Industry Guide to the I-SEM

I-SEM Project

Version 1.0

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The Oval,
160 Shelbourne Road,
Ballsbridge, Dublin 4,
Ireland.

Preface

Scope

This guide is one of a series of guides, with each guide designed to meet the needs of different audiences. The Industry Guide is designed to assist participants with the transition to the I-SEM arrangements, focusing on how participants can utilise the new markets to achieve their desired outcomes.

Application

This guide reflects changes to market codes that are currently being drafted and, as such, does not become effective until the supporting legislative changes are enacted and the new or amended market codes are implemented. At the time of publication, some aspects of the I-SEM arrangements were still under consideration. This guide will be updated as and when these arrangements are confirmed.

Time

Time is shown in GMT (UTC) or IST (UTC+0100) in 24-hour format unless otherwise indicated. The time 12:00 is noon GMT/IST and 0:00 is midnight. Note that all European electricity markets, including the I-SEM, observe daylight saving, and so an event that occurs at 12:00 GMT in winter also occurs at 12:00 IST in summer.

Currency

In this document, currency is shown in euros (€) unless otherwise indicated.

Further information

To obtain more information, visit the I-SEM project website[1] or contact SEMO by email at i-semproject@sem-o.com.

[1] <http://www.sem-o.com/isem/Pages/Home.aspx>

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Abbreviations and symbols

Terms and units of measurement

Abbreviation	Term
ACER	Agency for Cooperation of Energy Regulators
AGU	Aggregated Generator Unit
AOLR	Agent of Last Resort
ASP	Administered Scarcity Price
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Market
BMPS	Balancing Market Principles Statement
BOA	Bid Offer Acceptance
CACM	Guideline on Capacity Allocation and Congestion Management
CEST	Central European Summer Time (UTC+0200) (daylight saving time)
CET	Central European Time (UTC+0100) (standard time)
CM	Capacity Market
CMC	Capacity Market Code
CMU	Capacity Market Unit
CPM	Capacity Payments Mechanism
DAM	Day-Ahead Market
DSU	Demand Side Unit
ECC	European Commodity Clearing
ENTSO-E	European Network of Transmission System Operators for Electricity
FCA	Forward Capacity Allocation
FTR	Financial Transmission Right
FWM	Forwards Market

Abbreviation	Term
GBP	pound sterling
GMT	Greenwich Mean Time (UTC+0000) (standard time)
GU	Generator Unit
HAR	Harmonised Allocation Rules
ICO	Interconnector Owner
IDM	Intraday Market
IEM	Internal Energy Market
IEU	Interconnector Error Unit
IPF	Imbalance Price Flag
IRCU	Interconnector Residual Capacity Unit
I-SEM	Integrated Single Electricity Market (arrangements)
IST	Irish Standard Time (UTC+0100) (daylight saving time)
LTS	Long Term Scheduling
MCO	Market Coupling Operator
MW	megawatt (unit of electrical power)
MWh, GWh, TWh	megawatt hour (unit of electrical energy), also gigawatt hour (1 GWh = 1000 MWh) and terawatt hour (1 TWh = 1000 GWh)
NEMO	Nominated Electricity Market Operator
NIV	Net Imbalance Volume
PAR	Price Average Reference
PTR	Physical Transmission Right
QBOA	Bid Offer Acceptance Quantity
RAs	Regulatory Authorities
RCO	Regional Coupling Operator
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RTS	Real Time Scheduling

Abbreviation	Term
SCUC	Security Constrained Unit Commitment
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SEMOpx	Single Electricity Market Operator Power Exchange
SNSP	System Non-Synchronous Penetration
SO	System Operators
SU	Supplier Unit
TLAF	transmission loss adjustment factor
TSC	Trading and Settlement Code
TSO	Transmission System Operator
XBID	Cross Border Intraday

Timeline symbols

Symbol	Definition
D	trading day D commencing 23:00 GMT/IST the day before and ending 23:00 GMT/IST on day D
D-1, D+1	the day before trading day D, the day after trading day D
t, t-1, t+0.5	the time the trading (or imbalance settlement) period opens, one hour before the trading period opens, 30 minutes after the trading period opens
CY, CY-*n*	capacity year ending 30 September, *n* years before capacity year
Y-1	one year before trading day D

1. Background

The Integrated Single Electricity Market (I-SEM) is a new wholesale electricity market arrangement for Ireland and Northern Ireland. The new market arrangements are designed to integrate the all-island electricity market with European electricity markets, enabling the free flow of energy across borders. The Internal Energy Market (IEM) for electricity and gas is one of the key pillars for the European single market. Free trade across borders and non-discrimination between internal and cross-border transactions are the foundations of the single market.

To enable cross-border trade across the IEM, each coupled market implements its own rules based on a standard ex ante trading arrangement. This is achieved by adopting the EU Target Model, which is the blueprint for market integration across the IEM, including the I-SEM. Key features of the Target Model are:

- A common price coupling algorithm for scheduling all ex ante markets and determining flows between geographic regions.
- Energy trading within regions and across borders up to close to real time.
- Forward trading of physical and/or financial trading rights for cross-border capacity.
- Integrated balancing arrangements that will ultimately enable neighbouring system operators to trade between regions as part of balancing.

In a coupled market, energy transactions involving sellers and buyers from different bidding zones are centrally collected and cleared to maximise the most efficient trades. Trades from one bidding zone to another are only restricted by cross-border capacity, subject to allocation constraints, such as ramping limitations.[2] Market coupling involves system and market operators working together to allocate cross-border capacity and optimise cross-border flows, without the need for explicit auctions.

In theory, as long as energy can flow freely, there will be a single price across all coupled markets. When the network is congested between bidding zones, prices diverge between those zones. The price differential between bidding zones incentivises efficient short-run use of the available capacity given the constraint and efficient longer term investment in infrastructure to relieve the congestion.

By the time the I-SEM goes live in 2018, the IEM is expected to comprise more than 20 bidding zones, including the SEM, coupled by more than 40 cross-border interconnectors, containing a total generating capacity of over 3,000 terawatts (TW).

[2] As provided in the CACM (see Section 2.5 for description).

To learn more about market coupling and the I-SEM design, refer to the *Overview of the Integrated Single Electricity Market*[3] and the SEM Committee website[4].

[3] <http://www.sem-o.com/MarketMessages/Pages/I-SEMMarketOverviewGuide.aspx>

[4] SEM Committee is the peak decision-making body for the SEM, <https://www.semcommittee.com>.

2. Market governance, administration and operation

2.1 I-SEM governance and administration

SEM Committee

The SEM Committee (SEMC) is the governing body for the I-SEM, established by law. It oversees the design and implementation of the I-SEM and makes decisions on licenses and market codes relevant to the implementation of the I-SEM. The mission of the SEMC is to protect the interests of consumers of electricity by promoting effective competition in the sale and purchase of electricity through the I-SEM. The SEMC comprises six representatives from the Regulatory Authorities (RAs), three representing Ireland and three representing Northern Ireland, and two independent members.

Regulatory Authorities

The RAs—the Commission for Energy Regulation (CER) in Ireland and the Utility Regulator (UR) in Northern Ireland—participate jointly in decisions on SEM matters through their membership of the SEMC. The RAs are also individually responsible for local issues relating to the implementation of the market codes and procedures, licensing of market operators and participants, setting market parameters, and monitoring the operation of the I-SEM and the conduct of its participants.

2.2 Transmission system operation

The Transmission System Operators (TSOs), under license from the RAs, operate the transmission system. EirGrid is the TSO for Ireland, and SONI is the TSO for Northern Ireland. The TSOs are responsible for system security and balancing, operating transmission assets, managing grid connections, and forecasting and planning for the power system. The TSOs also have roles in operating the markets in their geographic regions, which are described later.

CORESO (Coordination of Electricity System Operators), a European body, assists the TSOs with security of supply at a regional level and in defining capacities between regions.

2.3 Market operation

Note. Unless otherwise stated, references to the Day-Ahead and Intraday Markets are specific to the I-SEM markets operated by SEMOpx.

Responsibilities for market operation, settlement and credit risk management are split between multiple entities, which are described separately for each market in Section 4 and summarised in Table 2. Refer to the market descriptions for definitions of the market operator roles listed in Table 2 (SEMOpx, MCO, SEMO, etc.).

Table 1 Market operation responsibilities

Market	Market Operation	Settlement and Credit Risk Management	Refer to
Day-Ahead Market	SEMOpx[5] (or another NEMO[6]), MCO	SEMOpx (or another NEMO[6])	Section 4.3.3
Intraday Market	SEMOpx (or another NEMO[6]), RCO	SEMOpx (or another NEMO[6])	Section 4.4.3
Balancing Market	System Operators (TSOs)[7]	SEMO	Section 4.5.3
Capacity Market	System Operators (TSOs)	SEMO/TSOs[8]	Section 4.6.3
Forwards Market	Under consideration		Section 4.7.3
FTR auctions	JAO (on behalf of ICOs)		Section 4.8.3

MCO Market Coupling Operator
RCO Regional Coupling Operator
TSO Transmission System Operator
SEMO Single Electricity Market Operator
SEMOpx Single Electricity Market Operator Power Exchange
NEMO Nominated Electricity Market Operator
JAO Joint Allocation Office
ICO Interconnector Owner

2.4 European network administration

Governance of the IEM and administration of intermarket network codes falls under the EU Agency for Cooperation of Energy Regulators (ACER). ACER oversees the development of the IEM and the European Network of Transmission System Operators for Electricity (ENTSO-E) is responsible for developing the detailed technical and commercial requirements for market coupling.

[5] EirGrid and SONI, as designated Nominated Electricity Market Operator (NEMO) for the SEM, will operate as SEMOpx.

[6] Participants can use other NEMOs, if designated or approved and available for the SEM, to trade in the DAM; however, each NEMO operates under their own set of rules and this guide is specific to SEMOpx.

[7] The Transmission System Operators, EirGrid and SONI, are the licensed System Operators for the SEM, as referred to in the market codes. In this guide, the term Transmission System Operators includes references to the System Operators.

[8] TSOs hold performance bonds for new entrant plant.

2.5 Market codes and guidelines

The market codes authorise and define the functions of the TSOs, market operators, and participants, and the processes by which the markets and interconnectors operate. The codes fall into two categories: codes specific to the I-SEM[9,10] and European network codes, guidelines, rules and agreements[11,12,13] relevant to the operation of the SEM. The processes for amending codes and the responsible bodies are defined in and differ for each code.

Table 2 Market codes, guidelines and agreements

Code	Application
I-SEM codes and rules	
Grid Code	Defines TSO functions and interactions with the TSOs, including forecasting, demand control, information exchange, scheduling, and dispatch
Trading and Settlement Code (TSC)	Defines the rules for participant registration, balancing, calculation of payments and charges, credit cover, collateral requirements and financial settlement for the Balancing Market and Capacity Market.
Capacity Market Code (CMC)	Defines the rules for conducting auctions for capacity, including requirements for participation and qualification.
SEMOpx Rules[14]	Defines the rules for governance, administration and operation of the Day-Ahead Market and the Intraday Market operated by SEMOpx.
European network codes, guidelines, rules and agreements	
Connection Network Codes	Defines the rules for the connection of new power generating installations, new demand facilities, and new high-voltage direct current systems.
Emergency and Restoration	Defines the rules for management of the electricity transmission system in emergency, blackout and restoration states.

[9] <http://www.sem-o.com/ISEM/>

[10] <http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx>

[11] <https://ec.europa.eu/energy/en/topics/wholesale-market/electricity-network-codes>

[12] <http://www.eirgridgroup.com/site-files/library/EirGrid/Allocation-Rules-for-Forward-Capacity.pdf>

[13] <http://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/Pages/default.aspx>

[14] SEMOpx Rules are currently under development.

Code	Application
System Operation Guideline	Defines the rules for operation of the interconnected transmission system in real time.
Forward Capacity Allocation (FCA)	Provides a framework for the calculation and allocation of interconnection capacity and cross-border trading in forward markets (i.e. time frames longer than day-ahead)
Capacity Allocation and Congestion Management (CACM)	Governs the establishment of cross-border EU electricity markets in the day-ahead and intraday time frames, and the calculation of interconnection capacity.
Electricity Balancing (EB)	Defines cross-border operation of balancing markets.
Harmonised Allocation Rules (HAR)	Defines the harmonised arrangements between Ireland, Northern Ireland, and Great Britain, as required under the FCA.
Balancing and Ancillary Service Agreements	Define the provision of commercial ancillary services across interconnectors.

Where conflicts occur between regulations and codes, the following order of precedence applies:

- requirements under European Laws
- requirements under Irish Laws or Northern Ireland Laws
- any applicable requirement, direction, determination, decision, instruction or rule of any Competent Authority
- the applicable Licence
- the Grid Code
- the Metering Code
- the Capacity Market Code
- the Trading and Settlement Code

2.6 Market monitoring and controls

Markets are monitored to identify any areas where the goals of the market are undermined by limitations of the design. The behaviour of market participants is subject to EU law[15], which provides controls for market manipulation, anti-competitive behaviour, and insider trading. The SEMC is currently considering what mitigation measures will be needed to address the abuse of market power in the I-SEM.

[15] Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), <http://www.acer.europa.eu/en/remit>

2.7 Market information

Market information is provided through the market systems to individual participants. All public information is published on the various websites operated by the market administrators and market operators. Market information is also made available via the ENTSO-E transparency platform[16]. The types of information made available to each participant and to the public depends on its commercial sensitivity.

2.8 Transitional Registration

Participant requirements and registration procedures for the I-SEM markets are defined in the respective market codes and administered by the relevant market operator.

Due to the introduction of new markets and new or revised market codes, market services, and market roles, transferring from the current arrangements to the I-SEM cannot be automatic for existing participants. However, every effort has been taken to reduce the effort by participants in transitioning to the new markets. Where possible, the existing SEM data will be used as the basis for the I-SEM. But participants will be required to confirm the accuracy of the data and, in some instances, to provide additional information.

A Transitional Registration Plan[17] has been developed to assist and advise existing participants on how and when to register for each market. The enduring registration process for new participants is also explained in this plan. For details of participant requirements and submission deadlines, participants must refer to the published plan.

Registration for the Balancing Market, Day-Ahead and Intraday Markets, and Capacity Market is centralised and coordinated through the I-SEM Registration Team. Participants in the Day-Ahead and Intraday Markets are also required to register with the European Clearing House. Registrations for the Forwards Market and FTR auctions are managed directly by the respective market operators.

Registration is a sequential process, with each step in the registration process building on the data previously submitted. The order of submission, detailed in the transition plan, is aligned with the timeline for the relevant market code approvals. Some registration activities cannot be completed until the relevant market codes come into force—for example, signing framework agreements.

The existing SEM registration data will be mapped to the new I-SEM entity model and provided to existing SEM participants for validation. Existing and new participants will then need to obtain and submit any additional data required for their core entity setup.

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[16] <https://transparency.entsoe.eu/>

[17] EirGrid, October 2016, *Transitional Registration Plan*, available <http://www.sem-o.com/ISEM/General/Transitional Registration Plan.pdf>

Important. Participants are strongly encouraged to submit the data required for registration as early as possible. In particular, registration for the DAM and IDM involves meeting ECC requirements and, given the influx of I-SEM participants to these European markets, delays can be expected.

A registration lock-down period will be enforced, commencing towards the end of the Market Trial and ending sometime after Go-Live, during which new registrations will be prohibited and only minor changes will be permitted to existing registration data.

3. Participation

Due to differences between the current SEM and the I-SEM arrangements in the markets, types of units and participant roles, all existing participants are urged to familiarise themselves with the transitional registration requirements (see Section 2.8) and consult with the Transitional Registration Team[18] on their particular circumstances.

For descriptions of market operator roles, refer to the relevant topics for each market in Section 4.

3.1 Participant roles

Participants can have a portfolio of resources, but, with some exceptions, participation in the I-SEM is at a unit level.

Generator

Generators supply energy to the transmission system. They can register Generator Units that are either dispatchable, non-dispatchable but controllable, or non-dispatchable and non-controllable. The following subtypes of Generator Units are available in the I-SEM:

- Wind Power Unit
- Energy Limited Generator Unit
- Pumped Storage Unit
- Battery Storage Unit
- Demand Side Unit
- Aggregated Generator Unit
- Trading Unit
- Assetless Unit (see *Assetless Trader* below)
- Dual Rated Generator Unit

Supplier

Suppliers purchase energy from the market for consumption. They register Supplier Units, which represent non-dispatchable demand (e.g. a distribution network or industrial load).

Assetless Trader

Assetless Traders take positions in the ex ante markets but have no physical assets. They register Assetless Units, which can be used to buy and sell energy. Assetless trading increases the level of trade in the ex ante markets, thereby increasing liquidity and reducing the potential for price separation between markets due to a lack of competition.

[18] mailto: I-SEMregistration@sem-o.com

Interconnector Owner

Interconnector owners (ICOs) operate the interconnectors that transport energy across borders. They register Capacity Market Units. They do not trade in energy markets, but they may have exposure in settlement through interconnector error units registered by the TSOs. They are responsible for facilitating the sale and settlement of transmission rights on the interconnector's capacity, facilitating cross-border trade in the ex ante markets, and facilitating balancing. The Harmonised Allocation Rules (HAR), which are a requirement of the FCA, define the contractual arrangements for cross-zonal capacity allocation in the long-term time frame.

Agent of Last Resort

SEMO provides an Agent of Last Resort (AOLR) service, which is available to below de minimis generators of any fuel type and renewable generators of any size. The AOLR is an automated data processing service provided through the market systems. Generators wanting to use the AOLR must register for the service with SEMO and be registered with SEMOpx for participation in the ex ante markets. It must have its own trading account and it is responsible for its own credit. The market operator levies an AOLR fee on the participating generators, which is subject to regulatory oversight.

3.2 Participation requirements

3.2.1 Generators

Generators are not required to participate in the ex ante markets, but there are links to other markets that might result in the participant being financially exposed if they do not. Participation in the balancing and capacity markets depends on the characteristics of the generator unit, as described below.

Dispatchable unit

A unit is "dispatchable" if it can follow (maintain) MW set-point instructions issued by the TSO. A dispatchable unit with a capacity exceeding the de minimis threshold of 10 MW is required to participate in the balancing and capacity markets. Units below the de minimis threshold can also participate if they meet dispatchability requirements of the relevant Grid Code.

Non-dispatchable but controllable unit

A unit is "non-dispatchabe but controllable" if the unit can limit its output to MW set-point instructions issued by the TSO. A non-dispatchable but controllable unit with a capacity exceeding the de minimis threshold is required to participate in the balancing and capacity markets.

Non-dispatchable and non-controllable unit

A "non-dispatchable and non-controllable" unit is any unit that cannot follow a MW set-point instruction from the TSO. A non-dispatchable and non-controllable unit cannot participate in the balancing market.

Priority dispatch unit

Priority dispatch units have special status, whereby the TSO is obliged to take energy from these units ahead of other generators, subject to system security considerations. Priority dispatch units participate in the I-SEM markets like any other units, but they receive special treatment in system balancing.

3.2.2 Suppliers

Suppliers are not required to participate in the ex ante markets, but there are links to other markets that might result in the participant being financially exposed if they do not. Suppliers do not actively participate in the balancing market (they are non-dispatchable) but are nevertheless involved in settlement. Suppliers do not trade capacity in the capacity market but are involved in the funding arrangements.

3.2.3 Interconnectors

All interconnectors are required to participate in the balancing market and the capacity market.

3.3 Trading Site

The connection point of a Generator Unit or group of Generator Units is represented by a Trading Site. Usually, the Trading Site maps to the connection agreement, but the Grid Code allows sites to be subdivided. A Trading Site has two particular purposes under I-SEM:

- to flag an autoproducer setup and thereby enable net trading through a Trading Unit, and
- to flag firm access at the connection point (not the Generator Unit).

3.4 Constraints and curtailment

Market participants are required to submit physically feasible physical notifications (PNs) to the TSOs based on the outcome, or expected outcome, of the ex ante markets. “Physically feasible” means that it is within the participant’s own plant technical capability. However the PNs do not have to be feasible from a power system perspective, i.e. they do not have to respect transmission line powerflow limits nor are they required to allow for the provision of reserve headroom. Also, PNs may not reflect the optimal dispatch for facilitating priority dispatch plant nor a feasible dispatch for facilitating maximum interconnector transfers. Addressing these other “constraints” is the core function of the scheduling and dispatch process.

Constraints can broadly be categorised into three groups: security, priority dispatch and statutory requirements. In general, the treatment of constraints is not directly affected by the I-SEM market arrangements although the new market arrangements may impact on the extent to which constraints bind and the underlying cost of constraints.

At times, the TSO has a requirement to reduce the output of controllable wind units to maintain system security. If a reduction in the output of priority dispatch wind units is required for a system wide reason, for example if the System Non-Synchronous Penetration (SNSP) limit is reached, then this is referred to as “curtailment”. If the TSO needs to reduce the output of one or a specific group of wind units to manage a local issue, such as a transmission network constraint, and only a select wind unit or a select group of wind units can alleviate the issue, this is also referred to as a “constraint”. The output of the selected wind units is limited until the constraint or curtailment has been relaxed or removed by the TSO.

3.5 Firm and non-firm access

A Trading Site can have firm access to the transmission system, or be considered partially firm. If a Trading Site is partially firm then any units on that site have firm access up to a defined MW with non-firm access applying beyond that. Firm access has no influence on clearing offers in the ex ante markets, but is given special treatment in imbalance settlement.

4. Markets

4.1 Overview

The I-SEM comprises two physical ex ante markets for energy trading:

- Day-Ahead Market (DAM)—see Section 4.3,
- Intraday Market (IDM)—see Section 4.4,

a market for energy and non-energy system balancing:

- Balancing Market (BM)—see Section 4.5,

primary and secondary capacity auctions:

- Capacity Market (CM)—see Section 4.6,

and two markets for energy-related financial instruments:

- Forwards Market (FWM)—see Section 4.7,
- FTR auctions—see Section 4.8.

Referring to Figure 1, in order of time, capacity is traded in the CM up to five years in advance of the trading day. Financial instruments are traded in the FWM and FTR auctions from over a year to one month ahead of the trading day. Energy is traded in the ex ante (or “spot”) physical markets (DAM and IDM) from one day ahead of the trading day up to shortly before real time. And the BM runs before and into real time. Note that the BM runs while the IDM is still open.

The function and operation of each market and the timelines for submission of orders, market clearing, publishing market schedules, and settlement are described in the following sections.

Refer to Abbreviations and symbols at the front of this guide for definitions of timeline symbols (e.g. D-1, t+0.5, CY-4, etc.) and other abbreviations.

