tools changed significantly for the revised market arrangements and remain under review on an ongoing basis. This process is therefore subject to change. Future updated versions of the BMPS will reflect any changes.

Scheduling and dispatch are a dynamic process that accounts for real-time and forecast conditions and other inputs that can change on a continuous basis. Steps within the process overlap and interact, however, for the purposes of this description we have presented the process in a logical sequence of input data processing, scheduling and then dispatch instructions being issued. We indicate the timelines under which each of the steps operates and, where available, we also provide a reference to an associated published Operational Process or publication relevant to that step. Note that Operational Processes and other relevant publications are subject to ongoing review and a sub-set of processes are published.

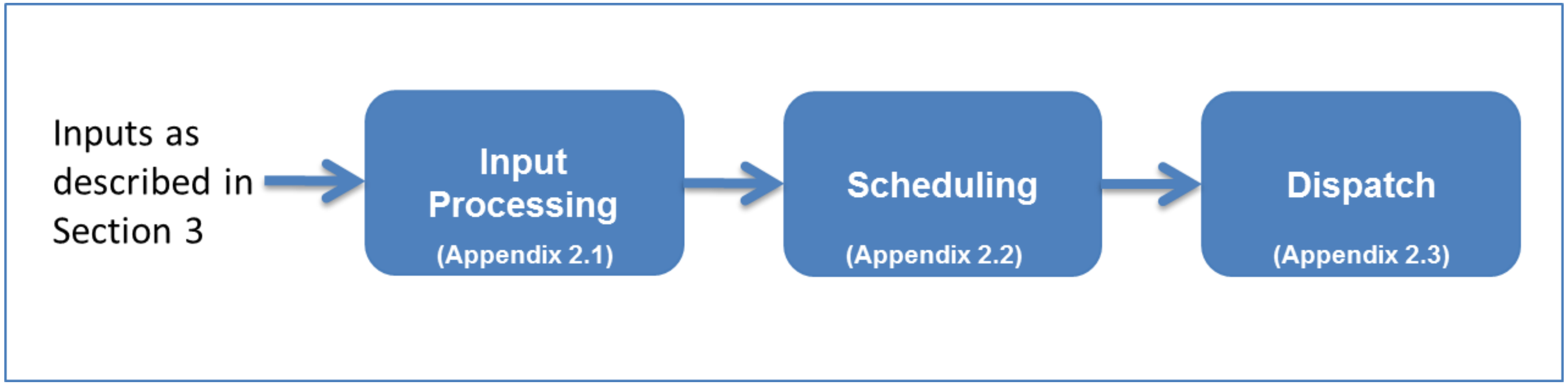


Figure 10 Overview of the Scheduling and Dispatch Process

APPENDIX 2.1 INPUT DATA PROCESSING

The inputs to the scheduling and dispatch process are described in section 2. These inputs are repeated in the following table along with a description of how this input data is processed for application in the scheduling and dispatch process.

The inputs to the scheduling and dispatch process range from relatively static parameters, forecasts that extend over several days to continuously changing power system conditions. As the scheduling process is divided into three timeframes, different input data is appropriate for each scheduling run type (RTD, RTC and LTS as described in Appendix 2.2). Each scheduling run is based on a snapshot of the inputs that are relevant to the timeframe over which the schedule is optimising.

Timelines	Description	References
Ad-hoc	**Negative Decremental Prices for Priority Dispatch Units:** We assign priority dispatch status in the scheduling and dispatch process by allocating a range of pre-determined negative decremental prices to the units defined as priority dispatch (see Inputs section). These prices reflect their relative position in the priority dispatch hierarchy – the higher the priority the more negative the decremental price. Any submitted decremental price is substituted by this predefined priority dispatch price for the purpose of the optimisation however this replacement price does not feed into pricing or settlement. These negative decremental prices are tuned to account for potential conflicts with other constraints or the prices of other units. The same negative decremental prices are used in all LTS, RTC and RTD schedules. The intent of these negative decremental prices is to have the optimisation avoid these actions as they would result in a high cost (the optimiser is trying to minimise cost). However, these units can still be decremented in order to avoid violation of any operational security constraints (which have a higher violation cost). These prices may be adjusted to reflect any changes to the priority dispatch hierarchy or the position of the hierarchy relative to other unit prices.	

