PXIL
Transforming Power Markets

Ref: PXIL/S&R/27092023/1 Date: 27th September 2023

To
The Secretary
Central Electricity Regulatory Commission
3rd and 4th floor, Chanderlok Building
36 Janpath
New Delhi - 110001

Sub: PXIL observations on 'Staff Paper on 'Market Coupling'

Ref: Public notice ref no Eco-14/1/2023-CERC dated 21.08.2023 inviting comments and suggestions on 'Staff paper on "Market Coupling'

Dear Sir,

Apropos to above. the Hon'ble Commission notified implementation of Central Electricity Regulatory Commission (Power Market) Regulations, 2021 ('PMR 2021') from 15th August 2021. Part-5 of PMR 2021, i.e. Regulations 37 to 39, provides enabling provision for 'Market Coupling' among the Power exchanges.

India has adopted multi-power exchange model, at present all the three Power exchanges undertake price discoveries in Collective transaction, i.e. in Green-Day Ahead Market ('G-DAM'), conventional Day Ahead Market ('DAM'), Real Time Market ('RTM') and recently introduced High Price–Day Ahead Market ('HP-DAM') Contracts, independently. Therefore, three different prices are discovered for the same set of market participants, time blocks and bid zones in these Contracts disconcerting the participants, cause splitting of social welfare and inadvertently create monopoly in Collective segment.

The 'Market Coupling' mechanism, in addition to fostering competition among the Power exchanges, would optimise transmission allocation at the national level and enhance efficiency of power markers in the country. The staff paper identifies key constructs of the market coupling mechanism, to enhance competitive efficiencies, increase economic welfare, promote competition between the power exchanges and provide greater choice to market participants.

We have prepared our suggestions keeping in view implementation of IEGC 2023, GNA, Ancillary Services Market and the Deviation Settlement Mechanism (the market linked penalty mechanism for grid discipline) to have a holistic approach towards this path-breaking development. Second, our views are to ensure harmonisation of the spot market with the forward market and the capacity and derivatives market, as and when, they become operational. Accordingly, our suggestions have also included 'principles of markets' which need to be defined / designed.

We have considered 'Social Welfare Maximisation' of the entire market as the overarching principle, both in letter and spirit, as enshrined in the PMR 2021. Our matching algorithm, PIOUS-22, a Multi Integer Linear Program (MILP) developed in collaboration with IIT Mumbai, has stood to Hon'ble CERC's scrutiny on the same, it can be augmented to include newer aspects as envisaged in the staff paper.

The electricity markets in Europe, which has been referred to in the Staff paper, have evolved to ensure that Price coupling in day ahead market is undertaken by operating a single price coupling algorithm commonly known as EUPHEMIA (acronym for Pan-European Hybrid Electricity Market Integration Algorithm). The Single Day-ahead Coupling (SDAC) has created a single pan European cross zonal day-ahead electricity market, an integrated day-ahead market was proposed to increase the overall efficiency of trading by promoting effective competition, increasing liquidity and more efficient utilisation of generation resources across Europe. Since February-2014, EUPHEMIA is progressively used to calculate energy allocation and electricity prices across Europe, maximizing the overall welfare and increasing the transparency of the computation of prices and flows. This has also resulted in allowing multiple exchanges to operate simultaneously in the same geography, resulting in increased competition while simultaneously ensuring that a single price benchmark is created thereby serving the overall market by maximizing the social welfare for all participants.

A similar Price coupling approach where the offers & bids received by multiple power exchanges when cleared by a common algorithm will result in single price being discovered for same delivery period and lead to system-wide social welfare maximization and enable multi-power exchange model to thrive in a competitive environment.

The Hon'ble Commission's decision of implementing 'Market Coupling' is step in the right direction to utilize the expertise developed by Power exchanges on matters related to price discovery and clearing & settlement functions over a decade of power exchange operations.

We take this opportunity to reiterate and assure you that Power Exchange India Limited ('PXIL'), with its institutional promoters and shareholders, segregation of ownership, Board and management thorough governance structure is suitably equipped to build a trustworthy Market Infrastructure Institution ('MII').

Future development in power sector depends on expansions in scope of market based electricity transaction in the country, the 'Market Coupling' mechanism will enable power exchange platform to fulfill its role as a MII and PXIL is prepared to execute this responsibility.

We request Hon'ble Commission to kindly take our suggestions on record and grant us an oppurtunity to present them to the Commission and staff.

Thanking You,

Yours faithfully,
For **Power Exchange India Limited**

ANIL VITTHAL KALE
Digitally signed by ANIL VITTHAL KALE
Date: 2023.09.27 11:57:54 +05'30'

Anil V. Kale
AVP and Head – Strategy and Regulatory

PXIL suggestions and observations on 'Staff Paper on Market Coupling'

PXIL submits that at present the three Power exchanges undertake price discoveries for the Integrated Day Ahead Market and Real Time Market Contracts independently. Therefore, nine different prices can be discovered in Integrated Day Ahead Market Contract comprising of three segments, i.e. G-DAM, conventional DAM and HP-DAM, as different Order books are created from same set of market participants, for same time block and same bid zone/geography. Similarly, three different prices are discovered in Real Time Market Contract for the same set of market participants, for same time block and same bid zone/geography.

However, on implementation of 'Market Coupling' mechanism as prescribed in PMR 2021, the process of combining bids received by the three Power exchanges will result in uniform market clearing price across the market participants, for same time block and same bid zone/geography.

Background:

1. The Hon'ble Commission in Suo-motu Order dated 18.01.2007 in Petition no 155/2006 in the matter of 'Development of common platform for electricity trading' approved operation of Multiple Power Exchanges in the Indian electricity market. PXIL is one of the three Power exchanges operating under provisions of Central Electricity Regulatory Commission (Power Market) Regulations, 2021.

2. The Hon'ble Commission vide Order in Petition no 21/2008 dated 27.05.2008 granted approval to PXIL for setting up and operation of Power exchange. Later, vide Order in Petition no 21/2008 dated 30.09.2008, the Hon'ble Commission approved Rules and Bye-laws and permitted PXIL to start operation of the Power exchange from a date to be announced in advance.

3. PXIL submits that prior to commencement of power exchange operation from 22.10.2008, vide letter ref no 20/4(24)/2008-CERC dated 14.10.2008, the Hon'ble Commission directed the Nodal agency for Collective transaction i.e. National Load Dispatch Centre ('NLDC') that the matter of congestion management in multi-exchange scenario be discussed with the two power exchanges with a view to evolve an agreeable practical and optimal solution. The referred letter is attached as Annexure-1.

4. Later NLDC in its letter ref no CSO/CERC dated 17.10.2008 submitted to Hon'ble Commission the 'Gist of discussions held between NLDC, IEX and PXI date 16.10.2008', wherein it submitted the issue of congestion management and sharing of available transmission capacity on various corridors between multiple exchanges as one of the matters discussed in the meeting

   NLDC had at point 2, 'Gist of discussions held between NLDC, IEX and PXI' dated 16.10.2008, informed the possible approaches to address the issue:

   > ***"2. The issues in handling congestion in a multi-exchange scenario were submitted to the Hon'ble Commission vide POWERGRID letter dated 18-Sep-08 ad copy of the same was also given to both exchanges ahead of the meeting. The following possible approaches were mentioned:***
   >
   > ***a. Priority Based Rules***
   >
   > ***b. Pro-rata***

c. Explicit auctioning
d. Merging of bids by each PX for finding a constrained solution"

PXIL had at point 5 of the discussion, submitted its views on the matter:

> *"5. On a query from IEX, PXI clarified that market splitting was being used for congestion management by them. PXI mentioned that most methodologies for sharing of available margins such as priority based rules and pro-rata led to sub-optimal solutions. The most optimal solution would be obtained by merging of bids of the multiple exchanges and PXI was agreeable to the same. However, the confidentiality issues were also to be taken care of. It was emphasised that the methodology adopted should be fair and transparent."*

NLDC had at point 7 of the discussion, submitted that

> *"7. It was agreed that adoption of the pro-rate methodology was a sub-optimal solution which would not lead to overall economy and efficiency and was difficult to implement.* ***Some of the difficulties of pro-rata are:***
>
> ***a. Fragmentation of the available margins***
> ***b. Sub-optimal utilisation of the grid***
> ***c. Possibility of congestion shifting from one corridor to another***
> ***d. Treatment in case of skewed requisition by exchanges***
> ***e. Treatment of counter flows***
> ***f. Impact of block bids***
> ***g. Over-estimation of requirement, gaming, non-delivery by players***
> ***h. Multiple price discovery leading to inter-play between different markets"***

NLDC had at point 9 of the discussion, confirmed that PXIL can commence power exchange operation on 22.10.2008 as proposed

> *"9. NLDC confirmed that PXI could start operations on 22nd Oct 2008 as proposed by them. ……………*

The letter ref no CSO/CERC dated 17.10.2008 is attached as Annexure-2

5. Later, PXIL commenced power exchange operation from 22nd October 2008 by running auction session for DAM between 10:00 to 12:00 hrs for delivery date 23.10.2008.

6. PXIL submits that the matter regarding allocation of transmission capacity in multi-power exchange model was placed for discussion to the Expert Group constituted in Petition No 158/MP/2013

   At para 15 of the Order dated 04.04.2016, the Expert Group identified that merging of bids requires changes in market design and amendment to Power Market Regulation

> *"Para 15*
> *15. The Expert Group considered the study carried out by Dr. Puneet Chitkara and Dr. Abhyankar on "Simulation of Alternatives Proposed allocation of Transmission Corridors between the Power Exchanges". The present models were tested on a 14 bus system with normal bids and congestion in one corridor. As per the study, merging of the bids of the power exchanges would be the first best solution in comparison to various other*

allocation methods. ***However, the Expert Group agreed that more in depth study was required to capture the full complexity such as loop flows and counter flows etc. The Expert Group has acknowledged that the solution of merging of bids was not acceptable to the power exchanges for various reasons including the apprehension that devoid of price discovery engine, exchange would be reduced to a glorified trader. Moreover, the Expert Group has recommended that merging of bids would require changes in the market design and amendment with the Power Market Regulations in addition to resolution of various other practical considerations such as confidentiality, running of merging solution, logistics, settlement among multiple exchanges, etc. The Expert Group has concluded that in case merging of bids is implemented, the power exchanges would compete of services they offer rather than the price discovered in by them in Day Ahead Market."***

At para 16 of the referred Order the Hon'ble Commission observes that the concept of merging of bids is pre-mature and is not relevant, and informs that recommendation of Expert Group for merging of bids is not considered

"Para 16.

As the Expert Group has itself suggested that resolution of various practical issues are required before considering the proposal for introduction of merging of bids /market coupling method. Moreover, the Expert Group has recommended for constitution of a separate committee for long term solution which may look into the market design issues in a holistic manner including the transmission access methodology besides requirement of infrastructure, logistics, settlement etc. for implementation of merging of bids for optimal solution of transmission corridor allocation amongst multiple exchanges. Both the power exchanges have expressed serious reservation about the solution of merging of bids. ***The Commission is of the view that the concept of merging of bids is pre-mature at this stage and is not relevant in the context of the present petition. During the hearing of the petition, CEO, POSOCO clarified that congestion on the transmission corridor is not that acute as it was prevailing four years back which was also endorsed by the representatives of both the power exchanges. Therefore, the Commission has not considered this recommendation of the Expert Group for merging of bids of the power exchanges"***

PXIL submits that, while the scope of the Expert committee was to evaluate the current practice of allocation of Transmission capacity for collective transaction on day ahead basis. It also considered and recommended that the merging the bids of the two Power exchanges for a common price discovery would give optimum solution as outlined in the Minutes of meeting of the 4th meeting of Expert group vide ref no 158/MP/2013/2015 dated 26.06.2015. The relevant extracts of page 4/5 of MoM is reproduced as follows:

"(d) The solution of merging of bids of the two Power exchanges would give the optimum solution thereby giving maximum Social welfare. Upon implementation, the exchanges would mainly compete on services, frontend (user interface), clearing mechanism, reports, etc. ***However, merging of bids methodology, would require designing of a suitable mechanism around it, e.g. Algorithm for merging, same bid structures, etc. Thus it is advisable to constitute a separate committee to facilitate its implementation.***

(e) It was also discussed that any solution other than merging of bids may be ultimately sub-optimal for transmission corridor allocation…"

Dr. Nicholas Ryan, Assistant Professor of Economics, Yale University who specializes in Indian Energy Sector presented his views in the expert group meeting endorsing the concept of 'Price coupling' as most viable alternative to maximize Social welfare along with Optimal corridor utilization.

7. The matter regarding allocation of transmission capacity in Real Time Market ('RTM') was implemented vide directions provided in Order dated 28.05.2020 in Petition No 10/SM/2020 (Suo-Motu) wherein allocation in case of transmission congestion was 'pro-rated' in ratio of initial market cleared volume of RTM in respective Power exchanges.

    "Para 11.
    The Commission considered the various options discussed above carefully and is of the view that Option-3 is the most optimal. This option envisages that after the gate closure, within the next fifteen minute time block, the entire process of file transfer and verification of combined volume cleared for both exchanges against the ATC for RTM, has to be completed. The Commission recognises the operational challenges of this option in the context of short time available for processing in RTM. Based on the review, the Commission is of the view that this option is feasible, but that greater confidence, especially in terms of robustness of software and communication link, would come with implementation experience over time

    The Option-3 as detailed in the referred Suo-motu Order was '***Allocation of transmission corridor in case of congestion based on the ratio of initial market clearing volume of RTM in the respective Power Exchanges"***

<u>14th report of Parliamentary Standing Committee on Energy</u>

8. The Parliamentary Standing Committee on Energy in its 14th report titled 'Evaluation of Role, Performance and Functioning of the Power exchanges' has acknowledged that the Price discovery mechanism for Day Ahead Market is governed by Regulation 11 of Power Market Regulations 2010 and has recommended as under to make the bidding process more transparent and to avoid human intervention at multiple points:

    '***<u>Clause 9 Price Discovery Mechanism</u>***
    .....
    (v) POSOCO/NLDC may be directed to declare the availability of transmission corridor in advance, to enable more informed decision making and robust price discovery in the Power Exchanges.

    (vi)The Price Discovery Mechanism needs to be verified to make sure that matching of bids and the resultant prices discovered are fair and not manipulated. While stringent regulatory oversight is the need of the hour, one alternative is to assign the responsibility of price discovery to a neutral Third Party.

    (vii) The Third Party, before initiating the bid process, should consider the availability of transmission corridor and then run the bids through the matching engine to arrive at MCV and MCP. The structure, functional responsibilities, over-sight mechanism, etc. for the Third Party service provider may be decided by the CERC.

(viii) Such an arrangement would enable greater social welfare maximisation as the number of bids for price matching will increase (as a result of combining the bids of all the Power Exchanges). This will also encourage establishment of multiple Power Exchanges and bring in more competition in this segment of the Power Market. The Power exchanges will then compete, based on the services they provide.'

Draft CERC (Power Market) Regulations, 2020

9. The Hon'ble Commission vide Public notice ref no L-1/257/2020/CERC dated 18.07.2020 issued draft CERC (Power Market) Regulations, 2020 inviting stakeholders to submit their comments and suggestions on draft Regulations by 07.08.2020, later submission from stakeholders was extended till 14.08.2020 and a public hearing was also scheduled on 14.08.2020.

   PXIL submits that Regulation 39 of the draft prescribed functions of the Market Coupling Operator

   'Regulation 39. Functions of the Market Coupling Operator

   1) *The Market Coupling Operator, with the approval of the Commission, shall issue a detailed procedure for implementing Market Coupling including management of congestion in transmission corridor, the timelines for operating process, information sharing mechanism with the Power Exchanges and any other relevant matters.*
   2) *The algorithm for enabling Market Coupling shall be developed and managed by the Market Coupling Operator and implemented with the approval of the Commission.*
   3) *Market Coupling Operator shall create and maintain a document on its website providing detailed description of the algorithm used for price discovery. The description shall include bid types, details of how the algorithm results in maximisation of economic surplus taking into account various bid types and congestion in transmission corridor, which shall be updated with every new version of the price discovery algorithm.*
   4) *The Market Coupling Operator shall use the algorithm to match the collected bids from all the Power Exchanges, after taking into account all bid types, to discover the uniform market clearing price, subject to market splitting.*
   5) *The Market Coupling Operator shall communicate the results of the auction to the Power Exchanges in a transparent manner.'*

PXIL submits that Regulation 40 of the draft proposed that each power exchange is responsible to communicate results of auction conducted by Market Coupling Operator to participating bidders

'Regulation 40
The Power Exchanges shall inform the participating bidders about the results of the auction as communicated by the Market Coupling Operator'

PXIL submits that the Explanatory Memorandum accompanying the draft Regulation detailed the issues in the present multi-power exchange model and the thought process for inclusion of provisions on Market Coupling

"Clause 3.5 Market Coupling

3.5.1. Multi-Power Exchange model, such as that exists in India, may result in scenarios in which

i. *there is difference in the prices discovered on different Power Exchanges for a particular market of collective transactions; or*
ii. *allocation of transmission corridor amongst the Power Exchanges is not optimal owing to skewed market share of various Power Exchanges; or*
iii. *overall economic surplus is not maximized since buyers and sellers may be spread out on various Power Exchanges.*

3.5.2. In addition to above mentioned issues, the Commission expects that financial products in the electricity market (which are under the process of being approved by the competent authority) would require uniform price discovery in the Day Ahead and Real-time markets.

3.5.3. In order to address the issues highlighted in 3.5.1 and 3.5.2 above, the Draft Regulations provide an enabling provision to introduce market coupling among the Power Exchanges, with the objective of discovering uniform clearing prices in the Day Ahead and Real-time markets, ensuring optimal utilisation of resources and maximisation of economic surplus. *Further, the charges for deviation settlement are currently indexed to the Day Ahead market clearing price. A uniform market clearing price in the Day Ahead market discovered by the market coupling process, would minimise the scope for any arbitrage between deviation settlement and the market."*

Implementation of PMR 2021

10. The Hon'ble Commission issued PMR 2021 on 15.02.2021 and vide notification ref no L-1/257/2020/CERC dated 28.07.2021 notified implementation of said provisions from 15.08.2021. Regulation 37 of PMR 2021 prescribes objectives of Market Coupling:

"Regulation 37 *Objectives of Market Coupling*

(1) Discovery of uniform market clearing price for the Day Ahead Market or Real-time Market or any other market as notified by the Commission;

(2) Optimal use of transmission infrastructure;

(3) Maximisation of economic surplus, after taking into account all bid types and thereby creating simultaneous buyer-seller surplus."

Similarly, Regulation 38 of PMR 2021 prescribes who shall be designated as Market Coupling Operator:

"Regulation 38 Designation of Market Coupling Operator

Subject to provisions of these regulations, the Commission shall designate a Market Coupling Operator who shall be responsible for operation and management of Market Coupling"

Similarly, Regulation 39 of PMR 2021 prescribes that the shape and form of implementation shall be based on directives issued by Hon'ble Commission:

"Regulation 39

The provisions with regard to market coupling and Market Coupling Operator in these regulations shall come into effect as and when decided by the Commission in accordance with the regulations to be specified separately"

PXIL submits that based on views, suggestion, comments and/or observations made by stakeholders on draft CERC (Power Market) Regulations, 2020, the Hon'ble Commission in PMR 2021 has deleted provisions detailing function of the MCO and responsibility of Power exchange to disseminate results to participating bidders and has instead prescribed that separate regulations would be framed for market coupling mechanism and MCO.

Roadmap for Development of electricity market in India

11. PXIL submits that Ministry of Power (MOP) has released report titled 'Development of Electricity Market in India' with an objective to create an efficient, optimal and reliable market framework to enable the energy transition and integration of renewable energy into the grid. The report identifies market elements to be implemented in three phases i.e. within one year from now, medium-term i.e. within 1-2 years from now and long-term i.e. two years and beyond from now.

    Chapter 5, Clause 5.3 (ii) of MOP reports has prescribed necessity to implement Market Coupling to ensure social welfare maximisation:

    > *"5.3. The key learnings, derived by the Group, which could be applied in Indian context from the international studies on Day Ahead markets, are being summarized below:*
    >
    > *i. Market-based despatch by the System Operator (SO) (such as in US) enable system cost optimization through unit commitment and economic dispatch. It is a system where participation is mandatory and the entire supplier fleet and demand from LSEs (Load Serving Entities) / Retailers / Distribution Utilities have to mandatorily participate.*
    >
    > *ii. De-centralized markets such as the ones in Europe provide for degrees of self-dispatch / bilateral operations.* ***However, to ensure social welfare maximization, bids and offers in the power exchanges across all the bidding areas / zones are combined through the Price Coupling of projects. Price coupling ensures that bids and offers are combined to discover a single uniform market clearing price for a zone / bidding area."***

    The MOP report establishes a roadmap for utilisation of Power exchanges as the central piece for development of robust, transparent and liquid Markets in Electricity

12. PXIL is keen to submit clause wise observations/suggestion on discussion paper

13. Clause 5.2

Does the current Indian power market scenario form a compelling case for market coupling.

5.2.4. Given the existing market share of power exchanges in the collective transaction segment, it seems that while the implementation of market coupling may not cause any major change in terms of price discovery, the bids could be divided among the exchanges, which at present are concentrated in one exchange. International evidence suggests that in countries *where multiple exchanges exist, for instance, in Norway, where there are Nord Pool and EPEX, the bids are sent to the Coupling Operator by the exchanges for rate discovery.*

5.2.5. Under such a scenario, what significant benefits can be derived in terms of uniform price discovery, and which model suits best for India?

Suggestions:

Market Coupling mechanism in European Union region

PXIL submits that 'Market Coupling' mechanism has been implemented in European Union ('EU') region where each Power exchange ('PX') caters to transaction needs of participants in a sovereign region. Market coupling in the EU context of Internal Electricity Market (IEM) refers to the integration of two or more electricity markets from different areas through an implicit cross-border allocation mechanism. Market Coupling uses so-called implicit auctions in which market participants do not individually receive allocations of cross-border capacity, they just bid for the electricity on the Exchange as an integrated electricity market.

1. Early initiatives for 'Market Coupling'

Before the introduction of Market Coupling, cross-border capacity on one hand and electricity on the other hand, had to be purchased separately. The Trader/Member had to reserve cross-border capacity in a first step, before using this capacity to transport the electricity bought in a second step.

Market Coupling maximizes social welfare, avoids artificial splitting of the markets, and discovers the most relevant price signal for investment in cross-border transmission capacities. The efficiency of Market Coupling is furthermore proven by an increasing price convergence between market areas. The route towards market/price coupling adopted by large electricity system in Europe necessitated optimal utilisation of transmission network

a. Germany's market design of multiple PXs did not work due to absence of Market Coupling in early period

Period	Particulars
May 2000	The first Power Exchange (APX "Deutschland", APXDE), similar to Dutch APX, was set up with the aim of developing a multi-hub market
June 2000	Leipzig Power Exchange (LPX) was launched with auction trading for individual hours and block contracts
August 2000	European Energy Exchange (EEX) was launched. The EEX system differed from previous exchanges as it used a continuous trading system
December 2000	APXDE ceased operation after many months of no trading
2002	LPX and EEX merged creating a single exchange. Soon hourly auction started to dominate the volumes of trade

b. Exchange operations in French electricity system

Period	Particulars
2001	Establishment of Powernext SA, operator of French Spot Power market
2008	Powernext SA and EEX AG create 50:50 venture EPEX SPOT SE
Jan 2009	Powernext Power Spot is transferred to EPEX SPOT SE

c. Coupling of markets

Period	Particulars
2006	Launch of Trilateral Coupling (TLC): The first MC initiative between France, Belgium and Netherlands established by Powernext SA and APX Dutch
2010	Market Coupling in Central Western Europe (CWE) and the interim
2014	Price Coupling in North-Western Europe (NWE) This was a project initiated by the Transmission System Operators and Power Exchanges of the countries in North-Western Europe. The 17 partners of this project comprise the Power Exchanges EPEX SPOT (including former APX and Belpex) and Nord Pool as well as the TSOs 50Hertz, Amprion, Creos, Elia, Energinet.dk, Fingrid, National Grid, RTE, Statnett, Svenska Kraftnät, Tennet B.V. (Netherlands), Tennet GmbH (Germany) and TransnetBW. It was the first initiative to use the pan-European **PCR** (Price Coupling of Regions) solution for the simultaneous calculation of market prices and flows on interconnectors with one single shared algorithm called Pan-European Hybrid Electricity Market Integration Algorithm ('EUPHEMIA'). At the time of the launch, NWE stretched from France to Finland and from Great Britain to German/Austria, covering the region of CWE, Great Britain, the Nordics and the Baltics
February – 2015	Multi-Regional Coupling (MRC) Italy coupled with France, Austria and Slovenia. The coupled area covered 19 countries, accounting for about 85% of power consumption in Europe

d. UK also adopted Market Coupling to discover one risk prior to Brexit on 31.12.2020

Before 2012, UK had two independent power exchanges, when issue of integrating the UK electricity markets with EU markets came up, it realized that two-Power exchange market design is an impediment to its implementation. UK decided to change the market design and adopted market coupling and discovered a single electricity price. NordPool Spot developed and operated a 'virtual hub' for UK electricity market in the NWE market coupling. The UK hub facilitates open access and participation of all PXs and ensures that there is a single electricity market price for UK.

2. Framework regulating electricity market in EU region

PXIL submits that 'Market Coupling' mechanism has been implemented in EU region where each Power exchange caters to transaction needs of participants in a sovereign region. The transaction services offered by a PX can be categorised into following three core functions:

(i) Collection of buy and sell Bids
(ii) Matching of Bids to determine the most efficient transactions between buy and sell bids; and
(iii) Physical and financial execution of the trades i.e. clearing and settlement of trade

Out of these three key functions performed by a PX, the matching or price discovery has been carved out of the PXs as a separate Market Coupling Operator ('MCO') function in Europe mainly because of its monopolistic attributes.

This is clearly evidenced in the EU Regulation 2015/1222 on 'Establishing a guideline on capacity allocation and congestion management' ('CACM') dated 24th July 2015, which came into effect from 14.08.2015, by recognising the fact that it will be impossible to achieve optimal allocation with parallel algorithms:

(i) Matching all bids and offers, such that Social welfare (consumer surplus + producer surplus + congestion revenue) is maximised, and
(ii) Allocating transmission capacity (both usage and direction of flows) in a centralised procedure is a necessary condition to achieve optimal capacity allocation across the concerned bidding zones

(the CACM Regulation ref no EU 2015/1222 dated 24th July 2015 is attached as Annexure-3)

The rationale for regulatory intervention stems from the fact that there is a natural tendency for liquidity to concentrate on one Power exchange over a period of time which defeats the whole objective of having a multi-power exchange model. The perception that a multi-power exchange model, without the separation of MCO function, will eventually result in convergence of prices and an equilibrium state for the liquidity across the power exchanges is misleading. This is analysed by studying the economic characteristics of the price discovery and concluding that the attributes have monopolistic properties

- The prices in the day ahead market are discovered by using a Double Sided Closed Bidding Auction with Uniform Market Clearing Price. Thus, without the separation of MCO, each power exchange will discovery its own distinct price
- To start with, even if it is assumed that there are comparable market shares across the power exchanges, it is not necessary that the prices and liquidity will converge to an equilibrium state over a period of time. This is because the power exchanges located within same geography and catering to same market have their own independent Order books and may not necessarily receive homogenous bids.

The CACM regulation in EU has recognised the monopolistic attributes of power exchanges and therefore separately carved out the Price Discovery and Non Price Discovery functions of power exchanges as MCO and Nominated Electricity Market Operators ('NEMOs') respectively. While the latter are competitive, the MCO services are not. The key highlights of the NEMOs and MCOs operating in EU are provided below:

- EU's CACM regulation divides the essential tasks of a power exchange between a MCO and a NEMO. The MCO is responsible for matching orders and ensuring an optimal allocation of transmission capacity across the bidding zones for the day-ahead and intraday market, while the NEMO provides the interface between the MCO function and the market participants. The long term vision of EU is that both the MCO and the NEMO function should be performed by NEMOs

- The designation criteria for NEMOs are applied in such a way that competition between NEMOs is organised in a fair and non-discriminatory manner
- Each member country has to ensure that at least one NEMO is designated in each bidding zone of its territory. A NEMO designated in one member country has the right to offer services with delivery in another member country

The EU member countries as of now have designated 16 NEMOs for organising and operating the day ahead and intraday Price Coupling of Regions across 27 EU countries. In the day ahead market, ten (10) countries have defined NEMO as a national monopoly with only one NEMO in each country except Spain and Portugal, both of which have designated OMIE S.A. as their NEMO. Such national NEMOs are not allowed to compete in other countries. Nearly, seven (7) countries, e.g. Austria, Denmark, Finland, Germany, Poland, Sweden and Norway have three competing NEMOs, while nine (9) other countries e.g. Belgium, Estonia, France, Ireland, Latvia, Lithuania, Luxembourg and Netherlands, have two designated NEMOs with passport rights. The passport rights, enables NEMO to operate in a Member State different from the one of designated, offering its transaction services as 'passporting NEMO' in other Member State.

In bidding zones with multiple operating NEMOs such as Austria, Germany, Poland and other countries, the liquidity from multiple NEMOs is first pooled together at a 'virtual hub' to create a single reference price and then the NEMOs are allowed to co-ordinate their Order books and transmission arrangements with the rest of Europe through designated MCO for the region.

The details of NEMOs and passporting rights available for different power exchanges in the EU region are attached as Annexure-4.

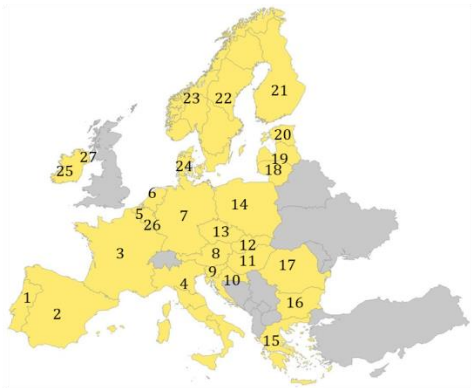
To sum-up, PXIL submits that to improve the integration of European markets, the Price Coupling of Regions (PCR) project was established by eight (8) nominated electricity market operators (NEMOs) in 2012, e.g. EPEX SPOT, GME, HEnEx, Nord Pool, OMIE, OPCOM, OTE and TGE. **The PCR project created a governance structure based on a Co-Ownership Agreement and a Co-Operation Agreement among power exchanges.** The CACM regulation has provided a governance structure to discover single price in EU area encompassing 27 European countries, with annual trade volume of 1,683 BU in 2022. This initiative developed a price coupling algorithm to calculate electricity prices across Europe, respecting the capacity of relevant network elements. Composing a common algorithm would create a transparent mechanism to determine day-ahead electricity prices and net position of a bidding area across Europe. The PCR announced the Pan-European Hybrid Electricity Market Integration Algorithm ('EUPHEMIA') in February 2014 to calculate energy allocation and electricity prices across Europe, maximize overall welfare, and increase transparency of price computation and flows. Participants may bid in block, complex, and merit orders.

The list of countries part of the EU day-ahead market is as under:

In 2020, despite pandemic and in 2021 despite Ukraine-Russia crisis, market integration progressed.

EU day ahead market areas coupled in 2010 (left) and 2023 (right)

2010 – 10 Sovereign Electricity areas
Portugal, Spain, France, Germany, Belgium, Netherlands, Finland, Sweden, Norway and Denmark



2023 – 27 Sovereign Electricity areas
1-Portugal, 2-Spain, 3-France, 4-Italy, 5-Belgium, 6- Netherlands, 7-Germany, 8-Austria, 9-Slovenia, 10-Croatia 11-Hungary, 12-Slovakia, 13-Czech Republic, 14-Poland, 15-Greece, 16-Bulgaria, 17-Romania, 18-Lithuania, 19-Latvia, 20-Estonia, 21-Finland, 22-Sweden, 23-Norway, 24-Denmark , 25-Ireland, 26-Luxembourg, 27-Northern Ireland

Further, EUPHEMIA, which is coupled with multiple power exchanges, demonstrates how India's current market, which operates with three power exchanges, can be coordinated to maximize efficacy in social welfare and power flow.

(EUPHEMIA Public Description: Single Price Coupling Algorithm, October 2020, is provided as Annexure-5)

<u>Market Coupling relevant to Indian electricity market</u>

PXIL submits that multi-power exchange model has been adopted in the country. At present all the three power exchanges undertake price discoveries for Collective transaction, i.e. in Green-Day Ahead Market ('G-DAM'), conventional Day Ahead Market ('DAM'), Real Time Market ('RTM') and recently introduced High Price–Day Ahead Market ('HP-DAM') Contracts, independently. Therefore, three different prices are discovered for the same set of market participants, time blocks and bid zone/geography. However, Market Coupling as provided in PMR 2021 will result in uniform market clearing pricing across the market participants, time blocks and bid zone/geography.

Further, in Collective transactions, the participants (buyer or sellers) place their bids blindly without being aware of what other participants are bidding, after the auction window is closed, the discovered price is a reflection of demand-supply bids received at the Power exchange platform.

In case of Distribution licensees ('Discom'), that transact on Power exchange platform to manage its portfolio, any intent to 'exercise choice' by participating on three Exchange platforms necessary leads to splitting of bids and settlement of transactions at different clearing prices, which are well-nigh impossible to explain internally to Audit authorities to the extent price is high on one Power exchange when compared to other two Power exchanges for meeting purchase requirement and vice versa when surplus power is being sold.

Further, with three Power exchanges discovering prices independently, nine different prices are discovered for the same time blocks and same geography in IDAM Contract. There is no mechanism to equilibrate the prices between the three Power exchanges which creates an opportunity cost for bided quantum because participation in one Power exchange forecloses the

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option of participating in two other Power exchanges for the same Contract, time block and bid zone/geography. It is submitted that the Explanatory Memorandum issued with Draft CERC (Power Market) Regulations, 2020 had detailed the issues regarding multi-power exchange model as:

> ***"Clause 3.5 Market Coupling***
> ***3.5.1. Multi-Power Exchange model, such as that exists in India, may result in scenarios in which***
> ***i. there is difference in the prices discovered on different Power Exchanges for a particular market of collective transactions; or***
> ***ii. allocation of transmission corridor amongst the Power Exchanges is not optimal owing to skewed market share of various Power Exchanges; or***
> ***iii. overall economic surplus is not maximized since buyers and sellers may be spread out on various Power Exchanges"***

Further, it is submitted that in the absence of market coupling, no equitable solutions has evolved in the past 15 years of power exchange operations that resolves the issue of price difference in multi-power exchange model. The other key advantages of the Market Coupling mechanism are:

a) It is a significant and essential step towards achieving one nation, one market. The mechanism enables greater flexibility to Members to trade across power exchanges purely on the basis of nature, quality and price of Contracts offered by an exchange, rather than on the basis of volumes transacted on an exchange

b) Having Market Coupling is indispensable for having a multi-power exchange model, as it addresses any liquidity related concerns. Having multiple exchanges will effectively increase competition in the market, thereby incentivising innovation by the exchanges. Introduction of Market Coupling is in furtherance of long-standing objective of this Hon'ble Commission to have a competitive power market comprising multiple exchanges, and addresses the key concern of fragmented liquidity caused due to multiple exchanges

c) It is especially critical to address the skewed market share of the current exchanges and facilitates the entry of new exchanges into the market

d) Market Coupling is a sine qua non in a multi-power exchange model to ensure discovery of a uniform marker clearing price in collective transactions

e) Deepening of markets with integration of market-wide Social Welfare Maximisation and increase in value of the transactions cleared in the collective segment, viz., DAM and RTM, by reducing the number of unexecuted bids of all power exchanges and maximising the volume of transaction. Overall economic surplus gets maximised even if buyers and sellers are spread across three or more power exchange platforms

f) Better allocation of transmission capacity; presently transmission capacity is allocated by the Load Despatcher to power exchanges in proportion of provisional transaction volumes. As a result, many bids may not get cleared on account of lack of/insufficient available transmission capacity to honour directional limits, leading to sub-optimal allocation of transmission capacity under the present mechanism. This issue will get resolved by the introduction of Market Coupling mechanism as there will be no requirement of exchange wise allocation of transmission capacity, honour directional limits for transmission of power resulting in optimum utilisation of transmission capacity

g) Better utilization of transmission capacity on account of higher transaction volumes due to lower number of uncleared bids across power exchanges

[An illustration for matters submitted at (f) and (g) above is provided at Annexure -6]

h) Effective identification of congestion in transmission corridors, so as to enable timely and appropriate investments in creation of necessary and adequate transmission capacity

i) Paves the way for implementation of Market Based Economic Dispatch ('MBED') and market based secondary reserve ancillary services

j) Will provide a single and robust price benchmark for introducing Derivatives in electricity and other financial instruments

k) Paves the way for integration of power markets from neighbouring countries as well

Thus, under Market Coupling mechanism, the bids received by multiple power exchanges get combined at a single platform, are cleared by a common algorithm, resulting in single price being discovered for same delivery period, in same geographical market and leads to system-wide social welfare maximisation. The mechanism allows for multi-power exchange model to operate in a competitive environment as prescribed in PMR 2021.

14. Clause 5.3

Effect of Coupling on technological innovation and competition

5.1.1. One school of thought could argue that price coupling would result in less incentive for product innovation and that the role of exchanges would be reduced to that of a bid-collecting agency. Further innovation, ease of transaction, technology solutions, dissemination of information, analytical tools, high-quality service will all be lost if the coupling of exchanges is centralised. The centralized algorithm, by design, may not be able to accommodate complex bid structures, keeping in view the compatibility of different power exchanges. As a result, the market may have to forego certain innovative products that could have improved participation.

5.3.1.The other school would point to the gains coupling could offer in terms of increased liquidity, efficiency, and competition among exchanges on the basis of the services they offer. Further, the increase in competition between the exchanges could result in a lowering of transaction fees, which would reduce the overall cost to the participants and may further increase the volume transacted.

5.3.2.Therefore, given the underlying economic principle of maximising social welfare and optimal corridor utilisation, which argument fits better in the Indian context

The queries posed in the above two clauses can be summed as:

a. Whether market may have to forego certain innovative products that could have improved participation (Clause 5.3.1), or

b. Whether gains in terms of increased liquidity, efficiency, and competition among power exchanges would reduce the overall cost to the participants and may further increase volume transacted (Clause 5.3.2)

Suggestions:

PXIL submits that Regulation 2 (1) (af) of PMR 2021 defines 'Market Coupling' as a process for collection of bids from all Power exchanges considering all bid types and discover the uniform market clearing price subject to market splitting

> *"**Regulation 2 Definitions and Interpretations***
> *(1) In these regulations, unless the context otherwise requires,*
> *(af) "Market Coupling" means the process whereby collected bids from all the Power Exchanges are matched, after taking into account all bid types, to discover the uniform market clearing price for the Day Ahead Market or Real-time Market or any other market as notified by the Commission, subject to market splitting"*

Regulation 2 (1) (ag) of PMR 2021 defines 'Market Coupling Operator' or ('MCO') as entity entrusted with the responsibility of operation and management of Market Coupling by the Hon'ble Commission

> *"**Regulation 2 Definitions and Interpretations***
> *(1) In these regulations, unless the context otherwise requires,*
> *(ag) "Market Coupling Operator" means an entity as notified by the Commission for operation and management of Market Coupling"*

PXIL submits that most of the design and operating aspects for Collective transactions i.e. double sided closed bid auction with uniform market clearing price, operating timelines for the markets, allocation of transmission capacities and congestion management, scheduling and dispatch rules etc. are all defined through the various provisions of PMR 2021, other CERC regulations and Procedures notified in this regard.

Since all the major design features and operational procedures for Collective transactions are tightly controlled and notified in Regulations and approved Procedures, the creation of MCO will not stifle innovation in these segments. The three power exchanges will continue to compete on the same fronts as they have been under the extant regulations:

a. **Technology platform for Transaction:** Technology plays a crucial role in the operation of power exchanges and can therefore be regarded as the core infrastructure required for operating a power exchange. With digitalisation of transactions gaining traction, the importance of technology is set to increase even further in the near future. The technology platform of power exchanges consists of the UI and UX systems for bid management & processing, clearing & settlement and MIS & report generation etc. and requires continuous capex & opex for regular upgrading and maintenance. As a result, the power exchanges make significant investments for innovation in order to stay ahead of the curve in their service offerings. With Market Coupling, the power exchanges will continue to compete on basis of the quality of their technology solutions and lead to further innovation in the space.

b. **Market Clearing Engine:** Piecewise (with linearized solution) and Stepwise are the two Mixed Integer Linear Program ('MILP') based market clearing algorithms being used by Indian Energy Exchange limited ('IEX') – Hindustan Power Exchange limited ('HPX') and PXIL respectively. These algorithms can yield different cleared volumes, traded at different market prices for the same set of inputs[1].

In Europe also, the power exchanges have adopted both Hourly Linear Piecewise (NORD POOL and EPEX) as well as Hourly Step (OMIE, EPEX (BE+NL+GB), GME, OPCOM and OTE) Orders[2]. The Market Clearing Algorithm EUPHEMIA used for Price Coupling of Regions (PCR) in Europe differentiates between the two algorithms i.e. the Piecewise and Stepwise orders within different geographies as well as the same geographies (bidding zones) by assigning unique IDs to them. Thus, with Market Coupling also, the preference of the market participants for a particular algorithm is assured and any innovation by a power exchange in its algorithm is not diminished. This was one of the key design criteria for EUPHEMIA, dictated by the market participants across Europe given the significant differences in the electricity market regulation, generation technologies, history, transacting and trading traditions etc. across each EU country. The competing power exchanges in Europe are obliged to cooperate with each other such that any extraordinary innovation in order formats by any power exchange which is better suited to the demand from market participants are included in the design of the algorithm.

A similar Standard Operating Procedure ('SOP') along with necessary protocols, system and procedures need to be introduced under PMR 2021 for capturing the nuances of bid structures applicable for different types of participants in Integrated DAM and RTM.

c. **Flexibility in Order submission:** Currently in Germany, three power exchanges operate as NEMO in Day-ahead product, e.g. EPEX Spot SE, Nord Pool EMCO AS and EXAA AG. It is submitted that the power exchanges have different number of days for opening of Order book

- EPEX Spot SE: In Day-ahead product the order book open 45 days in advance and closes one day before delivery at 12:00 hrs

  (the product specification for day-ahead and intra-day markets as published by EPEX Spot SE is provided as Annexure-7)

- Nord Pool EMCO AS: In Day-ahead product the order book opens 60 days in advance and closes one day before delivery at 12:00 hrs

  (the product specification for day-ahead and intra-day markets as published by Nord Pool EMCO AS is provided as Annexure-8)

It is submitted that Market Coupling has not deterred the competing power exchanges to offer different start dates for opening of order book

[1] Price discovery algorithm as available on websites of respective Power exchanges
[2] EUPHEMIA Public Description: Single Price Coupling Algorithm , October 2020

d. **Variety of Bid Types:** Currently, the most widely used bid types in Integrated DAM is Normal Orders and Block Orders, even though other bid types are also available in Day-ahead product of EU region. In EU region different power exchanges operating within the same geography or different geographies have adopted a variety of Bid types as per the geography as well as market participant requirements[3].

Italy: Operating power exchange – GME Spa

The most glaring example is the PREZZO UNICO NAZIONALE ('PUN') requirement in Italy with distinct Order types i.e. Supply Merit orders, Non-PUN demand orders and PUN Merit Orders from rest of the Europe. Similarly, all other Complex Order types such as Minimum Income Condition, Scheduled Stop, Load Gradient, Linked Block Orders, Flexible Hourly Orders and combinations thereof are offered by different power exchanges in different or same geographies. EUPHEMIA has coped with and supports a wide array of Bid formats as per the requirement of various geographies and market participants. Therefore, the perception that a centralized algorithm by design would not be able to accommodate new Bid structures in keeping with the compatibility of Bid types in different power exchanges is fallacious. As is evident from the European experience, the power exchanges don't have to compromise on innovative Bid types which improve market liquidity and enables evolution of market.

(The Bid types as available at GME Spa is provided as Annexure-9)

Germany: Operating power exchanges - EPEX Spot SE and Nord Pool EMCO AS

The two power exchanges offer different types of bids based on market participants requirements, few variances in the bid type parameter are:

Particular	EPEX Spot SE	Nord Pool EMCO AS
Types of Orders	Single hours, Block, Linked Block, Exclusive blocks, Big blocks and Loop blocks	Normal, Block, Exclusive Groups, Flexible orders
Single hours	Orders contain up to 256 price/quantity combinations for each hour of the following day	
Block Order volume limit	600 MW	900 MW
Big blocks	1500 MW	Not offered

[3] EUPHEMIA Public Description: Single Price Coupling Algorithm, October 2020

Particular	EPEX Spot SE	Nord Pool EMCO AS
Loop / Spread blocks (bundle buy and sell blocks to reflect storage)	Loop block: 2 blocks per portfolio	Spread block: 3 pairs per portfolio
Maximum amount of Block Orders		100 per Trading portfolio
Maximum amount of Exclusive Groups		5 per Trading portfolio
Maximum amount of Block Orders within an Exclusive Group		24
Linked Block Orders		Seven levels, maximum 6 Block Orders per level, maximum 13 total Block Orders in a linked block group
Price steps		The number of Price Steps is 200 per hour (including the upper and lower Order Price Limits)

It is submitted that in Germany where three power exchanges compete in the day-ahead market, the type of orders and their contract parameters differ based on market participant requirements.

Further, with increased RE penetration and emerging technologies such as BESS, Pumped storage systems, EVs etc., new and innovative Bid types become all the more important. With Market Coupling, all the power exchanges can propose new Bid types for increasing liquidity and work with MCO for incorporating the same in the algorithms

e. **Risk Management:** The Risk Management for collective transactions and/or bilateral transactions has been left to the power exchanges as per the broad framework provided under the PMR 2021. As a result, the power exchanges have freedom to use any prudent risk management technique and tools for assessment of the risks and define the margin framework for transacting in any Contract. This enables sufficient room for innovation and adoption of risk management principles for keeping the overall transaction costs minimal. Further, over the past 15 years, not a single default has been reported in the settlement of transactions at either of the power exchanges.

The Risk Management framework adopted by power exchanges has brought payment discipline and significantly improved the cash flow situation of the generators. With Market Coupling, the liquidity in Collective transactions will increase further and adoption of innovative Risk Management structures will continue.

f. **Clearing and Settlement:** The PMR 2021 has provided the operational freedom to power exchanges for managing their clearing & settlement function. The clearing & settlement is carried out by power exchanges diligently under the overall regulatory oversight of Hon'ble Commission and through the Market Surveillance Committee ('MSC') and Risk Assessment and Management Committees ('RAMC'). The importance of offering a robust, efficient and fast clearing & settlement by a power exchange can be hardly underestimated. It is of the utmost importance for market participants to maintain trust in the transactions.

   With Market Coupling, the power exchanges besides acting as the central counter parties to its members and clients will also be required to carry out financial settlement (transfer of money) amongst each other as is taking place in Price Coupling of Regions ('PCR') in Europe. The competing power exchanges will have to innovate further vis-à-vis their net positions as importing or exporting power exchange, transfer of congestion revenues and collateral requirements. Thus, Market Coupling provides enough space for power exchanges to compete and innovate on their clearing & settlement function.

g. **Information dissemination:** The power exchanges play a crucial role in reducing the information asymmetry in the market by providing extensive data related to prices, cleared volumes, congestion, aggregate demand and supply curves etc. to market participants so that they can make informed decisions with regards to their bidding in the Collective transactions. The power exchanges compete on various parameters such as transparency, amount of data and information availability, convenient data delivery mechanisms, up-to-date data, convenient formats, access over File Transfer Protocol ('FTP') or Application Programming Interface ('API') etc.

h. **Data Services and Analytical tools:** Data is the new oil of digital economy. However, analytical tools are required to synthesize and create value from data. The power exchanges compete on their data services viz. providing quality data i.e. clean, consistent data structures, from trusted sources with proactive quality management and tools for analysing and deciphering that data. In Europe, the power exchanges also compete on the basis of easy-to-integrate data services and analytical tools.

i. **Low-cost access:** With Market Coupling, a transparent and non-discriminatory access to power exchanges is ensured for market participants which would result in competition in the transacting fees thereby promoting attractive and innovative payment plans. Further, the competition amongst power exchanges will provide the necessary checks and balances regarding transaction fee to be charged by the Exchanges from the participants.

PXIL submits that, the potential rewards for innovations and improvements by power exchanges are not affected on implementation of Market Coupling mechanism. As is being perceived by few market participants that taking away the price discovery function

will incapacitate power exchange's value proposition by making them mere bid collection centres for MCO is fallacious.

Instead, Market Coupling will strengthen the competition leading to fructification of PMR's long standing objective for multi-power exchanges i.e. product innovation, efficiency in service delivery, no entry barriers for new power exchanges and control on transaction fees etc. along with system wide benefits like, e.g. maximising social welfare and optimal utilisation of transmission capacity. The development of competition in accordance with the precepts of the Electricity Act 2003 is a necessary condition to achieve a vibrant power market in the country. Competition delivers the best solutions and the regulatory framework needs to provide a stable level playing field.

15. Clause 5.4

Who shall be the Market Coupling Operator ?

As per the PMR 2021, a Market Coupling Operator (MCO) is to be designated by the Commission.

The various aspects related to these options are discussed below:

a. Power Exchanges to perform the function of Market Coupling Operator: The power exchanges, i.e. market operators in the Indian Power Market, just like the procedure followed in the European Market, may be made in charge of performing the role of the MCO on a rotational basis. If this scheme is adopted, the various aspects to be considered, but not limited to………

b. Third-Party Market Coupling Operator/ Super-Exchange: While the power exchanges have the expertise to run the algorithms and handle different market scenarios, having a third-party MCO shall ensure more objective operation and will not have any conflict of interest. The third party could be the system operator or an explicitly formed entity. A sample information flow in the case of a third-party MCO is used is provided in Annexure-II.

5.4.1. Given these requirements, what should be the ideal institutional/ structural design for market coupling and the extent of autonomy of various parties in such a design

The queries posed in the above two clauses can be summed as – Who shall be the MCO

a. Power exchange to perform the role of MCO
b. Third Party MCO / Super-Exchange
c. What should be role and responsibilities of MCO and/or Power exchanges to operate MCO within provisions prescribed in PMR 2021

Suggestions:

PXIL submits that Regulation 37 of PMR 2021 prescribes the objectives of Market Coupling:

> ***'Regulation 37. Objectives of Market Coupling***
>
> 1. *Discovery of uniform market clearing price for the Day Ahead Market or Real-time Market or any other market as notified by the Commission;*
> 2. *Optimal use of transmission infrastructure;*
> 3. *Maximisation of economic surplus, after taking into account all bid types and thereby creating simultaneous buyer-seller surplus.'*

Similarly, Regulation 38 of PMR 2021, prescribes CERC shall designate Market Coupling Operator, that shall be responsible for operation and management of Market Coupling.

> ***'Regulation 38. Designation of Market Coupling Operator***
>
> *Subject to provisions of these regulations, the Commission shall designate a Market Coupling Operator who shall be responsible for operation and management of Market Coupling.'*

It is submitted that PXIL and IEX have been operating Power exchange since July 2008 and October 2008, respectively, similarly HPX commenced its operations from July 2022. All the three power exchanges have invested in developing a fair, neutral, efficient and robust matching algorithm for price discovery, developing an IT based exchange platform for enabling transactions electronically and facilitate extensive, quick and efficient price discovery for transaction executed in different Contracts.

The requirement of identification and designation of MCO, has been part of consultative process vide four notifications/documents in public domain

a. Discussion paper on '*Market Based Economic Dispatch of Electricity: Re-designing of Day-Ahead Market (DAM) in India*' issued by Hon'ble Commission in December 2018
b. Draft CERC (Power Market) Regulations 2020 issued in July 2020
c. Ministry of Power detailed note on the subject '*Development of Renewable Energy Trade through Power Exchange*' issued in September 2020
d. Ministry of Power discussion paper titled '*Development of Power Market in India, Phase – 1: Implementation of Market Based Economic Dispatch*' issued in June 2021

The referred documents have proposed two models for performing the role of MCO

a. New entity i.e. other than existing Power exchanges

A new entity would be collecting Orders received from all Power exchanges, operate the matching algorithm, discover price, quickly disseminate information to all market participants

Ancillary Services Regulation 2022 – precursor to introduction of Market Coupling

The Hon'ble Commission notified implementation of CERC (Ancillary Services) Regulations, 2022 ('AS Regulation') from 5th December, 2022, in the first phase Primary Reserve Ancillary Services ('PRAS') and Secondary Reserve Ancillary Services ('SRAS') were implemented from 05.12.2023. In the next phase, Tertiary Reserve Ancillary Services ('TRAS'), comprising of Day Ahead Ancillary Services Market and Real Time Ancillary Services Market Contracts were introduced through power exchanges from 01.05.2023, PXIL introduced TRAS Contract in 'PRATYAY' system from 16.06.2023. It is submitted that the AS Regulation aims to provide mechanism for procurement, through administered as well as market-based mechanism, deployment and payment of Ancillary Services at the regional and national level for maintaining the grid frequency close to 50Hz, and restoring the grid frequency within the allowable band as specified in the Grid Code and for relieving congestion in the transmission network, to ensure smooth operation of the power system, and safety and security of the grid.

Under AS Regulation, for provision of TRAS, the power exchanges are required to collect bids from TRAS participants and share it with National Load Despatch Centre ('NLDC') for scheduling of TRAS-Up and/or TRAS-Down services. On receipt of bids from the three power exchanges, NLDC will match the collected bids, discover price and clear participants for providing TRAS-Up and/or TRAS-Down services. Later, based on grid management requirement, NLDC will provide despatch instruction to such cleared participants to meet ancillary service requirement. As prescribed in AS Regulation, settlement of transactions for TRAS services would be done by NLDC in coordination with Regional Power Committee.

Implementation of TRAS Contracts on power exchange platform with responsibility of clearance, despatch and settlement being handled by NLDC, has provided valuable insights on constructs of 'Market Coupling' that has become a necessity for shaping power markets to grow in a transparent and competitive manner without any distortions.

The discussion paper suggests that activities performed by NLDC are akin to functions to be performed by MCO. PXIL submits that other than the market operation(s) i.e. power exchanges and system operator, if there is any other entity we reserve our comments on the same, as in the absence of regulatory status of the 'third-party' / 'entity', qualification requirements, periodicity of review, etc., it will not be prudent for us to have a view formed on the same.

In case it is the system operator, we run the risks identified when the Hon'ble Commission decided in favour of the multi-power exchange model. System Operator running the matching engine will eliminate competition and the system operator may not have the incentive to periodically upgrade their matching engine.

Lack of competition will stifle all innovations in the market. **While it will achieve the objective of price convergence but it may be at a very high cost. It is worth our while to mention that during the last fifteen years of exchange operations, the power exchanges and the system operator have worked to provide checks and balances to each other on market aspects whether it is creation of a new zone, identification of congestion, transmission allocation, introduction of new Contracts, new bid features, etc. which will be lost should the MCO and the system operator roles be played by one entity.**

In case it is the market operator(s) who are to run the matching engine, it is important to ensure that there is no monopoly, and equal opportunity is extended to the power exchange(s) and therefore alternative (b), i.e. 'Rotation among power exchanges on periodic basis' is the best option.

b. Rotation among Power exchanges on periodic basis

The second alternative is to nominate each Power exchange as MCO on periodic basis. The nominated power exchange would collect bids from other power exchanges, operate matching algorithm, discover price, quickly disseminate information to other power exchanges and market participants, undertake clearing and settlement of transaction trades by coordinating with other PXs on matters related to pay-in/pay-out to cleared participants.

c. An alternative way could be to distribute the geographies/regions to exchange(s) for the bid solicitation. From the view point of the participants; they would be interacting with only one exchange at any given point in time. From the view point of the regulatory oversight, i.e. PMR 2021, equal opportunity is offered to power exchanges. In order to administer the power exchange towards innovation so that competition is ensured the allocation of geographies be on rotation every quarter so that there is no frequent change leading to confusion. This would also ensure that any new exchange which comes up is also accommodated in the cycle and the process is in the spirit of the multi-power exchange model.

It is worthwhile to mention that while bid solicitation can be entrusted to all the operating power exchanges, the matching activity be offered to the exchange whose software has been audited and not found wanting on principles prescribed in PMR 2021.

<u>To suggest</u>

In both the models, at provided in Clause 5.4 of staff paper, a participant which places a buy Bid on one power exchange can be matched with a participant with a sell Bid of another power exchange. It is submitted that Hon'ble Commission at Regulation 39 of draft CERC (Power Market) Regulations, 2020 had prescribed the functions of MCO as:

'Regulation 39. Functions of the Market Coupling Operator

1) *The Market Coupling Operator, with the approval of the Commission, shall issue a detailed procedure for implementing Market Coupling including management of congestion in transmission corridor, the timelines for operating process, information sharing mechanism with the Power Exchanges and any other relevant matters.*
2) *The algorithm for enabling Market Coupling shall be developed and managed by the Market Coupling Operator and implemented with the approval of the Commission.*
3) *Market Coupling Operator shall create and maintain a document on its website providing detailed description of the algorithm used for price discovery. The description shall include bid types, details of how the algorithm results in maximisation of economic surplus taking into account various bid types and congestion in transmission corridor, which shall be updated with every new version of the price discovery algorithm.*
4) *The Market Coupling Operator shall use the algorithm to match the collected bids from all the Power Exchanges, after taking into account all bid types, to discover the uniform market clearing price, subject to market splitting.*
5) *The Market Coupling Operator shall communicate the results of the auction to the Power Exchanges in a transparent manner.'*

PXIL submits that, as part of consultation process initiated by MOP and CERC in the subject matter of 'Market Coupling' and 'MBED', as referred above from time to time, PXIL has in all its submission advocated '**Rotation among Power exchanges on periodic basis**'. PXIL submits that the MCO, whether a third-party or designated among different power exchanges at periodic intervals, will have to comply with extant provisions of PMR 2021. The designated MCO will put in place all procedures, processes, systems and/or formats such that power exchanges obtain Bids from Members/Clients in similar formats and share them to the MCO with participant specific information in masked form; develop procedure for MCO to declare discovered price, transaction results; and also procedure/formats for inter-Power exchange sharing of information on scheduling and despatch of power and settlement of obligation i.e. pay-in/pay-out applicable for transaction.

It is submitted that, the MCO has to ensure that deposits and payment securities maintained with any one power exchange be granted fungibility, such that they can be used as Collateral for submitting/placing Bids on any other Power exchange with due emphasis on superior risk management practices.

With the implementation of Market Coupling, the participants can exercise choice and will no longer have to beholden to only one Power exchange, which hitherto due to the market design issue had the benefit of getting all the liquidity. With greater competition amongst power exchanges, the levels of offered service and most importantly with rationalization in cost of access in the form of transaction fees it should make the market efficient. The real benefits of competition in power exchange space would now be available to all the market participants.

We are of the opinion that 'Power exchange to perform function of MCO - Rotation on periodic basis' is the most elegant way of having the best of both the worlds i.e. convergence in prices and continuation of multi-power exchange model with regulatory oversight under PMR 2021. Over a period of time the market forces would ensure that similar/same processes are adopted even through subtle differences could remain. Also with periodic scrutiny and audit of the matching algorithm of the power exchanges, the findings can be used to ensure evolution of the matching engine along with the markets and market participants.

Today with multiple exchanges operating their respective matching engines, on implementation of market coupling mechanism, the system operator will integrate with designated power exchange, which augurs well with the structure of the market wherein dispatches are built over the transmission network and will also ensure that social welfare has both the components integrated viz. economic welfare and welfare on account of efficient transmission allocation. Moreover, the transmission would remain implicit as is the case in current market.

To conclude it would be prudent to nominate at periodic intervals each Power exchange as MCO on rotational basis. The nominated power exchange would undertake Bid collection and price discovery, the other power exchanges would also run the price discovery algorithm share the results with nominated power exchange and help in fine tuning the price discovery algorithm. The other power exchanges in the interim work on developing new Bid structures, to meet evolving requirements of market participants, undertake adequate tests and be-ready to deploy when it's their turn to perform the role of MCO.

16. Clause 5.5

Which Algorithm should be adopted for a coupled market ?

……...

5.5.3 Given these realities,

- *Would it be advisable to select a suitable algorithm out of the three existing algorithms, or should a new algorithm be designed jointly by the exchanges/ by the market coupling operator, like the PCR EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm) being used to calculate day-ahead electricity prices across Europe.*

- *To be able to match the bids received on the three exchanges, uniformity of bid types & relevant parameters is required. Would standardizing/ harmonising the bid types in DAM & RTM across the exchanges address the issue? If so, which bid types would be suitable for the various buyers and sellers?*

The queries posed in the above clauses can be summed as –
The three power exchanges utilise distinct algorithms for matching of bids and price discovery, Difference exist in bid types and bidding interface offered by each power exchange

a. Whether to select any algorithm out of the three power exchanges algorithm
b. Should a new algorithm be designed jointly by power exchanges/MCO similar to EUPHEMIA operating in EU market
c. Uniformity of bid types as offered by three power exchanges, which bid types are suited for different buyers and sellers

Suggestions:

PXIL submits that most of the design and operating aspects for Collective transactions i.e. double sided closed bid auction with uniform market clearing price, operating timelines for the markets, allocation of transmission capacities and congestion management, scheduling and dispatch rules etc. are all prescribed in various provisions of PMR 2021, other CERC regulations and Procedures notified in this regard.

Regulation 25 (1) of PMR 2021 enables power exchange to introduce new bid types or modify existing bid types by undertaking stakeholder consultations in coordination with NLDC.

*"**Regulation 25. Approval or Suspension of Contracts by the Commission***

(1) The Commission may, on its own or on an application made in this behalf, permit any Power Exchange to introduce new contracts as specified in clause (1) of Regulation 4 of these regulations:

Provided that no permission shall be required for the contracts which are being transacted on a Power Exchange on the date of coming into force of these regulations;

Provided further that the Power Exchanges may introduce new bid types or modify existing bid types conforming to the types and features of the contracts specified under Regulations 4, 5 and 6 of these regulations, after consultation with stakeholders and National Load Despatch Centre, under intimation to the Commission, along with the details of consultation with stakeholders and National Load Despatch Centre and the views of the Power Exchange."

It is submitted that currently, the most widely used bid types are Normal Bids and Block Bids, additional bid types can be developed and introduced to meet evolving needs of market participants for transacting in Integrated DAM and RTM.

EU context

In Europe also, where Market Coupling has been implemented, different Power exchanges operating within the same geography or multiple geographies have adopted a variety of Order types as per the geography as well as market participant's requirement. The most glaring example is the PREZZO UNICO NAZIONALE (PUN) requirement in Italy with distinct

Order types i.e. Supply Merit Orders, Non-PUN demand Orders and PUN Merit Orders from rest of the Europe.

Similarly, all other Complex Order types such as Minimum Income Condition, Scheduled Stop, Load Gradient, Linked Block Orders, Flexible Hourly Orders and combinations thereof are offered by different power exchanges in same or multiple geographies. EUPHEMIA has coped with and supports a wide array of Order formats as per the requirement of various geographies and market participants.

Therefore, the perception that a centralized algorithm by design would not be able to accommodate new order structures in keeping with the compatibility of order types in different power exchanges is fallacious. As is evident from the European experience, the power exchanges don't have to compromise on innovative order types which could have improved the market liquidity and development.

PXIL submits that introduction of new Bid types is sign of maturity in market place, as the number and type of participants in exchange market has increased significantly over the years, i.e. number of generators, types of generators, generators scheduled to meet peaking load pattern, increase in renewable generation capacity, separate segments for Green and High Price type of generators, etc. Also, based on technical limitation of each type of generating technology, the participants have from time-to-time requested to offer different bid type to enable smart operation of such generating units. Further, to overcome paradoxical rejection, volume rigidity, etc. as major constraints associated with a block bid, new Advanced Bid structures are required to enable optimal utilisation of generating units honouring their technical limits.

A comparison of different Bid structures as offered by 'EUPHEMIA' in prominent power exchanges operating in EU region and those offered by PXIL is as:

Bid Type	EPEX Spot SE	Nord Pool EMCO AS	OMIE	PXIL
Single Bid	Y	Y	Y	Y
Block Bid	Y	Y	Y	Y
Minimum Quantity Block Bid				
Profile Block Bid	Y			
Linked Bid	Y	Y		
Exclusive blocks / Exclusive Group – Flexible Orders#	Y	Y		
Big blocks	Y			
Loop blocks / Spread blocks*	Y	Y		
Minimum Quantity Bid				
Minimum Income Condition			Y	
Scheduled Stop			Y	
Load Gradient			Y	

[Note:

a. *'#' Exclusive blocks is offered by EPEX Spot SE and Exclusive Group – Flexible Orders is offered by Nord Pool EMCO AS*
b. *'*' Loop blocks is offered by EPEX Spot SE and Spread blocks is offered by Nord Pool EMCO AS]*

It is submitted that similar bid types can be developed and enabled by power exchanges under provision of Regulation 25(1) of PMR 2021 to meet evolving requirements of market participants.

PXIL submits that with implementation of Market Coupling, harmonisation / standardisation of bid types across all the power exchange platform is a necessity. Further, with increased RE penetration and emerging technologies such as BESS, EVs etc., new and innovative Bid types become all the more important. With Market Coupling, all the Power exchanges can propose new Bid types for increasing liquidity and work with MCO for incorporating the same in the algorithms.

17. Clause 5.6

How will Clearing and Settlement be carried out ?

………

5.6.4 Thus, in the scenario of a coupled market,

- *While the power exchanges will be the counterparty to the market participants, would the Market Coupling Operator act as a counterparty to the power exchanges with regard to settlement rights and obligations?*
- *Would it be advisable to allow the Market Coupling Operator to charge transaction fees from the power exchanges, which in turn charge related transaction fees from the market participants?*
- *What should the grievance handling framework be?*

The queries posed in the above clauses can be summed as –

a. Necessity to develop SOP for cross-settlements between power exchanges
b. Who would be counterpart, Power exchange or MCO
c. Transaction fee applicable for MCO
d. Requirements for Grievance handling mechanism under this framework

Suggestions:

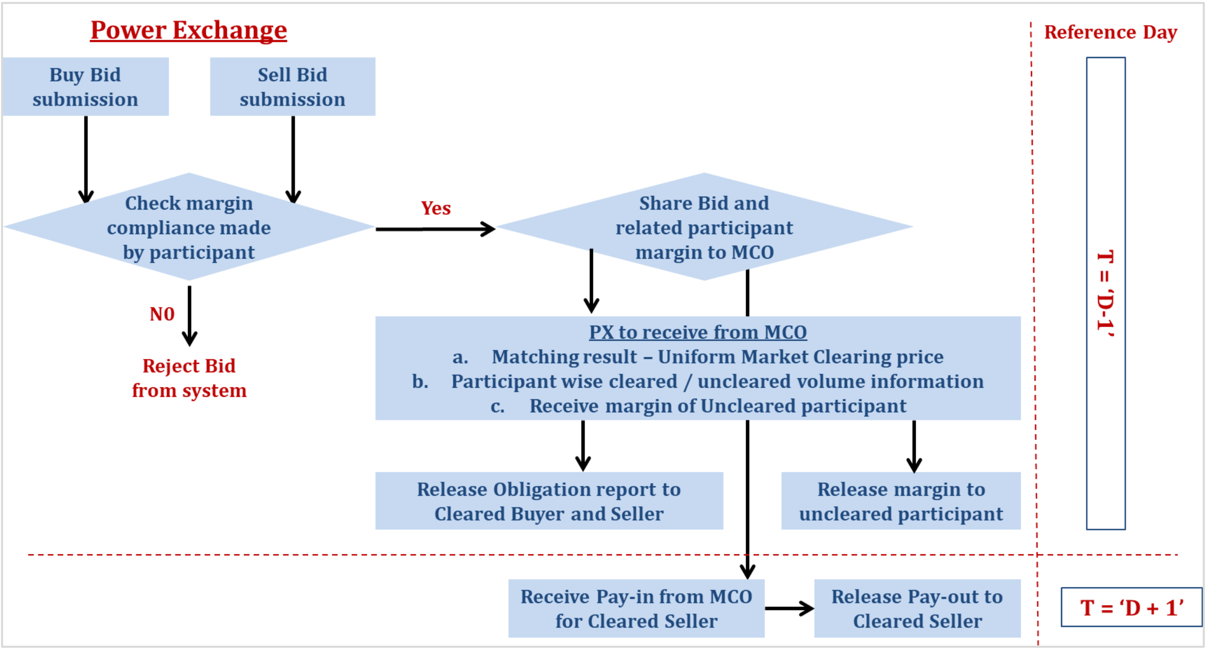
PXIL submits that in a power exchange both buyers and sellers participate equitably in bidding process, the exchange acts as counter-part to all transactions in order to ensure payment security to all the participants. Over the past 15 years, PXIL has while introducing new Contracts in its 'PRATYAY' system implemented a prudent risk management framework by adopting best practices that has placed transactions at its platform into orbit of self-sustaining growth that has energised the sector. However, we need to recognise that power exchange is merely a facilitator for transacting and discovered price in a Contract is reflection of order book built during an auction session.

Clearing and Settlement system

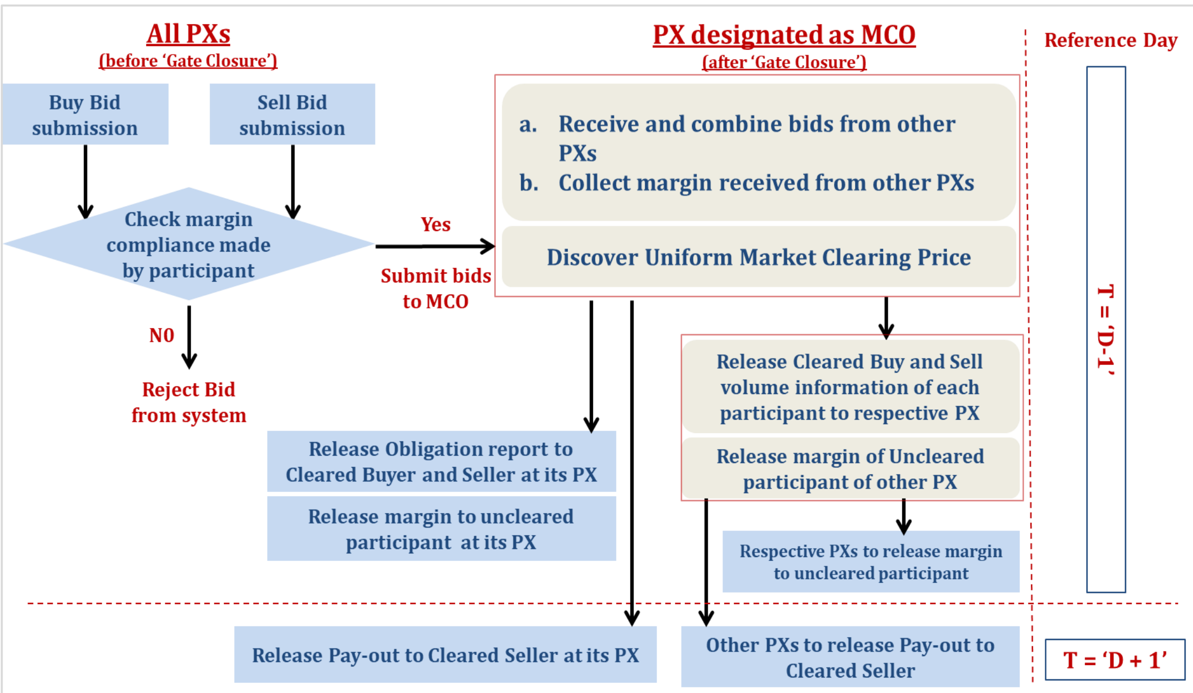
PXIL submits that assured and timely pay-outs are the hall market of exchange based transaction, the exchange has established a credible and viable clearing and settlement mechanism under provisions of PMR 2021. Since Power exchange is counterpart to all transaction it relies on receipt of payment from buyers to meet its payment obligation to sellers. Under Market Coupling mechanism, the suggested design for clearing and settlement of transactions would be:

a. The power exchange appoints one or more bank(s) as clearing bank(s) that shall be responsible for settlement of all dues on its behalf
b. Based on settlement responsibilities prescribed in PMR 2021, the market participant in turn open and maintain accounts with such clearing bank for settlement of obligation
c. Every power exchange ensure that the bids of Member(s) and/or Client(s) are accepted in the Bid book only when they comply with provisions of Regulation 28(2) of PMR 2021
d. In case the bids entered by the Member(s) do not adhere to the risk management framework approved under Regulation 26 of PMR 2021, the same needs to be rejected by the power exchange(s) and removed from the Bid book
e. The buy and sell trades for the power exchange(s) shall be netted-off based on the trades cleared from the Member(s) of the power exchanges(s) and settlement shall be made accordingly. The power exchange shall identify the net pay-in/pay-out of each Member and/or Client in case of a Facilitator Member. The power exchange shall be liable to pay for the trades cleared with the other power exchanges and each power exchange shall identify and match the amount as receivable/payable to the other power exchange.
f. The margins collected/received by the power exchange(s) from its Member(s) shall be used, for payments for the trades netted off in same power exchange and thereafter, to pay other power exchanges
g. All the power exchanges shall ensure that the inter-exchange 'pay-in' and/or 'pay-out' remains 'zero-sum' and that no outstanding sum remains between the power exchanges on 'trade-to-trade' basis for each auction session
h. All power exchanges shall be responsible for collecting the applicable transmission charges from their Member(s) and/or Client(s). The ISTS charges shall be applicable as per GNA Regulations and Sharing regulations as amended from time to time
i. Intra-state transmission charges and losses shall be applicable as per the concerned SERC regulations and the same shall be paid by respective power exchange
j. Operating charges for NLDC shall be payable by the concerned power exchange(s) in accordance with GNA Regulations, along with procedure for GNA and shall be recovered by the power exchange(s) from all buyers and sellers whose trades are cleared
k. In case the Hon'ble Commission prescribes operating charges for functioning and operation of MCO, to the designated power exchange, then the same shall be recovered by the power exchange(s) from all buyers and sellers whose trades are cleared and shall be deposited by the concerned power exchange(s) along with other charges

The envisaged Clearing and Settlement function by Power exchange under 'Market Coupling' mechanism would be:



Similarly, the envisaged Clearing and Settlement function by Power exchanges when one of the Exchange is designated as 'MCO' under 'Market Coupling' mechanism would be:



Further, since settlement of transaction is essence of exchange based Contract, the settlement mechanism under 'Market Coupling' mechanism requires a risk management framework, that enables monitoring of Member and/or Client margin limits, obligation system, settlement process, surveillance systems, sharing of Member and/or Client data, a robust default handling process and related dispute resolution process.