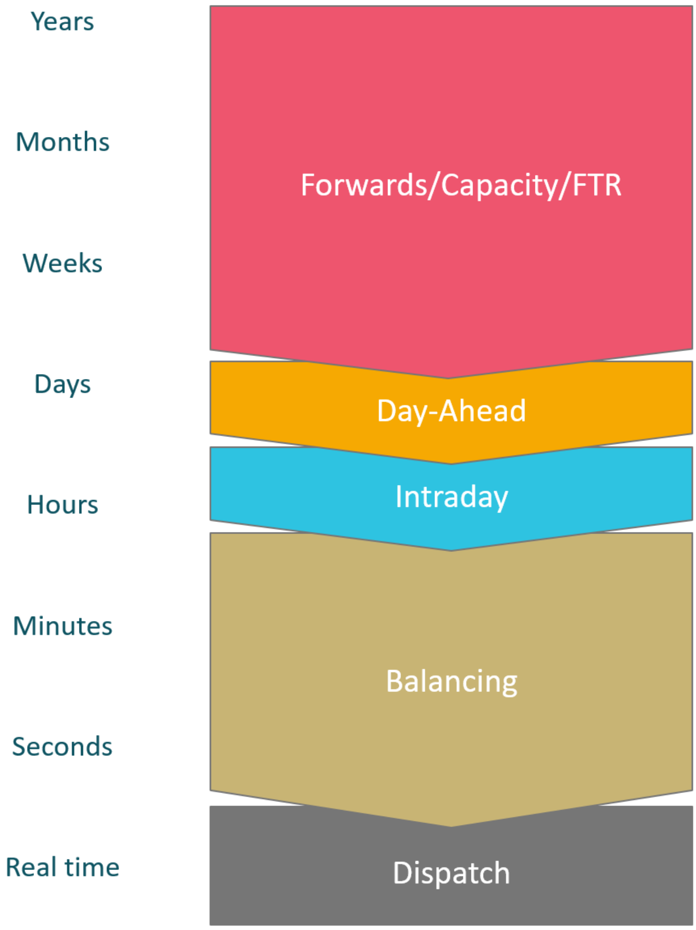

Figure 1 Market time frames

4.2 Market fundamentals

4.2.1 Trading currency

The use of dual currency (euros and GBP) is available in some markets, as shown in Table 4. Where trades are conducted in GBP, they are converted by the market operator into euros. Currency costs are charged to suppliers as a tariff.

Table 3 Trading currencies

Market	Currency
Day-Ahead Market	Euro and GBP
Intraday Market	Within-in Zone: Euro Cross-Border: Euro and GBP
Balancing Market	Euro and GBP
Capacity Market	Euro and GBP

Market	Currency
Forwards Market	To be advised
FTR auctions	Euro

4.2.2 Trading day

The I-SEM trading day (D) for trading energy and balancing services is from 23:00 GMT/IST the day before (D-1) to 23:00 GMT/IST on the day (D), which is midnight in Central European Time (CET). Note that the SEM and the IEM observe daylight saving, and so an event that occurs at 12 noon in the summer (IST) also occurs at 12 noon in the winter (GMT).

4.2.3 Energy position

A participant's energy position is the accumulated volume of all its trades in the physical markets—that is, in the ex ante markets (DAM and IDM) and any energy balancing actions taken by the TSO in the BM, as illustrated in Figure 2. Trades in the other markets are financial—that is, they do not change the net energy balance of the transmission system.

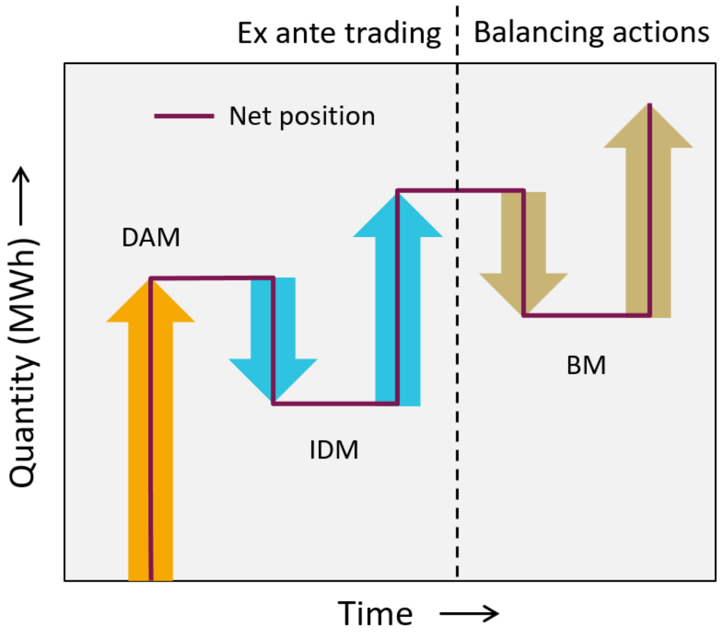

Figure 2 Participant's energy position

All physical trades in the ex ante markets are firm, and the participant is financially exposed in the BM if it cannot adhere to its commitments. In particular, if an assetless unit does not have a net zero position by the gate closure of the ex ante markets, it must buy back what it has sold or sell what it has purchased in the BM at the imbalance settlement price.

4.2.4 Transmission losses

Ex ante markets

Traded volumes are at the market boundary, and so bids and offers submitted to the DAM and IDM must be net of transmission losses (i.e. quantities are adjusted to account for losses).

Balancing market

Bids, offers and physical notifications submitted to the BM are gross of losses at the gate (i.e. quantities are not adjusted to account for losses).

Metering

Metered data is adjusted for losses in settlement.

4.3 Day-Ahead Market

4.3.1 Function

The Day-Ahead Market (DAM) is a single pan-European energy trading platform in the ex ante time frame for scheduling bids and offers and interconnector flows across participating regions of Europe. It is the cornerstone of European market integration. The goal of the DAM is to schedule orders such that the social welfare[19] generated is maximised without compromising the capacity of network elements.

The DAM involves the implicit allocation[20] of cross-border capacity through a single centralised price coupling algorithm (EUPHEMIA). The algorithm, taking into account the cross-border capacity advised by the TSOs, determines prices and positions for all participating participants in all coupled markets.

4.3.2 Relevant codes

The operation of the DAM and the roles and responsibilities of the market operator and market participants are governed by the following codes and guidelines:

- *Guideline on Capacity Allocation and Congestion Management* (CACM)
- *SEMOpx Rules* (or the NEMO market rules of any designated NEMO)

For further information, refer to Section 2.5.

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[19] For electricity markets, social welfare is defined as the consumer surplus plus the producer surplus plus the congestion rent across regions.

[20] The allocation is termed “implicit” because the capacity and the flow are allocated simultaneously (such as by market coupling), compared with an “explicit” allocation in which the flow is determined from (after) the capacity allocation.

4.3.3 Market operation

The DAM is operated by Nominated Electricity Market Operators (NEMOs) in each bidding zone or geographical region. In the SEM bidding zone (the island of Ireland), EirGrid has been designated as a NEMO for Ireland, and SONI has been designated as a NEMO for Northern Ireland. EirGrid and SONI will operate as SEMOpx in their roles as NEMO for the DAM. Participants can use other NEMOs, if available, to trade in the DAM; however, each NEMO operates under their own set of rules and this guide is specific to SEMOpx and the *SEMOpx Rules*.

SEMOpx is responsible for registration of participants, market systems operation (excluding running EUPHEMIA), settlement, credit risk management, currency risk, and access to market data.

Participants submit bids and offers to SEMOpx, who acts as the central counterparty to all trades—that is, participants buy and sell from SEMOpx (the NEMO) rather than from each other. SEMOpx interacts with the Market Coupling Operator (MCO), who runs the EUPHEMIA price coupling algorithm.

The market trading system for the SEMOpx DAM is provided by EPEX Spot[21] and settlement services are provided by European Commodity Clearing[22] (ECC) under contract to SEMOpx.

4.3.4 Participation

Participation in the DAM is not mandatory, but it is the only way of achieving a day-ahead position in the SEM, which is the primary mechanism through which participants establish a physical position to minimise their exposure in the Balancing Market. Participants do, however, have the opportunity to adjust their position by trading in the IDM.

Generators with non-firm access can trade in the DAM to levels above their firm access quantity; however, if they do so, they risk being scheduled back to their firm capacity in the BM, where the difference is settled at the imbalance price.

SEMO provides an Agent of Last Resort service to assist small or intermittent generators to participate in the DAM by making submissions to a NEMO on their behalf.

4.3.5 Market timeline

Trading participants submit orders in the DAM to support their desired physical position for each 1-hour trading period[23] in day D. Submission of orders opens at

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[21] <https://www.epexspot.com/>

[22] <http://www.ecc.de/ecc-en/>

[23] The IDM and BM operate on a 30-minute trading period. The DAM MWh quantities are split into two equal half-hour quantities for interpolation of the participant's initial physical nomination to the TSO for balancing.

11:00 D-19 (19 days before trading day D) and closes at 11:00 D-1 (see Figure 3). The market is then cleared and market schedules are published at 13:00 D-1. Settlement is performed daily by the market operator. Participants submit physical notifications reflecting the agreed trades to the TSOs by 13:30 D-1.

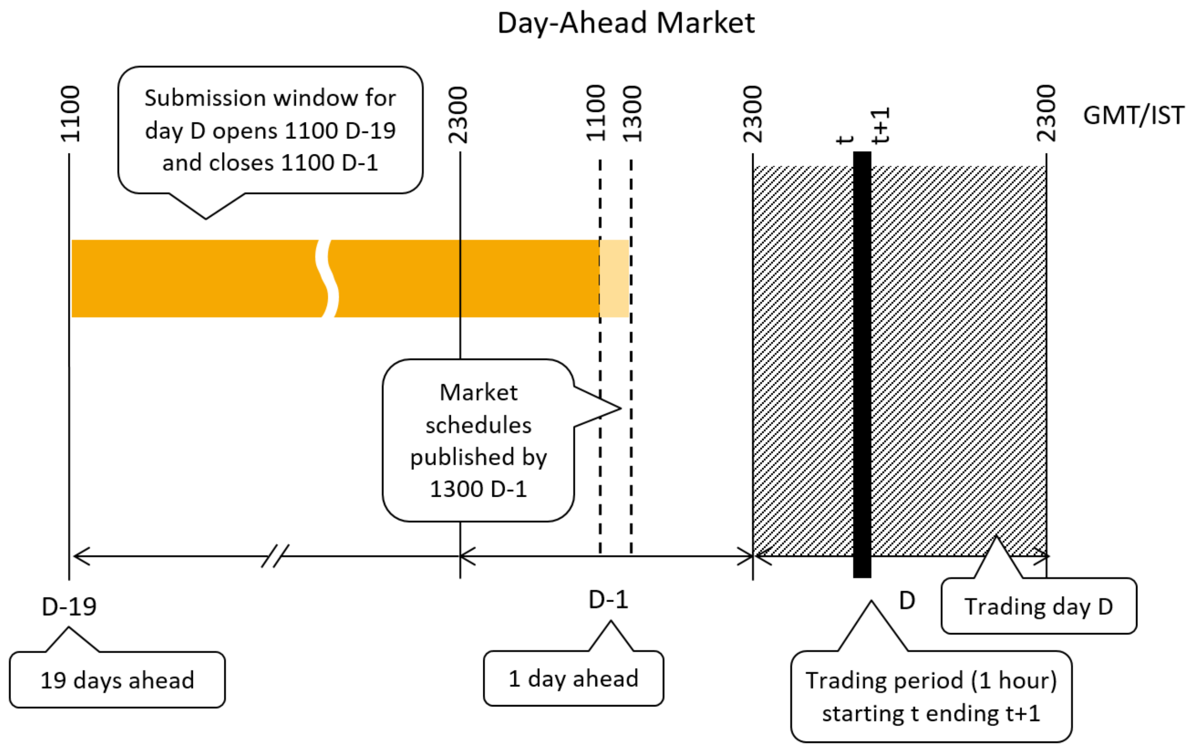

Figure 3 Day-Ahead Market timeline

4.3.6 Agent of Last Resort

The AOLR does not exercise commercial judgement in executing trades. Instead, it adopts a passive approach based on predefined inputs, forecasts and technical availability.

The AOLR submits simple hourly bids and offers in the DAM (and IDM) on behalf of its users. Bid and offer prices are set by a formula, based on the available information submitted by AOLR users and TSO forecasts of intermittent generation. In their submissions to SEMO, AOLR users can specify the portion of their capacity available to be offered into the market.

AOLR users are not guaranteed of achieving an ex ante position. To the extent that an AOLR user's unit output varies from its ex ante position, it will be subject to the balancing arrangements and imbalance settlement prices.

4.3.7 Order types

The following types of orders can be submitted to the DAM:

- **Simple:** one or more price-quantity pairs (€/MWh, MWh) to buy or sell in a specified one-hour period. Any order that is in-the-money is fully accepted.

Any order that is out-of-the-money is rejected. And any on-the-money (marginal) order can be accepted fully or partially or rejected.

- **Complex:** a simple order with a minimum income (with or without a scheduled stop) or a load gradient condition or both conditions. The minimum income condition applies a constraint such that the amount of money collected by the order in all periods must cover a fixed term (€) and a variable term (€/MWh) multiplied by the total volume (MWh). The load gradient condition defines the maximum increase or decrease of the accepted volume of the order between trading periods. A complex order can have a increase gradient (covering ramp-up) or a decrease gradient (covering ramp-down) or both or neither.

- **Block:** an order to buy or sell a volume below or above a set price limit over a number of (typically consecutive) periods.

- **Linked block:** a linked set of block orders containing a parent block and one or more child blocks. A child block cannot be accepted unless the parent block is also accepted. Any surplus revenue from child blocks is considered when evaluating the parent block, but a parent block cannot contribute revenue to a child block.

- **Exclusive group:** a group of block orders in which only one block order can be accepted.

4.3.8 Market clearing

After the auction gate closes, all orders are aggregated into two curves for each delivery hour in the SEM. Two curves are also generated for each European bidding zone. If there is no congestion, EUPHEMIA solves the problem as if it was a single Europe-wide market, setting a single market price for all bidding zones. However, if there is congestion, EUPHEMIA adjusts the curves by managing trades between bidding zones—in effect, offers in one zone supply bids in another—thereby optimising cross-border flows up to the limit of the interconnector capacity. When congestion occurs, market prices in each zone will diverge.

Consider the simplified example in Figures 4a, 4b and 4c, where there are only two zones. Zone A has surplus demand and Zone B has surplus supply. Figure 4a shows how the markets would clear if they were independent (uncoupled), with a high market price in Zone A and a low market price in Zone B. Now, if the markets are coupled (Figure 4b) and there is no congestion, the flow goes from the lower-price, surplus bidding zone B to the higher-price, deficit bidding zone A, equalising the prices in both zones. The coupled markets act as if they were a single market.

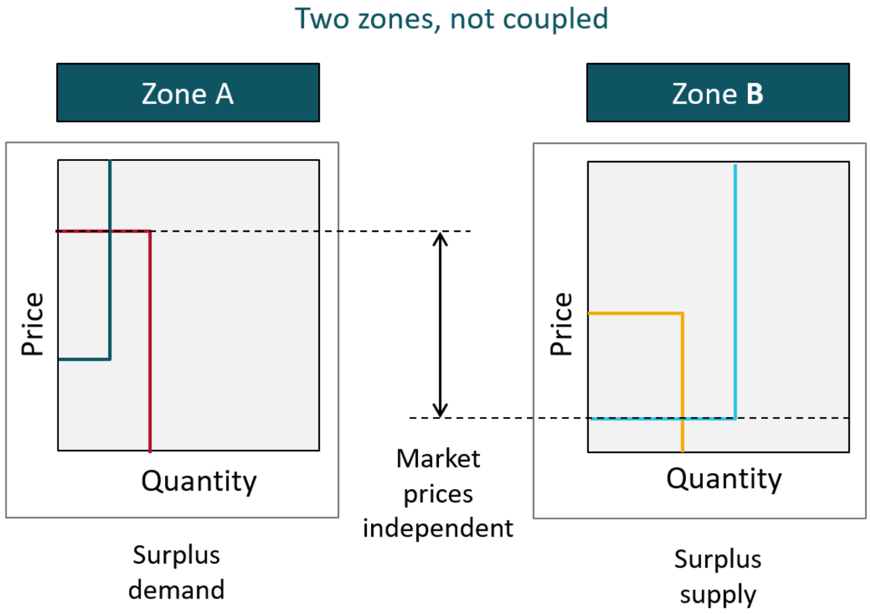

Figure 4a Independent markets

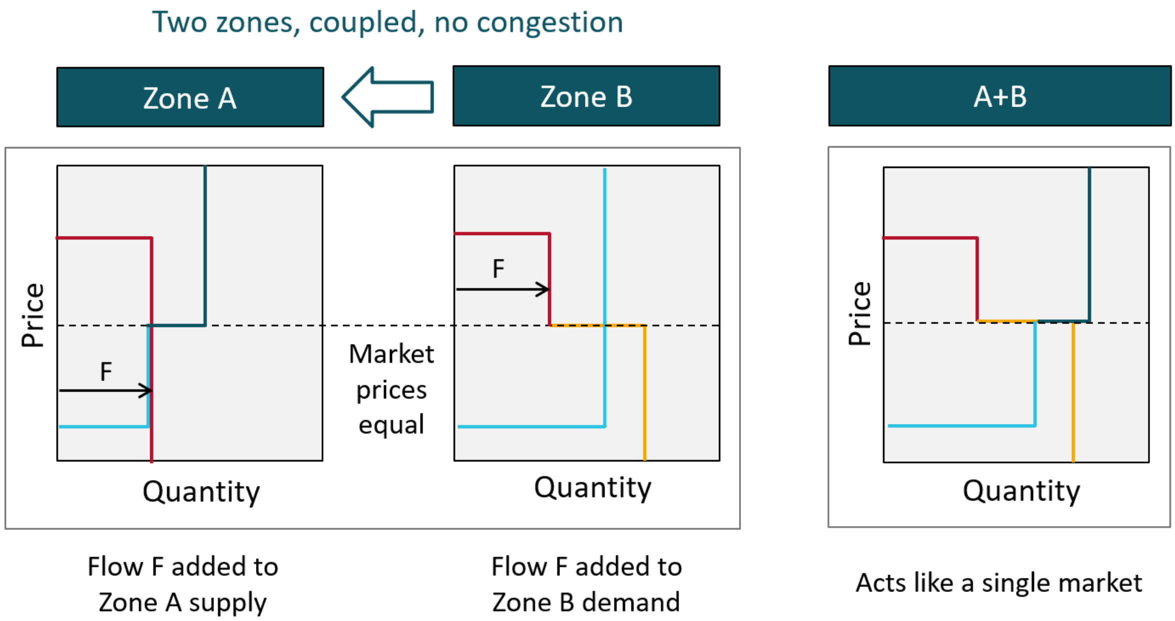

Figure 4b Coupled markets with no congestion

However, if the flow is constrained and there is not enough flow from Zone B to meet the demand in A (Figure 4c), the prices in each zone diverge.

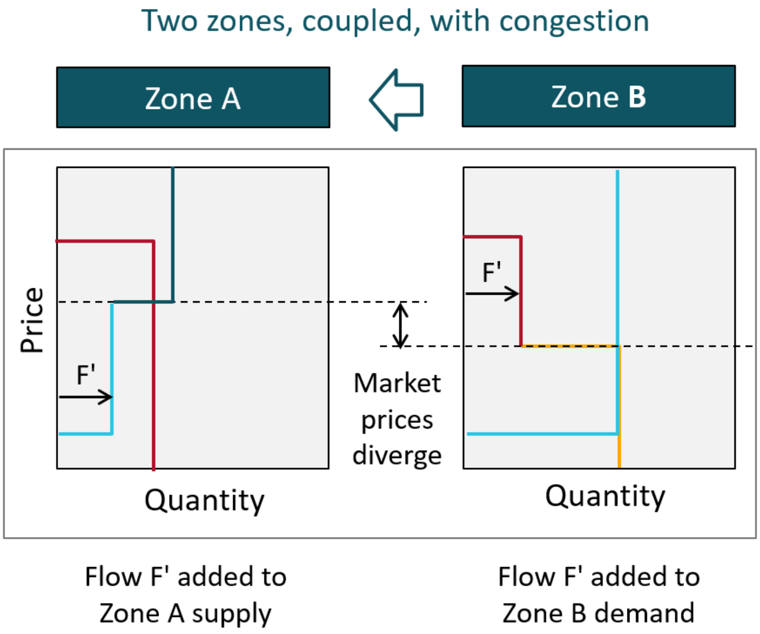

Figure 4c Coupled markets with congestion

The revenue generated from a difference in price between interconnected bidding zones is termed a "congestion rent".

4.3.9 Settlement

The ex ante markets (DAM and IDM) are settled daily by SEMOpx under its own settlement rules. Refer to Section 6 for information on SEMOpx collateral requirements. All transactions are settled at the DAM marginal price. FTRs are settled in accordance with the Harmonised Allocation Rules for forward capacity allocation.

4.4 Intraday Market

4.4.1 Function

The IDM allows participants to adjust their physical positions closer to real time. The need to adjust their positions can arise for a number of reasons, including orders failing to clear in the DAM, new information becoming available (e.g. plant shutdowns and changes to forecasts), congestion on interconnectors driving price differentials between zones, and assetless traders wishing to exit their positions.

The long-term model for a single European trading platform is based on continuous trading across interconnectors known as XBID (Cross Border Intraday). However, at go-live[24], the SEM will not be able to join in the XBID as the required preliminary tasks will not have been completed. The SEMC noted in its decisions that an interim

[24] The intent is ultimately to maintain a continuous trading platform that supports both within-zone and cross-border trades.

intraday solution will have to be developed by the designated NEMOs. The rest of this section discusses the interim intraday design proposed as part of the SEMOpx implementation being undertaken by EirGrid and SONI as designated NEMOs.

At go-live, intraday trading is only continuous within the SEM (within-zone), where bids and offers are continuously matched on a first-come-first-served basis. Three cross-border intraday auctions are also run using a version of the EUPHEMIA algorithm, which allow cross-border trades between SEM and BETTA (the bidding zone of the island of Great Britain), which can alter interconnector flows.

4.4.2 Relevant codes

The operation of the IDM and the roles and responsibilities of the market operator and market participants are governed by the following codes and guidelines:

- *Guideline on Capacity Allocation and Congestion Management* (CACM)
- *SEMOpx Rules (or the NEMO market rules* of any designated NEMO)

For further information, refer to Section 2.5.

4.4.3 Market operation

This implementation of the IDM is operated by SEMOpx, with the same responsibilities for registration, market operation, settlement and credit risk management as in the DAM.

Participants submit offers to SEMOpx, who acts as the central counterparty to all trades. On cross-border trades, SEMOpx interacts with a regional Coupling Operator, who runs the EUPHEMIA price coupling algorithm. As with the DAM, the SEMOpx IDM market trading system is provided by EPEX Spot and settlement services are provided by ECC.

4.4.4 Participation

Participation in the IDM is the same as the DAM, as described in Section 4.3.4.