N/A	**Scheduling and Dispatch Policy Parameters:** The scheduling and dispatch policy parameters, listed below, are currently inactive (set to zero) in the scheduling and dispatch process (per SEM-21-088 of 18 November 2021) so they have no impact on the schedule: • LNAFs per Notification Time; • SIFF per SSII; • The daily time for fixing the SSII/SIFF. SEM-21-088 requires us to re-evaluate the determination of these factors in time for application from January 2023.	Methodology for Determination of Scheduling and Dispatch Policy Parameters.
Weekly with ad-hoc updates	**Constraints:** We publish a weekly Operational Constraints Update to present the key system and generator constraints which are included in the scheduling process. Prior to the start of each week we prepare a weekly forecast of expected constraints on the transmission system including requirements for System Services. These constraints and requirements, along with any updates arising from changes to forecast conditions and our continuous monitoring of the real-time status of the power system will form an input to each schedule. Each constraint is assigned a constraint violation cost which is applied in each LTS, RTC and RTD schedule. This cost deters the optimisation process from breaching the constraint as to do so would result in a higher apparent cost within the optimisation. These constraint violation costs are parameters within the optimisation that we tune to give effect to each constraint. In principle all constraints are absolute requirements which must be respected.	Ref. Section 6. Publications

Daily with continuous updates	**Demand Forecast:** By 09:30 each day we prepare a four-day demand forecast at half hour resolution. This forecast is used in the LTS. On a continuous basis we interpolate and blend this forecast with real-time demand conditions to form an input to the shorter term RTC and RTD schedules.	'Short-term Demand Forecasting Methodology for Scheduling and Dispatch' and the BP_SO_4.2_Dema-nd Forecasting for Scheduling and Dispatch business process.
Every 6 hours with continuous updates	**Renewables Forecast:** Every six hours we prepare a 4.5day renewables forecast, at fifteen-minute resolution. This forecast is then be interpolated and blended with real-time renewables conditions on a continuous basis to form an input to each scheduling run.	'Wind and Solar Forecasting Methodology for Scheduling and Dispatch' and BP_SO_4.3_Wind Forecasting business process.
Daily with ad-hoc updates	**Participant / Service Provider Technical and Availability Data:** We receive technical data including availability data from units and interconnectors on an ongoing basis and use the latest appropriate data in each schedule. For the same unit, real-time availability can differ from the forecast availability (say due to a unit trip) so the scheduling run types use the following sources of unit availability data.	

Scheduling Run Type	Source of Unit Availability	
	Dispatchable Unit	Wind
LTS – Long-Term Schedule	Forecast availability as submitted via the BMI	Per TSO wind forecast
RTC – Real-Time Commitment	Forecast availability as submitted via the BMI or real-time availability as declared in EDIL	Per TSO wind forecast blended with real-time availability from EMS
RTD – Real-Time Dispatch	Real-time availability as declared in EDIL	Per TSO wind forecast blended with real-time availability from EMS

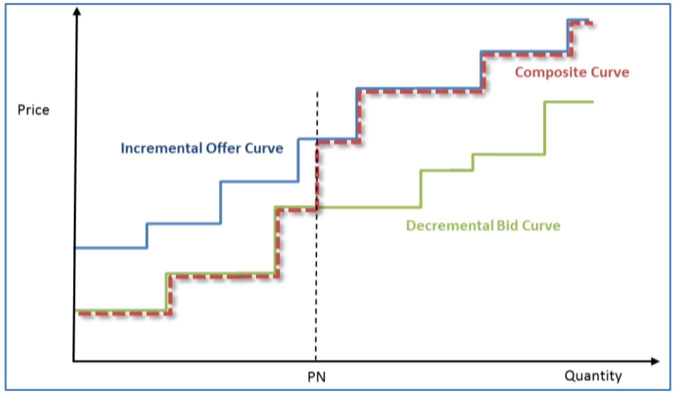
Daily with ad-hoc updates	**Selection of Participant Commercial Offer Data:** By 13:30 each day, we receive PNs and commercial data for units for the next trading day. We receive updates to this data on an ongoing basis up to one hour ahead of each imbalance settlement period. Participant commercial offer data submissions is provided in complex and simple formats as described in the Inputs section. This data is applied in each of the scheduling run types as described in the table below.	