PXIL submits that in stock exchange space regulated by Securities and Exchange Board of India ('SEBI') it has vide Circular no CIR / MRD / DRMNP/CIR/P/2018/145 dated November 27, 2018 notified 'Interoperability among Clearing Corporation' providing for market participants to consolidate their clearing and settlement functions at a single Clearing Corporation, irrespective of the stock exchange on which trade is executed. The interoperability facility leads to efficient allocation of capital for market participants, thereby saving on costs as well as provide better execution of trades. The SEBI Circular is attached as Annexure-10.

It is submitted that a similar framework providing flexibility to execute transaction in any power exchange and settlement within prescribed norms as provided in PMR 2021 is required to be developed for seamless functioning of 'Market Coupling' mechanism.

Transaction fee

PXIL submits that the existing fee structure as approved in Order in Petition no 143/MP/2023 dated 05.04.2023 would be recovered by each power exchange from cleared participants. Hence based on sell and/or buy side participants cleared by each power exchange the transaction fee would be recovered from such participant.

Grievance handling

a. PMR 2021 provision
PXIL submits that Regulation 36 of PMR 2021 prescribes constitution of 'Grievance Redressal Forum' to redress complaints lodged by market participants. Regulation 36 empowers the Hon'ble Commission to call for information on redressal of any specific grievance by the Power exchange. It is submitted that PXIL has a functioning dispute resolution mechanism as prescribed in Regulation 19 (1) (o) of PMR 2021

'Regulation 19. Bye-laws, rules and business rules of Power Exchange

(1) The Power Exchange shall function according to its bye-laws, rules and business rules as approved by the Commission, which amongst others, shall cover the following:
……
(o) Dispute resolution mechanism;'

b. Mechanism available in SEBI regulated stock exchanges
PXIL submits that in recent past SEBI has developed two tiered dispute resolution process:
   - Complaints pertaining to securities market can be lodged by investors on an online platform SEBI Complaints Redress System ('SCORES'). The complaints can be lodged against listed companies and SEBI registered intermediaries
   - Recently vide Master Circular for Online Dispute Resolution ref no SEBI / HO/ OIAE / OIAE_IAD-1/P/CIR/2023/145 dated 31.07.2023, the seven Market Infrastructure Institutions, e.g. NSE, BSE, MSE, CDSL, NSDL, MCX and NCDEX have built 'SMART ODR' platform, to file dispute when resolution provided under SCORES platform is dissatisfactory. Disputes filed in SMART ODR are to be redressed within prescribed period of 90 days.

The SEBI master circular is attached as Annexure-11.

Further, to address issues related to MCO, a Joint Council can be set-up comprising of representative from the Commission, GRID_INDIA, the designated MCO and the other power exchanges. The Joint Council can meet at periodic intervals i.e. once every 3 or 4 months, to review progress made in redressal of grievance and any other matter related to Market

Coupling mechanism. Also, any member of the Joint Council can request for an early meeting specifying the reasons for such request and the urgency of the matter involved.

18. Clause 5.7

Changes in the settlement process ?

………

5.7.1.Traders are already collecting bids from clients, submitting bids to exchanges, and doing the clearing and settlement. In fact, security maintained by traders is approximately double the cost of power purchased, i.e. maintain a weekly average margin equivalent to power purchased while maintaining a sufficient margin for net cleared volume for tomorrow. Under such a scenario, should traders be allowed to submit their bids directly to the market coupler to reduce the cost of power for trader clients, as the clients are presently paying margins to the trader and also bearing fees and margins of exchange?

The queries posed in the above clauses can be summed as –

a. Whether Traders should submit bid directly to MCO to reduce cost of power for trader clients

Suggestions:

PXIL submits that PMR 2021 prescribes Market Coupling mechanism is for DAM and RTM transactions that operate under provisions of Regulation 5(1) of PMR 2021, Procedure for Collective transaction notified under Regulation 4 of Open Access Regulations 2008 and where NLDC is designated as Nodal Agency under provisions of Regulation 5 of Open Access Regulations 2008. The transactions to be cleared by MCO are designated as 'Collective transaction' executed in the power exchange(s) and whose price is discovered through anonymous and simultaneous competitive bidding by buyers and sellers.

PXIL submits that Regulation 21 (1) (a) of PMR 2021 prescribes Trader Member to trade and clear on its own account or trade and clear on behalf of its client, this mechanism requires such Trader Member to enter/have back-to-back arrangements of adequate collaterals with their clients in order to fulfill the settlement obligations of concluded trade. However, Regulation 21 (1) (c) of PMR 2021 prescribes Client of Facilitator Member to settle their trades directly with the power exchange.

Thus, PMR 2021 permits Clients to engage services of Trader Member and/or Facilitator Member to fulfill their power trading requirements, based on value add service provided by Member, the Client has a choice to engage services of Trader Member or Facilitator Member.

PXIL submits that on implementation of price discovery function under 'Market Coupling' mechanism, in case clearing and settlement between market participants get centralised as proposed in staff paper, no additional benefits in terms of costs and simplicity is achieved, while introducing the risks of a single point of financial and operational failure. Further, collateral compliance for an independent and exclusive transaction directly with MCO would be capital inefficient approach.

PXIL submits that power exchanges offer different types of Contracts, i.e. G-DAM, Conventional DAM, HP-DAM, Intra-day, Day Ahead Contingency, Daily, Weekly, Monthly, Any Day, Day Ahead Ancillary Services, Real Time Ancillary Services, REC and ESCert for transacting in Conventional power, solar, wind, hydro, other types of Renewable energy, Renewable Energy Certificates and Energy Savings Certificates. Introduction of Market Coupling will enable Clients to exercise choice to engage different Members for different types of Contracts to meet their transacting requirements, including settlement efficiency by providing bundled services to meet technical and/or margin service requirements from a Member.

Further, since market participants transact in different Contracts on day-to-day basis, PXIL has implemented a robust and dynamic risk management framework that provides capital efficiency to market participants, the issue of submission of bids directly to MCO arises only when MCO is operated by 'third party or super exchange as referred at Clause 5.4, however no tangible benefits would be gained by market participants if they decide to place bids directly with MCO.

19. Clause 5.8

In which market segment should the coupling be introduced first ?

……...

> *5.8.4. It has also been contended by the stakeholders that the argument that the market is skewed due to design inefficiencies does not hold good, as behavioural aspects assume significance in collective transactions because a participant prefers to trade where the liquidity is higher, which shall ensure him both commensurate supply and a better price.*
> *5.8.5. In the case of continuous transactions, the buy bids and the sell bids are matched on a continuous basis with price-time priority. The participant behaviour here is different when compared to the collective transactions due to features like continuous matching. In this segment, all three exchanges seem to enjoy a good market share. The exchanges have introduced innovative products/ contracts/ bid types in this segment on their respective platforms, which provides a variety of avenues for the participants. This has made the segment attractive across the exchanges. 5.8.6. Considering the above, is it imperative that market coupling be introduced in collective transactions segment to begin with?*

The queries posed in the above clauses can be summed as –
Regulation 37(1) prescribes Market Coupling in DAM and RTM or any other Contract prescribed by CERC

a. In which market segment should coupling be introduced first

Suggestions:

PXIL submits that electricity cannot be differentiated on quality and the only attributes left are place of delivery and time of delivery. The current market structure of nine different prices for the same commodity, at the same location and the same time of delivery, in a voluntary market, are not in sync with the commodity's characteristics.

The value of electricity changes on the temporal scale also, which is also absent in the current IDAM structure when bids are solicited at the same time for delivery during the same time period. Therefore, the prices should converge in both the markets and as has been mentioned earlier in terms of experiences in the European markets, this would lead to promotion of competition and would allow multiple exchanges to become viable without any one exchange becoming a monopoly. **It is pertinent to mention here that with the price makers/takers remaining the same on a given day/period, there should be one price of electricity in the spot market.**

It is submitted that in the shortest segment of the market enabled by power exchange platform i.e. the TRAS segment, singularity of price has been achieved as power exchanges share the bids with NLDC and NLDC discover the price and provides despatch instructions for such participants. A singularity of prices in IDAM would also be essential for the development of electricity derivatives as IDAM auction captures the value of electricity changes on the temporal scale. Such markets in electricity derivative would take price cues from IDAM for settlement of the contracts and multiple prices in the IDAM would distort and disrupt the entire development of the power markets.

PXIL submits that coupling of bids received in IDAM is necessary to ensure system-wide social welfare maximization. Accordingly, the necessary and sufficient requirements for price convergence are:

(i) Uniform price discovery and market clearing at one price
(ii) Social welfare maximization, both on economic basis and welfare on transmission optimization to maximize the volumes without compromising on reliability

Further, with the envisaged implementation of MBED as provided in MOP report 'Development of Electricity market in India' the proposed market structure espouses mandatory participation in the IDAM which furthers the need for price convergence or one price in the spot markets. **This need of price convergence should be in all such markets / products where uniform price auction mechanism is being implemented. In case, phase wise implementation is envisaged then Market Coupling in RTM can be taken in second phase. Further, it is worthwhile to keep in mind that transmission network optimisation will be done under MBED in future and not with any other Contract; hence other Bilateral Contracts operating on power exchange platform is best left to power exchanges to design, develop and offer to the market.**

Further, the Hon'ble Commission is requested to implement Market Coupling mechanism in IDAM and RTM simultaneously, one of the power exchange can be designated as MCO for IDAM, second power exchange for RTM and the same can be rotated between the three power exchanges at periodic intervals.

Other suggestion

20. Gist of CACM framework – enabler for discovering single price in EU region

The CACM Regulation has helped Europe transcend from geographical monopolies to Market Coupling with multiple PXs within the same geography, the important take-aways from CACM Regulation are:

a. In a Member state where multiple Power exchanges operated, Nominated Electricity Market Operator (NEMO) were to be designated
b. Need for urgent completion of a fully functioning and interconnected Internal Energy Market
c. EU Price coupling of regions - A single Price coupling solution to be used to calculate electricity prices across Europe

Formation of NEMO

The NEMO is an entity designated by the competent authority to perform tasks related to Single Day-ahead or Single Intraday market coupling (i.e. SADC / SIDC). In other words, NEMOs are the organisations mandated to run the day-ahead and intraday integrated electricity markets in the EU.

Multiple NEMOs are allowed in one bidding zone and one NEMO can participate in multiple bidding zones. The NEMO designated in few countries are as under.

Country	NEMO	Operating status
Austria	EPEX Spot SE	Passporting
	EXAA AG	Designated
	Nord Pool EMCO AS	Designated
France	EPEX Spot SE	Designated
	Nord Pool EMCO AS	Designated
Germany	EPEX Spot SE	Passporting
	Nord Pool EMCO AS	Designated
	EXAA AG	Passporting
Sweden	Nord Pool EMCO AS	Designated
	Nasdaq Spot AB	Designated
	EPEX Spot SE	Passporting
Norway	Nord Pool EMCO AS	Designated
	EPEX SPOT SE	Passporting
	Nasdaq Spot AB	Passporting

Under CACM regulation, competition amongst marketplaces has thrived with multiple NEMOs being present in many markets.

All NEMO Committee Organisation

The establishment and efficient management of single day-ahead and intraday coupling process is enabled by a high level of cooperation between NEMO, who shall jointly carry out the MCO function based on the principle of non-discrimination (according to 'Article 7 of CACM Regulation').

To facilitate cooperation among NEMOs for all common European tasks required by the CACM Regulation, each NEMO signs the **All NEMO Cooperation Agreement (ANCA)** and joins the All NEMO Committee.

<u>Operating the common platform</u>

To perform the daily operations, one NEMO is appointed as '**Coordinator'** and one NEMO is appointed as '**Backup Coordinator'**

- The Backup Coordinator monitors the NEMO acting as Coordinator and is always prepared to take over the Coordinator role at any moment (i.e. a "hot backup")
- All other Operators may perform in parallel the same processes and can also take over from the Coordinator the role if necessary (i.e. a "warm back up")

The roles of Coordinator and Back up Coordinator are rotated

- To perform as a Coordinator / Back up Coordinator, a NEMO must also satisfy specific technical requirements established by the NEMO DA Operations Committee and ratified by the All-NEMO Committee to guarantee safe and reliable operation of the SDAC

Each NEMO is responsible for validating the individual results for its respective bidding areas

<u>CACM, Terms, Conditions and Methodologies</u>

It is submitted that objectives prescribed for seamless operation of Market Coupling is provided at Article 3 of CACM Regulation:

a. **Ensuring optimal use of the transmission infrastructure**
b. **Respecting need for a fair and orderly market and fair and orderly price formation**
c. **Ensure fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants**
d. **Ensuring and enhancing the transparency and reliability of information**
e. **Creating a level playing field for NEMOs**
f. **Contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union**

Under Article 4, 5 and 6 each Member State needs to ensure that at least one NEMO is designated to perform the single day-ahead and single intraday coupling.

Under Article 7(3) prescribes a **Market Coupling Operation (MCO) Plan**, that sets out how to jointly set up and perform the MCO function including draft agreements between NEMOs and with third parties

Under Article 37 prescribes **Single day ahead and intra day coupling algorithms**, wherein all NEMOs shall develop Single day-ahead and intraday coupling algorithm that is scalable, repeatable and aims for maximum economic surplus. It also ensures that any development and related changes, as well as its operation ensure the

- Efficient and timely implementation of the single European electricity market
- Close monitoring of the development and operations

Under Article 41(Day Ahead) and Article 54 (intra day54), provides terms and conditions for harmonised maximum and minimum clearing prices to be applied in market coupling.

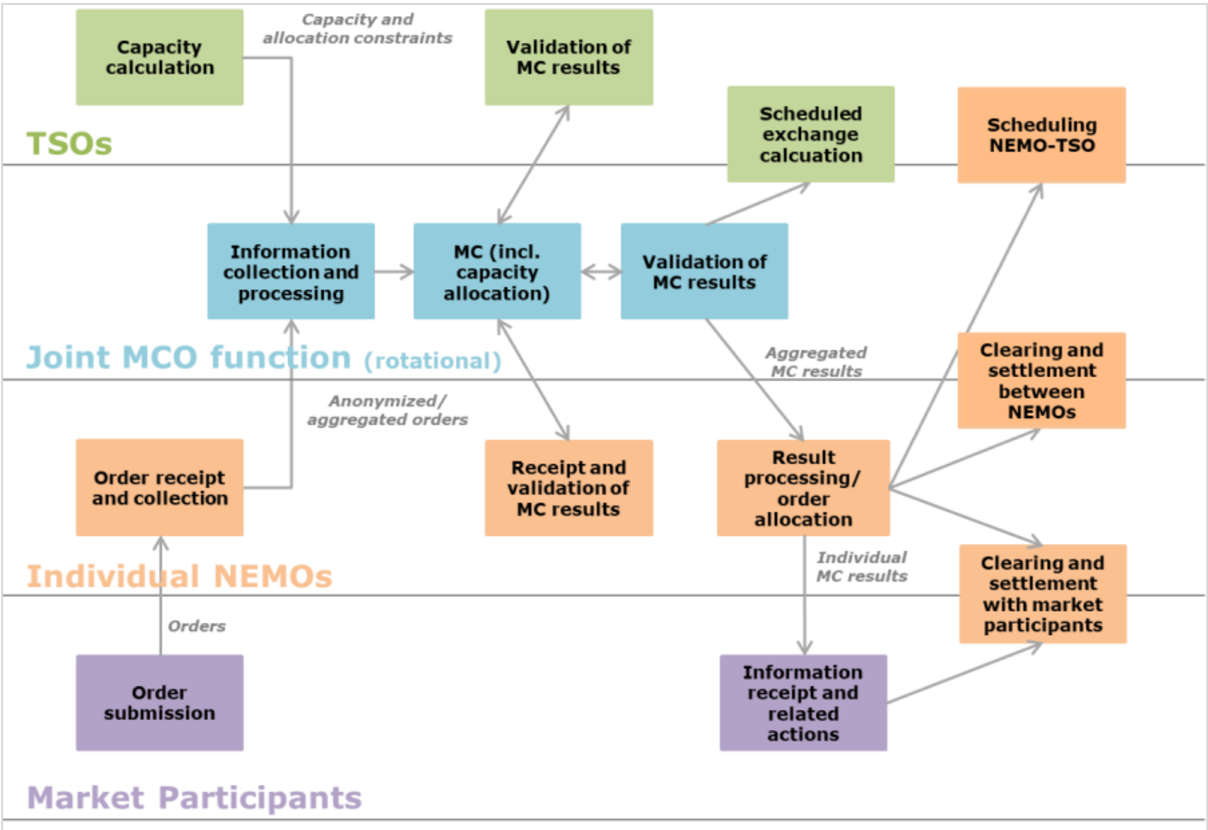
Under Article 36 prescribes **Back-up methodology**, wherein all NEMOs are responsible for establishing, together with the relevant TSOs, the backup procedures for national or regional market operation in case no results are available from the market coupling operation functions. The methodology ensures a back-up in operating the MCO functions, in case the responsible NEMO is unable to do so. This methodology takes into account the fall-back methodology under the CACM Regulation.

Under Article 44 prescribes **Fall-back procedure** that ensures efficient, transparent and non-discriminatory capacity allocation in case the single day-ahead coupling process is unable to produce results. Different regions have different fall-back solutions in place.

Under Article 69 prescribes **Day-ahead firmness deadline** wherein the methodology defines the deadline after which cross-zonal capacity for the day-ahead allocation becomes firm. The day-ahead firmness deadline is set to 60 minutes before the day-ahead market gate closure time.

Under Article 73 prescribes **Congestion income distribution** rules for collecting and distributing the congestion income on the bidding zone borders within capacity calculation regions from the day-ahead market and for distributing it among the TSOs having interconnectors on that border.

The CACM operational framework for coordination between Transmission System Operator, Market Coupling Operator, NEMO and Market participants



(Source: https://www.acer.europa.eu/en/Electricity/MARKET-CODES/Graphs/Day-ahead%20and%20Intraday%20markets.png)

It is submitted that a mechanism for coordination at operational level for managing different issues viz. system operations, energy accounting, clearing and settlement, exchange of information between MCO and power exchanges, etc. is required for operation of 'Market Coupling' mechanism as provided in PMR 2021.

21. **Research reports / discussion papers in public domain on implementation of Market Coupling in EU region**
    a) **European Union Agency for Cooperation of Energy Regulators ('ACER') report titled Wholesale Electricity Market Monitoring 2022 published in April 2022**

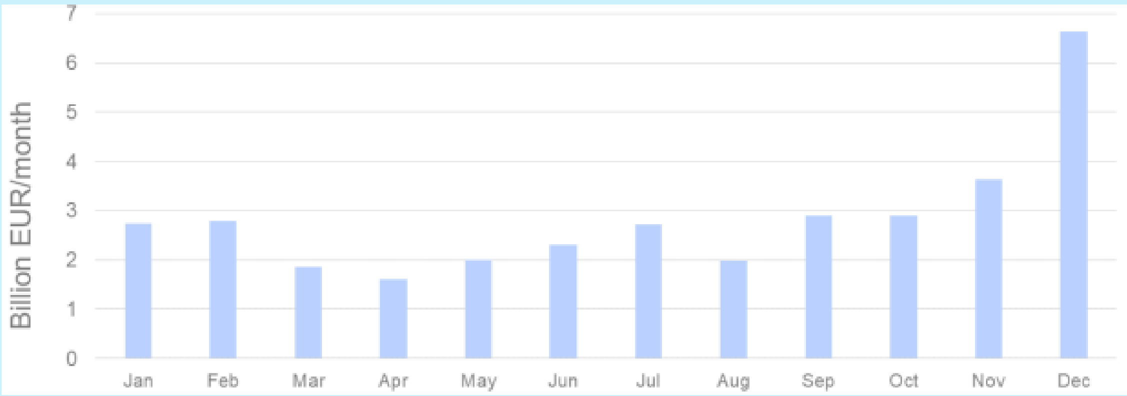
    <u>At Para 3.3.1 the report provides</u>

    3.3.1 Cross-border trade delivered 34 billion Euros of benefits in 2021 while helping smoothen price volatility

    <u>Cross-border trade delivers substantial benefits and mitigates price volatility</u>

    To estimate the benefits from cross-border electricity trading in Europe in 2021, ACER asked the European NEMOs to conduct an analysis for 2021. It compared actual 2021 market results ('historical' scenario) with a scenario where all cross-border capacities were set to zero (the 'zero scenario', implying no electricity trade across Member State borders). The difference in welfare benefit between the historical and the zero scenario (see Figure 11) is a proxy for the yearly welfare benefits currently obtained from cross-border trade in day-ahead markets. The benefits of cross-border electricity trading amounted to around 34 billion Euros in 2021 (source: ACER based on NEMOs). More than one third of these benefits correspond to the last quarter of 2021, when power prices were at their highest.

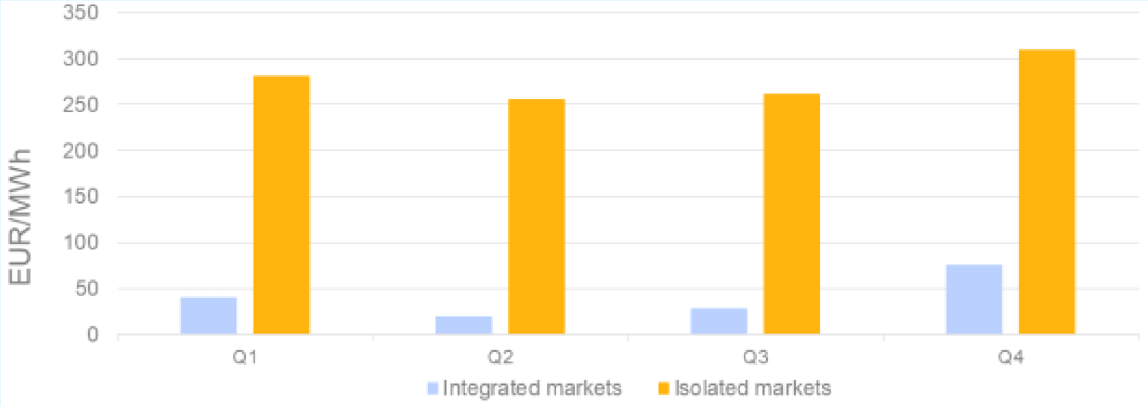
Figure 11: Estimated monthly welfare benefits (Billion EUR) from cross-border electricity trade in 2021



Source: ACER based on NEMOs' simulations.

In addition to the considerable savings associated with the current level of market integration, the analysis shows that this integration also reduces significantly price volatility. Figure 12 displays the differences in average price volatility between the two scenarios. It shows that price volatility would have been considerably higher (around seven times as high) if national markets were isolated.

Figure 12: Price volatility (EUR/MWh) in integrated and isolated electricity markets in the EU in 2021



Source: ACER based on NEMOs simulations.

Volatility was estimated by using the standard deviation of day-ahead wholesale prices. The standard deviation was calculated per bidding zone for the whole year, then averaged out across the EU.

Overall, in 2021, cross-border trade delivered an estimated 34 billion Euros of benefits while helping to smoothen price volatility. Additional benefits from higher market integration and cross-zonal capacities include enhanced cross-border competition and a reduced scope for market power, which helps lower the energy bill in the long-run. As further elaborated in Section 5, intervening to significantly alter the current market design may put a substantial share of the above benefits at risk, to the detriment of consumers. It should be emphasised that these benefits represent the overall value of cross-border trade compared to isolated national markets, rather than the benefits from the implementation of market coupling as such (the latter is accounted for in the afore mentioned benefits10). In fact, before market coupling was introduced, cross-border trade (though sometimes limited and inefficient) was already taking place. Market coupling enables the efficient use of interconnectors and renders more than one billion Euros of benefits per year

The ACER report is attached as Annexure-12.

b) Great Britain Wholesale Electricity Market Arrangements
The Department for Energy Security & Net Zero, Government of UK, in its report titled 'GB Wholesale Electricity Market Agreements - Government response to consultation on recoupling GB auctions for cross-border trade with the EU at the day-ahead timeframe'

a. Executive Summary

Para 6- In parallel we plan to engage with industry and stakeholders to explore and understand how the recoupling of the two hourly day-ahead GB auctions, offered by European Power Exchange EPEX Spot SE's (EPEX) and Nord Pool AS's (NP) at 09:20 and 09:50 respectively, can be successfully designed and implemented. We are disappointed that these arrangements have not progressed in a voluntary manner, particularly given the strong consensus of industry, and would strongly encourage the two power exchanges to work collaboratively to help ensure a solution resulting in a single GB clearing price is developed and implemented as soon as possible.

Para 9- Following the UK's exit from the European Union (EU), electricity is no longer traded through the EU market coupling regime established through the Capacity Allocation and Congestion Management (CACM) Regulation2. As a result, the EU market coupling process no longer determines prices for EPEX and NP's respective day-ahead GB markets that were previously coupled. Instead, interconnector capacity is sold to the market separately and independently of electrical energy through explicit auctions. EPEX and NP are now operating fully separated day-ahead markets, settling and clearing at different and independent prices

Para 23
Respondents who commented on this question highlighted a variety of concerns and impacts as a consequence of the power exchanges ceasing to couple their hourly day ahead auctions in GB. We have set out the key themes which were raised by respondents:

- *Reduced liquidity in each power exchange's respective hourly day-ahead timeframe auctions.*
- *Higher costs for market participants as a consequence of:*
  - *Managing the risks of price divergences between the two power exchanges;*
  - *Trading on two different platforms; and*
  - *Traders attempting to arbitrage between the two auctions*
- *Increased operational complexity due to needing to manage additional auctions at different times.*
- *Increased number of instances of flows against price differential for imports and exports over electricity interconnectors.*

Para 28
The majority of respondents (88%) agreed, acknowledging the inefficiencies highlighted in the consultation document and noting that the proposal should be implemented promptly, describing it as a 'no-regrets' solution

Para 108
We have made clear that we consider a single GB clearing price in the day-ahead timeframe to be highly beneficial in supporting the UK discharge its obligations under the UK-EU Trade and Cooperation Agreement ('TCA'). A single GB clearing price would support the efficient trade of electricity over interconnectors, as well as deliver broader benefits to the GB wholesale electricity market and its participants in trading electricity cross-border as efficiently as possible, as part of and in any case in advance of M*ulti-Region Loose Volume Coupling *('MRLVC').

Given no substantive progress has been made towards a voluntary solution to date, and taking full account of the consultation responses and our conclusion on the benefits, we intend to legislate to achieve a single GB clearing price,

subject to engagement with the Specialised Committee on Energy ('SCE'), industry and stakeholders.

The GB Wholesale Electricity Market Arrangements report published in August 2023 is attached as Annexure-13.

22. Sustainability of Multiple-Power Exchange Model

22.1. Role of Integrated Day Ahead Market

a. Integrated Day Ahead Market (IDAM) prices play critical role in the Power sector
   - Signal for investment decisions in adding new generation and transmission capacity
   - Reference for Contingency, RTM transactions, Deviation Settlement Mechanism (DSM) and short term bilateral (collectively accounting for nearly 8% of total electricity generation)
   - As reference price signal for all derivative instruments
   - Savings for the State governments and Discoms in power procurement. Cost savings from Market Based Economic Dispatch (MBED) estimated at 11% in CERC staff paper

b. Share of PXs to increase in the future
   - In the absence of long term PPAs, additional demand will be met through short term procurement on PXs platform
   - MBED when implemented will result in scheduling all power through PXs platform

22.2. Competition in IDAM between PXs has not worked

a. CERC's rationale for multiple Power Exchanges
   - Precedents from other exchanges such as Stock and Commodity exchanges
   - Only one Power exchange will result in complacency and discourage innovation
   - Risk would be diversified as no single exchange will have monopoly and no market failure as a result
   - To ensure fair, neutral, efficient and robust price discovery such that the price discovered reflects accurate demand/supply scenario

b. Structural challenges emanating from the adopted market design
   - Trading of electricity through IDAM on power exchanges is very different from the trading of securities on stock exchanges and commodities like wheat, oil, gold, etc. on commodity exchanges
   - Multiple prices are being discovered for electricity traded at the two power exchanges
   - No mechanism to equalise IDAM process, since only batch auction is possible
   - Market of dominant PX in IDAM is more than 99%

22.3. Creation of one dominant player in IDAM on PXs represents a risk for entire market –

The structural challenges create risks for the entire market and development of Power sector

a. Introduces systemic risk in case of market failure of the dominant Power exchange
b. Market participants cannot get the benefits from competition between multiple power exchanges i.e., innovation in Contracts and services
c. Creates potential for disruptions in the interlinked markets as IDAM prices act as a reference price for many other markets, e.g. DSM, RTM and electricity Derivative product (to be approved shortly by SEBI for introduction on Commodity Exchanges)
d. Current market design acts as an impediment for introduction of MBED and Secondary Ancillary Services Contract

22.4. Creation of unintended monopoly in IDAM and Power exchange space

Statement of reasons: Development of a common platform for electricity trading, 2006

a. Precedence of multiple stock exchanges and commodity exchanges as rationale for establishing multiple power exchanges

> ***"Citing the example of satisfactory multiplicity of Stock Exchange (NSE & BSE) and Commodities Exchange (MCX, NCDEX) in the country, they favoured establishment of more than one power exchange to encourage competition for their sustained performance, since one PX would be a monopoly and would tend to be complacent in the long run".***

22.5. Market Coupling – multiple benefit for stakeholders

a. A deeper market with larger trade surplus and increase in value of the transactions cleared on power exchanges both in IDAM and RTM
b. Avoiding monopoly in power exchange space reducing the long-term systemic risks
c. Better utilization of transmission capacity and improved congestion signaling
d. Increase in competition between power exchanges, introduce innovative Contracts and services
e. IDAM and RTM pricing algorithm can incorporate engineering constraints. e.g. ramp-up / ramp-down rates, transmission capacity constraints, etc.
f. Paves the way for implementation of
   - Market Based Economic Dispatch: Expansion of IDAM and RTM mechanism to the long-term electricity procurement by Discoms
   - Launch of derivatives market with a robust and clear price benchmark

The enabling provisions of Market Coupling as provided at Regulation 37 of CERC (Power Market) Regulations, 2021, needs to be implemented immediately to allow the power market to grow in a transparent and competitive manner without any distortions.

23. Limitations in growth of Market place – MBED and Derivatives in Electricity

Power exchanges are marketplaces, where buyer and seller can efficiently and transparently manage their portfolios better. Since its inception in 2008, the Exchange platform has been a catalyst in the growth and development of power market in India and PXIL has played its role for enabling fair and transparent transaction in electricity.

23.1. MBED

The discussion paper on 'Market Based Economic Dispatch of Electricity: Re-designing of Day Ahead Market (DAM) in India' issued vide public notice no RS-14026(11)/3/2018-CERC dated 31st December 2018 had proposed implemented of MBED; and later MOP also had in its discussion paper ref no 23/16/2020-R&R dated 1st June 2021 titled 'Development of Power Market in India, Phase-I: Implementation of Market Based Economic Dispatch', **proposed phase-wise implementation of MBED from 1st April-2022.** The MBED mechanism envisaged that the cheapest generating resources across the country are dispatched to meet the overall system demand and is a win-win for both the distribution companies and the generators and ultimately result in significant annual savings for the electricity consumers.

However, in a 'multi-power exchange model' the participants based on their mutual preferences would be constrained to split their bids across different power exchanges resulting in unintended fragmentation of liquidity, non-convergence of prices and expose themselves to settle at different prices at respective power exchange platform, defeating the stated objective of savings in power purchase cost envisaged under MBED.

The discussion paper had recognised that an essential next step in reforming electricity market operations and in moving towards **'One Nation, One Grid, One Frequency, One Price' framework is to implement MBED in the day-ahead horizon, initiated by Hon'ble CERC**. **MBED is the first step towards creating system operational efficiency and reducing costs with integrated pan-India approach for generators day-to-day scheduling and despatch.**

23.2. Derivatives in electricity

There's a need for **introducing Derivatives in electricity**, such financial instruments will help in hedging the off-taker risk and provide flexibility and certainty of supply to both Distribution licensees and Generators for sale of power in the futures market. With the settlement of decade- long matter on regulatory jurisdiction of electricity derivatives, the eco-system to introduce financial instruments on commodity exchanges is available.

However, since there's difference in discovered prices across PXs, clearing and settlement of such financial instruments at defined intervals and on expiry by referring to different discovered prices would create confusion in the market. Under this scenario, the financial instruments would fail in their basic objective of providing price signals, both peak/non-peak demand periods, for much needed capex investments.

Market Coupling would provide a single common price that acts as 'benchmark price' for whole set of participants, helps in generating liquidity in shortest time and enables seamless settlements of Derivatives operating on commodity exchanges. Further, since Distribution licensees collectively form the largest set of buy side entities in the spot market, non-availability of 'single common price' may lead to meek response from such critical set of market participant in Derivative segment.

To conclude

Power Exchanges are a 'Market Infrastructure Institution (MII)' operating in electricity space since 2008, that have demonstrated their ability to provide a fair, neutral, efficient and robust price discovery platform for transacting in electricity. PXIL and other power exchanges, operate under provisions of CERC (Power Market) Regulations, 2021 that

facilitates extensive and quick dissemination of transactions concluded in different standardised Contracts offered at respective platform.

Future development in power sector is dependent on increasing the scope of market based electricity transaction in the country, in this regard 'Market Coupling' can help create a more integrated and efficient Indian electricity market which support the growth of multiple power exchanges by increasing market liquidity, enhances competition and allows optimal utilisation of transmission capacity, enabling power exchange platform to enlarge their MII role in electricity space.

Building of two decades of competitive evolution post the Electricity Act 2003 and 15 years of power exchange market operation, the country needs to ensure the right electricity market construct to develop a reliable, flexible and cost-effective power sector. Early implementation of 'Market Coupling' mechanism, will enable country's actions towards deepening markets and maximising cost efficiency through competition in the form of multi-power exchange model.

India which is on path to become $5 trillion economy and has aspiration to become a developed economy must have vibrant, liquid & solvent electricity industry. Per capita electricity consumption is the most important benchmark while assessing a country's development and to attract right kind of infrastructure investments. **The country needs electricity futures market to deepen its power markets. Many policy & regulatory steps like MBED framework, Ancillary services, Indian Electricity Grid Code, General Network Access, Deviation Settlement Mechanism, Green energy Open access, etc. that have significant bearing on the market are being put in place to live the vision of 'One Nation, One grid, One Price'. Implementation of 'Market Coupling' shall bring in place much needed Futures electricity markets & will take Indian power sector to next level.**

PXIL welcomes and supports the staff paper on 'Market Coupling' issued by Hon'ble Commission seeking comments and suggestions of stakeholders on key issues related to designing the framework for the implementation of Market Coupling. PXIL is happy to provide any support to Hon'ble Commission for quicker implementation of Market Coupling in IDAM and RTM.

List of Annexure:

CENTRAL ELECTRICITY REGULATORY COMMISSION (CERC)
Core-3, 6th & 7th Floors, SCOPE Complex, Lodhi Road, New Delhi 110003
Tele No:24361145/Fax No.24360010

No...20/4(24)/2008-CERC

Dated: October 14, 2008

To

Shri S.K. Soone
Executive Director (SO)
Power Grid Corporation of India Limited,
B-9, Qutub Institutional Area,
Katwaria Sarai,
New Delhi-110016

Sub.: Approval to PXI to start power exchange operations.

Ref.: (i) PXI letter dated 10/10/08.
(ii) Your letter No. CSO/CERC dated 18/09/08

Sir,

The Commission has received minutes of the meeting held between National Load Dispatch Centre (NLDC) and Power Exchange India Limited (PXI) on 08/10/08 in which it is inter-alia stated, under Item-3, that the necessary directions of the Commission are required to enable NLDC to do testing for Congestion Management in case of multi-exchange scenario. As you are aware Congestion has not been experienced so far since the beginning of operations by India Energy Exchange (IEX) and the chances of Congestion on Transmission corridors are unlikely in the near future. However, in case Transmission Congestion does occur, the same may be managed by allotting limited transmission capacity to each exchange pro-rata to their respective requisition. The practical methodology for such pro-rata allocation may be implemented at your end with intimation to the Commission. Therefore, operationalisation of PXI need not be held up on this account.

With regards to your suggestions on Congestion Management in Multi-Exchange scenario contained in your letter dated 18/09/08, you are advised to discuss the matter with the officials of the two power exchanges with a view to evolving an agreeable practical and optimal solution.

Yours faithfully,

(Alok Kumar)
Secretary, CERC

Copy to: Ms. Rupa Devi Singh, Chief Executive Officer, Power Exchange India Limited, Exchange Plaza, Bandra Kurla Complex, Bandra (E), Mumbai-400051

पावर ग्रिड कारपोरेशन ऑफ इंडिया लिमिटेड
(भारत सरकार का उद्यम)
POWER GRID CORPORATION OF INDIA LIMITED
(A Government of India Enterprise)
पावरग्रिड
केन्द्रीय कार्यालय : "सौदामिनी" प्लॉट सं. 2, सैक्टर–29, गुड़गाँव–122 001, हरियाणा
फोन : 2571700 - 719 फैक्स : 2571760, 2571761 तार 'नेटग्रिड'
Corporate office : "Saudamini" Plot No. 2, Sector-29, Gurgaon-122 001 Haryana
Tel. : 2571700 - 719, Fax : 2571760, 2571761 Gram : 'NATGRID'

संदर्भ संख्या /Ref. Number

Dated: 17-Oct-08

CSO/CERC/

To
The Secretary,
Central Electricity Regulatory Commission,
Core – 3, 6-7th Floor,
SCOPE Complex,
Lodhi Road,
NEW DELHI – 110 003

Reference: CERC Letter No. 20/4(24)/2008-CERC dated 14th October 2008

Subject: Operationalization of PXI

Dear Sir,

With reference to CERC Letter dated 14th Oct 2008, a meeting was held at NLDC for discussing Congestion Management in Multi-Exchange Scenario with IEX and PXI. The Gist of Discussions held during the meeting is enclosed herewith.

Thanking you,

Yours faithfully,

(S.K. Soonce)
Executive Director (SO)

Encl: As above.

CC:
1. Managing Director, IEX
2. Chief Executive Officer, PXI

Gist of Discussions Held Between NLDC, IEX and PXI
16th October 2008

1. ED (NLDC) welcomed the participants to the meeting. CERC vide its order dated 30-Sep-08 granting approval to PXI to commence operations, has observed that as regards Congestion Management in a Multi-Exchange scenario, the Commission will issue necessary directions in due course. Subsequently, CERC vide its letter dated 14-Oct-08 has stated that the operationalization of the second power exchange, PXI, need not be held up on this account. Transmission congestion may be managed by allotting transmission capacity to the power exchanges pro-rata to their respective requisitions and NLDC has been advised to discuss the issue of congestion management with the power exchanges further with a view to evolving an agreeable practical and optimal solution.
2. The issues in handling congestion in a multi-exchange scenario were submitted to the Hon'ble Commission vide POWERGRID letter dated 18-Sep-08 and copy of the same was also given to both exchanges ahead of the meeting. The following possible approaches were mentioned:
   a. Priority Based Rules
   b. Pro-rata
   c. Explicit auctioning
   d. Merging of bids by each PX for finding a constrained solution.
3. ED (SO), POWERGRID emphasized that NLDC, IEX and PXI represented neutral agencies for an efficient, fair and transparent working of the markets. The Commission, in its guidelines for establishment of power exchange(s) had clearly mentioned voluntary participation, no mandate for one PX, no restriction regarding ownership, and minimal regulation. It was pointed out that limited experience and learning was available internationally for multi-exchange scenario. In view of this and the letter dated 14-Oct-08 from CERC, both IEX and PXI were requested to present their views on congestion management in a multi exchange scenario with the objective of evolving an optimal solution for a fair and efficient operation of the electricity market in India.
4. IEX stated that internationally, the possibility of coupling of exchanges in a multi-exchange scenario was being explored. There were various options available for sharing the available margins between exchanges such as priority based rules, pro-rata, merging of solutions, etc. Though priority based rules such as Lower MCP, Higher MCV, or MCP X MCV, were preferable, they may not result in the most optimal solution. IEX mentioned that pro-rata was difficult to implement specially in the Indian scenario, because of a meshed network and the possibility of congestion shifting from one corridor to another. However, pro-rata based on the import/export volumes requisitioned by the exchanges could be explored. Merging of bids of the two exchanges and working out a solution based on the combined inputs would pose confidentiality issues. However, IEX was open to the idea.
5. On a query from IEX, PXI clarified that market splitting was being used for congestion management by them. PXI mentioned that most methodologies

for sharing of available margins such as priority based rules and pro-rata led to sub-optimal solutions. The most optimal solution would be obtained by merging of bids of the multiple exchanges and PXI was agreeable to the same. However, the confidentiality issues were also to be taken care of. It was emphasized that the methodology adopted should be fair and transparent.

6. It was agreed that adoption of the pro-rata methodology was a sub-optimal solution which would not lead to overall economy and efficiency and was difficult to implement. Some of the difficulties of pro-rata are
   a. Fragmentation of the available margins
   b. Sub-optimal utilization of the grid
   c. Possibility of congestion shifting from one corridor to another
   d. Treatment in case of skewed requisition by exchanges
   e. Treatment of counter flows
   f. Impact of block bids
   g. Over-estimation of requirement, gaming, non-delivery by players
   h. Multiple price discovery leading to inter-play between different markets
7. It was agreed that more work was needed for an optimal solution for sharing of available margins in a multi exchange scenario. However, as a stop gap arrangement and as desired by Hon'ble Commission, pro-rata based on respective requisitions would be adopted. Regarding the practical aspects of implementation of the pro-rata in the interim, the following was agreed:
   a. Pro-rata treatment would be on cleared trade volumes on each Area and each Corridor based on the requisitions by each exchange.
   b. In order to avoid iterative process in case of congestion, post pro-rata treatment, the margins on all corridors and areas would be given to each of the exchanges.
   c. While checking for congestion, counter flow would be accounted for. However, on detection of congestion, separate directional treatment would be given to each Area and Corridor.

   NLDC would make the necessary modifications to their software by the 23rd Oct 2008. It was agreed that the constraints/margins given by NLDC would be on good faith basis.
8. It was decided that each of the exchanges would work out a detailed proposal for handling congestion in the multi-exchange scenario and submit a proposal which should aim at achieving the overall optimisation, economy and efficiency. It should be well researched, with literature survey and documentation of the international experience in this regard. The proposal is to be submitted to NLDC by the 24th Oct 2008 and would be discussed on the 31st Oct 2008.
9. NLDC confirmed that PXI could start operations on 22nd Oct 2008 as proposed by them. PXI agreed to revert back on the same and a coordination meeting between PXI and NLDC would take place before it goes live.
10. List of attendees is enclosed at Annex

Bapak

Annex

Gist of Discussions Held Between NLDC, IEX and PXI
16th October 2008

List of Attendees

POWERGRID – SO/NLDC
S/Shri
S.K. Soonee, ED(SO)
V. Mittal, ED(NLDC)
A. Mani, AGM(SO)
R.K. Bansal, DGM(NLDC)
P.K. Agarwal, DGM(NRLDC)
S.S.Barpanda, Ch. Mgr.(NLDC)
M.K.Agarwal, Ch. Mgr.(NLDC)
S.C.Saxena, Manager(NLDC)
Kundan Srivastava, Engr.(NLDC)

IEX
S/Shri
Akhilesh Awasthy, VP (MO)
Rajesh Mediratta, VP (Marketing)

PXI
S/Shri
Arvind Manglik, Consultant to PXI
S. Ganguly, Chief (Market Operation)
Arvind Pal Singh, AVP
Harsh Amin, Consultant to PXI

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COMMISSION REGULATION (EU) 2015/1222

of 24 July 2015

establishing a guideline on capacity allocation and congestion management

(Text with EEA relevance)

(OJ L 197, 25.7.2015, p. 24)

Amended by:

		Official Journal		
		No	page	date
►M1	Commission Implementing Regulation (EU) 2021/280 of 22 February 2021	L 62	24	23.2.2021

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COMMISSION REGULATION (EU) 2015/1222

of 24 July 2015

establishing a guideline on capacity allocation and congestion management

(Text with EEA relevance)

TITLE I

GENERAL PROVISIONS

Article 1

Subject matter and scope

1. This Regulation lays down detailed guidelines on cross-zonal capacity allocation and congestion management in the day-ahead and intraday markets, including the requirements for the establishment of common methodologies for determining the volumes of capacity simultaneously available between bidding zones, criteria to assess efficiency and a review process for defining bidding zones.

2. This Regulation shall apply to all transmission systems and interconnections in the Union except the transmission systems on islands which are not connected with other transmission systems via interconnections.

3. In Member States where more than one transmission system operator exists, this Regulation shall apply to all transmission system operators within that Member State. Where a transmission system operator does not have a function relevant to one or more obligations under this Regulation, Member States may provide that the responsibility for complying with those obligations is assigned to one or more different, specific transmission system operators.

4. The Union single day-ahead and intraday coupling may be opened to market operators and TSOs operating in Switzerland on the condition that the national law in that country implements the main provisions of Union electricity market legislation and that there is an intergovernmental agreement on electricity cooperation between the Union and Switzerland.

5. Subject to the conditions in paragraph 4 above being fulfilled, participation by Switzerland in day-ahead coupling and single intraday coupling shall be decided by the Commission based on an opinion given by the Agency. The rights and responsibilities of Swiss NEMOs and TSOs joining single day-ahead coupling shall be consistent with the rights and responsibilities of NEMOs and TSOs operating in the Union to allow a smooth functioning of the single day-ahead and intraday coupling systems implemented at Union level and a level-playing field for all stakeholders.

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Article 2

Definitions

For the purposes of this Regulation, the definitions in Article 2 of Regulation (EC) No 714/2009, Article 2 of Commission Regulation (EU) No 543/2013 ([1]) and Article 2 of Directive 2009/72/EC of the European Parliament and of the Council ([2]) shall apply.

In addition, the following definitions shall apply:

1. 'individual grid model' means a data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs, to be merged with other individual grid model components in order to create the common grid model;

2. 'common grid model' means a Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process;

3. 'capacity calculation region' means the geographic area in which coordinated capacity calculation is applied;

4. 'scenario' means the forecasted status of the power system for a given time-frame;

5. 'net position' means the netted sum of electricity exports and imports for each market time unit for a bidding zone;

6. 'allocation constraints' means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation;

7. 'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits;

8. 'coordinated net transmission capacity approach' means the capacity calculation method based on the principle of assessing and defining *ex ante* a maximum energy exchange between adjacent bidding zones;

([1]) Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council (OJ L 163, 15.6.2013, p. 1).

([2]) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (OJ L 211, 14.8.2009, p. 55).

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9. ‘flow-based approach’ means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements;

10. ‘contingency’ means the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security;

11. ‘coordinated capacity calculator’ means the entity or entities with the task of calculating transmission capacity, at regional level or above;

12. ‘generation shift key’ means a method of translating a net position change of a given bidding zone into estimated specific injection increases or decreases in the common grid model;

13. ‘remedial action’ means any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security;

14. ‘reliability margin’ means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation;

15. ‘market time’ means central European summer time or central European time, whichever is in effect;

16. ‘congestion income’ means the revenues received as a result of capacity allocation;

17. ‘market congestion’ means a situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints;

18. ‘physical congestion’ means any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system;

19. ‘structural congestion’ means congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions;

20. ‘matching’ means the trading mode through which sell orders are assigned to appropriate buy orders to ensure the maximisation of economic surplus for single day-ahead or intraday coupling;

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21. ‘order’ means an intention to purchase or sell energy or capacity expressed by a market participant subject to specified execution conditions;

22. ‘matched orders’ means all buy and sell orders matched by the price coupling algorithm or the continuous trade matching algorithm;

23. ‘nominated electricity market operator (NEMO)’ means an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling;

24. ‘shared order book’ means a module in the continuous intraday coupling system collecting all matchable orders from the NEMOs participating in single intraday coupling and performing continuous matching of those orders;

25. ‘trade’ means one or more matched orders;

26. ‘single day-ahead coupling’ means the auctioning process where collected orders are matched and cross-zonal capacity is allocated simultaneously for different bidding zones in the day-ahead market;

27. ‘single intraday coupling’ means the continuous process where collected orders are matched and cross-zonal capacity is allocated simultaneously for different bidding zones in the intraday market;

28. ‘price coupling algorithm’ means the algorithm used in single day-ahead coupling for simultaneously matching orders and allocating cross-zonal capacities;

29. ‘continuous trading matching algorithm’ means the algorithm used in single intraday coupling for matching orders and allocating cross-zonal capacities continuously;

30. ‘market coupling operator (MCO) function’ means the task of matching orders from the day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacities;

31. ‘clearing price’ means the price determined by matching the highest accepted selling order and the lowest accepted buying order in the electricity market;

32. ‘scheduled exchange’ means an electricity transfer scheduled between geographic areas, for each market time unit and for a given direction;

33. ‘scheduled exchange calculator’ means the entity or entities with the task of calculating scheduled exchanges;

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34. ‘day-ahead market time-frame’ means the time-frame of the electricity market until the day-ahead market gate closure time, where, for each market time unit, products are traded the day prior to delivery;

35. ‘day-ahead firmness deadline’ means the point in time after which cross-zonal capacity becomes firm;

36. ‘day-ahead market gate closure time’ means the point in time until which orders are accepted in the day-ahead market;

37. ‘intraday market time-frame’ means the time-frame of the electricity market after intraday cross-zonal gate opening time and before intraday cross-zonal gate closure time, where for each market time unit, products are traded prior to the delivery of the traded products;

38. ‘intraday cross-zonal gate opening time’ means the point in time when cross-zonal capacity between bidding zones is released for a given market time unit and a given bidding zone border;

39. ‘intraday cross-zonal gate closure time’ means the point in time where cross-zonal capacity allocation is no longer permitted for a given market time unit;

40. ‘capacity management module’ means a system containing up-to-date information on available cross-zonal capacity for the purpose of allocating intra-day cross-zonal capacity;

41. ‘non-standard intraday product’ means a product for continuous intraday coupling not for constant energy delivery or for a period exceeding one market time unit with specific characteristics designed to reflect system operation practices or market needs, for example orders covering multiple market time units or products reflecting production unit start-up costs;

42. ‘central counter party’ means the entity or entities with the task of entering into contracts with market participants, by novation of the contracts resulting from the matching process, and of organising the transfer of net positions resulting from capacity allocation with other central counter parties or shipping agents;

43. ‘shipping agent’ means the entity or entities with the task of transferring net positions between different central counter parties;

44. ‘firmness’ means a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed;

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45. '*force majeure*' means any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or economic point of view reasonably possible for the TSO, which has actually happened and is objectively verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this Regulation;

46. 'economic surplus for the single day-ahead or intraday coupling' means the sum of (i) the supplier surplus for the single day-ahead or intraday coupling for the relevant time period, (ii) the consumer surplus for the single day-ahead or intraday coupling, (iii) the congestion income and (iv) other related costs and benefits where these increase economic efficiency for the relevant time period, supplier and consumer surplus being the difference between the accepted orders and the clearing price per energy unit multiplied by the volume of energy of the orders.

Article 3

Objectives of capacity allocation and congestion management cooperation

This Regulation aims at:

(a) promoting effective competition in the generation, trading and supply of electricity;

(b) ensuring optimal use of the transmission infrastructure;

(c) ensuring operational security;

(d) optimising the calculation and allocation of cross-zonal capacity;

(e) ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants;

(f) ensuring and enhancing the transparency and reliability of information;

(g) contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union;

(h) respecting the need for a fair and orderly market and fair and orderly price formation;

(i) creating a level playing field for NEMOs;

(j) providing non-discriminatory access to cross-zonal capacity.

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Article 4

NEMOs designation and revocation of the designation

1. Each Member State electrically connected to a bidding zone in another Member State shall ensure that one or more NEMOs are designated by four months after the entry into force of this Regulation to perform the single day-ahead and/or intraday coupling. For that purpose, domestic and non-domestic market operators may be invited to apply to be designated as a NEMO.

2. Each Member State concerned shall ensure that at least one NEMO is designated in each bidding zone on its territory. NEMOs shall be designated for an initial term of four years. Except where Article 5(1) applies, Member States shall allow applications for designation at least annually.

3. Unless otherwise provided by Member States, regulatory authorities shall be the designating authority, responsible for NEMO designation, monitoring of compliance with the designation criteria and, in the case of national legal monopolies, the approval of NEMO fees or the methodology to calculate NEMO fees. Member States may provide that authorities other than the regulatory authorities be the designating authority. In these circumstances Member States shall ensure that the designating authority has the same rights and obligations as the regulatory authorities in order to effectively carry out its tasks.

4. The designating authority shall assess whether NEMO candidates meet the criteria set out in Article 6. Those criteria shall apply regardless of whether one or more NEMOs are appointed. When deciding upon NEMO designations, any discrimination between applicants, notably between non-domestic and domestic applicants, shall be avoided. If the designating authority is not the regulatory authority, the regulatory authority shall give an opinion on the extent to which the applicant for designation meets the designation criteria laid down in Article 6. NEMO designations shall only be refused where the designation criteria in Article 6 are not met or in accordance with Article 5(1).

5. A NEMO designated in one Member State shall have the right to offer day-ahead and intraday trading services with delivery in another Member State. The trading rules in the latter Member State shall apply without the need for designation as a NEMO in that Member State. The designating authorities shall monitor all NEMOs performing single day-ahead and/or intra-day coupling within their Member State. In accordance with Article 19 of Regulation (EC) No 714/2009 the designating authorities shall ensure compliance with this Regulation by all NEMOs performing single day-ahead and/or intra-day coupling within their Member State, regardless of where the NEMOs were designated. The authorities in charge of NEMO designation, monitoring and enforcement shall exchange all information necessary for an efficient supervision of NEMO activities.

A designated NEMO must notify the designating authority of another Member State if it proposes to perform single day-ahead or intraday coupling in that Member State two months before commencing operation.

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6. By way of exception to paragraph 5 of this Article, a Member State may refuse the trading services by a NEMO designated in another Member State if:

(a) a national legal monopoly for day-ahead and intraday trading services exists in the Member State or bidding zone of the Member State where delivery takes place in accordance with Article 5(1); or

(b) the Member State where delivery takes place can establish that there are technical obstacles to delivery into that Member State of electricity purchased on day-ahead and intraday markets using NEMOs designated in another Member State linked to the need to ensure the objectives of this Regulation are met while maintaining operational security; or

(c) the trading rules in the Member State of delivery are not compatible with the delivery into that Member State of electricity purchased on the basis of day-ahead and intraday trading services provided by a NEMO designated in another Member State; or

(d) the NEMO is a national legal monopoly in accordance with Article 5 in the Member State where it is designated.

7. In case of a decision to refuse day-ahead and/or intraday trading services with delivery in another Member State, the Member State of delivery shall notify its decision to the NEMO and to the designating authority of the Member State where the NEMO is designated, as well as to the Agency and the Commission. The refusal shall be duly justified. In the cases set out in subparagraphs 6(b) and 6(c), the decision to refuse trading services with delivery in another Member State shall also set out how and by when the technical obstacles to trading can be overcome or the domestic trading rules can be made compatible with trading services with delivery in another Member State. The designating authority of the Member State refusing the trading services shall investigate the decision and publish an opinion on how to remove the obstacles to the trading services or how to make the trading services and the trading rules compatible.

8. The Member State where the NEMO has been designated shall ensure that designation is revoked if the NEMO fails to maintain compliance with the criteria in Article 6 and is not able to restore compliance within six months of being notified of such failure by the designating authority. If the regulatory authority is not responsible for designation and monitoring, they shall be consulted on the revocation. The designating authority shall also notify the designating authority of the other Member States in which that NEMO is active of its failure to maintain compliance at the same time it notifies the NEMO.

9. If a designating authority of a Member State finds that a NEMO active but not designated in its country fails to maintain compliance with the criteria in Article 6 with respect to its activities in this country, it must notify the NEMO of its non-compliance. If the NEMO does not restore compliance within three months of being notified, the designating authority can suspend the right to offer intraday and day-ahead trading services in this Member State until such time as the NEMO restores compliance. The designating authority shall notify the designating authority of the Member State in which the NEMO is designated, the Agency and the Commission.

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10. The designating authority shall inform the Agency of the designation and revocation of NEMOs. The Agency shall maintain a list of designated NEMOs, their status and where they operate on its website.

Article 5

NEMOs designation in case of a national legal monopoly for trading services

1. If a national legal monopoly for day-ahead and intraday trading services which excludes the designation of more than one NEMO already exists in a Member State or Member State's bidding zone at the time of the entry into force of this Regulation, the Member State concerned must notify the Commission within two months after entry into force of this regulation and may refuse the designation of more than one NEMO per bidding zone.

If there are several applicants to be designated as the only NEMO, the Member State concerned shall designate the applicant which best meets the criteria listed in Article 6. If a Member State refuses the designation of more than one NEMO per bidding zone, the competent national authority shall fix or approve the NEMO fees for trading in the day-ahead and intraday markets, sufficiently in advance of their entry into force, or specify the methodologies used to calculate them.

In accordance with Article 4(6), the Member State concerned may also refuse cross-border trading services offered by a NEMO designated in another Member State; however, the protection of existing power exchanges in that Member State from economic disadvantages through competition is not a valid reason for refusal.

2. For the purposes of this regulation, a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a Member State or Member State bidding zone can carry out day-ahead and intraday trading services.

3. Two years after the entry into force of this Regulation, the Commission shall forward a report to the European Parliament and the Council in accordance with Article 24 of Regulation (EC) No 714/2009 on the development of single day-ahead and intraday coupling in the Member States, with particular emphasis on the development of competition between NEMOs. On the basis of that report, and if the Commission deems that there is no justification for the continuation of national legal monopolies or for the continued refusal of a Member State to allow cross-border trading by a NEMO designated in another Member State, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within Member States. The Commission shall also include an assessment in the report evaluating the governance of single day-ahead and intraday coupling established by this Regulation, with particular emphasis on the transparency of MCO functions carried jointly by the NEMOs. On the basis of that report, and if the Commission deems that there is ambiguity in carrying out the monopolistic MCO functions and other NEMO tasks, the Commission may consider appropriate legislative or other appropriate measures to further increase transparency and efficient functioning of single day-ahead and intraday coupling.

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Article 6

NEMO designation criteria

1. An applicant shall only be designated as a NEMO if it complies with all of the following requirements:

(a) it has contracted or contracts adequate resources for common, coordinated and compliant operation of single day-ahead and/or intraday coupling, including the resources necessary to fulfil the NEMO functions, financial resources, the necessary information technology, technical infrastructure and operational procedures or it shall provide proof that it is able to make these resources available within a reasonable preparatory period before taking up its tasks in accordance with Article 7;

(b) it shall be able to ensure that market participants have open access to information regarding the NEMO tasks in accordance with Article 7;

(c) it shall be cost-efficient with respect to single day-ahead and intraday coupling and shall in its internal accounting keep separate accounts for MCO functions and other activities in order to prevent cross-subsidisation;

(d) it shall have an adequate level of business separation from other market participants;

(e) if designated as a national legal monopoly for day-ahead and intraday trading services in a Member State, it shall not use the fees in Article 5(1) to finance its day-ahead or intraday activities in a Member State other than the one where these fees are collected;

(f) it shall be able to treat all market participants in a non-discriminatory way;

(g) it shall have appropriate market surveillance arrangements in place;

(h) it shall have in place appropriate transparency and confidentiality agreements with market participants and the TSOs;

(i) it shall be able to provide the necessary clearing and settlement services;

(j) it shall be able to put in place the necessary communication systems and routines for coordinating with the TSOs of the Member State.

2. The designation criteria set out in paragraph 1 shall be applied in such a way that competition between NEMOs is organised in a fair and non-discriminatory manner.

Article 7

NEMO tasks

1. NEMOs shall act as market operators in national or regional markets to perform in cooperation with TSOs single day-ahead and intraday coupling. Their tasks shall include receiving orders from market participants, having overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices and settling and clearing the contracts resulting from the trades according to relevant participant agreements and regulations.

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With regard to single day-ahead and intraday coupling, NEMOs shall in particular be responsible for the following tasks:

(a) implementing the MCO functions set out in paragraph 2 in coordination with other NEMOs;

(b) establishing collectively the requirements for the single day-ahead and intraday coupling, requirements for MCO functions and the price coupling algorithm with respect to all matters related to electricity market functioning in accordance with paragraph 2 of this Article, and Articles 36 and 37;

(c) determining maximum and minimum prices in accordance with Articles 41 and 54;

(d) making anonymous and sharing the received order information necessary to perform the MCO functions provided for in paragraph 2 of this Article and Articles 40 and 53;

(e) assessing the results calculated by the MCO functions set out in paragraph 2 of this Article allocating the orders based on these results, validating the results as final if they are considered correct and taking responsibility for them in accordance with Articles 48 and 60;

(f) informing the market participants on the results of their orders in accordance with Articles 48 and 60;

(g) acting as central counter parties for clearing and settlement of the exchange of energy resulting from single day-ahead and intraday coupling in accordance with Article 68(3);

(h) establishing jointly with relevant NEMOs and TSOs back-up procedures for national or regional market operation in accordance with Article 36(3) if no results are available from the MCO functions in accordance with Article 39(2), taking account of fallback procedures provided for in Article 44;

(i) jointly providing single day-ahead and intraday coupling cost forecasts and cost information to competent regulatory authorities and TSOs where NEMO costs for establishing, amending and operating single day-ahead and intraday coupling are to be covered by the concerned TSOs' contribution in accordance with Articles 75 to 77 and Article 80;

(j) Where applicable, in accordance with Article 45 and 57, coordinate with TSOs to establish arrangements concerning more than one NEMO within a bidding zone and perform single day-ahead and/or intraday coupling in line with the approved arrangements.

2. NEMOs shall carry out MCO functions jointly with other NEMOs. Those functions shall include the following:

(a) developing and maintaining the algorithms, systems and procedures for single day-ahead and intraday coupling in accordance with Articles 36 and 51;

(b) processing input data on cross-zonal capacity and allocation constraints provided by coordinated capacity calculators in accordance with Articles 46 and 58;

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(c) operating the price coupling and continuous trading matching algorithms in accordance with Articles 48 and 60;

(d) validating and sending single day-ahead and intraday coupling results to the NEMOs in accordance with Articles 48 and 60.

3. By eight months after the entry into force of this Regulation all NEMOs shall submit to all regulatory authorities and the Agency a plan that sets out how to jointly set up and perform the MCO functions set out in paragraph 2, including necessary draft agreements between NEMOs and with third parties. The plan shall include a detailed description and the proposed timescale for implementation, which shall not be longer than 12 months, and a description of the expected impact of the terms and conditions or methodologies on the establishment and performance of the MCO functions in paragraph 2.

4. Cooperation between NEMOs shall be strictly limited to what is necessary for the efficient and secure design, implementation and operation of single day-ahead and intraday coupling. The joint performance of MCO functions shall be based on the principle of non-discrimination and ensure that no NEMO can benefit from unjustified economic advantages through participation in MCO functions.

5. The Agency shall monitor NEMOs' progress in establishing and performing the MCO functions, in particular regarding the contractual and regulatory framework and regarding technical preparedness to fulfil the MCO functions. By 12 months after entry into force of this Regulation, the Agency shall report to the Commission whether progress in establishing and performing single day-ahead or intraday coupling is satisfactory.

The Agency may assess the effectiveness and efficiency of establishment and performance of the MCO function at any time. If that assessment demonstrates that the requirements are not fulfilled, the Agency may recommend to the Commission any further measures needed for timely effective and efficient delivery of single day-ahead and intraday coupling.

6. If NEMOs fail to submit a plan in accordance with Article 7(3) to establish the MCO functions referred to in paragraph 2 of this Article for either the intraday or the day-ahead market time-frames, the Commission may, in accordance with Article 9(4), propose an amendment to this Regulation, considering in particular appointing the ENTSO for Electricity or another entity to carry the MCO functions for single day-ahead coupling or for intraday coupling instead of the NEMOs.

Article 8

TSOs' tasks related to single day-ahead and intraday coupling

1. In Member States electrically connected to another Member State all TSOs shall participate in the single day-ahead and intraday coupling.

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2. TSOs shall:

(a) jointly establish TSO requirements for the price coupling and continuous trading matching algorithms for all aspects related to capacity allocation in accordance with Article 37(1)(a);

(b) jointly validate the matching algorithms against the requirements referred to in point (a) of this paragraph in accordance with Article 37(4);

(c) establish and perform capacity calculation in accordance with Articles 14 to 30;

(d) where necessary, establish cross zonal capacity allocation and other arrangements in accordance with Articles 45 and 57;

(e) calculate and send cross zonal capacities and allocation constraints in accordance with Articles 46 and 58;

(f) verify single day-ahead coupling results in terms of validated cross-zonal capacities and allocation constraints in accordance with Articles 48(2) and 52;

(g) where required, establish scheduled exchange calculators for calculating and publishing scheduled exchanges on borders between bidding zones in accordance with Articles 49 and 56;

(h) respect the results from single day-ahead and intraday coupling calculated in accordance with Article 39 and Article 52;

(i) establish and operate fallback procedures as appropriate for capacity allocation in accordance with Article 44;

(j) propose the intraday cross-zonal gate opening and intraday cross-zonal gate closure times in accordance with Article 59;

(k) share congestion income in accordance with the methodology jointly developed in accordance with Article 73;

(l) where so agreed, act as shipping agents transferring net positions in accordance with Article 68(6).

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Article 9

Adoption of terms and conditions or methodologies

1. TSOs and NEMOs shall develop the terms and conditions or methodologies required by this Regulation and submit them for approval to the Agency or the competent regulatory authorities within the respective deadlines set out in this Regulation. In exceptional circumstances, notably in cases where a deadline cannot be met due to circumstances external to the sphere of TSOs or NEMOs, the deadlines for terms and conditions or methodologies may be prolonged by the Agency in procedures pursuant to paragraph 6, jointly by all competent regulatory authorities in procedures pursuant to paragraph 7, and by the competent regulatory authority in procedures pursuant to paragraph 8.

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Where a proposal for terms and conditions or methodologies pursuant to this Regulation needs to be developed and agreed by more than one TSO or NEMO, the participating TSOs and NEMOs shall closely cooperate. TSOs, with the assistance of the ENTSO for Electricity, and all NEMOs shall regularly inform the competent regulatory authorities and the Agency about the progress of developing those terms and conditions or methodologies.

2. Where TSOs or NEMOs deciding on proposals for terms and conditions or methodologies listed in paragraph 6 are not able to reach an agreement, they shall decide by qualified majority voting. The qualified majority shall be reached within each of the respective voting classes of TSOs and NEMOs. A qualified majority for proposals listed in paragraph 6 shall require the following majority:

(a) TSOs or NEMOs representing at least 55 % of the Member States; and

(b) TSOs or NEMOs representing Member States comprising at least 65 % of the population of the Union.

A blocking minority for decisions on proposals for terms and conditions or methodologies listed in paragraph 6 shall include TSOs or NEMOs representing at least four Member States, failing of which the qualified majority shall be deemed attained.

For TSO decisions on proposals for terms and conditions or methodologies listed in paragraph 6, one vote shall be attributed per Member State. If there is more than one TSO in the territory of a Member State, the Member State shall allocate the voting powers among the TSOs.

For NEMOs deciding on proposals for terms and conditions or methodologies listed in paragraph 6, one vote shall be attributed per Member State. Each NEMO shall have a number of votes equal to the number of Member States where it is designated. If more than one NEMO is designated in the territory of a Member State, the Member State shall allocate the voting powers among the NEMOs, taking into account their respective volume of transacted electricity in that particular Member State in the preceding financial year.

3. Except for Article 43(1), Article 44, Article 56(1), Article 63 and Article 74(1), where TSOs deciding on proposals for terms and conditions or methodologies listed in paragraph (7) are not able to reach an agreement and where the regions concerned are composed of more than five Member States, they shall decide by qualified majority voting. The qualified majority shall be reached within each of the respective voting classes of TSOs and NEMOs. A qualified majority for proposals for terms and conditions or methodologies listed in paragraph 7 shall require the following majority:

(a) TSOs representing at least 72 % of the Member States concerned; and

(b) TSOs representing Member States comprising at least 65 % of the population of the concerned region.

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A blocking minority for decisions on proposals for terms and conditions or methodologies listed in paragraph 7 shall include at least the minimum number of TSOs representing more than 35 % of the population of the participating Member States, plus TSOs representing at least one additional Member State concerned, failing of which the qualified majority shall be deemed attained.

TSOs deciding on proposals for terms and conditions or methodologies listed in paragraph 7 in relation to regions composed of five Member States or less shall decide by consensus.

For TSO decisions on proposals for terms and conditions or methodologies listed in paragraph 7, one vote shall be attributed per Member State. If there is more than one TSO in the territory of a Member State, the Member State shall allocate the voting powers among the TSOs.

NEMOs deciding on proposals for terms and conditions or methodologies listed in paragraph 7 shall decide by consensus.

4. If TSOs or NEMOs fail to submit an initial or amended proposal for terms and conditions or methodologies to the competent regulatory authorities or the Agency in accordance with paragraphs 6 to 8 or 12 within the deadlines set out in this Regulation, they shall provide the competent regulatory authorities and the Agency with the relevant drafts of the proposals for the terms and conditions or methodologies, and explain what has prevented an agreement. The Agency, all competent regulatory authorities jointly, or the competent regulatory authority shall take the appropriate steps for the adoption of the required terms and conditions or methodologies in accordance with paragraphs 6, 7 and 8 respectively, for instance by requesting amendments or revising and completing the drafts pursuant to this paragraph, including where no drafts have been submitted, and approve them.

5. Each regulatory authority or where applicable the Agency, as the case may be, shall approve the terms and conditions or methodologies used to calculate or set out the single day-ahead and intraday coupling developed by TSOs and NEMOs. They shall be responsible for approving the terms and conditions or methodologies referred to in paragraphs 6, 7 and 8. Before approving the terms and conditions or methodologies, the Agency or the competent regulatory authorities shall revise the proposals where necessary, after consulting the respective TSOs or NEMOs, in order to ensure that they are in line with the purpose of this Regulation and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.

6. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by the Agency:

(a) the plan on joint performance of MCO functions in accordance with Article 7(3);

(b) the capacity calculation regions in accordance with Article 15(1);

(c) the generation and load data provision methodology in accordance with Article 16(1);

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(d) the common grid model methodology in accordance with Article 17(1);

(e) the proposal for a harmonised capacity calculation methodology in accordance with Article 21(4);

(f) back-up methodology in accordance with Article 36(3);

(g) the algorithm submitted by NEMOs in accordance with Article 37(5), including the TSOs' and NEMOs' sets of requirements for algorithm development in accordance with Article 37(1);

(h) products that can be taken into account by NEMOs in the single day-ahead and intraday coupling process in accordance with Articles 40 and 53;

(i) the maximum and minimum prices in accordance with Articles 41(1) and 54(2);

(j) the intraday capacity pricing methodology to be developed in accordance with Article 55(1);

(k) the intraday cross–zonal gate opening and intraday cross-zonal gate closure times in accordance with Article 59(1);

(l) the day-ahead firmness deadline in accordance with Article 69;

(m) the congestion income distribution methodology in accordance with Article 73(1).

7. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by all regulatory authorities of the concerned region:

(a) the common capacity calculation methodology in accordance with Article 20(2);

(b) decisions on the introduction and postponement of flow-based calculation in accordance with Article 20(2) to (6) and on exemptions in accordance with Article 20(7);

(c) the methodology for coordinated redispatching and countertrading in accordance with Article 35(1);

(d) the common methodologies for the calculation of scheduled exchanges in accordance with Articles 43(1) and 56(1);

(e) the fallback procedures in accordance with Article 44;

(f) complementary regional auctions in accordance with Article 63(1);

(g) the conditions for the provision of explicit allocation in accordance with Article 64(2);

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(h) the redispatching or countertrading cost sharing methodology in accordance with Article 74(1).

8. The following terms and conditions or methodologies and any amendments thereof shall be subject to individual approval by each regulatory authority or other competent authority of the Member States concerned:

(a) where applicable, NEMO designation and revocation or suspension of designation in accordance with Article 4(2), (8) and (9);

(b) if applicable, the fees or the methodologies used to calculate the fees of NEMOs relating to trading in the day-ahead and intraday markets in accordance with Article 5(1);

(c) proposals of individual TSOs for a review of the bidding zone configuration in accordance with Article 32(1)(d);

(d) where applicable, the proposal for cross-zonal capacity allocation and other arrangements in accordance with Articles 45 and 57;

(e) capacity allocation and congestion management costs in accordance with Articles 75 to 79;

(f) if applicable, cost sharing of regional costs of single day-ahead and intraday coupling in accordance with Article 80(4).

9. The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation. Proposals for terms and conditions or methodologies subject to the approval by several regulatory authorities in accordance with paragraph 7 shall be submitted to the Agency within 1 week of their submission to regulatory authorities. Proposals for terms and conditions or methodologies subject to the approval by one regulatory authority in accordance with paragraph 8 may be submitted to the Agency within 1 month of their submission at the discretion of the regulatory authority while they shall be submitted upon the Agency's request for information purposes in accordance with Article 3 paragraph 2 of the Regulation (EU) 2019/942 if the Agency considers the proposal to have a cross-border impact. Upon request by the competent regulatory authorities, the Agency shall issue an opinion within 3 months on the proposals for terms and conditions or methodologies.

10. Where the approval of the terms and conditions or methodologies in accordance with paragraph 7 or the amendment in accordance with paragraph 12 requires a decision by more than one regulatory authority, the competent regulatory authorities shall consult and closely cooperate and coordinate with each other in order to reach an agreement. Where applicable, the competent regulatory authorities shall take into account the opinion of the Agency. Regulatory authorities or, where competent, the Agency shall take decisions concerning the submitted terms and conditions or methodologies in accordance with paragraphs 6, 7 and 8, within 6 months following the receipt of the terms and conditions or

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methodologies by the Agency or the regulatory authority or, where applicable, by the last regulatory authority concerned. The period shall begin on the day following that on which the proposal was submitted to the Agency in accordance with paragraph 6, to the last regulatory authority concerned in accordance with paragraph 7 or, where applicable, to the regulatory authority in accordance with paragraph 8.