4.4.5 Market timeline

The IDM trading day is divided into 48 (30-minute) trading periods (compared with 1-hour periods in the DAM).

Within-zone (continuous)

Referring to Figure 5, the submission window for within-zone trades opens at 11:45 D-1 and closes one hour before real time (t-1).

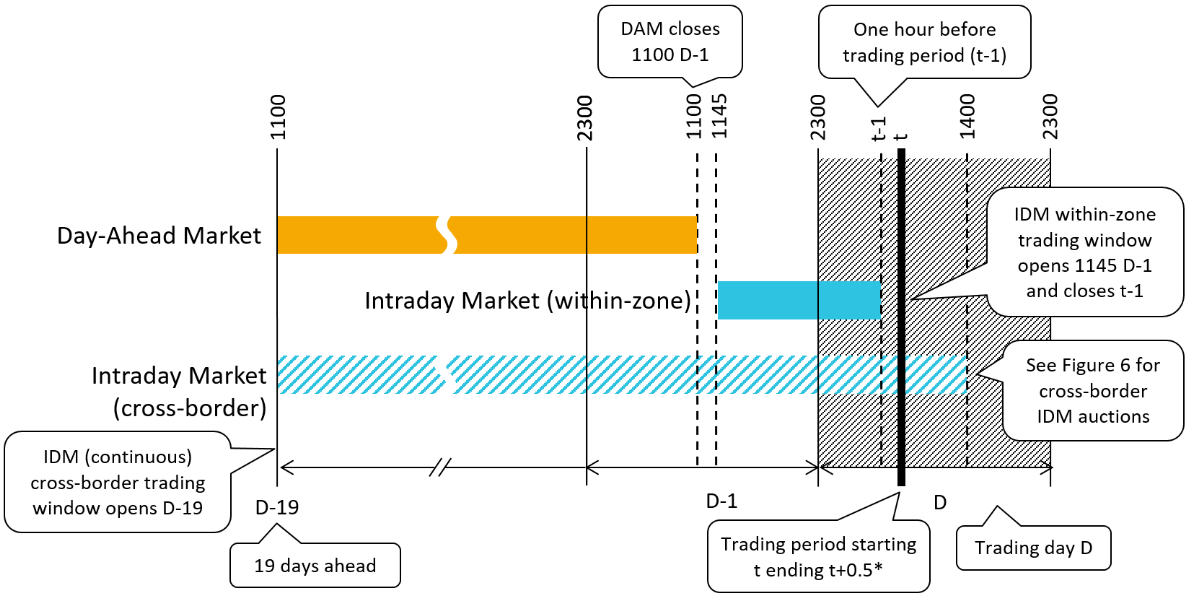

Figure 5 Intraday Market timeline

Cross-border (auctions)

Referring to Figure 6, the submission window for cross-border trades opens D-19 and closes at the time of each auction:

- **Auction 1 (cross-border)** at 15:30 D-1 for all 48 trading periods on day D.
- **Auction 2 (cross-border)** at 8:00 on day D for the 24 trading periods from 11:00 to 23:00 D.
- **Auction 3 (cross-border)** at 14:00 on day D for the 12 trading periods from 17:00 to 23:00 D.

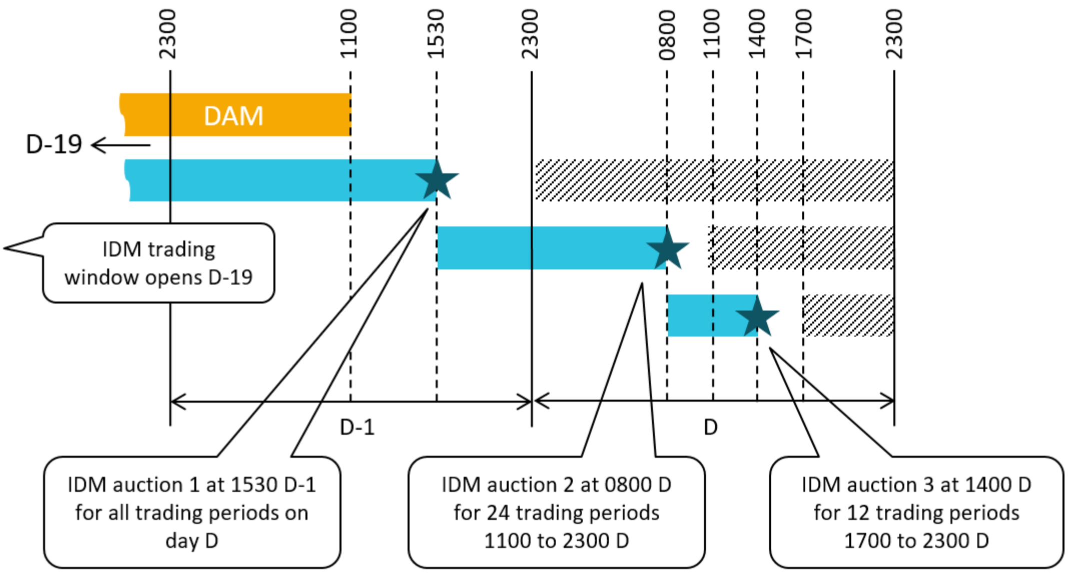

Figure 6 Cross-border intraday auction timeline

4.4.6 Order types

The following types of orders can be submitted to the IDM:

Within-zone (continuous)

- **Simple:** one or more price-quantity pairs (€/MWh, MWh) to buy or sell in a specified 30-minute period.
- **Fill or kill:** The order must be immediately accepted for its full volume or it will be cancelled.
- **Immediate or cancel:** The order must be immediately accepted fully or partially against one or more orders or it will be cancelled.
- **Good 'til date:** The order is cancelled if it cannot be matched by a specified date.
- **Iceberg:** The order is sliced and only the upper slice is displayed in the order book. After execution of the displayed slice, the next slice is displayed.
- **Block:** an order to buy or sell a volume below or above a set price limit over a number of (typically consecutive) periods.

Cross-border (auctions)

- **Simple:** one or more price-quantity pairs (€/MWh, MWh) to buy or sell in a specified 30-minute period.

4.4.7 Market clearing

The within-zone IDM (continuous matching) and cross-border IDM (auctions) are separate markets and are cleared independently.

Within-zone

Within-zone bids and offers for each 30-minute trading period (t to t+0.5) are matched continuously and paid-as-bid. Orders are stored in order books, which are visible to all traders.

An order is immediately executed if an opposite order already exists in the order book where an order to buy is priced at or above the lowest offer in the book, or an order to sell is priced at or below the highest bid in the book. If the order cannot be immediately executed, it is entered into an order book and executed in price merit order. In case of tied orders, the order with the older time stamp is executed first.

For example, if the order book contains two offers:

Order 1 – 16:00:00 Sell 10 MWh @ €50
Order 2 – 16:00:01 Sell 20 MWh @ €40

and the following bid is received:

Order 3 – 16:01:00 Buy 20 MWh @ €80

then order 3 is executed immediately and entirely from order 2 (the lowest priced offer in the book)—that is, 20 MWh @ €40—and order 1 is retained in the book.

If, however, orders 1 and 2 have the same offer price, the older order (order 1) would be executed first and the balance of order 3 would be met (if not restricted from partial execution) with 10 MWh from order 2, leaving 10 MWh from order 2 in the book.

And if order 3 was 35 MWh @ €80 and not restricted from partial execution, 30 MWh would be executed immediately (20 MWh @ €40 from order 2, then 10 MWh @ €50 from order 1) and the remaining 5 MWh @ €80 of order 3 would be retained in the book.

As indicated in these examples, offer and bid quantities may be partially executed and, depending on the restrictions attached to the order (see Section 4.4.6), any residual quantity is either retained in the order book for further matching or cancelled. Any bids and offers, whole or partial, that cannot be matched when the submission gate closes at t-1 are cancelled.

Products are based on their delivery period with orders for each product entered into different order books. Matching is restricted to the order book in which the order is stored; hence, a block offer cannot be matched with a daily bid.

Cross-border

The three cross-border auctions are cleared in the same manner as the DAM—that is, flows between coupled markets are optimised for each 30-minute trading period using the EUPHEMIA algorithm. For more information, see Section 4.3.8.

4.4.8 Settlement

Although the detail of quantities and prices used in settlement differ, the settlement arrangements for the IDM are broadly the same as the DAM, as described in Section 4.3.9.

Note. Intraday trading overlaps with the Balancing Market, which opens at the same time. Nevertheless, all cleared IDM trades are included in the participant’s ex ante quantity in settlement of the Balancing Market (see Section 4.5 for more information).

4.5 Balancing Market

4.5.1 Function

The Balancing Market (BM) determines the imbalance settlement price for settlement of the TSO’s balancing actions and any uninstructed deviations from a participant’s notified ex ante position. The BM is different from the other markets in that it reflects actions taken by the TSO to keep the system balanced and secure—for example, any differences between the market schedule and actual system demand, variations in wind forecasting, or following a plant failure.

4.5.2 Relevant codes

The operation of the BM and the roles and responsibilities of the market operator and market participants are governed by the following codes and guidelines:

- *Trading and Settlement Code* (TSC)
- *Balancing Market Principles Statement*[25] (BMPS)
- *Electricity Balancing Guidelines*

For further information, refer to Section 2.5.

4.5.3 Market operation

The responsibilities for market operation are split between the TSOs and SEMO. The TSOs are responsible for:

- Market systems operation and access to market data.
- System balancing and dispatch.

And SEMO is responsible for:

- Registration of participants.
- Administration of the market rules for the settlement of imbalances and the capacity market in the *Trading and Settlement Code*.
- Receiving submissions from participants.
- Determining prices used in settlement.
- Receiving unit metering data from meter data providers (MDPs).
- Settlement and billing.

[25] Under development.

- Credit risk management.

Planned changes to European balancing guidelines[26] will also place obligations on balancing market operators in each bidding zone of the IEM.

4.5.4 Participation

Participation in the BM is mandatory for all dispatchable generators with a maximum export capacity above the de minimis threshold and voluntary for dispatchable generators below that threshold. Generators that wish to qualify for the Capacity Market must be registered in the BM.

Participation is at the generating unit and supplier unit level; however, some portfolio participation is permitted in certain circumstances. Although only generators submit commercial offers in the BM, interconnectors can have exposure in settlement of the BM through an Interconnector Error Unit, which accounts for differences between dispatched and delivered positions.

4.5.5 Market timeline

The BM trading day is divided into 48 (30-minute) imbalance settlement periods (aligned with the IDM trading periods). Within each imbalance settlement period there are six (5-minute) imbalance pricing periods.

Referring to Figure 7, the submission window for market data opens 19 days ahead of the trading day (D-19) and closes 1 hour before the start of each 30-minute imbalance settlement period (t-1). Refer to Section 4.5.6 for the gate times specific to each type of data (TOD, COD and PN).

[26] <https://www.entsoe.eu/major-projects/network-code-implementation/cross-border-electricity-balancing-pilot-projects/Pages/default.aspx>

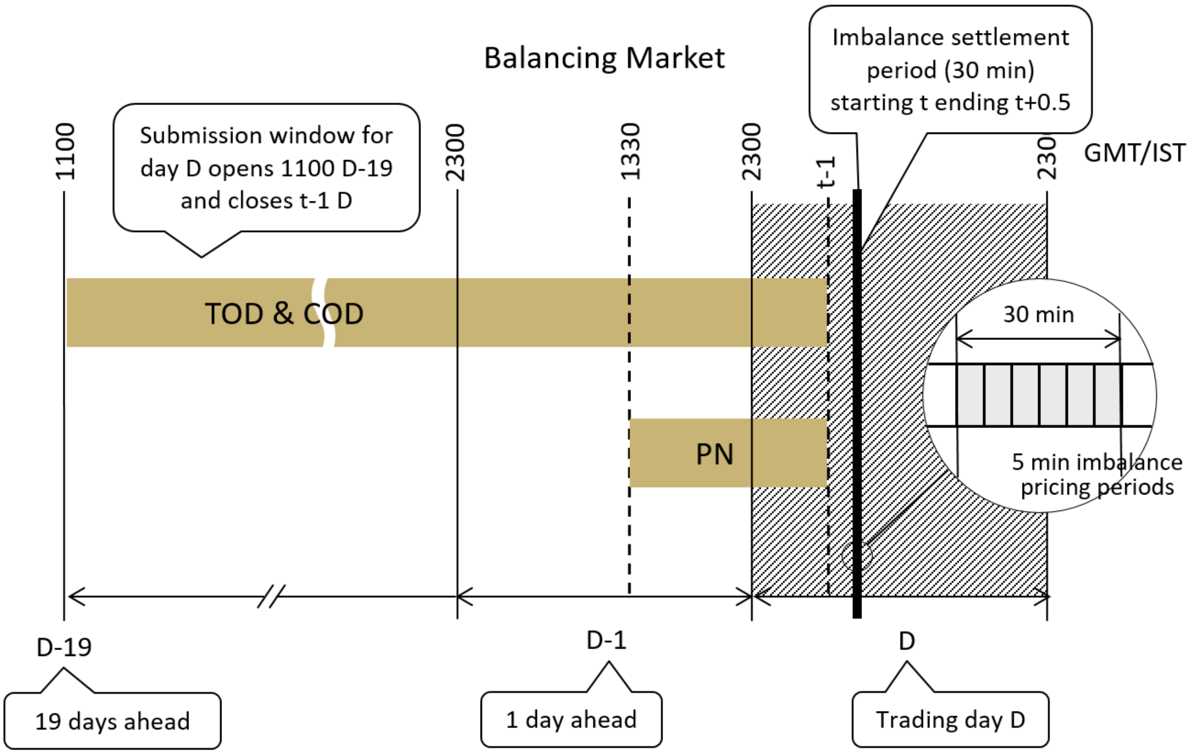

Figure 7 Balancing Market timeline

4.5.6 Data submissions

Participants provide the market operator and TSOs with physical, technical, and commercial data for each 30-minute imbalance settlement period, as described in the following sections and summarised in Table 5.

Table 4 Market data requirements

Unit	Physical Notification (PN)	Technical Offer Data (TOD)	Commercial Offer Data (COD)
Dispatchable generator	●	●	●
Non dispatchable but controllable generator	O	×	×
Non-dispatchable and non-controllable generator	O	×	×
Supplier	O	×	×
Interconnector	×	×	×
Assetless trader	×	×	×
● required O optional × not required			

Default data is converted to daily data on day D-19, which is then overwritten by daily data when or if submitted over the submission window.

4.5.6.1 Physical notifications

Physical notifications (PNs) define the expected output of generator units. A PN should reflect the participant's best estimate of its intended level of generation, taking into consideration the physical capability of plant to changes in operating level. It also reflects a participant’s position in the ex ante (DAM and IDM) markets.

Physical notifications (PNs) provide the TSO with a profile of the expected output of the unit at 1-minute or greater intervals within each imbalance settlement period. The unit is assumed to change output at a constant rate between these data points in accordance with their submitted Technical Offer Data. The TSO validates the profile against the technical capabilities and declared availability of the unit. Commercial offer data (see Section 4.5.6.3) is defined relative to the interpolated profile at the time a dispatch instruction is generated.

Initial PNs are required by 13:30 D-1. At 13:30, the TSO should have PNs for every hour of the next trading day. Participants can update their PNs up to 1 hour before the start of each 30-minute imbalance settlement period. At gate closure, the last-submitted PN becomes the participant’s final physical notification (FPN).

The requirements for participants to submit PNs are:

Dispatchable generators

Dispatchable that have achieved a position in the ex ante markets in the imbalance settlement period must submit physical notifications (PNs). If no PN is submitted, the TSO bases its decision on the available data.

When a dispatchable unit is under test, the PN should reflect the test profile. All test profiles and subsequent updates are subject to approval by the TSO. A test flag is applied to any PN associated with a unit under test so that it can be manually approved. The unit under test is dispatched to its test PN unless, for reasons of system security, it needs to be dispatched differently. If dispatch instructions take the unit away from its test PN, it will be settled at the imbalance settlement price. Uninstructed imbalance charges will apply for any failure to deliver on a dispatch instruction. The same applies to TSO-required tests. Testing tariffs are applied to a unit under test in I-SEM.

Non-dispatchable generators

Non-dispatchable-but-controllable and non-dispatchable-and-non-controllable generators are not required to submit PNs. Instead, the TSO uses energy output forecasts. If a non-dispatchable unit submits a PN (optional), the TSO may use that data instead of deriving its own estimates, but is not required to.

Priority dispatch generators

The requirement for priority dispatch generators to submit PNs is based on whether the unit is dispatchable, as described above.

Interconnectors

Interconnectors do not submit PNs.

Suppliers

Suppliers are not required to submit PNs. The TSO uses its own demand forecasts in scheduling.

Assetless traders

Assetless traders do not submit PNs. The net output from an assetless trader is assumed to be zero.

4.5.6.2 Technical offer data

Technical offer data (TOD) describes the physical characteristics of generator units. This includes, as applicable, information on its capacity, minimum running levels, start-up and shut-down characteristics, ramp limits, and energy limits. This information, which is updated infrequently, is used by the TSO in forming dispatch instructions.

Combined cycle and dual-rated plants, which can be configured in different ways, must hold TODs for each configuration and submit a new TOD each time the configuration changes.

Generators must provide and maintain standing (default) technical data. Generators can submit updated TOD for each imbalance settlement period from D-19 to t-1. If no submission is made during this period, the TSO uses the available standing data.

4.5.6.3 Commercial offer data

Generators and suppliers submit commercial offer data (COD) that defines the costs[27] at which generators are prepared to increase or decrease their output. Offers can be complex or simple (see below).

Generators must provide and maintain standing (default) complex offer data. Generators and suppliers can submit updated COD for each imbalance settlement period from D-19 to t-1. If no submission is made during this period, the TSO uses the available standing data.

Complex offers

Complex offers are used for balancing actions taken before balancing market gate closure. A complex offer comprises:

- a start-up cost (€) for committing a unit;
- a no-load cost (€) for each trading period that the unit is committed;

[27] The application of the SEM Bidding Code of Practice (BCoP), which requires that COD reflects the participant's actual cost of generation, is currently under consideration by the SEMC.

- an incremental offer curve (MWh, €/MWh) for increasing energy supplied at each level of output, and a decremental bid curve (MWh, €/MWh) for decreasing energy supplied at each level of output.

An absolute MW approach is used in interpreting €/MWh costs. Up to ten price-quantity steps can be provided in each incremental and decremental ("inc & dec") cost curve (i.e. potentially up to 20 steps), spanning the full output range, from zero to unit availability.

In the example shown in the Figure 8, a dispatch instruction to increase output from X to Y MWh follows the upper (blue) incremental curve, and an instruction to decrease output from Y to X MWh follows the lower (yellow) decremental curve. This pricing arrangement applies to all types of generator units, including demand-side units and pumped storage units. Example inc & dec curves for a pumped storage unit in pump or generator mode are shown in Figure 9.

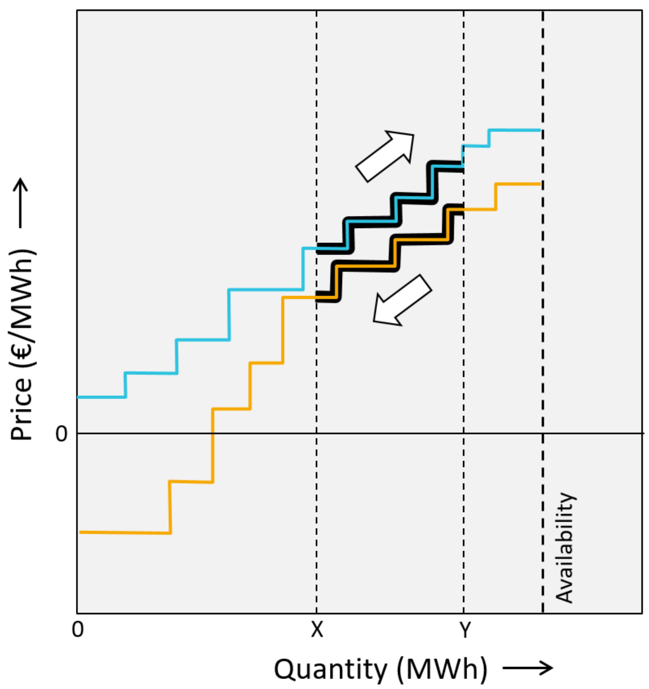

Figure 8 Incremental offer and decremental bid curves, generator unit

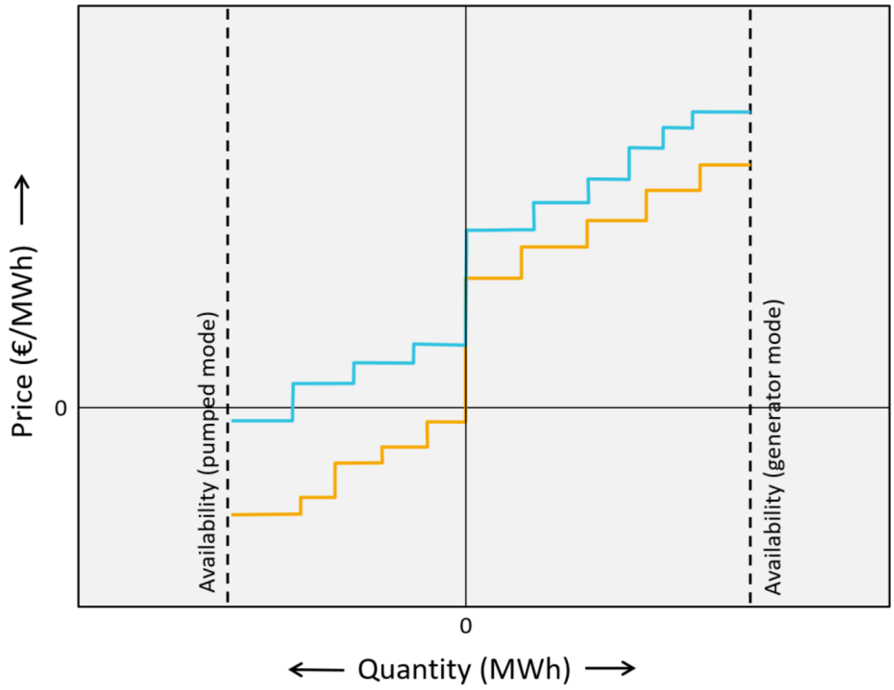

Figure 9 Incremental offer and decremental bid curves, pumped storage unit

If a complex offer has not been submitted by the time a dispatch instruction must be issued, the standing complex offer is used. If the dispatch instruction is issued prior to balancing market gate closure, then the price of that action is fixed to the complex offer that was held by the TSO at that time.

Simple offers

Simple offers are used for balancing actions taken after balancing market gate closure. A simple offer comprises only the inc & dec curves, as described for complex offers—that is, without start-up and no-load costs. The quantity-price steps in a simple offer can, however, be different from the steps in a complex offer.