<table>
<tr><td></td><td>
<table>
<tr><th rowspan="2">Scheduling Run Type</th><th colspan="3">Source of Commercial Data</th></tr>
<tr><th>Primary</th><th>Back-Up 1</th><th>Back-Up 2</th></tr>
<tr><td>LTS – Long-Term Schedule</td><td>Complex</td><td>Default</td><td>N/A</td></tr>
<tr><td>RTC – Real-Time Commitment</td><td>Complex</td><td>Default</td><td>N/A</td></tr>
<tr><td>RTD – Real-Time Dispatch</td><td>Simple</td><td>Complex*</td><td>Default*</td></tr>
</table>
*Note: only inc/dec component of complex or default commercial offer data is used in back-up.

The back-up sources are utilised if the primary source of commercial data is not available. Arrangements for the submission of default commercial offer data are set out in the TSC Part B section D.
</td><td></td></tr>
<tr><td>N/A</td><td>System Service Provider Commercial Data:

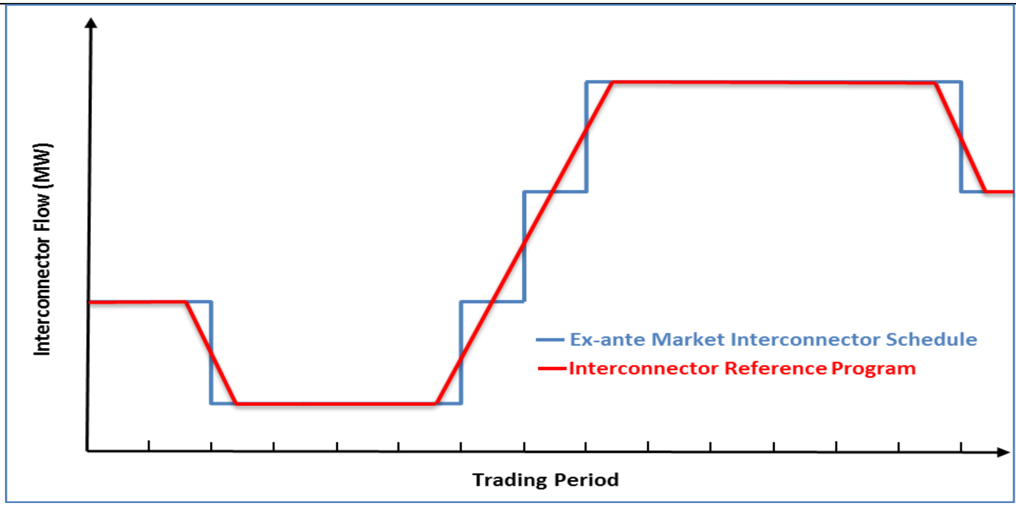
Commercial data associated with the provision of System Services does not currently form an input to the scheduling and dispatch process as each System Service considered in the scheduling and dispatch process is remunerated using common tariffs (i.e. a fixed payment rate per service is applied to each service provider). System Service providers are therefore selected based on their Balancing Market Commercial Offer Data and their technical capability to provide a service.</td><td></td></tr>
<tr><td>Per scheduling interval (5</td><td>Production of Composite Cost Curves:

The complex and simple commercial offer data submitted by Participants contains two separate Price/Quantity (PQ) curves based on absolute MW; one containing a range of break points and incremental</td><td></td></tr>
</table>

mins)	prices, the other containing a range of break points (not necessarily the same) and decremental prices. Within the scheduling process, for each scheduling interval (30 mins for LTS, 15 mins for RTC and 5 mins for RTD), for each unit, a composite PQ curve is created by using the PN value at that interval boundary to combine the two curves as described below: • All segments from the decremental curve where the MW range is below or equal to the PN; and • All segments from the incremental curve where the MW range is above or equal to the PN.  This composite curve (the red dashed line) for each unit, for each scheduling interval is used within the scheduling tool as the cost curve used to make incremental and decremental adjustments within the optimisation. Further information on costs curves is available in the Industry Guide to ISEM[21].	
Per market update	**Creation of the Interconnector Reference Programme:** Following ex-ante market and completion of cross-zonal intraday trading activity, we receive an intraday	

[21] http://lg.sem-o.com/ISEM/General/ISEM_Industry%20Guide.pdf

	schedule for each interconnector. The Moyle and EWIC interconnector schedules that are provided to us are block schedules – half-hourly for intraday updates. While the interconnectors are physically capable of achieving rapid changes between trading periods, a ramping rate is applied to ensure that changes to the physical interconnector flows respect the relatively slower ramping capability of units on the system and the slower rate of change in demand and wind production levels. Rapid changes to interconnector schedules could otherwise result in disturbances on the power system. We convert the block schedule for each interconnector to a physical Interconnector Reference Programme (ICRP) that describes the point in time flow on the interconnector and which respects the operational ramp rates applied to each interconnector. The conversion of the block market schedule to an ICRP is illustrated below. This conversion process seeks to minimise the energy volume difference between the ICRP and the block market interconnector schedule so as to minimise any energy imbalance that arises over the Trading Day. In the Figure below this imbalance is represented as the net area within each imbalance settlement period between the ex-ante market interconnector schedule and the ramp limited ICRP. Note that Day-Ahead Markets running since 31 December 2020 will not include any SEM-GB interconnection capacity so the resulting interconnector schedules will initially be set to zero. Interconnector capacity will continue to be allocated in the intraday auctions so the market will still be capable of producing non-zero interconnector schedules. As a consequence, from the 31 December 2020 we will not have day-ahead interconnector schedules until 18:10 each day. In light of the interim market arrangements that are in place as a result of the UK leaving the EU, artificial IC schedules are created in the first day-ahead LTS run to ensure that we can continue to operate securely given the later notice of actual interconnector schedules. The methodology used in this process places the emphasis on secure system operation and to therefore schedule ‘defensively’ to ensure we can manage unusual activity on the SEM-GB border.	

		
Ad-hoc	**Determination of Available Cross-Zonal Actions:** • We exchange CBB prices and volumes with National Grid and these are inputs which are used when CBB is employed or considered in the scheduling and dispatch process. • Both CTPT and CBB may only be employed to facilitate priority dispatch and system security. • Each instance of CTPT and CBB is subject to the agreement of National Grid. • For CTPT, the available, unused capacity on the Interconnectors is the primary consideration and input. • CTPT is more likely to be used than CBB, particularly for priority dispatch reasons, because it can be confirmed further ahead, and it can be for longer periods and higher volumes. CBB can only be used for two-hour blocks whereas CTPT can be used across the remaining trading periods for a given market closure.	BP_SO_11.1 Calculation of CBB Trade Prices and Volumes; BP_SO_11.2 CBB Trading between EirGrid/SONI and NGET; BP_SO_11.3 Interconnector Emergency Actions; BP_SO_11.4 Coordinated Third-Party Trading.
Ad-hoc	**Managing Units Under Test:**	The Operational

	We receive unit under test requests from participants and, once approved, fix test profiles in each appropriate scheduling run.	Process for Management of Unit Testing BP SO 12.1 and the Unit Under Test Guidelines for Market Participants.
Continuous	**Starting with Real-Time Power System Conditions:** We utilise information on the real-time status of the power system, collected from our Energy Management System (EMS) and Supervisory Control and Data Acquisition (SCADA) system, as a starting point for the scheduling and dispatch process. These inputs include: • the status of transmission circuits being in or out of service; • the status of units (on/off); • power-flows on circuits and interconnectors; • real-time demand; • real-time wind output; • system voltages; • system frequency; and • real-time contingency analysis results.	