11. Where the regulatory authorities have not been able to reach agreement within the period referred to in paragraph 10, or upon their joint request, or upon the Agency's request according to the third subparagraph of Article 5(3) of Regulation (EU) 2019/942, the Agency shall adopt a decision concerning the submitted proposals for terms and conditions or methodologies within 6 months, in accordance with Article 5(3) and the second subparagraph of Article 6(10) of Regulation (EU) 2019/942.

12. In the event that the Agency, or all competent regulatory authorities jointly, or the competent regulatory authority request an amendment to approve the terms and conditions or methodologies submitted in accordance with paragraphs 6, 7 and 8 respectively, the relevant TSOs or NEMOs shall submit a proposal for amended terms and conditions or methodologies for approval within 2 months following the request from the Agency or the competent regulatory authorities or the competent regulatory authority. The Agency or the competent regulatory authorities or the competent regulatory authority shall decide on the amended terms and conditions or methodologies within 2 months following their submission. Where the competent regulatory authorities have not been able to reach an agreement on terms and conditions or methodologies pursuant to paragraph 7 within the 2-month deadline, or upon their joint request, or upon the Agency's request according to the third subparagraph of Article 5(3) of Regulation (EU) 2019/942, the Agency shall adopt a decision concerning the amended terms and conditions or methodologies within 6 months, in accordance with Article 5(3) and the second subparagraph of Article 6(10) of Regulation (EU) 2019/942. If the relevant TSOs or NEMOs fail to submit a proposal for amended terms and conditions or methodologies, the procedure provided for in paragraph 4 of this Article shall apply.

13. The Agency, or all competent regulatory authorities jointly, or the competent regulatory authority, where they are responsible for the adoption of terms and conditions or methodologies in accordance with paragraphs 6, 7 and 8, may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals. TSOs or NEMOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities and the Agency.

The proposals for amendment to the terms and conditions or methodologies shall be submitted to consultation in accordance with the procedure set out in Article 12 and approved in accordance with the procedure set out in this Article.

14. TSOs and NEMOs responsible for establishing the terms and conditions or methodologies in accordance with this Regulation shall publish them on the internet after approval by the Agency or the competent regulatory authorities or, if no such approval is required, after their establishment, except where such information is considered as confidential in accordance with Article 13.

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Article 10

Day-to-day management of the single day-ahead and intraday coupling

TSOs and NEMOs shall jointly organise the day-to-day management of the single day-ahead and intraday coupling. They shall meet regularly to discuss and decide on day-to-day operational issues. TSOs and NEMOs shall invite the Agency and the Commission as observers to these meetings and shall publish summary minutes of the meetings.

Article 11

Stakeholder involvement

The Agency, in close cooperation with ENTSO for Electricity, shall organise stakeholder involvement regarding single day-ahead and intraday coupling and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the single day-ahead and intraday coupling. This shall not replace the stakeholder consultations in accordance with Article 12.

Article 12

Consultation

1. TSOs and NEMOs responsible for submitting proposals for terms and conditions or methodologies or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of each Member State, on the draft proposals for terms and conditions or methodologies where explicitly set out in this Regulation. The consultation shall last for a period of not less than one month.

2. The proposals for terms and conditions or methodologies submitted by the TSOs and NEMOs at Union level shall be published and submitted to consultation at Union level. Proposals submitted by the TSOs and NEMOs at regional level shall be submitted to consultation at least at regional level. Parties submitting proposals at bilateral or at multilateral level shall consult at least the Member States concerned.

3. The entities responsible for the proposal for terms and conditions or methodologies shall duly consider the views of stakeholders resulting from the consultations undertaken in accordance with paragraph 1, prior to its submission for regulatory approval if required in accordance with Article 9 or prior to publication in all other cases. In all cases, a clear and robust justification for including or not the views resulting from the consultation shall be developed in the submission and published in a timely manner before or simultaneously with the publication of the proposal for terms and conditions or methodologies.

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Article 13

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any person subject to the provisions of this Regulation.

3. Confidential information received by the persons referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant Union legislation.

4. Without prejudice to cases covered by national law, regulatory authorities, bodies or persons which receive confidential information pursuant to this Regulation may use it only for the purpose of the performance of their functions under this Regulation.

TITLE II

REQUIREMENTS FOR TERMS, CONDITIONS AND METHODOLOGIES CONCERNING CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

CHAPTER 1

Capacity calculation

Section 1

General requirements

Article 14

Capacity calculation time-frames

1. All TSOs shall calculate cross-zonal capacity for at least the following time-frames:

(a) day-ahead, for the day-ahead market;

(b) intraday, for the intraday market.

2. For the day-ahead market time-frame, individual values for cross-zonal capacity for each day-ahead market time unit shall be calculated. For the intraday market time-frame, individual values for cross-zonal capacity for each remaining intraday market time unit shall be calculated.

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3. For the day-ahead market time-frame, the capacity calculation shall be based on the latest available information. The information update for the day-ahead market time-frame shall not start before 15:00 market time two days before the day of delivery.

4. All TSOs in each capacity calculation region shall ensure that cross-zonal capacity is recalculated within the intraday market time-frame based on the latest available information. The frequency of this recalculation shall take into consideration efficiency and operational security.

Article 15

Capacity calculation regions

1. By three months after the entry into force of this Regulation all TSOs shall jointly develop a common proposal regarding the determination of capacity calculation regions. The proposal shall be subject to consultation in accordance with Article 12.

2. The proposal referred to in paragraph 1 shall define the bidding zone borders attributed to TSOs who are members of each capacity calculation region. The following requirements shall be met:

(a) it shall take into consideration the regions specified in point 3(2) of Annex I to Regulation (EC) No 714/2009;

(b) each bidding zone border, or two separate bidding zone borders if applicable, through which interconnection between two bidding zones exists, shall be assigned to one capacity calculation region;

(c) at least those TSOs shall be assigned to all capacity calculation regions in which they have bidding zone borders.

3. Capacity calculation regions applying a flow-based approach shall be merged into one capacity calculation region if the following cumulative conditions are fulfilled:

(a) their transmission systems are directly linked to each other;

(b) they participate in the same single day-ahead or intraday coupling area;

(c) merging them is more efficient than keeping them separate. The competent regulatory authorities may request a joint cost-benefit analysis from the TSOs concerned to assess the efficiency of the merger.

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Section 2

The common grid model

Article 16

Generation and load data provision methodology

1. By 10 months after the entry into force of this Regulation all TSOs shall jointly develop a proposal for a single methodology for the delivery of the generation and load data required to establish the common grid model, which shall be subject to consultation in accordance with Article 12. The proposal shall include a justification based on the objectives of this Regulation for requiring the information.

2. The proposal for the generation and load data provision methodology shall specify which generation units and loads are required to provide information to their respective TSOs for the purposes of capacity calculation.

3. The proposal for a generation and load data provision methodology shall specify the information to be provided by generation units and loads to TSOs. The information shall at least include the following:

(a) information related to their technical characteristics;

(b) information related to the availability of generation units and loads;

(c) information related to the schedules of generation units;

(d) relevant available information relating to how generation units will be dispatched.

4. The methodology shall specify the deadlines applicable to generation units and loads for providing the information referred to in paragraph 3.

5. Each TSO shall use and share with other TSOs the information referred to in paragraph 3. The information referred to in paragraph 3(d) shall be used for capacity calculation purposes only.

6. No later than two months after the approval of the generation and load data provision methodology by all regulatory authorities, ENTSO for Electricity shall publish:

(a) a list of the entities required to provide information to the TSOs;

(b) a list of the information referred to in paragraph 3 to be provided;

(c) deadlines for providing information.

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Article 17

Common grid model methodology

1. By 10 months after the entering into force of this Regulation all TSOs shall jointly develop a proposal for a common grid model methodology. The proposal shall be subject to consultation in accordance with Article 12.

2. The common grid model methodology shall enable a common grid model to be established. It shall contain at least the following items:

(a) a definition of scenarios in accordance with Article 18;

(b) a definition of individual grid models in accordance with Article 19;

(c) a description of the process for merging individual grid models to form the common grid model.

Article 18

Scenarios

1. All TSOs shall jointly develop common scenarios for each capacity calculation time-frame referred to in Article 14(1)(a) and (b). The common scenarios shall be used to describe a specific forecast situation for generation, load and grid topology for the transmission system in the common grid model.

2. One scenario per market time unit shall be developed both for the day-ahead and the intraday capacity calculation time-frames.

3. For each scenario, all TSOs shall jointly draw up common rules for determining the net position in each bidding zone and the flow for each direct current line. These common rules shall be based on the best forecast of the net position for each bidding zone and on the best forecast of the flows on each direct current line for each scenario and shall include the overall balance between load and generation for the transmission system in the Union. There shall be no undue discrimination between internal and cross-zonal exchanges when defining scenarios, in line with point 1.7 of Annex I to Regulation (EC) No 714/2009.

Article 19

Individual grid model

1. For each bidding zone and for each scenario:

(a) all TSOs in the bidding zone shall jointly provide a single individual grid model which complies with Article 18(3); or

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(b) each TSO in the bidding zone shall provide an individual grid model for its control area, including interconnections, provided that the sum of net positions in the control areas, including interconnections, covering the bidding zone complies with Article 18(3).

2. Each individual grid model shall represent the best possible forecast of transmission system conditions for each scenario specified by the TSO(s) at the time when the individual grid model is created.

3. Individual grid models shall cover all network elements of the transmission system that are used in regional operational security analysis for the concerned time-frame.

4. All TSOs shall harmonise to the maximum possible extent the way in which individual grid models are built.

5. Each TSO shall provide all necessary data in the individual grid model to allow active and reactive power flow and voltage analyses in steady state.

6. Where appropriate, and upon agreement between all TSOs within a capacity calculation region, each TSO in that capacity calculation region shall exchange data between each other to enable voltage and dynamic stability analyses.

Section 3

Capacity calculation methodologies

Article 20

Introduction of flow-based capacity calculation methodology

1. For the day-ahead market time-frame and intraday market time-frame the approach used in the common capacity calculation methodologies shall be a flow-based approach, except where the requirement under paragraph 7 is met.

2. No later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region. The proposal shall be subject to consultation in accordance with Article 12. The proposal for the capacity calculation methodology within regions pursuant to this paragraph in capacity calculation regions based on the ‘North-West Europe’ (‘NWE’) and ‘Central Eastern Europe’ (‘CEE’) as defined in points (b), and (d) of point 3.2 of Annex I to Regulation (EC) No 714/2009 as well as in regions referred to in paragraph 3 and 4, shall be complemented with a common framework for coordination and compatibility of flow-based methodologies across regions to be developed in accordance with paragraph 5.

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3. The TSOs from the capacity calculation region where Italy, as defined in point (c) of point 3.2 of Annex I to Regulation (EC) No 714/2009, is included, may extend the deadline without prejudice to the obligation in paragraph 1 for submitting the proposal for a common coordinated capacity calculation methodology using flow-based approach for the respective region pursuant to paragraph 2 up to six months after Switzerland joins the single day-ahead coupling. The proposal does not have to include bidding zone borders within Italy and between Italy and Greece.

4. No later than six months after at least all South East Europe Energy Community Contracting Parties participate in the single day-ahead coupling, the TSOs from at least Croatia, Romania, Bulgaria and Greece shall jointly submit a proposal to introduce a common capacity calculation methodology using the flow-based approach for the day-ahead and intraday market time-frame. The proposal shall provide for an implementation date of the common capacity calculation methodology using the flow-based approach of no longer than two years after the participation of all SEE Energy Community Contracting Parties in the single day-ahead coupling. The TSOs from Member States which have borders with other regions are encouraged to join the initiatives to implement a common flow-based capacity calculation methodology with these regions.

5. At the time when two or more adjacent capacity calculation regions in the same synchronous area implement a capacity calculation methodology using the flow-based approach for the day-ahead or the intraday market time-frame, they shall be considered as one region for this purpose and the TSOs from this region shall submit within six months a proposal for applying a common capacity calculation methodology using the flow-based approach for the day-ahead or intraday market time-frame. The proposal shall provide for an implementation date of the common cross regional capacity calculation methodology of no longer than 12 months after the implementation of the flow-based approach in these regions for the methodology for the day-ahead market time-frame, and 18 months for the methodology for the intraday time-frame. The timelines indicated in this paragraph may be adapted in accordance with paragraph 6.

The methodology in the two capacity calculation regions which have initiated developing a common capacity calculation methodology may be implemented first before developing a common capacity calculation methodology with any further capacity calculation region.

6. If the TSOs concerned are able to demonstrate that the application of common flow-based methodologies in accordance with paragraphs 4 and 5 would not yet be more efficient assuming the same level of operational security, they may jointly request the competent regulatory authorities to postpone the deadlines.

7. TSOs may jointly request the competent regulatory authorities to apply the coordinated net transmission capacity approach in regions and bidding zone borders other than those referred to in paragraphs 2 to 4, if the TSOs concerned are able to demonstrate that the application of the capacity calculation methodology using the flow-based approach would not yet be more efficient compared to the coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region.

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8. To enable market participants to adapt to any change in the capacity calculation approach, the TSOs concerned shall test the new approach alongside the existing approach and involve market participants for at least six months before implementing a proposal for changing their capacity calculation approach.

9. The TSOs of each capacity calculation region applying the flow-based approach shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones.

Article 21

Capacity calculation methodology

1. The proposal for a common capacity calculation methodology for a capacity calculation region determined in accordance with Article 20(2) shall include at least the following items for each capacity calculation time-frame:

(a) methodologies for the calculation of the inputs to capacity calculation, which shall include the following parameters:

(i) a methodology for determining the reliability margin in accordance with Article 22;

(ii) the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied in accordance with Article 23;

(iii) the methodology for determining the generation shift keys in accordance with Article 24;

(iv) the methodology for determining remedial actions to be considered in capacity calculation in accordance with Article 25.

(b) a detailed description of the capacity calculation approach which shall include the following:

(i) a mathematical description of the applied capacity calculation approach with different capacity calculation inputs;

(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;

(iii) rules for taking into account, where appropriate, previously allocated cross-zonal capacity;

(iv) rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;

(v) for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;

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(vi) for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(vii) where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.

(c) a methodology for the validation of cross-zonal capacity in accordance with Article 26.

2. For the intraday capacity calculation time-frame, the capacity calculation methodology shall also state the frequency at which capacity will be reassessed in accordance with Article 14(4), giving reasons for the chosen frequency.

3. The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

4. All TSOs in each capacity calculation region shall, as far as possible, use harmonised capacity calculation inputs. By 31 December 2020, all regions shall use a harmonised capacity calculation methodology which shall in particular provide for a harmonised capacity calculation methodology for the flow-based and for the coordinated net transmission capacity approach. The harmonisation of capacity calculation methodology shall be subject to an efficiency assessment concerning the harmonisation of the flow-based methodologies and the coordinated net transmission capacity methodologies that provide for the same level of operational security. All TSOs shall submit the assessment with a proposal for the transition towards a harmonised capacity calculation methodology to all regulatory authorities within 12 months after at least two capacity calculation regions have implemented common capacity calculation methodology in accordance with Article 20(5).

Article 22

Reliability margin methodology

1. The proposal for a common capacity calculation methodology shall include a methodology to determine the reliability margin. The methodology to determine the reliability margin shall consist of two steps. First, the relevant TSOs shall estimate the probability distribution of deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time. Second, the reliability margin shall be calculated by deriving a value from the probability distribution.

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2. The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time, and specify the uncertainties to be taken into account in the calculation. To determine those uncertainties, the methodology shall in particular take into account:

(a) unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;

(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time-frame and real time, for the market time unit being considered.

3. In the methodology to determine the reliability margin, TSOs shall also set out common harmonised principles for deriving the reliability margin from the probability distribution.

4. On the basis of the methodology adopted in accordance with paragraph 1, TSOs shall determine the reliability margin respecting the operational security limits and taking into account uncertainties between the capacity calculation time-frame and real time, and the remedial actions available after capacity calculation.

5. For each capacity calculation time-frame, the TSOs concerned shall determine the reliability margin for critical network elements, where the flow-based approach is applied, and for cross-zonal capacity, where the coordinated net transmission capacity approach is applied.

Article 23

Methodologies for operational security limits, contingencies and allocation constraints

1. Each TSO shall respect the operational security limits and contingencies used in operational security analysis.

2. If the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.

3. If TSOs apply allocation constraints, they can only be determined using:

(a) constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements; or

(b) constraints intended to increase the economic surplus for single day-ahead or intraday coupling.

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Article 24

Generation shift keys methodology

1. The proposal for a common capacity calculation methodology shall include a proposal for a methodology to determine a common generation shift key for each bidding zone and scenario developed in accordance with Article 18.

2. The generation shift keys shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the common grid model. That forecast shall notably take into account the information from the generation and load data provision methodology.

Article 25

Methodology for remedial actions in capacity calculation

1. Each TSO within each capacity calculation region shall individually define the available remedial actions to be taken into account in capacity calculation to meet the objectives of this Regulation.

2. Each TSO within each capacity calculation region shall coordinate with the other TSOs in that region the use of remedial actions to be taken into account in capacity calculation and their actual application in real time operation.

3. To enable remedial actions to be taken into account in capacity calculation, all TSOs in each capacity calculation region shall agree on the use of remedial actions that require the action of more than one TSO.

4. Each TSO shall ensure that remedial actions are taken into account in capacity calculation under the condition that the available remedial actions remaining after calculation, taken together with the reliability margin referred to in Article 22, are sufficient to ensure operational security.

5. Each TSO shall take into account remedial actions without costs in capacity calculation.

6. Each TSO shall ensure that the remedial actions to be taken into account in capacity calculation are the same for all capacity calculation time-frames, taking into account their technical availabilities for each capacity calculation time-frame.

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Article 26

Cross-zonal capacity validation methodology

1. Each TSO shall validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders or critical network elements provided by the coordinated capacity calculators in accordance with Articles 27 to 31.

2. Where a coordinated net transmission capacity approach is applied, all TSOs in the capacity calculation region shall include in the capacity calculation methodology referred to in Article 21 a rule for splitting the correction of cross-zonal capacity between the different bidding zone borders.

3. Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity referred to in paragraph 1 for reasons of operational security.

4. Each coordinated capacity calculator shall coordinate with the neighbouring coordinated capacity calculators during capacity calculation and validation.

5. Each coordinated capacity calculator shall, every three months, report all reductions made during the validation of cross-zonal capacity in accordance with paragraph 3 to all regulatory authorities of the capacity calculation region. This report shall include the location and amount of any reduction in cross-zonal capacity and shall give reasons for the reductions.

6. All the regulatory authorities of the capacity calculation region shall decide whether to publish all or part of the report referred to in paragraph 5.

Section 4

The capacity calculation process

Article 27

General provisions

1. No later than six months after the decision on the generation and load data provision methodology referred to in Article 16 and the common grid model methodology referred to in Article 17, all TSOs shall organise the process of merging the individual grid models.

2. No later than four months after the decisions on the capacity calculation methodologies referred to in Articles 20 and 21, all the TSOs in each capacity calculation region shall jointly set up the coordinated capacity calculators and establish rules governing their operations.

3. All TSOs of each capacity calculation region shall review the quality of data submitted within the capacity calculation every second year as part of the biennial report on capacity calculation and allocation produced in accordance with Article 31.

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4. Using the latest available information, all TSOs shall regularly and at least once a year review and update:

(a) the operational security limits, contingencies and allocation constraints used for capacity calculation;

(b) the probability distribution of the deviations between expected power flows at the time of capacity calculation and realised power flows in real time used for calculation of reliability margins;

(c) the remedial actions taken into account in capacity calculation;

(d) the application of the methodologies for determining generation shift keys, critical network elements and contingencies referred to in Articles 22 to 24.

Article 28

Creation of a common grid model

1. For each capacity calculation time-frame referred to in Article 14(1), each generator or load unit subject to Article 16 shall provide the data specified in the generation and load data provision methodology to the TSO responsible for the respective control area within the specified deadlines.

2. Each generator or load unit providing information pursuant to Article 16(3) shall deliver the most reliable set of estimations practicable.

3. For each capacity calculation time-frame, each TSO shall establish the individual grid model for each scenario in accordance with Article 19, in order to merge individual grid models into a common grid model.

4. Each TSO shall deliver to the TSOs responsible for merging the individual grid models into a common grid model the most reliable set of estimations practicable for each individual grid model.

5. For each capacity calculation time-frame a single, Union-wide common grid model shall be created for each scenario as set out in Article 18 by merging inputs from all TSOs applying the capacity calculation process as set out in paragraph 3 of this Article.

Article 29

Regional calculation of cross-zonal capacity

1. For each capacity calculation time-frame, each TSO shall provide the coordinated capacity calculators and all other TSOs in the capacity calculation region with the following items: operational security limits, generation shift keys, remedial actions, reliability margins, allocation constraints and previously allocated cross-zonal capacity.

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2. Each coordinated capacity calculator shall perform an operational security analysis applying operational security limits by using the common grid model created for each scenario in accordance with Article 28(5).

3. When calculating cross-zonal capacity, each coordinated capacity calculator shall:

(a) use generation shift keys to calculate the impact of changes in bidding zone net positions and of flows on direct current lines;

(b) ignore those critical network elements that are not significantly influenced by the changes in bidding zone net positions according to the methodology set out in Article 21; and,

(c) ensure that all sets of bidding zone net positions and flows on direct current lines not exceeding cross-zonal capacity comply with reliability margins and operational security limits in accordance with Article 21(1)(a)(i) and (ii), and take into account previously allocated cross-zonal capacity in accordance with Article 21(1)(b)(iii).

4. Each coordinated capacity calculator shall optimise cross-zonal capacity using available remedial actions taken into account in capacity calculation in accordance with Article 21(1)(a)(iv).

5. Each coordinated capacity calculator shall apply the sharing rules established in accordance with Article 21(1)(b)(vi).

6. Each coordinated capacity calculator shall respect the mathematical description of the applied capacity calculation approach established in accordance with Article 21(1)(b)(i).

7. Each coordinated capacity calculator applying the flow-based approach shall:

(a) use data on operational security limits to calculate the maximum flows on critical network elements;

(b) use the common grid model, generation shift keys and contingencies to calculate the power transfer distribution factors;

(c) use power transfer distribution factors to calculate the flows resulting from previously allocated cross-zonal capacity in the capacity calculation region;

(d) calculate flows on critical network elements for each scenario (taking into account contingencies), and adjust them by assuming no cross-zonal power exchanges within the capacity calculation region, applying the rules for avoiding undue discrimination between internal and cross-zonal power exchanges established in accordance with Article 21(1)(b)(ii);

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(e) calculate the available margins on critical network elements, taking into account contingencies, which shall equal the maximum flows reduced by adjusted flows referred to in point (d), reliability margins, and flows resulting from previously allocated cross-zonal capacity;

(f) adjust the available margins on critical network elements or power transfer distribution factors using available remedial actions to be considered in capacity calculation in accordance with Article 25.

8. Each coordinated capacity calculator applying the coordinated net transmission capacity approach shall:

(a) use the common grid model, generation shift keys and contingencies to calculate maximum power exchange on bidding zone borders, which shall equal the maximum calculated exchange between two bidding zones on either side of the bidding zone border respecting operational security limits;

(b) adjust maximum power exchange using remedial actions taken into account in capacity calculation in accordance with Article 25;

(c) adjust maximum power exchange, applying rules for avoiding undue discrimination between internal and cross-zonal exchanges in accordance with Article 21(1)(b)(ii);

(d) apply the rules set out in accordance with Article 21(1)(b)(vi) for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(e) calculate cross-zonal capacity, which shall be equal to maximum power exchange adjusted for the reliability margin and previously allocated cross-zonal capacity.

9. Each coordinated capacity calculator shall cooperate with the neighbouring coordinated capacity calculators. Neighbouring TSOs shall ensure such cooperation by exchanging and confirming information on interdependency with the relevant regional coordinated capacity calculators, for the purposes of capacity calculation and validation. Neighbouring TSOs shall provide information on interdependency to the coordinated capacity calculators before capacity calculation. An assessment of the accuracy of this information and corrective measures shall be included in the biennial report drafted in accordance with Article 31, where appropriate.

10. Each coordinated capacity calculator shall set:

(a) flow-based parameters for each bidding zone within the capacity calculation region, if applying the flow-based approach; or

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(b) cross-zonal capacity values for each bidding zone border within the capacity calculation region, if applying the coordinated net transmission capacity approach.

11. Each coordinated capacity calculator shall submit the cross-zonal capacity to each TSO within its capacity calculation region for validation in accordance with Article 21(1)(c).

Article 30

Validation and delivery of cross-zonal capacity

1. Each TSO shall validate the results of the regional capacity calculation for its bidding zone borders or critical network elements, in accordance with Article 26.

2. Each TSO shall send its capacity validation and allocation constraints to the relevant coordinated capacity calculators and to the other TSOs of the relevant capacity calculation regions.

3. Each coordinated capacity calculator shall provide the validated cross-zonal capacities and allocation constraints for the purposes of allocating capacity in accordance with Articles 46 and 58.

Section 5

Biennial report on capacity calculation and allocation

Article 31

Biennial report on capacity calculation and allocation

1. By two years after the entry into force of this Regulation, ENTSO for Electricity shall draft a report on capacity calculation and allocation and submit it to the Agency.

2. If the Agency requests it, in every second subsequent year ENTSO for Electricity shall draft a report on capacity calculation and allocation and submit it to the Agency.

3. For each bidding zone, bidding zone border and capacity calculation region, the report on capacity calculation and allocation shall contain at least:

(a) the capacity calculation approach used;

(b) statistical indicators on reliability margins;

(c) statistical indicators of cross-zonal capacity, including allocation constraints where appropriate for each capacity calculation time-frame;

(d) quality indicators for the information used for the capacity calculation;

(e) where appropriate, proposed measures to improve capacity calculation;

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(f) for regions where the coordinated net transmission capacity approach is applied, an analysis of whether the conditions specified in Article 20(7) are still fulfilled;

(g) indicators for assessing and following in the longer term the efficiency of single day-ahead and intraday coupling, including the merging of capacity calculation regions in accordance with Article 15(3) where relevant;

(h) recommendations for further development of single day-ahead and intraday coupling, including further harmonisation of methodologies, processes and governance arrangements.

4. After consulting the Agency, all TSOs shall jointly agree on the statistical and quality indicators for the report. The Agency may require the amendment of those indicators, prior to the agreement by the TSOs or during their application.

5. The Agency shall decide whether to publish all or part of the biennial report.

CHAPTER 2

Bidding zone configuration

Article 32

Reviewing existing bidding zone configurations

1. A review of an existing bidding zone configuration may be launched by:

(a) the Agency, in accordance with Article 34(7);

(b) several regulatory authorities, pursuant to a recommendation from the Agency in accordance with Article 34;

(c) TSOs of a capacity calculation region, together with all concerned TSOs whose control areas, including interconnectors, are within the geographic area in which the bidding zone configuration shall be assessed in accordance with paragraph 2(a);

(d) one single regulatory authority or TSO with the approval of its competent regulatory authority, for the bidding zones inside the TSO's control area, if the bidding zone configuration has negligible impact on neighbouring TSOs' control areas, including interconnectors, and the review of bidding zone configuration is necessary to improve efficiency, or to maintain operational security;

(e) Member States in a capacity calculation region.

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2. If a review is launched in accordance with paragraph 1(a),(b), (c) or (e), the entity launching the review shall specify:

(a) the geographic area in which bidding zone configuration shall be assessed and the neighbouring geographic areas for which impacts shall be taken into account;

(b) the participating TSOs;

(c) the participating regulatory authorities.

3. If a review is launched in accordance with paragraph 1(d), the following conditions shall apply:

(a) the geographic area in which bidding zone configuration is assessed shall be limited to the control area of the relevant TSO, including interconnectors;

(b) the TSO of the relevant control area shall be the only TSO participating in the review;

(c) the competent regulatory authority shall be the only regulatory authority participating in the review;

(d) the relevant TSO and regulatory authority, respectively, shall give the neighbouring TSOs and regulatory authorities mutually agreed prior notice of the launch of the review, giving reasons; and

(e) the conditions for the review shall be specified, and the results of the review and proposal for the relevant regulatory authorities shall be published.

4. The review process shall consist of two steps.

(a) In the first step, the TSOs participating in a review of bidding zone configuration shall develop the methodology and assumptions that will be used in the review process and propose alternative bidding zone configurations for the assessment.

The proposal on methodology and assumptions and alternative bidding zone configuration shall be submitted to the participating regulatory authorities, which shall be able to require coordinated amendments within three months.

(b) In the second step, the TSOs participating in a review of bidding zone configuration shall:

(i) assess and compare the current bidding zone configuration and each alternative bidding zone configuration using the criteria specified in Article 33;

(ii) hold a consultation in accordance with Article 12 and a workshop regarding the alternative bidding zone configuration proposals compared to the existing bidding zone configuration, including timescales for implementation, unless the bidding zone configuration has negligible impact on neighbouring TSOs' control areas;

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(iii) submit a joint proposal to maintain or amend the bidding zone configuration to the participating Member States and the participating regulatory authorities within 15 months of the decision to launch a review.

(c) On receiving the joint proposal to maintain or to amend the bidding zone configuration in accordance with point (iii) above, the participating Member States or, where provided by Member States, the regulatory authorities shall within six months reach an agreement on the proposal to maintain or amend the bidding zone configuration.

5. NEMOs or market participants shall, if requested by TSOs, provide the TSOs participating in a review of a bidding zone with information to enable them to assess bidding zone configurations. This information shall be shared only between the participating TSOs for the sole purpose of assessing bidding zone configurations.

6. The initiative for the review of the bidding zones configuration and its results shall be published by ENTSO for Electricity, or if the review was launched in accordance with paragraph 1(d), by the participating TSO.

Article 33

Criteria for reviewing bidding zone configurations

1. If a review of bidding zone configuration is carried out in accordance with Article 32, at least the following criteria shall be considered:

(a) in respect of network security:

(i) the ability of bidding zone configurations to ensure operational security and security of supply;

(ii) the degree of uncertainty in cross–zonal capacity calculation.

(b) in respect of overall market efficiency:

(i) any increase or decrease in economic efficiency arising from the change;

(ii) market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity, market concentration and market power, the facilitation of effective competition, price signals for building infrastructure, the accuracy and robustness of price signals;

(iii) transaction and transition costs, including the cost of amending existing contractual obligations incurred by market participants, NEMOs and TSOs;

(iv) the cost of building new infrastructure which may relieve existing congestion;

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(v) the need to ensure that the market outcome is feasible without the need for extensive application of economically inefficient remedial actions;

(vi) any adverse effects of internal transactions on other bidding zones to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;

(vii) the impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes.

(c) in respect of the stability and robustness of bidding zones:

(i) the need for bidding zones to be sufficiently stable and robust over time;

(ii) the need for bidding zones to be consistent for all capacity calculation time-frames;

(iii) the need for each generation and load unit to belong to only one bidding zone for each market time unit;

(iv) the location and frequency of congestion, if structural congestion influences the delimitation of bidding zones, taking into account any future investment which may relieve existing congestion.

2. A bidding zone review in accordance with Article 32 shall include scenarios which take into account a range of likely infrastructure developments throughout the period of 10 years starting from the year following the year in which the decision to launch the review was taken.

Article 34

Regular reporting on current bidding zone configuration by ENTSO for Electricity and the Agency

1. The Agency shall assess the efficiency of current bidding zone configuration every three years.

It shall:

(a) request ENTSO for Electricity to draft a technical report on current bidding zone configuration; and

(b) draft a market report evaluating the impact of current bidding zone configuration on market efficiency.

2. The technical report referred to in paragraph 1 second subparagraph point (a) shall include at least:

(a) a list of structural congestion and other major physical congestion, including locations and frequency;

(b) an analysis of the expected evolution or removal of physical congestion resulting from investment in networks or from significant changes in generation or in consumption patterns;

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(c) an analysis of the share of power flows that do not result from the capacity allocation mechanism, for each capacity calculation region, where appropriate;

(d) congestion incomes and firmness costs;

(e) a scenario encompassing a ten year time-frame.

3. Each TSO shall provide data and analysis to allow the technical report on current bidding zone configuration to be produced in a timely manner.

4. ENTSO for Electricity shall deliver to the Agency the technical report on current bidding zone configuration no later than nine months after the request by the Agency.

5. The technical report on current bidding zone configuration shall cover the last three full calendar years preceding the request by the Agency.

6. Without prejudice to the confidentiality obligations provided for in Article 13, ENTSO for Electricity shall make the technical report available to the public.

7. If the technical or market report reveals inefficiencies in the current bidding zone configuration, the Agency may request TSOs to launch a review of an existing bidding zone configuration in accordance with Article 32(1).

CHAPTER 3

Redispatching and countertrading

Article 35

Coordinated redispatching and countertrading

1. Within 16 months after the regulatory approval on capacity calculation regions referred to in Article 15, all the TSOs in each capacity calculation region shall develop a proposal for a common methodology for coordinated redispatching and countertrading. The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology for coordinated redispatching and countertrading shall include actions of cross-border relevance and shall enable all TSOs in each capacity calculation region to effectively relieve physical congestion irrespective of whether the reasons for the physical congestion fall mainly outside their control area or not. The methodology for coordinated redispatching and countertrading shall address the fact that its application may significantly influence flows outside the TSO's control area.

3. Each TSO may redispatch all available generation units and loads in accordance with the appropriate mechanisms and agreements applicable to its control area, including interconnectors.

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By 26 months after the regulatory approval of capacity calculation regions, all TSOs in each capacity calculation region shall develop a report, subject to consultation in accordance with Article 12, assessing the progressive coordination and harmonisation of those mechanisms and agreements and including proposals. The report shall be submitted to their respective regulatory authorities for their assessment. The proposals in the report shall prevent these mechanisms and agreements from distorting the market.

4. Each TSO shall abstain from unilateral or uncoordinated redispatching and countertrading measures of cross-border relevance. Each TSO shall coordinate the use of redispatching and countertrading resources taking into account their impact on operational security and economic efficiency.

5. The relevant generation units and loads shall give TSOs the prices of redispatching and countertrading before redispatching and countertrading resources are committed.

Pricing of redispatching and countertrading shall be based on:

(a) prices in the relevant electricity markets for the relevant time-frame; or

(b) the cost of redispatching and countertrading resources calculated transparently on the basis of incurred costs.

6. Generation units and loads shall *ex-ante* provide all information necessary for calculating the redispatching and countertrading cost to the relevant TSOs. This information shall be shared between the relevant TSOs for redispatching and countertrading purposes only.

CHAPTER 4

Algorithm development

Article 36

General provisions

1. All NEMOs shall develop, maintain and operate the following algorithms:

(a) a price coupling algorithm;

(b) a continuous trading matching algorithm.

2. NEMOs shall ensure that the price coupling algorithm and the continuous trading matching algorithm meet the requirements provided for in Articles 39 and 52 respectively.

3. By 18 months after the entry into force of this Regulation, all NEMOs shall in cooperation with TSOs develop a proposal for a back-up methodology to comply with the obligations set out in Articles 39 and 52 respectively. The proposal for a methodology shall be subject to consultation in accordance with Article 12.

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4. Where possible, NEMOs shall use already agreed solutions to efficiently implement the objectives of this Regulation.

Article 37

Algorithm development

1. By eight months after the entry into force of this Regulation:

(a) all TSOs shall jointly provide all NEMOs with a proposal for a common set of requirements for efficient capacity allocation to enable the development of the price coupling algorithm and of the continuous trading matching algorithm. These requirements shall specify functionalities and performance, including deadlines for the delivery of single day-ahead and intraday coupling results and details of the cross-zonal capacity and allocation constraints to be respected;

(b) all NEMOs shall jointly propose a common set of requirements for efficient matching to enable the development of the price coupling algorithm and of the continuous trading matching algorithm.

2. No later than three months after the submission of the TSO and NEMO proposals for a common set of requirements in accordance with paragraph 1, all NEMOs shall develop a proposal for the algorithm in accordance with these requirements. This proposal shall indicate the time limit for the submission of received orders by NEMOs required to perform the MCO functions in accordance with Article 7(1)(b).

3. The proposal referred to in paragraph 2 shall be submitted to all TSOs. If additional time is required to prepare this proposal, all NEMOs shall work together supported by all TSOs for a period of not more than two months to ensure that the proposal complies with paragraphs 1 and 2.

4. The proposals referred to in paragraphs 1 and 2 shall be subject to consultation in accordance with Article 12.

5. All NEMOs shall submit the proposal developed in accordance with paragraphs 2 and 3 to the regulatory authorities for approval by no later than 18 months after the entry into force of this Regulation.

6. No later than two years after the approval of the proposal in accordance with paragraph 5, all TSOs and all NEMOs shall review the operation of the price coupling algorithm and continuous trading matching algorithm and submit the report to the Agency. If requested by the Agency, the review shall then be repeated every second year.

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CHAPTER 5

Single day-ahead coupling

Section 1

The price coupling algorithm

Article 38

Objectives of the price coupling algorithm

1. The price coupling algorithm shall produce the results set out in Article 39(2), in a manner which:

(a) aims at maximising economic surplus for single day-ahead coupling for the price-coupled region for the next trading day;

(b) uses the marginal pricing principle according to which all accepted bids will have the same price per bidding zone per market time unit;

(c) facilitates efficient price formation;

(d) respects cross-zonal capacity and allocation constraints;

(e) is repeatable and scalable.

2. The price coupling algorithm shall be developed in such a way that it would be possible to apply it to a larger or smaller number of bidding zones.

Article 39

Inputs and results of the price coupling algorithm

1. In order to produce results, the price coupling algorithm shall use:

(a) allocation constraints established in accordance with Article 23(3);

(b) cross-zonal capacity results validated in accordance with Article 30;

(c) orders submitted in accordance with Article 40.

2. The price coupling algorithm shall produce at least the following results simultaneously for each market time unit:

(a) a single clearing price for each bidding zone and market time unit in EUR/MWh;

(b) a single net position for each bidding zone and each market time unit;

(c) the information which enables the execution status of orders to be determined.

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3. All NEMOs shall ensure the accuracy and efficiency of results produced by the single price coupling algorithm.

4. All TSOs shall verify that the results of the price coupling algorithm are consistent with cross-zonal capacity and allocation constraints.

Article 40

Products accommodated

1. No later than 18 months after the entry into force of this Regulation NEMOs shall submit a joint proposal concerning products that can be taken into account in the single day-ahead coupling. NEMOs shall ensure that orders resulting from these products submitted to the price coupling algorithm are expressed in euros and make reference to the market time.

2. All NEMOs shall ensure that the price coupling algorithm is able to accommodate orders resulting from these products covering one market time unit and multiple market time units.

3. By two years after the entry into force of this Regulation and in every second subsequent year, all NEMOs shall consult, in accordance with Article 12:

(a) market participants, to ensure that available products reflect their needs;

(b) all TSOs, to ensure products take due account of operational security;

(c) all regulatory authorities, to ensure that the available products comply with the objectives of this Regulation.

4. All NEMOs shall amend the products if needed pursuant to the results of the consultation referred to in paragraph 3.

Article 41

Maximum and minimum prices

1. By 18 months after the entry into force of this Regulation, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones which participate in single day-ahead coupling. The proposal shall take into account an estimation of the value of lost load.

The proposal shall be subject to consultation in accordance with Article 12.

2. All NEMOs shall submit the proposal to the regulatory authorities for approval.

Where a Member State has provided that an authority other than the national regulatory authority has the power to approve maximum and minimum clearing prices at the national level, the regulatory authority shall consult the proposal with the relevant authority as regards its impact on national markets.

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After receiving a decision for approval from all regulatory authorities, all NEMOs shall inform the concerned TSOs of that decision without undue delay.

Article 42

Pricing of day-ahead cross-zonal capacity

1. The day-ahead cross-zonal capacity charge shall reflect market congestion and shall amount to the difference between the corresponding day-ahead clearing prices of the relevant bidding zones.

2. No charges, such as imbalance fees or additional fees, shall be applied to day-ahead cross-zonal capacity except for the pricing in accordance with paragraph 1.

Article 43

Methodology for calculating scheduled exchanges resulting from single day-ahead coupling

1. By 16 months after the entry into force of this Regulation, TSOs which intend to calculate scheduled exchanges resulting from single day-ahead coupling shall develop a proposal for a common methodology for this calculation. The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology shall describe the calculation and shall list the information which shall be provided by the relevant NEMOs to the scheduled exchange calculator established in accordance with Article 8(2)(g) and the time limits for delivering this information. The time limit for delivering information shall be no later than 15.30 market time day-ahead.

3. The calculation shall be based on net positions for each market time unit.

4. No later than two years after the approval by the regulatory authorities of the concerned region of the proposal referred to in paragraph 1, TSOs applying scheduled exchanges shall review the methodology. Thereafter, if requested by the competent regulatory authorities, the methodology shall be reviewed every two years.

Article 44

Establishment of fallback procedures

By 16 months after the entry into force of this Regulation, each TSO, in coordination with all the other TSOs in the capacity calculation region, shall develop a proposal for robust and timely fallback procedures to ensure efficient, transparent and non-discriminatory capacity allocation in the event that the single day-ahead coupling process is unable to produce results.

The proposal for the establishment of fallback procedures shall be subject to consultation in accordance with Article 12.

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Article 45

Arrangements concerning more than one NEMO in one bidding zone and for interconnectors which are not operated by certified TSOs

1. TSOs in bidding zones where more than one NEMO is designated and/or offers trading services, or where interconnectors which are not operated by TSOs certified according to Article 3 of Regulation (EC) No 714/2009 exist, shall develop a proposal for cross-zonal capacity allocation and other necessary arrangements for such bidding zones in cooperation with concerned TSOs, NEMOs and operators of interconnectors who are not certified as TSOs to ensure that the relevant NEMOs and interconnectors provide the necessary data and financial coverage for such arrangements. These arrangements must allow additional TSOs and NEMOs to join these arrangements.

2. The proposal shall be submitted to the relevant national regulatory authorities for approval within 4 months after more than one NEMO has been designated and/or allowed to offer trading services in a bidding zone or if a new interconnector is not operated by a certified TSO. For existing interconnectors which are not operated by certified TSOs the proposal shall be submitted within four months after entry into force of this Regulation.

Section 2

The single day-ahead coupling process

Article 46

Provision of input data

1. Each coordinated capacity calculator shall ensure that cross-zonal capacity and allocation constraints shall be provided to relevant NEMOs in time to ensure the publication of cross-zonal capacity and of allocation constraints to the market no later than 11.00 market time day-ahead.

2. If a coordinated capacity calculator is unable to provide for cross-zonal capacity and allocation constraints one hour prior to the day-ahead market gate closure time, that coordinated capacity calculator shall notify the relevant NEMOs. These NEMOs shall immediately publish a notice for market participants.

In such cases, cross-zonal capacity and allocation constraints shall be provided by the coordinated capacity calculator no later than 30 minutes before the day-ahead market gate closure time.

Article 47

Operation of single day-ahead coupling

1. The day-ahead market gate opening time shall be at the latest 11:00 market time day-ahead.

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2. The day-ahead market gate closure time in each bidding zone shall be noon market time day-ahead. TSOs or NEMOs in the region based on the CEE region or its neighbouring countries may set a different gate closure time until this region has joined single day-ahead coupling.

3. Market participants shall submit all orders to the relevant NEMOs before day-ahead market gate closure time, in accordance with Articles 39 and 40.

4. Each NEMO shall submit the orders received in accordance with paragraph 3 to perform the MCO functions in accordance with Article 7(2) by no later than a time specified by all NEMOs in the proposal for a single price coupling algorithm set out in Article 37(5).

5. Orders matched in single day-ahead coupling shall be considered firm.

6. MCO functions shall ensure anonymity of submitted orders.

Article 48

Delivery of results

1. No later than by the time specified by all TSOs in the requirements set out in Article 37(1)(a), all NEMOs performing MCO functions shall deliver the single day-ahead coupling results:

(a) to all TSOs, all coordinated capacity calculators and all NEMOs, for the results specified in Article 39(2)(a) and (b);

(b) to all NEMOs, for the results specified in Article 39(2)(c).

2. Each TSO shall verify that the single day-ahead coupling results of the price coupling algorithm referred to in Article 39(2)(b) have been calculated in accordance with the allocation constraints and validated cross-zonal capacity.

3. Each NEMO shall verify that the single day-ahead coupling results of the price coupling algorithm referred to in Article 39(2)(c) have been calculated in accordance with the orders.

4. Each NEMO shall inform market participants on the execution status of their orders without unjustifiable delay.

Article 49

Calculation of scheduled exchanges resulting from single day-ahead coupling

1. Each scheduled exchange calculator shall calculate scheduled exchanges between bidding zones for each market time unit in accordance with the methodology established in Article 43.

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2. Each scheduled exchange calculator shall notify relevant NEMOs, central counter parties, shipping agents and TSOs of the agreed scheduled exchanges.

Article 50

Initiation of fallback procedures

1. In the event that all NEMOs performing MCO functions are unable to deliver part or all of the results of the price coupling algorithm by the time specified in Article 37(1)(a), the fallback procedures established in accordance with Article 44 shall apply.

2. In cases where there is a risk that all NEMOs performing MCO functions are unable to deliver part or all of the results within the deadline, all NEMOs shall notify all TSOs as soon as the risk is identified. All NEMOs performing MCO functions shall immediately publish a notice to market participants that fallback procedures may be applied.

CHAPTER 6

Single intraday coupling

Section 1

Objectives, conditions and results of single intraday coupling

Article 51

Objectives of the continuous trading matching algorithm

1. From the intraday cross-zonal gate opening time until the intraday cross-zonal gate closure time, the continuous trading matching algorithm shall determine which orders to select for matching such that matching:

(a) aims at maximising economic surplus for single intraday coupling per trade for the intraday market time-frame by allocating capacity to orders for which it is feasible to match in accordance with the price and time of submission;

(b) respects the allocation constraints provided in accordance with Article 58(1);

(c) respects the cross-zonal capacity provided in accordance with Article 58(1);

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(d) respects the requirements for the delivery of results set out in Article 60;

(e) is repeatable and scalable.

2. The continuous trading matching algorithm shall produce the results provided for in Article 52 and correspond to the product capabilities and functionalities set out in Article 53.

Article 52

Results of the continuous trading matching algorithm

1. All NEMOs, as part of their MCO function, shall ensure that the continuous trading matching algorithm produces at least the following results:

(a) the execution status of orders and prices per trade;

(b) a single net position for each bidding zone and market time unit within the intraday market.

2. All NEMOs shall ensure the accuracy and efficiency of results produced by the continuous trading matching algorithm.

3. All TSOs shall verify that the results of the continuous trading matching algorithm are consistent with cross-zonal capacity and allocation constraints in accordance with Article 58(2).

Article 53

Products accommodated

1. No later than 18 months after the entry into force of this Regulation NEMOs shall submit a joint proposal concerning products that can be taken into account in the single intraday coupling. NEMOs shall ensure that all orders resulting from these products submitted to enable the MCO functions to be performed in accordance with Article 7 are expressed in euros and make reference to the market time and the market time unit.

2. All NEMOs shall ensure that orders resulting from these products are compatible with the characteristics of cross-zonal capacity, allowing them to be matched simultaneously.

3. All NEMOs shall ensure that the continuous trading matching algorithm is able to accommodate orders covering one market time unit and multiple market time units.

4. By two years after the entry into force of this Regulation and in every second subsequent year, all NEMOs shall consult in accordance with Article 12:

(a) market participants, to ensure that available products reflect their needs;

▼B

(b) all TSOs, to ensure products take due account of operational security;

(c) all regulatory authorities, to ensure that the available products comply with the objectives of this Regulation.

5. All NEMOs shall amend the products if needed pursuant to the results of the consultation referred to in paragraph 4.

Article 54

Maximum and minimum prices

1. By 18 months after the entry into force of this Regulation, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones which participate in single intraday coupling. The proposal shall take into account an estimation of the value of lost load.

The proposal shall be subject to consultation in accordance with Article 12.

2. All NEMOs shall submit the proposal to all regulatory authorities for approval. Where a Member State has provided that an authority other than the national regulatory authority has the power to approve maximum and minimum clearing prices at the national level, the regulatory authority shall consult the proposal with the relevant authority as regards its impact on national markets.

3. After receiving a decision from the regulatory authorities, all NEMOs shall inform the concerned TSOs of that decision without unjustifiable delay.

Article 55

Pricing of intraday capacity

1. Once applied, the single methodology for pricing intraday cross-zonal capacity developed in accordance with Article 55(3) shall reflect market congestion and shall be based on actual orders.

2. Prior to the approval of the single methodology for pricing intraday cross-zonal capacity set out in paragraph 3, TSOs may propose an intraday cross-zonal capacity allocation mechanism with reliable pricing consistent with the requirements of paragraph 1 for approval by the regulatory authorities of the relevant Member States. This mechanism shall ensure that the price of intraday cross-zonal capacity is available to the market participants at the time of matching the orders.

3. By 24 months after the entry into force of this Regulation, all TSOs shall develop a proposal for a single methodology for pricing intraday cross-zonal capacity. The proposal shall be subject to consultation in accordance with Article 12.

4. No charges, such as imbalance fees or additional fees, shall be applied to intraday cross-zonal capacity except for the pricing in accordance with paragraphs 1, 2 and 3.

▼B

Article 56

Methodology for calculating scheduled exchanges resulting from single intraday coupling

1. By 16 months after the entry into force of this Regulation, the TSOs which intend to calculate scheduled exchanges resulting from single intraday coupling shall develop a proposal for a common methodology for this calculation.

The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology shall describe the calculation and, where required, shall list the information which the relevant NEMOs shall provide to the scheduled exchange calculator and the time limits for delivering this information.

3. The calculation of scheduled exchanges shall be based on net positions as specified in Article 52(1)(b).

4. No later than two years after the approval by the regulatory authorities of the concerned region of the proposal referred to in paragraph 1, the relevant TSOs shall review the methodology. Thereafter, if requested by the competent regulatory authorities, the TSOs shall review the methodology every two years.

Article 57

Arrangements concerning more than one NEMO in one bidding zone and for interconnectors which are not operated by certified TSOs

1. TSOs in bidding zones where more than one NEMO is designated and/or offers trading services, or where interconnectors which are not operated by TSOs certified according to Article 3 of Regulation (EC) No 714/2009 exist, shall develop a proposal for cross-zonal capacity allocation and other necessary arrangements for such bidding zones in cooperation with concerned TSOs, NEMOs and operators of interconnectors who are not certified as TSOs to ensure that the relevant NEMOs and interconnectors provide the necessary data and financial coverage for such arrangements. These arrangements must allow additional TSOs and NEMOs to join these arrangements.

2. The proposal shall be submitted for approval by the relevant national regulatory authorities within 4 months of more than one NEMO being designated and/or allowed to offer trading services in a bidding zone or if a new interconnector is not operated by a certified TSO. For existing interconnectors which are not operated by certified TSOs the proposal shall be submitted within 4 months after entry into force of this Regulation.

Section 2

The single intraday coupling process

Article 58

Provision of input data

1. Each coordinated capacity calculator shall ensure that cross-zonal capacity and allocation constraints are provided to the relevant NEMOs no later than 15 minutes before the intraday cross-zonal gate opening time.

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2. If updates to cross-zonal capacity and allocation constraints are required, due to operational changes on the transmission system, each TSO shall notify the coordinated capacity calculators in its capacity calculation region. The coordinated capacity calculators shall then notify the relevant NEMOs.

3. If any coordinated capacity calculator is unable to comply with paragraph 1, that coordinated capacity calculator shall notify the relevant NEMOs. These NEMOs shall publish a notice to all market participants without unjustifiable delay.

Article 59

Operation of single intraday coupling

1. By 16 months after the entry into force of this Regulation, all TSOs shall be responsible for proposing the intraday cross-zonal gate opening and intraday cross-zonal gate closure times. The proposal shall be subject to consultation in accordance with Article 12.

2. The intraday cross-zonal gate closure time shall be set in such a way that it:

(a) maximises market participants' opportunities for adjusting their balances by trading in the intraday market time-frame as close as possible to real time; and

(b) provides TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security.

3. One intraday cross-zonal gate closure time shall be established for each market time unit for a given bidding zone border. It shall be at most one hour before the start of the relevant market time unit and shall take into account the relevant balancing processes in relation to operational security.

4. The intraday energy trading for a given market time unit for a bidding zone border shall start at the latest at the intraday cross-zonal gate opening time of the relevant bidding zone borders and shall be allowed until the intraday cross-zonal gate closure time.

5. Before the intraday cross-zonal gate closure time, market participants shall submit to relevant NEMOs all the orders for a given market time unit. All NEMOs shall submit the orders for a given market time unit for single matching immediately after the orders have been received from market participants.

6. Orders matched in single intraday coupling shall be considered firm.

7. MCO functions shall ensure the anonymity of orders submitted via the shared order book.

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Article 60

Delivery of results

1. All NEMOs performing MCO functions shall deliver the continuous trading matching algorithm results:

(a) to all other NEMOs, for results on the execution status per trade specified in Article 52(1)(a);

(b) to all TSOs and scheduled exchange calculators, for results single net positions specified in Article 52(1)(b).

2. If, in accordance with paragraph 1(a), any NEMO, for reasons outside its responsibility, is unable to deliver these continuous trading matching algorithm results, it shall notify all other NEMOs.

3. If, in accordance with paragraph 1(b), any NEMO, for reasons outside its responsibility, is unable to deliver these continuous trading matching algorithm results, it shall notify all TSOs and each scheduled exchange calculator as soon as reasonably practicable. All NEMOs shall notify the market participants concerned.

4. All NEMOs shall send, without undue delay, the necessary information to market participants to ensure that the actions specified in Articles 68 and 73(3) can be undertaken.

Article 61

Calculation of scheduled exchanges resulting from single intraday coupling

1. Each scheduled exchange calculator shall calculate scheduled exchanges between bidding zones for each market time unit in accordance with the methodology established in accordance with Article 56.

2. Each scheduled exchange calculator shall notify the relevant NEMOs, central counter parties, shipping agents, and TSOs of the agreed scheduled exchanges.

Article 62

Publication of market information

1. As soon as the orders are matched, each NEMO shall publish for relevant market participants at least the status of execution of orders and prices per trade produced by the continuous trading matching algorithm in accordance with Article 52(1)(a).

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2. Each NEMO shall ensure that information on aggregated executed volumes and prices is made publicly available in an easily accessible format for at least 5 years. The information to be published shall be proposed by all NEMOS within the proposal for continuous trading matching algorithm pursuant to Article 37(5).

Article 63

Complementary regional auctions

1. By 18 months after the entry into force of this Regulation, the relevant NEMOs and TSOs on bidding zone borders may jointly submit a common proposal for the design and implementation of complementary regional intraday auctions. The proposal shall be subject to consultation in accordance with Article 12.

2. Complementary regional intraday auctions may be implemented within or between bidding zones in addition to the single intraday coupling solution referred to in Article 51. In order to hold regional intraday auctions, continuous trading within and between the relevant bidding zones may be stopped for a limited period of time before the intraday cross-zonal gate closure time, which shall not exceed the minimum time required to hold the auction and in any case 10 minutes.

3. For complementary regional intraday auctions, the methodology for pricing intraday cross-zonal capacity may differ from the methodology established in accordance with Article 55(3) but it shall nevertheless meet the principles provided for in Article 55(1).

4. The competent regulatory authorities may approve the proposal for complementary regional intraday auctions if the following conditions are met:

(a) regional auctions shall not have an adverse impact on the liquidity of the single intraday coupling;

(b) all cross-zonal capacity shall be allocated through the capacity management module;

(c) the regional auction shall not introduce any undue discrimination between market participants from adjacent regions;

(d) the timetables for regional auctions shall be consistent with single intraday coupling to enable market participants to trade as close as possible to real-time;

▼B

(e) regulatory authorities shall have consulted the market participants in the Member States concerned.

5. At least every two years after the decision on complementary regional auctions, the regulatory authorities of the Member States concerned shall review the compatibility of any regional solutions with single intraday coupling to ensure that the conditions above continue to be fulfilled.

Section 3

Transitional intraday arrangements

Article 64

Provisions relating to explicit allocation

1. Where jointly requested by the regulatory authorities of the Member States of each of the bidding zone borders concerned, the TSOs concerned shall also provide explicit allocation, in addition to implicit allocation, that is to say, capacity allocation separate from the electricity trade, via the capacity management module on bidding zone borders.

2. The TSOs on the bidding zone borders concerned shall jointly develop a proposal on the conditions that shall be fulfilled by market participants to participate in explicit allocation. The proposal shall be subject to the joint approval by the regulatory authorities of the Member States of each of the bidding zone borders concerned.

3. When establishing the capacity management module, discrimination shall be avoided when simultaneously allocating capacity implicitly and explicitly. The capacity management module shall determine which orders to select for matching and which explicit capacity requests to accept, according to a ranking of price and time of entrance.

Article 65

Removal of explicit allocation

1. The NEMOs concerned shall cooperate closely with the TSOs concerned and shall consult market participants in accordance with Article 12 in order to translate the needs of market participants linked to explicit capacity allocation rights into non-standard intraday products.

2. Prior to deciding on the removal of explicit allocation, the regulatory authorities of the Member States of each of the bidding zone borders concerned shall jointly organise a consultation to assess whether the proposed non-standard intraday products meet the market participants' needs for intraday trading.

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3. The competent regulatory authorities of the Member States of each of the bidding zone borders concerned shall jointly approve the introduced non-standard products and the removal of explicit allocation.

Article 66

Provisions relating to intraday arrangements

1. Market participants shall ensure the completion of nomination, clearing and settlement related to explicit allocation of cross-zonal capacity.

2. Market participants shall fulfil any financial obligations, relating to clearing and settlement arising from explicit allocation.

3. The participating TSOs shall publish relevant information on the interconnections to which explicit allocation is applicable, including the cross-zonal capacity for explicit allocation.

Article 67

Explicit requests for capacity

A request for explicit cross-zonal capacity may be submitted by a market participant only for an interconnection where the explicit allocation is applicable. For each request for explicit capacity the market participant shall submit the volume and the price to the capacity management module. The price and volume of explicit allocated capacity shall be made publicly available by the relevant TSOs.

CHAPTER 7

Clearing and settlement for single day-ahead and intraday coupling

Article 68

Clearing and settlement

1. The central counter parties shall ensure clearing and settlement of all matched orders in a timely manner. The central counter parties shall act as the counter party to market participants for all their trades with regard to the financial rights and obligations arising from these trades.

2. Each central counter party shall maintain anonymity between market participants.

3. Central counter parties shall act as counter party to each other for the exchange of energy between bidding zones with regard to the financial rights and obligations arising from these energy exchanges.

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4. Such exchanges shall take into account:

(a) net positions produced in accordance with Articles 39(2)(b) and 52(1)(b);

(b) scheduled exchanges calculated in accordance with Articles 49 and 61.

5. Each central counter party shall ensure that for each market time unit:

(a) across all bidding zones, taking into account, where appropriate, allocation constraints, there are no deviations between the sum of energy transferred out of all surplus bidding zones and the sum of energy transferred into all deficit bidding zones;

(b) electricity exports and electricity imports between bidding zones equal each other, with any deviations resulting only from considerations of allocation constraints, where appropriate.

6. Notwithstanding paragraph 3, a shipping agent may act as a counter party between different central counter parties for the exchange of energy, if the parties concerned conclude a specific agreement to that effect. If no agreement is reached, the shipping arrangement shall be decided by the regulatory authorities responsible for the bidding zones between which the clearing and settlement of the exchange of energy is needed.

7. All central counter parties or shipping agents shall collect congestion incomes arising from the single day-ahead coupling specified in Articles 46 to 48 and from the single intraday coupling specified in Articles 58 to 60.

8. All central counter parties or shipping agents shall ensure that collected congestion incomes are transferred to the TSOs no later than two weeks after the date of settlement.

9. If the timing of payments is not harmonised between two bidding zones, the Member States concerned shall ensure that an entity is appointed to manage the timing mismatch and to bear the relevant costs.

CHAPTER 8

Firmness of allocated cross-zonal capacity

Article 69

Proposal for day-ahead firmness deadline

By 16 months after the entry into force of this Regulation, all TSOs shall develop a common proposal for a single day-ahead firmness deadline, which shall not be shorter than half an hour before the day-ahead market gate closure time. The proposal shall be subject to consultation in accordance with Article 12.

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Article 70

Firmness of day-ahead capacity and allocation constraints

1. Prior to the day-ahead firmness deadline, each coordinated capacity calculator may adjust cross-zonal capacity and allocation constraints provided to relevant NEMOs.

2. After the day-ahead firmness deadline, all cross-zonal capacity and allocation constraints shall be firm for day-ahead capacity allocation unless the requirements of Article 46(2) are met, in which case cross-zonal capacity and allocation constraints shall be firm as soon as they are submitted to relevant NEMOs.

3. After the day-ahead firmness deadline, cross-zonal capacity which has not been allocated may be adjusted for subsequent allocations.

Article 71

Firmness of intraday capacity

Cross-zonal intraday capacity shall be firm as soon as it is allocated.

Article 72

Firmness in the event of force majeure **or emergency situations**

1. In the event of *force majeure* or an emergency situation referred to in Article 16(2) of Regulation (EC) No 714/2009, where the TSO shall act in an expeditious manner and redispatching or countertrading is not possible, each TSO shall have the right to curtail allocated cross-zonal capacity. In all cases, curtailment shall be undertaken in a coordinated manner following liaison with all directly concerned TSOs.

2. A TSO which invokes *force majeure* or an emergency situation shall publish a notice explaining the nature of the *force majeure* or the emergency situation and its probable duration. This notice shall be made available to the market participants concerned through NEMOs. If capacity is allocated explicitly to market participants, the TSO invoking *force majeure* or an emergency situation shall send notice directly to contractual parties holding cross-zonal capacity for the relevant market time-frame.

3. If allocated capacity is curtailed because of *force majeure* or an emergency situation invoked by a TSO, the TSO shall reimburse or provide compensation for the period of *force majeure* or the emergency situation, in accordance with the following requirements:

(a) if there is implicit allocation, central counter parties or shipping agents shall not be subject to financial damage or financial benefit arising from any imbalance created by such curtailment;

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(b) in the event of *force majeure*, if capacity is allocated via explicit allocation, market participants shall be entitled to reimbursement of the price paid for the capacity during the explicit allocation process;

(c) in an emergency situation, if capacity is allocated via explicit allocation, market participants shall be entitled to compensation equal to the price difference of relevant markets between the bidding zones concerned in the relevant time-frame; or

(d) in an emergency situation, if capacity is allocated via explicit allocation but the bidding zone price is not calculated in at least one of the two relevant bidding zones in the relevant time-frame, market participants shall be entitled to reimbursement of the price paid for capacity during the explicit allocation process.

4. The TSO invoking *force majeure* or an emergency situation shall limit the consequences and duration of the *force majeure* situation or emergency situation.

5. Where a Member State has so provided, upon request by the TSO concerned the national regulatory authority shall assess whether an event qualifies as *force majeure*.

TITLE III

COSTS

CHAPTER 1

Congestion income distribution methodology for single day-ahead and intraday coupling

Article 73

Congestion income distribution methodology

1. By 12 months after the entry into force of this Regulation, all TSOs shall develop a proposal for a methodology for sharing congestion income.

2. The methodology developed in accordance with paragraph 1 shall:

(a) facilitate the efficient long-term operation and development of the electricity transmission system and the efficient operation of the electricity market of the Union;

(b) comply with the general principles of congestion management provided for in Article 16 of Regulation (EC) No 714/2009;

(c) allow for reasonable financial planning;

(d) be compatible across time-frames;

(e) establish arrangements to share congestion income deriving from transmission assets owned by parties other than TSOs.

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3. TSOs shall distribute congestion incomes in accordance with the methodology in paragraph 1 as soon as reasonably practicable and no later than one week after the congestion incomes have been transferred in accordance with Article 68(8).

CHAPTER 2

Redispatching and countertrading cost sharing methodology for single day-ahead and intraday coupling

Article 74

Redispatching and countertrading cost sharing methodology

1. No later than 16 months after the decision on the capacity calculation regions is taken, all TSOs in each capacity calculation region shall develop a proposal for a common methodology for redispatching and countertrading cost sharing.

2. The redispatching and countertrading cost sharing methodology shall include cost-sharing solutions for actions of cross-border relevance.

3. Redispatching and countertrading costs eligible for cost sharing between relevant TSOs shall be determined in a transparent and auditable manner.

4. The redispatching and countertrading cost sharing methodology shall at least:

(a) determine which costs incurred from using remedial actions, for which costs have been considered in the capacity calculation and where a common framework on the use of such actions has been established, are eligible for sharing between all the TSOs of a capacity calculation region in accordance with the capacity calculation methodology set out in Articles 20 and 21;

(b) define which costs incurred from using redispatching or countertrading to guarantee the firmness of cross-zonal capacity are eligible for sharing between all the TSOs of a capacity calculation region in accordance with the capacity calculation methodology set out in Articles 20 and 21;

(c) set rules for region-wide cost sharing as determined in accordance with points (a) and (b).

5. The methodology developed in accordance with paragraph 1 shall include:

(a) a mechanism to verify the actual need for redispatching or countertrading between the TSOs involved;

(b) an *ex post* mechanism to monitor the use of remedial actions with costs;

(c) a mechanism to assess the impact of the remedial actions, based on operational security and economic criteria;

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(d) a process allowing improvement of the remedial actions;

(e) a process allowing monitoring of each capacity calculation region by the competent regulatory authorities.

6. The methodology developed in accordance with paragraph 1 shall also:

(a) provide incentives to manage congestion, including remedial actions and incentives to invest effectively;

(b) be consistent with the responsibilities and liabilities of the TSOs involved;

(c) ensure a fair distribution of costs and benefits between the TSOs involved;

(d) be consistent with other related mechanisms, including at least:

(i) the methodology for sharing congestion income set out in Article 73;

(ii) the inter-TSO compensation mechanism, as set out in Article 13 of Regulation (EC) No 714/2009 and Commission Regulation (EU) No 838/2010 [1];

(e) facilitate the efficient long-term development and operation of the pan-European interconnected system and the efficient operation of the pan-European electricity market;

(f) facilitate adherence to the general principles of congestion management as set out in Article 16 of Regulation (EC) No 714/2009;

(g) allow reasonable financial planning;

(h) be compatible across the day-ahead and intraday market time-frames; and

(i) comply with the principles of transparency and non-discrimination.

7. By 31 December 2018, all TSOs of each capacity calculation region shall further harmonise as far as possible between the regions the redispatching and countertrading cost sharing methodologies applied within their respective capacity calculation region.

CHAPTER 3

Capacity allocation and congestion management cost recovery

Article 75

General provisions on cost recovery

1. Costs relating to the obligations imposed on TSOs in accordance with Article 8, including the costs specified in Article 74 and Articles 76 to 79, shall be assessed by the competent regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered in a timely manner through network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

(1) Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and common regulatory approach to transmission charging (OJ L 250, 24.9.2010, p. 5).

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2. Member States' share of the common costs referred to in Article 80(2)(a), regional costs referred to in Article 80(2)(b) and national costs referred to in Article 80(2)(c) assessed as reasonable, efficient and proportionate shall be recovered through NEMO fees, network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

3. If requested by the regulatory authorities, relevant TSOs, NEMOs and delegates in accordance with Article 78 shall, within three months of the request, provide information necessary to facilitate the assessment of the costs incurred.

Article 76

Costs of establishing, amending and operating single day-ahead and intraday coupling

1. All NEMOs shall bear the following costs:

(a) common, regional and national costs of establishing, updating or further developing the price coupling algorithm and single day-ahead coupling;

(b) common, regional and national costs of establishing, updating or further developing the continuous trading matching algorithm and single intraday coupling;

(c) common, regional and national costs of operating single day-ahead and intraday coupling.

2. Subject to agreement with the NEMOs concerned, TSOs may make a contribution to the costs provided for in paragraph 1 subject to approval by the relevant regulatory authorities. In such cases, within two months of receiving a forecast from the NEMOs concerned, each TSO shall be entitled to provide a cost contribution proposal to the relevant regulatory authority for approval.

3. The NEMOs concerned shall be entitled to recover costs in accordance with paragraph 1 which have not been borne by TSOs in accordance with paragraph 2 by means of fees or other appropriate mechanisms only if the costs are reasonable and proportionate, through national agreements with the competent regulatory authority.

Article 77

Clearing and settlement costs

1. All costs incurred by central counter parties and shipping agents shall be recoverable by means of fees or other appropriate mechanisms if they are reasonable and proportionate.

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2. The central counter parties and shipping agents shall seek efficient clearing and settlement arrangements avoiding unnecessary costs and reflecting the risk incurred. The cross-border clearing and settlement arrangements shall be subject to approval by the relevant national regulatory authorities.

Article 78

Costs of establishing and operating the coordinated capacity calculation process

1. Each TSO shall individually bear the costs of providing inputs to the capacity calculation process.

2. All TSOs shall bear jointly the costs of merging the individual grid models.

All TSOs in each capacity calculation region shall bear the costs of establishing and operating the coordinated capacity calculators.

3. Any costs incurred by market participants in meeting the requirements of this Regulation shall be borne by those market participants.

Article 79

Costs of ensuring firmness

The costs of ensuring firmness in accordance with Articles 70(2) and 71 shall be borne by the relevant TSOs, to the extent possible in accordance with Article 16(6)(a) of Regulation (EC) No 714/2009. These costs shall include the costs from compensation mechanisms associated with ensuring the firmness of cross-zonal capacities as well as the costs of redispatching, countertrading and imbalance associated with compensating market participants.

Article 80

Cost sharing between NEMOs and TSOs in different Member States

1. All relevant NEMOs and TSOs shall provide a yearly report to the regulatory authorities in which the costs of establishing, amending and operating single day-ahead and intraday coupling are explained in detail. This report shall be published by the Agency taking due account of sensitive commercial information. Costs directly related to single day-ahead and intraday coupling shall be clearly and separately identified and auditable. The report shall also provide full details of contributions made to NEMO costs by TSOs in accordance with Article 76(2).

2. The costs referred to in paragraph 1 shall be broken down into:

(a) common costs resulting from coordinated activities of all NEMOs or TSOs participating in the single day-ahead and intraday coupling;

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(b) regional costs resulting from activities of NEMOs or TSOs cooperating in a certain region;

(c) national costs resulting from activities of the NEMOs or TSOs in that Member State.

3. Common costs referred to in paragraph 2(a) shall be shared among the TSOs and NEMOs in the Member States and third countries participating in the single day-ahead and intraday coupling. To calculate the amount to be paid by the TSOs and NEMOs in each Member State and, if applicable, third countries, one eighth of the common cost shall be divided equally between each Member State and third country, five eighths shall be divided between each Member State and third country proportionally to their consumption, and two eighths shall be divided equally between the participating NEMOs. To take into account changes in the common costs or changes in the participating TSOs and NEMOs, the calculation of common costs shall be regularly adapted.

4. NEMOs and TSOs cooperating in a certain region shall jointly agree on a proposal for the sharing of regional costs in accordance with paragraph 2(b). The proposal shall then be individually approved by the competent national authorities of each of the Member States in the region. NEMOs and TSOs cooperating in a certain region may alternatively use the cost sharing arrangements set out in paragraph 3.

5. The cost sharing principles shall apply to costs incurred from the entry into force of this Regulation. This is without prejudice to existing solutions used for the development of single day-ahead and intraday coupling and costs incurred prior to the entry into force of this Regulation shall be shared among the NEMOs and TSOs based on the existing agreements governing such solutions.

TITLE IV

DELEGATION OF TASKS AND MONITORING

Article 81

Delegation of tasks

1. A TSO or NEMO may delegate all or part of any task assigned to it under this Regulation to one or more third parties in the case the third party can carry out the respective function at least as effectively as the delegating entity. The delegating entity shall remain responsible for ensuring compliance with the obligations under this Regulation, including ensuring access to information necessary for monitoring by the regulatory authority.

2. Prior to the delegation, the third party concerned shall have clearly demonstrated to the delegating party its ability to meet each of the obligations of this Regulation.

3. In the event that all or part of any task specified in this Regulation is delegated to a third party, the delegating party shall ensure that suitable confidentiality agreements in accordance with the confidentiality obligations of the delegating party have been put in place prior to delegation.

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Article 82

Monitoring of the implementation of single day-ahead and intraday coupling

1. The entity or entities performing the MCO functions shall be monitored by the regulatory authorities or relevant authorities of the territory where they are located. Other regulatory authorities or relevant authorities, and the Agency, shall contribute to the monitoring where adequate. The regulatory authorities or relevant authorities primarily responsible for monitoring a NEMO and the MCO functions shall fully cooperate and shall provide access to information for other regulatory authorities and the Agency in order to ensure proper monitoring of single day-ahead and intraday coupling in accordance with Article 38 of Directive 2009/72/EC.

2. Monitoring of the implementation of single day-ahead and intraday coupling by ENTSO for Electricity in accordance with Article 8(8) of Regulation (EC) No 714/2009 shall in particular cover the following matters:

(a) progress and potential problems with the implementation of single day-ahead and intraday coupling, including the choice of different available options in each country;

(b) preparing the report on capacity calculation and allocation in accordance with Article 31(1);

(c) the efficiency of current bidding zone configuration in coordination with the Agency in accordance with Article 34;

(d) the effectiveness of the operation of the price coupling algorithm and of the continuous trading matching algorithm in cooperation with NEMOs in accordance with Article 37(6);

(e) the effectiveness of the criterion concerning the estimation of the value of lost load, in accordance with Articles 41(1) and 54(1); and

(f) the review of the methodology for calculating scheduled exchanges resulting from single day-ahead coupling in accordance with Article 43(4).

3. ENTSO for Electricity shall submit a monitoring plan which includes the reports to be prepared and any updates in accordance with paragraph 2, to the Agency for an opinion by six months after entry into force of this Regulation.

4. The Agency, in cooperation with ENTSO for Electricity, shall draw up by six months after the entry into force of this Regulation a list of the relevant information to be communicated by ENTSO for Electricity to the Agency in accordance with Articles 8(9) and 9(1) of Regulation (EC) No 714/2009. The list of relevant information may be subject to updates. ENTSO for Electricity shall maintain a comprehensive, standardised format, digital data archive of the information required by the Agency.