If a simple offer has not been submitted by the time a dispatch instruction must be issued, then the curves in the complex offer are used (there is no standing simple offer) or, if a complex offer is not available, the standing complex offer is used.

4.5.6.4 Other data

Other data required for balancing and settlement includes:

Ex ante schedules

The NEMOs submit trade data from the DAM and IDM to SEMO to support settlement.

Interconnectors

Interconnector owners submit operating data to the TSOs, which are inputs to the Interconnector Reference Program. The Interconnector Reference Program is maintained by the TSO based on day-ahead and intraday market data provided by NEMOs that gives visibility on the current expected flows of interconnectors.

Unit availability

Generators submit their expected unit availabilities to the TSOs (maximum availability, minimum stable generation and minimum output) two days ahead and update forecasts if they change. Generators submit changes to forecast unit availabilities in real time.

4.5.7 System security and balancing actions

The TSOs are responsible for the safe, secure and reliable operation of the power system as well as an obligation to maximise priority dispatch generation whilst minimising the cost of deviation from participant PNs. Security requirements include ensuring the supply is equal to the demand, there is sufficient reserves available at all times, and the power system is stable at all times.

If the generator FPNs do not balance against the forecast demand, the TSO dispatches bids or offers to either increase or decrease generation or demand to restore the energy balance. The TSO may need to dispatch a unit away from its PN for other system reasons including managing of transmission constraints or to provide system services. If required, the TSO can also vary the interconnector flow by arranging a cross-border trade with the neighbouring TSO.

4.5.7.1 Actions taken before BM gate closure

Before BM gate closure (13:30 D-1 to t-1), the TSOs identify if the commitment of units needs to be changed for system security reasons. If needed, the TSOs issue indicative operational schedules to change the commitment of units for system security reasons, choosing the least-cost solution for the deviation based on generator COD. Indicative operational schedules to change the commitment of units are non-binding and reversible until the latest time that the unit’s operator can be notified to start.

Before BM gate closure, the TSO uses the Security Constrained Unit Commitment (SCUC) tool to make commitment decisions. SCUC runs in two modes: Long Term Scheduling (LTS) and Real Time Commitment (RTC). In LTS, runs occur every 4 hours for the period 4 hours ahead at a half-hour resolution over an optimisation horizon of up to 48 hours. In the last hour, RTC is used to make commitment decisions. In RTC, runs occur every 15 minutes for the period 30 minutes ahead at a 15 minute resolution over an optimisation horizon of up to 3.5 hours.

SCUC uses complex (three-part) offers to ensure that the unit commitment is capable of delivering a secure schedule. Although PNs and generation forecasts generally do not exactly match forecast demand, the SCUC ensures that there is sufficient capacity committed to resolve any imbalance and to ensure all system constraints are observed.

The inputs to each LTS and RTC run include the latest:

- Physical notifications (PNs)
- TSO wind forecast
- Generator availability
- Interconnector schedules
- Complex offers
- TSO demand forecast
- Security constraints

Early actions

One of the I-SEM objectives is that the day-ahead and intraday markets should be the primary mechanisms by which the energy supply-demand balance is resolved. If the market finds a balanced energy position through the ex ante markets, the need for TSO energy actions will be minimised. However, if the market is not balanced, there is a risk that the proposed approach could result in “early” actions that could dilute the signals to market participants or appear to impact on the intraday market.

For example, a large imbalance indicated by the initial PNs may suggest the need for the TSO to start up additional generating plant. If generator units with long-notice times offer the lowest cost option in rebalancing the system, such decisions need to be taken well before gate closure. However, this could pre-empt potential trading activity in the intraday market or lead to suboptimal outcomes if the supply-demand balance subsequently changes prior to real-time dispatch.

To overcome this problem, weighting factors are applied to the unit start-up costs, which reduces the attractiveness of starting up long-notice units in preference to shorter notice units. If the scheduler has no choice but to start a long-notice unit to satisfy a security constraint, then it will do so. However, given a choice of a number of resources with the same (or similar) cost, the scheduler will tend to favour shorter notice resources in the scheduling process.

4.5.7.2 Actions taken after BM gate closure

From t-1 into real time, the TSOs continuously issue dispatch instructions both to maintain system security and to keep supply and demand in balance, choosing the least cost solution for the deviation based on generator and supplier COD.

After BM gate closure, the TSO uses the Security Constrained Economic Dispatch (SCED) tool to produce balancing and security actions for given a unit commitment to. SCED does not change the commitment of units: SCUC in RTC mode (see Section 4.5.7.1) is also used in this time frame to make unit commitment decisions. The output from SCED forms the real-time dispatch instructions.

Inputs to SCED runs are the latest:

- Final physical notifications (FPNs)
- TSO wind forecast
- Real-time unit commitment
- Generator availability
- Interconnector schedules
- Simple offers and bids
- TSO demand forecast
- Security constraints

4.5.8 Bid offer acceptances

Dispatch instructions comprise an instruction from the TSO to a participant to change the output of a unit and to stay at that level until further notice or until a set time. The SCED process creates a dispatch profile, which is an estimate of the unit's output. The area between the dispatch profile and the FPN represents the accepted quantity of a bid or an offer.

Referring to Figure 10, the blue line shows the FPN over the scheduling period and the red line shows the dispatch profile for the same time period. The horizontal bands are the bid and offer steps defined by the COD. When the dispatch profile is above the FPN, an offer acceptance is generated for each offer step. Similarly, when the dispatch profile is below the FPN, then a bid acceptance is generated for each bid step. This quantity is then matched with the incremental offer curve (for an increase) or the decremental offer curve (for a decrease) to identify the bid offer acceptance (BOA) and the associated MWh quantity (QBOA) and bid or offer price. The QBOA and associated step prices for a scheduling period are determined by integrating the acceptances across each step.

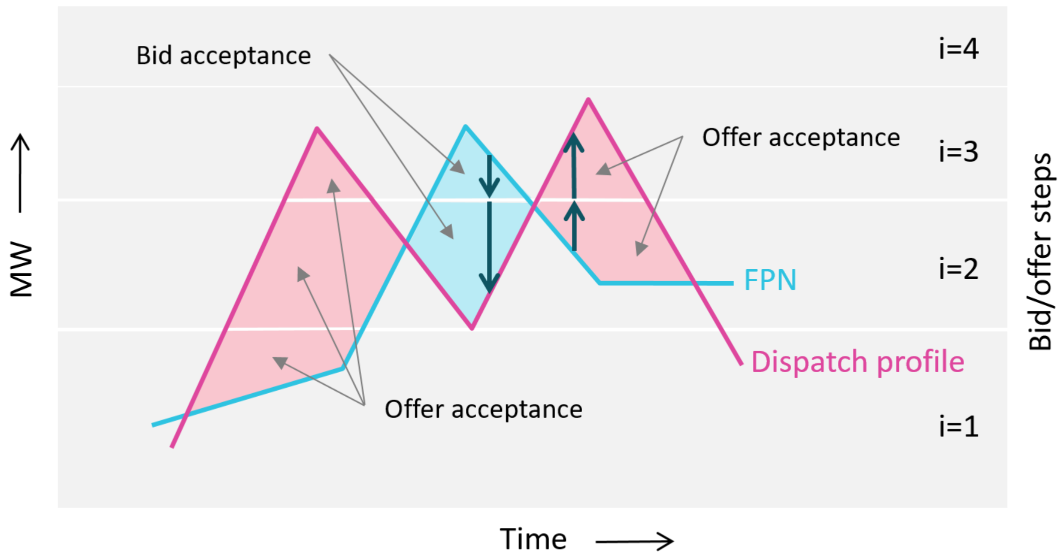

Figure 10 Bid and offer acceptance

Referring again to Figure 10, the black arrows show BOAs at two instances of time within the scheduling period, where the arrow lengths indicate the MW quantity and the associated incremental offer price and a decremental bid price. The bid and offer acceptances (QBOA and price) are represented by the intersected areas, as shown.

There can be multiple BOAs associated with a single step, reflecting dispatch instructions at different times. For example, if a unit is scheduled up, then scheduled down, and then later scheduled up again, all for the same scheduling interval, there will be two offer BOAs and one bid BOA for a that unit in that time interval. And if the dispatch instructions were issued prior to the balancing market gate closure, the incremental bid and offer prices could also have been updated between dispatch instructions.

4.5.9 Settlement

4.5.9.1 Actions taken before or after BM gate closure

The commitment of a unit resulting from an action taken before BM gate closure (see Section 4.5.7.1) is settled based on the generator's complex offer data. Additional compensation is paid or recovered if, over the continuous run time of the unit, the unit fails to recover or pay back additional fixed costs incurred or saved because the dispatch instructions were different to the unit's FPN.

Energy actions taken after BM gate closure (see Section 4.5.7.2) are settled based on the generator's simple offer data, and non-energy actions taken after BM gate closure are settled based on the generator's complex offer data.

4.5.9.2 Prices

The prices calculated or used for settlement of the BM can include:

Imbalance price

Although not used directly in settlement of the BM, the imbalance prices for each 5-minute imbalance pricing period are used to calculate the imbalance settlement price (see below) for each 30-minute imbalance settlement period.

A rules-based, flagging-and-tagging process is used to determine the initial imbalance price in each 5-minute imbalance pricing period. The flagging-and-tagging process prevents bids and offers that are scheduled due to system constraint or where units are operating at a unit constraint from influencing the imbalance price. The flagging-and-tagging process is described in Appendix A, including a worked example of how the initial imbalance price is determined for a set of BOAs.

The imbalance price of an imbalance pricing period is the greater of the initial imbalance price and the administered scarcity price (see below).

Imbalance settlement price

The imbalance settlement price for a 30-minute imbalance settlement period is the average of the six imbalance prices for the 5-minute imbalance pricing periods.

Bid offer price

The price as bid or offered in the COD.

Curtailment price

If a wind unit is constrained due to local issues, it is compensated based on the decremental bid curve, but if the curtailment is system-wide (too much wind on the system), curtailed units are compensated at a curtailment price determined for each unit based on their undelivered day-ahead market commitments.

Administered scarcity price

The administered scarcity price (ASP) may be applied during periods of depleted operating reserve if the operating reserve cannot be restored within one hour. The ASP increases in response to the depletion of the operating reserve, ranging from the capacity strike price (see Section 4.6) up to the EUPHEMIA day-ahead price cap[28].

Information imbalance price

Initially set at zero. For more information, see information imbalance charge in Section 4.5.9.3.

4.5.9.3 Quantities

Quantities calculated or used for settlement of the BM can include:

- **Metered quantities**—the actual quantities delivered.
- **Ex ante quantities**—the traded position in the ex ante markets.
- **Bid offer acceptance quantities**—these quantities are described in Section 4.5.8 and are calculated for each 5-minute imbalance pricing period for pricing purposes, and 30-minute imbalance settlement period for settlement purposes.
- **Biased quantities**—these arise when the ex ante quantity needs to be adjusted due to the position of the FPN.
- **Trade in opposite direction quantities**—these arise during the overlap of the IDM and BM if a participant changes its FPN in the opposite direction to a BM action that has already been accepted.
- **Non-firm access quantities**—these arise from bids being accepted on a unit whose FPN is above their firm access quantity.

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[28] This arrangement will apply throughout the I-SEM transition period to the commencement of the first T-4 capacity year. After that, the full ASP will be based on the system VoLL.

- **Undelivered quantities**—these arise from the metered quantity of the unit not being sufficient to have delivered accepted BM actions.
- **Accepted offers/bids below/above the physical notification**—these arise when a dispatch instruction is issued in one direction, and then another is issued in the opposite direction.
- **Curtailed quantities**—these arise when a unit is curtailed.

4.5.9.4 Payments and charges

The payments and charges that arise from balancing depend on the volume and nature of the imbalance, the COD submitted, the status of the generating unit, the available metering data, and other data.

Any imbalance which is not due to a balancing action is settled at the imbalance settlement price. And any imbalance which is due to a balancing action is settled at the better of the imbalance settlement price and the bid offer price. The difference between the ex ante quantity and the metered quantity (which covers all imbalances and all delivered, non-biased balancing actions) is settled first (at the imbalance settlement price), and then a premium (for offers with a higher price) or discount (for bids with a lower price) is calculated for other quantities.

The balancing settlement components are outlined in Table 5. For a complete definition, refer to the TSC.

Table 5 Balancing settlement components

Settlement component	Description
Imbalance Payments and Charges	The actual generation or consumption position (metered quantity) less the traded position (ex ante quantity) is settled at the imbalance settlement price.
Premium Payments	Paid when an offer is scheduled in balancing (and delivered) at an offer price above the imbalance settlement price.
Discount Payments	Paid when a bid is scheduled in balancing (and delivered) at a bid price below the imbalance settlement price.
Above and below physical notification payments and charges	Adjustment payment or charge when a dispatch instruction is issued in one direction, and then another is issued in the opposite direction. The reversed quantity is settled at the imbalance settlement price.

Settlement component	Description
Uninstructed Imbalance Charges	Charges for imbalances, and bids and offers accepted in balancing but not delivered, which were outside of a tolerance. Undelivered quantities are settled at the imbalance settlement price.
Curtailment Payments and Charges	Adjustment payment or charge to result in net settlement at a specific curtailment price for curtailment actions on generators.
Bid Price Only and Offer Price Only Payments and Charges	Adjustment payment or charge to result in net settlement at the offer price for incs, or bid price for decs, for undo actions on generators.
Fixed Cost Payments and Charges	Payments for additional fixed costs incurred, or charges for fixed costs saved from dispatching a unit differently to its market position, if not sufficiently covered through the unit's other payments or charges.
Imperfection Charges	Charges to fund balancing market payments.
Testing Charges	Charges applied to units under test.
Residual Error Volume Charges	Charges to recover the costs arising from differences between loss adjusted metered generation and metered demand.
Currency Adjustment Charges	Charges related to settling in two currencies.
Information Imbalance Charges	Charges for significant deviations between PNs, submitted during the trading day, and FPNs (initially zero charge).

4.5.9.5 Billing period

The BM is settled weekly. Settlement documents reflect balancing transactions and imbalance settlement in that billing period. The settlement for each billing week is rerun after four months and again after 13 months to account for improved metering data.

Note. Monthly capacity payments and charges are included on the first scheduled billing run after the end of the month. For information on capacity settlement components, see Section 4.6.15.

4.6 Capacity Market

4.6.1 Function

The Capacity Market (CM) replaces the current SEM Capacity Payments Mechanism (CPM). In the CM, capacity providers sell qualified capacity (see Section 4.6.8) to the market based on the generation capacity required in a future capacity year. Capacity providers who are successful in the CM receive a regular capacity payment that assists with funding generation capacity and, in return, they have an obligation to generate when the system is stressed. The duration of the obligation over which capacity payments are made is normally 12 months, but terms of up to 10 years may be available on new units requiring significant investment.

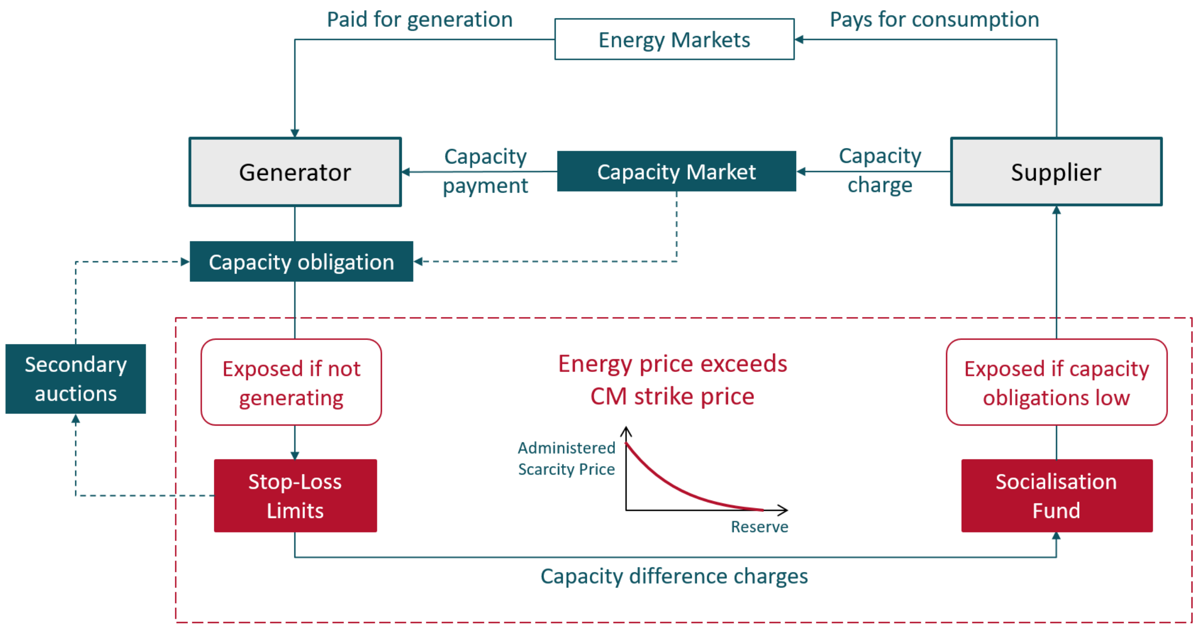

Figure 11 Overview of the Capacity Market

The cost of the CM is funded by suppliers. In return, suppliers are protected against high energy prices. This hedge is dependent on a strike price, which is set by a formula which considers prices of fuels, unit efficiency and DSU running costs. When energy prices exceed the strike price (Figure 12) the market pays the suppliers the difference between the energy price and the strike price. This limits the exposure of suppliers to the strike price. This process is applied to each of the DAM, IDM and BM.

To fund this arrangement, generators must pay difference charges for capacity not delivered based on the difference between the strike price and a reference price. The reference price is a derived price that reflects the price at which the capacity provider traded in the DAM, IDM and BM. If the reference price exceeds the strike price, the capacity provider pays a difference charge for the relevant volume.

Demand-side units (DSUs) and interconnectors have different treatment to other participants in capacity difference charges.[29].

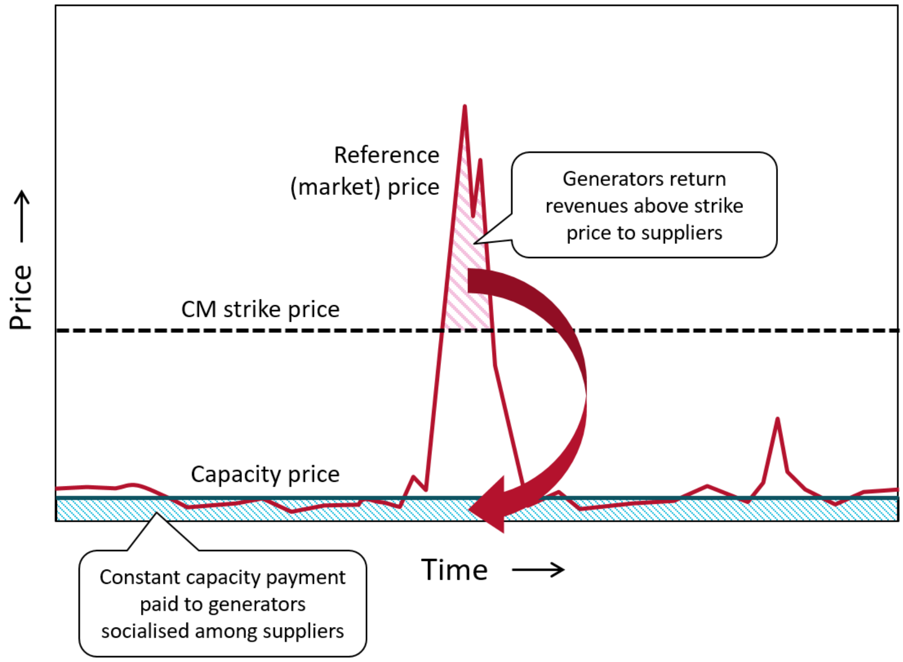

Figure 12 Capacity difference charges

Capacity providers are expected to provide energy at times of system stress, defined as times when the imbalance settlement price exceeds the strike price. The capacity provider meets this obligation by being contracted in the DAM or IDM or scheduled in the BM (even if subsequently traded or scheduled to a lower level).

Capacity providers are most exposed to the strike price if they fail to maintain adequate availability during periods of peak demand. They therefore have a strong incentive to be on at times that the reference price goes above the strike price because they must pay capacity difference charges whether they are scheduled on or not.

At times of low demand, there is more capacity available than is required, and the hedging needs of suppliers are reduced. Consequently, the capacity requirement used in settlement is reduced, which reduces the difference charges. This provides an opportunity for capacity providers that want to maintain equipment to procure spare capacity from other generators to cover their obligations during the period their capacity is unavailable. The secondary trade of capacity is discussed later.

The processes involved in operating the CM are outlined in Figure 13 and further described in the following sections.

[29] Provided they respond as expected to dispatch instructions.

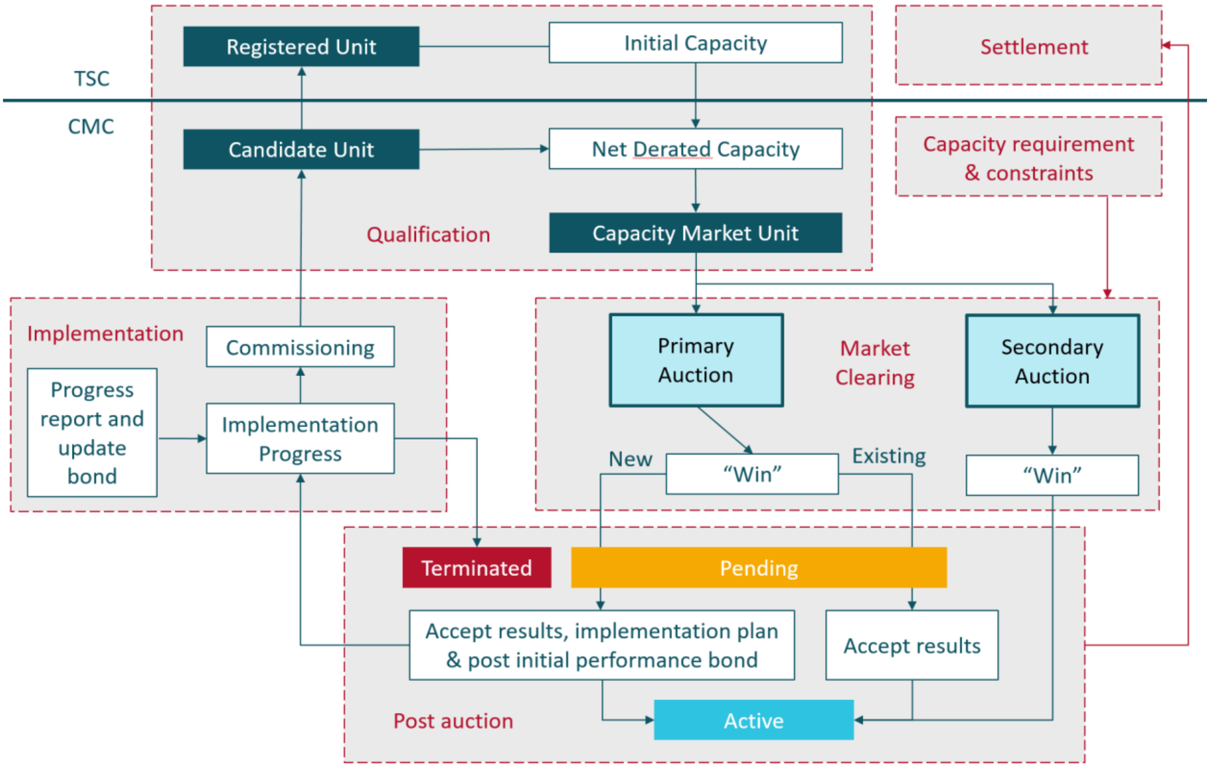

Figure 13 Capacity Market processes

4.6.2 Relevant codes

The operation of the CM and the roles and responsibilities of the market operator and participants are governed by the following codes:

- *Capacity Market Code* (CMC)
- *Trading and Settlement Code* (TSC)

For further information, refer to Section 2.5.