APPENDIX 2.2 SCHEDULING

Scheduling is the process of planning the dispatch instructions that we issue based on the inputs described above. Our scheduling process operates from close to real-time through to the end of the Trading Day or the next Trading Day. Given the volume of inputs to the process and the complex nature of the process itself, it is split into a number of timeframes that allow for short-term analysis to be performed quickly and regularly while longer term analysis, which takes more time to process, is performed less frequently. The aim is to achieve a rolling, integrated and current plan of ‘unit commitment’ and ‘economic dispatch’ actions.

We run three scheduling processes in parallel:

- Long-Term Schedule (LTS)
- Real-Time Commitment (RTC)
- Real-Time Dispatch (RTD)

The output of each schedule is an Indicative Operations Schedule (IOS) which is a list of unit production (generation) and consumption (demand of storage units and demand side units rather than supplier units) levels (MW levels per scheduling interval) that meet the objectives of the scheduling and dispatch process.

Timelines	Description	References
Refer to Section 4.3.3.	**Run Long-Term Schedule (LTS):** As particular milestones are reached during the day (Section 4.3.3), we take a snapshot of the inputs described above and manually initiate a Long-Term Schedule (LTS). This produces a schedule at 30-minute resolution (i.e. a MW value for each unit is determined for each 30 minute interval) commencing 2 or 3 hours after the run initiation time for a period of up to 30 hours. Only the first LTS run which includes the next trading day's day-ahead market results has a schedule start time of 3 hours ahead. The output of an LTS run is an IOS that is used to provide long-term unit commitment/de-commitment advice. Manually initiated LTS runs can also be performed to consider significant changes to inputs (such as a forced outage of a large unit) so that we can, if necessary, update our plans to ensure that system security requirements are met. Note that in light of the interim market arrangements that are in place as a result of the UK leaving the EU, artificial IC schedules are created in the first day-ahead LTS run to ensure that we can continue to operate securely given the later notice of actual interconnector schedules. The methodology used in this process places the emphasis on secure system operation and to therefore schedule 'defensively' to ensure we can manage unusual activity on the SEM-GB border.	BP_SO_10.1 Perform Long-Term and Short-Term Scheduling.

Every 15 minutes	**Run Real-Time Commitment (RTC):** Every 15 minutes we take a snapshot of the inputs described above and the commitment status of units as determined by LTS and run a Real-Time Commitment (RTC) schedule. This produces a schedule at 15-minute resolution (i.e. a MW value for each unit is determined for each 15 minute interval) commencing 30 minutes after the run initiation time for a period of 3½ hours. The output of RTC is an IOS that is used to provide short to medium term unit commitment/de-commitment advice.	BP_SO_10.1 Perform Long-Term and Short-Term Scheduling.
Every 5 minutes	**Run Real-Time Dispatch (RTD):** Every 5 minutes we take a snapshot of the inputs described above and the commitment status of units as determined by RTC and LTS and run a Real-Time Dispatch (RTD) schedule. This produces a schedule at 5-minute resolution (i.e. a MW value for each unit is determined for each 5 minute interval) commencing 10 minutes after the run initiation time for a period of 1 hour. The output of RTD is an IOS that is used to provide incremental and decremental dispatch advice. It does not make unit commitment/de-commitment decisions.	BP_SO_10.1 Perform Long-Term and Short-Term Scheduling.