5. All TSOs shall submit to ENTSO for Electricity the information required to perform the tasks in accordance with paragraphs 2 and 4.

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6. NEMOs, market participants and other relevant organisations regarding single day-ahead and intraday coupling shall, at the joint request of the Agency and the ENTSO for Electricity, submit to the ENTSO for Electricity the information required for monitoring in accordance with paragraph 2 and 4, except for information already obtained by the regulatory authorities, the Agency or the ENTSO for Electricity in the context of their respective implementation monitoring tasks.

TITLE V

TRANSITIONAL AND FINAL PROVISIONS

Article 83

Transitional provisions for Ireland and Northern Ireland

1. Except for Articles 4, 5 and 6 and participation in the development of terms and conditions or methodologies, for which the respective deadlines shall apply, the requirements of this Regulation shall not apply in Ireland and Northern Ireland until 31 December 2017.

2. From the date of the entry into force of this Regulation until 31 December 2017, Ireland and Northern Ireland shall implement preparatory transitional arrangements. Those transitional arrangements shall:

(a) facilitate the transition to full implementation of and full compliance with this Regulation, and include all necessary preparatory measures for full implementation of and full compliance with this Regulation, by 31 December 2017;

(b) guarantee a reasonable degree of integration with the markets in adjacent jurisdictions;

(c) provide for at least:

(i) allocation of interconnector capacity in an explicit day-ahead auction and in at least two implicit intraday auctions;

(ii) joint nomination of interconnection capacity and energy at the day-ahead market time-frame;

(iii) application of the 'Use-It-Or-Lose-It' or 'Use-It-Or-Sell-It' principle, as specified in point 2.5 of Annex I to Regulation (EC) No 714/2009, to capacity not used at the day-ahead market time-frame.

(d) ensure fair and non-discriminatory pricing of interconnector capacity in the implicit intraday auctions;

(e) put in place fair, transparent and non-discriminatory compensation mechanisms for ensuring firmness;

(f) set out a detailed roadmap, approved by the regulatory authorities for Ireland and Northern Ireland, with milestones for achieving full implementation of and compliance with this Regulation;

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(g) be subject to a consultation process, involving all relevant parties and give the utmost consideration to the consultation's outcome;

(h) be justified on the basis of a cost-benefit analysis;

(i) not unduly affect other jurisdictions.

3. Regulatory authorities for Ireland and Northern Ireland shall provide to the Agency at least quarterly, or upon the Agency's request, any information required for assessing the transitional arrangements for the electricity market on the island of Ireland and the progress towards achieving full implementation of and compliance with this Regulation.

Article 84

Entry into force

This Regulation shall enter into force on the twentieth day following that of its publication in the *Official Journal of the European Union*.

This Regulation shall be binding in its entirety and directly applicable in all Member States.

LAST UPDATE SEPT 2023	Day-ahead				
	NEMO	**Operating as**	**Competitive status**	**Operating (YES/NO)**	**Designating authority**
Austria	EPEX Spot SE	passporting	Competitive	YES	E-Control (Austrian regulator for electricity and natural gas markets)
	EXAA AG	designated		YES	
	Nord Pool EMCO AS	designated		YES	
Belgium	EPEX Spot SE	designated	Competitive	YES	Minister of Energy
	Nord Pool EMCO AS	designated		YES	
Bulgaria	Independent Bulgarian Power Exchange (IBEX)	designated	Monopoly	YES	EWRC (Energy and water regulatory commission)
Croatia	CROPEX Ltd	designated	Competitive	YES	HERA (Croatian Energy Regulator Agency)
Czech Republic	OTE a.s.	designated	Monopoly	YES	ERU (Energy Regulatory Office)
Denmark	Nord Pool EMCO AS	designated	Competitive	YES	DUR (Danish Utility Regulator)
	EPEX Spot SE	passporting		YES	
	Nasdaq Spot AB	passporting		NO	
Estonia	Nord Pool EMCO AS	designated	Competitive	YES	Estonian Competition Authority
	EPEX Spot SE	passporting		NO	
Finland	Nord Pool EMCO AS	designated	Competitive	YES	Energiavirasto
	EPEX Spot SE	passporting		YES	
	Nasdaq Spot AB	passporting		NO	
France	EPEX Spot SE	designated	Competitive	YES	CRE (Commission de régulation de l'énergie)
	Nord Pool EMCO AS	designated		YES	
Germany	EPEX Spot SE	passporting	Competitive	YES	BNetzA (Bundesnetzagentur)
	Nord Pool EMCO AS	designated		YES	
	EXAA AG	passporting		YES	
Greece	HEnEx SA	designated	Monopoly	YES	RAE (Regulatory Authority for Energy)
Hungary	HUPX Zrt.	designated	Monopoly	YES	MEKH (Hungarian Energy and Public Utility Regulatory Authority)
Ireland	EirGrid plc	designated	Competitive	YES	CRU (Commission for Regulation of Utilities)
	Nord Pool EMCO AS	passporting		NO	
Italy	GME Spa	designated	Monopoly	YES	Ministry of Economic Development (from 2021 Ministry for Ecological Transition), opinion by ARERA, the Italian Regulatory Authority for Energy, Networks and Environment
Latvia	Nord Pool EMCO AS	designated	Competitive	YES	PUC (Public Utilities Commission)
	EPEX Spot SE	passporting		NO	
Lithuania	Nord Pool EMCO AS	designated	Competitive	YES	NERC (National Energy Regulatory Council)
	EPEX Spot SE	passporting		NO	
Luxembourg	EPEX Spot SE	passporting	Competitive	YES	ILR (Institut luxembourgeois de régulation)
	Nord Pool EMCO AS	passporting		YES	
Netherlands	EPEX Spot SE	passporting	Competitive	YES	ACM (Authority for Consumers & Markets)
	Nord Pool EMCO AS	designated		YES	
Poland	Towarowa Gielda Energii S.A.	designated	Competitive	YES	President of the Energy Regulatory Office
	Nord Pool EMCO AS	passporting		YES	
	EPEX Spot SE	passporting		YES	
Portugal	OMIE S.A.	designated	Monopoly	YES	ERSE
Romania	OPCOM S.A.	designated	Competitive	YES	ANRE (Romanian Energy Regulatory Authority)
	BRM S.A.	designated		YES	
Slovakia	OKTE a.s.	designated	Monopoly	YES	URSO (Regulatory Office for Network Industries)
Slovenia	BSP Energetska Borza d.o.o.	designated	Competitive	YES	AGEN (Agencija za energijo)
Spain	OMIE S.A.	designated	Monopoly	YES	Ministry of Industry, Energy and Tourism
Sweden	Nord Pool EMCO AS	designated	Competitive	YES	Ei (Swedish Energy Markets Inspectorate)
	Nasdaq Spot AB	designated		NO	
	EPEX Spot SE	passporting		YES	
Northern Ireland	SONI	Designated	Competitive	YES	UREGNI (Utilities Regulator Northern Ireland)
Norway	Nord Pool EMCO AS	Designated	Competitive	YES	NVE-RME (Norwegian Energy Regulatory Authority)
	EPEX Spot SE	passporting		YES	
	Nasdaq Spot AB	passporting		NO	

LAST UPDATE SEPT 2023	Intraday				
	NEMO	Operating as	Competitive status	Operating (YES/NO)	Designating authority
Austria	EPEX Spot SE	passporting	Competitive	YES	E-Control (Austrian regulator for electricity and natural gas markets)
	ETPA Holding B.V.	passporting		NO	
	Nord Pool EMCO AS	designated		YES	
Belgium	EPEX Spot SE	designated	Competitive	YES	Minister of Energy
	ETPA Holding B.V.	passporting		NO	
	Nord Pool EMCO AS	designated		YES	
Bulgaria	Independent Bulgarian Power Exchange (IBEX)	designated	Monopoly	YES	EWRC (Energy and water regulatory commission)
Croatia	CROPEX Ltd	designated	Competitive	YES	HERA (Croatian Energy Regulator Agency)
Czech Republic	OTE a.s.	designated	Monopoly	YES	ERU (Energy Regulatory Office)
Denmark	Nord Pool EMCO AS	designated	Competitive	YES	DUR (Danish Utility Regulator)
	EPEX Spot SE	passporting		YES	
Estonia	Nord Pool EMCO AS	designated	Competitive	YES	Estonian Competition Authority
	EPEX Spot SE	passporting		NO	
Finland	Nord Pool EMCO AS	designated	Competitive	YES	Energiavirasto
	EPEX Spot SE	passporting		YES	
France	EPEX Spot SE	designated	Competitive	YES	CRE (Commission de régulation de l'énergie)
	Nord Pool EMCO AS	designated		YES	
Germany	EPEX Spot SE	passporting	Competitive	YES	BNetzA (Bundesnetzagentur)
	ETPA Holding B.V.	passporting		NO	
	Nord Pool EMCO AS	designated		YES	
Greece	HEnEx SA	designated	Monopoly	YES	RAE (Regulatory Authority for Energy)
Hungary	HUPX Zrt.	designated	Monopoly	YES	MEKH (Hungarian Energy and Public Utility Regulatory Authority)
Republic of Ireland	EirGrid plc	designated	Competitive	YES	CRU (Commission for Regulation of Utilities)
	Nord Pool EMCO AS	passporting		NO	
Italy	GME Spa	designated	Monopoly	YES	Ministry of Economic Development (from 2021 Ministry for Ecological Transition), opinion by ARERA, the Italian Regulatory Authority for Energy, Networks and Environment
Latvia	Nord Pool EMCO AS	designated	Competitive	YES	PUC (Public Utilities Commission)
	EPEX Spot SE	passporting		NO	
Lithuania	Nord Pool EMCO AS	designated	Competitive	YES	NERC (National Energy Regulatory Council)
	EPEX Spot SE	passporting		NO	
Luxembourg	EPEX Spot SE	passporting	Competitive	YES	ILR (Institut luxembourgeois de régulation)
	Nord Pool EMCO AS	passporting		YES	
Netherlands	EPEX Spot SE	passporting	Competitive	YES	ACM (Authority for Consumers & Markets)
	ETPA Holding B.V.	designated		YES	
	Nord Pool EMCO AS	designated		YES	
Poland	Towarowa Gielda Energii S.A.	designated	Competitive	YES	President of the Energy Regulatory Office
	Nord Pool EMCO AS	passporting		YES	
	EPEX Spot SE	passporting		YES	
Portugal	OMIE S.A.	designated	Monopoly	YES	ERSE
Romania	OPCOM S.A.	designated	Competitive	YES	ANRE (Romanian Energy Regulatory Authority)
	BRM S.A.	designated		YES	
Slovakia	OKTE a.s.	designated	Monopoly	YES	URSO (Regulatory Office for Network Industries)
Slovenia	BSP Energetska Borza d.o.o.	designated	Competitive	YES	AGEN (Agencija za energijo)
Spain	OMIE S.A.	designated	Monopoly	YES	Ministry of Industry, Energy and Tourism
Sweden	Nord Pool EMCO AS	designated	Competitive	YES	Ei (Swedish Energy Markets Inspectorate)
	EPEX Spot SE	passporting		YES	
Norway	Nord Pool EMCO AS	designated	Competitive	YES	NVE-RME (Norwegian Energy Regulatory Authority)
	EPEX Spot SE	passporting		YES	

NEMO COMMITTEE

EUPHEMIA Public Description

Single Price Coupling Algorithm

10th April 2019

Contents

1. Introduction

The Algorithm methodology in force, adopted by ACER Decision 08/2018, states in Art. 4.20 the following:

"All NEMOs shall create and maintain a document with the detailed description of the price coupling algorithm, including the description of calculation of scheduled exchanges in accordance with the methodology for calculating scheduled exchanges for the day-ahead timeframe. This document shall be published and kept updated with every new version of the price coupling algorithm. The document shall be publicly available by all NEMOs on a public webpage."

The main purpose of this document is to seek legal compliance with the abovementioned mandate. Furthermore, this public description aims at disseminating and facilitating the understanding of the single price coupling algorithm among stakeholders and the wider public.

Additionally, the MCO Plan approved by all EU National Regulatory Authorities on 26 June 2017 confirms the adoption of the "Price Coupling of Regions" (PCR) solution as the basis for the single day-ahead coupling.

Price Coupling of Regions (PCR) project is an initiative of eight Power Exchanges (PXs): EPEX SPOT, GME, HEnEx, Nord Pool, OMIE, OPCOM, OTE and TGE covering the electricity markets in Austria, Belgium, Czech Republic, Croatia, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Ireland, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and UK. PCR is implemented in both the MRC region as well as the 4M Market Coupling (4M MC).

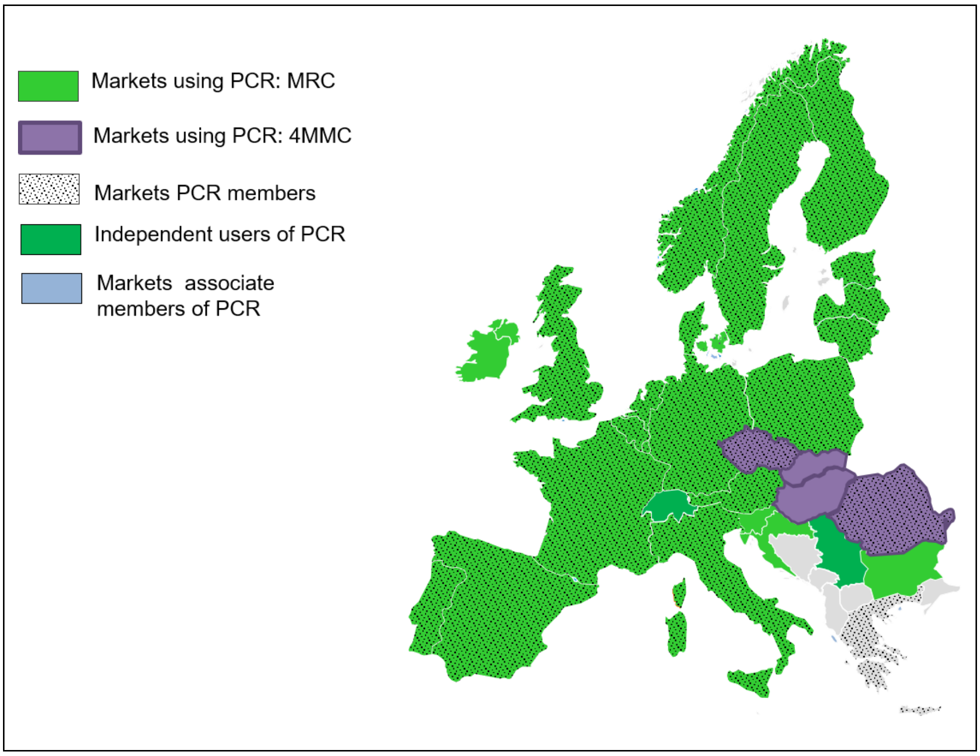


Figure 1 – PXs promoting PCR project

One of the key achievements of the PCR project is the development of a single price coupling algorithm, commonly known as EUPHEMIA (acronym for Pan-European Hybrid Electricity Market Integration Algorithm). Since February 2014, Euphemia is progressively used to calculate energy allocation and electricity prices across Europe, maximizing the overall welfare and increasing the transparency of the computation of prices and flows.

In the past, several algorithms were used locally by the involved PXs. All these algorithms (COSMOS, SESAM, SIOM and UPPO) have been focusing on the products and features of the corresponding PX, but none was able to cover the whole set of requirements. This made the implementation of the new algorithm (EUPHEMIA) necessary, to cover all the requirements at the same time and give solutions within a reasonable time frame.

2. Day-Ahead Market Coupling Principle

Market Coupling (MC) is a way to join and integrate different energy markets into one coupled market. In a coupled market, demand and supply orders in one market are no longer confined to the local territorial scope. On the contrary, in a market coupling approach, energy transactions can involve sellers and buyers from different areas, only restricted by the electricity network constraints.

The main benefit of the Market Coupling approach resides in improving of the market liquidity combined with the beneficial side effect of less volatile electricity prices. Market coupling is beneficial for market players too. They no longer need to acquire transmission capacity rights to carry out cross-border exchanges, since these cross-border exchanges are given as the result of the MC mechanism. They only have to submit a single order in their market (via their corresponding PX) which will be matched with other competitive orders in the same market or other markets (provided the electricity network constraints are respected).

3. Introducing EUPHEMIA

Euphemia is the algorithm that has been developed to solve the problem associated with the coupling of the day-ahead power markets in the PCR region.

First, Market participants start by submitting their orders to their respective power Exchange. All these orders are collected and submitted to Euphemia that has to decide which orders are to be executed and which orders are to be rejected in concordance with the prices to be published such that:

- The *social welfare* (consumer surplus + producer surplus + *congestion rent* across the regions) generated by the executed orders is maximal.
- The power flows induced by the executed orders, resulting in the *net positions* do not exceed the capacity of the relevant network elements.

Euphemia handles standard and more sophisticated order types with all their requirements. It aims at rapidly finding a good first solution from which it continues trying to improve and increase the overall welfare. EUPHEMIA is a generic algorithm: there is no hard limit on the number of markets, orders or network constraints; all orders of the same type submitted by the participants are treated equally.

The development of Euphemia started in July 2011 using one of the existing local algorithms COSMOS (being in use in CWE since November 2010) as starting point. The first stable version able to cover the whole PCR scope was internally delivered one year after (July 2012). Since then, the product has been evolving, including both corrective and evolutionary changes. On the 4th of February 2014, Euphemia was used for the first time in production to couple the North Western Europe (NWE) in common synchronized mode with the South-Western Europe. One year later, no the 25th of February 2015, GME was successfully coupled. Recently, on the 21st of May 2015, the Central Western Europe was coupled for the first time using Flow-based model. On 20 November 2014 the 4M MC coupling was launched coupling the markets of Czech Republic, Hungary, Romania and Slovakia.

In the two following chapters, we explain which network models and market products can be handled by EUPHEMIA. Chapter 6 gives a high-level description of how EUPHEMIA works.

4. Power Transmission Network

EUPHEMIA receives information about the power transmission network which is enforced in the form of constraints to be respected by the final solution.

This information is provided by TSOs as an input to the algorithm.

4.1. Bidding Zones

A *bidding zone* (previously called *bidding area*, but the two are synonyms) corresponds to a geographical area to which network constraints are applied. Consequently all submitted orders in the same bidding zone will necessarily be subjected to the same unique clearing price. EUPHEMIA computes a market clearing price for each *bidding zone* and each period along with a corresponding *net position* (calculated as the difference between the matched supply and the matched demand quantities belonging to that *bidding zone*).

Bidding zones can exchange energy between them in an ATC model (Section 4.2), a flow based model (Section 4.3) or a hybrid model (combination of the previous two models).

The *net position* of a *bidding zone* can be subject to limitations in the variation between periods.

4.1.1. Net position ramping (hourly and daily)

The algorithm supports the limitation on the variations of the *net position* from one hour to the next. There are two ramping requirements that can be imposed on the *net position*.

- Hourly *net position* ramping: this is a limit on the variation of the *net position* of a *bidding zone* from one hour to the next.
- Daily (or cumulative) *net position* ramping: this is a limit on the amount of reserve capacity that can be used during the day.

Reserve capacity is needed as soon as the variation of the *net position* from one hour to the next exceeds a certain threshold. There is a fixed limit on the total amount of reserve that can be used during the day. Reserve capacity is defined separately for each direction (increase/decrease).
By including the *net position* of the last hour for the previous (delivery) day, overnight ramping can be taken into account.

4.2. ATC Model

In an ATC model, the *bidding zones* are linked by interconnectors (bidding zone lines) representing a given topology. The energy from one *bidding zone* to its neighbouring zone can only flow through these lines and is limited by the available transfer capacity (ATC) (Section 4.2.1) of the line.

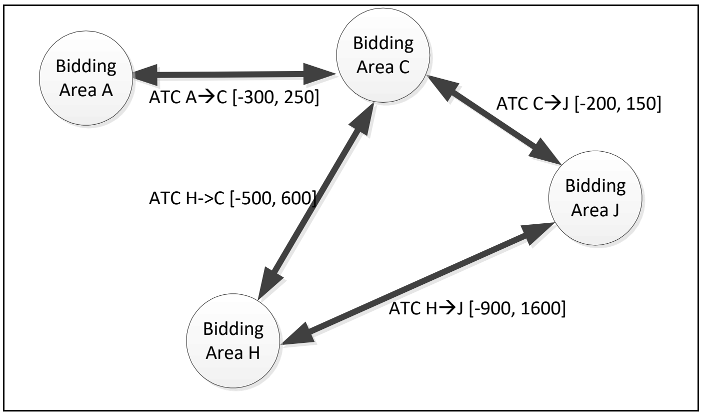


Figure 2 – *Bidding zones* connected in ATC model

Additional restrictions may apply to the interconnectors:

- The flow through a line can be subject to losses (Section 4.2.2)
- The flow through a line can be subject to tariffs (Section 4.2.3)
- The flow variation between two consecutive hours can be restricted by an hourly flow ramping limit (Sections 4.2.4 and 4.2.5)

4.2.1. Available Transfer Capacity (ATC)

ATC limitations constrain the flow that passes through the interconnectors of a given topology.

In EUPHEMIA, lines are oriented from a source *bidding zone* (A) to a sink *bidding zone* (C). Thus, in the examples hereafter, a positive value of flow on the line indicates a flow from A to C, whereas a negative value indicates a flow from C to A.

The available transfer capacity of a line can be different per period and direction of the line (Figure 2).

- As an example, let us consider two *bidding zones* A and C connected by a single line defined from A to C (A→C). For a given period, the ATC in the direction (A→C) is assumed to be equal to 250 MW and equal to 300 MW in the opposite direction (C→A). In practice, this implies that the valid value for the algebraic flow through this line in this period shall remain in the interval [-300, 250].

ATC limitations can also be negative. A negative ATC value in the same direction of the definition of the line A→C (respectively, in the opposite direction C→A) is implicitly indicating that the flow is forced to only go in the direction C→A (respectively, A→C).

- In the previous example, if the ATC was defined to be equal to -250 MW instead of 250 MW in the direction A→C then this would imply that the valid value for the flow will now be in the interval [-300, -250], forcing the flow to be in the C→A direction (negative values of the flow on a line defined as A→C).

4.2.2. Losses

Flow through a line between *bidding zones* may be subject to losses. In this case, part of the energy that is injected in one side of the line is lost, and the energy received at the end of the cable is less than the energy initially sent (Figure 3).

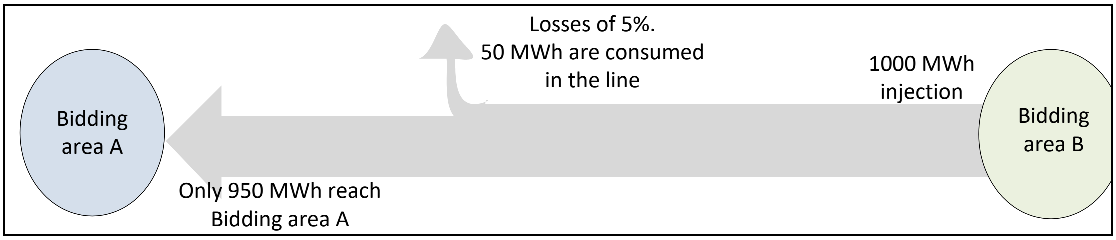


Figure 3 – Example of the effect of losses in one line.

4.2.3. Tariffs

In an ATC network model, the DC cables might be operated by merchant companies, who levy the cost incurred for each 1MWh passing through the cable. In the algorithm, these costs can be represented as flow tariffs.

The flow tariff is included as a loss with regard to the *congestion rent*. This will show up in the results as a threshold for the price between the connected bidding zones. If the difference between the two corresponding market clearing prices is less than the tariff then the flow will be zero. If there is a flow the price difference will be exactly the flow tariff, unless there is congestion. Once the price difference exceeds the tariff the *congestion rent* becomes positive.

4.2.4. Hourly Flow Ramping Limit on Individual Lines

The hourly variation of the flows through an interconnector can be constrained by a ramping limit. This limitation confines the flow in an "allowed band" when moving from one hour to the next (Figure 4). The ramping limit constrains the flow that can pass through the line in hour h depending on the flow that is passing in the previous hour h-1.

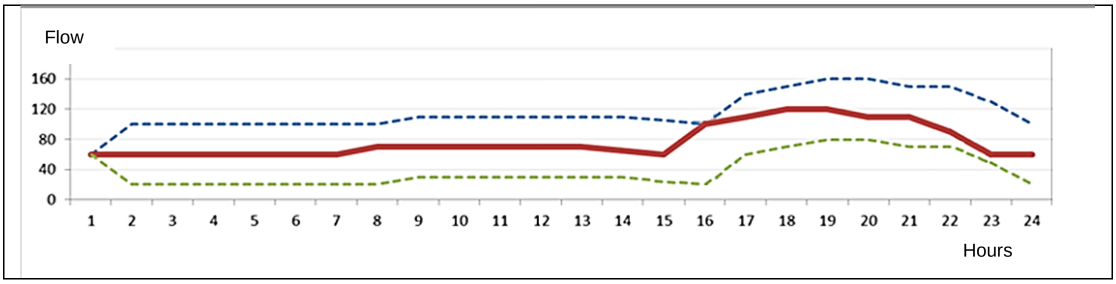


Figure 4 – Effect of the hourly flow ramping limit. The flow stays in the allowed band between hours.

The ramping limit is defined by: The maximum increment of flow from hour h-1 to hour h (called ramping-up), and the maximum decrement of flow from hour h-1 to hour h (called ramping-down). The ramping limits may be different for each period and direction. For period 1, the limitation of flow takes into account the value of the flow of the last hour of the previous day.

4.2.5. Constraints on Line Sets

4.2.6. Hourly Flow Ramping Limit on Line Sets

Flow ramping constraints can apply to a group of interconnectors at once, i.e. the sum of the flows through a set of lines can be restricted by ramping limits.

- As an example, let us consider a line set composed by two interconnectors: the former between areas A and B and the latter between areas A and C. If we set the hourly flow ramping limit for this line set to 450 MW, this will enforce that the sum of the flow from bidding zone A to B and the flow from bidding zone A to C is allowed to vary by only 450 MW from one hour to the next.

4.2.7. Line set capacity constraint

Cumulative capacity constraints can apply to a group of interconnectors at once, i.e. the sum of the flows through a set of lines can be restricted by cumulative capacity limits.

- As an example, let us consider a line set composed by two interconnectors: the former between areas A and B and the latter between areas A and C. If we set the cumulative capacity for this line set to 1000 MW, this will enforce that the sum of the flow from bidding zone A to B and the flow from bidding zone A to C cannot exceed 1000 MW.

4.3. Flow Based Model

The Flow Based (FB) model is an alternative to ATC network constraints. Modeling network constraints using the flow based model allows a more precise modeling of the physical flows.

The FB constraints are given by means of two components:

- **Remaining Available Margin (RAM):** number of MW available for exchanges
- **Power Transfer Distribution Factor (PTDF):** ratio which indicates how much MWh are used by the *net position*s resulting from the exchanges

PTDFs can model different network constraints that constrain the exchanges allowed. Each constraint corresponds to a single row in the $PTDF$ matrix, and has one corresponding margin (one value of the RAM vector). The $PTDF$ matrix has columns for each hub where it applies to (e.g. FB in CWE has columns for the *net position*s of all CWE hubs: BE, DE, FR and NL). Net position in the FB context should be read as the net position of a market as a result of the exchanges via the meshed (flow-based) network (thus excluding the exchange via ATC lines).

Therefore, the constraint that is being imposed is the following:

$$PTDF \cdot nex \leq RAM$$

Here nex is the vector of *net position*s which are subject to the flow based constraints. The flow based modeling has some consequences to price formation, and can potentially result in "non-intuitive" situations that happen when the energy goes from high priced areas to low priced areas.

Example:
Consider a three market example (Figure 5), with a single PTDF constraint:

$$0.25 \cdot nex_A - 0.5 \cdot nex_B - 0.25 \cdot nex_C \leq 125$$

And consider the market outcome shown in Figure 5 below.

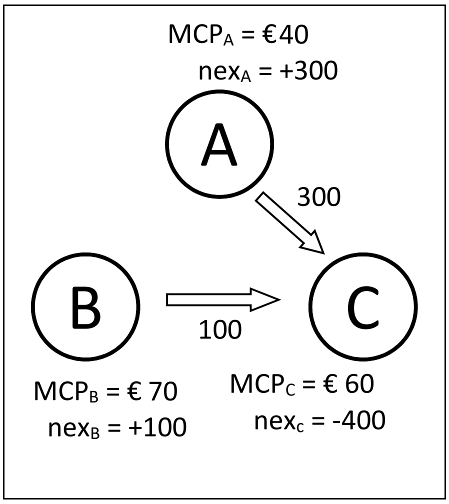


Figure 5 – Example of *net position*s decompositions into flows

In the representation of the result, "bilateral exchanges" between *bidding zones* have been indicated. This is merely one potential decomposition of *net position*s into flows out of many. Alternative flows could have been reconstructed too. However, since market B is exporting energy, whereas it is the most expensive market, any breakdown into flows shall result in market B exporting energy to a cheaper market.

Intuitiveness
From the example above we see that FB market coupling can lead to non-intuitive situations. The reason is that some non-intuitive exchanges free up capacity, allowing even larger exchanges between other markets. In our example, exporting from B to C loads the critical branch with (-0.5) – (-0.25) = -0.25 MWh for each MWh exchanged, i.e. it actually relieves the line. Welfare maximization can therefore lead to these non-intuitive situations.

EUPHEMIA integrates a mechanism to suppress these non-intuitive exchanges. This mechanism seeks "flows" between areas which match the *net position*s. Rather than imposing the PTDF constraints directly on the *net position*s, in intuitive mode they are applied to these "flows". So far the two models are fully equivalent. However in case a PTDF constraint is detected that leads to a non-intuitive situation, all of its relieving effects are discarded: the impact of a "flow" from i to j actually is $PTDF_i - PTDF_j$, but is replaced by $max(PTDF_i\text{-}PTDF_j, 0)$.

Flow-factor competition at maximum price
Another side-effect of the Flow-based model is the flow factor competition in case of market curtailment at maximum price. If several markets end up at maximum price in a flow-based domain, the PTDF coefficients can lead to unfair distribution of the available energy and in some extreme cases, the solution that maximizes the welfare is the one where one market is totally curtailed while all the available energy is given to another market which is not necessarily at maximum price. Euphemia implements a mechanism that allows a fairer distribution of the curtailment between all the markets in a Flow-based domain.

4.4. Scheduling Area Topology

4.4.1. Scheduling Areas

Scheduling areas define a sub-level of bidding zones: one or more scheduling areas must be present in each bidding zone, and aim at modeling scheduling exchanges in bidding zones where several TSOs coexist.

Unlike bidding zones, scheduling area net positions cannot themselves be subject to limitations.

4.4.2. Scheduling Area Lines

Scheduling areas can exchange energy between them through *Scheduling Area Lines*. These lines may connect scheduling areas within a same bidding zone, or scheduling areas corresponding to distinct bidding zones (in the latter case, a line between the two corresponding bidding zones must exist). One or more scheduling area lines may be associated to a line between two bidding zones.

Scheduling area lines are populated with so-called *Thermal Capacities*. These values do not in themselves bound the energy exchanges between scheduling areas. They are however used to uniformly distribute energy between a set of scheduling area lines in case several of them are associated with a same bidding zone line. See section 6.8.5 for more details.

If multiple scheduling areas exist within a given bidding zone, they shall all be (directly or indirectly) connected to each other so that a unique price can be determined by Euphemia.

4.5. NEMO Trading Hub Topology

4.5.1. NEMO Trading Hubs

Orders cannot directly be submitted in bidding zones, nor scheduling areas. They are associated to *NEMO Trading Hubs (NTHs)*. In each Scheduling Area, there shall exist (unless specific exceptions) one or more NEMO trading hubs.

NEMO trading hub net positions cannot be subject to limitations.

4.5.2. NEMO Trading Hub lines

NEMO trading hubs can exchange energy between them through *NEMO Trading Hub Lines*. These lines may connect NTHs within a same scheduling area, or NTHs corresponding to distinct scheduling areas (in the latter case, a line between the two corresponding scheduling areas must exist). One or more NTH lines may be associated to a line between two scheduling areas.

NTH lines are not provided with any specific property: any capacity may transit between two NTHs. Also, all NTHs of a same scheduling area shall be (directly or indirectly) connected so that Euphemia can determine a unique price. See section 6.8.5 for more details.

5. Market Orders

The algorithm can handle a large variety of order types at the same time, which are available to the market participants in accordance with the local market rules:

- Aggregated Hourly Orders
- Complex Orders
    - MIC orders
    - Load Gradient orders
- Block Orders
    - Linked Block Orders
    - Exclusive Groups of Block Orders
    - Flexible Hourly Orders
- Merit Orders and PUN Orders.

5.1. Aggregated Hourly Orders

Demand (resp. supply) orders from all market participants belonging to the same *bidding zone* will be aggregated into a single curve referred to as aggregated demand (resp. supply) curve defined for each period of the day. Demand orders are sorted from the highest price to the lowest. Conversely, supply orders are sorted from the lowest to the highest price.

Aggregated supply and demand curves can be of the following types:

- Linear piecewise curves containing only interpolated orders (i.e. two consecutive points of the monotonous curve cannot have the same price, except for the first two points defined at the maximum / minimum prices of the *bidding zone*).

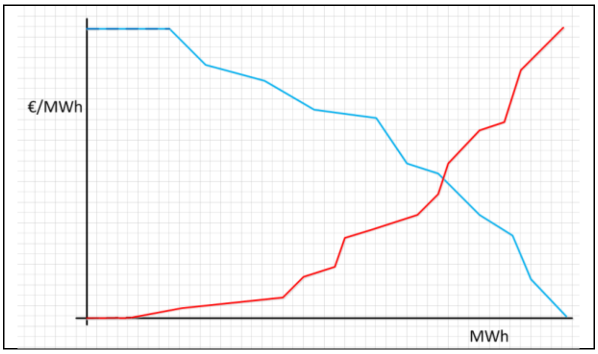


Figure 6 – Linear piecewise aggregated curve.

- Stepwise curves containing only step orders (i.e. two consecutive points always have either the same price or the same quantity).

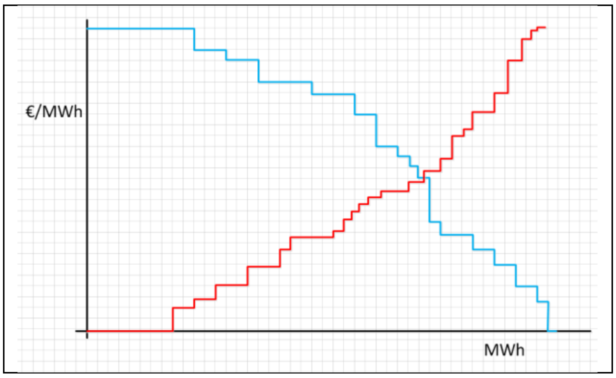


Figure 7 – Stepwise aggregated curve.

- Hybrid curves containing both types of orders (composed by both linear and stepwise segments).

The following nomenclature is used when speaking about hourly orders[1] and market clearing prices:

- One demand (resp. supply) hourly order is said to be *in-the-money* when the market clearing price is lower (resp. higher) than the price of the hourly order.
- One demand or supply hourly order is said to be *at-the-money* when the price of the hourly order is equal to the market clearing price.
- One demand (resp. supply) hourly order is said to be *out-of-the-money* when the market clearing price is higher (resp. lower) than the price of the hourly order.
- For linear piecewise hourly orders starting at price p_0 and finishing at price p_1, p_0 is used as the order price for the nomenclature above (except for energy *at-the-money*, where the market clearing price is in the interval $[p_0, p_1]$).

The rules that apply for the acceptance of hourly orders in the algorithm are the following:

- Any order in-the-money must be fully accepted.

[1] Whenever hourly orders are mentioned through this document, we are referring to the aggregated hourly orders that are the input of EUPHEMIA.

- Any order out-of-the money must be rejected.
- Orders at-the-money can be either accepted (fully or partially) or rejected.

Price-taking orders, defined at the maximum / minimum prices of the *bidding zone*, have additional requirements which are detailed in Section 6.5.1.

5.2. Complex Orders

A complex order is a set of simple supply stepwise hourly orders (which are referred to as hourly sub-orders) belonging to a single market participant, spreading out along different periods and are subject to a complex condition that affects the set of hourly sub-orders as a whole.

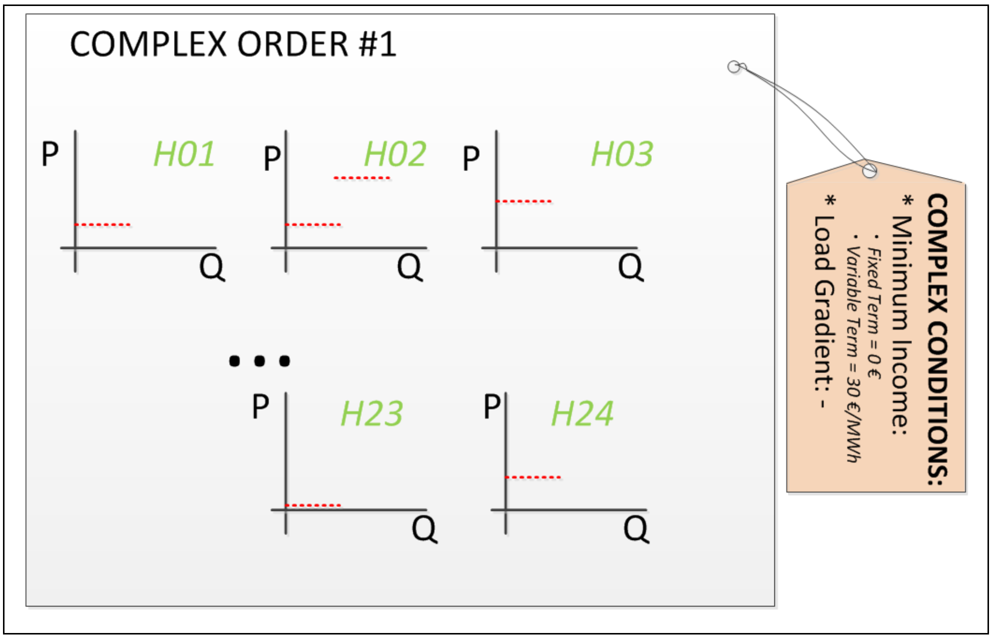


Figure 8 – A complex order is composed of a set of hourly sub-orders (in dotted line) associated with complex conditions

Complex conditions are of two types: Minimum Income Condition (with or without scheduled stop), and Load Gradient.

Since several NEMOs can be present in the same bidding zone, complex orders of NEMOs that belong to the same bidding zone need to be combined.. Complex orders' IDs uniqueness within one bidding zone will be assured by generating unique internal complex order IDs per session automatically.

Furthermore, each complex order will also be associated with a hash: this hash can then be used for settling ties between identical complex orders submitted by different NEMOs in the same bidding zone. More information is available in paragraph 5.2.5

5.2.1. Minimum Income Condition (MIC)

Complex orders (with their set of hourly sub-orders) subject to Minimum Income Condition constraints are called MIC orders (or MICs).

Generally speaking, the Minimum Income economical constraint means that the amount of money collected by the order in all periods must cover its production costs, which is defined by a fix term (representing the startup cost of a power plant) and a variable term multiplied by the total assigned energy (representing the operation cost per MWh of a power plant).

The Minimum Income Condition constraint is in short defined by:

- A fix term (FT) in Euros
- A variable term (VT) in Euros per accepted MWh.

In the final solution, MIC orders are activated or deactivated (as a whole):

- In case a MIC order is activated, each of the hourly sub-orders of the MIC behaves like any other hourly order, which means accepted if they are in-the-money and rejected if they are out-of-the-money, and can be either accepted (fully or partially) or rejected when at-the-money.
- In case a MIC order is deactivated, each of the hourly sub-orders of the MIC is fully rejected, even if it is in-the-money (with the exception of scheduled stop, see Section 5.2.2).

The final solution given by EUPHEMIA will not contain active MIC orders not fulfilling their Minimum Income Condition constraint (also known as paradoxically accepted MICs).

5.2.2. Scheduled Stop

In case the owner of a power plant which was running the previous day offers a MIC order to the market, he may not want to have the production unit stopped abruptly in case the MIC is deactivated.

For the avoidance of this situation, the sender of a MIC has the possibility to define a "scheduled stop". Using a schedule stop will alter the deactivation of the MIC: the deactivation will not imply the automatic rejection of all the hourly sub-orders. On the contrary, the first (i.e. the cheapest) hourly sub-order in the periods that contain scheduled stop (up to period 3) will not be rejected but will be treated as any hourly order.

5.2.3. Load Gradient

Complex orders (with their set of hourly sub-orders) on which a Load Gradient constraint applies are called Load Gradient Orders.

Generally speaking, the Load Gradient constraint means that the amount of energy that is matched by the hourly sub-orders belonging to a Load Gradient order in one period is limited by the amount of energy that was matched by the hourly sub-orders in the previous period. There is a maximum increment / decrement allowed (the same value for all periods). Period 1 is not constrained by the energy matched in the last hour of the previous day. If only one of these values is defined, the other value (i.e. empty) is considered as unconstrained.

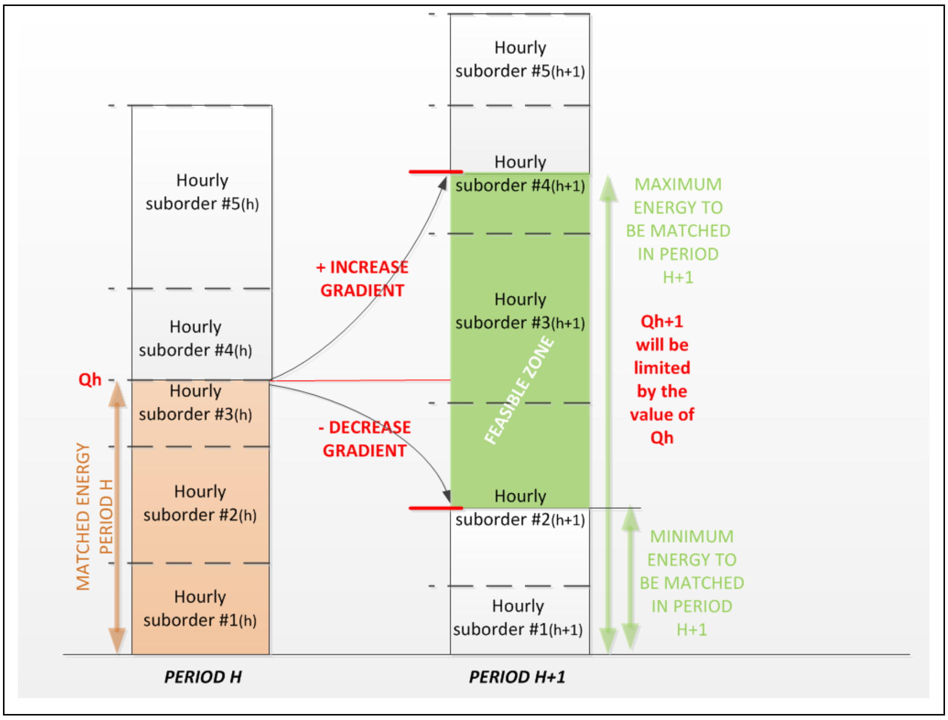


Figure 9 – A Load Gradient order. Effect produced by the amount that is matched in period (h) on period (h+1).

5.2.4. Complex orders combining Load Gradient and MIC

Complex orders (with their set of hourly sub-orders) can be subject to both Load Gradient and Minimum Income Condition (with or without scheduled stop).

5.2.5. Complex order tie rules

Euphemia implements complex order tie rules to arbitrate between identical complex orders in the same bidding zone, when only some, but not all can be activated in the final solution.

Two complex orders are considered equal, if:

- The bidding zones are identical;
- The signs (buy or sell) are identical;
- The fixed terms are identical;
- The variable terms are identical;
- The increase gradients are identical;
- The decrease gradients are identical;
- The scheduled stop periods are identical;
- The sub orders have identical:
    - Periods;
    - Prices;
    - Quantities;

For this case, economic criteria are insufficient to arbitrate: accepting one or the other will result in identical welfare. Instead some secondary criteria are used to make the arbitration, and allow ties to be deterministically broken:

1. The complex order with an earlier last modification timestamp will be prioritized;
2. If 1. does not break the tie, we consider two sub cases:
   a. For bidding zones where only a single NEMO exists, the priority is set according to the lowest "external id", the id assigned to the complex order by the local trading system of the corresponding power exchange. These ids must be unique, and therefore will necessarily break any tie;
   b. For bidding zones with multiple NEMOs ties are broken differently: To avoid unequal treatment the preferred complex order is selected "randomly": random in the sense bias are avoided, and complex orders from one NTH will not be more or less likely to be accepted than complex orders from another NTH. In order to make sure Euphemia behaviour is repeatable, repeatable randomness is applied. This is managed by using the hashes that were compiled for each complex order (on the basis of the different parameters describing the complex orders). These hashes will be used to settle ties, and should be sufficiently random to meet this fairness objective.

5.3. Block Orders

A block order is defined by:

- sense (supply or demand)
- price limit (minimum price for supply block orders and maximum price for demand block orders),
- number of periods,
- volume that can be different for every period,
- minimum acceptance ratio.

In the simplest case, a block order is defined for a consecutive set of periods with the same volume and with a minimum acceptance ratio of 1. These are usually called regular (fill-or-kill) block orders. In general, the periods of the block orders can be non-consecutive, the volume can differ over the periods and the minimum acceptance ratio can be less than 1 (Curtailable Block Orders –partial acceptance is allowed).

Example of a block order:

Block Order #1

- ➢ Sense: supply
- ➢ Price: 40 €/MWh
- ➢ Minimum acceptance ratio: 0.5
- ➢ Intervals: Hours (3-7), hours (8-19) and hours (22-24)
- ➢ Volume: 80 MWh in the first interval, 220 MWh in the second one, and 40 MWh in the third one.

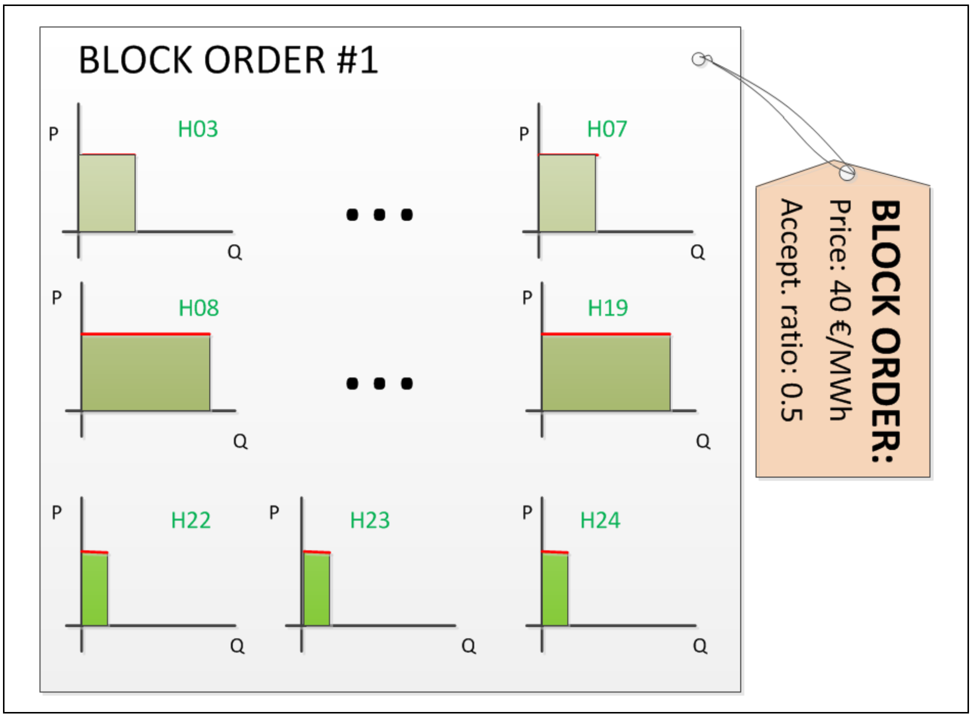


Figure 10 – Block order example

Block orders that are *out-of-the-money* cannot be accepted. As a consequence, all block orders will fall in one of the below categories:

- if the block is *in-the-money* or *at-the-money*, then the block can be one of: fully rejected (PRB), entirely accepted or partially accepted (PPRB), to the extent that the ratio "accepted volume/total submitted volume" is greater than or equal to the minimum acceptance ratio of the block (e.g. 0.5) and equal over all periods;
- or if the block is *out-of-the-money*, then the block must be entirely rejected;

Since several NEMOs can be present in the same bidding zone, block orders of NEMOs that belong to the same bidding zone need to be combined, despite their order type ("normal" blocks, linked block families, flexible hourly orders and exclusive groups).
Block IDs' uniqueness within one bidding zone will be assured by generating unique internal block IDs per session automatically.
Furthermore each block will also be associated with a hash: this can then be used for settling ties between identical blocks submitted by different NEMOs. More information are available in paragraph 5.3.4.

5.3.1. Linked Block Orders

Block orders can be linked together, i.e. the acceptance of individual block orders can be made dependent on the acceptance of other block orders. The block which acceptance depends on the acceptance of another block is called "child block", whereas the block which conditions the acceptance of other blocks is called "parent block".

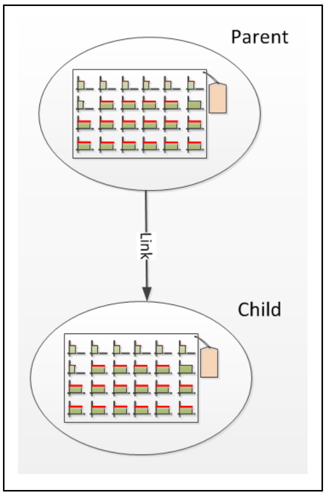


Figure 11 – Linked block orders

The rules for the acceptance of linked block orders are the following:

1. The acceptance ratio of a parent block is greater than or equal to the highest acceptance ratio of its child blocks (acceptance ratio of a child block can be at most the lowest acceptance ratio among own parent blocks)
2. (Possibly partial) acceptance of child blocks can allow the acceptance of the parent block when:
    a. the surplus of a family is non-negative
    b. leaf blocks (block order without child blocks) do not generate welfare loss
3. A parent block which is *out-of-the-money* can be accepted in case its accepted child blocks provide sufficient surplus to at least compensate the loss of the parent.
4. A child block which is *out-of-the-money* cannot be accepted even if its accepted parent provides sufficient surplus to compensate the loss of the child, unless the child block is in turn parent of other blocks (in which case rule 3 applies).

In an easy common configuration of two linked blocks, the rules are easy. The parent can be accepted alone, but not the child that always needs the acceptance of the parent first. The child can "save" the parent with its surplus, but not the opposite.

5.3.2. Block Orders in an Exclusive group

An Exclusive group is a set of block orders for which the sum of the accepted ratios cannot exceed 1. In the particular case of blocks that have a minimum acceptance ratio of 1 it means that at most one of the blocks of the exclusive group can be accepted.

Between the different valid combinations of accepted blocks the algorithm chooses the one which maximizes the optimization criterion (*social welfare*, see Section 6.3).

5.3.3. Flexible Hourly Orders

A flexible "hourly" order is a block order with a fixed price limit, a fixed volume, minimum acceptance ratio of 1, with duration of 1 hour. The hour is not defined by the participant but will be determined by the algorithm (hence the name "flexible"). The hour in which the flexible hourly order is accepted, is calculated by the algorithm and determined by the optimization criterion (see Section 6.3)

5.3.4. Block order tie rule

Euphemia implements block order tie rules to arbitrate between identical blocks, when only some, but not all can be accepted.

Two blocks are considered equal, if they:

- Belong to the same bidding zone;
- Have the same minimum acceptance ratio;
- Have the same price;
- Both are on supply side, or both are on demand side;
- Are defined on the same periods and are offering the same quantities on each period
- Belong to the same exclusive group
- Have no links

For this case economic criteria are insufficient to arbitrate: accepting on or the other will result in identical welfare. Instead some secondary criteria are used to make the arbitration, and allow ties to be deterministically broken:

1. A block with an earlier last modification timestamp will be prioritized;

With the introduction of the MNA there is also the need to arbitrate between identical blocks, which were submitted by different NTHs. The initial criterion of the time stamps has been maintained.

On other hand, the second criterion cannot be applied anymore, as ids from the local trading systems are not coordinated. E.g. if NTHs 1 and 2 use a continuous sequence of increasing ids to identify their blocks, but NTH 1 is higher up in its sequence than NTH 2, the NTH 2 blocks will always be prioritized, and the NTHs will not be treated equally.

To avoid unequal treatment the preferred block is selected "randomly": random in the sense bias are avoided, and blocks from one NTH will not be more or less likely to be accepted than blocks from another NTH.

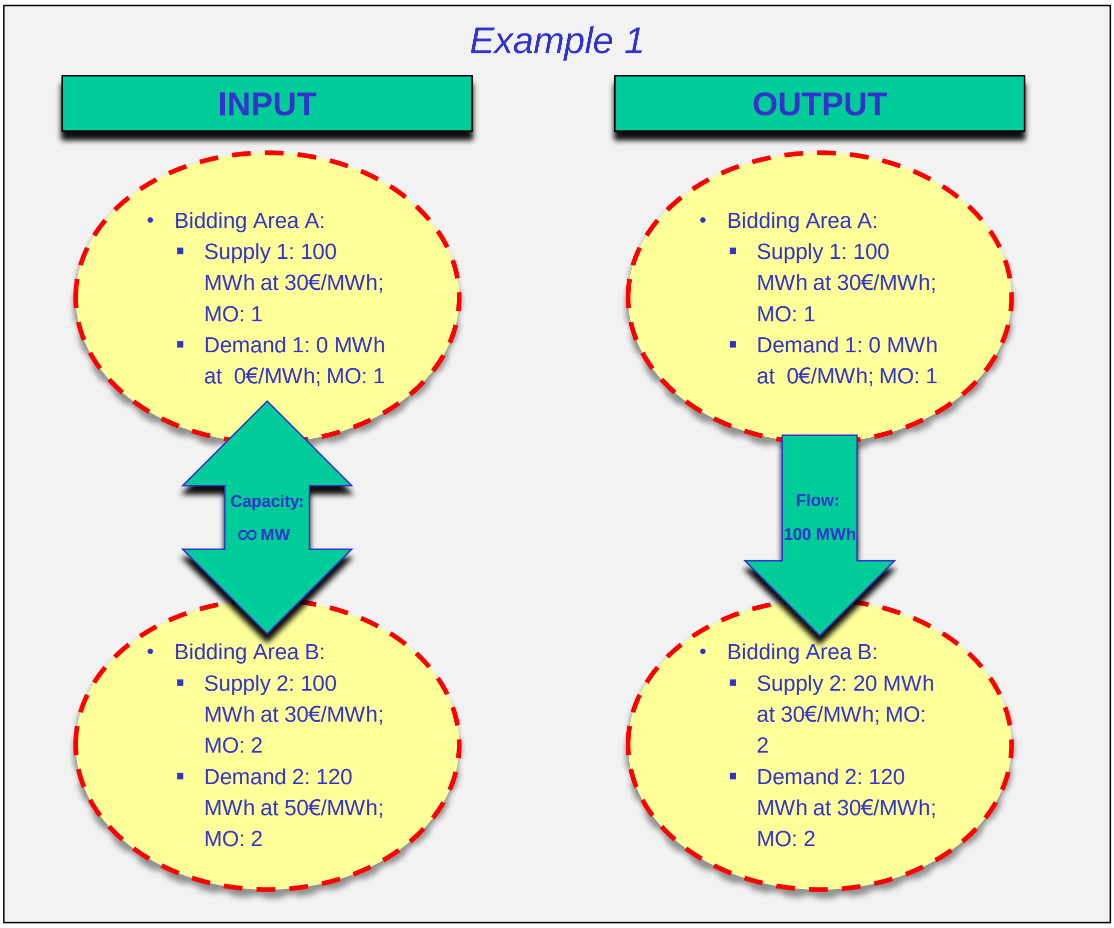
In order to be sure Euphemia behaviour is repeatable, repeatable randomness is applied. This is managed by using the hashes that were compiled for each block (on the basis of the different parameters describing the blocks). These hashes will be used to settle ties, and should be sufficiently random to meet this fairness objective.

5.4. Merit Orders and PUN Orders

5.4.1. Merit Orders

Merit orders are individual step orders defined at a given period for which is associated a so-called merit order number.

A merit order number is unique per period and order type (Demand; Supply; PUN) and is used for ranking merit orders in the *bidding zones* containing this order type. The lower the merit order number, the higher the priority for acceptance. More precisely, when, within an uncongested set of adjacent *bidding zones*, several merit orders have a price that is equal to the market clearing price, the merit order with the lowest merit order number should be accepted first unless constrained by other network conditions.



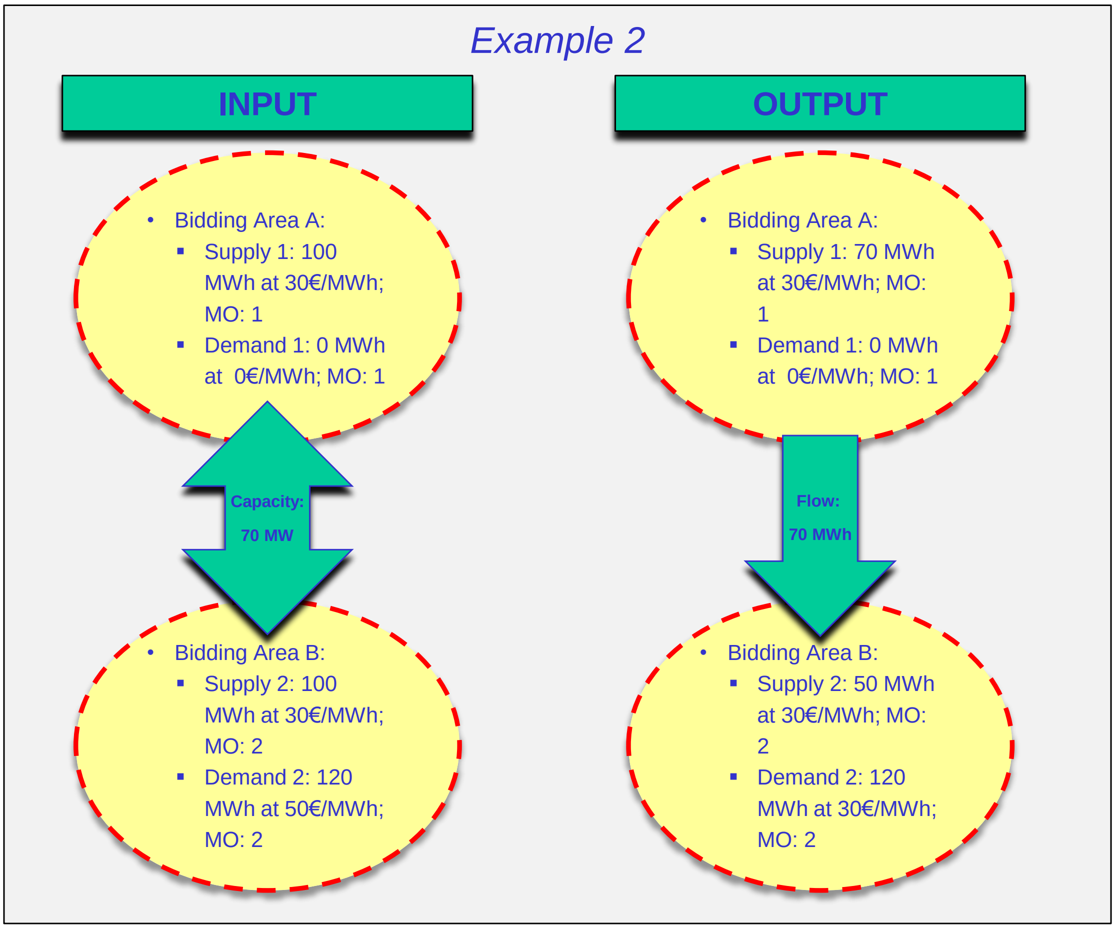


Figure 12: Merit Orders examples

5.4.2. PUN Orders

PUN orders are a particular type of demand merit orders. They differ from classical demand merit orders in such sense that they are cleared at the *PUN price* (PUN stands for "Prezzo Unico Nazionale") rather than the *bidding zone* market clearing price (i.e. a PUN order with an offered price lower than market clearing price of its associated *bidding zone*, but higher than *PUN price* would be fully accepted by EUPHEMIA).

For each period, the values of the accepted PUN merit orders volumes multiplied by the *PUN price* is equal to the value of the accepted PUN merit orders volumes multiplied by the corresponding *market clearing prices* (up to a defined tolerance named PUN imbalance[2]), according to the following Formula:

$$P_{PUN} \times \Sigma_z Q_z = \Sigma_z P_z \times Q_z \pm \Delta$$

With:

- P_{PUN}: *PUN price*
- Q_z: Volumes consumed in *bidding zone* z

[2] In other words, the value (PUN Volume * *PUN price*) must be able to refund producers (who receives the price of their bidding zone), congestion rents and a PUN imbalance.

- P_z: Price of *bidding zone* z
- Δ: PUN imbalance

In case of more than one PUN order submitted at a price equal to *PUN price*, the merit order number rule is applied to PUN orders as well.

6. EUPHEMIA Algorithm

6.1. Preamble: order aggregation

In the following sections, EUPHEMIA solving process is presented.

However, it is important to notice that **EUPHEMIA core computation is performed at bidding zonal level**. Indeed, as presented earlier in the document (4.4.1 and 4.5.1), orders are defined at NTH level but all orders within a same bidding zone are subjected to an identical market clearing price (due to the absence of limitation in terms of flows either between SAs or between NTHs).

While block orders and complex orders remain individually defined, all curve orders from the different NTHs of each bidding zone will be aggregated by EUPHEMIA into a single set of curves for each period, as a pre-processing step. Aggregating orders at a bidding zone level allows simplifying EUPHEMIA mathematical model: this way, SA and NTH topologies need not be considered, preventing significant degradation of the algorithm performance.

The type of the aggregated curve will depend on that of the underlying NTH curve types: if all NTHs are all either stepwise or piecewise curves, the generated aggregated curve shall result (respectively) into stepwise and piecewise curves. If NTH curves are however both stepwise and piecewise curves, the resulting curves shall have a hybrid type.

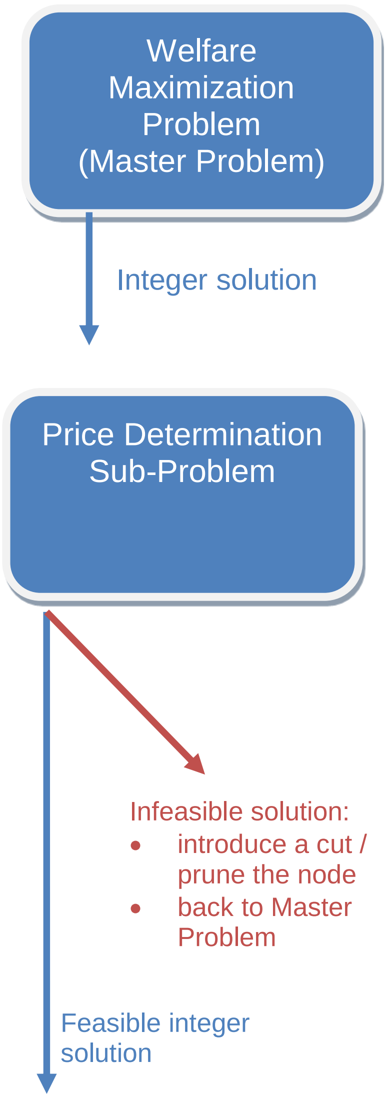
To retrieve the results at NTH level, EUPHEMIA also implements a disaggregation post-processing step, once solutions have been found.

6.2. Overview

As mentioned previously, EUPHEMIA is the algorithm that has been developed to solve the Day-Ahead European Market Coupling problem. EUPHEMIA matches energy demand and supply for all the periods of a single day at once while taking into account the market and network constraints. The main objective of EUPHEMIA is to maximize the *social welfare*, *i.e.* the total market value of the Day-Ahead auction expressed as a function of the *consumer surplus*, the *supplier surplus*, and the *congestion rent* including tariff rates on interconnectors if they are present. EUPHEMIA returns the *market clearing prices*, the matched volumes, and the *net position* of each *bidding zone* as well as the flow through the interconnectors. It also returns the selection of block, complex, merit, and PUN orders that will be executed. For curtailable blocks the selection status will indicate the accepted percentage for each block.

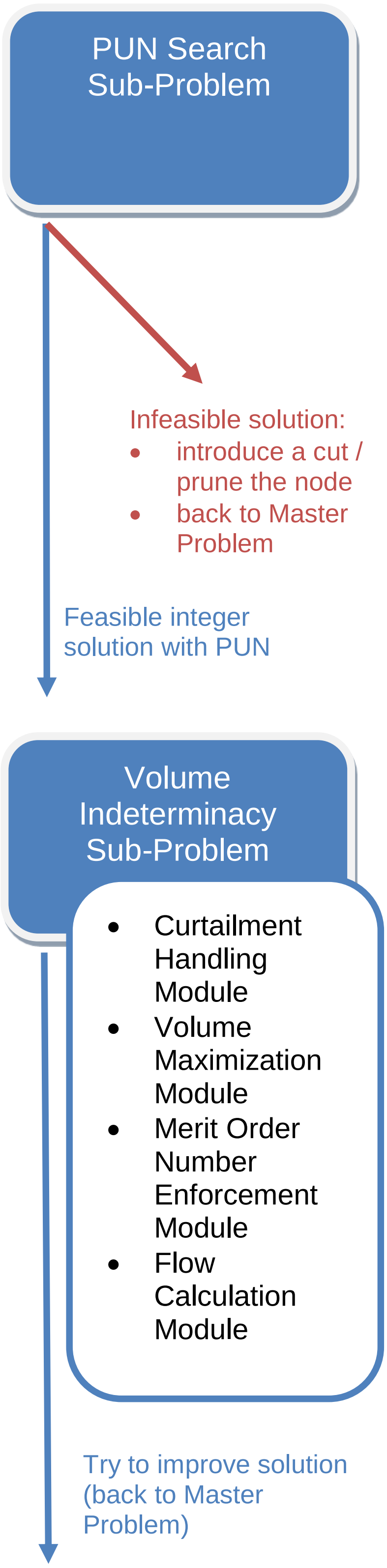
By ignoring the particular requirements of the block, complex, merit and PUN orders, the market coupling problem resolves into a much simpler problem which can be modeled as a Quadratic Program (QP) and solved using commercial off-the-shelf solvers. However, the presence of these orders renders the problem more complex. Indeed, the "kill-or-fill" property of block orders and the minimum income condition (MIC) of complex orders requires the introduction of binary (i.e. 0/1) variables. Moreover, the strict consecutiveness requirement of merit and PUN orders adds up to the complexity of the problem.

In order to solve this problem, EUPHEMIA runs a combinatorial optimization process based on the modeling of the market coupling problem. The reader can refer to the Annex B for a more detailed mathematical formulation of the problem. EUPHEMIA aims to solve a welfare maximization problem (also referred to as the master problem) and three interdependent sub-problems, namely the price determination sub-problem, the PUN search sub-problem and the volume indeterminacy sub-problem.



In the welfare maximization problem, EUPHEMIA searches among the set of solutions (solution space) for a good selection of block and MIC orders that maximizes the *social welfare*. In this problem, the PUN and merit orders requirements are not enforced. Once an integer solution has been found for this problem, EUPHEMIA moves on to determine the *market clearing prices*.

The objective of the price determination sub-problem is to determine, for each *bidding zone*, the appropriate *market clearing price* while ensuring that no block and complex MIC orders are *paradoxically accepted* and that the flows price-network requirements are respected (more precisely: that the primal-dual relations are satisfied, cf. Annex B). If a feasible solution could be found for the price determination sub-problem, EUPHEMIA proceeds with the PUN search sub-problem. However, if the sub-problem does not have any solution, we can conclude that the block and complex orders selection is not acceptable, and the integer solution to the welfare maximization problem must be rejected. This is achieved by adding a cut to the welfare maximization problem that renders its current solution infeasible. Subsequently, EUPHEMIA resumes the welfare maximization problem searching for a new integer solution for the problem.



The objective of the PUN search sub-problem is to find valid PUN volumes and prices for each period of the day while satisfying the PUN imbalance constraint and enforcing the strong consecutiveness of accepted PUN orders. When the PUN search sub-problem is completed, EUPHEMIA verifies that the obtained PUN solution does not introduce any *paradoxically accepted block/complex orders*. If some orders become *paradoxically accepted*, a new cut is introduced to the welfare maximization problem that renders the current solution infeasible. Otherwise, EUPHEMIA proceeds with the lifting of volume indeterminacies.

In the previous sub-problems, the algorithm has determined the *market clearing prices* for each *bidding zone*, the *PUN prices* and volumes for the area with PUN orders, and a selection of block and complex MIC orders that are feasible all together. Though, there might exist several aggregated hourly volumes, *net positions*, and bidding zone line flows that are coherent with these prices and that yield the same welfare. Among all these possible solutions, EUPHEMIA pays special attention to the *price-taking orders*, enforces the merit order number, and maximizes the traded volume.

The flow calculation module here also takes into account both scheduling area and NEMO trading hubs topologies. More details can be found in section 6.8.5.

6.3. Welfare Maximization Problem (Master Problem)

As mentioned previously, the objective of this problem is to maximize the *social welfare*, *i.e.* the total market value of the Day-Ahead auction. The *social welfare* is computed as the sum of the *consumer surplus*, the *supplier surplus*, and the *congestion rent*. The latter takes into account the presence of tariff rates for the flows through defined interconnectors.

In case there is the risk of a curtailment situation in an area where Flow Based constraints apply, a special penalty is applied in the objective function for the non-acceptance of price taking demand. This is linked to the curtailment sharing rules, which are described in 0.

EUPHEMIA ensures that the returned results are coherent with the following constraints (see Chapters 4 and 5):

- The acceptance criteria for aggregated hourly demand and supply curves and merit orders
- The fill-or-kill requirement of block orders

1. The scheduled stop, load gradient, and minimum income condition of complex orders

- The capacities and ramping constraints imposed on the ATC interconnectors while taking into account the losses and the tariff rates if applicable.
- The flow limitation through some critical elements of the network for *bidding zones* managed by the flow-based network model. All bidding zones should be balanced: the net position equals the total export minus the total imports for this zone, and this should match the zone's imbalance: the difference between total matched supply and total matched demand.
- The hourly and daily net position ramping should be respected;

It should be noted that the strict consecutiveness requirement of merit and PUN orders is not enforced in this problem. In other words, the merit orders are considered in this problem as aggregated hourly orders while, the PUN orders are just ignored. The main difficulty of the welfare maximization problem resides in selecting the block/MIC orders that are to be accepted and those to be rejected. The particularity of the block and MIC orders lies in the fact that they require the introduction of 0/1 variables in order to model their acceptance (0: rejected order, 1: accepted order). The discrete nature of these decision variables is referred to as the integrality constraint. The solution of this problem requires some decision variables to be integer (0/1) and the overall problem can be modeled as a Mixed-Integer Quadratic Program (MIQP).

A possible approach to solve such an MIQP problem is to use the branch-and-cut method. The branch-and-cut method is a very efficient technique for solving a wide variety of integer programming problems. It involves running a branch-and-bound algorithm and using cutting planes to tighten the QP relaxations. In the sequel, we will describe how the branch-and-cut method can be adapted to our particular welfare maximization problem and how cutting planes will be generated in the subsequent sub-problems in order to reduce the number and range of solutions to investigate.

6.3.1. Overview

EUPHEMIA starts by solving the initial MIQP problem where none of the variables is restricted to be integer. The resulting problem is called the integer relaxation of the original MIQP problem. For instance, relaxing the fill-or-kill constraint, *i.e.* the integrality constraint on the acceptance of the block orders, is equivalent to allowing all the block orders to be partially executed.

Because the integer relaxation is less constrained than the original problem, but still aims at maximizing *social welfare*, it always gives an upper bound on attainable *social welfare*. Moreover, it may happen that the solution of the relaxed problem satisfies all the integrality constraints even though these constraints were not explicitly imposed. The obtained result is thus feasible with respect to the initial problem and we can stop our computation: we got the best feasible solution of our MIQP problem. Note that this is rarely the case and the solution of the integer relaxation contains very often many fractional numbers assigned to variables that should be integer values.

6.3.2. Branching

In order to move towards a solution where all the constraints, including the integrality constraints, are met, EUPHEMIA will pick a variable that is violating its integrality constraint in the relaxed problem and will construct two new instances as following:

- The first instance is identical to the relaxed problem where the selected variable is forced to be smaller than the integer part of its current fractional value. In the case of 0/1 variables, the selected variable will be set to 0. This will correspond, for instance, to the case where the block order will be rejected in the final coupling solution.
- The second instance is identical to the relaxed problem where the selected variable is forced to be larger than the integer part of its current fractional value. In the case of 0/1 variables, the selected variable will be set to 1. This will correspond, for instance, to the case where the block order will be accepted in the final coupling solution.

Duplicating the initial problem into two new (more restricted) instances is referred to as branching. Exploring the solution space using the branching method will result in a tree structure where the created problem instances are referred to as the nodes of the tree. For each created node, the algorithm tries to solve the relaxed problem and branches again on other variables if necessary. It should be highlighted that by solving the relaxed problem at each of the nodes of the tree and taking the best result, we have also solved the initial problem (i.e. the problem in which none of the variables is restricted to be integer).