4.6.3 Market operation

The responsibilities for market operation are split between the TSOs and SEMO. As System Operators[30] under the CMC, the TSOs are responsible for:

- Registration of participants.
- Supporting the RAs' determination of the capacity requirement for a capacity year (the amount to be auctioned based on a pre-defined security standard).
- Determining local capacity constraints for each auction.

[30] The rules and licenses a System Operators are referred to as the Transmission System Operators (TSOs), but

- Conducting the qualification process to establish the capacity that a provider can offer in an auction.
- Scheduling and running capacity auctions.
- Market systems operation and providing access to market data.
- Maintaining a registry of primary and secondary capacity trades.
- Monitoring the development / construction process of new capacity procured through the CM.
- Providing settlement data to SEMO.
- Regulatory reporting.
- Maintaining the *Capacity Market Code* for approval by the SEM Committee.

And as Market Operator under the TSC, SEMO is responsible for:

- Settlement of capacity payments and charges and capacity difference charges.
- Credit risk management.

4.6.4 Participation

Participants are required to accede to the CMC, including all suppliers (even though they do not trade in the market), most generators (generators below the de minimis threshold can elect not to accede), and all interconnectors.

Participation is limited to capacity providers in the island of Ireland.[31] All existing interconnectors and dispatchable or non-dispatchable-but-controllable generator units that are required to register for the BM must apply to be qualified to participate in capacity auctions for each capacity year. Any new capacity must hold a connection offer before participating in the qualification process.

Participation by generators below the de minimis threshold, variable units above the de minimis threshold, uncommissioned new units, and units that plan to close before the end of the capacity year is voluntary.

Participation in the CM is via a capacity market unit (CMU). Each interconnector and, typically, each generator is represented as one CMU. Generators below the de minimis threshold and variable units can be aggregated into a single CMU. The CMU must be registered to the same participant as the generator unit or interconnector.

[31] Resources located outside of the island of Ireland may be allowed in the future to participate in the CM with improved pan-European balancing arrangements.

4.6.5 Market timeline

Capacity market auctions are run for a specified capacity year. The timelines for each auction are developed by the System Operators and approved by the RAs. This takes into account processes for setting capacity requirements and local constraints, unit qualification, and running the auction and post-auction processes. As such, participants are notified when the timing for each auction has been set by the TSOs.

Capacity year

The capacity year commences at the start of the trading day on 30 September and ends at the end of the trading day on 30 September in the following year. The length of the first capacity “year”, however, may be longer to accommodate the market start date.

Transitional arrangement

Transitional one-year-ahead primary capacity auctions (T-1) will be run for the first three years of operation of the I-SEM. Secondary capacity auctions will be run at regular intervals up to the start of each capacity year.

Enduring arrangement

Primary capacity auctions will be run four years ahead (T-4) of each capacity year and T-1 auctions will be held just before the start of the capacity year. The first T-4 auction will be run in 2018 for the capacity year ending 30 September 2022. Additional auctions may be run if required—for example, if a new capacity project is cancelled.

4.6.6 Capacity zone

There is one capacity zone for the island of Ireland—that is, all capacity providers participate in the same auctions, and the same mechanism for capacity payments and capacity difference charges applies to all providers.

4.6.7 Capacity requirement and local constraints

The RAs are responsible, supported by the TSOs, for determining the system-wide capacity required in each auction. The requirement is set to maintain a system-wide 8-hour loss-of-load expectation (LOLE) per capacity year, based on historical demand and derated capacity.

The TSOs also determine local capacity constraints for each auction. This ensures that sufficient capacity is procured in geographical regions where supply into the region is restricted due to transmission or operational constraints. Constraints can be nested within another constraint, as illustrated in the hypothetical example in Figure 14.

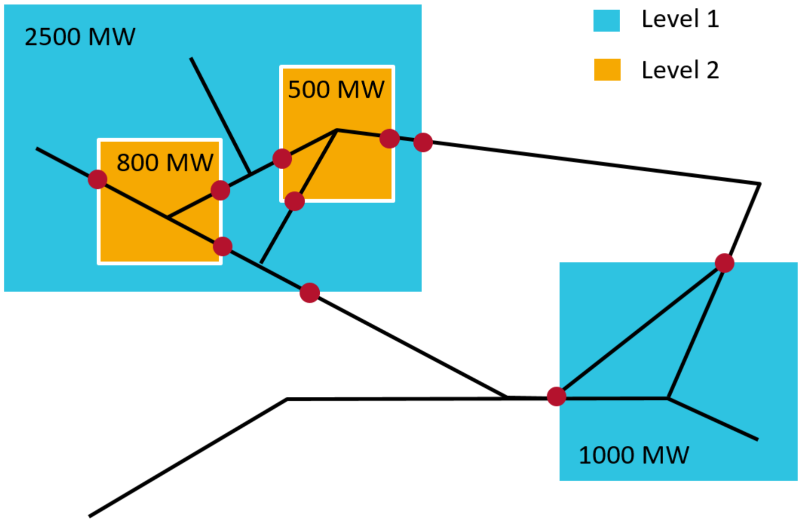

Figure 14 Nested local capacity constraints (illustration only)

The RAs produce a demand curve for each auction, which is used in conjunction with local capacity constraints (if imposed by the RAs) for clearing offers of qualified capacity. The shape of the demand curve will account for any capacity that exists but is not required to participate in the auction.

4.6.8 Qualified capacity

The installed capacity or maximum output of a unit is not always available due to outages and temperature-dependent derating and energy limits. Consequently, capacity offered into the auction is the derated capacity, which reflects the statistical availability of a unit and locational constraints that might cause a unit to be constrained on. This qualification process ensures that there is spare capacity to address outages and lack of availability.

Qualification assesses information on physical units proposed as Capacity Market Units (CMUs)—called candidate units—which may be existing or proposed. Typically there is a one-to-one relationship between a candidate unit and a CMU, but variable and small candidate units can be aggregated into one CMU.

Qualification is performed for each capacity auction. For each CMU, the qualification process confirms or determines:

- The candidate unit or units that form the CMU.
- Whether the capacity provided by each candidate unit is existing, new, or a combination of both (augmented).
- The initial capacity of an existing or augmented candidate unit—the registered capacity.
- The gross derated capacity of an existing, new or augmented candidate unit—the capacity after derating has been applied.

- The net derated capacity of an existing or new unit—after allowing for capacity awarded in previous auctions for the same capacity year.
- Whether the CMU is clean technology.
- Which local capacity constraints the CMU contributes to (if any).
- The firm offer requirement—the minimum quantity that must be offered into an auction.
- The maximum capacity duration of existing and new CMUs—between 1 and 10 years.
- The implementation plan for developing new capacity.
- The price cap on offer steps.

Generator and demand-side units are qualified by the TSOs using derating curves provided by the RAs. For new generator units, derating is estimated from the known performance of similar technology. Interconnectors are also qualified by the TSOs using derating curves and availability factors provided by the RAs.

Note. The performance of a generator in meeting its capacity obligation is assessed on the generator’s maximum energy position, whereas the performance of an interconnector is assessed on its availability (see Section 4.6.11).

Capacity providers are permitted to adjust their deratings within limits. Specifically, wind units can nominate a lower derating, and units with deratings above their firm capacity can be lowered to their level of firm capacity.

Prior to the qualification process starting, a capacity auction information pack is released, which provides information about the timetable and various auction parameters, such as the local capacity constraints, expected demand curve, exchange rates, etc. Some of this data is updated just prior to the auction as the “final auction parameters”. Note that the exchange rate for investment in Northern Ireland is fixed for the duration of the obligation.

The qualification process starts with the participant submitting an application to qualify a CMU for an auction. The application provides the details of the candidate units or aggregated candidate units that are to be combined into a CMU. For each candidate unit, the applicant includes the initial (before derating) capacity of existing and any new capacity. Applications for new capacity must also include an implementation plan, which specifies milestones for securing finance, commencing construction, and commissioning the capacity. If a participant provides incorrect data, the System Operators are empowered by the CMC to correct the data.

As illustrated in Figure 15, the gross derated capacity for a candidate unit is derived by applying derating curves appropriate to the technology of these initial capacities. Different derating factors are applied to the existing capacity and the total (including the new) capacity. These values are aggregated for all candidate units contributing to a CMU. Capacity already awarded in previous auctions is then deducted to derive the net derated capacity of the CMU.

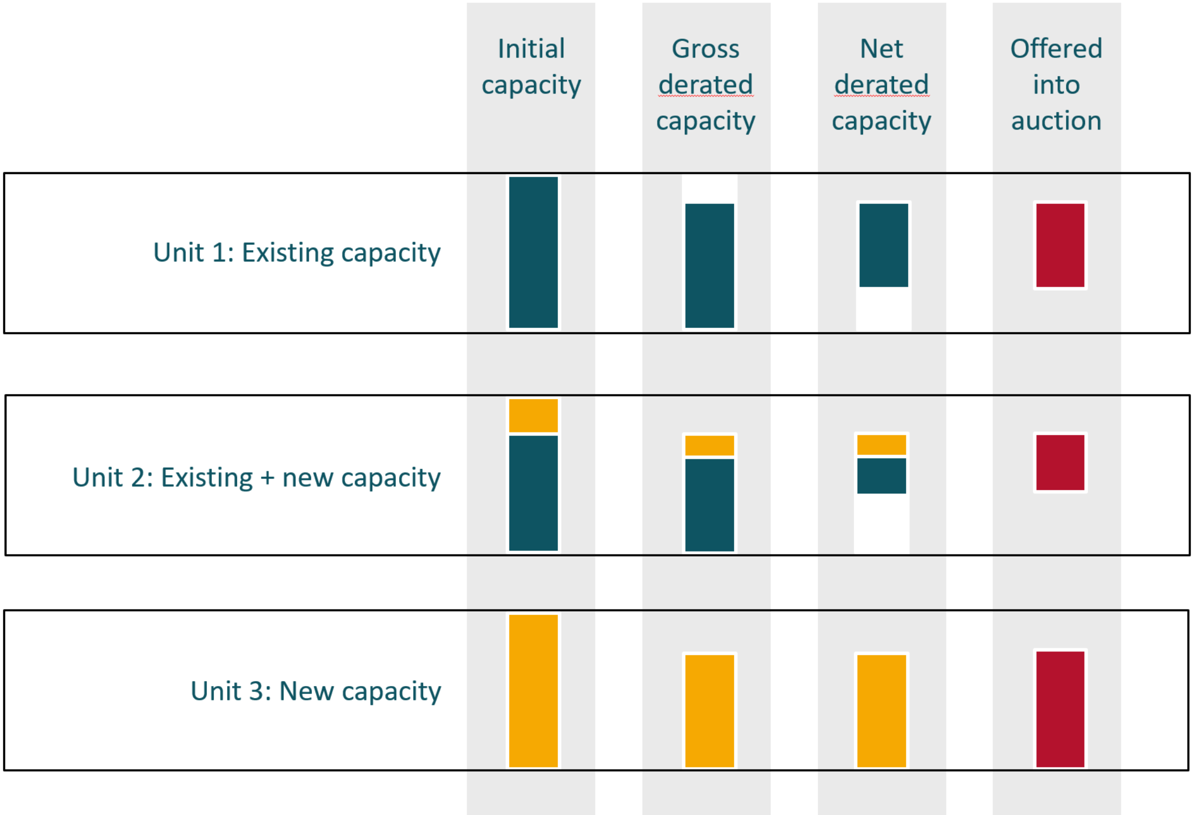

Figure 15 Capacity qualification process

Qualification determines a number of other parameters, including the maximum price at which existing and new capacity can be offered into the auction, the maximum quantity of capacity that can be offered into the auction (reflecting the firm access), and the maximum duration of the capacity. Note that:

- In special cases and with RA approval, higher price caps can be set for existing capacity where the CMU has unusually high costs either in providing capacity or in reducing demand (e.g. an autoproducer).
- All existing capacity has a maximum duration of one capacity year. The duration of new capacity is also one year, but, with RA approval, the duration of higher cost capacity can be extended to a maximum duration of 10 years.
- With the RA approval, the qualification of a CMU that qualifies for a particular capacity year can be extended backwards (into the previous year) where the unit is commissioned before the start of that capacity year. Similarly, the qualification can be extended forwards (into the next capacity year) where a unit is closing in the next capacity year. This allows the unit to participate in secondary auctions for these extended periods but not in the primary auctions.

Provisional qualification results are approved by the RAs and released to participants. Participants can request a review or dispute the results before they are finalised by the RAs.

4.6.9 Submission of offers

Participants must offer into the capacity auction up to the lesser of their net derated capacity and their firm offer requirement.

Capacity providers submit offers to the Systems Operator. Each offer represents one CMU. An offer can have up to five steps. If the CMU comprises both existing and new capacity, the maximum number of steps is still five. Offer steps must not exceed the price caps on existing and new capacity. And the lowest price offer for new capacity must be greater than the highest price offer for existing capacity.

An offer step can be flexible (between 0 and the offered quantity can clear) or inflexible (either 0 or the offered quantity can clear). An offer can consist of both flexible and inflexible steps, but if any step is flexible, then all higher priced steps must be flexible.

Each offer step includes the duration of the capacity. If the maximum capacity duration of the capacity associated with that step is 1 year, the duration of the offer step must be 1 year. If the maximum capacity duration of the capacity associated with the step is 10 years, the duration of the offer step can be any value between 1 year and 10 years. A CMU with both existing and new capacity could have some steps with a duration of 1 year and others with longer durations.

An example offer is shown in Figure 16 for a CMU with existing capacity and two stages of new capacity, where the first stage is below the investment threshold (1 year duration) and the second stage is above the threshold (approved in qualification for up to 10 years).

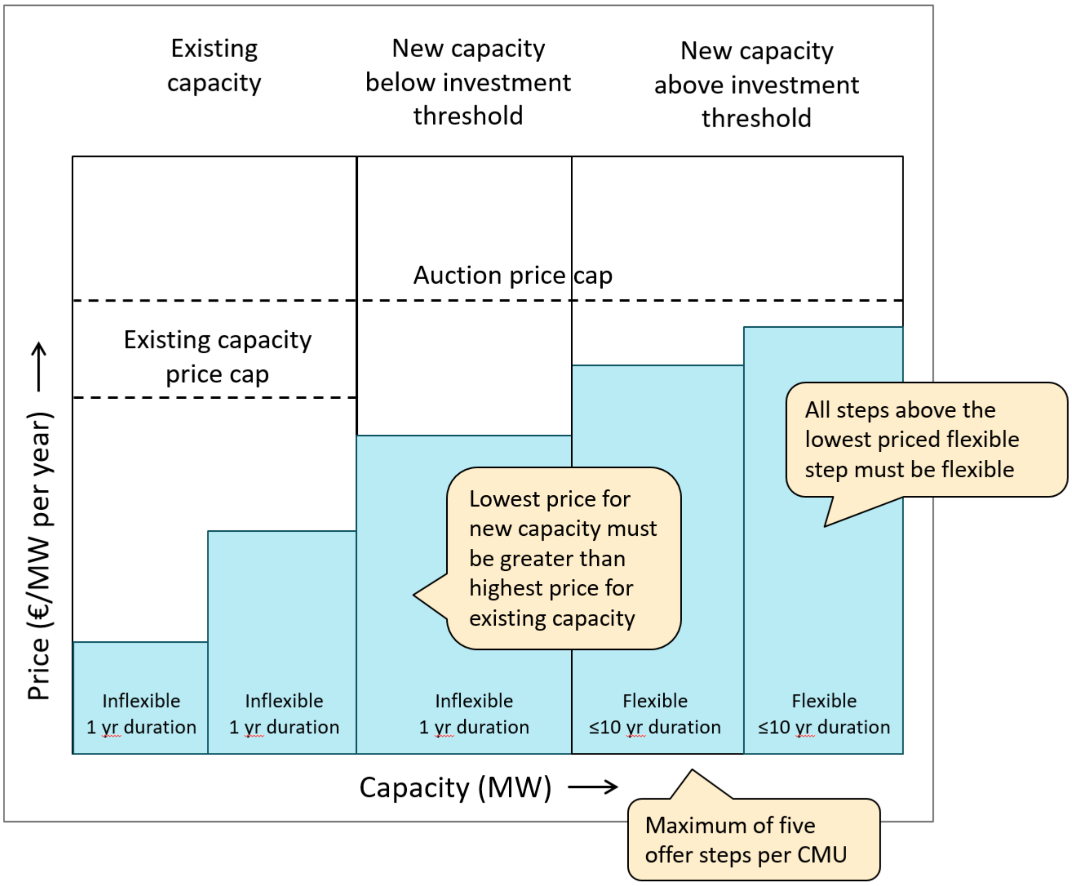

Figure 16 Capacity offer steps for existing capacity with two stages of new capacity

4.6.10 Market clearing (primary auction)

The primary auction uses a demand curve reflecting the value of capacity to the system, locational capacity constraints (Section 4.6.7), and offers of qualified capacity (Sections 4.6.8 and 4.6.9). This auction is solved in two stages. First an unconstrained auction is solved, which determines the auction clearing price, and then a constrained auction is solved, which determines which offers are cleared.

Unconstrained auction

The unconstrained auction is solved ignoring inflexibility and without local capacity constraints to determine a clearing price. As shown in Figure 17, the auction clearing price is the price of the last offer scheduled at the intersection of the demand and offer curves. The maximum price that the auction can clear at is the auction price cap.

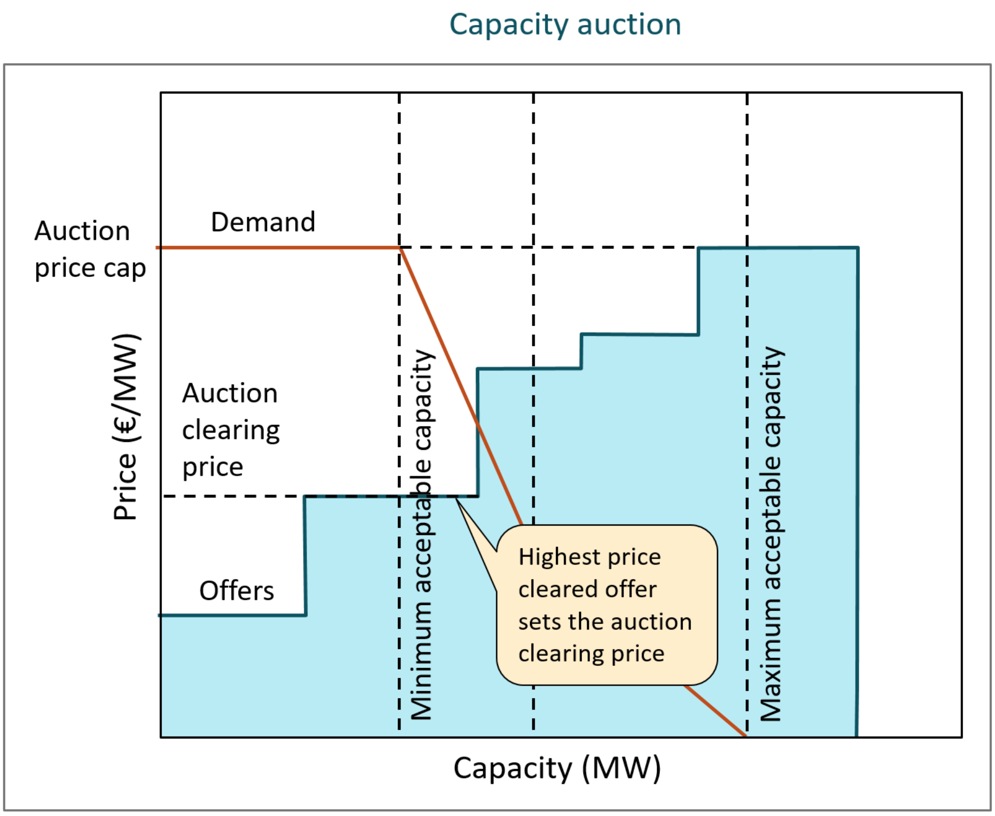

Figure 17 Setting the auction clearing price

Tied offers are scheduled in the following order:

1. Clean technology units (as determined in qualification)
2. The unit that provides the greatest net social welfare (see below)
3. The unit with the shortest duration
4. Other offers

The last offer scheduled is called the price setting offer. Although the unconstrained market generally just sets the auction price, during the transitional period, all scheduled offers, except the price setting offer if it is partially scheduled and inflexible, will be automatically cleared in the constrained auction. Hence it is important how ties are broken between inflexible and flexible offers at the same price.

It is the net social welfare step that differentiates between inflexible and flexible tied offers. If there are three steps at the same price, then each step is assessed for its contribution to net social welfare. As illustrated in Figure 18, for a flexible unit, the net social welfare is determined by allowing the step to be partially scheduled. For an inflexible unit, the net social welfare is determined by fully accepting the step and not accepting it. After clearing a tied offer on the net social welfare criterion, the remaining tied offers are assessed again. If the remaining tied offers cannot be separated on net social welfare, the duration criterion is applied.