APPENDIX 2.3 DISPATCH AND CONTROL ACTIONS

Based on the Indicative Operations Schedules (IOSs) produced by LTS, RTC and RTD, and taking real-time system conditions into account (such as system frequency, voltage, thermal circuit loadings and dynamic stability), dispatch instructions and other control actions are determined and issued by us to individual dispatchable and controllable units. Any required deviation from the IOS will be taken in line with a merit order of available actions (to increment/start-up units or decrement/shut-down units) taking into account real-time unit operating levels, unit response characteristics and operational security requirements.

Timelines	Description	References
Continuous	**Issue Dispatch Instructions:** We issue dispatch instructions on a continuous basis. These are based on the advice provided by the LTS, RTC and RTD IOSs taking into account the real-time status of the power system and the latest forecast conditions. Dispatch instructions take the following form: • Synchronise – connect to the power system; • De-synchronise – disconnect from the power system; and • MW Level – the active power MW level to which the unit should operate. All MW instructions are 'open' meaning that once achieved; the MW level should be maintained until a subsequent instruction is issued. Within this instruction type the TSO has the ability to define a time until which the instruction applies, known as the *effective until time*, however this is only relevant to settlement and not physical operation. Dispatch instructions that deviate from the IOSs are taken in line with the merit order of actions available to us taking into account system requirements and unit technical capability. We issue unit commitment instructions in line with unit notification times subject to system security requirements.	BP_SO_3.2 Issue Dispatch Instructions

Continuous	**Control Wind and Solar Units** Categorised as priority dispatch, wind and solar units will generate to their full availability unless curtailed or constrained by us. In such an event we issue an Active Power Control (MW) set-point directly to the wind/solar unit control system. This set-point limits the MW output of the unit. In the event of wind curtailment or constraint being required, we issue control set-points to wind units on a pro-rata basis at the time of application– to all wind units for global system curtailment events or to a subset of wind units within a constraint group. Constraint/curtailment instructions apply sequentially to wind units (starting in category 1) categorised as follows: • Category 1 is a wind unit that is not compliant with controllability requirements. For a wind unit with the active power control system not working, we open the circuit breaker or point of connection to the system; • Category 2 is a wind unit with controllability status compliant with the controllability requirements; and • Category 3 is a wind unit which has been recently energised and are undertaking an agreed commissioning and testing programme. Solar units are treated like wind units with respect to constraint and curtailment (Ref. Section 3.1).	Wind Farm Controllability Categorisation Policy
Continuous	**Other Instructions** Other instruction types that we issue are: • Instructions to explicitly or implicitly provide System Services: o Explicit: an instruction to provide reactive power or operate in a specific mode (see ‘Operating Mode’ below) or	

<table>
<tr><td></td><td><li style="list-style-type:circle">Implicit: an instruction implied from the MW dispatch instruction such as a unit being instructed to operate below its maximum output to provide operating reserve;

Operating Mode – Pumped Storage and some CCGT units can operate in different modes. The scheduling process will be based on the mode of operation determined by the Participant via their TOD set selection however we may also instruct a mode change;
Instructions to change fuel – some units are capable of operating on different fuels and may be instructed to switch fuel based on their own requirements, for the purposes of a test or in a fuel emergency situation;
Maximisation instruction – an instruction to operate at a level in excess of declared availability; and
Emergency Instruction – an instruction that could require operation outside of normal declared capability.
</td><td></td></tr>
<tr><td>Ad-hoc</td><td>Utilisation of Available Cross-Zonal Actions:

Both CTPT and CBB may be employed to facilitate priority dispatch and system security (including congestion management) only.
SONI and EirGrid determine the Maximum Transfer Capacities for the interconnectors to ensure the system will be secure.
Each instance of CTPT and CBB is subject to the agreement of National Grid.