6.3.3. Fathoming

Expanding the search tree all the way till the end is termed as fathoming. During the fathoming operation, it is possible to identify some nodes that do not need to be investigated further. These nodes are either pruned or terminated in the tree which will considerably reduce the number of instances to be investigated. For instance, when solving the relaxed problem at a certain node of the search tree, it may happen that the solution at the current node satisfies all the integrality restrictions of the original MIQP problem. We can thus conclude that we have found an integer solution that still needs to be proved feasible. This can be achieved by verifying that there exist valid *market clearing prices* for each *bidding zone* that are coherent with the market constraints. For this purpose, EUPHEMIA moves on to the price determination sub-problem (see section 6.4). If the latter sub-problem finds a valid solution for the current set of blocks/complex orders, we can conclude that the integer solution just found is feasible. Consequently, it is not required to branch anymore on this node as the subsequent nodes will not provide higher *social welfares*. Otherwise, if no valid solution could be found for the price determination sub-problem, we can conclude that the current block and complex order selection is unacceptable. Thus, a new instance of the welfare maximization problem is created where additional constraints are added to the welfare maximization problem that renders the previous integer solution infeasible (see section 6.3.4).

Let us denote the best feasible integer solution found at any point in the search as the incumbent. At the start of the search, we have no incumbent. If the integer feasible solution that we have just found has a better objective function value than the current incumbent (or if we have no incumbent), then we record this solution as the new incumbent, along with its objective function value. Otherwise, no incumbent update is necessary and we simply prune the node.

Alternatively, it may happen that the branch, that we just added and led to the current node, has added a restriction that made the QP relaxation infeasible. Obviously, if this node contains no feasible solution to the QP relaxation, then it contains no integer feasible solution for the original MIQP problem. Thus, it is not necessary to further branch on this node and the current node can be pruned.

Similarly, once we have found an incumbent, the objective value of this incumbent is a valid lower bound on the *social welfare* of our welfare maximization problem. In other words, we do not have to accept any integer solution that will yield a solution of a lower welfare. Consequently, if the solution of the relaxed problem at a given node of the search tree has a smaller welfare than that of the incumbent, it is not necessary to further branch on this node and the current node can be pruned.

6.3.4. Cutting

Introducing cutting planes is the other most important contributor of a branch-and-cut algorithm. The basic idea of cutting planes (also known as "cuts") is to progressively tighten the formulation by removing undesirable solutions. Unlike the branching method, introducing cutting planes creates a single new instance of the problem. Furthermore, adding such constraints (cuts) judiciously can have an important beneficial effect on the solution process.

As just stated, whenever EUPHEMIA finds a new integer solution with a better *social welfare* than the incumbent solution, it moves on to the price determination sub-problem and subsequent sub-problems. If in these sub-problems, we find out that the sub-problem is infeasible, we can conclude that the current block and complex order selection is unacceptable. Thus, the integer solution of the welfare maximization problem must be rejected. To do so, specific local cuts are added to the welfare maximization problem that renders the current selection of block and complex orders infeasible. Different types of cutting planes can be introduced according to the violated requirement that should be enforced in the final solution. For instance, if at the end of the price determination sub-problem, a block order is *paradoxically accepted*, the proposed cutting plane will force some block orders to be rejected so that the prices will change and will eventually make the block order no longer *paradoxically accepted*. Further types of cutting planes will be introduced in the subsequent sub-problems.

6.3.5. Stopping Criteria

Euphemia stops in case:

- A time limit is reached;
- The full branch and bound tree is explored;

In case the time limit is reached, but no valid solution is found, the calculation continues and stops only when a first solution is found.

A second time limit applies for finding this first solution: if it times out the session fails and Euphemia does not return any solution.

6.4. Price Determination Sub-problem

In the master problem, EUPHEMIA has determined an integer solution with a given selection of block and complex orders. In addition, EUPHEMIA has also determined the matched volume of merit and aggregated hourly orders. In this sub-problem, EUPHEMIA must check whether there exist *market clearing prices* that are coherent with this solution while still satisfying the market requirements. More precisely, EUPHEMIA must ensure that the returned results satisfy the following constraints:

- The *market clearing price* of a given *bidding zone* at a specific period of the day is coherent with the offered prices of the demand orders and the desired prices of the supply orders in this particular market.
- The *market clearing price* of a *bidding zone* is compatible with the minimum and maximum price bounds fixed for this particular market.

However, the solution of this price determination sub-problem is not straightforward because of the constraints preventing the *paradoxical acceptance of block and MIC orders*, or preventing the presence of *non-intuitive FB results*. Indeed, whenever EUPHEMIA deems that the price determination sub-problem is infeasible, it will investigate the cause of infeasibility and a specific type of cutting plane will be added to the welfare maximization problem aiming at enforcing compliance with the corresponding requirement. This cutting plane will discard the current selection of block and complex orders.

- In order to prevent the *paradoxical acceptance of block orders*, the introduced cutting plane will reject some block orders that are *in-the-money*. Special attention will be paid when generating these cuts in order to prevent rejecting *deep-in-the money* orders.
- In order to prevent the acceptance of complex orders that do not satisfy their minimum income condition, the introduced cutting plane will reject the complex orders that will most likely not fulfill their minimum income condition.
- When the market coupling problem at hand features both block and complex orders, EUPHEMIA associates both cutting strategies in a combined cutting plane.

Cuts will also be generated under the following circumstances:

2. Furthermore, if the bilateral intuitiveness mode is selected for the flow based model, the prices obtained at the end of the price determination sub-problem must satisfy an additional requirement. This requirement states that there cannot be *adverse flows*, *i.e.* flows exporting out of more expensive markets to cheaper ones. If the intuitiveness property is not satisfied, appropriate cutting planes are added as well to the welfare maximization problem.
3. In the presence of losses in a situation where a market clears at a negative price bi-directional flows may occur: energy is send back and forth between two areas only to pick up losses.

   Algorithmically this makes sense: when a market clears at a negative price, it is willing to pay for destroying energy (e.g. through losses). However physically it is nonsensical: energy can only be scheduled in one direction. To avoid this situation Euphemia will generate a cut forcing one or the other flow to be zero.

At this stage, we have obtained a feasible integer selection of block and complex orders along with coherent *market clearing prices* for all markets. Next, EUPHEMIA moves on to the PUN search sub-problem where it enforces the strong consecutiveness of the merit and PUN orders as well as the compliance with the PUN imbalance constraint.

6.4.1. Branch-and-Cut Example

Here is a small example of the execution of the Branch-and-Cut algorithm (Figure 13).

At the start of the algorithm, we do not have an incumbent solution. EUPHEMIA first solves the relaxed welfare maximization problem where all the integrality constraints have been relaxed (Instance A). Let us assume that the solution of this problem has a *social welfare* equal to 3500 but has two fractional decision variables related to the acceptance of the block orders ID_23 and ID_54. At this stage, we can conclude that the upper bound on the attainable *social welfare* is equal to 3500.

Next, EUPHEMIA will pick a variable that is violating its integrality constraint (block order ID_23, for instance) and will branch on this variable. Thus, two new instances are constructed: Instance B where the block order ID_23 is rejected (associated variable set to 0) and Instance C where the block order

ID_23 is accepted (associated variable set to 1). Then, EUPHEMIA will select one node that is not yet investigated and will solve the relaxed problem at that node. For example, let us assume that EUPHEMIA selects Instance B to solve and finds a solution where all the variables associated with the acceptance of block and complex orders are integral with a *social welfare* equal to 3050. Furthermore, we assume that the price determination sub-problem was successful and that a valid solution could be obtained. We can conclude that the solution of Instance B is thus feasible and can be marked as the incumbent solution of the problem. In addition, the obtained *social welfare* is a lower bound on any achievable welfare and it is not necessary to further branch on this node.

EUPHEMIA continues exploring the solution space and selects Instance C to solve. Let us assume that an integer solution was found with a *social welfare* equal to 3440. As the obtained *social welfare* is higher than that of the incumbent, EUPHEMIA moves on to the price determination sub-problem but let us assume that no valid *market clearing prices* could be found for this sub-problem. In this case, a local cut will be introduced to the welfare maximization problem. More precisely, an instance D is created identical to instance C where an additional constraint is added to render the current selection of block and complex orders infeasible. At this stage, we can conclude that the upper bound on the attainable *social welfare* is equal to 3440.

Now, let us assume that when solving the instance D of the problem, we get a solution with a *social welfare* equal to 3300 and a fractional decision variable related to the acceptance of the block order ID_30. As carried out previously, we need to branch on this variable. Thus, two new instances are constructed: Instance E where the block order ID_30 is rejected (associated variable set to 0) and Instance F where the block order ID_30 is accepted (associated variable set to 1). After solving the relaxed problem of Instance E, we assume that the obtained solution is integer with a *social welfare* equal to 3200. This *social welfare* is higher than that of the incumbent, so we try to solve the price determination sub-problem.
We assume that the price determination sub-problem has a valid solution. Thus, the current solution for Instance E is feasible and is set as the new incumbent solution. We note that the lower bound on any achievable *social welfare* is now equal to 3200.

Similarly, after solving the relaxed problem of Instance F, we assume that the obtained solution has a *social welfare* equal to 3100 along with some fractional decision variables. As this solution has a lower *social welfare* than that of the incumbent, there is no need to further branch on this node and the current node can be pruned.

Figure 13 shows the search tree associated with our example.

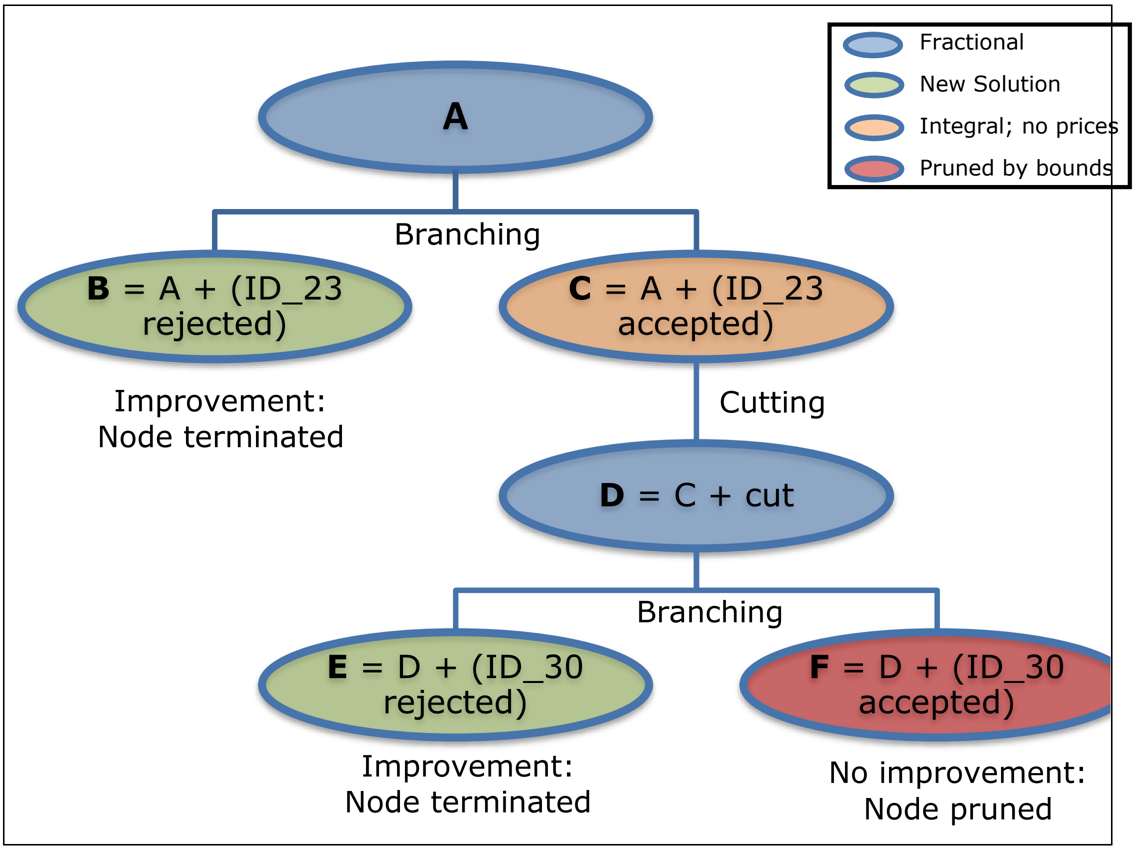


Figure 13 - Branch-and-Cut example

6.5. PUN Search Sub-problem

In order to avoid *paradoxically accepted* PUN orders, PUN (see Section 6.5) cannot be calculated as ex post weighted average of market price, but it must definitely be determined in an iterative process. Consider the following example:

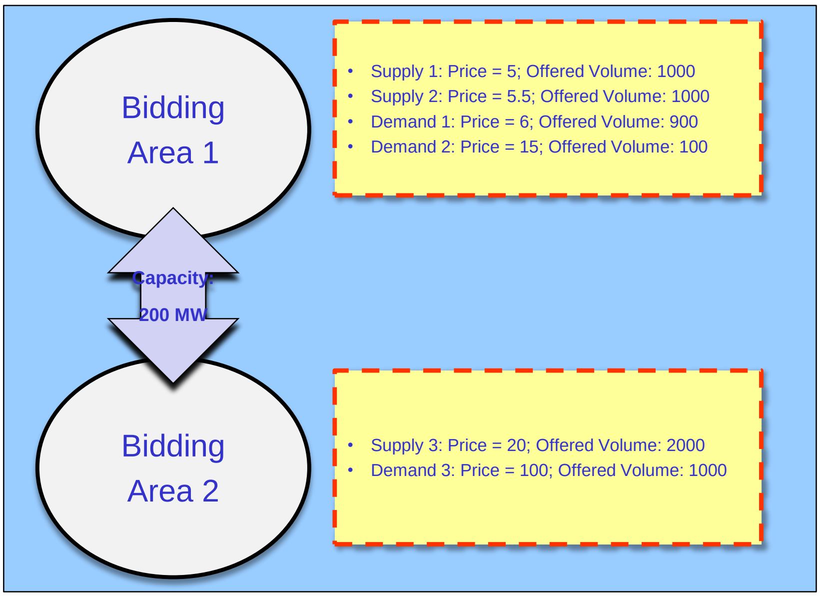


Figure 14 – PUN acceptance

If in Figure 15, Demand 1, Demand 2 and Demand 3 Orders were "simple" demand merit orders, then the market results would be:

- *Bidding zone* 1:
  - *Market clearing price*: 5.5 €/MWh;
  - Executed Supply Volume: 1000 MWh;
  - Executed Demand Volume: 1000 MWh.
- *Bidding zone* 2:
  - *Market clearing price*: 20 €/MWh;
  - Executed Supply Volume: 1000 MWh;
  - Executed Demand Volume: 1000 MWh.

If Demand 1, Demand 2 and Demand 3 Orders were "PUN" demand merit orders, then this solution is not acceptable. In fact, given a PUN imbalance tolerance=0, PUN calculated as weighted average will be:

$$[(1000 * 5.5) + (1000 * 20)] / 2000 = 12.75 \text{ €/MWh}.$$

In this case, order Demand 1 would be *paradoxically accepted*.

Through an iterative process, the final solution will be the following:

- *Market clearing price* of *Bidding zone* 1: 5 €/MWh;
- *Market clearing price* of *Bidding zone* 2: 20 €/MWh;
- *PUN price*: 20 €/MWh;
- Supply order Supply 1: partially accepted (200 MWh);
- Supply order Supply 2: fully rejected;
- Supply order Supply 3: partially accepted (800 MWh)
- Demand orders Demand 1 and Demand 2: fully rejected;
- Demand order Demand 3: fully accepted;
- Flow from *Bidding zone* 1 to *Bidding zone* 2: 200 MWh;
- Imbalance: (1000 * 20) – (1000 * 20)= 0;
- Welfare: (1000 * 100) – [(200 * 5 + 800 * 20)] = 83000 €;

The PUN search is launched as soon as a first candidate solution has been found at the end of the price determination sub-problem (activity 1 in Figure 15). This first candidate solution respects all PCR requirements but PUN. The objective of the PUN search is to find, for each period, valid PUN volumes and prices (activity 2 in Figure 15) while satisfying the PUN imbalance constraint and enforcing the strong consecutiveness of accepted PUN orders.

If the solution found for all periods of the day, is compatible with the solution of the master problem (activity 3 in Figure 16), it means that a solution is found after PRMIC reinsertion (see next section) has been performed. Otherwise, the process will resume calculating, for each period, new valid PUN volumes and prices to apply to PUN Merit orders.

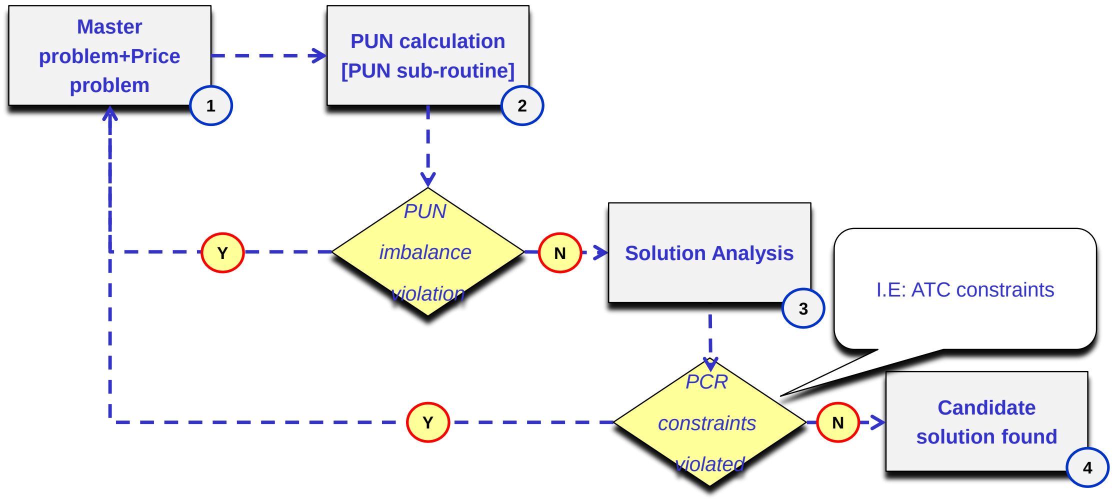


Figure 16 – PUN Search Sub-problem process

The PUN search is essentially an hourly sub-problem where the requirements are defined on an hourly basis, in which:

- Strong consecutiveness of PUN order acceptance is granted: a PUN order at a lower price cannot be satisfied until PUN orders at higher price are fully accepted
- PUN imbalance is within accepted tolerances.

For a given period, the selected strategy consists in selecting the maximum PUN volume (negative imbalance), and then trying to select smaller volumes until a feasible solution is found that minimizes the PUN imbalance.

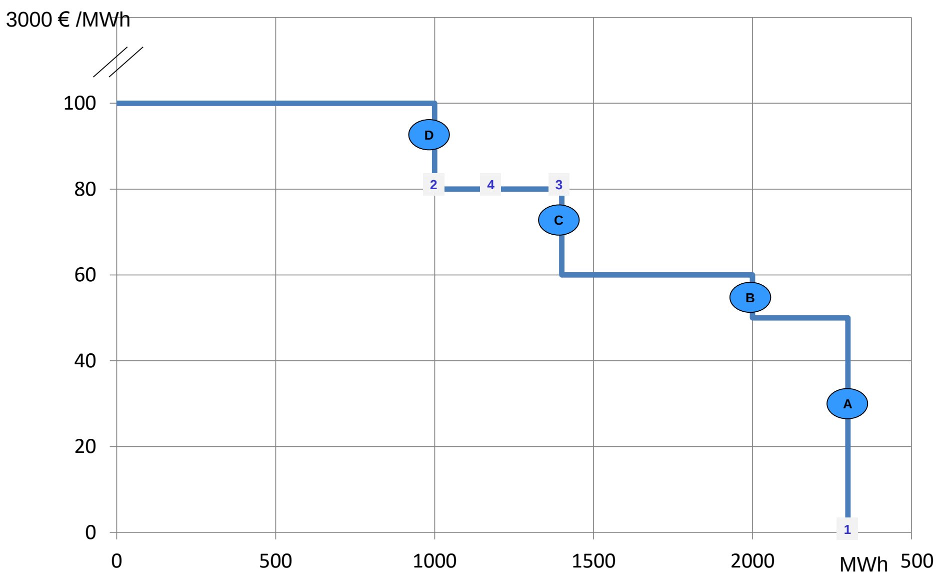


Figure 17 – PUN hourly curve

EUPHEMIA starts by calculating the PUN imbalance associated with the maximum accepted PUN volume (negative imbalance expected[3]; point 1 in Figure 17). If the PUN imbalance associated with the maximum PUN doesn't violate PUN imbalance tolerance, a candidate solution is found.

[3] PUN consumers paid 0, producers receive market prices. Unless all market prices are equal to 0, imbalance will be negative

On the contrary, EUPHEMIA calculates the price which minimizes PUN imbalance (in Figure 17, analysis on vertical segment A) while the volume is fixed to the maximum accepted PUN volume. If the PUN imbalance calculated in this way is within the PUN imbalance tolerance interval, a candidate solution is found. If not, the next vertical segment (i.e. in Figure 17, vertical segment B), will be analyzed. This process is repeated until between 2 consecutive vertical segments, a change in sign of PUN imbalance is found (i.e. in Figure 17, positive PUN Imbalance in segment D; and negative PUN Imbalance in segment C). In this case, EUPHEMIA fixes the price (i.e. in Figure 17, the horizontal segment between point 2 and 3, to which corresponds a price of 80 €/MWh), and tries to minimize the PUN imbalance, using the volume as decision variable.

If the PUN imbalance calculated in this step is compatible with PUN imbalance tolerance, a candidate solution is found. If not, Euphemia continues the search on the horizontal segment (*i.e.* considering in Figure 17, let point 4 the one associated with PUN imbalance minimization at the price of 80 €/MWh. If in point 4, the imbalance is positive and greater than positive PUN imbalance tolerance, search will be continued in the interval between [4;3]; If in point 4, the imbalance is negative and less than negative PUN imbalance tolerance, the search will be continued in the interval between [2;4]).

PUN SEARCH SUMMARY

1. *Calculation of PUN imbalance associated with maximum accepted PUN volume:*
    - *If minimum PUN imbalance tolerance ≤ calculated imbalance ≤ maximum PUN imbalance: candidate solution found*
    - *If imbalance < minimum PUN imbalance, next vertical segment is analyzed*
2. *Vertical segment analysis: Fixed the volume, minimization of the imbalance*
    - *If minimum PUN imbalance ≤ calculated imbalance ≤ maximum PUN imbalance: candidate solution found*
    - *If imbalance < minimum PUN imbalance, next vertical segment is analyzed*
    - *If imbalance > maximum PUN imbalance, next horizontal segment is analyzed*
3. *Horizontal segments analysis: Fixed the volume, minimization of the imbalance:*
    - *If minimum PUN imbalance ≤ calculated imbalance ≤ maximum PUN imbalance: candidate solution found*
    - *If imbalance < minimum PUN Imbalance, next horizontal segment is analyzed*
    - *If imbalance > maximum PUN Imbalance, next horizontal segment is analyzed*

As soon as PUN search is completed, EUPHEMIA verifies that the obtained PUN solution does not introduce any *paradoxically accepted block orders* or violates any other PCR constraints. If some block orders become *paradoxically accepted* or some other constrains are violated, a new cut is introduced to the welfare maximization problem that renders its current solution infeasible. Otherwise, EUPHEMIA proceeds with the PRMIC reinsertion.

6.6. PRMIC reinsertion

Finally, if the PUN sub-problem is successful, the solution returned by Euphemia should be made free of any false paradoxically rejected complex MIC order (PRMIC). Thus, once the market clearing prices have been found, Euphemia proceeds with an iterative procedure aiming to verify that all the rejected complex MIC orders, that are in-the-money, cannot be accepted in the final solution. For this purpose, Euphemia first determines the list of false PRMIC candidates. Then, Euphemia goes through the list, takes each complex MIC order from this list, activates it, and re-executes the price determination sub-problem. Two possible outcomes are expected:

- If the price computation succeeds and the *social welfare* was not degraded, we can conclude that the PRMIC reinsertion was successful. In this case, a new list of *false PRMIC* candidates is generated and the PRMIC reinsertion module is executed again.
- Conversely, if the price determination sub-problem is infeasible, or the *social welfare* is reduced, the complex MIC order candidate is simply considered as a true PRMIC, and the algorithm picks the next *false PRMIC* candidate. It should be noted that this case will not result to add a new cutting plane to the welfare maximization problem.

The PRMIC reinsertion module execution is repeated until no false PRMIC candidate remains. At this stage, we have obtained a feasible integer selection of block and complex orders along with coherent market clearing prices for all markets.

6.7. PRB reinsertion

In much the same way as the PRMIC reinsertion procedure, a module is in charge of reinserting PRBs after a fully valid solution has been found in the Branch-and-Bound tree. This local search approach helps reduce the number of PRBs, and usually leads quickly to a new solution, with a better welfare.
As soon as a solution has been stored, a local search algorithm tries to find neighbor solutions where some PRBs are newly activated. The MICs selection is fixed for this step. Of course, just like the PRMICs, not all PRBs may be reactivated. Some of them, when they are reinserted, change the prices in such a way that the solution is not valid anymore. They are true PRBs.
The procedure for the local search stops for each neighbour type when either one of these criteria is met:

- The list of candidate neighbours is empty. In this case, a local search for the next neighbour type is started or the local search stops if all neighbour types were already considered.
- The time limit is getting too close: based on historical performance 3 minutes is required for the remaining sub-problems

After selecting a neighbour solution, it is possible that a new PUN search is needed. The newly activated and deactivated blocks may indeed have invalidated the PUN

results, since the imbalance is not enforced by a constraint in this module, contrary to what is done in the PRMIC reinsertion module. In any case, the PRMIC reinsertion procedure and the volume problems are then run to obtain a second fully valid solution. Like the false PRMIC reinsertion module, this module allows EUPHEMIA to bypass the branch and cut mechanism, by taking a "shortcut" in the tree. The welfare of the new solution will be used as a cut-off value to prune other nodes.
Note that the local search module is only applied once at each node where a valid solution is found. After that, the search is resumed in the Branch-and-Bound tree.

Heuristic A heuristic approach is used at multiple levels in the local search procedure:
We have to restrict the neighbourhood in our search. Thus, we consider only single orders. However, a combination of orders can sometimes lead to better solutions and it can be impossible to reach those solutions via this local search.
The candidate neighbours are given in a certain order. By choosing to reactivate the orders according to this criterion, EUPHEMIA might miss other combinations of activations leading to a solution.
If the price computation fails, no cuts are added. We assume that the reinsertion of the order makes the prices problem infeasible and therefore reject it.

6.8. Volume Indeterminacy Sub-problem

With calculated prices and a selection of accepted block, MIC and PUN orders that provide together a feasible solution to market coupling problem, there still might be several matched volumes, *net positions* and flows coherent with these prices. Among them, EUPHEMIA must select one according to the volume indeterminacy rules, the curtailment rules, the merit order rules and the flow indeterminacy rules. These rules are implemented by solving five closely related optimization problems:

- Curtailment minimization
- Curtailment sharing
  - Partially addressed via the curtailment mitigation in the welfare definition;
- Volume maximization
- Merit order indeterminacy
- Flow indeterminacy

6.8.1. Curtailment minimization

A *bidding zone* is said to be in curtailment when the *market clearing price* is at the maximum or the minimum allowed price of that *bidding zone and submitted quantity at these extreme prices if not fully accepted*. The curtailment ratio is the proportion of *price-taking orders* which are not accepted. All orders have to be submitted within a (technical) price range set in the respective *bidding zone*. Hourly supply orders at the minimum price of this range and hourly demand orders at the maximum price of this range are interpreted as *price-taking orders*, indicating that the member is willing to sell/buy the quantity irrespective of the *market clearing price*.

The first step aims at minimizing the curtailment of these *price-taking* limit orders, *i.e.* minimizing the rejected quantity of *price-taking orders*. More precisely, EUPHEMIA enforces local matching of *price-taking hourly orders* with hourly orders from the opposite sense in the same *bidding zone* as a counterpart. Hence, whenever curtailment of *price-taking orders* can be avoided locally on an hourly basis – *i.e.* the curves cross each other - then it is also avoided in the final results. This can be interpreted as an additional constraint setting a lower bound on the accepted *price-taking quantity* (see Figure 18 where the dotted line indicates the minimum of *price-taking supply quantity* to be accepted).

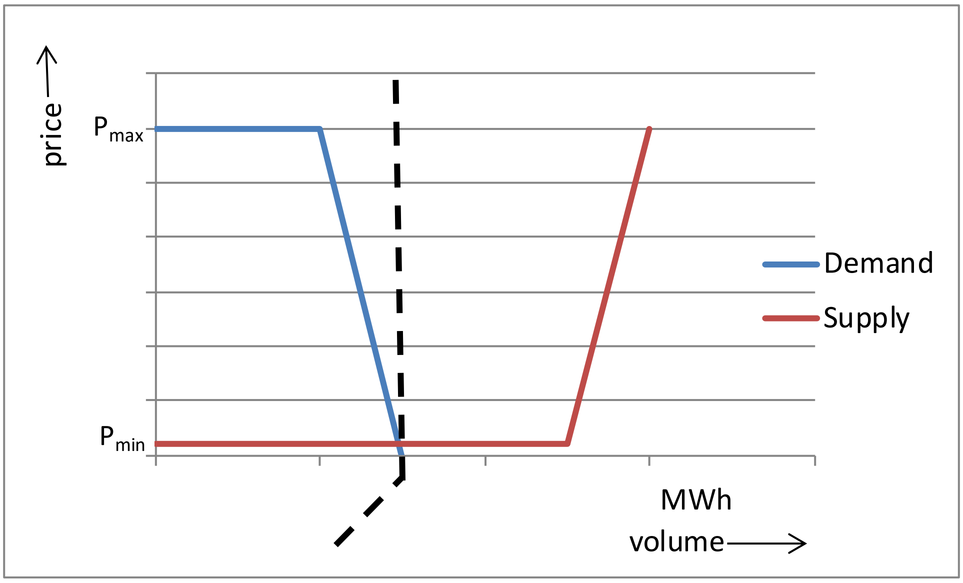


Figure 18 – Dotted line indicates the minimum of (*price-taking*) supply volume to be accepted

This constraint is referred to as the LOCAL_MATCHING constraint, and it is active in the master problem, i.e. prior to the price- and volume- coupling problems, but as an additional constraint to the welfare maximization problem.

6.8.2. Curtailment sharing

The aim of curtailment sharing is to equalize as much as possible the curtailment ratios between those bidding zones that are simultaneously in a curtailment situation, and that are configured to share curtailment.

This curtailment sharing is implemented in part in the master problem and in part in the curtailment sharing volume problem step.

Curtailment Sharing – Master Problem[4]

The objective function of the master problem is to maximize welfare. For an ATC line this results in a situation where areas that are not in curtailment will export to areas that are in curtailment.

However under FB this is not necessarily the case: if an exchange from area A to area B results in a higher usage of the capacity compared to an exchange A to C it is possible that is more beneficial to exchange from A to

[4] This functionality will first be available in Euphemia 9.3

C, whereas market B is in curtailment. This is referred to as "flow factor competition".

In order to prevent such cases on demand side (effectively treating curtailment outside of the welfare maximizing framework) we penalize the non-acceptance of price taking demand orders (or PTDOs) by adding to the primal objective:

$$M \cdot \sum_{z} Q_z^{PTDO} \left(1 - x_z^{PTDO}\right)^2 ,$$

Where:

x_z^{PTDO}: the acceptance ratio of the price taking order of area z (and $1\text{-}x_z^{PTDO}$ consequently the non-acceptance ratio).

Q_z^{PTDO}: the volume of the PTDO of area z;

M: a large value

This expression is added to the welfare. If the value of M is sufficiently large, it will help minimize the rejected price-taking quantity in all markets, before looking for a solution with a good welfare. The quadratic penalty function will tend to harmonize the curtailment ratios across the curtailed markets if any.

Curtailment sharing volume problem

For the case where areas were not affected by "flow factor competition", i.e. under ATC market coupling, curtailment sharing is targeted in the volume problem. Provided ATC capacity remains, the welfare function is indifferent between accepting price taking orders of one bidding zone or another.

This step aims to equalize curtailment ratios as much as possible among *bidding zones* willing to share curtailment. Bidding zones that are not willing to share curtailment will have their curtailment fixed in the welfare maximizing solution where the LOCAL_MATCHING constraint prevented these areas to be forced to share curtailments. At the same time the LOCAL_MATCHING constraint of adjacent areas prevented non-sharing areas to receive support from sharing areas. The supply or demand orders within a *bidding zone* being in curtailment at maximum (minimum) price are shared with other *bidding zones* in curtailment at maximum (minimum) price. For those markets that share curtailment, if they are curtailed to a different degree, the markets with the least severe curtailment (by comparison) would help the others reducing their curtailment, so that all the *bidding zones* in curtailment will end up with more equal curtailment ratios while respecting all network constraints.

The curtailment sharing is implemented by solving a dedicated volume problem, where all network constraints are enforced, but only the acceptance of the price taking volume is considered in the objective function. The curtailment ratios weighted by the volumes of price taking orders is minimized:

$$\min \sum_{h} \sum_{\substack{m: \\ m \in C_{h,Supply}}} \sum_{\substack{o: \\ market(o)=m \\ p_o = p_{\min,m}}} |q_o| \, (1 - ACCEPT_o)^2$$
$$+ \sum_{h} \sum_{\substack{m: \\ m \in C_{h,Demand}}} \sum_{\substack{o: \\ market(o)=m \\ p_o = p_{\max,m}}} |q_o| \, (1 - ACCEPT_o)^2$$

One can prove that for optimal solutions for this problem in the absence of any active network constraints this will result into equal curtailment ratios.

6.8.3. Maximizing Accepted Volumes

In this step, the algorithm maximizes the accepted volume.

All hourly orders, complex hourly sub-orders, merit orders and PUN orders are taken into account for maximizing the accepted volumes. The acceptance of most orders is already fixed at this point. Either because it is completely below or above the *market clearing price*, or it is a *price-taking order* fixed at the first or second volume indeterminacy sub-problem (curtailment minimization or curtailment sharing). Block orders are not considered in this optimization because a feasible solution has been found prior to this step in the master problem.

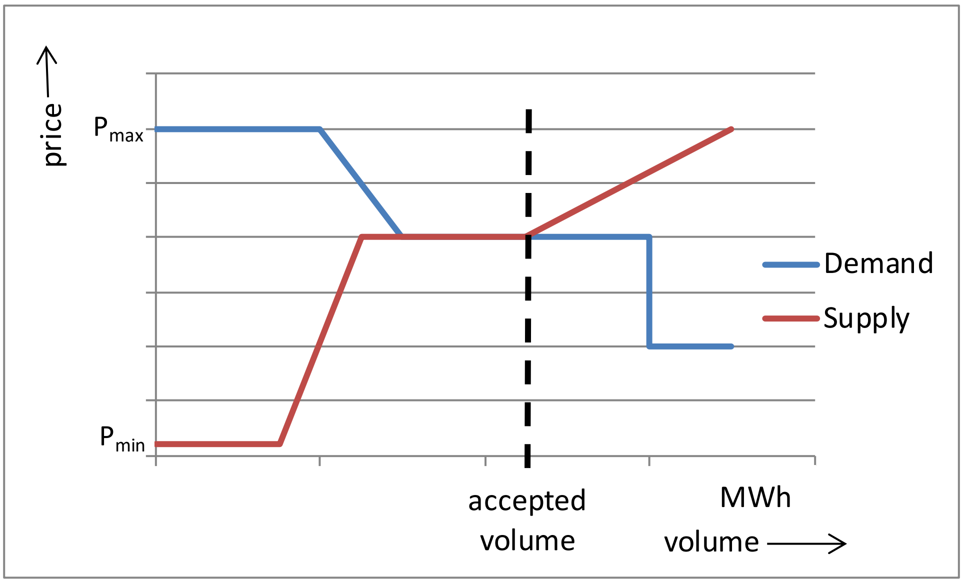


Figure 19 – The accepted volume is maximized

6.8.4. Merit order enforcement

This step enforces merit order numbers of the hourly orders if applicable. The acceptance of hourly orders with merit order numbers *at-the-money* is relaxed and re-distributed according to their acceptance priority. This problem is solved only if the solution found satisfies the PUN requirements (after the PUN search) or if there are no PUN orders but there exist some merit orders.

6.8.5. Flow indeterminacy

The last sub-problems re-attribute flows at the bidding zone, scheduling area and NEMO trading hub levels, to have fully determined rules. This section outlines the high-level principles that are applied. More details on the implementation can be found in the annexes.

Bidding Zone flow indeterminacy

At bidding zone level, scheduled exchanges between pairs of bidding zones are computed. Scheduled exchanges on the lines are based on the linear and quadratic cost coefficients of associate to these lines. Apart from the scheduled exchanges, all other variables are fixed to their predetermined value. This step can only affect the results in situations where there is full price convergence within a meshed network, allowing multiple flow assignments to result in identical *net position*s. By using specific values for the cost coefficients, certain routes will be chosen and unique flows will be determined.

Scheduling Area flow indeterminacy

Where the scheduling area equals to bidding zone then the same rules like for BZ scheduled exchanges shall apply. If there is more than one scheduling area in bidding zone, then scheduled exchanges between pairs of scheduling areas are computed, once bidding zone flows have been determined. In case of cross zonal scheduling area lines thermal capacity constraints are considered to distribute the bidding zone flows among the corresponding SA lines proportionally to their thermal capacities. In case of intra zonal scheduling area lines the SA scheduled exchanges are determined based on the linear and quadratic cost coefficients associated to each intra zonal scheduling area line. Similarly like in case of scheduling calculation at BZ level, by using specific values for the cost coefficients, certain routes will be chosen and unique intra zonal scheduling area flows will be determined.

NEMO Trading Hub flow indeterminacy

Once both inter zonal and intra zonal Scheduling Area flows have been defined, EUPHEMIA will compute the flow corresponding to each existing NTH line. Such flows are computed via the Inter-NEMO Flow Calculation (INFC) module, whose approach aims at minimizing the *net financial exposure* between each pair of Central Counterparties (CCPs) which manage the financial exchanges between NEMOs. The Annex B.3 details the mathematical aspects of this minimization.

If any indeterminacies remain, these are resolved using linear and quadratic cost coefficients associated to each of the NEMO trading hub lines.

Degraded mode

Numerical difficulties might happen (at least in theory) during the SA flow determination or during INFC, as these are themselves based on optimization problems. For such cases, a fallback flow determination approach has been designed in order not to discard a valid market coupling solution. It is based on simple heuristics which will provide sub-optimal solutions, but solutions which are still valid with regards to the business constraints.

See Annex B.3 for more details on the details relative to the degraded mode implementation.

7. Additional Requirements

7.1. Precision and Rounding

EUPHEMIA provides results (unrounded) which satisfy all constraints with a target tolerance. These prices and volumes (flows and *net positions*) are rounded by applying the commercial rounding (round-half-up) convention before being published.

7.2. Properties of the solution

During the execution of EUPHEMIA, several feasible solutions can be found. However, only the solution with the highest welfare value (complying to all network and market requirements) found before the stopping criterion of the algorithm is met is reported as the final solution.

It should be noted that for difficult instances some heuristics[5] are used by EUPHEMIA in its execution. Thus, it cannot be expected that the "optimal" solution is found in all cases.

7.3. Stopping Criteria

As an optimization algorithm, EUPHEMIA searches the solution space for the best feasible solution until some stopping criterion is met. The solution space is defined as the set of solutions that satisfy all the constraints of the problem.

EUPHEMIA is tuned to provide a first feasible solution as fast as possible. However, after finding the first solution, EUPHEMIA continues searching, the solution space for a better solution until a stopping criterion for example the maximum time limit of 10 minutes, is reached or until no more feasible selection of blocks and MIC orders exists.

[5] In mathematical optimization, a **heuristic** is a technique designed for solving a problem more quickly when classic methods are too slow, or for finding an approximate solution when classic methods fail to find any exact solution. This is achieved by trading optimality, completeness, accuracy, and/or precision for speed (Ref-: http://en.wikipedia.org/wiki/Heuristic_(computer_science)).

Additional stopping criteria have also been implemented in the algorithm and can be used. The calculation will stop when one of these criteria is reached:

- **TIME LIMIT**
  This parameter sets a limit to the total running time of EUPHEMIA. However, since the time taken by operations after calculation (e.g. writing of the solution in the database) can be variable, this is an approximate value.

- **ITERATION LIMIT**
  EUPHEMIA can stop after it has processed a given number of nodes.

- **SOLUTION LIMIT**
  EUPHEMIA can stop after it has found a given number of solutions (regardless of their quality).

7.4. Transparency

EUPHEMIA produces feasible solutions and chooses the best one according to the agreed criterion (welfare-maximization). Therefore the chosen results are well explainable to the market participants: published solution is the one for which the market value is the largest while respecting all the market rules.

7.5. Reproducibility

The reproducibility of an algorithm is defined as the capability of the algorithm to reproduce the same results upon request. On the same machine, two subsequent runs with the same input data should find the same solutions, meaning that the intermediate/final solutions found at iteration 'X' are the same. In other words, when the stopping criterion is the number of investigated solutions, a reproducible algorithm can guarantee to obtain the same final result when run on the same machine. However, when the stopping criterion is a time limit, a faster computer will allow the algorithm to investigate more solutions than a slower one. In this case, the reproducibility consists in investigating on the faster computer at least the same set of solutions as the ones investigated on the slower computer.

Mind that with the introduction of PRB reinsertion (cf. section 6.7), another time limit is introduced: the PRB reinsertion process times out too, ahead of the final time limit. This should therefore be understood as a time limit in its own right and reproducibility only applies up until this point.

Annex A. Glossary

Item	Description
Adverse Flow	In market coupling, it is expected that the flow between two bidding zones goes from the market with a lower price towards the market with a higher prices. However, it may happen that, due to some constraints such as the ramping constraint imposed on some interconnectors, the cross-border flow end up being, at some particular periods, in the direction from a higher price bidding zone towards a lower price bidding zone. These flows are commonly known as "Adverse flows" and force the Congestion Rent to be negative.
At-the-money	A supply (demand) order is considered at-the-money if its price is equal to the market clearing price. For blocks this notion is generalized by considering the volume weighted average price.
Bidding zone	A bidding zone is a geographical area to which network constraints are applied. Consequently all submitted orders in the same bidding zone will necessarily be subjected to the same unique price.
Congestion Rent	In an ATC model, the Congestion Rent measures for each interconnector traversed by a flow the difference between the total amount of money to be paid to the supplier of this flow at one end of the interconnector (market clearing price of the supplying bidding zone × the volume of the energy flow through the interconnector) and the total amount of money to be received from the consumer of this flow at the other end of the interconnector (market clearing price of the consuming bidding zone × the volume of the energy flow through the interconnector). It is equal to the product of the cross-border price spread and the implicit flow obtained by Euphemia. The presence of losses on the interconnector will not impact the congestion rent. However, if the interconnector implements tariffs, the congestion rent will be reduced by the product of the tariff rates and the implicit flow obtained by Euphemia.
Consumer Surplus	The Consumer Surplus measures for the buyers whose orders are executed the difference between the maximum amount of money they are offering (limit price of their order × the executed volume of their order) and the amount of money they will effectively pay (market clearing price × the executed volume of their order).
Deep in the money	A supply (demand) order is considered In-the-money if its price is smaller (greater) than the market clearing price plus a specified parameter (Max Delta P).

False paradoxically deactivated complex MIC orders	A false paradoxically deactivated MIC order (false PR MIC) is a deactivated MIC whose economic condition seems to be fulfilled with the MCPs obtained in the final solution (so it seems that it should be activated) but, after acceptance its economic condition is not fulfilled anymore.
Interconnector	a physical connection between two hubs
In-the-money	A supply (demand) order is considered in-the-money if its price is smaller (greater) than the market clearing price. For blocks this notion is generalized by considering the volume weighted average price.
Line	an abstract representation that connects two bidding zones;
Market Clearing Price (MCP)	A common reference price for the whole Market area, when not considering transmission constraints.
Net position (net export position)	The difference between accepted local supply and demand for a bidding zone.
Out of the money	A supply (demand) order is considered out-of-the-money if its price is greater (smaller) than the market clearing price. For blocks this notion is generalized by considering the volume weighted average price.
Paradoxical acceptance of block orders	A block which is accepted while being out-of-the-money.
Price-taking orders	Price taking orders (PTOs) are hourly buy (resp. sell) orders at the maximum (resp. minimum) price. PTOs are not block orders.
Producer Surplus	The Producer Surplus measures for the sellers whose orders are executed the difference between the minimum amount of money they are requesting (limit price of their order × executed volume of their order) and the amount of money they will effectively receive (market clearing price × executed volume of their order).
PUN price	PUN is the average (weighted by purchased quantity of PUN orders) of GME Zonal Market Prices (Italian "physical" zones). PUN is the price to consider accepting/rejecting purchase hourly orders made by PUN orders ("consumption purchase hourly orders").
Social welfare	The Social Welfare is defined as the sum of the Consumer Surplus, the Producer Surplus, and the Congestion Rent.

Annex B. Mathematical Approach

Purpose of EUPHEMIA algorithm is to grant the maximization of welfare, under a set of given constraints:

- network constraints
- clearing constraints
- hourly order acceptance rules
- price network properties
- kill – or – fill conditions
- no PAB constraints
- MIC constraints
- PUN consecutiveness constraints
- PUN imbalance constraints

In order to pursue this issue, EUPHEMIA relies on the concept of duality[6] to calculate prices and volumes on which welfare calculation is based on.

In the case of EUPHEMIA, the primal and dual problem can be synthesized as follows:

Problem	Unit	Variables	Constraints
Primal	MWh	Acceptance of Order Flow between bidding zones	Precedence between orders Network load limitations
Dual	€/MWh	Market Clearing Prices Congestion Rent	Constraints on price differences

[6] Duality is a relationship between two problems, called respectively the primal and dual. Each constraint in the primal problem corresponds to a variable in the dual problem (called its dual variable), and each variable in the primal problem has a corresponding constraint in the dual problem. The coefficients of the objective in the dual problem correspond to the right-hand side of the constraints in the primal problem. When the primal problem is a maximization problem, the dual is a minimization problem and vice-versa. Linear optimization problem is the dual of its dual. In the case of a convex problem, duality theory states that if both primal and dual problems are feasible, the optimal solutions of the primal and dual problems share the same objective value and exhibit a special relationship, called complementary slackness conditions. Specifically, whenever a constraint is not binding in the optimal primal (resp. dual) solution, then the corresponding dual (resp. primal) variable has a value of zero in the optimal dual (resp. primal) solution. Conversely, when a variable has a non-zero value in the primal (resp. dual), the corresponding constraint must be binding in the dual (resp. primal).

Strictly speaking, there are some reasons why the primal and dual problems in EUPHEMIA do not fit exactly in the above duality context.

1. The objective of the primal problem (the social welfare) is quadratic in terms of the acceptance variables. This is due to the interpolated orders: their marginal contribution to the welfare varies with the proportion matched. Fortunately, the Lagrangian duality principle still applies in the context of problems with quadratic objectives.
2. The primal problem contains integer variables. This is due to the presence of binary variables to represent the activation of blocks and complex orders. The linear duality theory unfortunately does not extend immediately to problems with integral variables. However, as soon as all integer variables have been fixed to certain values (that is, for a given selection of blocks and complex orders), then we are back into the regular duality theory context.
3. The dual problem in EUPHEMIA contains additional constraints which do not emerge naturally from the primal problem[7].
4. The coupling problem involves so called primal-dual constraints, i.e. constraints involving both primal and dual variables in their expression[8].
5. Not all dual variables are created. In particular, each order acceptance variable is bound to 1. This constraint should normally have a dual surplus variable, which would then play a role on the admissible prices. Almost all of those constraints would be redundant, so in the dual model of EUPHEMIA the price bounds are computed explicitly, and the surplus variables are not created.
6. The objective of the dual problem used by EUPHEMIA does not correspond to the primal one. Indeed, the objective value is already known from the primal problem and the goal of the dual problem will be to tackle other requirements, e.g. price indeterminacy rules.

Annex B.1. Welfare Maximization Problem

The purpose of the Master Problem is to find a good selection of blocks and complex orders (i.e. all binary variables) satisfying all of their respective requirements. The objective function of this problem is to maximize the global welfare:

$$- \sum_{\substack{m,h,s,o: \\ Step\ Orders}} ACCEPT_{m,h,s,o} q_{m,h,s,o}\ p^{O}_{m,h,s,o} \quad (1)$$

[7] For example: the condition of accepted blocks to be not paradoxically accepted is not naturally met by an optimal primal-dual solution. Intuitively, this is related to the integer nature of the primal problem: by imposing the selection of blocks, we are exposed to the fact that some are losing money individually for the benefit of the social welfare.

[8] For example, the Minimum Income Condition for complex orders involves both the volumes matched (i.e. primal variables) and the market clearing prices (i.e. dual variables). Those constraints can only be formulated in the dual problem by substituting the corresponding primal variables by their optimal value in the primal problem, and reciprocally in dual one.

$$- \sum_{\substack{m,h,s,o: \\ Interpolated\ Orders}} ACCEPT_{m,h,s,o} q_{m,h,s,o} \left(p^{O}_{m,h,s,o} \right.$$

$$\left. + ACCEPT_{m,h,s,o} \ \frac{p^{1}_{m,h,s,o} - p^{O}_{m,h,s,o}}{2} \right) (2)$$

$$- \sum_{bo,h} ACCEPT_{bo} q_{bo,h}\, p_{bo} \ (3)$$

$$- \sum_{m,co,h} ACCEPT_{m,co,h,o}\ q_{m,co,h,o} p_{m,co,h,o} \ \ (4)$$

$$- \sum_{mo} ACCEPT_{mo}\ \ q_{mo} p_{mo} (5)$$

$$- \sum_{l,u,h} Tariff_{l,h}\ FLOW_{l,u,h} (6)$$

$$-M \sum_{\substack{m,h,o: \\ Price\ Taking\ Hourly \\ Demand\ orders}} |q_o\ |(1 - ACCEPT_o)^2 (7)$$

where (bearing in mind that q_o is positive for a supply order and negative for demand orders):

1. is the contribution of hourly step orders
2. is the contribution of hourly interpolated orders
3. is the contribution of block orders
4. is the contribution of complex orders
5. is the contribution of merit orders
6. is the impact of Tariffs
7. This expression is added to the welfare. If the value of M is sufficiently large, it will help minimize the rejected price-taking quantity in all markets, before looking for a solution with a good welfare. The quadratic function will tend to harmonize the curtailment ratios across the curtailed markets if any

Subject to:

- Market constraints
  - Balance/clearing constraints
  - Block order acceptance constraint
  - Complex suborders acceptance constraints
  - Load Gradient constraint
  - Merit order acceptance constraints
- Network constraints
  - ATC constraints
  - PDTF constraints

- Various ramping constraints

Annex B.2. Price Determination Sub-problem

For each feasible solution of the primal problem, EUPHEMIA solves the following price problem:

$$\min_{prices} distance\ to\ mid\ point$$

i.e.:

$$min \sum_{m,h} \left(MCP_{m,h} - \frac{UpperBound_{m,h} + LowerBound_{m,h}}{2} \right)^2$$

Subject to:

- complementarity slackness conditions
- price bounds
- no PAB constraints
- Minimum Income Condition
- PUN imbalance

Note in case of price indeterminacy where either the lower bound is at minimum price, or the upper bound is at maximum price, a satellite bidding zone, defined as a bidding zone with only simple hourly orders of one type, all supply or all demand (including PTOs), that is connected with a single ATC line with the rest of the topology, no losses, no tariff, no ramping, doesn’t participate to price determination sub-problem. When all the submitted volume is matched and equal to the ATC value the price in the satellite bidding zones will be set to the price of the adjacent bidding zone.

Annex B.3. Flow calculation models

This section outlines the different models that Euphemia solves, to uniquely establish scheduled exchanges at the bidding zone, scheduling area and NEMO trading hub levels respective. See section 6.8.5.

This model shall be compatible with the eventual TSO DA Scheduled Exchanges Calculation Methodology.

Bidding Zone flow calculation

This step aims at uniquely define the flow results between bidding zones, in case indeterminacies remain. It uses linear and quadratic cost coefficients associated to each of the BA lines: Euphemia minimizes the following function:

$$\min\left(\sum_{h}\sum_{l}\left(lc_{l} * \left(f_{l,h,up} + f_{l,h,down}\right) + \ qc_{l} * \left(f_{l,h,up}^{2} + f_{l,h,down}^{2}\right)\right)\right)$$

Where *h* represents the periods, *l* the lines (both ATC and FB), *up* and *down* the direction of the line, *lc* and *qc* the linear and quadratic cost coefficients of a line, and *f* the flow variables to be determined.

Scheduling Area flow calculation

The objective function of scheduling area flow calculation model is comparable to the one from the BZ flow calculation, but here the flows (or exchanges) between scheduling areas are considered when minimizing linear and quadratic flow function:

$$\min\left(\sum_{h}\sum_{sl}\left(lc_{sl} * \left(f_{sl,h,up} + f_{sl,h,down}\right) + \ qc_{sl} * \left(f_{sl,h,up}^{2} + f_{sl,h,down}^{2}\right)\right)\right)$$

Where *h* represents the periods, *sl* the Scheduling Area lines, *up* and *down* the direction of the line, *lc* and *qc* the linear and quadratic cost coefficients of the line, and *f* the flow variables to be determined.

Moreover following constraint need to be satisfied to pro-rates cross border exchanges across the underlying scheduling area flows[9] according to installed thermal capacities:

$$\left(f_{sl,h,up} + f_{sl,h,down}\right) = \frac{TC_{sl}}{\sum TC_{sl}} * \left(\overline{f_{l,h,up} + f_{l,h,down}}\right)$$

Where *h* represents the periods, *l* the BZ lines, *ls* the Scheduling Area lines, *up* and *down* the direction of the Scheduling Area or BZ line,

[9] In case both bidding zones only have a single scheduling area, the full bidding zone flow will flow between the scheduling areas.

TC_{sl} the Thermal Capacity of the Scheduling Area line and $\overline{f_{l,h,up} + f_{l,h,down}}$ represents flows of the BZ lines being parent of the underlying Scheduling Area lines *sl*.

Calculation of Scheduled Exchanges between NEMO trading hubs

1. The Scheduled Exchange Calculator shall calculate the Scheduled Exchanges between NEMO trading hubs based on NEMO trading hubs' net positions.
2. The calculation of Scheduled Exchanges between NEMO trading hubs aims at minimizing the Net Financial Exposure (hereinafter referred to as "NFE") between the central counter parties associated to each NEMO (hereinafter referred to as "CCP"). The NFE between two pairs of CCPs is expressed with relation to the Scheduled Exchanges between the NEMO trading hubs of their corresponding NEMO as follows:

$$NFE_{A|B} = \sum_{h \in H} \sum_{l \in L_{A,B}} P_B^h * \left(1 - loss_{n_1,n_2}\right) flow_{n_1,n_2}^h - P_A^h * \left(1 - loss_{n_2,n_1}\right) flow_{n_2,n_1}^h$$

with:
- A, B being two different CCPs
- $L_{A,B} = \{l = (n_1, n_2) \in L^d \mid ccp(n_1) = A \wedge ccp(n_2) = B\}$ being the set of all lines linking NEMO trading hubs of NEMO corresponding to CCP A and NEMO trading hubs of NEMO corresponding to CCP B. L^d is the set of all directed lines connecting two NEMO Trading Hubs.
- $ccp(n_1)$, $ccp(n_2)$ is a function giving the CCP corresponding to NEMO trading hub n_1 and n_2 respectively
- P_A^h, P_B^h is the clearing price for bidding zone of CCP A and B respectively for market time unit h
- $flow_{n_1,n_2}^h$ is the Scheduled Exchange from NEMO trading hub n_1 to NEMO trading hub n_2 for market time unit h
- $loss_{n_1,n_2}$ is the loss associated to the network constraint underlying scheduled exchange, or 0 if no such constraint exists
- h is the market time unit and H is the set of all market time units

The net financial exposure $NFE_{A|B}$ of a CCP A with regards to a CCP B expresses the financial risk that B will induce on A. As can be seen, it is netted over all BZs and periods. A net financial exposure can either be positive or negative. Also, it can be shown that $NFE_{A|B} = -NFE_{B|A}$ (therefore, as soon as it is non-null, they shall have opposite signs). The sum of all net financial exposures among all pairs of CCPs shall always be zero (financial balance).

3. The NFE is firstly minimized using a sum of quadratic terms

$$\min \sum_{c \in CCP} \sum_{c' \in CCP \setminus \{c\}} \left(NFE_{c|c'}\right)^2$$

with:
- CCP is the set of all the CCPs
- c is a CCP
- c' is other CCP different than CCP c

4. A second minimization problem is applied using linear and quadratic cost coefficients to avoid any indeterminacies and define a solution consistent with the Scheduled Exchanges between scheduling areas calculated.

$$\min\left(\sum_{i=1}^{n} lc_i * flow_{n_1,n_2}^{h} + \sum_{i=1}^{n} qc_i * \left(flow_{n_1,n_2}^{h}\right)^2\right)$$

with:

• lc_i is linear cost coefficient associated to of NEMO trading hub border i

• qc_i is quadratic cost coefficient associated to of NEMO trading hub border i

• $flow_{n_1,n_2}^{h}$ is the Scheduled Exchange from NEMO trading hub n_1 to NEMO trading hub n_2 for market time unit h

• n is total number of NEMO trading hub borders considered in the optimization, meaning Scheduled Exchange from NEMO trading hub n_1 to NEMO trading hub n_2

Degraded mode

The first step computes the "inter-BA" SA and NTH flows. Given the SA line thermal capacities, the flows on the BA lines are split among the SA lines. Then the flow on each SA line is assigned to the corresponding NTH line with the smallest linear cost-coefficient. In case there exist more than one NTH line with the same lowest linear cost coefficient, the flows are split equally.

The second step computes the "intra-BA" SA and NTH flows. This step will be applied to all bidding zones separately. We use the term inner-BA net position to describe the value of the NTH net position increased by the incoming flows on inter-BA NTH lines and decreased by the outgoing flows on inter-BA NTH lines.

The heuristic computes the flows on intra-BA NTH lines by solving a minimum-cost maximum flow problem. To model the problem, we add a source and a sink node to the bidding zone's NTH topology. We add lines between the source node and all NTH with positive inner-BA net position and use the inner-BA net positions as capacities on these lines.

In the same way, we connect the NTHs with negative inner-BA net position to the sink node. All other lines correspond to intra-zonal nemo lines, and only the linear cost coefficients are applied. Given this input, a combinatorial minimum-cost maximum flow algorithm can be used to compute the flows on the NTH lines. The intra-BA SA flows are determined using the sum of the flows on the corresponding NTH lines.

Note that with this fallback, intra-BA inter-SA area NTH flows may not necessarily follow the same direction as the corresponding SA flow.

Annex B.4. Indexes and Annotations

m	Bidding zone
h	Period
s	Supply/Demand
c	Curve identified by *m,h,s*
o	Hourly Order identified by *m,h,s,o*
bo	Block Order
mo	Merit order
po	PUN order
co	Complex Order , where • complex curve is identified by *m,co,h* • complex suborder by *m,co,h,o*
l	(DC/ATC) Line
uu(convention: up=0 and down=1)	Up/Down direction
ACCEPT [0;1]	Acceptance variables
p	Offered Price
q	Offered Volume
MCP	*Market clearing price*

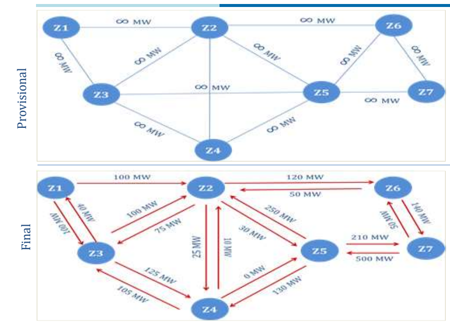
Annexure - 6

PXIL
Transforming Power Markets

Individual PX vs Combined Platform
-
Market Clearing and Social Welfare Maximisation

August 2023

Flow optimisation - sample

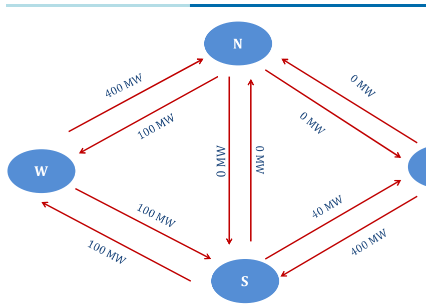


- Zone
  a. Multiple Buyers and Sellers
  b. Exclusively Buyer or Seller
- Infinite transmission capacity in all links
- Provisional matching identifies Buyers and Seller

Post Provisional matching
- Zone
  a. Multiple Buyers and Sellers
  b. Exclusively Buyer or Seller
- Power
  a. Net requirement
  b. **'Sink' or 'Source'**

Requisition to NLDC
- Quantum 'in MW' of inter-zonal flow
  a. G-DAM
  b. Conventional-DAM
  c. HP-DAM
  d. Combined/Integrated

Available Transmission Capacity - declared



Direction	Declared
N to W	100
W to N	400
W to S	100
S to W	100
S to E	40
E to S	400
E to N	0
N to E	0
N to S	0
S to N	0

Assumption – Individual Clearing vs Combined Clearing

- Bids are received at three PXs
  - Four Zones are considered – even though 13 bid zone exist
- Liquidity conundrum
  - Different participants may participate on each PX
  - A participant may not submit bids on two or more PXs
  - All PXs do not receive multiple buyers and/or Sellers in each Zone
- Combined PX
  - Enables reduction in uncleared quantum
  - Increases Social Welfare
  - Enhances clearing oppurtunity for marginal participant of smaller PX

PX1 - sample Order book

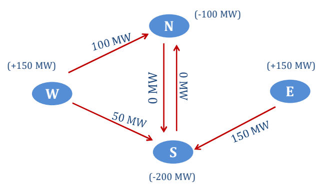
- PX1 receives below bids till 'gate closure':

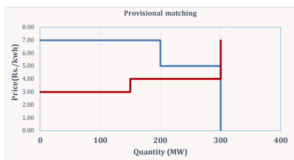
Buy bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Buyer 1	5	100	North
Buyer 2	7	200	South

Sell bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Seller 1	4	150	West
Seller 2	3	150	East





MCP (Rs. /kWh) = Rs. 4.50	MCV = 300 MW
Social Welfare = 850	

PX2 - sample Order book

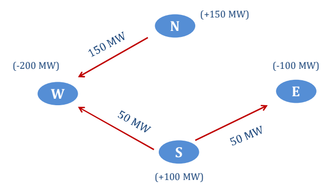
- PX2 received below bids till 'gate closure'

Buy bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Buyer 3	4	100	East
Buyer 4	6	200	West

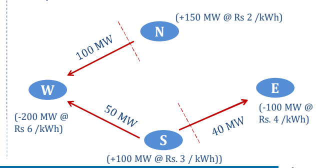
Sell bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Seller 3	2	150	North
Seller 4	3	100	South



Constraint for flow:

- Export from North to West restricted to 100 MW
- Export from South to East restricted to 40 MW



PX2 - sample Order book

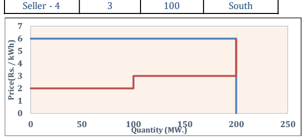
- Market split in PX2 in two parts

Part -1

Surplus	Deficit
North	West and South

Surplus

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Buyer 4	6	200	West
Seller - 3	2	100	North
Seller - 4	3	100	South



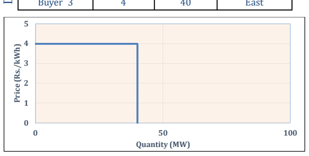
MCP (Rs. /kWh) = Rs. 4.50	MCV = 200 MW
Social Welfare = 700	

Part - 2

Surplus	Deficit
South and West	East

Deficit

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Buyer 3	4	40	East



MCP (Rs. /kWh) = 0	MCV = 0 MW
Social Welfare = 0	

PX3 - sample Order book

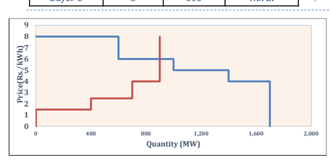
- PX3 receives below bids till 'gate closure':

Buy bids

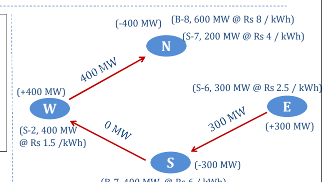
Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Buyer 5	4	300	West
Buyer 6	5	400	East
Buyer 7	6	400	South
Buyer 8	8	600	North

Sell bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
Seller 5	1.5	400	West
Seller 6	2.5	300	East
Seller 7	4	200	North



MCP (Rs. /kWh) = Rs. 6	MCV = 900 MW
Social Welfare = 4450	



Coupling of Orders

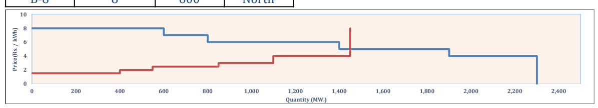
- Bids from all three PXs are combined

Buy bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
B-1	5	100	North
B-2	7	200	South
B-3	4	100	East
B-4	6	200	West
B-5	4	300	West
B-6	5	400	East
B-7	6	400	South
B-8	8	600	North

Sell bids

Participant	Price (Rs. / kWh)	Qty (in MW)	Location (region)
S-1	4	150	West
S-2	3	150	East
S-3	2	150	North
S-4	3	100	South
S-5	1.5	400	West
S-6	2.5	300	East
S-7	4	200	North



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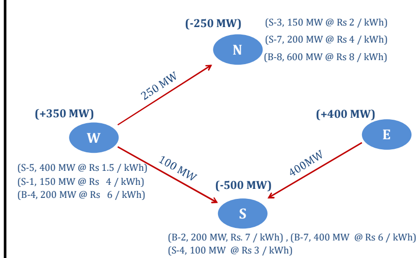
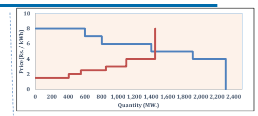
Coupling of Orders

- Bids from three PXs are combined





Direction	Declared	Required	Issued	Utilised
N to W	100	0	100	
W to N	**400**	**250**	**250**	**250**
W to S	**100**	**100**	**100**	**100**
S to W	100	0	100	
S to E	40	0	40	
E to S	**400**	**400**	**400**	**400**

MCP (Rs. /kWh) = Rs. 5	**MCV = 1450 MW**
Social Welfare = 6250	

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Conclusion

- Platform wise MCV and Social Welfare
  - Utilise Transmission capacity issued by NLDC
  - Bids received in PX-2 platform are exposed to constraint
    - Export from North to West
    - Export from East to South

Platform	SW	MCV (in MW)	Uncleared
PX-1	850	300	
PX-2	700	200	
PX-2	4,450	900	47%
Subtotal	**6,000**		
Combined	**6,250**	**1,450**	**38%**

Social Welfare of combined bids is more than summation of individual Social Welfare at different platforms

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THANK YOU

PXIL
Transforming Power Markets

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CIN:- U74900MH2008PLC179152

part of eex group

epexspot

Trading at EPEX SPOT

About EPEX SPOT

The European Power Exchange EPEX SPOT SE operates organised short-term electricity markets with 24/7 market operation services. In 2021, our community of over 300 companies has traded 621 TWh of electricity on EPEX SPOT representing roughly 30% of the European electricity consumption (source: eurostat).

From Day-Ahead to Intraday trading, After-Market and Local Flexibility products – EPEX SPOT is your partner in trading – boosting innovation and providing a truly pan-European offer across the entire trading value chain.

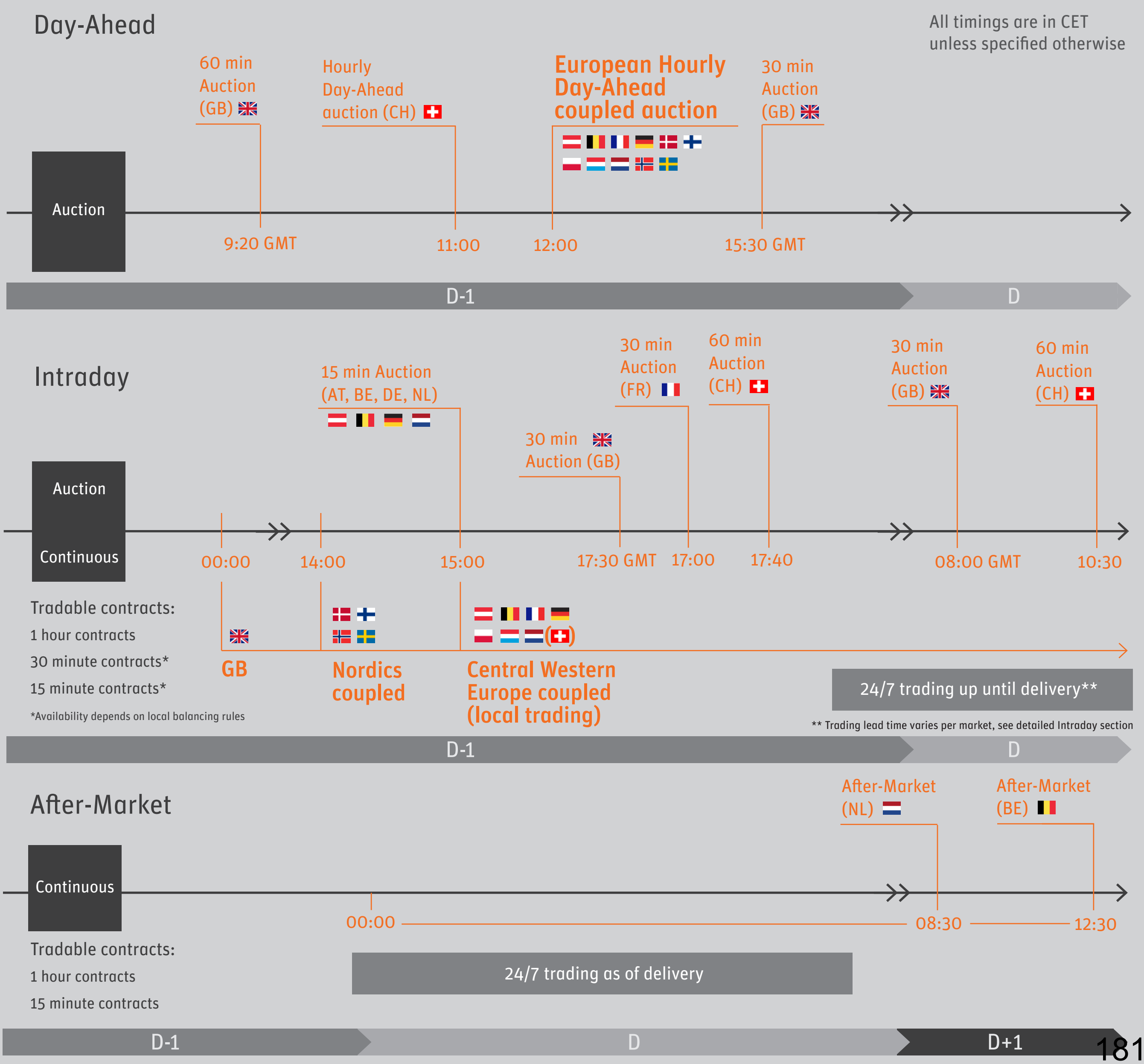
Market Areas: Austria, Belgium, France, Germany, Great Britain, Luxembourg, The Netherlands, Switzerland, Denmark, Finland, Norway, Sweden and Poland.

EEX Group 51%

TSOs Holding
Amprion / APG / Elia / RTE / Swissgrid / TenneT
49%

epexspot

EPEX SPOT is a European company (Societas Europaea) in corporate structure and staff, based in Paris with offices or affiliates in Amsterdam, Berlin, Bern, Brussels, London and Vienna. EPEX SPOT is held by EEX Group, part of Deutsche Börse, and HGRT, a holding of European electricity transmission system operators.



Markets and volumes

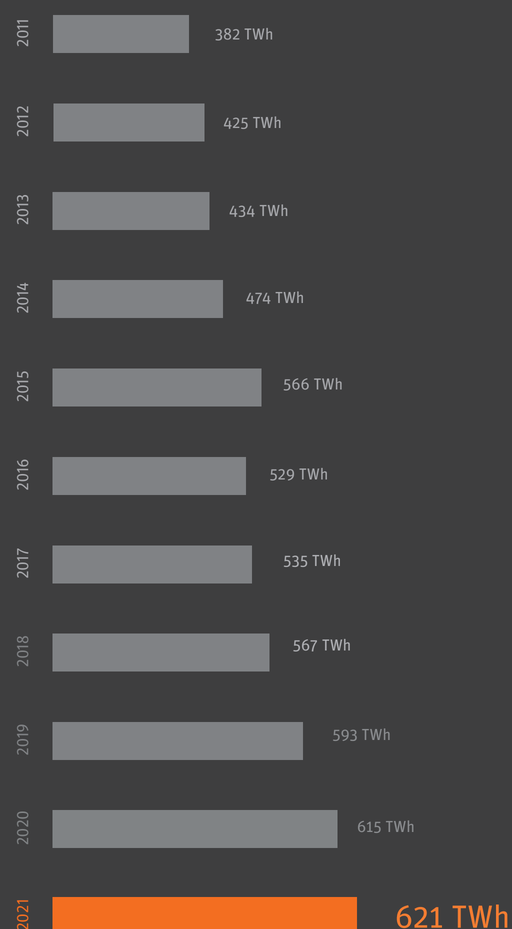
EPEX SPOT markets

Coming soon

Serviced Power Exchanges

Exchange members

- Utility / Aggregator
- Local Supplier / Consumer
- Trading Company
- Transmission System Operator
- Bank and financial service provider



EPEX SPOT is your partner in trading

Innovation

All products and innovations at EPEX SPOT are developed in close cooperation with our customers. The Exchange Council represents our trading community and makes sure all products and innovations are discussed and decided upon jointly with the market.

Member first

With 24/7 market operations call support, geographical proximity, data & reporting services - we are at your service to ensure the most performant and complete trading experience.

Secured markets

Trade with confidence at each step of the process: starting from key safety settings and trade cancellation possibilities on our trading systems; to proven default risk management with our trusted Clearing House, ECC. Our Market Surveillance Office also ensures the markets are running in a fair and orderly manner with their proven expertise.