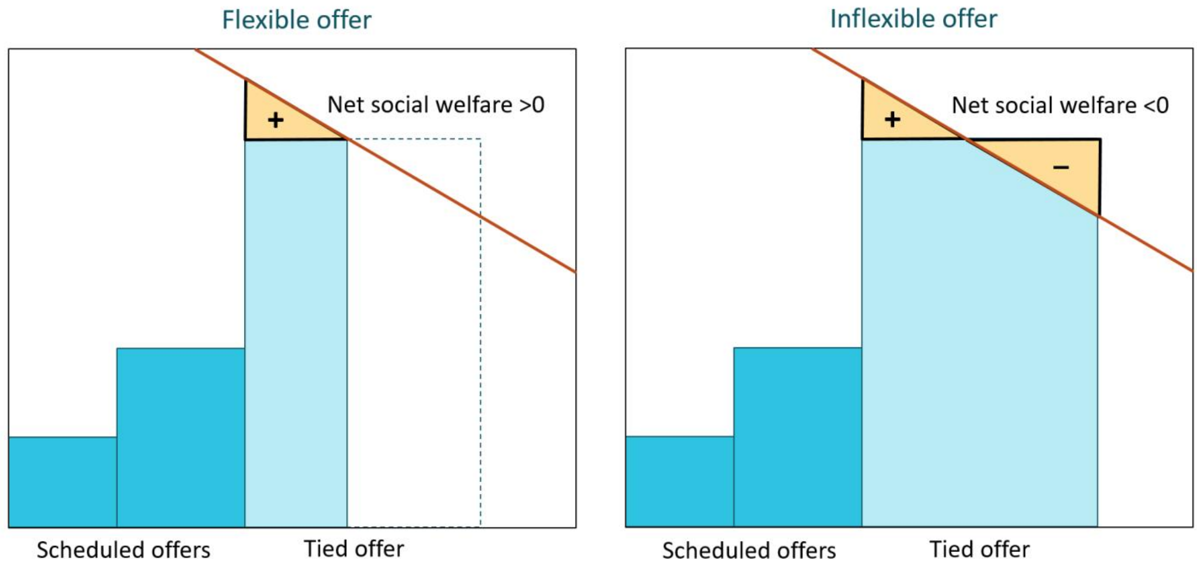

Figure 18 Assessing net social welfare of a tied offer

Constrained auction

After setting the auction clearing price, the constrained auction is then solved with the local capacity constraints included. For all auctions run during the transition period, all capacity scheduled in the unconstrained auction will automatically be cleared in the constrained auction, with the exception of the price setting offer if it was a partially scheduled inflexible offer.

Unless exempted by the RAs, the auction excludes any offer steps from new capacity that is offered at a price above the (unconstrained) auction clearing price. This prevents new high-cost capacity being locked in for 10 years because of a local capacity constraint that might be resolved within a year or two. If the RAs allow the inclusion of such offer steps, e.g. because there is not enough existing capacity to satisfy the constraint, then they can only be scheduled after all existing capacity is scheduled.

Due to the complexity of the auction clearing process, for an interim period controlled by the RAs, approximations may be made to allow a simpler solution method to be used, which may not always find the best possible solution.

All cleared offer steps with an offer price at or below the auction clearing price are awarded the cleared capacity at the auction clearing price. All cleared offer steps with an offer price greater than the market clearing price, are awarded the cleared capacity at the offer price of that step.

4.6.11 Post auction and implementation processes

The auction results must be approved by the RAs. Once this is done, the System Operators publish both the qualification results and the auction results, including what price was paid for each cleared offer step. The auction results must then be accepted by the participants. Providers of new capacity awarded in the auction must also accept an implementation plan and post a performance bond.

All trades resulting from the auction are recorded in the Capacity and Trade Register, which provides the information required for settlement.

Developers of new capacity must report to the System Operators on progress at intervals of approximately six months. Based on those reports, the schedule may be modified and (ultimately) awarded capacity can be terminated. The performance bond is then used to offset the cost of securing replacement capacity in a subsequent auction or the cost of socialising the cost of capacity hedges among suppliers if there is no time to run another auction.

4.6.12 Secondary auctions

Secondary auctions allow capacity providers to purchase additional capacity to temporarily offset obligations awarded in a capacity market auction or procured through an earlier secondary auction for the same period. For example, a capacity provider with a unit on an outage can purchase additional capacity from another generator to offset its capacity obligations while the unit is offline.

Capacity providers can only offer existing (commissioned) capacity in a secondary auction, including:

- Capacity awarded in primary auctions.
- Qualified capacity that did not clear in a primary auction.

Secondary trading will be available for discrete periods of time within the capacity year—for example, for peak times during a specific week. Secondary trading for a capacity year commences shortly after the primary auction and the last opportunity to trade may be shortly before real time.

Secondary capacity can be offered up to the nameplate capacity of a unit (beyond the derated capacity). To mitigate the risk of the unit supplying secondary capacity itself having an outage, secondary trades above the derated capacity are limited to 70 days per unit per year.

The trading and use of secondary capacity is monitored to ensure that:

- Secondary capacity is only used for legitimate technical reasons—planned, forced or ambient outages, for example—and not to cover obligations on a decommissioned unit.
- The parties offering secondary capacity into the market are qualified to provide that capacity.

Participants will be consulted by the System Operators on the time frame and products to be offered in secondary trade. The intention is to maintain flexibility to define and change secondary capacity products (capacity year, duration, and delivery period) and set auction times as required to suit the needs of the market.

All trades resulting from the auction are recorded in the Capacity and Trade Register.

Note. If the secondary trading arrangements are not ready for market go-live, as an interim arrangement, the RAs have proposed that, during planned outages, units holding capacity obligations will not receive capacity payments and will not be liable for difference charges.

4.6.13 Performance

The performance of a capacity provider (and its exposure to difference charges) is assessed differently for generators, interconnectors and DSUs, as described below.

Generators

A generator's capacity performance for an imbalance settlement period is measured against the unit's derated capacity (as obligated in the CM) adjusted for actual demand in that period. Performance is assessed on the generator's maximum energy position. There are also provisions for determining the quantity relevant to certain system services, which are also deemed to meet the generator's capacity obligations.

For example, if the total market capacity requirement for the period is 600 MWh but actual demand was 400 MWh and the derated capacity of the generating unit is 90 MWh, then the adjusted capacity requirement for that generator in that trading period is 60 MWh (90 x 400 / 600).

Referring to the example in Figure 19, the delivered capacity in an imbalance settlement period is the maximum energy position (see Section 4.2.3) achieved by the capacity provider for that period in the DAM, IDM and BM. The undelivered capacity is the difference between the adjusted capacity requirement and the delivered capacity for that period. If the energy position equals or exceeds the capacity provider's adjusted capacity requirement, the undelivered capacity is zero and the capacity provider is deemed to have met its capacity obligations.

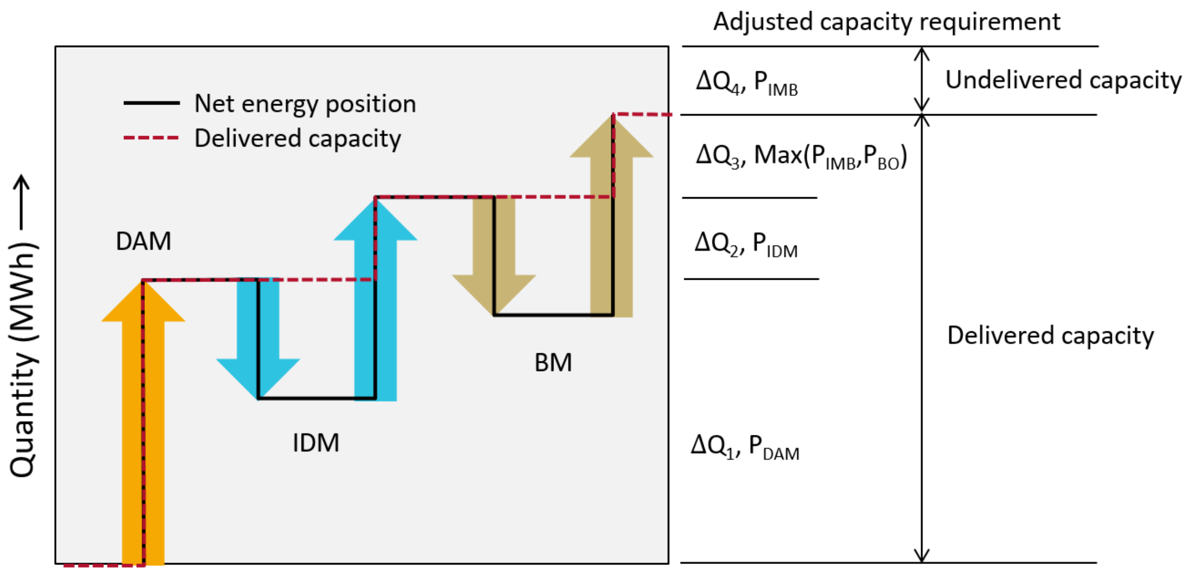

Figure 19 Delivered and undelivered capacity, generators

Interconnectors

An interconnector's capacity performance for a trading period is measured against the derated capacity (as obligated in the CM). Performance is assessed on the interconnector's availability, not the actual flow. For example, if the derated capacity of the interconnector is 240 MWh, availability was 220 MWh, and actual flow (due to market conditions) was 150 MWh, then the interconnector's exposure to capacity difference charges is 20 MWh (240 – 220).

Demand-side units

A DSU's capacity performance for a trading period is measured against the derated capacity (as obligated in the CM). Performance is assessed on the DSU's maximum energy position achieved by the DSU for that period in the DAM, IDM and BM. DSUs are, however, exempt from capacity difference payments provided they respond as expected to dispatch instructions. If a DSU fails to deliver that energy as instructed, then they are liable for difference charges on any undelivered energy.

4.6.14 Prices

Strike price

The strike price is an administratively set price, based on a formula defined in the *Trading and Settlement Code*. The formula uses the greater of the cost of a low-efficiency peaking unit or the cost of a demand-side unit. The strike price is updated monthly as a function of fuel cost and other data.

Reference price

The reference price is the price of trades or actions that caused an increase in the capacity provider's delivered capacity or an increase in the supplier's traded position. As shown in Figure 19, if the capacity provider is scheduled in the DAM, the reference price for the volume of that trade (ΔQ1) is the DAM market price (P_{DAM}). If subsequent trades in the IDM increase the capacity provider's net position, the reference price for the net increase in the IDM (ΔQ2) is the IDM trade price (P_{IDM}). And if the capacity provider is subsequently instructed to increase its output in the BM, the reference price for the net increase in the BM (ΔQ3) is the higher of the imbalance settlement price (P_{IMB}) and the bid offer price (P_{BO}). The reference price for any undelivered capacity (ΔQ4) (charge applies to all capacity providers, including DSUs and interconnectors) or any imbalance (payment applies to suppliers) is the imbalance settlement price (P_{IMB}).

4.6.15 Settlement

Capacity Market settlement can include:

- Payment to capacity provider for awarded capacity (primary or secondary auction).
- Charge on capacity provider for buying awarded capacity (secondary auction).
- Difference charges on providers of capacity when reference price exceeds strike price.

- Difference payments to suppliers when reference price exceeds strike price.
- Charge on supplier to cover the cost of the (net) payment required to fund capacity.
- Charge on supplier to cover shortfalls in difference payments.

The CM settlement components and prices are further described below.

Capacity payments

Capacity providers receive a monthly capacity payment based on the capacity provider's awarded capacity and the capacity auction price. Payment is made regardless of whether the capacity provider is scheduled to or delivers energy. Payments are not indexed for inflation, fuel costs, or other cost drivers: capacity providers bear the risk of changes to costs and the value of money over the term of the obligation.

Difference charges and payments

If the reference price exceeds the strike price, capacity providers (excluding DSUs and interconnectors) receiving a capacity payment for that period pay a difference charge on the volume of capacity delivered during that period. Capacity providers (including DSUs and interconnectors) also pay a capacity difference charge for any undelivered capacity. These difference charges are settled weekly to align with the billing period for energy payments and charges.

If the capacity provider is not scheduled in the ex ante markets, the reference price is set to the imbalance settlement price—that is, the price at which it might sell energy into the BM. If the imbalance settlement price exceeds the strike price, the capacity provider must pay capacity difference charges. If the capacity provider is also scheduled in the ex ante markets, then the reference price is derived from the relevant ex ante market and BM prices.

Annual and billing period stop-loss limits are placed on the difference charges for undelivered capacity incurred by the capacity provider to limit the financial risk of capacity providers. When a capacity contract is traded in a secondary auction, the accumulated losses on the contract are retained by the party that incurred them.

Capacity charges

Suppliers pay capacity charges to fund the CM. The charge is derived from the expected annual value of capacity payments and a forecast of demand, which are reviewed annually taking into account any shortfalls or surpluses in previous years. The charge is levied in particular imbalance settlement periods in the capacity year, decided in advance by the RAs. An additional charge is levied to make up for any shortfall in difference payments caused by application of stop-loss limits, charges based on interconnector availability, errors in demand forecasting, and other potential causes.

4.7 Forwards Market

Note. The arrangements for forward trading in the I-SEM are still under consideration.

4.7.1 Function

The Forwards Market (FWM) provides participants with the opportunity to hedge their positions in the DAM, IDM and BM by purchasing contracts-for-difference (CfDs) at a strike price referenced to the price at which the participant sells energy in a specified market.

When the market price exceeds the strike price, the party that sold the CfD pays the buyer the market price less the strike price on each unit of contracted capacity. And when the market price is less than the strike price, the buyer pays the difference to the seller. If the CfD is backed by trades by both parties in the reference market, then the effective price to both parties is the strike price, protecting them from price volatility.

The Forwards Market (FWM) is a financial market and does not give rise to a physical schedule. A participant must participate in the DAM or IDM or both to be sure of achieving a physical notification in the BM.

4.7.2 Relevant codes

The governance and operation of the FWM and the roles and responsibilities of the market operators and market participants are yet to be defined by the Regulatory Authorities.

4.7.3 Market operation

The arrangements for forward trading in the I-SEM are still under consideration.

4.7.4 Participation

Any participant in the I-SEM can participate in the FWM. Participation in the FWM is not mandatory. Participants must be registered with the market operator.

4.7.5 Market timeline

The market time frame for the FWM is still under consideration.

4.7.6 Hedging example

Consider a generator on the island of Ireland (SEM zone) with the capacity to supply 10 MWh of energy at a cost of 35 €/MWh. The generator offers the 10 MWh into the DAM at 40 €/MWh. The generator also holds a 10 MWh CfD at a strike price of 40 €/MWh referenced to the DAM to protect it against price volatility.

For a specific trading period, if the spot price is 45 €/MWh, the generator sells 10 MWh at 45 €/MWh. The spot price is higher than the strike price, so the generator pays the CfD seller the difference of 5 €/MWh on the 10 MWh of contracted capacity, and earns a profit of €50 for that hour, being the difference between the strike price and its cost of production.

However, if the spot price is 35 €/MWh, the generator is not scheduled in the DAM. The spot price is lower than the strike price, so the generator is paid by the CfD seller the difference of 5 €/MWh on the 10 MWh of contracted capacity, and, despite not being scheduled, still earns a profit of €50 for that hour.

4.7.7 Settlement

Billing and settlement arrangements for the FWM are still under consideration.

4.8 FTR auctions

4.8.1 Function

Unlike the current SEM arrangements, in which participants can explicitly reserve physical capacity on an interconnector, under the I-SEM arrangements ex ante interconnector flows are based on the net position results of the day-ahead and intraday market coupling. When a flow is identified between markets, it is typically due to a price differential between those adjacent coupled markets (e.g. SEM and GB). Participants seeking a hedge against price differential between the SEM and GB markets can purchase a financial transmission right ("FTR option"). These are financial instruments and do not give the holder a physical right of transmission.

The FTR option products refer to specific interconnectors and a specific direction (to or from SEM). These products are offered in auctions and may be sold for various long-term time frames, for example annual and monthly. The FTR option holder is paid the loss-adjusted day-ahead market price spread when positive in that direction for that market period.

4.8.2 Relevant regulations

The operation of FTR auctions and the roles and responsibilities of the market operator and market participants are governed by the following guidelines and regulations:

- *Forward Capacity Allocation Guidelines* (FCA)
- *Harmonised Allocation Rules* (HAR), as required under the FCA guideline
- *Capacity Allocation and Congestion Management* (CACM)

For further information, refer to Section 2.5.

4.8.3 Market operation

The FTR options on the SEM-GB border and other long-term products on bidding zone borders across Europe adhere to a common set of harmonised allocation rules[32] and, when implemented, will be sold through a single allocation platform.

The Moyle and EWIC interconnectors are putting arrangements in place with the Joint Allocation Office (JAO) in the expectation that it will be appointed as the single allocation platform. JAO currently run auctions for twenty-eight European borders on behalf of twenty TSOs.

JAO will be the single point of contact for the FTR market—that is, they handle registration, systems, auctions, and manage all settlement.

4.8.4 Participation

Participation in FTR auctions is optional. Participants will register directly with JAO and need to meet the requirements of the HAR to participate in JAO-operated FTR auctions.

4.8.5 Market timeline

FTR auctions occur from a few months up to a few weeks in advance of the start of the product time frame.

4.8.6 FTR products

FTR option products will be sold per interconnector and per direction in euros for both Moyle and EWIC products. The product design will be part of a public consultation in Q1 2017, as required by the FCA.

Product time frames of SEM Annual (October to September), Calendar Annual (January to December), Seasonal (winter and summer), Quarterly, and Monthly are in place in the current market and likely to be part of the product time frames under the I-SEM arrangements.

The form of product can be base load (all hours of a product period) or peak load or off-peak load. Currently only base-load products are offered.

The FTR option entitles the holder to the loss-adjusted day-ahead market spread when positive in that direction on that interconnector. The loss adjustment depends on the loss factor for the interconnector the product refers to.

The amount of FTR options sold is linked with the available capacity of the interconnectors. This may be curtailed in certain circumstances in advance of the

[32] Version 3 of the HAR, aligned with the FCA Regulation, are being consulted on in Q1 2017 <https://consultations.entsoe.eu/markets/fca-har/> and will apply for long-term auctions in 2018 and SEM-GB FTR Options products for delivery from I-SEM go-live.

day ahead firmness deadline—approximately 1 hour in advance of the DAM gate closure. The specific rules for curtailment scenarios are detailed in the HAR and associated regional annex.

4.8.7 Hedging example

Consider a generator on the island of Ireland (SEM zone) with an off-market contract to supply a steady load of 10 MWh in Great Britain (GB zone) at a price of 40 €/MWh, which it can supply at a cost of 35 €/MWh. Under normal conditions (free flow between the SEM and GB), this earns the generator a profit of €50 per hour. In each one-hour trading period, the generator sells 10 MWh into the SEM DAM at the spot price and the supplier purchases 10 MWh from the GB DAM. The generator also holds a 10 MW FTR option in the SEM>GB direction on the Moyle or EWIC interconnectors to protect it against price differences between the SEM and GB.

If there is no congestion on the interconnectors, then the spot price in the SEM and GB may be the same or at least very close[33]. For a specific trading period, if the spot price is, say, 45 €/MWh, the generator sells its energy into the SEM DAM at 45 €/MWh and the supplier buys it from the GB DAM at 45 €/MWh. The spot price is higher than the contract price, so the generator pays the supplier the difference of 5 €/MWh off-market on the contracted 10 MWh. The supplier and the generator have effectively settled at the contract price of €40/MWh, and the generator makes a profit of €50 for that hour.

Now suppose, due to high wind levels and low generation prices, congestion occurs on the interconnectors in the SEM>GB direction, causing the spot price in the SEM DAM to drop to 30 €/MWh. But the price in the GB DAM is still 45 €/MWh, so the generator must still pay 5 €/MWh on each of the contracted 10 MWh to the supplier, but the generator is not scheduled in the DAM at that price. The DAM market spread is thus 15 €/MWh and this is paid to the FTR holder, the generator. The FTR holder (generator) therefore receives €150 on each 10 MWh and this gives the generator a profit of €100 (less the cost of the FTR).

Note. The FTR option actually pays out the loss-adjusted day-ahead market spread. The loss factor is specific to the interconnector the FTR option product is for.

The DAM has thus enabled the most efficient solution, with a lower-cost generator in the SEM effectively providing the energy at 30 €/MWh instead of the contracted generator running at a loss. And despite the generator not being scheduled, its FTR protects it from the price difference between the SEM and GB, allowing it to still profit under its contract.

[33] There would be no congestion if the market spread does not exceed the cost of losses across an interconnector. This simplified example ignores the effect of losses and ramping. In practice, the FTR pays out the loss-adjusted market spread,

4.8.8 Settlement

The JAO operates billing and settlement arrangements with respect to FTR auctions. These arrangements include:

- The JAO collects the proceeds of FTRs cleared at auction from participants.
- The JAO settles the FTR option pay-out with rights holders.
- All amounts and payments with JAO are in euros for both Moyle and EWIC product auctions and settlement.

5. Trading

5.1 Submission timelines

Each market operates over different timelines, as described in Section 4. By way of an example, the combined submission timelines for the physical markets in trading period 17, which starts at 07:00 and ends 07:30, on day D is illustrated in Figure 20. Note that the DAM trading day is divided into 24 (1-hour) trading periods, whereas the IDM trading day is divided into 48 (30-minute) trading periods. The BM is also divided into 30-minute imbalance settlement periods with six (5-minute) imbalance pricing periods in each imbalance settlement period.

Note. The BM imbalance settlement period and IDM trading period are aligned and generally referred to, simply, as the "trading period".

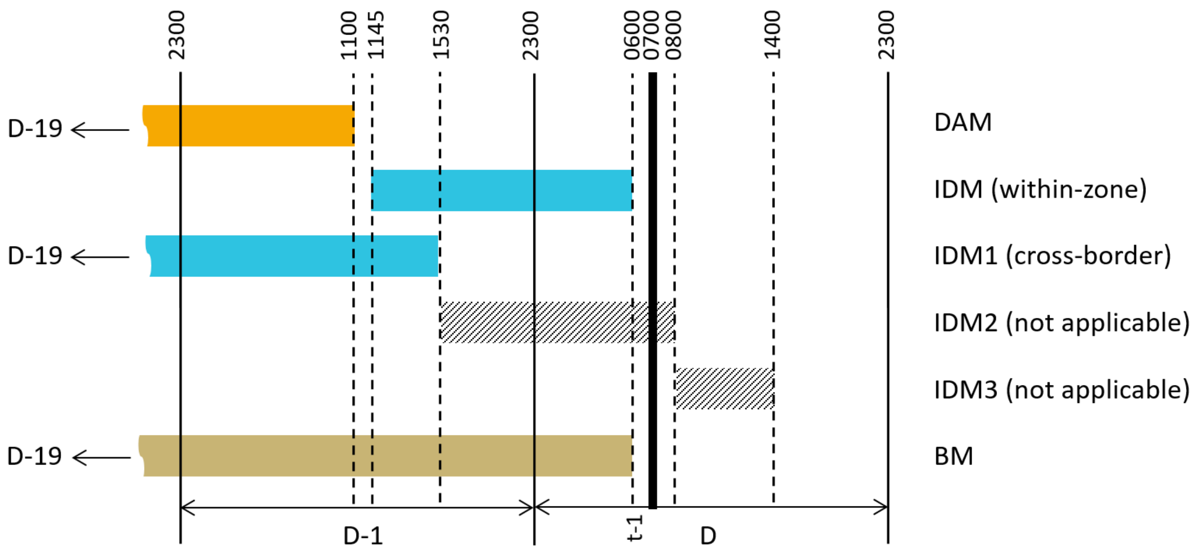

Figure 20 Market submission timelines for trading period 17 (0700–0730) on day D

5.2 Trading options

It is expected that participants will establish a physical position in the DAM to reduce their exposure in the BM. This affords traders the flexibility of adjusting their position in the IDM up to one hour before real time. Participants can further reduce their risk by adopting arbitrage and hedging strategies prior to entering the ex ante markets.