CTPT is more likely to be used than CBB, particularly for priority dispatch reasons, because it can be confirmed further ahead, and it can be used for longer periods and higher volumes. CBB can only be used for two-hour blocks whereas CTPT can be used across the remaining trading periods for a given market closure.</td><td>BP_SO_11.1 Calculation of CBB Trade Prices and Volumes; BP_SO_11.2 CBB Trading between EirGrid/SONI and NGET;

BP_SO_11.3 Interconnector Emergency Actions; BP_SO_11.4 Coordinated Third-Party Trading.</td></tr>
</table>

APPENDIX 2.4 EXAMPLE

The following presents an example of a schedule and resulting dispatch instructions based on Participant submitted PNs. Below is a snapshot of PNs submitted at 16:00 D-1, for 08:00–21:00 on D (in blue) and resulting IOS from an LTS run (red). Note that for illustration purposes the PNs and IOS are presented at hourly granularity.

PNs	Availability Max / Min	08:00	09:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00
Unit A	400 / 200	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Unit B	400 / 200	300	350	400	400	400	400	400	400	400	400	400	400	300	200
Unit C	400 / 200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unit D	300 / 100	100	200	250	250	300	250	200	200	200	250	300	300	250	200
Unit E	300 / 100	100	200	200	200	200	200	200	200	200	250	300	200	100	100
Unit F	100 / 20	0	0	0	0	0	0	0	0	0	100	100	50	0	0
Unit G	100 / 20	0	0	0	0	0	0	0	0	0	0	50	0	0	0
Unit H	50 / 10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total PN		900	1150	1250	1250	1300	1250	1200	1200	1200	1400	1550	1350	1050	900
Demand		900	1150	1250	1250	1300	1250	1200	1200	1200	1400	1550	1350	1050	900

Schedule	Availability Max / Min	08:00	09:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00
Unit A	400 / 200	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Unit B	400 / 200	330	350	370	370	370	370	370	370	370	370	370	370	280	230
Unit C	400 / 200	0	200	200	200	200	200	200	200	200	200	250	200	200	0
Unit D	300 / 100	100	130	210	210	260	210	160	160	160	250	270	270	100	200
Unit E	300 / 100	100	100	100	100	100	100	100	100	100	190	270	120	100	100
Unit F	100 / 20	0	0	0	0	0	0	0	0	0	20	20	20	0	0
Unit G	100 / 20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unit H	50 / 10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Sch		900	1150	1250	1250	1300	1250	1200	1200	1200	1400	1550	1350	1050	900
Demand		900	1150	1250	1250	1300	1250	1200	1200	1200	1400	1550	1350	1050	900

Dec
Inc

Commentary on the example

In this example the IOS produced by LTS deviates from PNs for the following reasons:

- Unit C is committed for local voltage support, provision of inertia and operating reserve.
- Units A, B, D, E and F are decremented (constrained down) below their PN to provide operating reserve headroom.
- Given these constraints, units are incremented and decremented to re-balance.
- Unit G is not scheduled to run over the peak as it is more economic to increment Unit C.

The schedule represents a plan that is continually re-assessed in subsequent LTS, RTC and RTD scheduling runs. Actual dispatch instructions (MW dispatch points, commitment and de-commitment instructions) are taken in line with unit technical capabilities and actual system conditions. The time critical decision arising from this LTS run is the commitment of Unit C as all other actions are incremental and decremental MW adjustments to already committed units. The sequence of dispatch instructions (assuming minimum change to this schedule in subsequent scheduling runs) is then:

- at 03:00 Unit C is instructed to synchronise and go to minimum load by 09:00 as it requires 6 hours' notice to get to minimum load. This instruction is based on the advice provided by the last LTS run before 03:00.
- All of the incremental and decremental MW dispatch instructions are issued in line with the latest RTD run taking into account real-time system conditions. For example, the RTD run at 09:45 advises that Unit B is dispatched to 370 MW (from 350 MW) at 09:57 however taking into account actual system conditions at the time (e.g. demand is above forecast and system frequency is below target) the actual dispatch instruction to Unit B is to 380 MW at 09:50.
- Unit G does not receive any new instruction as its last de-sync instruction remains valid.

For queries relating to this document please contact bmps@soni.ltd.uk or bmps@eirgrid.com