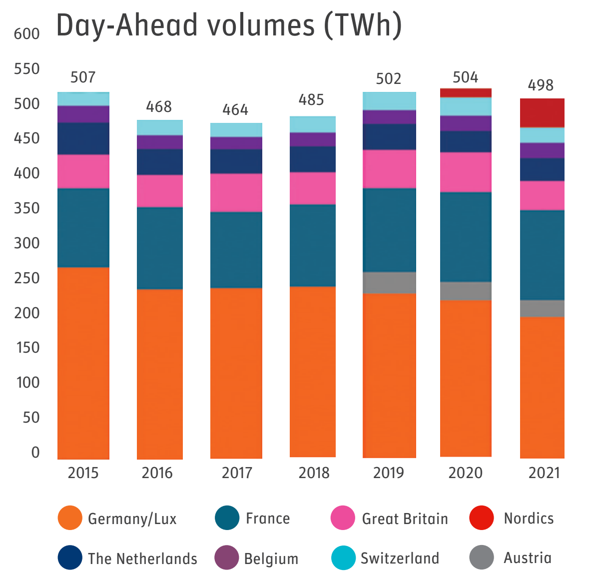
› dayahead

EPEX SPOT operates daily Day-Ahead auctions that are part of the European Market Coupling.

The Day-Ahead price, in particular, the German Phelix™, has become a European reference thanks to its underlying liquidity. Apart from Great Britain and Switzerland, all markets are part of the Single Day-Ahead Coupling (SDAC) which stretches across 20 markets from Portugal to Finland and from Ireland to Poland.

Coupled auction market areas: Austria, Belgium, France, Germany, Luxembourg, The Netherlands, Denmark, Finland, Norway, Sweden and Poland.

Local auction market areas: Great Britain and Switzerland



Tradable Contracts

24 hourly contracts are available on the auction, corresponding to the 24 hours of the following day. Hour 1 starts at 24:00 and ends at 1:00, hour 24 starts at 23:00 and ends at 24:00. Contracts can be traded either in single hours or in blocks of combined hours.

Single hours

Orders contain up to 256 price/quantity combinations for each hour of the following day. The 256 prices are not necessarily the same for each hour. A volume – whether positive, negative or nil – must be entered at the price limits. A price-inelastic order is sent by putting the same quantity at the price limits.

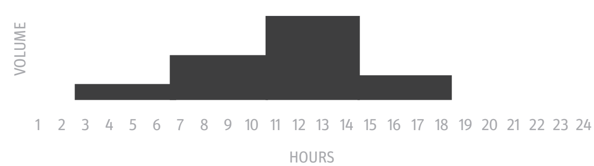
Blocks

Block Orders encompass several hours at the same price. A block order is executed at the same ratio on all its hours.

Specific conditions:

- Maximum volume per classic block order is 600 MW in DE/LU, AT and FR, 500 MW in DK, FI, GB, NO, PL and SE, 600 MW in NL and BE and 150 MW in CH
- Either buy or sell
- Can be either entirely executed or entirely rejected (All-or-None); or executed above a minimum acceptance ratio defined by traders **(curtailable blocks)**
- Volumes can be different across hours (profiled blocks):

Profiled Blocks:



Smart and big blocks

Smart and big blocks portfolios are classic portfolios with the additional functionality allowing the submission of linked, exclusive and big blocks.

- **Linked blocks** are a set of blocks with a linked execution constraint, meaning the execution of one block depends on the execution of its father block. They allow to represent the variation of electricity generation with regards to the market price.
- **Exclusive blocks** are a group of blocks within which a maximum of one block can be executed, so that electricity is traded at the most profitable moment.
- **Big blocks** are larger than classic blocks with the maximum size going up to 1500 MW and allows to cover large produc tion capacities.
- **Loop blocks** are families of two blocks which are executed or rejected together. They allow to bundle buy and sell blocks to reflect storage activities.

60 min Day-Ahead Auctions

Trading Procedure

A blind auction takes place once a day, 365 days a year. Results are published as soon as possible from 12:57 for all Day-Ahead coupled markets; as soon as possible from 11:10 for Switzerland. The order book opens 45 days in advance and closes one day before delivery at 12:00 for all Day-Ahead coupled markets, at 11:00 for Switzerland.

Clearing and Settlement

EPEX SPOT transmits trade information to the central counterparty, European Commodity Clearing (ECC), for settlement and delivery. ECC nominates to the concerned TSO on behalf of the Exchange Member 4 times per hour until the local nomination deadline.

Minimum and maximum prices

Min: -500 €/MWh
Max: 4000 €/MWh

Delivery Zones

50Hertz, Amprion, APG, Elia, NationalGrid, RTE, Swissgrid, TenneT DE & NL, TransnetBW, Energinet, Fingrid, PSE, Statnett, Svenska kraftnät

Minimum price/ volume increment

Price tick: 0.1 €/MWh
Volume tick: 0.1 MW

API (Application Programming Interface)

Order submission and results retrieval are both available through API access, in addition to the client access.

Local GB 60 min Day-Ahead Auction at 9:20 and 30 min Day-Ahead Auction at 15:30

Since 31 December 2020, Great Britain has decoupled from the Internal Energy Market (IEM) and European Single Day-Ahead Coupling (SDAC) due to Brexit. To accommodate this change, the GB 60 min Day-Ahead auction timing has been moved up from 11:00 GMT to 9:20 GMT – allowing market participants to quickly react to the results of the daily interconnectors capacity auctions.

The GB 30 min Day-Ahead auction at 15:30 GMT allows market participants to trade half hour contracts and offers further arbitrage opportunities.

Trading Procedure

An auction takes place once a day, 365 days a year. Results are published as soon as possible from 9:30 GMT and 15:45 GMT respectively.

Minimum price/volume increment

Price tick: 0.1 £/MWh
Volume tick: 0.1 MW

Minimum and maximum prices

Min: -500 £/MWh
Max: 6000 £/MWh

API (Application Programming Interface)

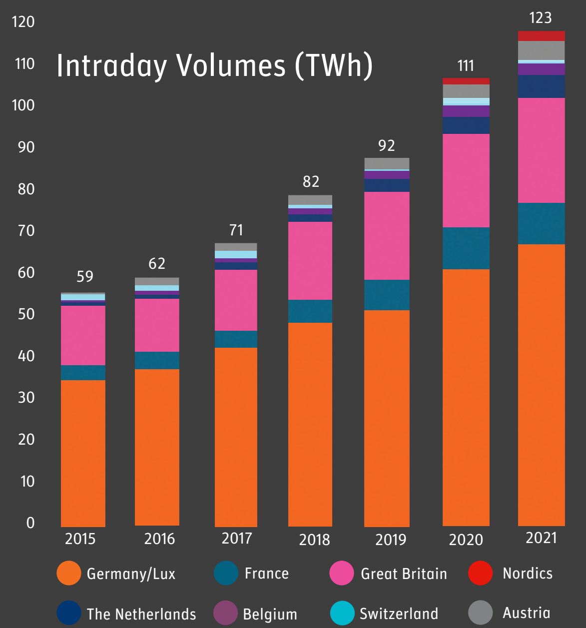
Order submission and results retrieval are both available through API access, in addition to the client access.

› intraday

Our Intraday markets cover the entire European region: CWE, Nordics and Poland. Intraday markets are mainly used for:

- Plan generation and adjust purchases & sales closer to delivery
- Managing forecast errors or unforeseen events
- Adjusting from hourly positions to finer granularities (30 min or 15 min)
- Offering flexible generation as a substitution for renewables
- Enabling cross-border arbitrage and trading

The Intraday market is divided into continuous and auction trading. All Intraday continuous markets of EPEX SPOT run on the M7 trading system, an industry-standard in terms of performance. These markets are by far the most liquid Intraday markets in Europe.



Continuous Markets

Trading Procedure

24/7

- Continuous trading 7 days a week, 24 hours a day, all year around

Minimum price/ volume increment

Price tick: 0.01 €/MWh
Volume tick : 0.1 MW

Minimum and maximum price

Min: -9999 €/MWh (GB: -500 £/MWh)
Max: 9999 €/MWh (GB: 6000 £/MWh)

Tradable Contracts

1 hour contracts
30 minute contracts
15 minute contracts

API (Application Programming Interface)

Versatile, performant and standardized API services are available for order submission and results retrieval, in addition to the client access.

Lead Time

30

- FI: 0 minutes
- AT, BE, DE, NL: 5 minutes
- GB: 15 minutes for 30 minutes contracts
- FR: 30 minutes
- CH: 30 minutes
- Cross-border (SIDC markets): 60 minutes

The lead time is the time between the end of the trading session and the start of the delivery period.

Clearing and Settlement

ECC nominates to the concerned TSO on behalf of the exchange member every 15 minutes.

Delivery Zones

50Hertz, Amprion, APG, Elia, NationalGrid, RTE, Swissgrid, TenneT DE & NL, TransnetBW, Energinet, Fingrid, PSE, Statnett, Svenska kraftnät

Trade Registration

OTC clearing services allowed for hourly and block orders.

DE, AT, BE & NL 15 min, FR 30 min, and CH 60 min Intraday auctions

Trading Procedure

A blind auction takes place once a day, 365 days a year. Results are published as soon as possible from the given times below. The order book opens 45 days in advance. All timings are in CET/CEST.

Closure of order book: DE 15:00, AT 15:00, BE & NL 15:00, FR 17:00
CH IDA1 17:40, CH IDA2 10:30

Results publication: DE 15:10, AT 15:20, BE & NL 15:40, FR 17:15
CH IDA1 17:55, CH IDA2 10:45

Tradable contracts: DE 15 min, AT 15 min, BE & NL 15 min, FR 30 min
CH IDA1 60 min, CH IDA2 60 min

Clearing and Settlement

EPEX SPOT transmits trade information to the central counterparty, ECC, for settlement and delivery. ECC nominates to the concerned TSO on behalf of the Exchange Member until the local nomination deadline.

Minimum and maximum prices

Min: -3000€/MWh (CH IDA1 & IDA2: -500/MWh)
Max: 4000€/MWh

Minimum price /volume increment

Price tick: 0.1€/MWh
Volume tick: 0.1MW

GB 30 min Intraday coupled auctions with Ireland

Trading Procedure

A blind auction takes place twice a day, 365 days a year in GB. Results are published as soon as possible from the given times below. The order book opens 14 days in advance. Timings are in GMT/BST.

Closure of order book: GB IDA1 17:30, GB IDA2 8:00
Results publication: GB IDA1 18:00, GB IDA2 8:30
Tradable contracts: GB IDA1 30 min, GB IDA2 30 min

Clearing and Settlement

EPEX SPOT transmits trade information to the central counterparty, ECC, for settlement and delivery. ECC nominates to the concerned TSO on behalf of the Exchange Member until the local nomination deadline.

Minimum and maximum prices

Min: GB -150 £/MWh
Max: GB 3000 £/MWh

Minimum price/volume increment

Price tick: GB 0.1 £/MWh
Volume tick: 0.1MW

› aftermarket

The After-Market is a new product on the continuous trading segment where you are able to adjust your physical positions in the ex-post timeframe, once the final information on production and consumption are available. It can be instrumental in reducing imbalance settlement costs. The products are available on the M7 trading system – allowing you to trade Intraday & After-Market through one trading screen.

Trading Procedure

Countries: BE & NL

Opening of the trading session: at delivery start

Closure of trading (CET): BE 12:30 on the Day after Delivery (D+1), NL 8:30 on the Day after Delivery (D+1)

Minimum and maximum prices

Min: -9999€/MWh
Max: 9999€/MWh

Minimum price /volume increment

Price tick: 0.01€/MWh
Volume tick: 0.1MW

How to become a member

1. Contact us to find the membership that suits you best
   E-mail: sales@epexspot.com, Tel +33 1 73 03 62 62
2. Find a clearing bank or sign a direct clearing agreement with ECC
3. Become a Balance Responsible Party
4. Follow the admission process including the trader exam
5. Start trading

More services: E-learning, Market Data & API offers

Exchange members and third parties can benefit from a range of additional services:

- e-learning, to better understand the power market and take the trader exam
- market data and indices, as soon as available, to derive crucial market insights
- API solutions, to customize and automate your trading experience

Contact us: **marketdata.sales@epexspot.com**
elearning@epexspot.com
Link to webshop: **https://webshop.eex-group.com**

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Continuous Intraday Hotlines
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Product Specifications

German Market Area

Nord Pool AS

CONTENTS

1. INTRODUCTION

1.1 Scope

This Product Specifications for the German market area relate to the Physical Markets organized by Nord Pool, and form part of the Rulebook. Further rules and regulations regarding each market are set out in the Intraday Market Regulations, and the Day-ahead Market Regulations as applicable.

1.2 Time references

References to points in time refer to CET time, and unless otherwise specified time is denoted in the 24-hour format. Date references are to calendar days unless otherwise specified.

Short-clock change:

On the short-clock change day in March (beginning of summer savings time), there will only be 23 hours so that the clock hour between 02:00 and 03:00 will be skipped on that day. The length of all Products comprising several Delivery Hours that are directly affected by the clock change will be 1 hour shorter than normal.

Long-clock change:

On the long-clock change day in October (end of summer savings time) there will be 25 hours, so that the clock hour between 02:00 and 03:00 will occur twice, i.e. an additional Product will be listed corresponding to 02:00 - 03:00 CET. The length of all Products comprising several Delivery Hours that are directly affected by the clock change will be 1 hour longer than normal.

1.3 Cash Settlement

Cash Settlement for Deliveries taking place on each Delivery Day will take place as follows, regardless of Product Series:

For the Intraday Market:
- For each invoice with net Cash Settlement Amounts owing to Nord Pool: D + 2
- For each invoice with net Cash Settlement Amounts owing from Nord Pool: D + 3

For the Day-ahead Market:
- For each invoice with net Cash Settlement Amounts owing to Nord Pool: D
- For each invoice with net Cash Settlement Amounts owing from Nord Pool: D + 1

Further rules and procedures relating to Cash Settlement and Delivery are set out in the Rulebook.

2. DAY-AHEAD MARKET

2.1 General

- **Quotation Method:** Continuous submission of Orders until Gate Closure, following qualifying Orders will be matched using the Auction method set out in the Day-ahead Market Regulations.
- **Trading Hours:** The coming 24 hours starting from 00:00 CET.
- **Gate Closure:** 12:00 CET
- **Trade Lot:** 0,1 MW

- **Tick Size:** Euro 0,01/MWh
- **Currency:** Euro
- **Order Types:** (a) Hourly Orders, (b) Block Orders, (c) Exclusive Groups, (d) Flexible Orders*
- **Block Order Volume Limit:** 900 MW
- **Minimum number of consecutive hours in Block Orders:** 1 hour
- **Maximum amount of Block Orders:** 100 per Trading Portfolio
- **Maximum amount of Exclusive Groups:** 5 per Trading Portfolio
- **Maximum amount of Block Orders within an Exclusive Group:** 24
- **Linked Block Orders:** Seven levels, maximum 6 Block Orders per level, maximum 13 total Block Orders in a linked block group
- **Spread Block Orders:** One buy block and one sell block mutually linked, maximum 3 pairs of spread blocks per portfolio
- **Price Steps:** The number of Price Steps is 200 per hour (including the upper and lower Order Price Limits)
- **Lower Technical Order Price Limit:** Euro – 500
- **Upper Technical Order Price Limit:** Euro + 4000
- **Maximum Price Threshold:** Euro + 2400
- **Minimum Price Threshold:** Euro -500
- **Delivery:** Per applicable Delivery Period and pursuant to the Clearing Rules.
- **Cash Settlement:** See item 1.3 above. Settlement calculations will be based on actual Deliveries per Delivery Hour on each applicable Delivery Day.

* Flexible orders are a part of the Exclusive Groups orders

2.2 Day-ahead Market Contract Codes:

The following Contract Codes are used to identify CWE Day-ahead products:

Type	Prefix (fixed)	Example
1 hour	CWE_H_DA_1	CWE_H_DA_1-20190310-01 Year 2019, March 10th, hour 1

Suffix (variable)	Explanation	Range
dd	Day of month (two digits)	01 - 31
mm	Month of year (two digits)	01 - 12
yyyy	Year (four digits)	Current year (next year)
nn	Clock hour	00:00 – 24:00

Effective from: 15 June 2023

2.3 Day-ahead Market Trading Hours

The time (gate opening) from which Orders for Contracts within a Delivery Day (starting on 0:00h and ending on 24:00h) may be submitted, will normally occur 60 days prior to the start of such day provided that, Nord Pool may, in its sole discretion, postpone the gate opening, for example, but not limited to, in case of technical or operational reasons.

3. INTRADAY MARKET

A. CONTINUOUS TRADING

3.1 General

- **Quotation method**: Continuous trading during Trading Hours where Transactions will be matched automatically when concurring Orders are registered in the Trading Platform.
- **Trading Hours:** a series of delivery hours for the following day are listed and opened for Trading from 08:00 until 13:45 CET and from 15:00 until 20 minutes before delivery commences.
- For Germany within each TSO area series of delivery hours for the following day are listed and opened for Trading from 08:00 until 13:45 and from 15:00 until delivery commences.
- **Trade Lot:** 0,1 MW
- **Tick Size:** Euro 0,01/MWh
- **Currency:** Euro
- **Order Types:** (a) Limit, (b) Fill-or-Kill Order, (c) Immediate-or-Cancel, (d) Iceberg Order (minimum Clip Size 5 MW),
- **Products:** (a) 1 Hour, (b) Half Hour, (c) Quarterly hour, (d) Block Order
- **Order quotation:** Please see Section 3 of the Intraday Market Regulations.
- **Lower Technical Order Price Limit:** Euro -9 999
- **Upper Technical Order Price Limit:** Euro +9 999
- **Delivery:** As specified in relation to each Product and per applicable Delivery Period, see sections 3.3 below and 1.3 above and pursuant to the Clearing Rules.
- **Cash Settlement:** See item 1.3 above.

3.2 Available Products

- Quarterly Hour,
- Half Hour,
- 1-Hour,
- Block Order

3.3 Continous Trading contract code

The following Contract Codes are used to identify the Intraday Market Products in the Trading Platform:

Type	Prefix (fixed)	Suffix (variable)	Example
1 Hour	PH-	yyyymmdd-ph	PH-20140517-01 = Year 2014, May 17th – Hour 01
Half Hour	HH-	yyyymmdd-hh	HH-20140517-08 = Year 2014, May 17th – 2nd Half hour of PH-04
Quarterly Hour	QH-	yyyymmdd-qh	QH-20140517-15 = Year 2014, May 17th – 3rd Quarter of PH-04
User Defined Block Orders	PH-<Suffix>-PH-<Suffix>	yyyymmdd-ph	PH-20140517-01- PH20140517-04 = Year 2014, May 17th – Hour 01 to hour 04

Suffix (variable)	Explanation	Range
Yyyy	Year (four digits)	Current year (next year)
Mm	Month of year (two digits)	01-12
Dd	Day of month (two digits)	01-31
PH	Hour of day (two digits)	01-24
HH	Half hour of day (two digits)	01-48
QH	Quarter of day (two digits)	01-96

B. INTRADAY AUCTIONS

3.4 General

- **Quotation Method:** Submission of Orders from the Intraday Auction Gate Opening until the Intraday Auction Gate Closure as specified for the relevant Auction in the table below (see paragraph 3.4), following which, qualifying Orders will be matched using the Auction method set out in the Intraday Market Regulations (B. Intraday Auctions).
- **Delivery Period:** The 24 or 12 hours, respectively, as specified for the relevant auction in the table below (see paragraph 3.4) following the Intraday Auction Gate Closure of the relevant Intraday Auction.
- **Trade Lot:** 0,1 MW
- **Tick Size:** Euro 0,01/MWh
- **Currency:** Euro
- **Order Types:** Curve Orders and Block Orders – granularity as specified for the relevant auction in the table below (see paragraph 3.4)
- **Block Order Volume Limit:** 900 MW

- **Minimum number of consecutive hours in Block Orders:** 1 hours
- **Maximum amount of Block Orders:** 100 per Trading Portfolio
- **Price Steps:** The number of Price Steps is 200 per hour (including the upper and lower Order Price Limits)
- **Lower Technical Order Price Limit:** Euro -500
- **Upper Technical Order Price Limit:** Euro +3 000.
- **Linked Basket Order limit:** maximum of 100 linked limit orders, TimeInForce 'FOK'
- **Delivery:** Per applicable Delivery Period and pursuant to the Clearing Rules.
- **Cash Settlement:** See item 1.3 above. Settlement calculations will be based on actual Deliveries per Delivery Hour on each applicable Delivery Day.

3.5 Intraday Auctions offered:

Auction short name	22:00h Auction	10:00h Auction
Intraday Auction Gate Opening	See 3.7 below	
Intraday Auction Start Time	21:45	09:45
Intraday Auction Gate Closure	22:00	10:00
Intraday Auction End Time	22:30	10:30
Countries	DE	
Delivery Period	[00:00 – 24:00]	[12:00 – 24:00]
Granularity	60 min	

3.6 Intraday Auctions: Market and Contract Codes

Market code: NPIDA

Contract Codes:

Suffix (variable)	Explanation	Range
dd	Day of month (two digits)	01 - 31
mm	Month of year (two digits)	01 - 12
yyyy	Year (four digits)	Current year (next year)
nn	Clock hour	00:00 – 24:00
x	Auction: 1 denotes contract traded in 22:00 auction and, 2 in 10:00 auction	1,2

Examples: PHA-20170901-14-1 and PHA-20170901-14-2

3.7 Intraday Auction Gate Opening

The time (gate opening) from which Orders for Contracts within a Delivery Day (starting on 0:00h and ending on 24:00h) may be submitted, will normally occur 60 days prior to the start of such day provided that, Nord Pool may, in its sole discretion, postpone the gate opening, for example, but not limited to, in case of technical or operational reasons.

PCR
PRICE COUPLING OF REGIONS

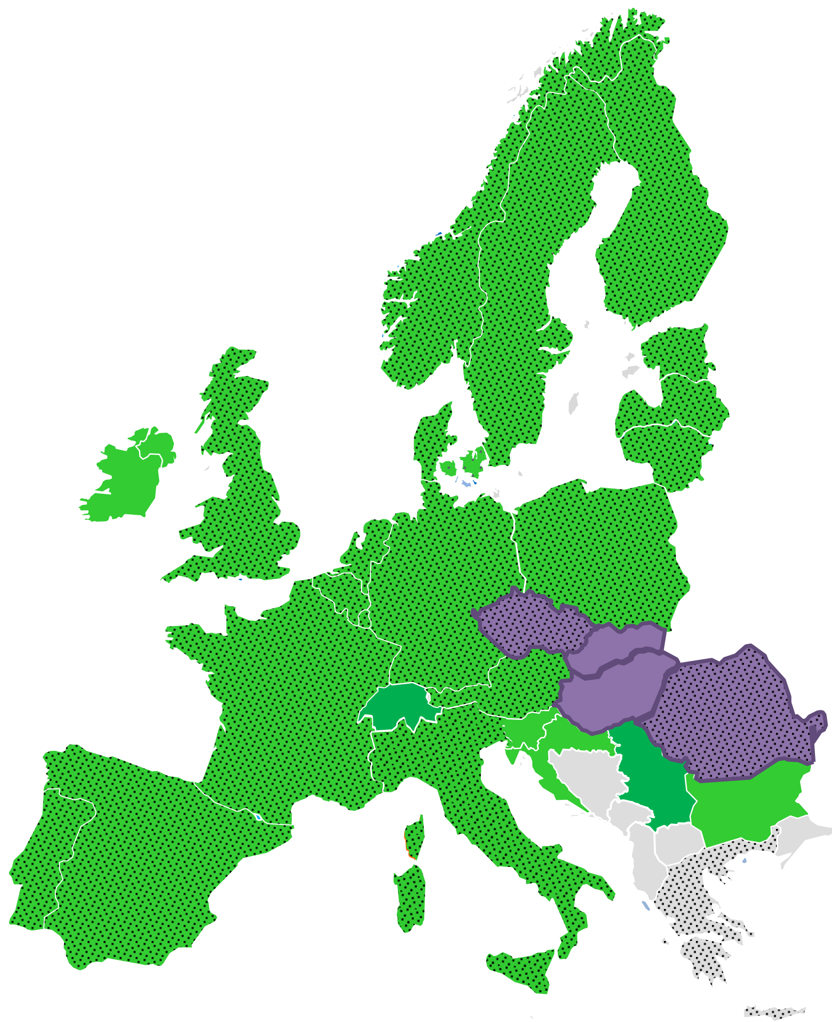
EUPHEMIA:
Description and functioning

Date: December 2018

Supported by Europex

PCR users and members

- Markets using PCR: MRC
- Markets using PCR: 4MMC
- Markets PCR members
- Independent users of PCR
- Markets associate members of PCR

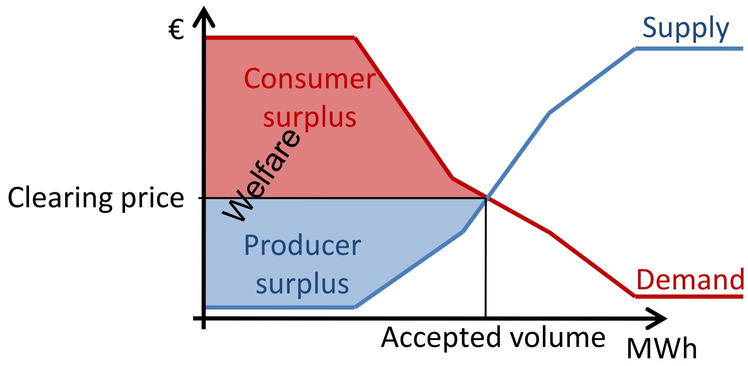


PRICE COUPLING OF REGIONS

ALGORITHM EUPHEMIA

- EUPHEMIA is an algorithm that solves the market coupling problem on the PCR perimeter.
  – EUPHEMIA stands for: EU + Pan-european Hybrid Electricity Market Integration Algorithm.

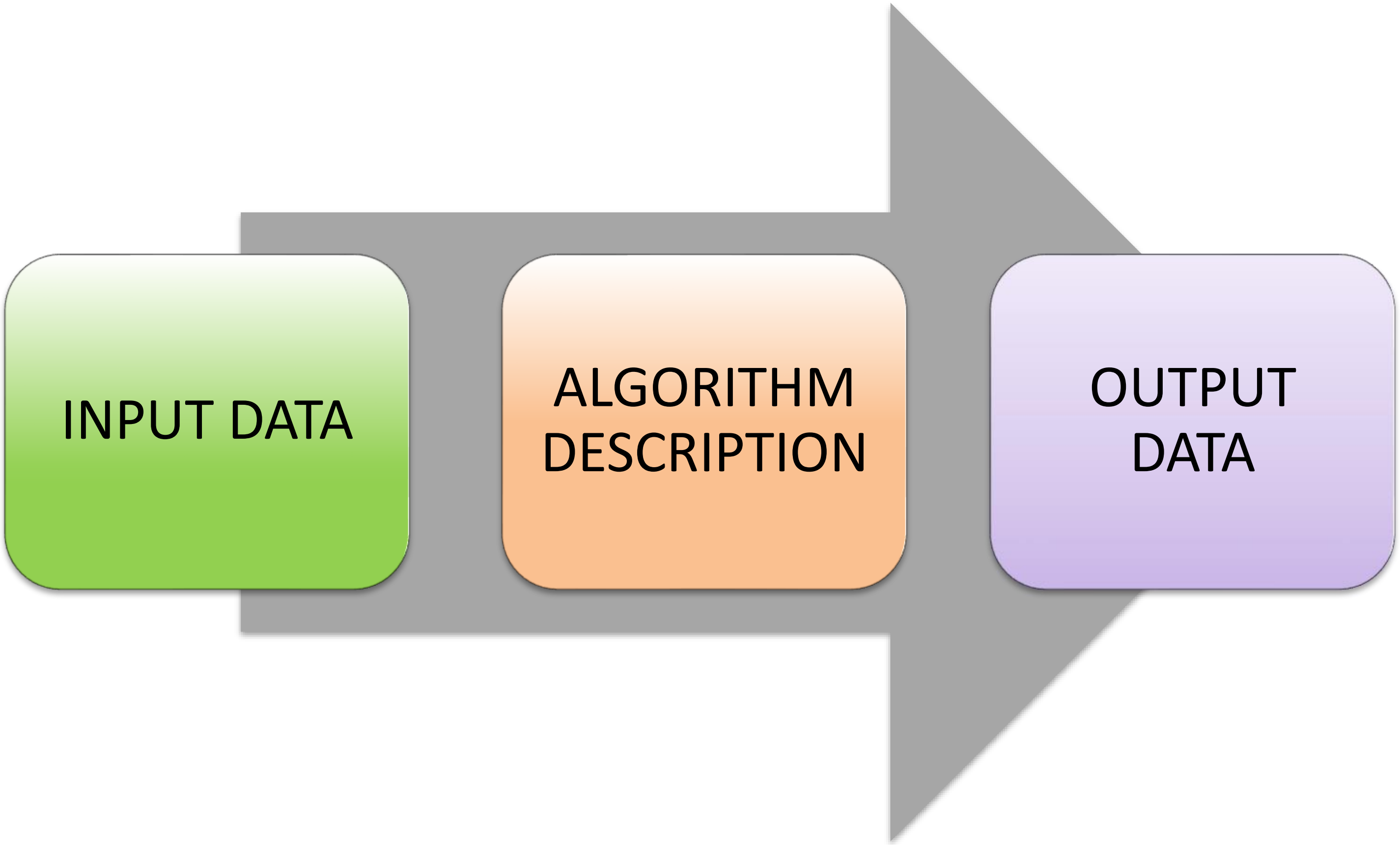
- It maximizes the welfare of the solution
  - Most competitive price will arise
  - Overall welfare increases
  - Efficient capacity allocation



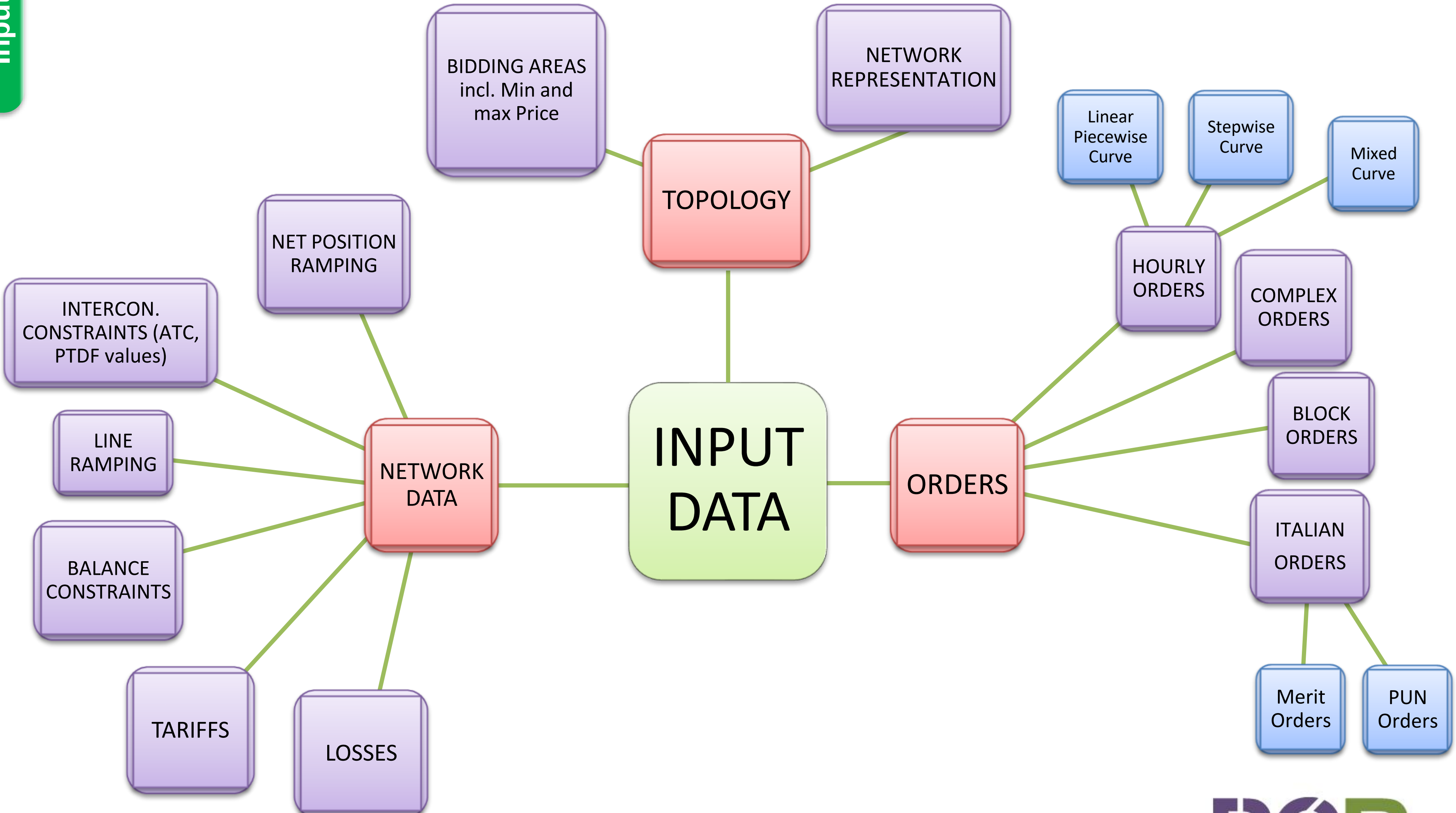
Algorithm has been tested using real 2011/2012/2013/2014 daily order books (around 50 bidding areas and 60 ATC lines)

PRICE COUPLING OF REGIONS

GENERAL DESCRIPTION



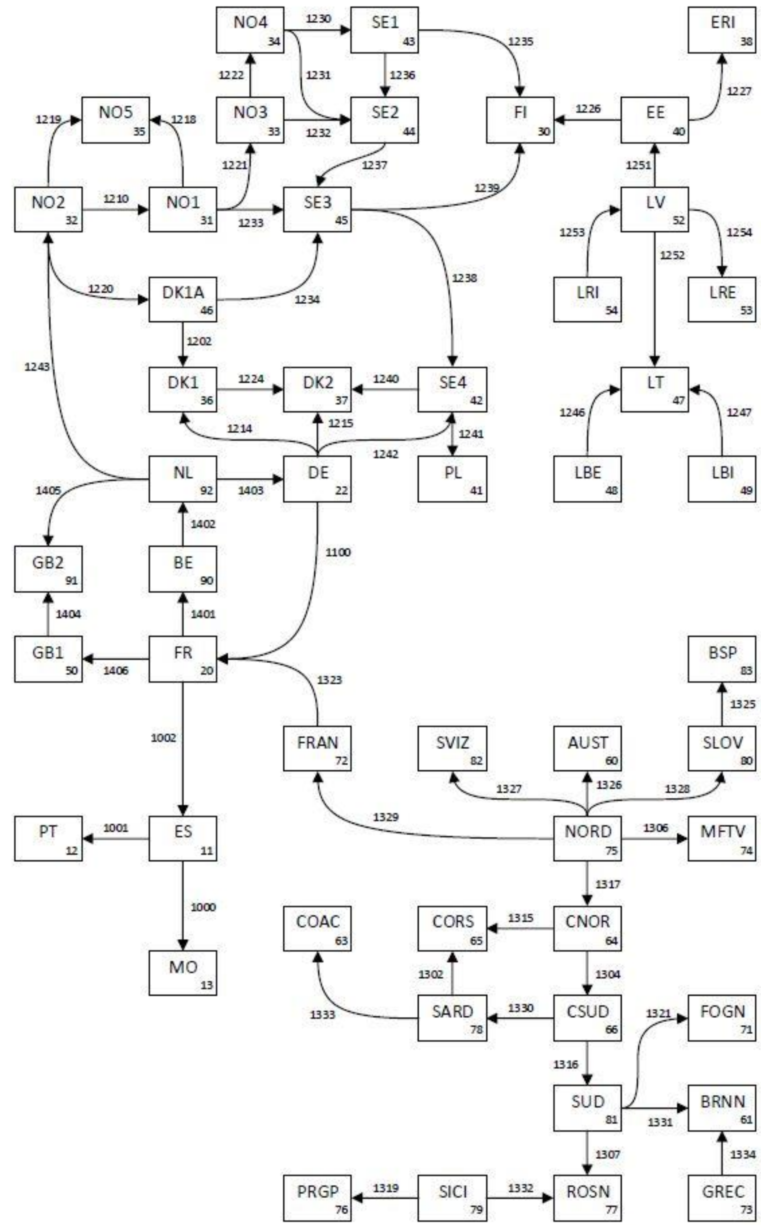
INPUT DATA



PCR PRICE COUPLING OF REGIONS

MARKET DATA

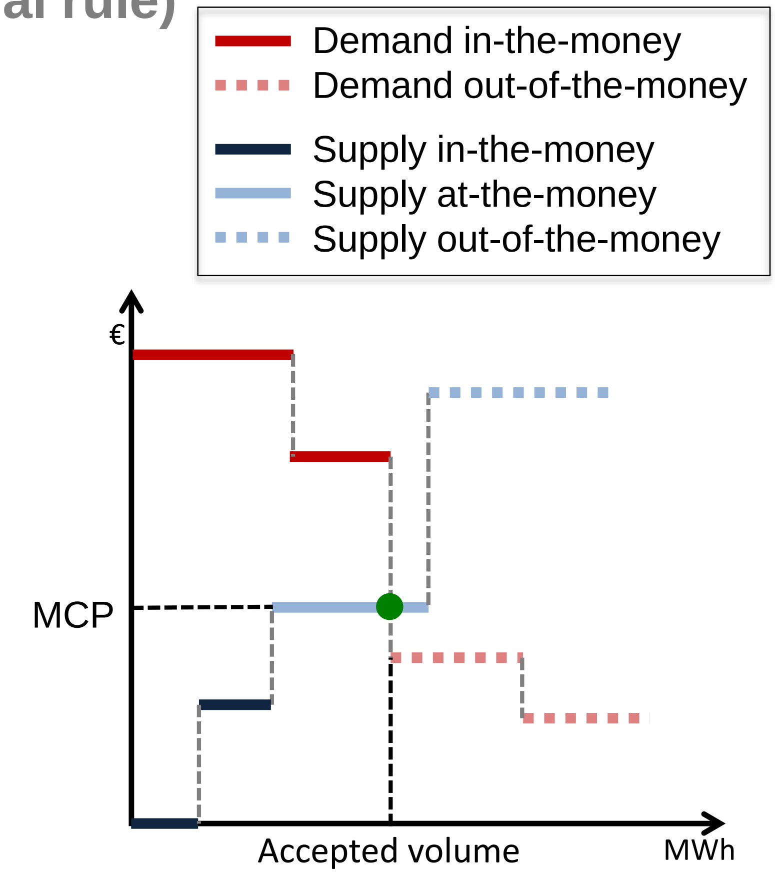
- Each PX (Market) operates several bidding areas.
- All bidding areas are matched at the same time.
- A different price can be obtained for each bidding area.
- The price for the bidding area must respect maximum and minimum price market boundaries.



HOURLY STEP ORDERS (general rule)

- Hourly step orders are defined by
  - A type (buy or sell)
  - A volume
  - A limit price

- EUPHEMIA provides solutions such that
  - Orders in-the-money are fully accepted
    - Supply at price < MCP
    - Demand at price > MCP
  - Orders out-of-the-money are fully rejected
    - Supply at price > MCP
    - Demand at price < MCP
  - Orders at-the-money can be curtailed

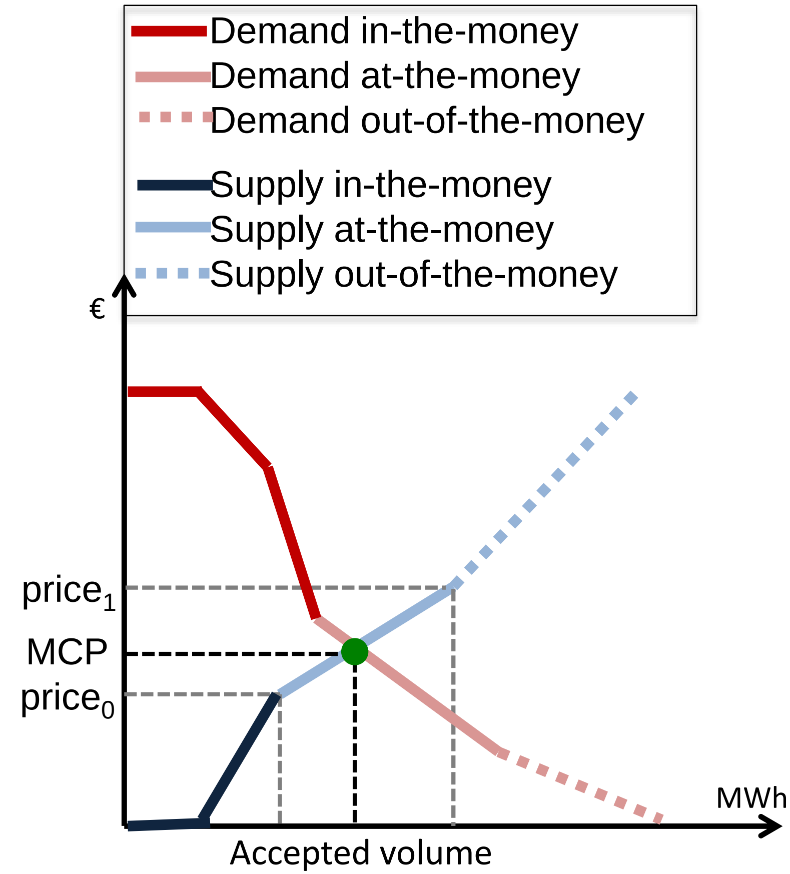


OMIE, OPCOM, EPEX SPOT, GME and OTE use this kind of orders.

HOURLY LINEAR PIECEWISE ORDERS (general rule)

- Hourly piecewise orders are defined by
  - A side (buy or sell)
  - A volume
  - $price_0$: at which the order starts to be accepted
  - $price_1$: at which the order is totally accepted ($price_1 > price_0$)
- EUPHEMIA provides solutions such that
  - Orders in-the-money are fully accepted
    - Supply where $price_1 < MCP$
    - Demand where $price_1 > MCP$
  - Orders out-of-the-money are fully rejected
    - Supply where $price_0 > MCP$
    - Demand where $price_0 < MCP$
  - Orders at-the-money are accepted to the corresponding proportion

    Acceptance ratio = $(MCP-price_0) / (price_1-price_0)$



NORDPOOL and EPEX SPOT use this kind of orders.

PCR PRICE COUPLING OF REGIONS

REGULAR BLOCK ORDERS

Regular Block orders are defined by

- Type (buy or sell).
- one single price.
- one single volume.
- Period: consecutive hours over which the block spans.

A regular block order <u>cannot</u> be accepted partially. It is either totally rejected or accepted (Fill-or-Kill condition).

PROFILE BLOCK ORDERS

Profile Block orders are defined by

- Type (buy or sell).
- one single price.
- Minimum Acceptance Ratio.
- Period: hours over which the block spans.
- Volume for each hour

The Profile Block orders can only be accepted with an acceptance ratio higher or equal than the minimum acceptance ratio.

Examples :

Type	PERIOD	PRICE	VOLUME
BLOCK BUY	Hours 1-24	40 Euros	200 MWh
BLOCK SELL	Hours 8-12	40 Euros	50 MWh

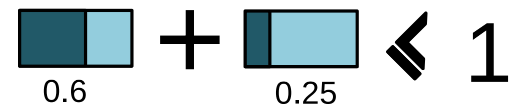
Type	PERIOD	PRICE	MIN. ACCEPT. RATIO	VOLUME
BLOCK SELL	Hours 1-7 Hours 16-24	40 Euros	**50%**	80 MWh 220 MWh

Acceptance Criterion :
a regular or profile block order out-the-money cannot be accepted

PCR
PRICE COUPLING OF REGIONS

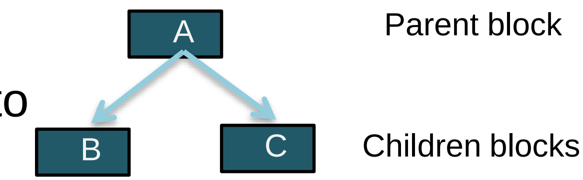
EXCLUSIVE BLOCK ORDERS

- Exclusive Group = Set of Block Orders in which the sum of the accepted ratios cannot exceed 1.
- Acceptance rules of Block Orders totally apply.

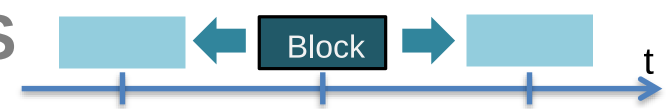


LINKED BLOCK ORDERS

- Several Block orders may be linked together in a parent-child relationship
- The acceptance of a child Block Order is conditional to the acceptance of its parent.
- However a loss giving parent can be saved by a child as long as the combination of accepted block orders is not making a loss.



FLEXIBLE HOURLY BLOCK ORDERS



- A Flexible Hourly Order is a Regular Block Order which lasts for only one period.
- If accepted, the block will be executed once and the period is determined by the algorithm such as the welfare is maximized.
- Acceptance rules of Regular Block Orders apply fully.

PCR PRICE COUPLING OF REGIONS

COMPLEX ORDERS & MIC ORDERS

MIC (Minimum Income Orders) are Stepwise Hourly Orders under an economical condition defined by two terms:

- FT: Fixed Term in Euros which shows the fixed costs of the whole amount of energy traded in the order.
- VT: Variable Term in Euros per accepted MWh which shows the variable costs of the whole amount of energy traded in the order.

The same acceptance rules for Stepwise Hourly Orders are applied to MIC Orders and the revenue received by an activated MIC must be greater or equal to the Fixed Term plus Variable Term times the energy matched.

SCHEDULED STOP CONDITION

- It only applies to deactivated MICs.
- It applies to periods declared as Scheduled Stop by the MIC.
- A MIC order can declare a maximum of three periods as Scheduled Stop interval. (Periods 1, 2 or 3).
- The hourly sub-orders in the periods declared as Scheduled Stop interval must have decreasing energy as period increases.
- The first hourly sub-order will remain active (although the MIC is deactivated).
- For a deactivated MIC, its active hourly sub-orders corresponding to Scheduled Stop periods will be accepted if they are in/at the money (as any other hourly order).

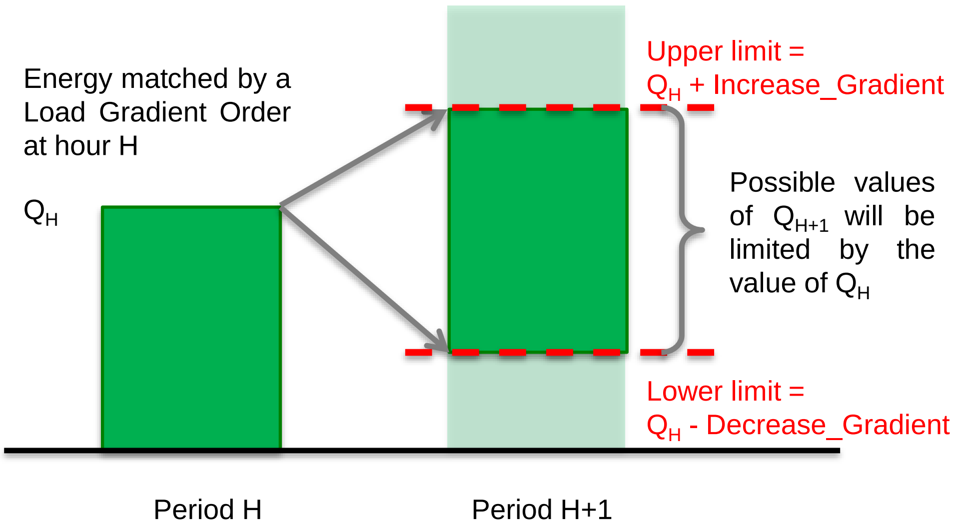
PCR PRICE COUPLING OF REGIONS

COMPLEX ORDERS & LOAD GRADIENT

The load gradient condition limits the variation between the accepted volume of an order at a period and the accepted volume of the same order at the adjacent periods.

A Load Gradient Order (LG) is defined by the next terms:

- ***Increase Gradient:*** Maximum increase gradient in MWh.
- ***Decrease Gradient:*** Maximum decrease gradient in MWh.



PRICE COUPLING OF REGIONS

PREZZO UNICO NAZIONALE (PUN) REQUIREMENT

- National demand of Italy (with the exception of storage pumps) is matched to a single purchase price (PUN), regardless of its location
- Expenses coming from the consumers paying the PUN must be equal to the expenses that would have come from consumers with zonal prices (minimum tolerance accepted)
- Acceptance/rejection of buying bids subject to PUN must respect the following conditions
  - Buying bids in-the-money (Offered price > PUN) are fully accepted
  - Buying bids out-of-the-money (Offered price < PUN) are fully rejected
  - Buying bids at-the-money (Offered price = PUN) can be curtailed
- In order to respect the aforementioned requirements, PUN and bidding area prices must be calculated simultaneously (PUN cannot be calculated ex-post)

PRICE COUPLING OF REGIONS

PUN AND MERIT ORDERS

In GME:

- Supply Merit orders are selling offers. They are cleared at their bidding area price.

- Non-PUN demand orders (pump plants and buying bids on cross-border long term capacities) : Buying Bids from pump plants and buying bids in non-Italian national zones* are demand Merit Orders. They are cleared at the price of their bidding area.

- PUN Merit Orders : the rest of the buying bids (the ones related to national consumption) are cleared at the common national PUN price (which is different from their bidding area price).

This PUN price is defined as the average price of GME marginal market prices for its bidding areas, weighted by the purchase quantity assigned to PUN Orders in each bidding area (subject to a tolerance, ϵ). That is:

$$P_{PUN} * \Sigma_z Q_z = \Sigma_z P_z * Q_z + \epsilon$$

* «Non Italian Zones» are limited poles of productions (available production capacity is bigger than ATC) and zones where holders of crossborders capacities rights submit bids .

PRICE COUPLING OF REGIONS

NETWORK DATA AND BALANCE CONSTRAINTS

The energy balance concept is defined as : The global supply minus the losses must be equal to the global demand of all markets involved. Depending on the manner the interconnections are modeled, there are the following:

- ***ATC network model:*** The network is described as a set of lines interconnecting bidding areas. The nomination of the line can be made up to its Available Transfer Capacity (ATC).

- ***Flow-based network model:*** Also known as PTDF model, with all bidding areas connected in a meshed network. It expresses the constraints arising from Kirchhoff's laws and physical elements of the network in the different contingency scenarios considered by the TSOs. It translates into linear constraints on the net positions of the different bidding areas.

- ***Hybrid network model:*** Some bidding areas are connected using the Flow-based network model; the remaining using the ATC network model.

NETWORK DATA AND RAMPING LIMITS

- EUPHEMIA supports a wide range of network restrictions:
  - Ramping limit for individual or sets of lines between consecutive hours.
  - Line tariffs.
  - Line losses.
  - Hourly and daily net position ramping limits for bidding areas.

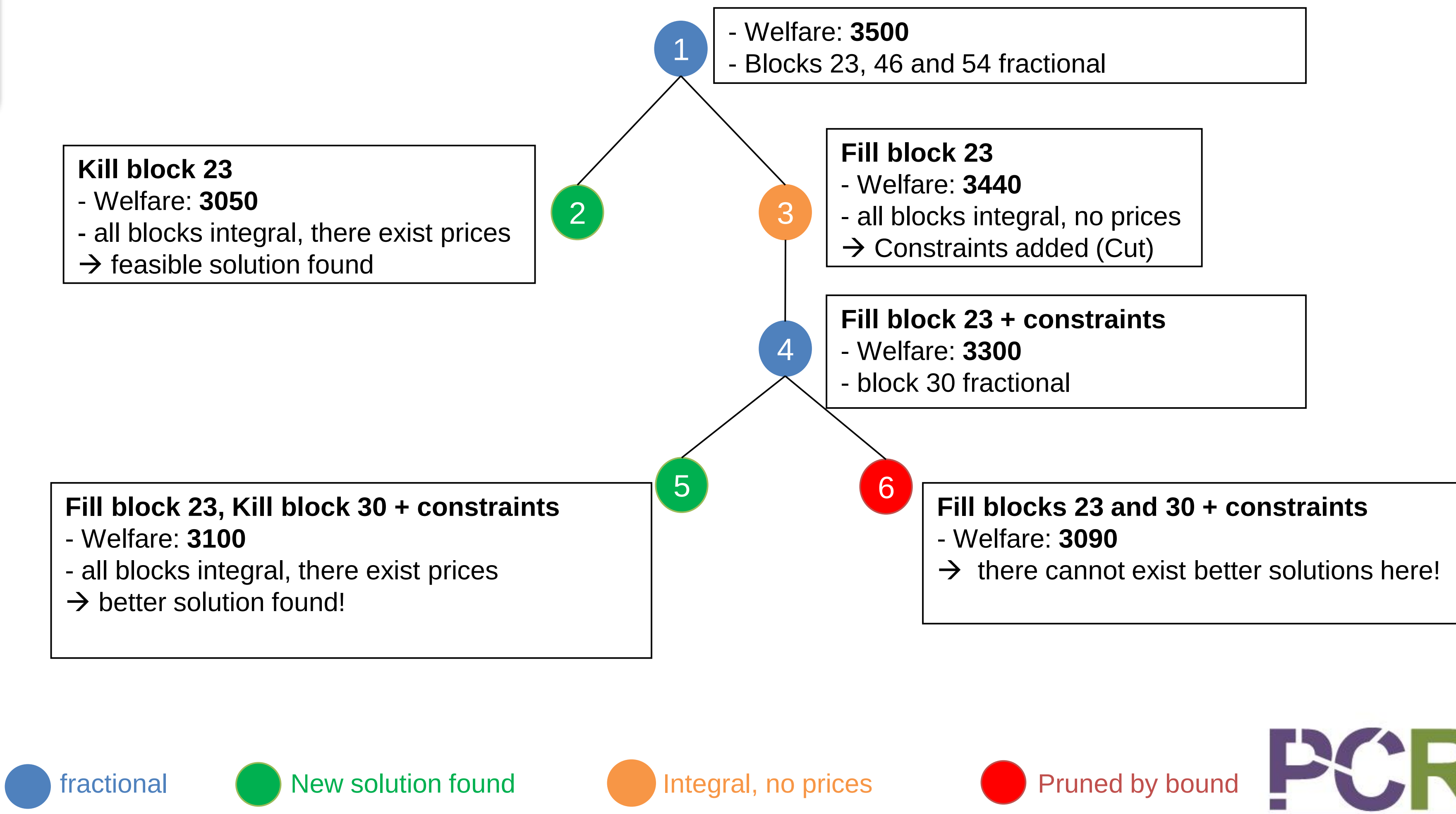
EUPHEMIA USES BRANCH-AND-CUT

- Branch-and-Cut method is a way to
  - Search among all block and MIC selections in a structured way
  - Find feasible solutions quickly
  - Prove early that large groups of these selections cannot hold good solutions

- The idea is as follows
  - Try first without the fill-or-kill requirement
  - If the solution happens to have no partially accepted block ➔ OK
  - If it has, then
    - Select one block which is partially accepted
    - Create two sub-problems (called *branches*)
      - One where the block is killed
      - One where the block is filled
  - Continue to explore until there is no unexplored branch

PRICE COUPLING OF REGIONS

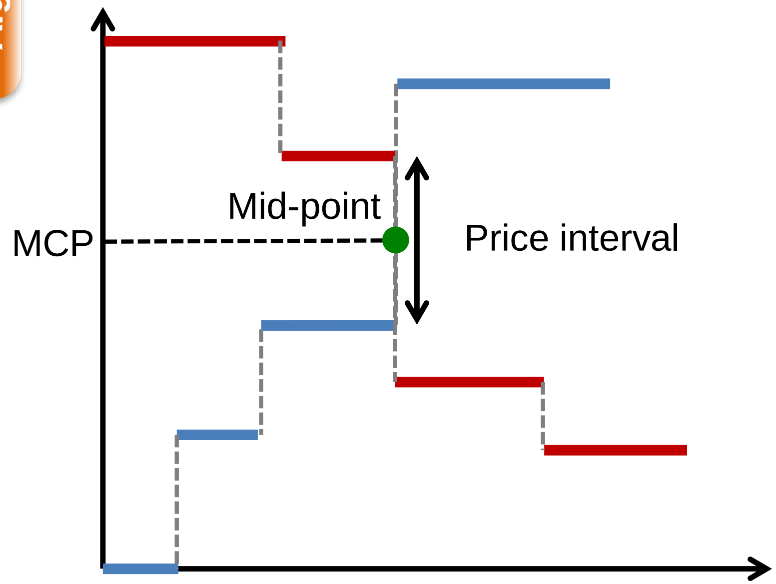
BRANCH-AND-CUT



PRICE COUPLING OF REGIONS

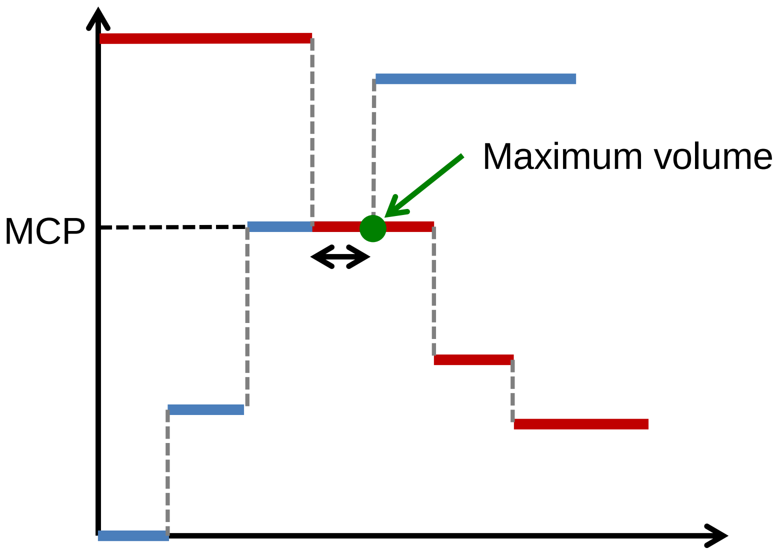
PRICE AND VOLUME INDETERMINACY RULES
(general rule)

PRICE



Minimize the distance to the middle of the price interval

VOLUME



Maximize traded volume

PRICE COUPLING OF REGIONS

STOPPING CRITERIA

In production, the algorithm will stop calculating whenever one of the following situations is reached:

- The algorithm has explored all nodes.
- The time limit has been reached.

OUTPUT DATA

EUPHEMIA results:

- Price per bidding area
- Net position per bidding area
- Flows per interconnection
- Matched energy for each block, MIC and PUN orders

PRICE COUPLING OF REGIONS

Thank You

For more information, in particular on the treatment of special cases, please refer to the extensive public description (available for download).

Copyright disclaimer

PCR
PRICE COUPLING OF REGIONS

भारतीय प्रतिभूति और विनिमय बोर्ड
Securities and Exchange Board of India

CIRCULAR

CIR/MRD/DRMNP/CIR/P/2018/145 November 27, 2018

To

All recognised Stock Exchanges and Clearing Corporations except Stock Exchanges and Clearing Corporations in International Financial Services Centre

Dear Sir / Madam

Interoperability among Clearing Corporations

1. Interoperability among Clearing Corporations (CCPs) necessitates linking of multiple Clearing Corporations. It allows market participants to consolidate their clearing and settlement functions at a single CCP, irrespective of the stock exchange on which the trade is executed. It is expected that the interoperability among CCPs would lead to efficient allocation of capital for the market participants, thereby saving on costs as well as provide better execution of trades.

2. An expert Committee constituted by SEBI, under the Chairmanship of Shri K V Kamath, had, inter alia, examined the *'Viability of Interoperability between different Clearing Corporations'*. Thereafter, proposals on Interoperability, received from CCPs, were placed before the Secondary Market Advisory Committee (SMAC) of SEBI. As recommended by SMAC, three working sub-groups pertaining to relevant subjects viz. Risk Management, Technology, and Finance and Taxation were constituted comprising academicians, market participants and relevant stakeholders to examine the related issues and provide their recommendations. The reports of these sub-groups were placed before SMAC and their recommendations were deliberated upon.

3. Thereafter, SEBI Board approved suitable amendments to the Securities Contracts (Regulation) (Stock Exchanges and Clearing Corporations) Regulations to, inter alia, enable interoperability among clearing corporations.

4. The Committee on Payments and Settlement Systems (CPSS) and the Technical Committee of International Organization of Securities Commissions (IOSCO) have prescribed the Principles for Financial Market Infrastructures (PFMIs) with a view to enhance safety and efficiency in payment, clearing, settlement, and recording arrangements as well as to limit systemic risk, and foster transparency and financial stability. Principle 20 of PFMIs, which is relevant to the proposed interoperability among clearing corporations, prescribes that *“An FMI that establishes a link with one or more FMIs should identify, monitor, and manage link-related risks.”*

5. Keeping the aforementioned in view, the broad guidelines for operationalizing the interoperable framework among CCPs are prescribed for compliance hereunder :-

5.1. **Scope of Interoperability among CCPs**

(1) The interoperability framework shall be applicable to all the recognised clearing corporations excluding those operating in International Financial Services Centre.

(2) All the products available for trading on the stock exchanges (except commodity derivatives) shall be made available under the interoperability framework.

5.2. **Interoperable links among CCPs**

(1) The recognised clearing corporations shall establish peer-to-peer link for ensuring interoperability. A CCP shall maintain special arrangements with another CCP and shall not be subjected to normal participant (membership) rules. Risk management between the CCPs shall be based on a bilaterally approved framework and shall ensure coverage of inter-CCP exposures. CCPs shall exchange margins and other financial resources on a reciprocal basis based on mutually agreed margining models.

(2) However, SEBI, in certain cases, may require a CCP to establish participant link for interoperability. In such cases the CCP concerned shall become participant of another CCP (the host CCP) and shall be subjected to the host CCP’s normal participant rules. Since the participant CCP would be posting margins with the host CCP, but would not be collecting margins from the host CCP, it shall be

required to hold additional financial resources to protect itself against default of the host CCP.

5.3. **Inter CCP Collateral**

(1) To manage the inter-CCP exposure in the peer-to-peer link, CCPs shall maintain sufficient collateral with each other so that any default by one CCP, in an interoperable arrangement, would be covered without financial loss to the other non-defaulting CCP. The inter-CCP collateral shall comprise two components, viz.

(a) Margins as per the existing Risk Management Framework (initial margin, extreme loss margin, calendar spread margin, etc.) prescribed by SEBI; and

(b) Additional capital, to be determined by each CCP, based on the credit risk from the linked CCP, on which no exposure shall be granted to the linked CCP.

(2) The collateral posted by one CCP with another CCP shall be maintained in a separate account which can be clearly identified in the name of such linked CCP which is providing collateral and shall not be included in the Core SGF of the CCP receiving them.

(3) The liquid assets as well as hair-cuts as prescribed vide SEBI Circular MRD/DoP/SE/Cir-07/2005 dated February 23, 2005 on *"Comprehensive Risk Management Framework for the cash market"* and SEBI Circular CIR/MRD/DRMNP/9/2013 dated March 20, 2013 on *"Corporate bonds and Government securities as collateral"* shall be applicable for inter-CCP transactions.

5.4. **Inter CCP Settlement**

The CCPs shall undertake multilateral netting to create inter-CCP net obligations and exchange funds and securities on a net basis. The pay-in and pay-out shall be completed as per the settlement schedule prescribed vide SEBI Circular MRD/DoP/SE/Dep/Cir-18/2005 dated September 02, 2005 on *"Revised Activity schedule for T+2 rolling settlement".*

5.5. **CCP-Trading Venue Link**

(1) In an interoperable arrangement, the stock exchange and the CCP may not be located at same venue. Accordingly, to ensure real time flow of information between the stock exchange (trading venue) and the CCP, so as to facilitate effective real-time risk monitoring and mitigation, each interoperable CCP shall put in place appropriate infrastructure including deployment of adequate servers at each of the linked trading venues.

(2) In order to mitigate any risk arising out of latency, in partial modification of para-7 of the SEBI Circular CIR/MRD/DP/34/2012 dated December 13, 2012 on *"Pre-trade Risk Controls",* Stock Exchanges shall ensure that stock brokers are mandatorily subjected to risk reduction mode on utilization of 85% of the stock broker's collateral available for adjustment against margins.

(3) Other provisions with regard to risk reduction mode, prescribed vide the above-mentioned SEBI Circular dated December 13, 2012 shall continue to be applicable.

5.6. **Default Handling Process**

In case of default by a CCP, in the interoperable arrangement, the collateral provided by such CCP shall be utilized by the non-defaulting CCP to cover losses arising from such default, as per the default waterfall prescribed vide SEBI Circular CIR/MRD/DRMNP/25/2014 dated August 27, 2014 on *"Core Settlement Guarantee Fund, Default Waterfall and Stress Test".*

5.7. **Charges by Stock Exchanges/Clearing Corporations**

(1) In order to promote transparency in terms of charges levied by the Stock Exchanges/ Clearing Corporations, the transaction charges levied shall be clearly identified and made known to the participants upfront.

(2) The Stock Exchanges and Clearing Corporations shall comply with the provisions under Para-2 of SEBI Circular MRD/DoP/SE/Cir-14/2009 dated October 14, 2009 on "*Revision of transaction charges by the stock exchanges".*

5.8. **Dispute Resolution**

The Conflict Resolution Committee, as prescribed vide SEBI Circular SEBI/HO/MRD/DSA/CIR/P/2017/9 dated January 27, 2017 on *"Procedures for Exchange Listing Control Mechanism"* shall address disputes, among CCPs and Stock Exchanges, arising out of interoperability.

5.9. **Inter-CCP Agreement**

(1) Securities Contracts (Regulation) (Stock Exchanges and Clearing Corporations) Regulations, 2018 prescribes that *"...in case a recognised stock exchange enters into an arrangement with more than one recognised Clearing Corporation, it shall enter into a multipartite agreement in writing with such recognised clearing corporations to ensure interoperability among the clearing corporations".*

(2) The agreements entered into by the Stock Exchanges/ Clearing Corporations shall, inter alia, include system capability, inter-CCP links and CCP-trading venue link, risk management framework, monitoring of client margin/position limits, obligation system, settlement process, surveillance systems, sharing of client data, sharing of product information, default handling process and dispute resolution process.

6. Stock Exchanges and Clearing Corporations shall adhere to aforesaid guidelines and accordingly, take all necessary steps to operationalize interoperability at the earliest but not later than June 01, 2019.

7. The Stock Exchange and Clearing Corporations are directed to:

(1) take necessary steps to put in place requisite infrastructure and systems for implementation of the circular, including necessary amendments to the relevant bye-laws, rules and regulations;

(2) bring the provisions of this circular to the notice of their members and also disseminate the same on its website; and

(3) communicate to SEBI, the status of implementation of the provisions of this circular.

8. This circular is being issued in exercise of powers conferred under Section 11 (1) of the Securities and Exchange Board of India Act, 1992 to protect the interests of investors in securities and to promote the development of, and to regulate, the securities market.

Yours faithfully

(Sanjay Purao)
General Manager
Division of Risk Management and New Products
Market Regulation Department
Email: sanjayp@sebi.gov.in

भारतीय प्रतिभूति और विनिमय बोर्ड
Securities and Exchange Board of India

MASTER CIRCULAR FOR ONLINE DISPUTE RESOLUTION
(Updated as on August 11, 2023)

SEBI/HO/OIAE/OIAE_IAD-1/P/CIR/2023/145

July 31, 2023
(Updated as on August 4, 2023)

To,

All Recognized Stock Exchanges (including Commodity Derivatives)
All Clearing Corporations
All Depositories
All Stock Brokers
All Depository Participants
All Listed Companies
All SEBI Registered Intermediaries / All SEBI Regulated Entities

Sir / Madam,

Subject: Master Circular for Online Resolution of Disputes in the Indian Securities Market

1. After extensive public consultations and in furtherance of the interests of investors and consequent to the gazette notification (dated July 3, 2023) of the SEBI (Alternative Dispute Resolution Mechanism) (Amendment) Regulations, 2023 the existing dispute resolution mechanism in the Indian securities market is being streamlined under the aegis of Stock Exchanges and Depositories (collectively referred to as Market Infrastructure Institutions (**MIIs**)),[1] by expanding their scope and by establishing a common Online Dispute Resolution Portal ("**ODR Portal**") which harnesses online conciliation and online arbitration for resolution of disputes arising in the Indian Securities Market.

[1] presently excluding Clearing Corporations and its constituents

Investors and Listed Companies/Specified Intermediaries/Regulated entities under the ambit of ODR

2. Disputes between Investors/Clients and listed companies (including their registrar and share transfer agents) or any of the specified intermediaries / regulated entities in securities market (as specified in **Schedule A**) arising out of latter's activities in the securities market, will be resolved in accordance with this circular and by harnessing online conciliation and/or online arbitration as specified in this circular. Listed companies / specified intermediaries / regulated entities OR their clients/investors (or holders on account of nominations or transmission being given effect to) may also refer any unresolved issue of any service requests / service related complaints[2] for due resolution by harnessing online conciliation and/or online arbitration as specified in this circular.

3. Disputes between institutional or corporate clients and specified intermediaries / regulated entities in securities market as specified in **Schedule B** can be resolved, at the option of the institutional or corporate clients:

    a. in accordance with this circular and by harnessing online conciliation and/or online arbitration as specified in this circular; OR

    b. by harnessing any independent institutional mediation, conciliation and/or online arbitration institution in India.

    For existing and continuing contractual arrangements between institutional or corporate clients and specified intermediaries / regulated entities in the securities market as specified in **Schedule B**, such option should be exercised within a period of six months, failing which option as specified in (a) above will be deemed to have been exercised. For all new contractual arrangements, such choice should be exercised at the time of entering into such arrangements.

4. Disputes between MII and its constituents which are contractual in nature shall be included in the framework at a future date as may be specified[3] while

[2] Service related complaints shall include non-receipt/ delay of account statement, non-receipt/ delay of bills, closure of account/branch, technological issues, shifting/closure of branch without intimation, improper service by staff, freezing of account, alleged debit in trading account, contact person not available, demat account transferred without permission etc.

[3] As and when the same is made operational, in order to avoid conflict of interest, in case of a complaint/dispute involving a MII or its holding or subsidiary or associate company, the same will not be allocated to that MII and the ODR Institution empaneled by such MII or to the direct competitor of such MII and the ODR Institution empaneled by such MII: such dispute will be directed to another MII and the ODR Institution empaneled by it. For instance, any dispute against NSE shall be allocated to CDSL and in case of a dispute in relation to BSE, the same be allocated to NSDL and vice versa.

expressly excluding disputes/appeals/reviews/challenges pertaining to the regulatory, enforcement role and roles of similar nature played by MIIs.

Introduction of the common Online Dispute Resolution Portal

5. The MIIs shall, in consultation with their empaneled ODR Institutions, establish and operate a common Online Dispute Resolution Portal ("**ODR Portal**"). The MIIs will make joint efforts to develop and operationalize the ODR Platform. For the purposes of implementation of this circular, the MIIs shall enter into an agreement amongst themselves, which will, *inter alia,* outline the nature of their responsibilities, the cost of development, operating, upgradation, maintenance (including security of data of investors and intermediaries as specified by the Board from time to time) and for inspection and/or audit of the ODR Platform. The Board may, from time to time, undertake inspection in order to ensure proper functioning of ODR Portal and MIIs shall provide complete cooperation to the Board in this regard.

   It is clarified that MIIs which are initially excluded from the round robin system (as described below) are not required to incur any costs for development and maintenance of the ODR Portal during the period of such exclusion.

6. Each MIIs will identify and empanel one or more independent ODR Institutions which are capable of undertaking time-bound online conciliation and/or online arbitration (in accordance with the Arbitration and Conciliation Act, 1996 and any other applicable laws) that harness online/audio-video technologies and have duly qualified conciliators and arbitrators. The norms for empanelment of ODR Institutions are specified in **Schedule C** of this circular as also the continuing obligations of the ODR Institutions. The ODR Portal shall have due connectivity with each such ODR Institution as is required for undertaking the role and activities envisaged in this circular. Such ODR Portal shall establish due connectivity with the SEBI SCORES portal / SEBI Intermediary portal.

7. All the MIIs shall participate on the ODR Portal and provide investors/clients and listed companies (including their registrar and share transfer agents) and the specified intermediaries / regulated entities in the securities market access to the ODR Portal for resolution of disputes between an investor/client and listed companies (including their registrar and share transfer agents) and the specified intermediaries / regulated entities in the securities market, through time bound online conciliation and/or online arbitration.

8. All listed companies / specified intermediaries / regulated entities in the securities market (collectively referred to as "**Market Participant/s**") shall enrol on the ODR

Portal within the timelines as specified at paragraphs 46 and 47 of this circular and shall be deemed to have been enrolled on the ODR Portal at the end such specified timeline. The enrolment process shall also include executing electronic terms/agreements with MIIs and the ODR Institutions, which shall be deemed to be executed at the end such specified timeline. Facility to enrol Market Participants into the ODR Portal by utilising the credentials used for SEBI SCORES portal / SEBI Intermediary portal may be also provided in the ODR Portal.

9. All market participants and MIIs are advised to display a link to the ODR Portal on the home page of their websites and mobile apps.

10. The modalities of the ODR Portal along with the relevant operational guidelines and instructions may be specified by the Board from time to time.

Initiation of the dispute resolution process

11. An investor/client shall first take up his/her/their grievance with the Market Participant by lodging a complaint directly with the concerned Market Participant. If the grievance is not redressed satisfactorily, the investor/client may, in accordance with the SCORES guidelines, escalate the same through the SCORES Portal in accordance with the process laid out therein. After exhausting these options for resolution of the grievance, if the investor/client is still not satisfied with the outcome, he/she/they can initiate dispute resolution through the ODR Portal.

12. Alternatively, the investor/client can initiate dispute resolution through the ODR Portal if the grievance lodged with the concerned Market Participant was not satisfactorily resolved or at any stage of the subsequent escalations mentioned in the paragraph 11 above (prior to or at the end of such escalation/s). The concerned Market Participant may also initiate dispute resolution through the ODR Portal after having given due notice of at least 15 calendar days to the investor/client for resolution of the dispute which has not been satisfactorily resolved between them.