A capacity provider is most exposed in the CM when the imbalance settlement price is high. Although not required, the expectation is that on peak days, when supply is short, participants will strive to be fully scheduled in the DAM and IDM, and then rely on balancing to bring them down to required levels. In this way, their ex ante schedules ensure they meet their capacity obligations.

5.3 A day in the life of…

The following sections describe a number of hypothetical trading scenarios in a typical day in the I-SEM.

Important. This section should be read in conjunction with the Disclaimer at the front of this guide. These scenarios do not constitute advice and are provided only as examples of some trading options that might be available to some participants.

5.3.1 A dispatchable generator

Example—Dispatchable generator with capacity obligation

A 100 MW thermal unit is registered in the SEM as dispatchable generator unit GU1. The generator has previously supplied the TSO with standing technical offer data and commercial offer data (simple and complex) that accurately reflects the normal operating characteristics and costs of each unit. The generator receives capacity payments based on a derated capacity of 90 MW.

Submissions made for GU1 on a typical day are shown in Figure 21 and further described below.

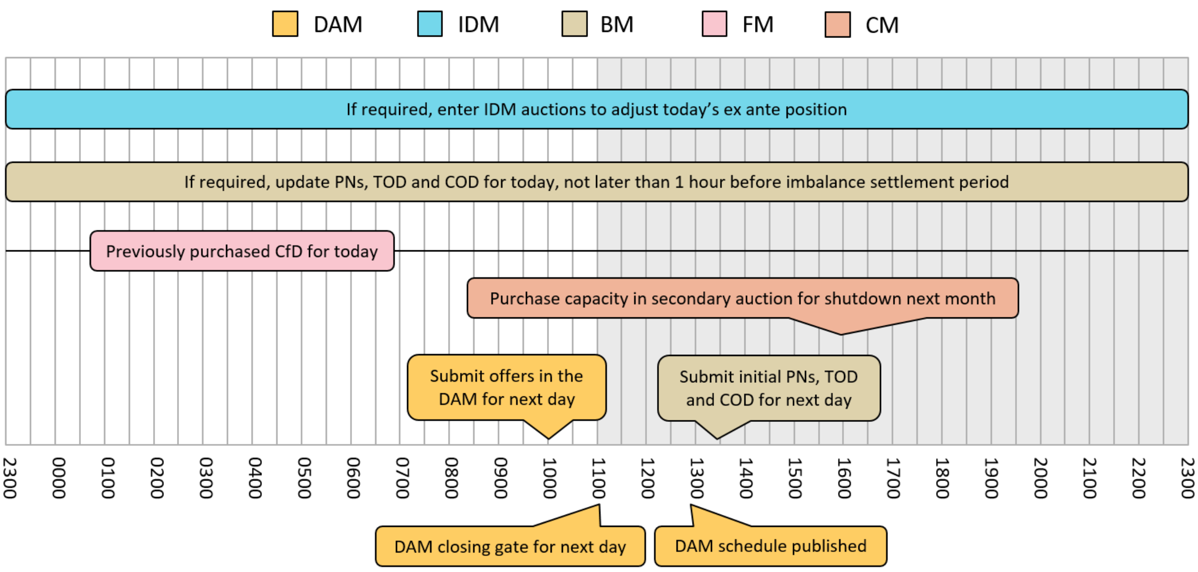

Figure 21 Submissions made by generator GU1 in a typical day

To ensure that GU1 is scheduled every day, the generator offers 100 MWh on GU1 into the DAM at 0 €/MWh in each of the twenty-four 1-hour trading periods. Assuming GU1 is scheduled, the generator is paid at the DAM spot price in each period. If GU1 is not scheduled in the DAM, the generator enters the IDM on the day to establish its position.

GU1 is constrained up and so is not used by the TSO in system balancing. By being scheduled every hour of every day, the generator also ensures that its capacity obligations on GU1 are met.

GU1 submits TOD and COD to the TSO daily for each of the 48 imbalance settlement periods of the next trading day (commencing 23:00). The TSO will only use the COD if it needs to constrain output on GU1 in balancing. GU1 also submits initial PNs daily for each of the 48 imbalance settlement periods for the next trading day. The PNs reflect the position of its cleared trades in the DAM and IDM for that day. The generator continuously monitors performance and, if required, submits revised PNs on the day, not later than one hour before each imbalance settlement period.

A typical demand profile over a midweek 24-hour period is shown in Figure 22. The operating cost (ignoring start-up and ramping) for GU1 is 28 €/MWh. The DAM spot price is typically above that level throughout the day, and often peaks above 100 €/MWh for a short period each day (see Figure 21). However, to reduce its exposure to a sustained period of low prices, the generator takes a CfD at a strike price of 40 €/MWh referenced to the DAM, which ensures an operating margin of 12 €/MWh each and every hour of each and every day.

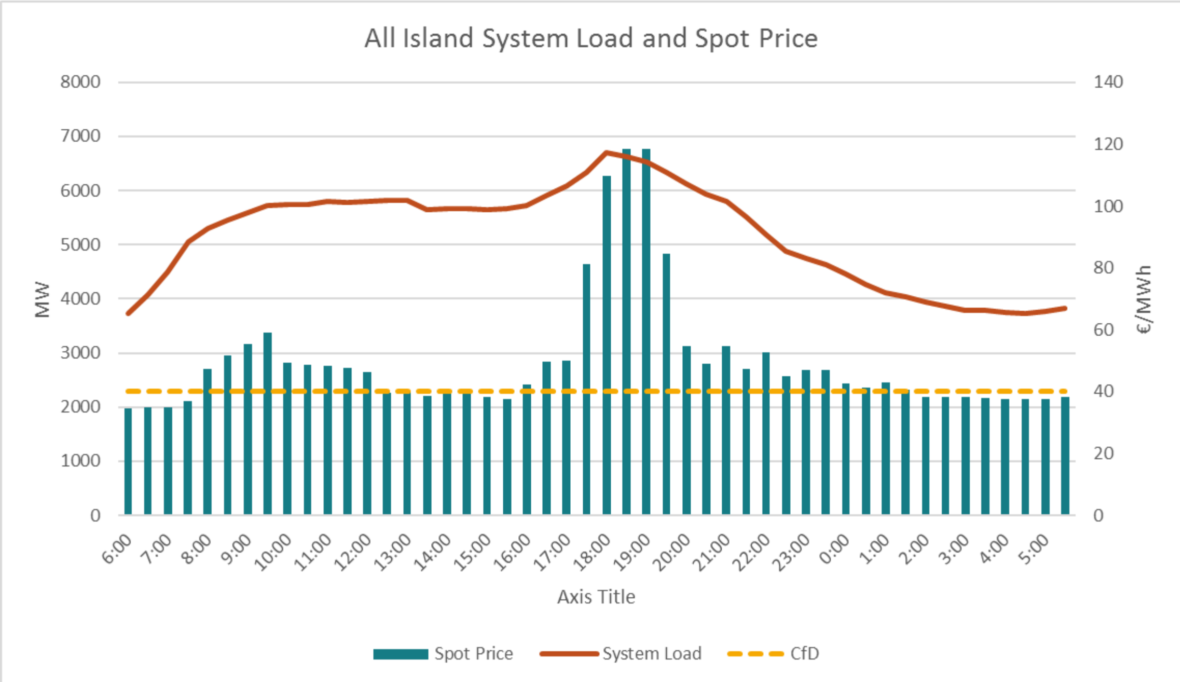

Figure 22 A typical demand profile and day-ahead spot price

GU1 is scheduled for a 48-hour maintenance shutdown next month. During this period, the generator is financially exposed on GU1 capacity if the spot price exceeds the capacity strike price at any time during that 48 hours. To cover that risk, the generator purchases capacity in the secondary capacity market, but only for the peak periods (8:00 to 10:00 and 17:00 to 20:00) in each of the two days that GU1 is shutdown (auctions aren't run every day, but there is one today).

Example—Dispatchable generator with no capacity obligation

A 100 MW thermal unit is registered in the SEM as dispatchable generator unit GU2. The generator has previously supplied the TSO with standing technical offer data and commercial offer data (simple and complex) that accurately reflects the operating characteristics and costs of each unit. The GU2 derated capacity is being offered into the secondary capacity market but currently has no capacity obligations.

The submissions made for GU2 on a typical day are shown in Figure 23 and further described below. Note that although the diagram focuses on the peak period during which GU2 expects to be scheduled or deliver balancing services, the TSO can commit GU2 at any time for reasons of system security or balancing.

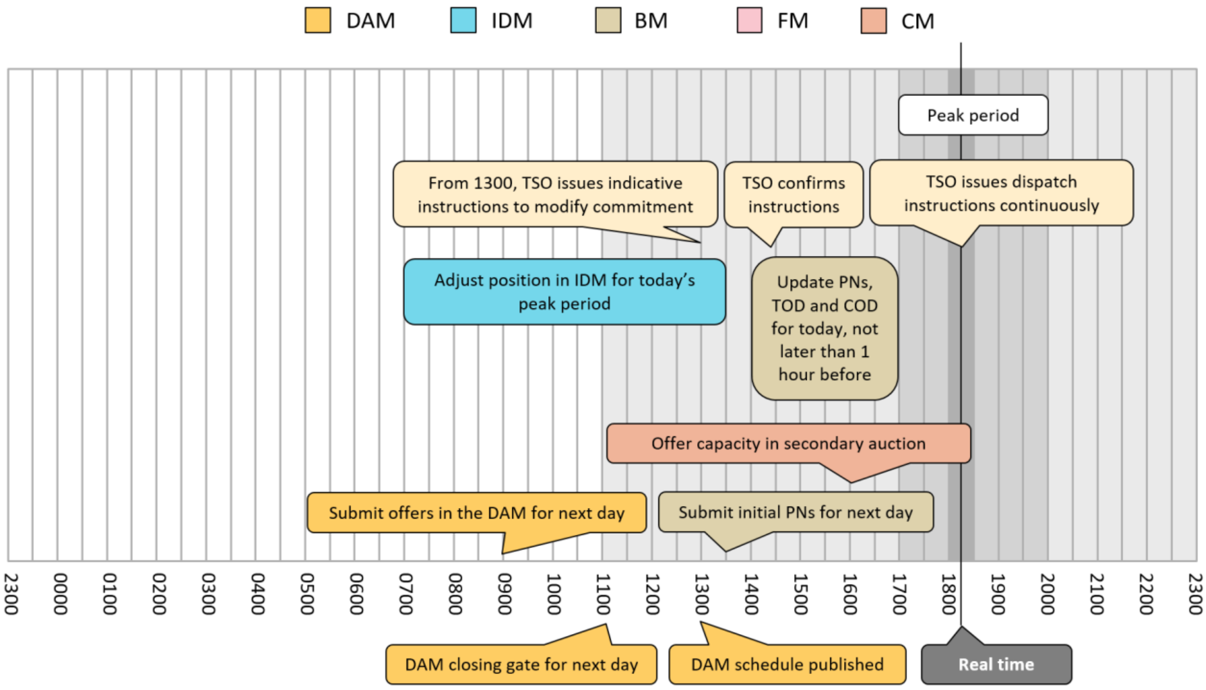

Figure 23 Submissions made by generator GU2 in a typical day

GU2 is typically cycled each weekday during the peak demand period for approximately 5 hours (see Figure 22), excluding unit start-up, ramp-up and shutdown. The 100 MW output from GU2 is offered into the DAM at a variable price, based on the generator's own forecast of the level of demand and interconnector flows. The generator continuously assesses the 3-day outlook and places offers and bids in the DAM and IDM to adjust its position as information improves closer to each trading period. The generator's trading strategy is designed to have 50 MW of the GU2 output scheduled during the peak period, making the remaining 50 MW available for balancing.

5.3.2 A wind generator

Consider a wind farm comprising 12 wind turbines with a maximum combined generating capacity of 30 MW (each turbine has a rated maximum output capacity of 2.5 MW). The wind forecast for the next 24-hour period ranges between 12 and 46 kph and resulting power output ranges between 385 and 1650 kW.

The generator previously submitted offers prior to DAM gate closure the day before, which was based on the forecast available at that time. After the DAM clears for the next day, the generator also submitted a PN to the TSO that reflected its cleared trades.

The generator continuously reviews the wind and demand forecast for the next 24 hours (Figure 24) and adjusts its position as the forecast changes by placing offers and bids in the IDM not later than one hour before each 30-minute trading period. If the trade clears before the BM gate closure, the generator also updates its PN.

Figure 24 Eirgrid system information dashboard[34]

5.3.3 A supplier

Consider a supplier on the island of Ireland with a forecast next-day demand of 500 MWh with a retail value of 65 €/MWh. The supplier uses its own forecast to place bids in the DAM ranging from 35 €/MWh to 85 €/MWh. The supplier also holds a CfD at a strike price of 50 €/MWh referenced to the DAM to protect it against price volatility.

For a specific trading period in which the forecast demand is 20 MWh, if the DAM spot price is 45 €/MWh, the supplier's bid of 65 €/MWh clears at 45 €/MWh. The DAM spot price is lower than the CfD strike price, so the supplier pays the CfD seller the spread of 5 €/MWh on the 20 MWh, and earns a profit of €300 for that hour, being the difference between the retail price and the strike price (65 x 20 – 45 x 20 – [50 – 45] x 20).

However, if the spot price is 100 €/MWh, the supplier, in this example, will not be scheduled in the DAM. After publication of the DAM results (13:00 the day before), the supplier then bids in the IDM cross-border auctions and succeeds in purchasing 20 MWh at 110 €/MWh.

The DAM spot price (100 €/MWh) is higher than the strike price (50 €/MWh), so the supplier is paid by the CfD seller the difference of 50 €/MWh on the entire 20 MWh. The supplier earns a profit of €100 for that hour (65 x 20 – 110 x 20 – [50 – 100] x 20), being the difference between the retail price and the IDM purchase price plus the CfD-DAM spread.

5.3.4 An assetless trader

An assetless trader arbitrages its position between the DAM and IDM. To ensure that it achieves a zero energy position before the BM gate closure, any trades cleared in the DAM must be reversed in the IDM.

The assetless trader continuously reviews the wind and demand forecast for the next 24 hours (Figure 24) and exits its position by placing offers and bids in the IDM not later than one hour before each 30-minute trading period.

For example, an assetless trader places a bid in the DAM for 50 MWh at 25 €/MWh for each 1-hour trading period between 7:00 and 10:00 the next day (D). The DAM closes at 11:00 D-1 and, when the results are published at 13:00, the assetless trader is informed that all three bids were successful. The assetless trader's exposure before entering the IDM is the spread between the DAM market price and the imbalance settlement price in each corresponding imbalance settlement period.

The assetless trader then offers the energy into the same periods in the IDM within-zone (continuous matching) or cross-border auctions. The IDM trading period is 30

[34] <http://www.eirgridgroup.com/how-the-grid-works/system-information/>

minutes, so the DAM trade is split equally between each half-hour period. So, to reduce its exposure in the BM, the assetless trader offers 25 MWh at 35 €/MWh into the six trading periods between 7:00 and 10:00 the next day (D), thereby making a profit, if cleared, of €250 in each period.

6. Credit risk management

6.1 Collateral requirements with SEMOpx

Note. These requirements are specific to SEMOpx and do not apply to other NEMOs that might be designated in the I-SEM.

As part of the registration process, participants are admitted to the European Commodity Clearing (ECC) as either a non-clearing member or a direct clearing participant.

Non-clearing member

Each participant appoints a clearing member—a bank that is a member of the European Commodity Clearing (ECC) clearing house—who settles with SEMOpx on behalf of the participant. The ECC acts as a central counterparty for all payments in the market and guarantees payments in the event of a default by a participant. The ECC assesses the collateral requirements of each clearing member and ensures it holds adequate security to protect against default. Each clearing member then imposes similar obligations on the participant.

Direct clearing participant

This membership class allows participants to participate in the ex ante markets without appointing a clearing member. Instead, the participant appoints a settlement bank, who settles with SEMOpx and guarantees payments in the event of a default by a participant. The participant can nominate either a trading limit or a collateral amount. The ECC then assesses the collateral amount (for a nominated trading limit) or the trading limit (for a nominated collateral amount).

6.2 Collateral requirements with SEMO

Collateral requirements for the BM and CM are established at the participant level—netting the collateral requirements for all supply and generation units registered by the participant.

Credit management is in the form of credit cover provided by a qualified bank. SEMO draws on the participant's credit cover to cover any defaults. SEMO monitors the exposure of every participant and can request an increase in credit cover if required. If a request to increase a participant's credit cover is not complied with, then the participant can be suspended from the market.

6.3 Collateral requirements with JAO

Collateral with JAO can be as cash (held in a bank account) or via a letter of credit. The collateral is considered for all trading with JAO, which may be on multiple European borders. Before considering auction bids, the participant's credit cover is checked and bids above the level of collateral may be excluded.

Glossary

Agent of Last Resort (AOLR)

An automated data processing service provided through the market systems, which facilitates participation of small generators in the ex ante markets.

arbitrage

A trade that profits by exploiting price differences of identical or similar products on different markets or in different forms—for example, purchasing in the Day-Ahead Market at price X, and reselling in the Intraday Market at price Y. Arbitrage provides a mechanism to ensure prices do not deviate substantially from fair value for long periods of time.

Assetless Trader

A trading role in the ex ante markets in which the participant has physical assets but no generation or demand.

balancing action

An action taken by a TSO to maintain the system frequency within a predefined stability range and to comply with the required amount of reserves.

Balancing Market (BM)

The institutional, commercial and operational arrangements that establish market-based management of the function of system balancing.

balancing service

The end-to-end process of assessing, planning, procuring, and maintaining the system frequency within a predefined stability range.

bid

An intention to purchase energy or capacity in a market.

Bidding Code of Practice (BCoP)

The code of practice for how commercial bids or offers should be formed and priced.

bidding zone

The transmission network area in which market participants can purchase or sell energy or capacity without requiring capacity allocation. A generation or load unit can belong to only one bidding zone in any one market trading period.

British Electricity Trading and Transmission Arrangements (BETTA)

The electricity market operating in the island of Great Britain.

Capacity Market (CM)

The institutional, commercial and operational arrangements that establish market-based management of capacity remuneration in the I-SEM.

Capacity Market Unit (CMU)

The unit by which capacity providers offer capacity in the Capacity Market.

capacity payment

A payment made to capacity providers for capacity availability.

Capacity Payments Mechanism (CPM)

The method of capacity remuneration currently employed in the SEM.

capacity remuneration

A mechanism for assisting generators (including physical generators and demand-side units) and interconnectors to fund generation capacity, in which they are remunerated for making generation capacity available to the transmission network.

clearing

A process in which financial or physical transactions are brought to a single entity, the clearing house, which steps into the middle of the transaction and becomes the counterparty to each buyer and seller. Generally, clearing is used to manage counterparty risk.

clearing house

The clearing house acts as the counterparty to each side of a transaction and assumes the risk that either the buyer or seller will fail to perform its obligations. Clearing houses maintain rules about the creditworthiness of traders, collateral that must be posted, and fees that must be paid for the service.

commercial offer data (COD)

The costs at which generators and suppliers are prepared to increase or decrease the energy supplied or consumed. Offers can be complex (fixed and variable costs) or simple (variable costs only).

complex offer

A three-part order comprising a start-up cost (€) for committing a unit, a no-load cost (€/trading period) for each trading period that the unit is committed, and incremental/decremental price-quantity (€/MWh) pairs. Also see simple offer.

congestion

Occurs when there is insufficient capacity on a transmission network element (cable, line, interconnector etc.) to carry the physical flows resulting from trade requested by market participants.

congestion rent

The difference in price between interconnected bidding zones when congestion occurs on their interconnections.

contract-for-difference (CfD)

A contract that is settled based on the difference between a market reference price and the contract strike price on a specified volume. If the reference price is greater than the strike price, the contract seller pays the difference to the contract buyer. If the difference is negative, the buyer pays the seller.

credit cover

Collateral posted as a guarantee against a participant’s potential exposure in a market.

Day-Ahead Market (DAM)

The institutional, commercial and operational arrangements that establish market-based management of physical trades in the day-ahead time frame, i.e. commercial transactions are executed the day before the delivery of traded products.

de minimis threshold

The maximum export capacity above which generators must sell their output through the SEM and suppliers must purchase their consumption from the SEM.

demand-side unit (DSU)

A generator unit that supplies energy by reducing net demand through use of a portfolio of demand-side response and non-market generation.

dispatch instruction

An instruction issued by a TSO to change the output or mode of operation of a generating unit.

double-sided auction

An auction in which bids (demand) and offers (supply) are ordered by cost and the point at which demand equals supply sets the market price.

EirGrid

The Transmission System Operator (TSO) for Ireland.

energy position

A participant's energy position is the accumulated volume of all its trades in the ex ante markets (day-ahead and intraday) and any balancing actions taken by the TSO in the Balancing Market.

EUPHEMIA algorithm

EUPHEMIA (EU Pan-European Hybrid Electricity Market Integration Algorithm) is the market coupling algorithm used to resolve the Day-Ahead Market and cross-border Intraday Market.

ex ante

From the Latin, meaning "from before", describes any market that clears in advance of the delivery of energy.

ex post

From the Latin, meaning "from after", describes any market that clears after the delivery of energy.

explicit allocation

An allocation that results from a contractual arrangement between a buyer and a seller.

final physical notification (FPN)

For units that are mandated to submit a physical notification (PN), the last valid PN submitted by a participant before the balancing market gate closure becomes its FPN for the relevant trading period. For units that are not mandated to submit a PN, their availability profile in real-time operation of the system becomes its FPN.

Financial Transmission Right (FTR)

A financial product that entitles its owner to be paid the transmission price on a given transmission path, independent of their physical use of that path. An FTR returns revenue to the holder funded by the price differentials in the Day-Ahead Market across interconnectors (also see congestion rent).

flagging-and-tagging

A process of identifying bids and offers that are included or excluded when setting the imbalance price in an imbalance pricing period.

Forwards Market (FWM)

The institutional, commercial and operational arrangements that establish market-based management of financial trades in the forwards time frame, i.e. monthly, quarterly, yearly, multi-yearly. Products traded in the FWM are typically for hedging purposes.

FTR auction

An auction, run by the Joint Allocation Office (JAO), in which Financial Transmission Right (FTR) products are offered to participants by interconnector owners. The revenues collected from purchasers of FTRs provide interconnector owners with a revenue stream for offsetting investment costs.

gate

The opening or closing time of the trading window in which market participants submit bids and offers with respect to a specific delivery period.