13. The dispute resolution through the ODR Portal can be initiated when the complaint/dispute is not under consideration in terms of the paragraph 11 above or SCOREs guidelines as applicable or not pending before any arbitral process, court, tribunal or consumer forum or are non-arbitrable in terms of Indian law (including when moratorium under the Insolvency and Bankruptcy Code is in operation due to the insolvency process or if liquidation or winding up process has been commenced against the Market Participant).

14. The dispute resolution through the ODR Portal can be initiated when within the applicable law of limitation (reckoned from the date when the issue arose/occurred that has resulted in the complaint/date of the last transaction or the date of disputed transaction, whichever is later).

ODR Portal and allocation system

15. The ODR Portal shall have the necessary features and facilities to, *inter alia*, enrol the investor/client and the Market Participant, and to file the complaint/dispute and to upload any documents or papers pertaining thereto. It shall also have a facility to provide status updates on the complaint/dispute which would be obtained from the ODR Institutions. The features and facilities shall be periodically reviewed and upgraded by the MIIs as well as new features and facilities added from time to time as required by the Board. The ODR Portal shall be subject to inspection and/or audit for, inter alia, verifying the adherence to these norms and applicable SEBI regulations, circulars and advisories.

16. A complaint/dispute initiated through the ODR Portal will be referred to an ODR Institution empaneled by a MII and the allocation system on a market-wide basis will be a round-robin system to govern the allocation of each such dispute among all such empaneled ODR Institution/s *subject that* for an initial period (as specified by the Board):

    a. complaints/disputes arising with a specific trading member for an exchange transaction or a listed company, shall be referred to the ODR Institution/s empaneled by the relevant Stock Exchange[4], and disputes arising with a specific depository participant, shall be referred to the ODR institution/s empaneled by the relevant DepositoryIf the MII has empaneled more than one ODR Institution, then at such level as well, a round robin system will govern allocation of references among them.

    b. Further, Stock Exchanges operating only commodities segment, the ODR Institution/s empaneled by such Stock Exchange is/are excluded from the market-wide round robin system. Other conditions in (a) above will continue to apply to such Stock Exchanges and ODR Institution/s.

    c. Further, references to ODR Institutions shall be made after a review of such

[4] For instances where the dispute pertains to an intermediary linked to more than one Stock Exchange/ Depository (or a company listed on more than Stock Exchange) then the Stock Exchange/ Depository with which the complaint was escalated becomes the relevant Stock Exchange/ Depository, otherwise it shall be subject to round robin

complaint/dispute by the relevant MII with the aim of amicable resolution and which review shall be concluded within 21 calendar days (or such other period that the Board may specify).

Conciliation

17. The ODR Institution that receives the reference of the complaint/dispute shall appoint a sole independent and neutral conciliator from its panel of conciliators. Such conciliator shall have relevant qualifications or expertise (please refer to **Schedule D)**, and should not be connected with or linked to any disputing party. MIIs shall ensure that appropriate measures are put in place regarding appointment of conciliators by the ODR Institutions.

18. Such conciliator shall conduct one or more meeting/s for the disputing parties to reach an amicable and consensual resolution within 21 calendar days (unless extended for a maximum period of 10 calendar days by consent of the disputing parties to be recorded in writing/electronically) from the date of appointment of conciliator by the ODR Institution, which shall do so within 5 days of receipt of reference of the complaint/dispute by the ODR Institution. Apart from attempting to actively facilitate consensual resolution of the complaint/dispute, the conciliator may consider advising the Market Participant to render required service in case of service-related complaints/disputes and/or consider issuance of findings on admissibility of the complaint/dispute or otherwise in case of trade related complaints/dispute (as the case may be).

19. If the process of conciliation is successful, the same shall be concluded by a duly executed settlement agreement between the disputing parties. Such an agreement shall be executed and stamped through an online mode, as permissible in law. When such agreement requires the Market Participant to pay the admissible claim value to the investor/client, the MII shall monitor the due payment/adherence to the terms of the settlement agreement until due receipt by the investor/client and/or performance of the required terms of settlement agreement.

20. In case the matter is not resolved through the conciliation process within the 21 calendar days (or within the extended period of 10 calendar days, extended by consent of the disputing parties):

    a. the conciliator should ascertain the admissible claim value of the complaint/dispute that the conciliator determines is payable to the investor/client and notify the disputing parties as well as the ODR Institution and the MII of the same. Such determination should also be made in all claims/complaints/disputes where the monetary value has not been ascribed by the person initiating the dispute;

b. An investor/client may pursue online arbitration (which will be administered by the ODR Institution which also facilitated the conduct of conciliation) on or after the conclusion of a conciliation process when the matter has not been resolved through such process, subject to payment of fees as applicable for online arbitration;

c. In case the Market Participant wishes to pursue online arbitration (which will be administered by the ODR Institution which facilitated the conduct of conciliation), then the Market Participant must deposit 100% of the admissible claim value with the relevant MII prior to initiation of the online arbitration and make the payment of fees as applicable for online arbitration. In case the Market Participant fails to deposit the amount then they may not initiate online arbitration and they may also face consequences as determined necessary or appropriate by the Stock Exchange and could also be liable to be declared as not 'Fit and Proper' in terms of the SEBI (Intermediaries) Regulations, 2008 and would be, inter-alia, liable to have their registration cancelled or their business activities suspended. A listed company that fails to deposit the amount may also face consequences as determined necessary or appropriate by the Stock Exchange. On an application made by the investor/client in this behalf to the relevant MII, the MII may, from the deposit received, release such amount to the investor/client not exceeding Rs 5,00,000/- (Rupees Five lakhs) or such sum as may be specified from time to time. On or before release of the said amount to the investor/client, the MII shall obtain appropriate undertaking/ indemnity / security in such form, manner and substance from the investor/client to ensure return of the amount so released, in case the arbitration proceedings are decided against the investor/client. If the arbitration proceeding is decided against the investor/client, subject to the terms of the arbitral award, such investor/client should return the released amounts. If the investor/client fails to return the amount released, then the investor/client (based on PAN of the investor/client) shall not be allowed to trade on any of the Stock Exchanges or participate in the Indian Securities Market till such time the investor/client returns the amount to the Market Participant. Further, the securities lying in the demat account(s) or the mutual fund holdings of the investor/client shall be frozen till such time as the investor/client returns the amount to the Market Participant. If security had been obtained, the same could be enforced/realised and adjusted towards the amount required to be returned. In the event, the arbitration proceeding is decided in favour of the investor/client, subject to the terms of the arbitral award, the MII shall release the balance deposit held by it (as deposited by the Market Participant) to the investor/client. The MII shall also monitor the due compliance by the Market

Participant with the terms of the arbitral award.

Arbitration

21. When the investor/client and/or the Market Participant pursue online arbitration, the ODR Institution shall appoint a sole independent and neutral arbitrator from its panel of arbitrators within 5 calendar days of reference and receipt of fees, costs and charges as applicable. Such arbitrator shall have relevant qualifications or expertise (please refer to **Schedule D**), and should not be connected with or linked to any disputing party. In the event that the aggregate of the claim and/or counter-claim amount exceeds Rs 30,00,000/- (Rupees Thirty Lakhs) or such amount as the Board may specify from time to time, the matter shall be referred to an Arbitral Tribunal consisting of three Arbitrators within 5 calendar days of reference and receipt of fees, costs and charges as applicable. MIIs shall ensure that measures are put in place regarding appointment of arbitrators by the ODR Institutions. In the instance where the parties wish to withdraw from arbitration before the arbitrator has been appointed then the fees shall be refunded after deducting the applicable expenses not exceeding Rs 100/- (Rupees One Hundred). However, withdrawal shall not be permitted after appointment of an arbitrator.

22. Subject to value of claim and/or counter-claim being in excess of Rs 1,00,000/- (Rupees One Lakh), the Sole Arbitrator or Arbitral Tribunal shall conduct one or more hearing/s and pass the arbitral award within 30 calendar days (or such other period as the Board may specify) of the appointment in the matter. When the value of claim and/or counter-claim is Rs 1,00,000/- (Rupees One Lakh) or below (or such other sum as the Board may specify from time to time), the Sole Arbitrator shall conduct a document-only arbitration process and pass the arbitral award within 30 calendar days (or such other period as the Board may specify) of the appointment in the matter.[5] However, the arbitrator, for reasons to be recorded in writing/electronically , may grant a hearing to the parties to the dispute. The Sole Arbitrator or Arbitral Tribunal shall be at liberty to extend such time for disputes exceeding claims and/or counterclaims of Rs 1,00,000/- (Rupees One Lakh) (or such other sum as the Board may specify from time to time), upto a further period of 30 calendar days (or such other period as the Board may specify) and for reasons to be recorded in writing/electronically, when the matter requires detailed consideration. The Sole Arbitrator or Arbitral Tribunal may, having regard to the nature of the claim and/or counterclaim, provide interim relief as may be required

5 If parties to the dispute do not provide any representation in the arbitral proceedings, the arbitrator may pass an ex-parte order after giving a notice of 7 calendar days to the concerned non-cooperative party(ies).

for reasons to be recorded after affording hearing to the parties to the dispute. The parties may make an application under the relevant section of the Arbitration and Conciliation Act, 1996 for correction/rectification of the award.

23. Upon the conclusion of the arbitration proceedings and issuance of the arbitral award, subject to the terms of the arbitral award, when such arbitral award requires payment of any amount by the Market Participant or performance by it of a certain nature, then such payment shall be made by the Market Participant within a period of 15 calendar days from the date of the arbitral award (unless such award requires payment sooner), and/or performance within such period as specified by the arbitral award. The MII shall monitor the due payment/adherence to the terms of the arbitral award until due receipt by the investor/client and/or performance of the terms of arbitral award. In the event, the parties do not comply with the arbitral award, the relevant MII shall inform the Board regarding such non-compliance on a periodic basis. Furthermore, the relevant MII shall provide necessary assistance to the investor/client for enforcement of the arbitral award.

24. Upon the issuance/pronouncement of the arbitral award, the party against whom order has been passed, will be required to submit its intention to challenge the award under Section 34 of the Arbitration Act within 7 calendar days in the ODR Portal for onward notification to the party/ies in whose favour the arbitral award has been passed and the relevant MII. Further, in the course of such a challenge, if a stay is not granted within 3 months from the date of the receipt of award, complete adherence to the terms of the arbitral award must be done.

25. If the Market Participant wishes to challenge such an arbitral award, then the Market Participant must deposit 100% of the amounts payable in terms of the arbitral award with the relevant MII prior to initiation of the challenge. In case the specified intermediary/regulated entity fails to deposit the amount then they may also face consequences as determined necessary or appropriate by the Stock Exchange and could also be liable to be declared as not 'Fit and Proper' in terms of the SEBI (Intermediaries) Regulations, 2008 and would be inter-alia, liable to have their registration cancelled or their business activities suspended. A listed company that fails to deposit the amount may also face consequences as determined necessary or appropriate by the Stock Exchange. On an application made by the investor/client in this behalf to the relevant MII, the MII may, from the deposit received, release such amount to the investor/client not exceeding Rs 5,00,000/- (Rupees five lakhs) or such sum as may be specified from time to time. On or before release of the said amount to the investor/client, the MII shall obtain appropriate undertaking/ indemnity / security from the investor/client to ensure return of the amount so released, in case the challenge is decided against the investor/client. If the challenge is decided against the investor/client, subject to

the judgement of the appellate forum, such investor/client should return the released amounts. If the investor/client fails to return the amount released, then the investor/client (based on PAN of the investor/client) shall not be allowed to trade on any of the Stock Exchanges or participate in the Indian Securities Market till such time the investor/client returns the amount to the Market Participant. Further, the securities lying in the demat account(s) or the mutual fund holdings of the investor/client shall be frozen till such time as the investor/client returns the amount to the Market Participant. If security had been obtained, the same could be enforced/realised and adjusted towards the amount required to be returned. In the event, the challenge is decided in favour of the investor/client, subject to the terms of the judgement of the appellate forum, the MII shall release the balance deposit held by it (as deposited by the Market Participant) to the investor/client. The MII shall also monitor the due compliance by the Market Participant with the terms of the arbitral award/judgement of the appellate forum.

Form of Proceedings

26. The ODR Institutions shall conduct conciliation and arbitration in the online mode, enabling online/audio-video participation by the investor/client, the Market Participant and the conciliator or the arbitrator as the case may be. The investor/client may also participate in such online conciliation and arbitration by accessing/utilizing the facilities of Investor Service Centers (ISCs) operated by any of the MIIs.

27. The venue and seat of the online proceedings shall be deemed to be the place:

    a) In case of disputes between investor/client and listed companies (including their registrar and share transfer agents) or any of the specified intermediaries / regulated entities in securities market (as specified in Schedule A): where the investor resides permanently or, where the investor is not an individual, the place where it is registered in India or has its principal place of business in India, as provided in the relevant KYC documents

    b) In case of disputes between institutional or corporate clients and specified intermediaries / regulated entities in securities market as specified in Schedule B:

        (i) where the institutional or corporate clients has its registered in India or has its principal place of business in India, as provided in the relevant KYC documents, and

        (ii) if in case the the institutional or corporate client is not registered in

India or does not have its principal place of business in India, then the place where the specified intermediaries / regulated entities in securities market as specified in Schedule B has its registered in India or has its principal place of business in India or

(iii) such court of competent jurisdiction in India as the institutional or corporate clients and specified intermediaries / regulated entities in securities market as specified in Schedule B may agree upon.

Fees & Charges

28. The costs of the dispute resolution mechanism on the ODR Portal will be borne in the following manner:

a. There shall be no fees for registration of a complaint/dispute on the ODR Portal.

b. Fees for conciliation process (*irrespective of claim or counter-claim value*) will be as under:

	Amount in Rupees
Conciliator's fee (*to be collected by ODR Institution and paid to Conciliator*) - for successful conciliation - for unsuccessful conciliation	 ₹ 4,800/- ₹ 3,240/-
ODR Institution's fees, in addition to the conciliator's fees (*to be collected by ODR Institution)*	₹ 600/-
Applicable GST, Stamp Duty, etc. on actual outgoings shall be borne by the concerned Market Participant	

Such fees may be borne by the MIIs and will be recoverable by them from the concerned Market Participant against whom the complaint/dispute is raised. Such fees shall be borne directly by the concerned Market Participant if it is initiating the dispute process. The Market Participant shall not shift the incidence of such fees to the investor/client at any time.

Unsuccessful Conciliation: In the event the disputing parties are not able to arrive at a settlement within the stipulated time (or such extended period as agreed to by them) it shall be said to be unsuccessful conciliation.

Late Fees: Initiation of conciliation process after six months from the date of transaction/dispute arising will require payment of Rs 1,000/- by the initiator of the complaint/dispute (whether such initiator be the investor/client or the Market Participant) and shall be collected by the MIIs and applied as specified by the Board from time to time.

c. The fees for the arbitration process will be as under:

	Rs 0 – 1 lakh *	Above Rs 1 lakh - 10 lakh	Above Rs 10 lakh - 20 lakh	Above Rs 20 lakh - 30 lakh	Above Rs 30 lakh - 50 lakh	Above Rs 50 lakh
Arbitrator's fee (*to be collected by ODR Institution and paid to Arbitrator*)	₹4,800 /-	₹8,000 /-	₹12,000 /-	₹16,000 /-	₹60,000 /-**	₹1,20,000 /-**
ODR Institution's fees, in addition to the arbitrator's fees (*to be collected by ODR Institution*)	₹600/-	₹1,000 /-	₹1,500/-	₹2,000/-	₹7,500/-	₹15,000/-
Applicable GST, Stamp Duty, etc. on actual outgoings						

* This slab will be applicable for service request related disputes also
** Fee for panel of arbitrators shall be split into a ratio of 40:30:30 with the higher proportion being payable to the arbitrator writing the arbitral award

Such fees will be payable at the time of initiation of the arbitration by the initiator (whether the investor/client *or* the concerned Market Participant), <u>and</u> by the person against whom the arbitration has been initiated. When the person initiating the arbitration has not specified a claim amount or has specified a lower claim amount, the admissible claim value as determined by the conciliator shall be reckoned for arriving at the claim value in such arbitration being initiated.

Such fees have to be deposited at the time of choosing to initiate arbitration through the ODR Portal within 7 days or such period as specified from time to time. In case the person against whom the arbitration has been initiated fails to deposit the fee payable within such period as specified then the person choosing to initiate the arbitration can deposit the fees payable on such person's behalf and shall be recoverable from such person through the arbitration process.

Subject to the terms of the arbitral award, the person who is successful in the arbitration proceedings shall receive a refund of amounts deposited by such person.

Late Fees: Arbitration initiated after one month of failure of conciliation and upto six months, the fees payable would be double of the non-refundable fees specified in the table above. Arbitration initiated after six months by a Market Participant will require payment of, additional fee of 50% of the fees, specified in the table above applicable per additional month of delay and which shall be on non-refundable basis. Such late fees shall be collected by the MIIs and applied in relation to operationalization and effective functioning of the ODR Platform and for the purposes as specified by the Board from time to time.

The fees shall be uniform across MIIs, ODR Institutions, conciliators and arbitrators.

29. All other usage or administrative fees as well as out-of-pocket expenses borne by the MIIs or the ODR Institutions in the management or operation or use of the ODR Portal would be subsumed in these fees and would not be separately chargeable.

<u>Empanelment and Training of the Panel of Conciliator and Arbitrators</u>

30. All MIIs and the ODR Institutions empaneled by the MIIs shall ensure that:

a. The number of conciliators and arbitrators on the panel of the ODR

Institutions is commensurate to the number of references of complaints/disputes received so that a conciliator / arbitrator / panel of arbitrators handle a reasonable number of references simultaneously and that all references are disposed of within the prescribed time.

b. The conciliators and arbitrators on the panel of the ODR Institutions should have undergone training and certification program/s or possess sufficient experience for such individual being regarded qualified or expert in online dispute resolution (conciliation or arbitration) and technology, finance, securities law, securities product or services, etc. to cater to the specific nature of a given complaint/dispute arising in the Indian securities market or such programs as specified by the Board from time to time (including courses provided by National Institute for Securities Market – NISM). Such training shall be taken on a periodic basis and at least annually. Initially, all the members of IGRCs or arbitrators who have been at present approved by the Board shall be eligible to be empaneled by the ODR Institutions.

c. The conciliators and arbitrators on the panel of the ODR Institutions shall be evaluated annually. MIIs will require the empaneled ODR Institution to submit an evaluation report to the MII.

d. Information on conciliators and arbitrators on the panel of the ODR Institutions will be disseminated on the website of each ODR Institution, including brief profile, qualifications, training and certifications, areas of experience, number of conciliation/arbitration matters handled, etc.

e. The mode and manner for an individual to be added to the panel of the ODR Institutions shall be specified by it, including the required experience and/or training and certifications.

f. The conciliator or arbitrators should be neutral and independent in respect of each and every matter or reference received by them, and not connected with or linked to any disputing party in any manner whatsoever.

Roles and Responsibilities of MIIs

31. MIIs shall enter into appropriate agreements with ODR Institutions outlining the role and responsibilities of each party in adherence to this circular, and also specify mechanism for handling and resolution of their inter-se disputes. The MIIs and the ODR Institutions empaneled by MIIs may also enter into necessary and appropriate contractual frameworks with the Market Participants, for them and their investors/clients in the Indian Securities Market, participating on the ODR

Portal and in the ODR mechanism as specified.

32. All MIIs (and the ODR Institutions empaneled by MIIs as applicable) shall enter into agreements with financial institutions/Banks for opening accounts and effective receipt, payment and disbursal of any amount including the fees, payments as required to be made vide the settlement agreement / arbitral awards or at the time of initiating an arbitration or challenge to an arbitral award, etc.

33. MIIs shall ensure that resolution of complaints/disputes referred on the ODR Portal are undertaken by the ODR Institutions empaneled by the MIIs within the stipulated timelines.

34. MIIs and the ODR Institutions empaneled by the MIIs, shall maintain Management Information Systems (**MIS**) reports, which shall be shared with the concerned Market Participant so the latter can adequately track timelines of any dispute. The Board may also require MIIs to furnish MIS reports in such form and on such periodicity as it may specify.

35. MIIs and the ODR Institutions empaneled by the MIIs, shall maintain relevant records, including directions/recommendations/orders passed at pre-conciliation, conciliation and arbitration stage for the period as specified in the extant law, and produced to relevant authorities as and when required. MIIs shall also ensure, in terms of their internal processes and contractual arrangements with ODR Institutions, that documents are adequately preserved, including in cases of change in the ODR Institution.

36. The ODR Portal and the facilities provided by the ODR Institutions will be user-friendly and accessible online/through audio-video to all the concerned parties and stakeholders, at all times.

37. The ODR Institutions to whom the dispute is referred and the Market Participant which is party to the dispute shall provide complete cooperation to the conciliator and/or arbitrator and/or panel of arbitrators including providing any information required to resolve the complaint in effective manner and within stipulated timelines.

38. MIIs, ODR Institutions and the Market Participants shall make reasonable efforts to undertake promotion of investor education and investor awareness programmes through seminars, workshops, publications, training programmes etc. aimed at creating awareness about the ODR Portal for the Indian Securities Market.

39. The MIIs shall lay down or modify their Code of Conduct, outlining the ethical standards that every party viz. the ODR Institution empaneled by the MIIs, Market Participants, the conciliators, the arbitrators must follow, and espouse the interests of investors in the Indian Securities Market, and resolve their complaints/disputes efficiently and in a time-bound manner.

40. The MIIs and the ODR Institution empaneled by the MIIs shall publish at such frequency as specified, statistics on the ODR Portal which provide information as to:
    a. Aggregate references of complaints/disputes received
    b. Aggregate number of complaints/disputes resolved by means of conciliation
    c. Aggregate number of complaints/disputes resolved by means of arbitration
    d. Aggregate value of claims decided in favour of investors/clients
    e. Summary of complaints/disputes on the ODR Portal against each category of specified intermediary or regulated entity and against listed companies

<u>Responsibilities of the Market Participants</u>

41. All agreements, contractual frameworks or relationships entered into by Market Participants with investors/clients in the Indian Securities market presently existing or entered into hereafter shall stand amended or be deemed to incorporate provision to the effect that the parties agree to undertake online conciliation and/or online arbitration by participating in the ODR Portal and/or undertaking dispute resolution in the manner specified in this Circular.

42. The Market Participants shall promptly attend to all complaints or disputes raised by its investors or clients in accordance with applicable SEBI rules, regulations and circulars. The communications shall clearly specify, the availability of the SCOREs portal and the ODR Portal to the investor/client and that the same could be accessed by such investor/client if unsatisfied with the response (or the lack thereof) of the Market Participant.

43. The Market Participants shall duly train their staff in attending to complaints/disputes and in handling the references arising from the SCOREs portal or the ODR Portal, and in participating in online conciliation and arbitration. Due cooperation and coordination with the MIIs and with the ODR Institutions shall be ensured by the Market Participants.

44. The Board may require the Market Participants to maintain such level of interest-free deposit with the MIIs or with the concerned designated body identified vide

the revised SCOREs guidelines and shall be such sums that it considers necessary and appropriate for honouring of any arbitral awards or amounts payable pending initiation of arbitration or challenge to an arbitral award. The amount of such deposit may vary depending on the category of Market Participant and may factor in the extent and nature of complaints or disputes against any specified Market Participant that are observable.

Timelines for Implementation

45. The provisions of this Circular will be implemented in phases:

46. The first phase shall include:

    a. development of the ODR Portal, empanelment of ODR Institutions by the MIIs, empanelment of conciliators and arbitrators by such ODR Institutions on or before August 1, 2023

    b. registration of Trading Members and Depository Participants on the ODR Portal by August 15, 2023, and

    c. commencement of registering of complaints/disputes against brokers and depository participants and their resolution on and from August 16, 2023.

47. The second phase shall include:

    a. registration of all other Market Participants on the ODR Portal by September 15, 2023

    b. commencement of registering of complaints/disputes against all other Market Participants and their resolution on and from September 16, 2023, and

    c. implementation of related processes and requirements envisaged in this Circular shall be in effect by September 16, 2023.

48. The Market Participants are directed to bring the provisions of this circular to the notice of the investors/clients and also to disseminate the same on their website.

49. This Circular supersedes the circulars/directions (and /or sections of the same dealing with mediation, conciliation and arbitration) issued by the Board till date on the subject matter and such supersession shall be the date of implementation of the first phase or second phase, as applicable, specified above. For ease of reference, such circulars are listed below:

    a. Circular No. SEBI/HO/MRD1/ICC1/CIR/P/2022/94 dated July 4, 2022

b. Circular No. SEBI/HO/MRDSD/DOS3/P/CIR/2022/78 dated June 3, 2022
c. Circular No: SEBI/HO/MIRSD/MIRSD_RTAMB/P/CIR/2022/76 dated May 30, 2022
d. Circular No.: SEBI/HO/CFD/SSEP/CIR/P/2022/48 dated April 8, 2022
e. Circular No SEBI/HO/CDMRD/DoC/P/CIR/2021/649 dated October 22, 2021
f. Circular No. SEBI/HO/MRD1/ICC1/CIR/P/2021/625 dated September 2, 2021
g. Circular No. SEBI/HO/MIRSD/DOC/CIR/P/2020/226 dated November 6, 2020
h. Circular No. SEBI/HO/MRD/DDAP/CIR/P/2020/16 dated January 28, 2020
i. Circular No. CIR/CDMRD/DCE/CIR/P/2018/48 dated March 14, 2018
j. Circular No. CIR/CDMRD/DEICE/CIR/P/2017/77 dated July 11, 2017
k. Circular No: CIR/CDMRD/DEICE/CIR/P/2017/53 dated June 13, 2017
l. Circular No: SEBI/HO/MRD/DRMNP/CIR/P/2017/24 dated March 16, 2017
m. Circular No. SEBI/HO/DMS/CIR/P/2017/15 dated February 23, 2017
n. Circular No. CIR/CDMRD/DIECE/02/2015 dated November 16, 2015
n-i. Circular No.: CIR/MIRSD/11/2013 dated October 28, 2013
o. Circular No. CIR/MRD/ICC/30/2013 dated September 26, 2013
p. Circular No. CIR/MRD/ICC/20/2013 dated July 05, 2013
q. Circular No. CIR/MRD/ICC/8/2013 dated March 18, 2013
r. Circular No. CIR/MRD/ICC/ 29 /2012 dated November 7, 2012
s. Circular No. CIR/MIRSD/2/2012 dated February 15, 2012
t. Circular No. CIR/MRD/DSA/03/2012 dated January 20, 2012
u. Circular No. CIR/MRD/DP/4/2011 dated April 7, 2011
v. Circular No. CIR/MRD/DSA/2/2011 dated February 09, 2011
w. Circular No. Cir. /IMD/DF/13/2010 dated Oct 05, 2010
x. Circular No. CIR/MRD/DSA/29/2010 dated August 31, 2010
y. Circular No. CIR/MRD/DSA/24/2010 dated August 11, 2010
z. Circular No. CIR/MRD/DP/19/2010 dated June 10, 2010
aa. Circular No. SEBI/MRD/ OIAE/ Dep/ Cir- 4/2010 dated January 29, 2010

50. Notwithstanding such supersession,

a. anything done or any action taken or purported to have been done or taken under the superseded circulars, prior to such supersession shall be deemed to have been done or taken under the corresponding provisions of this Circular;

b. the previous operation of the superseded circulars or anything duly done or suffered thereunder, any right, privilege, obligation or liability acquired, accrued or incurred under the superseded circulars, any penalty, incurred in respect of any violation committed against the superseded circulars, or any investigation, legal proceeding or remedy in respect of any such right, privilege, obligation, liability, penalty as aforesaid, shall remain unaffected as if the superseded circulars have never been superseded;

c. Matters or references currently under consideration of the IGRC or in arbitration (sole, panel or appellate arbitration) shall be disposed of as per the superseded circulars and within the timelines specified in such circulars;

d. For disputes pertaining to claims against defaulting trading members the same shall be addressed through the existing mechanism via the Core Settlement Guarantee Fund (Core SGF); and

e. All matters that are appealable before the Securities Appellate Tribunal in terms of Section 15T of SEBI Act, 1992 (other than matters escalated through SCOREs portal in accordance with SEBI SCOREs Circular), Sections 22A and 23L of Securities Contracts (Regulation) Act, 1956 and 23A of Depositories Act, 1996 shall be outside the purview of the ODR Portal.

51. The MIIs are directed to:

a. make necessary amendments to the relevant bye-laws, rules and regulations for the implementation of the above decision immediately;

b. disseminate the aforesaid provisions on their website and bring the same to the notice of all stakeholders including the Market Participants and investors/clients in the Indian Securities Market.

52. This Circular is issued in exercise of powers conferred under Section 11(1) of the Securities and Exchange Board of India Act, 1992 to protect the interests of investors in securities and to promote the development of, and to regulate the securities market. This circular is issued with the approval of the competent authority.

53. This Circular is available on the SEBI website at www.sebi.gov.in under the link "Legal > Master Circulars". This circular consolidates the circulars listed at Annexure I.

Yours faithfully,

S. Manjesh Roy
General Manager
Tel no.: 022- 26449710
Email: manjeshsr@sebi.gov.in

<u>Schedule A</u>
(See Paragraph 2 of the Circular)

Specified Intermediaries and Regulated Entities

List of securities market intermediaries / regulated entities against whom investors may invoke the ODR process:

1. *AIFs – Fund managers*
2. *CIS – Collective Investment management company*

2A. Commodities Clearing Corporations

3. *Depository Participants*
4. *Investment Advisors*
5. *InvITs - Investment Manager*
6. *Mutual Funds - AMCs*[6]
7. *Portfolio Managers*
8. *Registrars and Share Transfer Agents*
9. *REITs – Managers*

9A. Research Analyst

10. *Stock brokers*[7]

[6] Including for any claims/complaints/disputes arising on account of Mutual Fund Distributors of the Mutual Fund AMCs
[7] Including for any claims/complaints/disputes arising on account of Authorised Persons of the Trading Members

<u>Schedule B</u>
(See Paragraph 3 of the Circular)

Specified Intermediaries and Regulated Entities

1. *Clearing Corporations and their constituents*
2. *Credit Rating Agency and rating clients*
3. *Custodians and their clients/FPIs*
4. *Debenture Trustees and issuers*
5. *Designated Depository Participant and their clients/FPIs*
6. *KYC Registration Agency and their clients/intermediaries*
7. *Merchant Banker and issuers*
8. *Mutual Funds and Mutual Fund Distributors*
9. *Proxy Advisory and their clients*
10. *Proxy advisors and listed entities*
11. *Registrars and Share Transfer Agents and their clients*
12. *Research Analyst and their clients*
13. *Stock brokers and their Authorised Persons*
14. *Trading Members and Clearing Members*
15. *Vault Managers and beneficial owners*

Schedule C

Norms for empanelment of ODR Institutions by MIIs and continuing obligations of ODR Institutions

MIIs role and responsibility:

1. An MII shall empanel one or more ODR Institutions as a service provider and enter into relevant agreements with such ODR Institution(s) in accordance with guidelines issued by the Board on outsourcing of activities by stock exchanges, depositories and clearing corporations (as amended from time to time) and this circular. An MII should ensure that the primary/first ODR Institution to be empaneled with it, is not empaneled as the primary/first ODR Institution with any other MII .

2. An MII shall collect requisite information of a ODR Institution desirous of being empaneled for providing ODR services for the Indian Securities Market. Such information shall include: copies of registration certificate, memorandum of association and articles of association/ constitutional documents, rules governing conciliation and arbitration, PAN, Legal Entity Identifier number, composition of its board of directors, governing bodies and advisory councils, if any, and details of its shareholders and investors, and list of its authorised officials / signatories. Changes if any to any of these may be notified to the concerned MII promptly. An MII may drop an ODR Institution from its panel, if there is a delay in notifying or if the changes are viewed by the concerned MII as not conducive to continuance of the ODR institution on the panel.

3. An ODR Institution shall also furnish other credentials that are deemed relevant to the empanelment process including: details of conciliators and arbitrators empaneled by the ODR Institution, norms for such empanelment, fees, costs and charges levied for conduct of online conciliation and arbitration, institutional/corporate clients or other ecosystems where rendering online conciliation and arbitration, aggregate number of disputes received for resolution whether for online conciliation or arbitration, aggregate number of disputes resolved by means of online conciliation and arbitration, aggregate value of disputes resolved by means of online conciliation and arbitration, types and nature of disputes resolved by mean of online conciliation and arbitration, technologies, platform, platform features and facilities in conducting online conciliation and arbitration. Such credentials shall be furnished at the time of empanelment and thereafter on a quarterly basis (April/July/October/January).

4. The details of conciliators and arbitrators required to be furnished shall include: unique count of conciliators and arbitrators trained in the securities market, along with the education, training and professional qualification, number of years of experience, previous experience in conciliation / arbitration including experience in specific types, natures or sectors, languages conversant with (spoken/written) and other demographic details such as age, sex, location.

5. MIIs shall ensure that the ODR Institutions eligible for empanelment have the ability to integrate their own platform/systems with the ODR Portal for requirements and purposes as specified from time to time, and on or prior to empanelment undertake necessary integration. MIIs shall also ensure that the ODR Institutions also have sufficient technologies to ensure due secrecy, confidentiality and cyber-security for the dataflow between the ODR Portal and its platform/systems, collection of fees and charges (or its refund) and for the conduct of online conciliation and arbitration. MIIs shall also ensure the ODR Institution deploys and makes available such features or facilities on its platform/systems as required by the Board from time to time.

6. MIIs shall ensure that the ODR Institution and its conciliators and arbitrators abide by the Code of Conduct (**Schedule E**) and highest standards of independence, impartiality, ethics and confidentiality as befits conciliation and arbitration, and interests of Indian Securities Market and with the applicable laws including the Arbitration and Conciliation Act, 1996.

ODR Institutions' role and responsibility:

7. An ODR Institution empaneled by an MII should be/become a member of association/trade body having as its members MII empaneled ODR Institutions for the Indian Securities Market on or before October 31, 2023. Details of such association / trade body shall be furnished to the MIIs and the Board, and shall include: copies of registration certificate, memorandum of association and articles of association/ constitutional documents, PAN, Legal Entity Identifier number, composition of its board of directors, governing bodies and advisory councils, if any, and details of its members, and list of its authorised officials / signatories. Such association / trade body shall undertake such activities and perform such roles and responsibilities as may be specified from time to time.

8. Any complaint received against a conciliator or arbitrator shall be promptly examined by the ODR Institution and the findings/conclusions/actions taken will be reported to the MII. MII may conduct its own review into such a process and/or specific matter. Any complaint against an ODR Institution shall be

promptly examined by the MII and post the findings/conclusions, MII shall take appropriate actions.

9. An ODR institution may seek to be removed as an empaneled ODR Institution after disposal of all pending references. Further, in the event of a breach by the ODR Institution of the norms of empanelment specified, and/or SEBI regulations, circulars and advisories or norms of the MII, the MII may suspend/terminate the empanelment of the ODR Institution, without prejudice to its rights to take any further action against the ODR Institution. No new complaints/disputes will be assigned after the receipt of its notice to such effect.

10. MII shall ensure that each ODR institution shall abide by the following norms for furthering transparency and evolving precedents:
    a) Publish at pre decided regularity, data regarding disputes assigned, count of disposal of such references through conciliation, and count of disposal of references through arbitration (indicating to the extent feasible, decisions in favour of investors and in favour of intermediaries), which will be available freely to the public in such form, manner and mode as the Board may specify, and
    b) Publish decisions of the arbitrators, redacted or masked to ensure identity of the parties is not ascertainable, to help develop a database of matters and decisions, which will be available freely to the public in such form, manner and mode as the Board may specify.

11. MIIs shall inspect and/or audit the ODR Institution directly or through such person or firm that it may appoint, for, inter alia, verifying the adherence to these norms and applicable SEBI regulations, circulars and advisories.

12. MIIs shall ensure that the ODR Institutions abide by the SEBI regulations, circulars and advisories on online conciliation and online arbitration as applicable. MIIs shall ensure empaneled ODR institutions shall furnish an irrevocable, unconditional undertaking that it shall abide by the norms of empanelment specified, and SEBI regulations, circulars and advisories or norms as may be notified by SEBI and the respective MII from time to time. The ODR institutions shall also acknowledge through such undertaking that the grievance redressal and dispute resolution mechanisms have been set up by the Board as a part of its institutional framework to provide robust dispute resolution processes for the investors and Market Participants.

13. Any complaints/grievances against the ODR Institutions with respect to their services pursuant to this circular shall be resolved in accordance with agreements entered into the MIIs with their ODR Institutions.

14. MIIs shall ensure that the empaneled ODR Institutions have adequate infrastructure, manpower and resources to assist the former in maintaining compliance with their responsibilities under paragraphs 31 – 40 of this circular.

Schedule D

Suggested norms for empanelment of Conciliators and Arbitrators

The following factors are suggested for empaneling a person as a conciliator or arbitrator by the ODR Institutions:

1. Age: between 35 years to 75 years.

2. Qualification in the area of law, finance including securities market, accounts, economics, technology, management, or administration.

3. Experience: Minimum 7 years of experience as provided below.

4. Professional experience as outlined below could be considered:
   a. Financial services including securities market i.e. Banks, NBFCs, MIIs, other intermediaries of securities market;
   b. Legal services – Certified professionals handling conciliation, and /or arbitration independently; and/or
   c. Ex-officials from the Indian financial sector regulators viz., the Insurance Regulatory and Development Authority, the Pension Funds Regulatory and Development Authority, the Reserve Bank of India and the Securities and Exchange Board of India.

5. Knowledge and Skills such as:
   a. Knowledge on the functioning of the securities market;
   b. Securities Laws and Arbitration & Conciliation laws in India;
   c. Proficiency in English language (reading, writing and speaking);
   d. Proficiency in one or two regional languages and ability to read/write/speak/all - required for communication and for effective dispute resolution;
   e. Legal drafting and communications skills;
   f. Decision making skills required for imparting fair judgement;
   g. Understand party psychology and common online behaviours: Diversity and cross- cultural communication and possessing professional behaviour

7. The Conciliators and Arbitrators should satisfy the following criteria for empanelment:
   a. The person has a general reputation and record of fairness and integrity, including but not limited to (i) financial integrity; (ii) good reputation and character; and (iii) honesty;
   b. The person has not been convicted by a court for any offence involving moral turpitude or any economic offence or any offence against the securities laws;
   c. The person has not been declared insolvent and if yes, has not been discharged;
   d. No order, restraining, prohibiting or debarring the person, from dealing in securities or from accessing the securities market, has been passed by the Board or any other regulatory authority;
   e. No other order is passed against the person, which has a bearing on the securities market;

f. The person has not been found to be of unsound mind by a court of competent jurisdiction; and
g. The person is financially sound and has not been categorised as a willful defaulter.

<u>Schedule E</u>

Code of Conduct for Conciliators and Arbitrators

The Conciliators and Arbitrators shall:

i. Act in a fair, unbiased, independent and objective manner;
ii. Maintain the highest standards of personal integrity, truthfulness, honesty and fortitude in discharge of his duties;
iii. Disclose his/her/their interest or conflict in a particular case, i.e., whether any party to the proceeding had any dealings with or is related to the Conciliator and Arbitrator;
iv. Not engage in acts discreditable to his/her/their responsibilities;
v. Avoid any interest or activity which is in conflict with the conduct of his/her/their duties as a conciliatory or arbitrator;
vi. Avoid any activity that may impair, or may appear to impair, his/her/their independence or objectivity;
vii. Conduct proceedings in compliance with the principles of natural justice and the relevant provisions of the Arbitration and Conciliation Act, 1996, the SEBI Act, 1992, the Securities Contracts (Regulation) Act, 1956, the Depositories Act, 1996 and the Rules, Regulations and Bye-laws framed thereunder and the circulars, directions issued thereunder, and the contractual arrangements;
viii. Undertake training courses as may be specified time to time by the Board, including from NISM;
ix. Endeavour to pass arbitral award expeditiously and within prescribed time;
x. Pass reasoned and detailed arbitral awards; and
xi. Maintain confidentiality with respect to the proceeding and its associated recordings and only disclose confidential information as required by law or Courts of competent jurisdiction or legal authority.

Annexure I

List of circulars consolidated by the Master Circular

Sl No.	Reference Number of Circular	Date	Subject of the Circular
1	SEBI/HO/OIAE/OIAE_IAD-1/P/CIR/2023/131	Jul 31, 2023	Online Resolution of Disputes in the Indian Securities Market
2	SEBI/HO/OIAE/OIAE_IAD-1/P/CIR/2023/135	Aug 04, 2023	Corrigendum cum Amendment to Circular dated July 31, 2023 on Online Resolution of Disputes in the Indian Securities Market

ACER

European Union Agency for the Cooperation of Energy Regulators

ACER's Final Assessment of the EU Wholesale Electricity Market Design

April 2022

ACER

Executive Summary

The current energy crisis is in essence a gas price shock, which also impacts electricity prices. With the economic recovery in 2021, global gas demand bounced back to pre-pandemic levels and outstripped supply. Despite increasing LNG deliveries to Europe (linked with the rise in gas prices), sharply decreasing Russian gas pipeline supplies and the related geopolitical uncertainty put strong upward pressure on prices. In 2022, Russia's invasion of Ukraine heightened the crisis resulting in unprecedentedly high gas and electricity prices that severely impact consumers, retail suppliers, market participants and others.

Whilst this ACER assessment is likely to be read against the backdrop of the current energy crisis, its main focus is a somewhat longer-term perspective on the EU's wholesale electricity market design, in line with the original task assigned to ACER by the European Commission. Well before the height of the current crisis, the EU's wholesale electricity market design has been the subject of debate (in technical, academic as well as policy circles), in particular as to whether the current market design is fit-for-purpose given the significant changes needed to deliver the clean energy transition or whether, and if so, to what extent, the market design would need further adjustment.

"The current energy crisis is in essence a gas price shock, which also impacts electricity prices."

Need for improvements to the current market design?

In its 'Toolbox' Communication of October 2021, the European Commission tasked ACER with assessing the benefits and the drawbacks of the EU's current wholesale electricity market design and with providing recommendations for its improvement. This report seeks to deliver on that mandate.

ACER finds that the current wholesale electricity market design ensures efficient and secure electricity supply under relatively 'normal' market conditions. As such, ACER's assessment is that the current market design is worth keeping. In addition, some longer-term improvements are likely to prove key in order for the framework to deliver on the EU's ambitious decarbonisation trajectory over the next 10-15 years, and to do so at lower cost whilst ensuring security of supply.

Whilst the current circumstances impacting the EU's energy system are far from 'normal', ACER finds that the current electricity market design is not to blame for the current crisis. On the contrary, the market rules in place have to some extent helped mitigate the current crisis, thus avoiding electricity curtailment or even blackouts in certain quarters.

"... ACER finds that the current electricity market design is not to blame for the current crisis. On the contrary, the market rules in place have to some extent helped mitigate the current crisis ..."

The electricity market design is, however, not designed for the 'emergency' situation that the EU currently finds itself in. The ongoing political discussions on various exceptional interventionist measures bear witness to this.

Whilst not the primary focus of this assessment, ACER nevertheless offers some views on select interventionist measures contemplated in the current emergency situation and their respective risks. ACER also offers reflections on possible structural measures to hedge electricity customers against possible future periods of sustained high energy prices.

Ill-designed emergency measures could endanger hard-earned benefits of electricity market integration

Over the last decade, cross-border trade and the major efforts undertaken to further integrate electricity markets in Europe have delivered significant benefits for consumers. These benefits are estimated to be approximately 34 billion Euros a year. The benefits are due to the structure of the wholesale energy market enabling cross-border trade between Member States and improving security of supply across a larger geographical area. The electricity market design also facilitates the significant uptake of renewable generation, the acceleration of which is likely to prove a prerequisite for achieving the EU's ambitious decarbonisation trajectory at pace. Ongoing initiatives to further implement the current market design via a number of existing EU rules and regulations will deliver additional benefits.

Conversely, ill-designed emergency measures or distorting price signals by interfering in market price formation may roll back EU market integration and overall competition, thereby endangering the benefits achieved up until now and possibly increasing the overall cost of the energy transition up ahead, as further expanded below.

Future-proofing the electricity market design to help deliver the energy transition

"... Whilst increased energy independence vis-à-vis (particular) third-countries is a policy objective of growing importance, realising this may well depend on enhanced energy inter-dependence amongst EU Member States."

Going forward, the EU's ambitious decarbonisation trajectory requires fast and massive transformation across sectors. Given enhanced electrification of energy demand is amongst the most cost-efficient ways to drive down emissions from the wider economy, this trajectory is likely to be driven in large part by the decarbonisation of the electricity sector.

Electricity market integration across EU Member States will be key to pursue such power sector decarbonisation at lower cost, in turn ensuring security of supply by being able to draw on neighbouring jurisdictions in times of need. Put differently, whilst increased energy independence vis-à-vis (particular) third-countries is a policy objective of growing importance, realising this may well depend on enhanced energy inter-dependence amongst EU Member States.

What implications will this have for the current wholesale electricity market design?

The market design will need to facilitate a massive rollout of low-carbon generation, and in particular renewable generation characterised by high upfront investment costs, while ensuring that flexible resources complement intermittent renewable production where and when needed. Related to this, price volatility in the electricity system is likely to increase in the years ahead, indicating increasing flexibility needs of the system. Hence the market design will need to send adequate price signals to meet flexibility needs going forward, again where and when needed.

All in all, this ACER assessment identifies several areas where policy makers could put further emphasis to future-proof the current electricity market design. These fall under 6 broad headings:

1. Making short-term electricity markets work better everywhere: Overall, short-term markets are working well. In order to realise further benefits, Member States and national regulatory authorities should implement what has already been agreed in EU legislation and beyond. ACER highlights four such areas relevant for enhanced EU market integration: meeting the minimum 70% cross-zonal capacity target by 2025 (thus enhancing electricity trade between Member States); rolling out flow-based market coupling in the Core and Nordic regions as soon as possible; integrating national balancing markets; and reviewing the current EU bidding zones to improve locational price signals.

"... This ACER assessment identifies several areas [...] to future-proof the current electricity market design."

2. Driving the energy transition through efficient long-term markets: Long-term markets and improved hedging instruments need more attention to drive the massive investments needed up ahead. Currently, such long-term markets lack liquidity, particularly beyond three years in the future. ACER highlights that access for smaller market participants to Power Purchase Agreements (PPAs) could be improved (e.g. through public guarantees); that liquidity could be further stimulated via so-called 'market-making' efforts to help independent companies, traders etc. compete with large established firms (e.g. via tenders, mandatory measures or financial incentives); that national forward markets should be further integrated; and that collateral requirements imposed on market participants could benefit from being reviewed. Market-based centralised procurement could complement long-term electricity markets to address market failures (e.g. the procurement of ancillary services) or to speed up the deployment of specific technologies.

3. Increasing the flexibility of the electricity system: Enhanced flexibility resources, covering also for example seasonal flexibility needs, will be key for the electricity system going forward. Here, freely determined and competitive price signals are invaluable instruments for showing true system flexibility needs. These price signals should thus be preserved in order to drive relevant investment efficiently. Hence, national regulatory authorities and system operators should focus on removing barriers to the use of such flexibility resources.

4. Protecting consumers against excessive volatility whilst addressing inevitable trade-offs: Targeted measures to protect vulnerable consumers should be considered in times of sustained high prices, whilst not limiting the ability of e.g. energy communities or aggregators to provide innovative energy services for the benefit of the system and thus also consumers. Preserving some price signalling to incentivise desired behaviour remains important. In addition, Member States should strike a balance between ensuring the financial responsibility of retail energy suppliers for the benefit of consumer confidence, market stability etc., and keeping the market open for new responsible suppliers to reduce costs for consumers.

5. Tackling non-market barriers and political stumbling blocks: Member States should consider enhanced coordination of approaches to and plans for large-scale generation and grid infrastructure deployment, as a likely prerequisite for the efficient and accelerated roll-out of such investment. This in turn will rely on greater attention being paid to cross-border perspectives and needs, supplementing more national perspectives. In addition, addressing barriers and recurrent delay factors to infrastructure roll-out remains key.

6. Preparing for future high energy prices in 'peace time'; being very prudent towards wholesale market intervention in 'war time': The need for interventions in market functioning should be considered prudently and carefully in situations of extreme duress and if pursued should, ideally, seek to tackle 'the root causes' of the problem (currently gas prices). Additionally, ACER points to a few structural measures for hedging, which might be considered to alleviate possible concerns about future periods of sustained high energy prices.

Exceptional emergency measures currently under debate

The current energy price crisis is exceptional in nature. Many Member States have introduced short-term measures to alleviate the impact of the high prices. In addition, governments across the EU debate whether additional interventionist measures should be taken, what the relative benefits and risks of such measures are, and how such measures may jeopardise (or not) the current benefits resulting from electricity market integration across the EU.

Whilst such measures are not the primary focus of this ACER assessment, Section 5 below lists a spectrum of such measures, all of them proposed or hinted at by different quarters across the EU. These range from less interventionist measures that safeguard wholesale market functioning (such as targeted support for vulnerable customers) to the more interventionist (e.g. taxing windfall profits through to capping the price of the electricity market). As a rule of thumb, ACER considers that the more interventionist the approach, the higher the potential to distort the market, especially in the medium to long-term. Such distortions imply that wrong investment choices are likely to be made vis-à-vis future needs and/or that much-needed innovations to address changing system needs are less likely to happen. Furthermore, measures that are more interventionist may dampen private sector investment, influence perceptions of political risk and/or inadvertently exacerbate supply shortages.

Accordingly, when contemplating extraordinary measures here and now, policy makers should carefully consider the potential for negative consequences in the medium and long-term. This is further accentuated by the fact that much effort over many years has been put into creating the current electricity market framework. If it were to be suddenly 'uprooted', as opposed to further improved or enhanced, it could have significant implications for the ability of the electricity market to deliver on key policy objectives over the coming decade. ACER cautions to consider prudently the need for interventions in electricity market functioning in the current circumstances, and if pursued for policymakers to tackle the root cause of the problem (currently gas prices) rather than the electricity market framework itself.

Hence, if Member States consider such a 'root cause' intervention necessary, it would seem relevant to pursue measures that accelerate gas demand reduction (efficiency efforts, fuel switching etc.) and/or deploy additional efforts that can put downward pressure on gas prices (e.g. new supply or lower-price supply coming to Europe), whilst retaining prices that still secure needed liquified natural gas (LNG) deliveries. The latter effort would likely require intense dialogue between governments in the EU and key gas suppliers.

Finally, regarding more structural measures for the future, ACER points to a few options being debated in academic circles for hedging against future periods of sustained high energy prices. These are not immediate options to alleviate the current extraordinary prices, but may alleviate possible concerns about future energy price shocks. One such measure is a 'temporary relief valve' when wholesale electricity prices change unusually rapidly to high levels over a sustained period. Another is a financial option (sometimes dubbed 'affordability option') whereby pre-identified consumer groups are hedged against sustained high prices occurring over a longer period above a certain threshold. ACER points out that each such measure has advantages and drawbacks.

Gas markets require our focus in the coming years

Given the renewed impetus towards diversifying the EU's gas supply, gas prices are likely to be determined increasingly by the global LNG market in the coming years. Accordingly, this ACER assessment considers some of the key developments impacting the LNG market. In particular, ACER suggests for policy makers and others to pay close attention to mechanisms that can limit gas price exposure and secure additional gas supply to offset decreasing supplies of Russian gas. Such measures include for example enhanced long-term contracting and higher gas storage stocks, noting however that both come at a cost. As a result, long-term and short-term gas contracts are likely to coexist for some years to come. Gas storage will increasingly support security of supply, whilst also assisting flexible operation of the energy system.

This assessment is not 'the full story'. As the energy transition unfolds, new challenges are likely

This ACER assessment focuses primarily on the current wholesale electricity market design, looking at what the design is called upon to deliver over the next 10-15 years. In the conclusions section, ACER sets out an overview of the measures it puts forward for consideration by EU policymakers, these numbering 13 in total (a summary infographic is provided below).

This assessment does not seek to be 'the full story' of how energy systems in Europe may evolve over this time frame. By way of example, some of the evolutionary trends not so readily tackled in this assessment are: (a) the increased integration of the energy system across energy carriers, transport, buildings and other sectors (implying e.g. that energy system-wide benefit assessments and planning will become more complex); (b) the application of 'energy efficiency first' principles in an evolving system (likely drawing on enhanced resource sharing and balancing energy savings solutions with low-cost capacity additions); or (c) the relative weight of more centralised, utility-scale solutions vis-à-vis smaller and more localised solutions (the latter possibly bringing enhanced resilience and lower price volatility at the consumer-level whilst perhaps raising questions of overall system costs).

Notwithstanding the considerable breadth of measures put forward, it is likely that new regulatory challenges and opportunities will appear as the clean energy transition further unfolds. Hence, it will be key for governments and regulators to detect and address such challenges early on and to tackle them in a coordinated manner across the EU.

In summary, ACER puts forward the following 13 measures for the consideration of policymakers

13 measures for the consideration of policymakers, **future-proofing** the EU wholesale electricity market design

ACER
European Union Agency for the Cooperation of Energy Regulators

1. Speed up electricity market integration, implementing what is already agreed

2. Improve access to renewable Power Purchase Agreements (PPAs)

3. Improve the efficiency of renewable investment support schemes

4. Stimulate 'market making' to increase liquidity in long-term markets

5. Better integrate forward markets

6. Review (and potentially reduce, if warranted) collateral requirements

7. Preserve the wholesale price signal and remove barriers to demand resources providing flexibility

8. Shield those consumers that need protection the most from price volatility

9. Tackle avoidable supplier bankruptcies, getting the balance right

10. Tackle non-market barriers, ensuring generation and infrastructure is built at pace

11. Consider prudently the need for market interventions in situations of extreme duress; if pursued, consider tackling 'the root causes'

12. Consider public intervention to establish hedging instruments against future price shocks

13. Consider a 'temporary relief valve' for the future when wholesale prices rise unusually rapidly to high levels

Want to learn more?

Check out the full report on ACER's Final Assessment of the EU Wholesale Electricity Market Design.

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1. Introduction

1.1. Background to this assessment

The recent energy price surge sparked a call by some to reform the EU electricity market design. The European Commission in October 2021, in its 'Tackling rising energy prices: a toolbox for action and support' Communication (hereafter 'Toolbox' Communication), tasked ACER with assessing the benefits and drawbacks of the EU's current wholesale electricity market design and with providing recommendations for its improvement.

ACER published a Preliminary Assessment in November 2021. In that report, ACER made clear that the root of the problem was the rise in global gas prices for various supply and demand dynamics prevalent at the time. Other factors also played a role such as Europe's lower-than-average gas storage stocks; limited additional pipeline gas imports to the EU; rising Emissions Trading System (ETS) allowance prices; and somewhat unusual weather patterns in Europe in 2021 affecting both generation and demand. Since then, a number of developments have significantly impacted gas and thus also electricity prices most notably Russia's invasion of Ukraine in February, leading to high uncertainty as to the near-term outlook for gas supply to the EU.

This report is ACER's final assessment, delivering on the European Commission's mandate.

1.2. Structure of this assessment

This assessment confirms that the current EU electricity market design is based on relevant and enduring principles and that as such, in ACER's view, it should be preserved. However, looking to the future, the current market design should be complemented to support the policy objectives set for the EU as a whole, in particular to deliver on the EU's ambitious decarbonisation trajectory.

Section 2 explains the steep rise in European energy prices over the past year. It describes the evolution of the price shock and illustrates how markets reacted to it. It briefly touches upon the consequences for consumers (addressed in further detail in Section 7), as well as the latest market outlook for energy prices throughout 2022 and into the first quarter of 2023.

Section 3 explains how the current market design works both in 'normal' times and as a mitigating factor during more extreme events such as the current energy price shock. The section describes the relevance of certain market design fundamentals, giving examples of the benefits provided by the current market design and overall EU electricity market integration. Finally, it shows why completing a number of already-decided, but still-to-be-implemented market integration priorities remains key.

Section 4 examines ways to improve the current market design in light of the EU's ambitious decarbonisation trajectory and the resulting changes in the power system. Elements outlined include for example improvements to long-term markets and the availability of hedging instruments (e.g. on enhanced forward markets and wider access to PPAs) as well as the better use of flexibility resources. The section also touches upon the benefits of further coordination amongst Member States as regards generation and grid infrastructure roll-out.

Section 5 notes the calls for temporary interventions in electricity market functioning given the current extreme price shocks. ACER offers certain considerations for policy makers ahead of taking such intervention decisions, suggesting a possible different route that targets the root cause of the current situation (gas prices) rather than the symptoms (electricity prices). Finally, this section points to a few structural measures relevant for 'insuring' or hedging against possible future periods of sustained high energy prices.

Section 6 takes a closer look at the outlook for gas markets, relevant for the EU's attempts to further diversify its gas supply in the coming years. It adds perspectives on likely gas contracting models and the role of gas storages across Member States in the years ahead.

Section 7 focuses on limiting the undesirable impacts of increased price volatility on energy consumers. It considers options that balance the respective interests of retail suppliers, consumers and society as a whole. In addition, it lists some of the learnings from last year's application in many Member States of the so-called Supplier of Last Resort mechanism. Finally, it points to the facilitation of demand-side response as a measure for enhanced system benefit and for the alleviation of unwanted price volatility.

Section 8 concludes with a summary of the 13 measures that ACER puts forward for policy makers' consider-ation.

2. Price levels and drivers

2.1. ‘Roller coaster gas prices’: High global LNG prices followed by restricted Russian gas flows send gas prices soaring

Energy prices reached record high levels across 2021 and hit their highest point in the first weeks of March 2022. The price surge can be split into three distinct phases (see Figure 1 below):

- Phase 1 (‘the first price crunch’) across Summer and Fall 2021, when scarce LNG imports and narrow pipeline flows led to the first wave of price rise;
- Phase 2 (‘market-response from LNG’), from late 2021 through early 2022, when high gas prices attracted extra LNG, while Russian pipeline supplies decreased; and
- Phase 3 (‘war emergency’) from late February 2022, when the Russian invasion of Ukraine further aggravated the price surge.

Figure 1: Overview of events and market fundamentals driving EU gas prices, TTF month-ahead contract (EUR/MWh), (May 2021 - April 2022)

Source: ACER based on ICIS Heren’s price data.

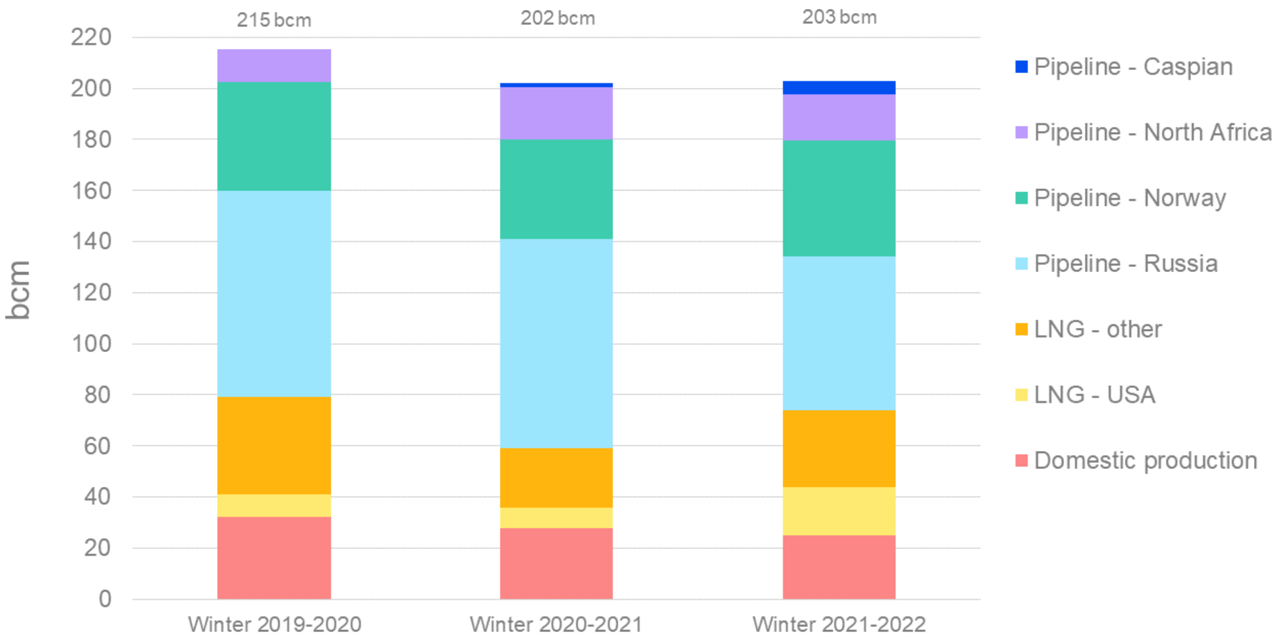
The main price drivers in Phase 1 were increased EU gas demand together with tight global gas supply; this occurring amidst a global rebound in economic activity and unexpected gas production outages. During Phase 2, EU LNG imports (which had decreased in Phase 1 because spot LNG cargoes had been attracted to higher-priced Asian markets) recovered due to stronger EU gas hub price signals. Phase 3 is the period from late-February 2022 onwards when the Russian invasion of Ukraine led to an immediate and sharp rise in gas prices.

> *"... The current price shock and very significant price volatility would seem to stem less from physical shortages and more from perceived risks of potential significant disruption of Russian gas flows going forward."*

Looking more closely at this latest phase, it would seem that price developments are significantly influenced by the extreme uncertainty as to the near-term outlook for gas supplies to the EU. As shown in Figure 2, so far this year, physical gas supplies to the EU have remained close to historical levels, with LNG deliveries replacing Russian gas pipeline flows to a considerable extent. Hence, the current price shock and very significant price volatility would seem to stem less from physical shortages and more from perceived risks of potential significant disruption of Russian gas flows going forward.

As the outlook for such disruptions remains very uncertain for market participants, day-to-day price volatility is unusually high. This in turn has knock-on effects on market functioning, leading e.g. to rising collateral needs[1] for market participants vis-à-vis financial institutions given the latter's concerns about the former's ability to manage the increased price risks and their fluctuations in the very near-term[2].

Figure 2: Evolution of EU gas supply sourcing origins - bcm (Winters 2019 - 2022)



Source: ACER based on ENTSOG and Refinitiv.

Note: Winter season is the sum of Q4 year 1 and Q1 year 2 (i.e. Winter 2021-2022 sums the flows across Q4 2021 and Q1 2022). The assessment does not include storage withdrawals.

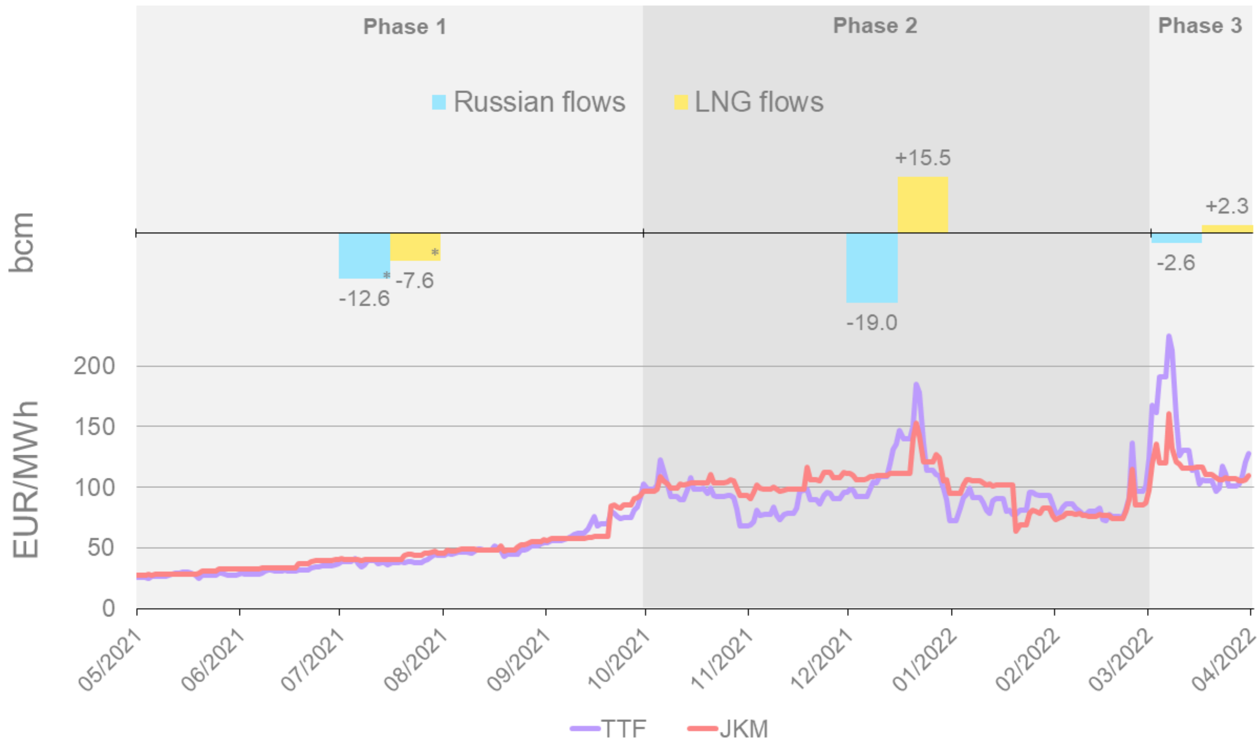
[1] Collateral refers to money put aside as a guarantee by the buyer and seller of forward products. This guarantee covers the risk of failure of one of the counterparties.

[2] From the strict point of view of market functioning (whilst of course acknowledging the many other factors and political priorities in play), if greater up-front clarity could be provided as to the intentions of EU governments vis-à-vis Russian gas imports for the rest of the year, it would likely have a price volatility-dampening impact.

Figure 3 below traces the evolution of EU prices (represented by the Dutch TTF hub) and Asian gas prices (represented by the Japan Korea Market price Index) relative to the year-on-year changes in EU LNG (shown in yellow) and Russian pipeline imports (shown in blue) across these three phases. The recovery of LNG imports in Phase 2 demonstrates the value of retaining price signalling as significant volumes of flexible LNG cargoes were redirected towards the EU (attracted by the higher prices). However, the increase in LNG supplies were insufficient to fully offset the overall effect on prices of the limited Russian pipeline flows (as Gazprom did not offer additional volumes at EU hubs beyond its long-term supply commitments). Below-average underground gas storage stocks (attributable to a large extent to limited Gazprom injections) further exacerbated the high gas price environment in Europe. The result was a further tightening of the European gas market and continuous upward pressure on prices.

Going forward, with the outbreak of war and given Russia's role as a major energy and commodity exporter, Europe (like Asia or other gas importing jurisdictions) are likely to face high energy and commodity prices in the near term, see further below.

Figure 3: Comparison of EU and Asian gas prices (EUR/MWh) and year-on-year changes in EU LNG and Russian pipeline imports (bcm) across three phases (May 2021 - April 2022)



Source: ACER based on ICIS Heren, ENTSOG and GIE.

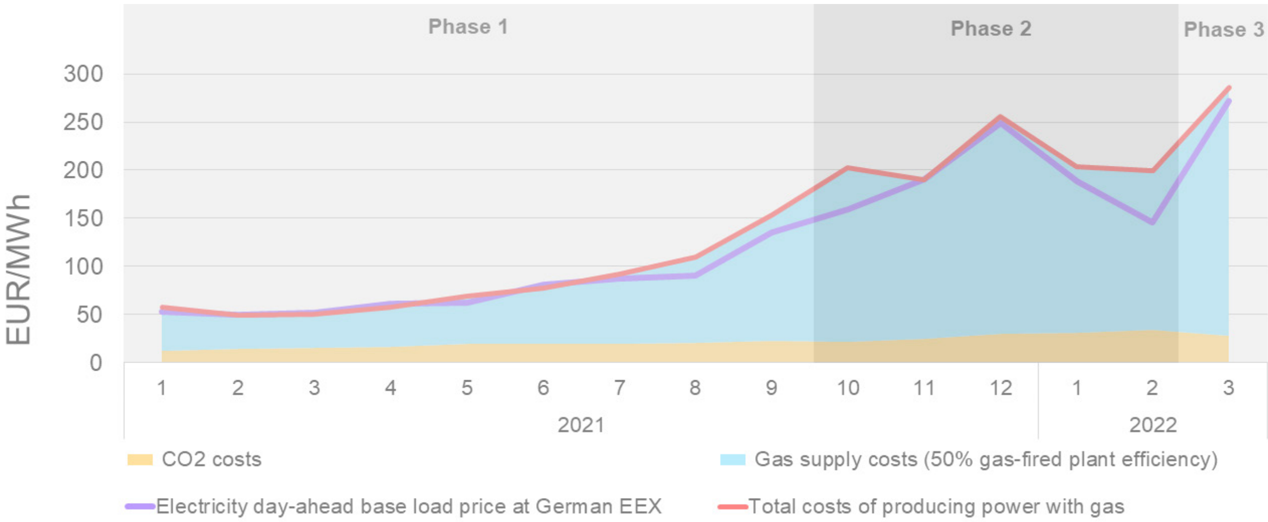
Note: The relative year-on-year changes for Phase I are referenced against the May-September period of the year 2019. The imports across the May-September period of 2020 were non-typical, due to Covid-19 impacts on demand.

2.2. High gas prices drive up electricity prices

The rising costs of gas-fired power generation drove up electricity prices, due to the strong influence of gas-fired plants in setting electricity prices in the short-term EU power markets[3].

Additional factors such as unfavourable wind conditions, maintenance on nuclear reactors and growing emission allowance prices under the ETS further amplified electricity prices[4]. Figure 4 illustrates the main drivers underlying the record-high electricity prices traded on the German EEX market (which serves as a reference for European electricity markets), with spiralling gas prices being the primary driver (compared for example to the price of emission allowances).

Figure 4: Electricity price development in Germany and breakdown of the costs (EUR/MWh) of producing electricity from gas (May 2021 - March 2022)



Source: ACER based on ICIS Heren.

Besides reaching high overall levels, the volatility of electricity and gas prices also reached record-high levels across the EU (e.g. spot-priced gas more than doubled the ten-year average, rising by a factor of four in December 2021). Prices varied with LNG and pipeline supply estimates, weather forecasts (including renewable generation prospects) and in the last phase, with increased geopolitical risks.

The high-risk environment also impacted the liquidity of forward markets. From Q4 2021 some traders found it difficult to maintain their financial positions which worsened by Q1 2022; this in turn affected the ability of companies to hedge their future price risks. Indeed, as prices rose so did the financial guarantees (collaterals) required for trading. Some counterparties were priced out and some became increasingly risk averse. This led some traders and industry representatives to seek potential mitigating measures from public authorities so as to facilitate continuous energy trade, including e.g. reducing or backing-up collaterals or waiving trading cancellation fees. Solutions to mitigate volatility and excessive price spikes are discussed further in Section 4.

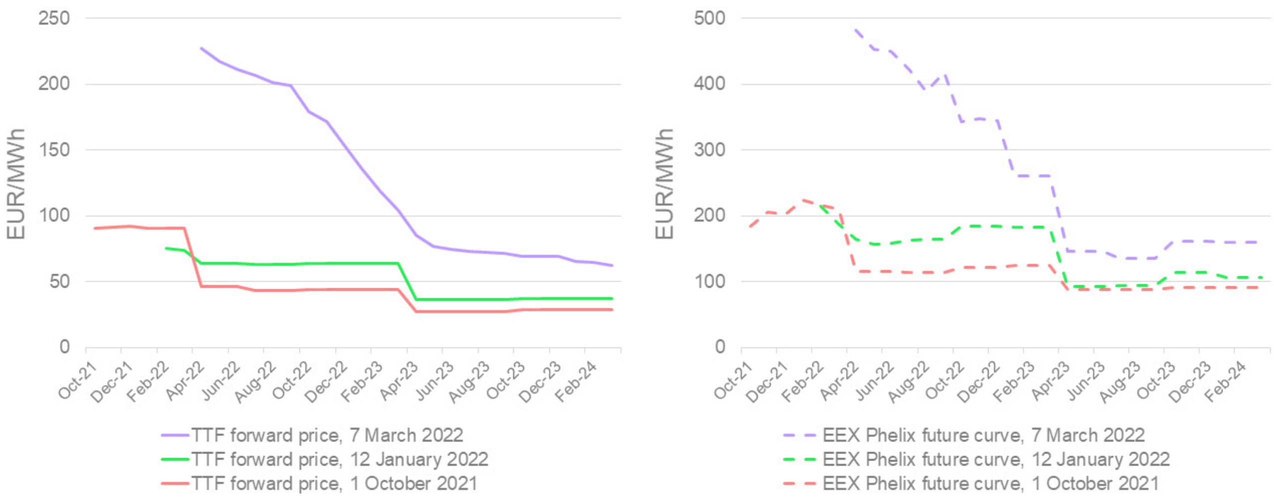
[3] Gas-fired plants often set marginal electricity prices in EU power markets. When hydro plants act as price setting-units instead, they optimise their yearly production and thereby tend to relate their opportunity cost to the costs of generating electricity with gas. Bidding at opportunity costs is thus an integral part of competitive electricity markets. To prevent and address market abuses, ACER and national regulatory authorities (NRAs) closely monitor trading activity under the EU-wide REMIT framework. For further details on the electricity (pay-as-clear) marginal pricing mechanism, see ACER's Preliminary Assessment (November 2021).

[4] These additional factors had a distinct bearing in different time periods. Renewable power generation was particularly low in Q1 and Q2 2021, whilst the nuclear outages experienced in France were more significant from Q4 2021 onwards. ETS prices rose since the end of Q1 2021 and at a faster pace from the end of Q3 2021 when gas-to-coal switches created upward pressure.

2.3. Energy prices will likely remain high in the near term

The latest market estimates indicate that energy prices will remain high for the rest of 2022 and into 2023; this not least in view of the ongoing tension and uncertainty around near-term gas supply. As seen in the electricity and gas forward curves in Figure 5, market participants anticipate a gradual downward trend from Q2 2023, though noting as a general word of caution that forward price estimates can be subject to rapid changes under the current stressed market conditions (spot prices' rapid variations also influence forward prices to some extent). Figure 5 also shows the evolution of forward prices across the three previously identified price phases.

Figure 5: Evolution of gas (TTF) and electricity (EEX) forward prices (EUR/MWh), comparing the contractual outlook (October 2021 and March 2022)



Source: ACER based on ICIS Heren.