Generator

Generators offer energy into the market. They register generating and demand-side units. A demand-side unit is the supplier equivalent of a generating unit, i.e. represents dispatchable demand.

grid

Another term for an electricity transmission network.

hedge, hedging

A trade that is intended to reduce the risk of adverse price movements or other adverse impacts, e.g. a generator purchases a CfD in the Forwards Market at an advantageous price.

imbalance price

The price at which deviations from a participant’s market schedule are calculated for an imbalance period, in the first instance, which is a component of the imbalance settlement price used in settlement of the Balancing Market.

imbalance pricing period

The period over which the imbalance price is calculated.

imbalance settlement period

The period over which the imbalance settlement price is calculated.

imbalance settlement price

The time-weighted average of imbalance prices in the imbalance settlement period, which is a component in determining the cost of uninstructed deviations.

implicit allocation

An allocation that is determined algorithmically or is rules-based—for example, by the application of the market coupling EUPHEMIA algorithm.

inc & dec bids

Increment and decrement bid structure, where participants submit prices and quantities by which they are willing to increase or decrease their generation or consumption to provide a balancing service.

Integrated Single Electricity Market (I-SEM)

The new market arrangements for the SEM.

Interconnector (role)

Interconnectors offer capacity in the Capacity Market. They do not trade in energy markets but they can have exposure in settlement of the Balancing Market through an Interconnector Error Unit which accounts for differences between dispatched and delivered positions. Interconnector owners are responsible for facilitating the sale and settlement of interconnector capacity, cross-border trades, and balancing services.

interconnector

A transmission line that connects bidding zones. The SEM is connected to the IEM (via BETTA) by the Moyle Interconnector, between Northern Ireland and Scotland, and the East West Interconnector, between Ireland and Wales.

Internal Energy Market (IEM)

A single, pan-European market for electricity and gas.

internal trade

Trading of energy or capacity that does not affect cross-border flows between bidding zones: the only impacts are those internal to the bidding zone.

Intraday Market (IDM)

The institutional, commercial and operational arrangements that establish market-based management of physical trades in the intraday time frame, i.e. after closure of the Day-Ahead Market into real time.

Joint Allocation Office (JAO)

The body responsible for the operation, settlement and credit risk management of FTR auctions.

liquidity

The amount of trade in a market. Assets that can be easily bought or sold are known as liquid assets. Markets with a large volume of trades are known as liquid markets.

marginal price

The price at which a market is cleared that corresponds to the cost of meeting the last required (marginal) MW of demand.

market codes

See *Market Network Codes*.

market coupling

Matching orders for all bidding zones in Europe in the single day-ahead and intraday coupling, taking into account cross-zonal capacity.

Market Coupling Operator (MCO)

The body responsible for running the day-ahead and intraday market coupling processes.

Market Network Codes

A set of rules drafted by the European Network of Transmission System Operators (ENTSO-E), with guidance from the Agency for the Cooperation of Energy Regulators (ACER), to facilitate the harmonisation, integration and efficiency of the European electricity market. Network codes are legally binding documents and are an integral part of the drive towards completion (and implementation) of the Internal Energy Market.

market operator

The body responsible for operating a market (there are multiple market operators in the I-SEM). The market operator's responsibilities vary between each market and may include access to market systems and data, market system operation, settlement, and credit risk management.

market power

The ability of participants, alone or jointly with others, to behave independently of competitors, customers and consumers to profitably alter prices away from competitive levels.

market price

A general term for the price at which a market clears in a specific trading period.

market schedule

A general term for the outcome of clearing a market, which refers to the quantities of energy each successful participant is scheduled to deliver or consume.

matched trades

A process where bids and offers are individually matched on a first-come-first-served basis by price and quantity independently of other trades.

merit order

Offers or bids ordered by price.

metering

Data supplied by a Metering Data Provider (MDP) for settlement.

Nominated Electricity Market Operator (NEMO)

The regional market operator who acts as a central counterparty to orders placed by participants in the Day-Ahead and Intraday Markets.

non-energy action

A balancing action that results in a zero net energy change to the system, such as an action involving reserves or voltage.

offer

An intention to sell energy or capacity in a market.

order

An intention to purchase (bid) or sell (offer) energy or capacity in a market.

pay-as-bid

The price is set equal to the price of the matched bid.

physical notification (PN)

A MW profile that reflects a participant's best estimate of its intended and physically feasible generation or consumption position over a trading period.

physical trade

A transaction in which electricity is actually generated and consumed.

physical transmission right (PTR)

A product that entitles its owner to use a defined quantity of capacity on a given transmission path.

position

The outcome of a trading round for a participant. For example, a 100 MW generator who successfully offers their whole availability has a position of 100 MW in that period. Also see *energy position*.

price coupling

The process of deriving a price from the matching of orders for all bidding zones in Europe, carried out by the EUPHEMIA algorithm developed by the Price Coupling of Regions initiative.

Price Coupling of Regions (PCR)

Initiative to implement the coupling of markets across Europe at the day-ahead time frame and developer of the EUPHEMIA price coupling algorithm.

real time

At the time of delivery, as in real-time dispatch.

reference price

The price in a specified market for a specified delivery period against which the strike price of a trade or contract is referenced for settlement.

Regulatory Authorities (RAs)

The bodies responsible for administration of the market codes; licensing of market operators and participants; and monitoring the operation of the SEM and the conduct of its participants: specifically, in Ireland, the Commission for Energy Regulation (CER) and, in Northern Ireland, the Utility Regulator (UR).

SEM Committee (SEMC)

The peak decision-making body for the SEM.

settlement

A business process whereby products (e.g. electrical energy, capacity rights) are delivered in exchange for payment of money to fulfill contractual obligations, such as those arising through energy market trades.

scheduling

The process of determining the output of individual generator units.

simple offer or bid

An order comprising one or more price-quantity pairs. Also see complex offer.

Single Electricity Market (SEM)

The wholesale electricity market for the island of Ireland (Ireland and Northern Ireland).

Single Electricity Market Operator (SEMO)

A joint venture between EirGrid (the TSO for Ireland) and SONI (the TSO for Northern Ireland), responsible for the settlement and credit risk management of the Balancing Market and Capacity Market.

single-sided auction

An auction in which offers to supply are ordered by cost and the point at which the forecast demand equals supply sets the market price.

social welfare

Social welfare refers to the overall welfare of society. With sufficiently strong assumptions, it can be specified as the summation of the welfare of all the individuals in the society. For electricity markets, it can be defined as “the consumer surplus plus the producer surplus plus the congestion rent across regions.”

SONI

The Transmission System Operator (TSO) for Northern Ireland.

spot market

A general term for market in which a commodity is traded for immediate payment and delivery, such as on the day or a day ahead.

spot price

A general term for the current market price at which a commodity is traded for immediate payment and delivery.

strike price

The price struck in a contract (e.g. a CfD offered in the Forwards Market) or set by an administrator (e.g. by the RAs in the Capacity Market), which is applied in settlement against a specified reference price (e.g. the Day-Ahead Market marginal price) for a specified delivery period.

submission window

The trading window in which market participants submit bids and offers with respect to a specified delivery period.

Supplier

Suppliers purchase energy from the market for consumption. They register supplier units, which represent non-dispatchable demand (e.g. a distribution network or industrial load).

system balancing

The processes by which a TSO ensures, in all time frames, in a continuous way, to maintain the system frequency within a predefined stability range and to comply with the amount of reserves needed and to the required quality.

system services

Services secured by a TSO from balancing service providers (BSPs), which benefit all users of the system, such as reserves and reactive power control. The cost of system services are socialised and recovered through tariffs.

Target Model

A set of principles, primarily in relation to allocation of and use of interconnector capacity, designed to facilitate progress towards a single European electricity market—the blueprint for the Internal Energy Market.

technical offer data (TOD)

Data describing the technical capabilities of units in the Balancing Market.

trading day (D)

The 24-hour period commencing at 23:00 GMT/IST each day and ending at 23:00 the next day.

trading period

The delivery period for which participants place orders in a market. The trading period in the Day-Ahead Market is one hour and 30 minutes in the Intraday and Balancing Markets.

Transmission System Operator (TSO)

The licensed body responsible for coordinating and directing the flow of electricity across the electricity transmission system.

uninstructed imbalance

Deviations between generation, consumption and commercial transactions within a given imbalance settlement period.

unit commitment

Scheduling ("on/off decision") of generation or load resource for each delivery time interval.

volume

The amount of energy being traded, either in a single order or in a whole market for a particular period of time. For example, if a generator offers to sell 100 MW of power in an hour period, their volume for that period is 100 MW.

XBID

The market coupling initiative and solution currently under development for the intraday time frame.

Appendix A Flagging-and-tagging process

The following flagging-and-tagging process is applied to the BOA in each 5-minute imbalance pricing period:

1. BOA are ranked in order of price (see Section A.1).
2. Ranked BOA are flagged (see Section A.2).
3. The reference price is identified (see Section A.3).
4. BOA are tagged (see Section A.4).
5. The initial imbalance price is determined (see Section A.5)

The results of the flagging-and-tagging process are used to determine the imbalance price for each imbalance pricing period (see Section 4.5.9.2).

A.1 Ranking

The ranking process orders the BOA by price. If there are M accepted bids and N accepted offers, then the bids are ranked from 1 to M in order of increasing bid price and the offers are ranked from M+1 to N in order of increasing price. This is illustrated in Table A-1, where M is 6 and N is 15.

Table A-1 Ranked bid offer acceptances

Rank	Type	Price (€/MWh)	QBOA (MWh)	Rank	Type	Price (€/MWh)	QBOA (MWh)
15	Offer	100	20	7	Offer	20	20
14	Offer	90	40	6	Bid	50	–10
13	Offer	80	2	5	Bid	40	–20
12	Offer	70	10	4	Bid	30	–3
11	Offer	60	15	3	Bid	20	–20
10	Offer	50	10	2	Bid	10	–20
9	Offer	40	5	1	Bid	5	–10
8	Offer	30	10				

A.2 Flagging

The flagging process identifies the BOA that are caused by system or unit constraints. The process sets the following flags:

- **SO flag** – BOA determined to be non-energy actions as a result of binding network or operational constraints.
- **Non-marginal flag** – BOA that cannot set price because the unit's ability to respond to changing demand is limited, e.g. because it is at its minimum operating limit, its maximum capacity, or its output is restricted by being at its ramp limits.

Each flag is initially set to 1 for each BOA, indicating that the BOA is not excluded from setting the imbalance price. These flags are switched to equal 0 for BOA that satisfy the conditions of the flag. The imbalance price flag (IPF) is the product of these two flags. If any flag has a value of zero, then the IPF is zero. BOA with an IPF of 1 are said to be "unflagged". An example of flagged BOAs (from Table A-1) is provided in Table A-2.

Table A-2 Derivation of imbalance price flag

Rank	Type	SO Flag	Non-Marginal Flag	Imbalance Price Flag	Reason
15	Offer	0	1	0	Reserve
14	Offer	0	1	0	Congestion
13	Offer	1	1	1	
12	Offer	1	1	1	
11	Offer	0	1	0	Congestion
10	Offer	1	1	1	
9	Offer	1	1	1	
8	Offer	1	0	0	
7	Offer	1	0	0	At max output
6	Bid	1	1	1	
5	Bid	0	1	0	Congestion
4	Bid	1	1	1	
3	Bid	1	0	0	Ramp limited
2	Bid	0	1	0	Reserve
1	Bid	1	1	1	

A.3 Marginal energy action

This process identifies the marginal energy action that sets the reference price in the scheduling period. Conceptually, if only offers were accepted, then the price of the marginal energy action would be the price of the highest priced offer with an IPF of 1. This would then set the reference price. Similarly, if only bids had been accepted (for decreased supply), then the price of the marginal energy action would be the price of the lowest priced bid with an IPF of 1. In practice, both offers and bids can be accepted. The net imbalance volume (QNIV) is used to resolve this.

The QNIV is the sum of the QBOA in the imbalance pricing period. QBOA for bids are negative and offers are positive. So the QNIV is positive if the volume of accepted offers is greater than accepted bids, and negative if the volume of accepted bids is greater than accepted offers.

- If the QNIV value is positive, then the marginal energy action is the highest priced offer with an IPF = 1, and the reference price for each bid/offer is the lesser of the bid offer price and the price of the marginal energy action.

- If the QNIV value is negative, then the marginal energy action is the lowest priced bid with an IPF = 1, and the reference price for each bid/offer is the greater of the value of the bid offer price and the price of the marginal energy action.

Continuing the example in Tables A-1 and A-2, the QNIV is 49 MWh (the sum of the QBOA in Table 6). The highest priced unflagged offer is ranked offer 13 with a price of 80 €/MWh, and the lowest priced unflagged bid is ranked bid 1 with a price of 5 €/MWh. The QNIV is positive, so the marginal energy action is ranked offer 13, and the reference prices are capped at 80 €/MWh, as shown in Table A-3.

Table A-3 Reference prices for positive QNIV

Rank	Type	Price (€/MWh)	QBOA (MWh)	Imbalance Price Flag	Reference price (€/MWh)
15	Offer	100	20	0	80
14	Offer	90	40	0	80
13	Offer	80	2	1	80
12	Offer	70	10	1	70
11	Offer	60	15	0	60
10	Offer	50	10	1	50
9	Offer	40	5	1	40
8	Offer	30	10	0	30

Rank	Type	Price (€/MWh)	QBOA (MWh)	Imbalance Price Flag	Reference price (€/MWh)
7	Offer	20	20	0	20
6	Bid	50	-10	1	50
5	Bid	40	-20	0	40
4	Bid	30	-3	1	30
3	Bid	20	-20	0	20
2	Bid	10	-20	0	10
1	Bid	5	-10	1	5

A.4 Tagging

The tagging process identifies which BOA are excluded from the imbalance price calculation. Two tagging methods are used: net imbalance volume (NIV) tagging and price average reference (PAR) tagging.

A.4.1 NIV tagging

When the QNIV value is non-zero, there are potentially more or less unflagged offers than the QNIV, i.e. the remaining unflagged quantity does not correspond exactly to the QNIV. NIV tagging eliminates or reinstates some bids or offers such that the sum of the remaining untagged offers or bids equals the QNIV.

The flagged BOA (IPF = 1) indicate non-energy actions. The QBOA values for bids are negative and offers are positive. Non-energy actions should net to zero; where this is not the case, they need to be corrected as follows:

1. If QNIV > 0 set the initial TINIV tag for each BOA bid to zero and for each BOA offer to its IPF—a TINIV tag of 1 indicates the BOA that are potentially energy actions. This means that only BOA offers can set the price as their volume exceeds the volume of BOA bids.

   If QNIV < 0 set the initial TINIV tag for each BOA offer to zero and for each BOA bid to its IPF—a TINIV tag of 1 indicates the BOA that are potentially energy actions. This means that only BOA bids can set the price as their volume exceeds the volume of BOA offers.

2. The residual tagged quantity (QRTAG) is calculated as -1 times the sum all BOA quantities with a TINIV tag of 0. RTQ is positive if non-energy actions are dominated by bid volumes and negative if dominated by offer volumes.

The next steps tag bids or offers as either energy or non-energy actions so that the net volume of non-energy actions is zero and QRTAG equals zero.

Where QNIV > 0 (a greater volume of BOA offers than BOA bids)

3. If QRTAG < 0, identify the lowest ranked (i.e. lowest priced) flagged BOA offers with a cumulative volume equal to –QRTAG and set their TNIV tags to a value of 1 except for the most expensive one identified which has a TNIV value between 0 and 1 to indicate the fraction of its volume required to cancel the -QRTAG value. Set all other TNIV values equal to TINIV.

   If QRTAQ > 0, identify the highest ranked (i.e. highest priced) unflagged BOA offers with a cumulative volume equal to RTAG and set their TNIV tags to a value of 0 except for the least expensive one identified which has a TNIV value between 0 and 1 to indicate the fraction of the volume not required to cancel the QRTAG value. Set all other TNIV values equal to TINIV.

Where QNIV < 0 (a greater volume of BOA bids than BOA offers)

4. If QRTAQ < 0, identify the highest ranked (i.e. highest priced) flagged BOA bids with a cumulative volume equal to –QRTAG and set their TNIV tags to a value of 1 except for the least expensive one identified which has a TNIV value between 0 and 1 to indicate the fraction of its volume required to cancel the -QRTAG value. Set all other TNIV values equal to TINIV.

   If QRTAQ > 0, identify the lowest ranked (i.e. lowest priced) unflagged BOA bids with a cumulative volume equal to RTAG and set their TNIV tags to a value of 0 except for the most expensive one identified which has a TNIV value between 0 and 1 to indicate the fraction of the volume not required to cancel the QRTAG value. Set all other TNIV values equal to TINIV.

The flagged non-energy actions now sum to zero.

Continuing the example in Tables A-1 to A-3, the QNIV is positive. This means that there are more untagged BOA offers than BOA bids, so the TINIV Tag is initially set to zero for all BOA bids (as shown in Table A-4) and to the Imbalance Price Flag value for all BOA offers. The value of RTQ is –22 MW. We wish to set RTQ to zero, so we need to remove 22 MW of the lowest priced flagged BOA offer quantities. This is achieved by setting the TNIV tag of ranked offer 7 to 0 (20 MW) and ranked offer 8 to 0.2 (2 MW), while all other TNIV are set to TINIV, as shown in Table A-4. As all bid TINIV values were zero this table also shows that all BOA bids have a TNIV of zero.

Table A-4 NIV tagging

Ranking	Type	Reference price (€/MWh)	Imbalance Price Flag	QBOA (MWh)	NIV Tag
15	Offer	80	0	20	0
14	Offer	80	0	40	0
13	Offer	80	1	2	1
12	Offer	70	1	10	1
11	Offer	60	0	15	0
10	Offer	50	1	10	1
9	Offer	40	1	5	1
8	Offer	30	0	10	0.2
7	Offer	20	0	20	1
6	Bid	50	1	-10	0
5	Bid	40	0	-20	0
4	Bid	30	1	-3	0
3	Bid	20	0	-20	0
2	Bid	10	0	-20	0
1	Bid	5	1	-10	0

A.4.2 PAR tagging

PAR tagging uses the price average reference quantity (QPAR) range of bid/offer acceptance volumes to set the imbalance price. The price is a weighted average of the bid/offer prices within the QPAR range. If QPAR is very small, then a single bid/offer price can set the price. The PAR tagging process is as follows:

Note. The value of QPAR has yet to be decided.

1. Set the PAR tag for each BOA to its TNIV—a PAR tag of 1 indicates the BOA that can potentially set the price.

Where QNIV > 0 (a greater volume of BOA offers than bids)

2. If QNIV > QPAR, identify the highest ranked (i.e. highest priced) unflagged BOA offers, the sum of which is QPAR. Change their PAR tags to a value between 0 and 1 to indicate the fraction of the volume required from the

lowest priced BOA offer in the set. Set the PAR tag for all lower priced BOA offers to 0.

If QNIV < QPAR, the PAR tags are unchanged.

Where QNIV < 0 (a greater volume of BOA bids than offers)

1. If QNIV < –1 x QPAR, identify the lowest ranked (i.e. lowest priced) unflagged BOA bids and change their PAR tags to a value between 0 and 1 to indicate the fraction of the volume required from the highest priced BOA offer in the set. Set the PAR tag for all higher priced BOA offers to 0.

   If QNIV > –1 x QPAR, the PAR tags are unchanged.

Continuing the example in Tables A-1 to A-4, assume a QPAR value of 20 MW. The QNIV value is 49 MW, which is greater than QPAR. So, as shown in Table A-5, all except the highest priced 20 MW of offer BOA with an TNIV of 1 are flagged.

Table A-5 PAR tagging

Rank	Type	Reference price (€/MWh)	TNIV tag	QBOA (MWh)	Highest priced unflagged offer quantities	PAR Tag
15	Offer	80	0	20		0
14	Offer	80	0	40		0
13	Offer	80	1	2	2	1
12	Offer	70	1	10	10	1
11	Offer	60	0	15		0
10	Offer	50	1	10	8	0.8
9	Offer	40	1	5		0
8	Offer	30	0.2	10		0
7	Offer	20	1	20		0
6	Bid	50	0	-10		0
5	Bid	40	0	-20		0
4	Bid	30	1	-3		0
3	Bid	20	0	-20		0
2	Bid	10	0	-20		0
1	Bid	5	0	-10		0

A.5 Initial imbalance price

The initial imbalance price is a volume weighted average price of BOAs where:

- NIV flagged (TNIV Tag = 0) BOA have no impact—only (some) offers or bids, but not both, set the price.
- PAR flagged (PAR Tag =0) BOA have no impact—only a range of offers or bids around the price setting point are considered and then only in proportion to their accepted quantities within that range.
- Reference prices are capped above (for offers) and below (for bids) by the price of the marginal energy action.

For each imbalance pricing period, the initial imbalance price is set as follows:

1. The imbalance price tag is set equal to the product of the TNIV tag and the PAR tag for each BOA.
2. If QNIV = 0, then the initial imbalance price is set to the market backup price. This default price is used if there is no basis to set a price.
3. If QNIV ≠ 0, the initial imbalance price for each BOA equals the sum of the product of the reference price, QBOA and imbalance price tag divided by the sum of the product of the QBOA and imbalance price tag

Continuing the example in Tables A-1 to A-5, Table A-6 shows the resulting imbalance price calculations based on a 20 MW QPAR, which results in an initial imbalance price of 63 €/MWh (= 1260/20).

Table A-6 PAR 20 initial imbalance price

Ranked List	Type	Reference Price (RP)	QBOA	TNIV Tag	PAR Tag	Imbalance Price Tag (TIP)	RP × QBOA × TIP	QBOA × TIP
15	Offer	80	20	0	0	0	0	0
14	Offer	80	40	0	0	0	0	0
13	Offer	80	2	1	1	1	160	2
12	Offer	70	10	1	1	1	700	10
11	Offer	60	15	0	0	0	0	0
10	Offer	50	10	1	0.8	0.8	400	8
9	Offer	40	5	1	0	0	0	0
8	Offer	30	10	0.2	0	0	0	0

Ranked List	Type	Reference Price (RP)	QBOA	TNIV Tag	PAR Tag	Imbalance Price Tag (TIP)	RP × QBOA × TIP	QBOA × TIP
7	Offer	20	20	1	0	0	0	0
6	Bid	50	-10	0	0	0	0	0
5	Bid	40	-20	0	0	0	0	0
4	Bid	30	-3	0	0	0	0	0
3	Bid	20	-20	0	0	0	0	0
2	Bid	10	-20	0	0	0	0	0
1	Bid	5	-10	0	0	0	0	0
							1260	20

Note that if the QPAR value was 1 MW (PAR 1), then only offer 13 would have a PAR tag of 1 and would alone set the initial imbalance price at €80/MWh.