"The latest market estimates indicate that energy prices will remain high for the rest of 2022 and into 2023 ..."

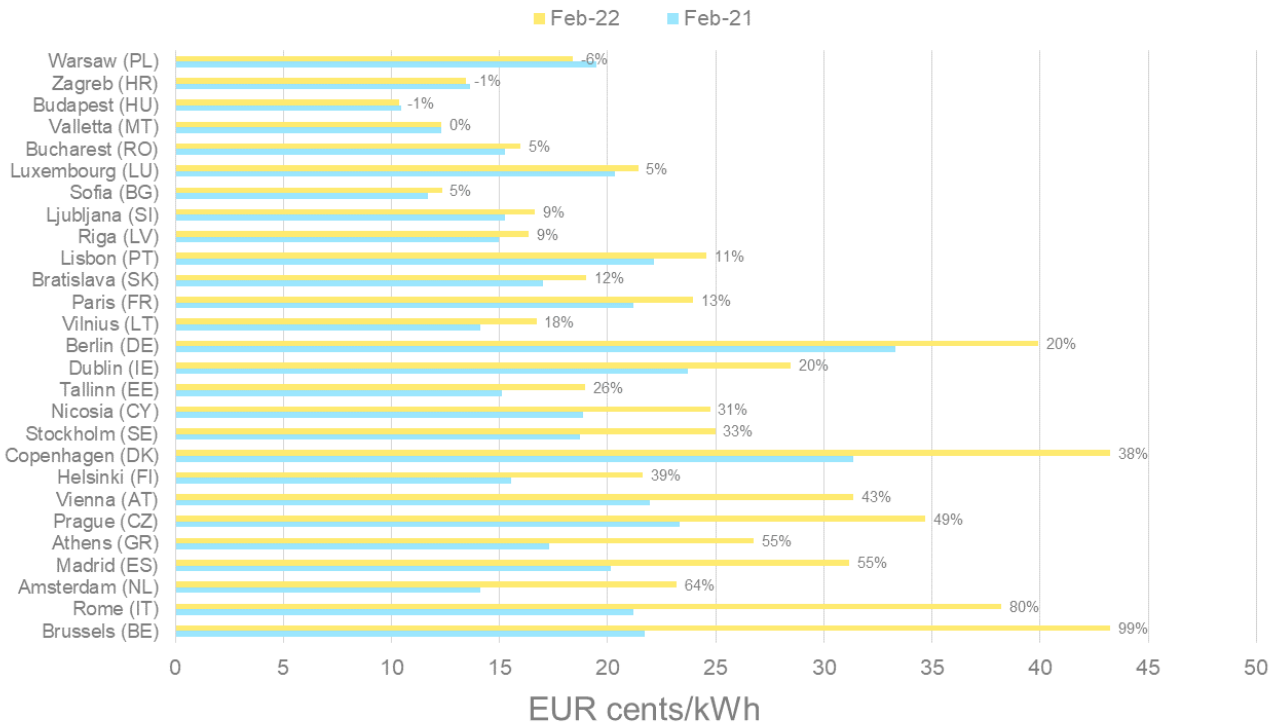
While mid-term electricity and gas prices are highly correlated via gas-fired power generation often setting the marginal price of electricity, a few specific factors explain the different shapes of their respective forward curves. These factors include (among others) seasonal demand patterns, different storage capabilities, gas storage restocking needs and the intermittency of renewable electricity generation[5].

[5] By way of example, renewable electricity production is usually higher relative to demand in the summer, thereby lowering electricity prices. Interestingly, in 2021 despite the record-high average electricity prices, the occurrence of negative electricity prices continued to increase, becoming more frequent than in pre-COVID years (see the most recent ACER Market Monitoring Report data for the year 2021). This results from expanding renewable generation capacity (with negative prices more common when the national subsidy scheme in place is detached from price signals reflecting the system needs) coupled with a lack of cost-efficient storage solutions. The prevalence of negative prices might also indicate additional interconnection capacity needs and, more generally, underlines the need to adequately reward flexibility services (negative prices are more common in market zones with less flexible assets).

2.4. Households and industrial consumers are heavily impacted

The high energy prices led to significantly higher bills, adversely affecting European consumers. Up to February 2022, retail electricity prices rose by 30% on average (65% for retail gas) from February 2021 to February 2022, though with significant variation amongst Member States as seen in Figure 6. The impacts on individual households varied according to the types of contracts and pricing mechanisms as well as the short-term mitigating measures taken by national governments. Unusually, lower prices were recorded in a few Member States in February 2022 compared to the previous year. The highest rise in household electricity prices (99%) was in Belgium.

Figure 6: Evolution of household electricity prices (EUR cents/kWh) and % year-on-year (Feb 2021 - Feb 2022)



Source: ACER based on Vaasa ETT.

Continued high energy prices could further impact industrial activity. EU industrial gas demand dropped year-on-year by -6% in Q4 2021 and by -9% in Q1 2022, some of this due to reduced production by parts of energy-intensive industry. High gas prices have also triggered a rise in inflation and impacted economic recovery efforts after the COVID-19 pandemic.

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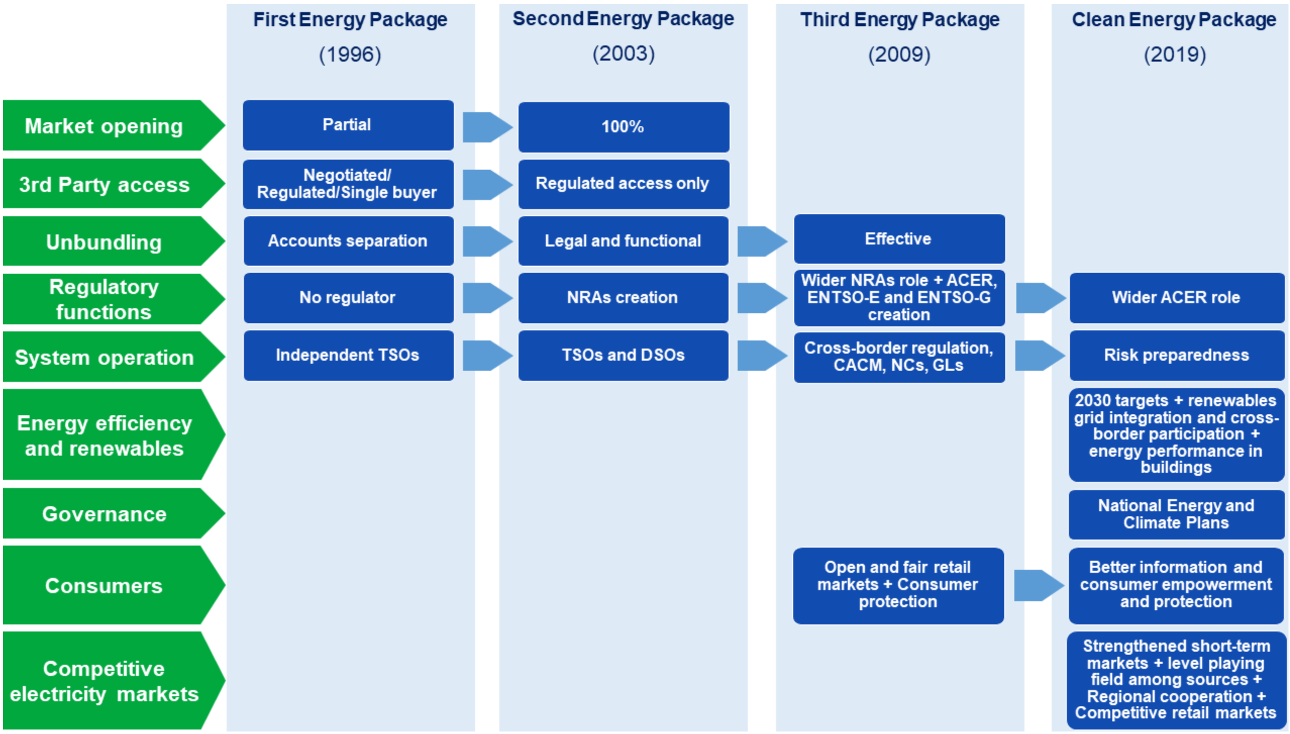
3. EU wholesale electricity market design: benefits and remaining implementation challenges

The liberalisation of national electricity markets across Europe and their integration into a single European market (often called the EU's 'Internal Electricity Market') is a massive project which has evolved over the past twenty years (Figure 7).

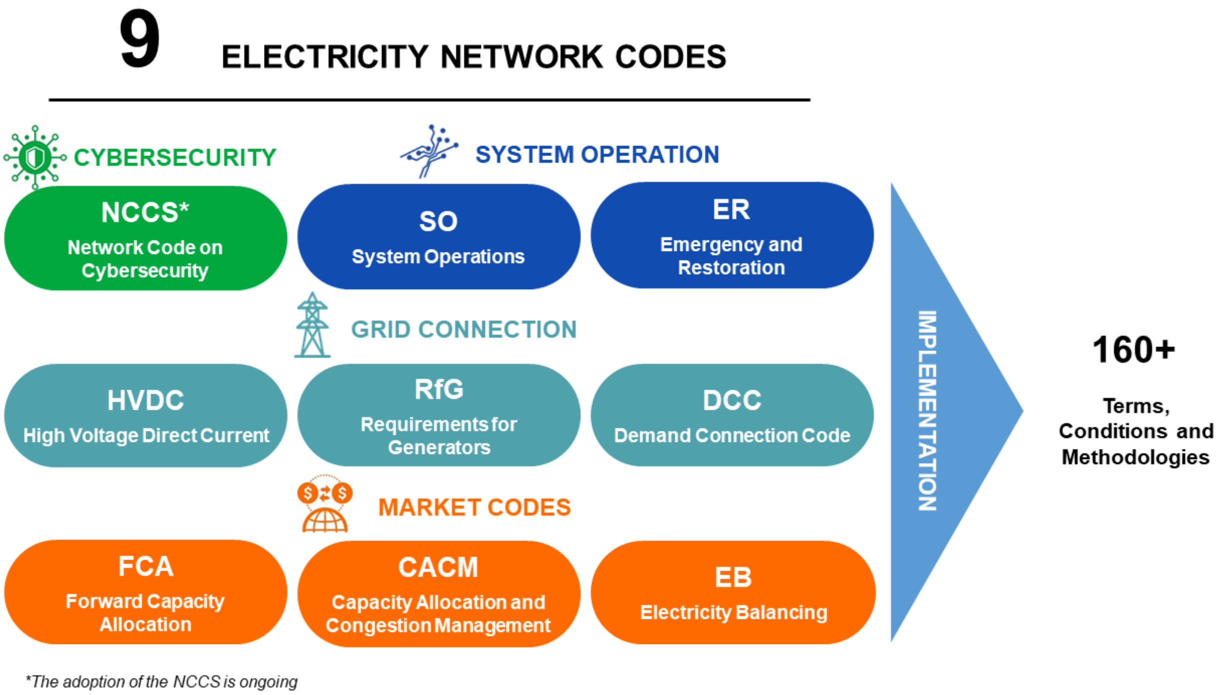
Figure 7: Evolution of EU energy legislation to build the market and support the clean energy transition



Source: ACER elaboration.

For EU electricity market integration to progress at pace, harmonisation of national markets and their integration need to go hand in hand. This is achieved by adopting and implementing the same rules across the EU. This is the role of EU-wide legally-binding rules called 'network codes'. Figure 8 below provides an overview of the range of aspects regulated by EU network codes today.

Figure 8: Overview of the legally-binding EU electricity network codes



Source: ACER.

The alignment and coordination of national policies and rules is key for Europe's integrated market model to deliver on key objectives such as competitive prices, security of supply and decarbonisation. The continued integration of European energy markets will be critical to deliver the EU's ambitious decarbonisation trajectory.

3.1. Some fundamentals (liquidity, price formation, carbon price signals)

The EU electricity market design is influenced by both the characteristics of electricity (e.g. that it cannot be stored easily) and broader policy goals. A few features are noteworthy.

First, markets (from long-term to short-term) need to be sufficiently 'liquid' (i.e. with sufficient buyers and sellers) to function well. The short-term electricity markets aim at optimising operational decisions, whereas the long-term markets focus on hedging risks related to investments. European regulation has so far mainly focused on short-term markets because, among other reasons, strong coordination here is necessary to ensure efficient cross-border trading close-to-real-time.

Long-term markets have received less attention possibly because, in the past, managing uncertainty was slightly less critical compared to today. Whatever the reason, currently there seems to be a mismatch between the increasing levels of price uncertainty and the liquidity observed in long-term horizons, particularly beyond 3 years ahead of delivery. Consequently, long-term markets (including bilateral PPAs) and hedging instruments deserve increased attention. While hedging instruments have been available for many years, their liquidity is very different in different markets. A key question therefore is whether there is a need for measures to strengthen long-term markets and, if so, how. These issues are addressed in Section 4.

Second, in the current EU electricity market design, market prices are freely formed by demand and supply. This ensures not only an optimal market outcome but also a level-playing field across the EU. By contrast, when electricity wholesale prices are regulated, e.g. by introducing price caps, undesired effects including security of supply concerns or market exit issues may arise.

Third, the current electricity market design takes account of the carbon emission pricing signal from the ETS. Fossil fuels (e.g. coal) are rendered more expensive because of the ETS price. Hence, the current market design and ETS taken together incentivise efficient investment in lower-carbon technologies.

Overall, any market design will need to consider the special fundamental characteristics of electricity as a commodity, the evolving challenges of the system as it incorporates a growing share of renewables, the different needs of market participants and the policy objectives set for what the market should deliver. The market design can then be tuned to meet these objectively efficiently and at lower cost.

3.2. Dispelling some myths about the 'pay-as-bid' vs 'pay-as-clear' market design model

"Past analyses tend to reach similar conclusions, namely that in day-ahead markets, a 'pay-as-clear' approach is more efficient than a 'pay-as-bid' approach."

The current price shock situation has led to calls in certain quarters to re-examine the pricing methods in electricity markets. For example a 'pay-as-bid' model was proposed by some as an alternative to the current 'pay-as-clear' model.

Different pricing methods currently coexist for the different electricity market timeframes in the EU. In particular, the 'pay-as-clear' model currently applies for the day-ahead market, the overall reference market for other markets, and will soon apply to pan-European intraday auctions. However, other pricing models apply in other market timeframes, in long-term markets and in intraday (continuous) markets. The 'pay-as-clear' model maximises the social welfare benefits from cross-border electricity trading. In Europe, such trading mostly takes place in the day-ahead and increasingly in the intraday markets.

Whenever electricity prices rise considerably, one sees increased debate over the prevalent market model and pricing system. Past analyses tend to reach similar conclusions[6], namely that in day-ahead markets, a 'pay-as-clear' approach is more efficient than a 'pay-as-bid' approach.

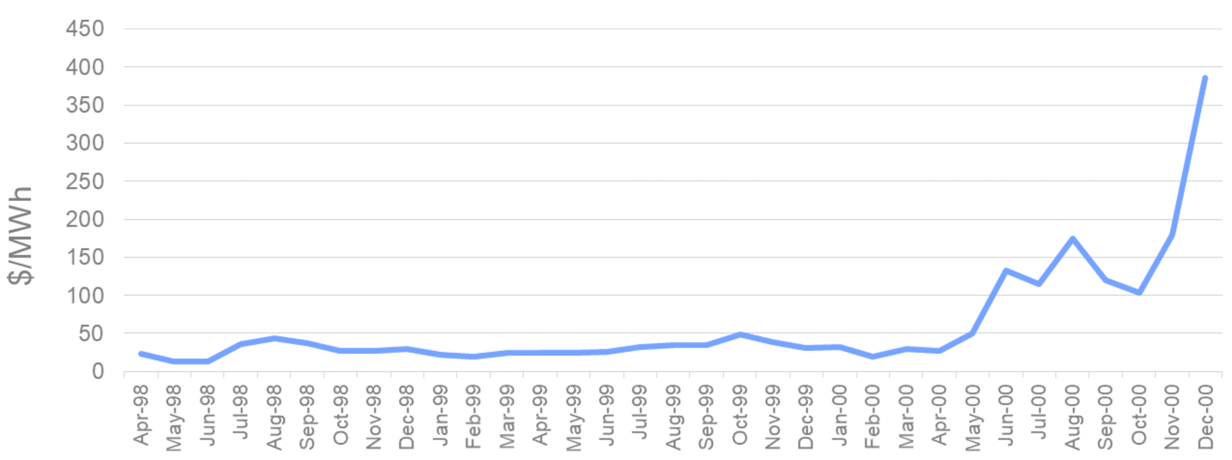
Case: The pricing model and high electricity prices in California (2000) and Great Britain (2001)

In California, wholesale electricity prices increased by 500% between the second half of 1999 and the second half of 2000 (as illustrated in Figure 9 below). In November 2000, the California Power Exchange assessed whether implementing pay-as-bid auctions in the day-ahead market could improve market performance. Experts concluded that such measure would be counter-productive[7]. In particular, the measure was thought to introduce inefficiencies in dispatch and weaken competition amongst generation sources. Instead, experts suggested measures to incentivise new generation, combined with market-based mechanisms to limit energy prices in the spot market.

[6] See e.g. the Florence School of Regulation's policy brief on Recent energy price dynamics and market enhancements for the future energy transition.

[7] Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond, Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, Richard D. Tabors.The Electricity Journal Volume 14, Issue 6, July 2001, Pages 70-79.

Figure 9: Average day-ahead prices ($/MWh) in California (April 1998 - December 2000)



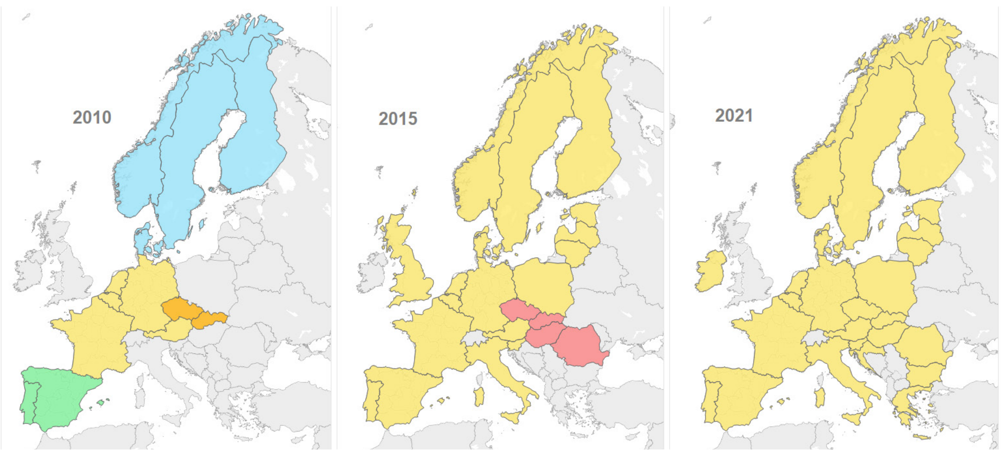
Source: ACER.

Similarly, the UK energy regulator, Ofgem, when considering changes in the New Electricity Trading Arrangements ('NETA') back in 2001, concluded that a 'pay-as-bid' auction would be inappropriate for a day-ahead market[8].

3.3. The current EU electricity market design delivers major benefits

While the EU market design envisages the integration across borders of all electricity market timeframes, short-term markets (specifically day-ahead and intraday) have been the focal point of EU market integration up until now. Their integration relies on a coordinated process that efficiently sets local prices and quantities exchanged across borders, known as 'market coupling'. Figure 10 shows the evolution of the geographical scope of day-ahead market coupling since 2010.

Figure 10: Evolution of EU wholesale electricity day-ahead market coupling (2010 - 2021)



Source: ACER.

Note: The different colours represent the different initiatives that coexisted before their integration into the single day-ahead market coupling.

[8] Uniform-Pricing versus Pay-as-Bid in Wholesale Electricity Markets: Does it Make a Difference? Susan F. Tierney, Ph.D., Todd Schatzki, Ph.D., Rana Mukerji, March 2008.

3.3.1. Cross-border trade delivered 34 billion Euros of benefits in 2021 while helping to smoothen price volatility

Day-ahead market integration delivers cheaper electricity across Europe and facilitates the growth of renewables while increasing overall welfare. In particular, market coupling ensures that electricity generally flows from areas with low prices to areas with high prices. When there are limited amounts of wind and solar electricity generated locally, Member States benefit from relatively cheaper electricity (including renewable electricity) produced elsewhere in Europe. Similarly, market coupling enables Member States to benefit from their neighbours' flexibility and adequacy (i.e. ability to guarantee desired security of supply levels) solutions, including back-up generation, storage, or demand-side response. Such solutions will be increasingly necessary to balance the fluctuating generation patterns of wind and solar power plants.

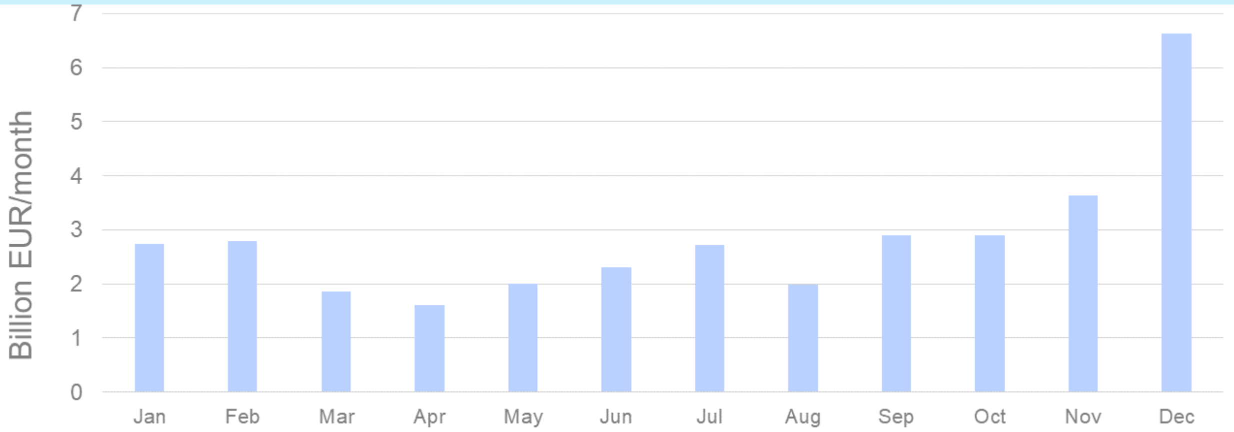
"Day-ahead market integration delivers cheaper electricity across Europe and facilitates the growth of renewables while increasing overall welfare."

In addition, market integration keeps price volatility lower than would otherwise be the case, as confirmed by analysis carried out by the Nominated Electricity Market Operators (NEMOs) at the request of ACER (see case study below).

Case: Cross-border trade delivers substantial benefits and mitigates price volatility

To estimate the benefits from cross-border electricity trading in Europe in 2021, ACER asked the European NEMOs to conduct an analysis for 2021. It compared actual 2021 market results ('historical' scenario) with a scenario where all cross-border capacities were set to zero (the 'zero scenario', implying no electricity trade across Member State borders)[9]. The difference in welfare benefit between the historical and the zero scenario (see Figure 11) is a proxy for the yearly welfare benefits currently obtained from cross-border trade in day-ahead markets. The benefits of cross-border electricity trading amounted to around 34 billion Euros in 2021 (source: ACER based on NEMOs). More than one third of these benefits correspond to the last quarter of 2021, when power prices were at their highest.

Figure 11: Estimated monthly welfare benefits (Billion EUR) from cross-border electricity trade in 2021

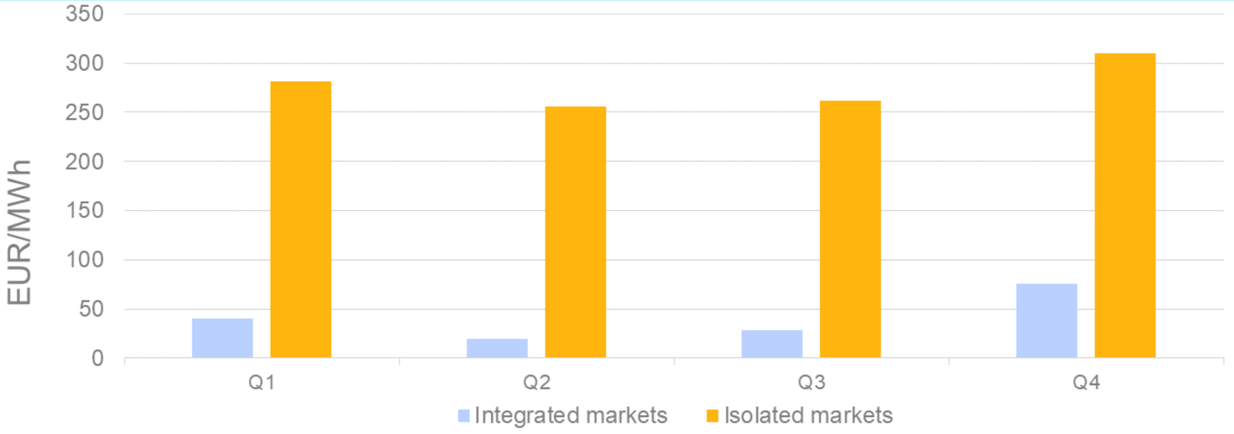


Source: ACER based on NEMOs' simulations.

[9] The geographical scope of this analysis is the countries and borders integrated through single day-ahead market coupling (see Figure 10). The main assumption of the analysis is that for the two scenarios, all elements (market bids, market rules, etc.) except cross-zonal capacities remain unaltered.

In addition to the considerable savings associated with the current level of market integration, the analysis shows that this integration also reduces significantly price volatility. Figure 12 displays the differences in average price volatility between the two scenarios. It shows that price volatility would have been considerably higher (around seven times as high) if national markets were isolated.

Figure 12: Price volatility (EUR/MWh) in integrated and isolated electricity markets in the EU in 2021



Source: ACER based on NEMOs simulations.

Volatility was estimated by using the standard deviation of day-ahead wholesale prices. The standard deviation was calculated per bidding zone for the whole year, then averaged out across the EU.

"Overall, in 2021, cross-border trade delivered an estimated 34 billion Euros of benefits while helping to smoothen price volatility."

Overall, in 2021, cross-border trade delivered an estimated 34 billion Euros of benefits while helping to smoothen price volatility. Additional benefits from higher market integration and cross-zonal capacities include enhanced cross-border competition and a reduced scope for market power, which helps lower the energy bill in the long-run. As further elaborated in Section 5, intervening to significantly alter the current market design may put a substantial share of the above benefits at risk, to the detriment of consumers.

It should be emphasised that these benefits represent the overall value of cross-border trade compared to isolated national markets, rather than the benefits from the implementation of market coupling as such (the latter is accounted for in the afore mentioned benefits[10]). In fact, before market coupling was introduced, cross-border trade (though sometimes limited and inefficient) was already taking place. Market coupling enables the efficient use of interconnectors and renders more than one billion Euros of benefits per year.

10 See paragraph 288 of the Wholesale Electricity Market Volume of the ACER-CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Wholesale Markets in 2013 (hereafter the Electricity Wholesale Market Volume of the ACER-CEER 2013 Market Monitoring Report (or '2013 MMR')).

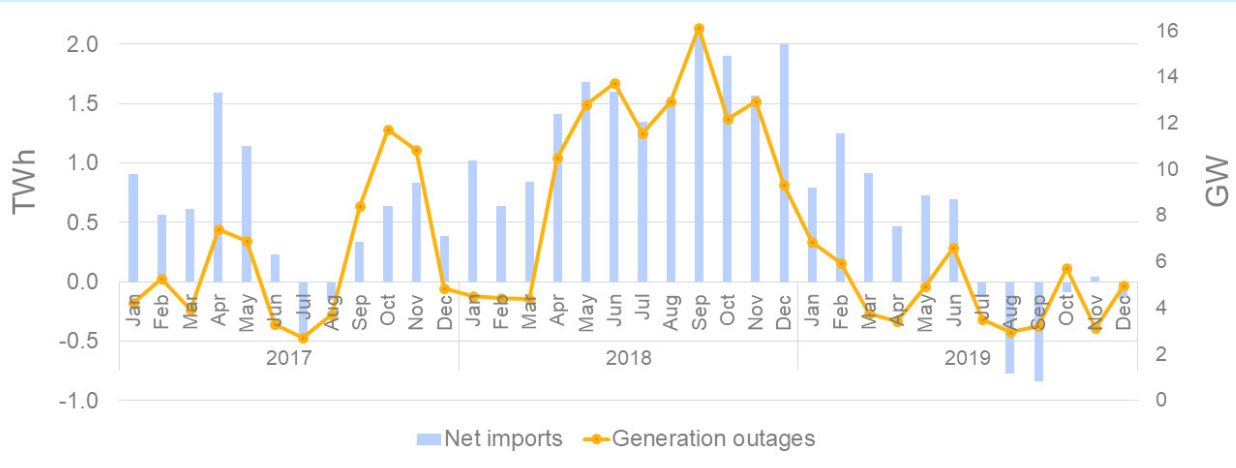
3.3.2. The EU electricity market design enhances each Member State's security of supply and its resilience to price shocks

Another key benefit of EU electricity market integration is that it enhances security of supply and leads to better resilience to short-term price shocks. The two examples below illustrate this.

Case: Belgium imports electricity to meet the shortfall in its own generation (2018-2019)

The first example of how market integration alleviates supply shortage refers to the situation in Belgium in winter 2018-2019. Unplanned and unusually large nuclear power plants outages in Belgium led to a shortage of generation to meet demand. The Belgian Transmission System Operator (TSO) and its neighbours jointly maximised import capacity into Belgium. Subsequently, Belgium's imports allocated through day-ahead market coupling increased sharply, as illustrated in Figure 13. More specifically, Belgium's hourly imports reached almost 2.5 GWh on average in the last quarter of 2018 compared to less than 0.85 GWh for the same months of 2017, thus alleviating the local shortage of generation capacity.

Figure 13: Evolution of net imports and average generation outages (MWh and MW) in Belgium (2017 - 2019)



Source: ACER based on ENTSO-E Transparency Platform.

Case: France moves from net exporter to net importer during nuclear power outages (2021)

The second case refers to the evolution of exports and imports in France in 2021 (see Figure 14).

During the first ten months of 2021, as electricity prices in France were lower than in the neighbouring markets, France was a net exporter (as indeed has frequently been the case in the past). In November and December, however, the situation reversed as France faced significant nuclear power plant outages. For many days during these two months the French power system became a net importer, mitigating the sharp increase of electricity prices in France and enhancing French security of electricity supply.

Figure 14: Evolution of net imports (MW) in France (2020 – 2021)

Source: ACER based on the ENTSO-E Transparency Platform.

The two examples above (Belgium's shortfall of generation and France's nuclear outages) illustrate how the notion of 'resource-sharing' (through market integration) benefits Member States. Without this inter-dependency approach, the security of electricity supply of different Member States could have come under stress in such periods. Similarly, as further highlighted in Section 5, the introduction of interventionist measures might put such resource-sharing approaches at risk to the extent cross-border flows are negatively impacted.

Recent national adequacy assessments also highlight the increasing reliance on neighbouring jurisdictions to address security of supply issues. For example, in a 2021 report[11] by TenneT, the Dutch TSO, the issue of whether the Netherlands has enough production capacity to meet national electricity demand was analysed. Among other conclusions, the report found that to cope with increasing uncertainty until 2030, coordination amongst Member States would prove increasingly important to ensure resource adequacy in the Netherlands and neighbouring countries. These findings reiterate the importance of increasing coordination both of underlying policies and deployment of infrastructure (see also Section 4.4.4 for further considerations on the need for better coordination).

In this respect, the European Resource Adequacy Assessment – a seminal new mechanism for enhanced EU electricity market integration introduced via the EU's Clean Energy Package - aims at detecting adequacy concerns in a consistent and coordinated manner across the EU. Once fully implemented, it will enhance co-ordination in the area of security of electricity supply.

Finally, there are additional benefits in the area of security of supply to be garnered by further enhancing cross-border coordination. One example is safer and more reliable and efficient operation of the power system; aiming e.g. to avoid and/or mitigate incidents similar to the so-called power 'system split' of 8 January 2021, which caused a large drop in the frequency of part of the Continental Europe Synchronous Area[12]. ACER considers that an enhanced framework, to ensure a more coordinated and robust reaction when coping with similar incidents in the future, would be beneficial for EU Member States.

11 See TenneT's Monitoring Security of Supply 2021 report commissioned by the Dutch Ministry of Economic Affairs & Climate Policy.

12 On 8 January 2021, a significant operational incident led to a split of the electricity network of Continental Europe. The investigation into the incident revealed uncoordinated approaches to ensuring operational electricity system security across the EU.

3.4. Further potential benefits

Beyond the benefits that EU electricity market integration currently yields, there is significant scope to further improve market integration efforts, in particular regarding:

- The amount of capacity available for cross-zonal electricity trade and the way it is used, and implementing ongoing projects, some of which are delayed;
- The accuracy of price signals to ensure efficient short-term decisions, e.g. related to the daily planning of generation and consumption, and long-term decisions, e.g. related to seasonal maintenance or investment; and
- The barriers to market entry that should be removed to attract innovative and more efficient energy providers, and barriers to efficient price formation that should be removed to lower the overall cost of the energy transition.

3.4.1. Increasing cross-zonal capacity and using the capacity provided more efficiently

"... The amount of interconnection capacity made available for trade with neighbouring jurisdictions needs to increase significantly [...] a prerequisite for being able to fundamentally rely on cross-border trade for one's needs."

Adequate interconnection levels, and ensuring that the related interconnection capacity is made available for cross-zonal trade, are indispensable for a well-functioning EU Internal Electricity Market. In particular, the provision of sufficient cross-zonal capacity to trade across all market timeframes is an essential prerequisite for reaping the market integration benefits; these benefits include the ones described in Section 3.3, and the ones described below. In its so-called '70% monitoring report', ACER finds that the amount of interconnection capacity made available for trade with neighbouring jurisdictions needs to increase significantly in line with the binding 'minimum 70% target'[13]. At its core, this is a prerequisite for being able to fundamentally rely on cross-border trade for one's needs. As such, it is a key component of an integrated electricity market, likely of increasing importance in the years ahead.

Two flow-based market coupling projects in the so-called Core[14] and Nordic regions seek to improve the way cross-zonal capacity is used in the day-ahead timeframe. Unfortunately, both are facing recurrent delays. These projects are essential to ensure the optimal use of cross-zonal capacity in a highly interconnected and interdependent EU power system.

Other ongoing projects are key for the integration of the intraday and balancing markets across the EU. Given the expected increase in renewables in the EU electricity mix, intraday and balancing markets will become increasingly important. Hence, further integration of intraday and balancing markets would seem crucial to facilitate the EU's decarbonisation trajectory.

"... Further integration of intraday and balancing markets would seem crucial to facilitate the EU's decarbonisation trajectory."

[13] The Clean Energy Package requires that at least 70% of physical capacity of critical network elements is made available for cross-zonal trade.
[14] The flow-based market-coupling project in the Core region involves thirteen Member States of Central Europe. Project implementation has been facing recurrent delays, with another delay announced in April 2022.

Intraday markets are key for renewable generators as they can adapt their trading positions closer to real time, based on more accurate information (e.g. in response to weather pattern updates or short-term availability issues). The progressive integration of intraday markets across Europe through the so-called 'single intraday coupling' enables market participants' access to a larger variety of bids and offers to manage their adjustment needs. Concerning the balancing timeframe, market integration contributes to ensure that supply continuously meets demand at a lower cost across the EU. For example, the ongoing integration of balancing energy markets, through the establishment of pan-European balancing platforms, is expected to yield more than 1.3 billion Euros of yearly benefits to consumers[15].

Work is ongoing to upgrade the rules governing the use of cross-zonal capacities. For example, ACER recently issued a recommendation on amendments to the network code governing Capacity Allocation and Congestion Management (the so-called CACM network code). A similar amendment process is expected to update the network code governing Forward Capacity Allocation. This leads to certain considerations as to how this update might help further improve overall market design functioning, see Section 4 below.

3.4.2. Improving the accuracy of price signals to make better investment decisions

An important element of the current market design is the accuracy of price signals, i.e. that electricity prices precisely inform generators and customers when and where power is cheap or expensive. This is often referred to as 'time and space granularity' of electricity markets.

In particular, spatial granularity requires that electricity prices reflect the underlying network congestions. This implies that a bidding zone with supply scarcity would have a higher price than a market area with excess supply. An adequate configuration of bidding zones is widely understood to incentivise efficient operational and investment decisions. The better the bidding zone configuration reflects the physical congestions, the more efficient the price signals.

Case: Accurate price signals enable better investment decisions in Norway and Sweden

Norway and Sweden comprise five and four bidding zones, respectively. These bidding zones are an approximation of the underlying congestions in the grid. Different bidding zones may have different wholesale prices, reflecting the local supply and demand.

For example, prices observed in Norway and Sweden in December 2021 (see Figure 15) illustrate the relevance of accurate locational price signals. During this period, the prices of the bidding zones located in the South were around three times higher than the prices of the bidding zones in the Northern bidding zones.

15 See footnote 348 and paragraph 582 of the Electricity Wholesale Market Volume of the ACER-CEER 2014 Market Monitoring Report (or '2014 MMR').

Figure 15: Average electricity prices (EUR/MWh) in the Nordic area in December 2021

Source: ACER based on the ENTSO-E Transparency Platform.

These price differences are an important input both in the short-term (e.g. for planning the next days' generation or consumption), and in the long-term (e.g. for seasonal planning of maintenance or investment decisions related to power plants or large consumption units). Current price differentials incentivise generators to be located in the South and large consumers to be located in the North, something that is taken into account when considering the need for network investments[16].

Ignoring these incentives would aggravate the existing grid congestions. Consequently, the perceived needs to invest in network infrastructure would increase, investments may be inefficiently located, and such increased (and partly avoidable) costs would ultimately be borne by consumers.

"... An adequate definition of bidding zones brings substantial savings in the long run ..."

All in all, an adequate definition of bidding zones brings substantial savings in the long run, not only because generation and demand assets would be incentivised to be located where they are needed, but also because it would be easier to identify the most valuable network investments. Whether and how locational market signals may drive a more cost-effective decarbonisation of the energy system is currently subject to debate in a number of jurisdictions, including beyond the EU; such debate includes the possibility of implementing locational marginal pricing, often referred to as nodal pricing[17].

[16] Indeed, when considering grid development for the Nordic area, the Nordic TSOs take into account the expectation of more consumption to be situated in the northern parts of the Nordics, see e.g. the 'Nordic Grid Development Perspective (2021)'.

[17] See for example the conclusions of a recent presentation published by National Grid.

3.4.3. Removing barriers to the entry of innovative market participants

In its latest Market Monitoring Report[18], ACER identified numerous barriers to market entry and price formation across the different Member States. Those barriers reduce overall welfare. Removing such barriers would allow more market players, such as those offering demand-side response services, to compete on an equal footing. In 2022, ACER will develop a framework guideline setting principles for the participation of demand-side flexibility (amongst other resource providers) in electricity markets; such a guideline will serve as basis for the preparation of EU regulation in this area.

In sum, the accomplishment of the 'minimum 70% target', the completion of the aforementioned integration projects and the removal of barriers to efficient price formation and barriers to entry of new market players are key in ACER's view for maintaining or increasing the substantial welfare benefits described in Section 3.3. In this respect, ACER's Preliminary Assessment from November 2021 showed that continued and strengthened efforts in the areas identified could deliver more than 300 billion Euros[19] in benefits over the next decade. Those efforts and benefits outlined rely on the current market design and its fundamentals. As such, deviating significantly from the current market design may put at risk the benefits already obtained as well as those currently being pursued.

Besides ongoing initiatives to further harness the benefits from EU electricity market integration, the electricity system will face new challenges up ahead as it is called upon to deliver on the EU's ambitious decarbonisation trajectory. The next section describes these challenges and the measures ACER deems relevant to further future-proof the EU wholesale electricity market design in light of these challenges.

18 See the Electricity Wholesale Market Volume of the ACER-CEER 2020 Market Monitoring Report (or '2020 MMR').

19 See Section 4.4, in particular Figure 10, of ACER's Preliminary Assessment.

4. Ways to improve the EU wholesale electricity market

The EU power system faces new challenges to deliver on the EU's ambitious decarbonisation objectives. These challenges, and the recent energy price shocks, raise the question of whether the current market design can fully address these challenges and if not, how then to improve the market design.

This section focuses on the following key 'asks' of the current market design going forward:

- First, the need to drive substantial investments in low-carbon generation; and
- Second, the challenges in complementing increasing shares of intermittent renewable electricity, not least via tackling rising price volatility and enhancing the flexibility of the power system.

4.1. Flexible resources are needed to address increased volatility of the power system

The EU needs massive additions of low-carbon electricity generation to reach its decarbonisation objectives. This jump in low-carbon electricity generation is a paradigm shift for the power system and market. As a result, price volatility is likely to be a dominant feature of the energy transition.

Volatility is a natural feature of well-functioning electricity markets. It is the result of frequent and/or sudden changes of market fundamentals and other variables such as weather conditions. Volatility can refer to short-term movements or long-term structural swings. The following elements will likely push volatility upwards:

- Numerous market entries and exits;
- The impact of intermittent generation on the system; and
- Volatility of other underlying market fundamentals.

First, the energy transition is likely to trigger numerous exits especially regarding more carbon-intensive power plants. It will also trigger market entries for generation (not least renewables) and for demand (via increased electrification). A lack of coordination on these elements is likely to significantly affect electricity prices. It is thus crucial that Member States manage these entry and exits to maintain the supply/demand balance throughout the energy transition.

Second, a vast share of new renewable generation is intermittent. At the same time, some dispatchable technologies (such as coal generation) will be phased out. As a result, electricity prices will be low for many hours, but high in other hours when cheaper renewable resources are scarce. As such, price volatility is bound to rise.

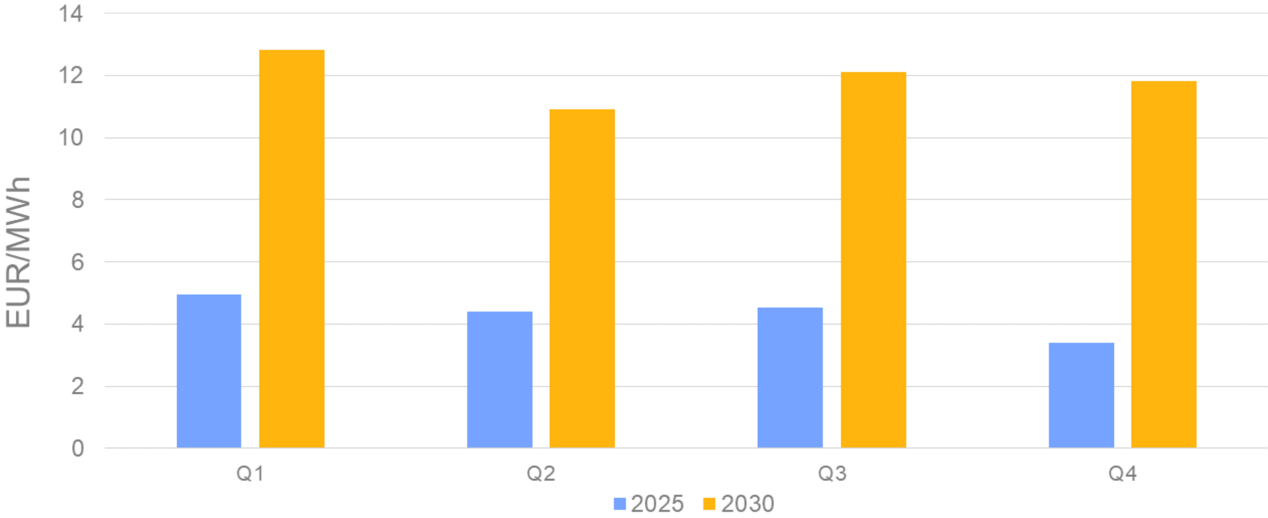
Third, other factors will drive price volatility as well. These include changing fuel and ETS prices, varying availability of dispatchable assets and demand, and changes in bidding behaviour. Extreme events (fuel supply crisis, economic crisis, extraordinary cold spells etc.) affect these factors and can lead to extreme volatility. Precisely because such events can occur, price shocks are difficult to rule out in the future.

There will also be factors that potentially mitigate volatility such as:

- Increases in demand-side response due e.g. to enhanced digitalisation and lower transaction costs;
- Electrification of transport and heating sectors; and
- Lower cost and wider availability of short-term and long-term electricity storage.

Figure 16 illustrates the expected increase in price volatility in 2030 compared to 2025 based on the scenarios used.

Figure 16: Expected evolution of price volatility (EUR/MWh) in 2025 and 2030



Source: ACER based on simulations made by the Joint Research Centre.

Note: For 2025 and 2030, ENTSO-E's Ten-Year Network Development Plan scenarios were adapted to reflect the penetration of intermittent renewable generation envisaged in the MIX scenario of the Fit-for-55 Package. Volatility was estimated by using the standard deviation of day-ahead wholesale prices. The standard deviation was calculated per bidding zone for the whole year, then averaged out across the EU. The figure aims to show volatility trends, however the absolute values shown in this figure are not directly comparable with the values shown in Figure 12 referring to 2021 when prices were exceptionally high. Moreover Figure 12 relies on historical bids and prices while this figures relies on simulated bids.

The power system will need significant and diverse flexible resources to optimise the value of growing shares of intermittent generation and to smoothen the increased volatility.

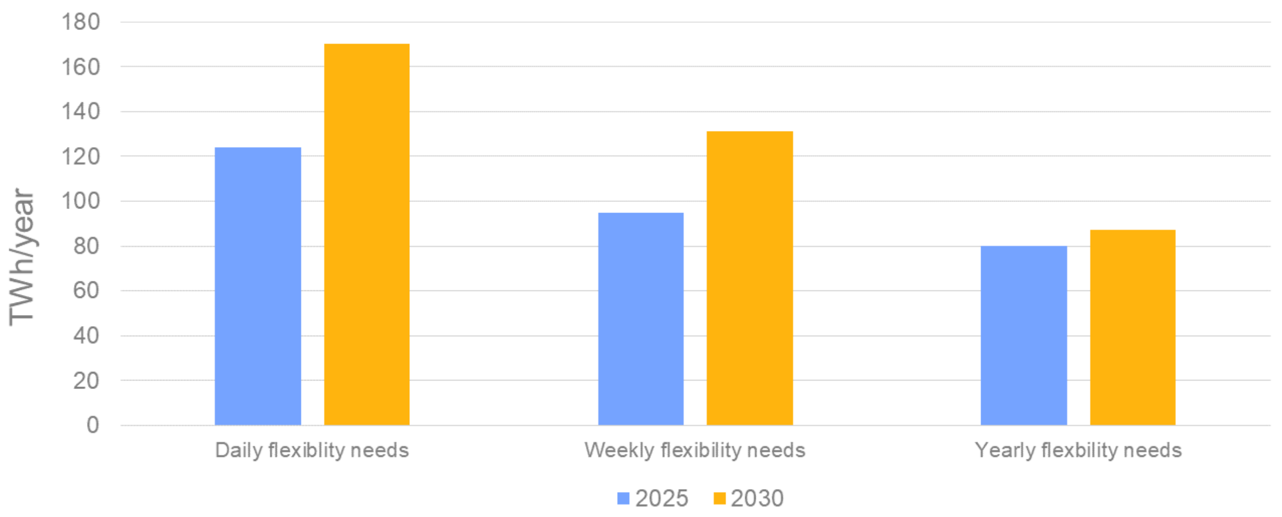
Flexibility is the ability of the power system to adapt to changing needs. Flexible resources enable the safe operation of the system and mitigate price volatility. With sufficient flexible resources, the power system can provide firm capacity to the market, meaning that it can confidently deliver electricity in line with time- and location-specific needs.

"The power system will need significant and diverse flexible resources ..."

Flexibility needs arise at every possible timeframe, from seconds to weeks to years. Similarly, flexible resources operate on the short and/or the long run. Generation, storage, demand and grid infrastructure (such as transmission lines or grid-enhancing technologies) all provide flexibility, each with different characteristics. To manage the major changes highlighted above, the power system will need a combination of flexible resources, noting that efficient grid development and operation, energy efficiency and enhanced sector integration[20] can reinforce the impact of flexible resources or even substitute them. Figure 17 illustrates an increasing trend in flexibility needs towards 2030.

[20] Sector integration implies linking the various energy carriers - electricity, heating, cooling, gas, solid and liquid fuels - with each other and with the end-use sectors, such as buildings, transport or industry.

Figure 17: Expected evolution of flexibility needs (TWh/year) in the EU in 2025 and 2030

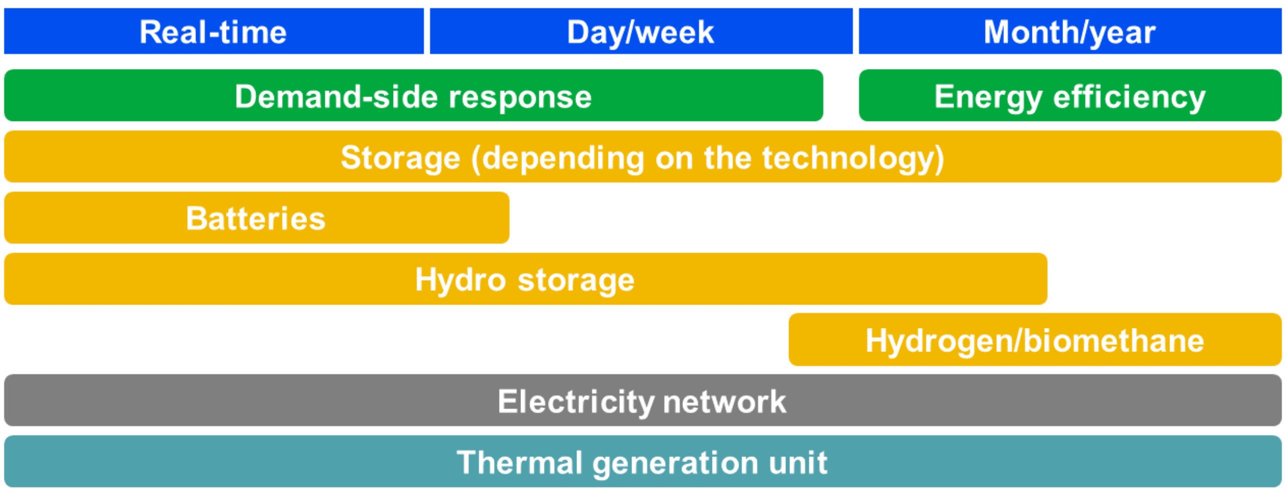


Source: ACER based on simulations made by the Joint Research Centre.

Note: The estimation of the flexibility needs was based on the methodology described in section 2.2.1 of the European Commission report Mainstreaming RES Flexibility portfolios - Design of flexibility portfolios at Member State level to facilitate a cost-efficient integration of high shares of renewables as tasked by the European Commission. Compared to the original methodology, some simplifications were applied, e.g. to calculate the residual load, only information on load and wind and solar generation was used, as information on other intermittent renewable sources and must-run generation was not available to ACER.

A market participant's own resources or short-term market trading are the common sources to tackle short-term flexibility needs, ranging from seconds to several days. Dispatchable generation units (such as gas-fired turbines), batteries, pumped hydro storage and demand-side response are typical examples of short-term flexible resources. Electrification of industry and transportation also offer increased potential for demand-side response to tackle short-term flexibility needs.

Figure 18: Flexibility services provided by various technologies



Source: ACER.

Note: The list of technologies is non-exhaustive (with e.g. the storage category covering several different technologies). As mentioned, coupling electricity with other energy sectors (sector integration) may provide significant flexibility services.

Figure 18 above illustrates different flexibility services provided by different technologies, across different time-frames.

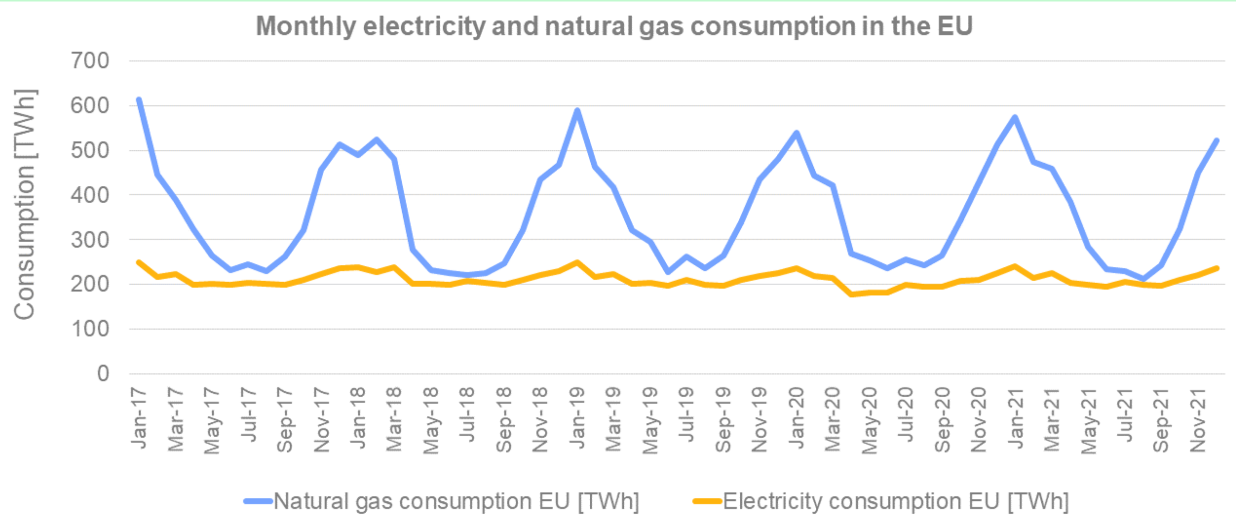
A key focus area for the coming decade:
More long-term flexibility is needed for when demand is high or supply is low

A key challenge with increasing volatility is the need for longer-term flexibility (from weeks to several months). Indeed, seasonal demand peaks (possibly exacerbated by further electrification of heating, especially beyond 2030) or long periods with lower renewable generation require longer-term flexible resources.

As shown in Figure 18, fossil fuel power plants (such as gas and coal fired power plants) and hydro power plants with large reservoirs provide seasonal flexibility. When phasing out fossil fuels, alternatives to provide this type of flexibility will be needed. Such alternatives could include low-carbon fuels (such as low-carbon hydrogen, bio-methane and biomass) or more flexible renewables. Increased storage of (renewable) gases, diversification of resources and better interconnections for electricity and (renewable) gases can enhance the potential of these new technologies for providing flexibility.

This challenge is likely to become further acute if policy makers across the EU deem it necessary to transition away from natural gas more rapidly, a key provider of seasonal flexibility needs up until now (noting that further electrification of heating for example, whilst reducing overall gas demand, may shift seasonal swings from the gas system to the electricity system, thereby significantly increasing seasonal flexibility needs in the electricity system). This is also illustrated by Figure 19 below.

Figure 19: Comparing seasonal swings in electricity and natural gas demand in the EU from January 2017 to July 2021



Source: Eurostat data, based on an International Energy Agency (IEA) concept.

A clear price signal is essential to attract investment in flexible resources. Conversely, removing price signals may discourage market entry, in particular of flexibility providers, thus leading to more costly integration of intermittent generation in the long-run.

Thus, the current wholesale market design's ability to attract sufficient longer-term (including seasonal-level) flexibility commensurate with the broader balancing needs of the power system is linked to its ability to indicate an appropriate price for meeting such needs. In the absence of such a price signal, innovation in new technologies or solutions, which currently might not always be price-competitive with fossil fuels (although price evolutions in 2021 and 2022 have temporarily shifted the balance in some respects), will be hampered or may not materialise at all. Hence, the need to retain clear price signals, complementing e.g. upstream research & development support.

The increasing flexible resources entering the power system need market places where their contribution can be recognised and traded. Introducing products that better reflect a changing reality (e.g. products linked with renewable generation or net demand) could offer better hedging solutions and stimulate trading and the related investments in flexible resources. The most straightforward incentive to invest in flexible resources remains the price signal. Indeed, expected price volatility sends a clear investment signal of the need for flexible resources.

Scarcity pricing and capacity mechanisms are two tools that can further trigger investments in flexible resources. Scarcity pricing gives an explicit value to reserves being available in times of scarcity, thereby giving extra incentives to all possible sources (including storage and demand-side response) to offer energy to the market.

Capacity mechanisms support generation, storage and demand-side response to address adequacy concerns by ensuring the availability of enough firm capacity (meaning the electricity is available when and where it is needed). As a result, capacity mechanisms indirectly support investments in flexibility resources, although they do not usually differentiate between flexible and less flexible resources. Figure 20 gives an overview of the different capacity mechanisms in the EU.

By default, capacity mechanisms are national. Coordination at the EU level can achieve more efficient outcomes also in terms of flexible resources (noting the European Resource Adequacy Assessment as a key instrument to drive such enhanced alignment, as mentioned in Section 3 above).

Figure 20: **Capacity mechanism in EU Member States in 2020**

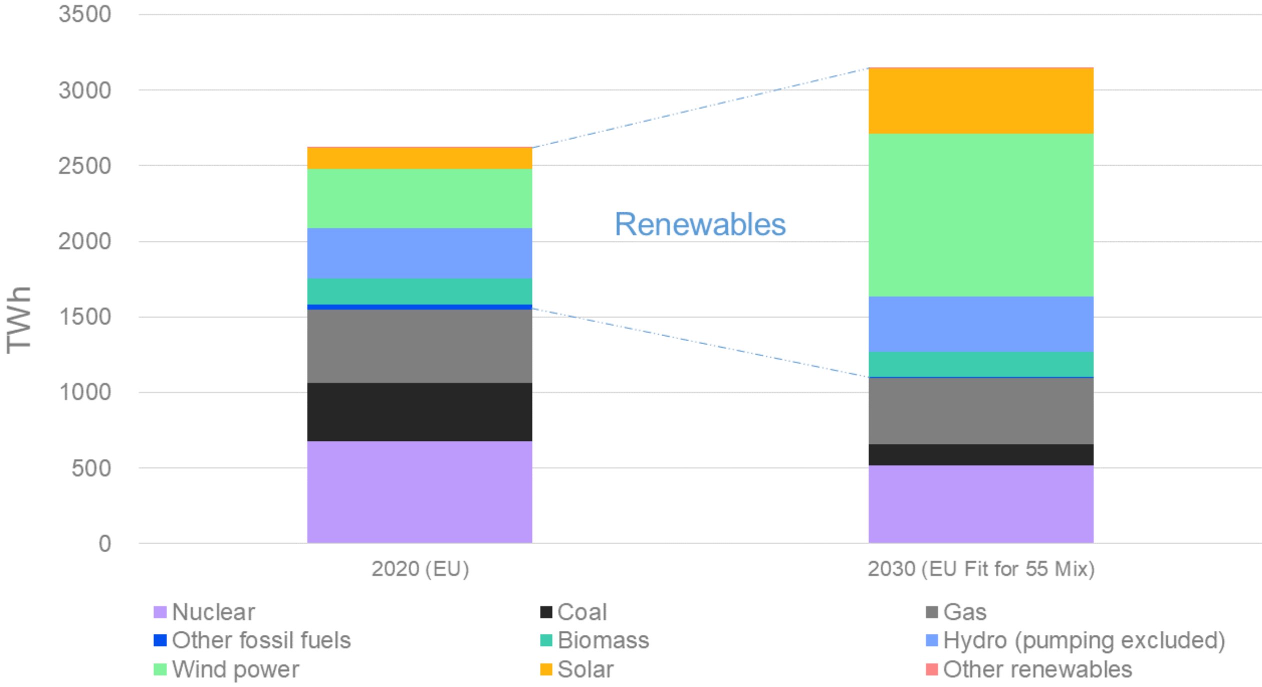
Source: ACER-CEER Market Monitoring Report 2020.

4.2. Investments in low-carbon generation need a massive ramp-up

Significant new investments are needed to deliver the EU’s decarbonisation trajectory.

Figure 21 below illustrates the magnitude of this task, taking as point of departure the targets envisaged in the European Commission’s 'Fit-for-55' package (seeking a 55% reduction in greenhouse gas emissions by 2030 and carbon neutrality by 2050). It shows the substantial change in the generation mix expected for the next decade. This change will need to happen at speed. A sizeable share of this renewable generation will be connected to distribution grids. As mentioned above, the ETS plays a critical role to incentivise investments in low-carbon technologies.

Figure 21: Expected evolution of the EU-27 electricity generation mix (TWh) in 2020 and 2030



Source: ACER based on European Commission data in the context of the Fit-for-55 Package. For 2030 the European Commission's MIX scenario was used.

Competitive long-term electricity markets play a key role in managing risk, thus supporting investments that carry risk. Furthermore, many EU Member States have introduced different schemes to support investments. These schemes usually aim at supporting renewable energy sources by providing long-term hedging or complementing revenues or they have sought to improve security of supply.

The following government support schemes are used in different Member States:

- Feed-in-Tariff: provides a fixed payment per MWh of electricity produced;
- Constant Feed-in-Premium: complements the electricity market price with a fixed payment, sometimes supplemented by a cap and a floor;
- Sliding Feed-in-Premium: tops up the electricity market price to a reference price, when the market price stays below this reference. The asset owner keeps the market price when it is above the reference price;
- Contracts for Difference (CfD): A CfD pays the asset operator the difference between the market price and a reference price. When the market price exceeds the reference price, the asset owner pays back the difference. The effect of a CfD is similar to a Feed-in-Tariff.
- Other support schemes also exist. These include direct subsidies, tax reductions, exemptions on certain market rules (such as balancing responsibilities), or free grid connection.

"Competitive long-term electricity markets play a key role in managing risk ..."

Tenders or auctions often facilitate the above support schemes as a tool to identify adequate levels of financial support, e.g. by ensuring that prices are set competitively.

Some Member States consider centralised measures to speed up the energy transition, such as the systematic and centralised procurement of energy or capacity whereby regulatory or other public authorities directly procure electricity from specific low-carbon generators. Others allow a fixed regulated price for certain technologies.

Centralised specific measures are sometimes seen as a possible solution to alleged market failures (e.g. the procurement of public goods such as ancillary services) or to kick-start immature markets. As the targets are not necessarily set by the market, the deciding authority (rather than the competitive market) could end up defining the technology mix to pursue. Such centralised approaches therefore need to ensure investments are efficient, to preserve price signals and to strike a balance between technologies.

Support for investments can also originate from the market. A commercial PPA is a long-term contract (e.g. of 5-20 years) between a generator (often a renewable power plant) and a private entity (e.g. a utility, trader or large electricity consumer) purchasing the energy from the generator. Unlike the schemes previously mentioned that involve the government or a public entity as a key procurer or intermediary, a PPA is purely commercial.

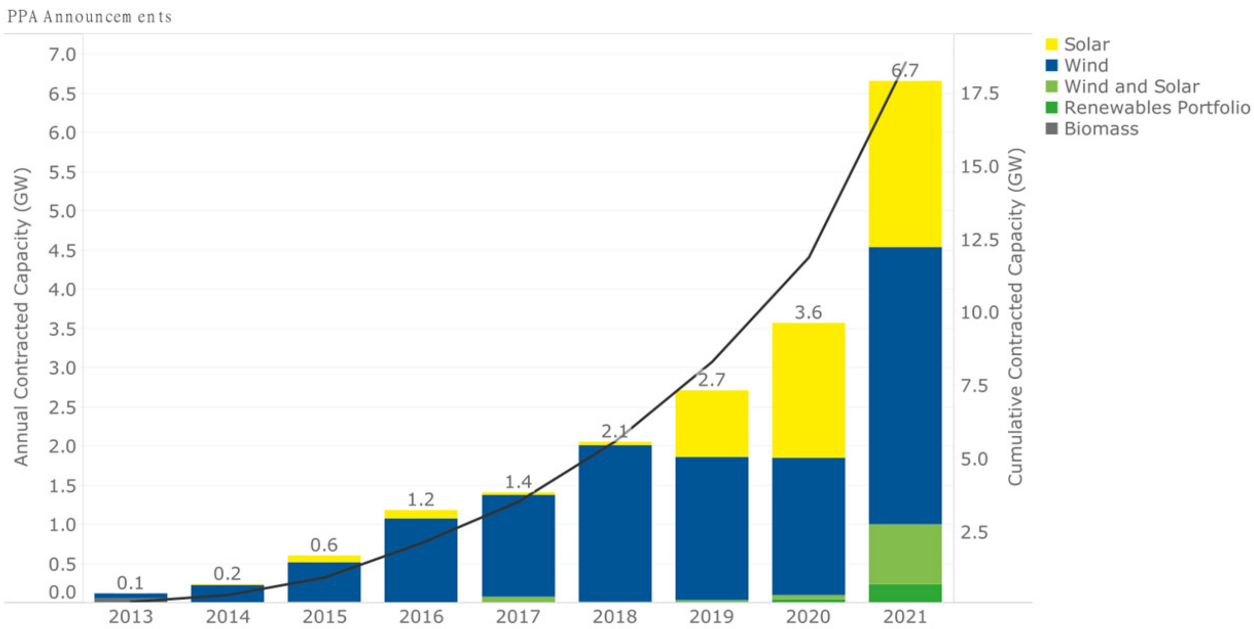
PPAs already play a significant role today. By providing some visibility about the financial viability of a project, PPAs make it easier for renewable project developers to secure funding. To ensure that the long-term commitments are met throughout the contract lifetime, even if the counterparty defaults, market participants may hedge the counterparty risk associated with entering into the PPA.

Many low-carbon generation sources, such as on-shore and off-shore wind farms and solar parks, have in the past benefitted from government-driven support mechanisms. Several such support schemes often coexist in the same country, for example with older plants falling under a Feed-In Tariffs system and new plants supported by more market-based systems like Feed-In Premiums. Subsidising renewables comes at significant cost to consumers. The ACER-CEER Market Monitoring Report (for 2020)[21] shows that on average these subsidies accounted for 12% of consumers' bills.

Several renewable technologies are now mature, accounting for a significant share of generation, and their costs have lowered significantly. In 2018 and 2019, for the first time, several offshore wind farms won auctions without any direct subsidies being awarded. This illustrates how market-based solutions can drive investments in low-carbon generation, maintain a competitive environment and ensure efficient allocation of resources. Figure 22 illustrates the growth in commercially-driven PPAs from 2013 to 2021.

[21] See page 81 of the Energy Retail Markets and Consumer Protection Volume of the ACER-CEER Market Monitoring Report (or '2020 MMR'.

Figure 22: Annual and cumulative contracted PPA capacity in Europe (2013 - 2021)



Source: RE-Source (2021).

The allocation of and investment in certain low-carbon generation sources is incrementally shifting towards PPAs and centralised competitive tenders (e.g. auctions for renewable energy sources). An important question is whether commercial instruments are sufficient to drive the investment needs ahead or whether a mix of subsidy-driven and commercially-driven approaches will coexist. A study commissioned by the European Investment Bank (EIB) and the European Commission estimates that, by 2030, PPAs will cover a range of 10% -23% of combined solar and wind generation[22].

4.3. Boosting competitive long-term markets will help hedge against risks and stimulate investments

Many wholesale market participants (traders, retail suppliers, energy-intensive companies, etc.) hedge against risks as a fully integrated part of their business activities. They use advanced hedging strategies and trade energy over different timeframes to smooth out financial flows.

"Many wholesale market participants [...] hedge against risks as a fully integrated part of their business activities."

When considering future costs or revenues, electricity generators and suppliers face significant volume and price risks. They can hedge this risk by trading electricity in advance, in forward markets. Hedging through long-term bilateral contracts (such as multi-year PPAs) are also a means to secure long-term financing for investors (e.g. renewable producers) as the price is set long into the future.

[22] Final Report by Baringa 'Commercial Power Purchase Agreements. A market study including an assessment of potential financial instruments to support renewable energy Commercial Power Purchase Agreements (2022)'.

Hedging: How does it work?

Example: A generator may be interested in hedging its revenues from producing electricity in a given year. If this market participant sells 100 MWh of electricity for every hour of a year at say 50 EUR/MWh in a forward market, it will hedge against the risk of prices (and thus revenues) dropping to say 30 EUR/MWh. On the other hand, it will also give up potential additional revenues if prices were to increase to say 100 EUR/MWh.

At the same time, an electricity-intensive consumer will also wish to hedge its costs. If the consumer buys that annual 100 MWh contract for 50 EUR/MWh, it avoids the risk of losing money if prices increase to 100 EUR/MWh, but gives up on the potential of lower costs of 30 EUR/MWh.

The recent high energy prices have drawn attention to measures that could shield consumers from perceived excessive levels of price volatility that impact affordability. Forward electricity markets enable buyers and sellers to contract at a price well in advance of when the electricity is actually produced or consumed, hence cushioning them from subsequent price volatility. This in turn allows some retailers to offer consumers more predictable prices over a longer period of time. Market participants are free to decide whether to hedge against risks or not and the type of hedging instrument (e.g. how far in advance to lock in a price) that best suits their needs.

Hedging may help cushion the impact of price shocks but it does not remove them. This is mainly due to two factors. First, a perfect hedge might not exist or be too expensive[23]. Second, in line with financial regulation, hedging via trading in forward and futures markets requires collateral. When prices jump and volatility rises, collateral requirements also significantly grow, increasing the financial guarantee that market participants need in order to hedge for future years. Central clearing counterparties (regulated financial institutions that manage the trading parties' credit risk) require high-quality collateral, whilst collateral provision of market participants to banks depends on the participant's credit scores and therefore on the economic situation of a country, thereby adding to the complexity.

Increase in Collateral Requirements

The price evolutions in 2021 and 2022 have resulted in steep increases in collateral requirements and increased awareness about the constraints they can impose on energy suppliers. A survey launched by ACER[24] confirmed the steep increase in the amount of cash tied up in collateral requirements. All but one respondent reported that the total amount of collateral requirements in their markets at least doubled (with some seeing the total amount of collaterals growing more than four-fold) between 21 August 2021 and 21 December 2021.

[23] In general, the forward risk premium tends to be positive. A large part of the risk can be attributed to the electricity sector per se - risk aversion to scarcity, volatility and extreme events.

[24] ACER conducted this survey in 2022 amongst market surveillance experts of power exchanges and brokers, in the framework of ACER's so-called 'Market Surveillance Forum'.

Such extraordinary increases translate into difficulties in sourcing cash, as reported by market participants.

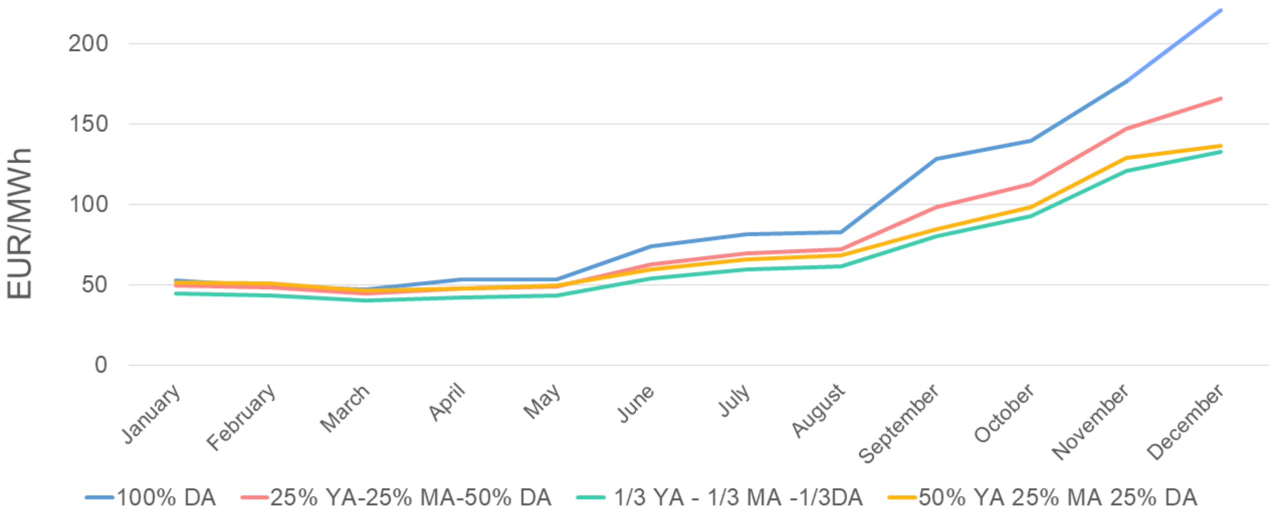
By way of example, at the beginning of January 2022, Uniper, a large German utility, reportedly had to secure liquidity backing in the order of 10 billion EUR in order to cover the collaterals for its trading in electricity and gas. Uniper had to obtain loans from its parent company Fortum and the German KfW IPEX-Bank. Similar liquidity issues were also raised by other (large) market participants. Ensuing developments in the market has lead the German government in the first half of April 2022 to enact broader liquidity coverage measures[25].

Figure 23 displays different procurement strategies that a retailer could have followed in the German electricity market in 2021. The strategies range from fully procuring electricity in day-ahead markets to procuring different shares of month- or year-ahead contracts. The example illustrates that hedging the procurement smoothens the impact of the high prices recorded since September 2021. The longer the hedge, the smoother the price increase observed by the retailer and its customers. Importantly, volatility does not necessarily increase the average cost that the consumer pays over time. Similarly, the long-term procurement in this example does not shield consumers from the price increase over time; it only cushions them from the immediate impact of the high price and spreads the impact of the increase over a longer period of time.

"Hedging may help cushion the impact of price shocks but it does not remove them."

Importantly, forward contracting facilitates planning and avoids the costs of unexpected changes in prices. It allows business to set prices and make forward sales secure in the knowledge of their cost structure, and consumers to plan their budgets. However, forward contracting also fixes those costs. It reduces the ability to take advantage of lower energy costs.

Figure 23: Unit procurement costs (EUR/MWh) of a supplier using diverse hedging strategies in the German electricity market in 2021



Source: ACER based on Platts.

[25] The German government announced a EUR 100 billion financing instrument to assist energy companies having liquidity issues in their hedging.

A key issue is whether the hedging instruments that are available today are sufficient to meet the needs of the various market participants. These needs may be split into:

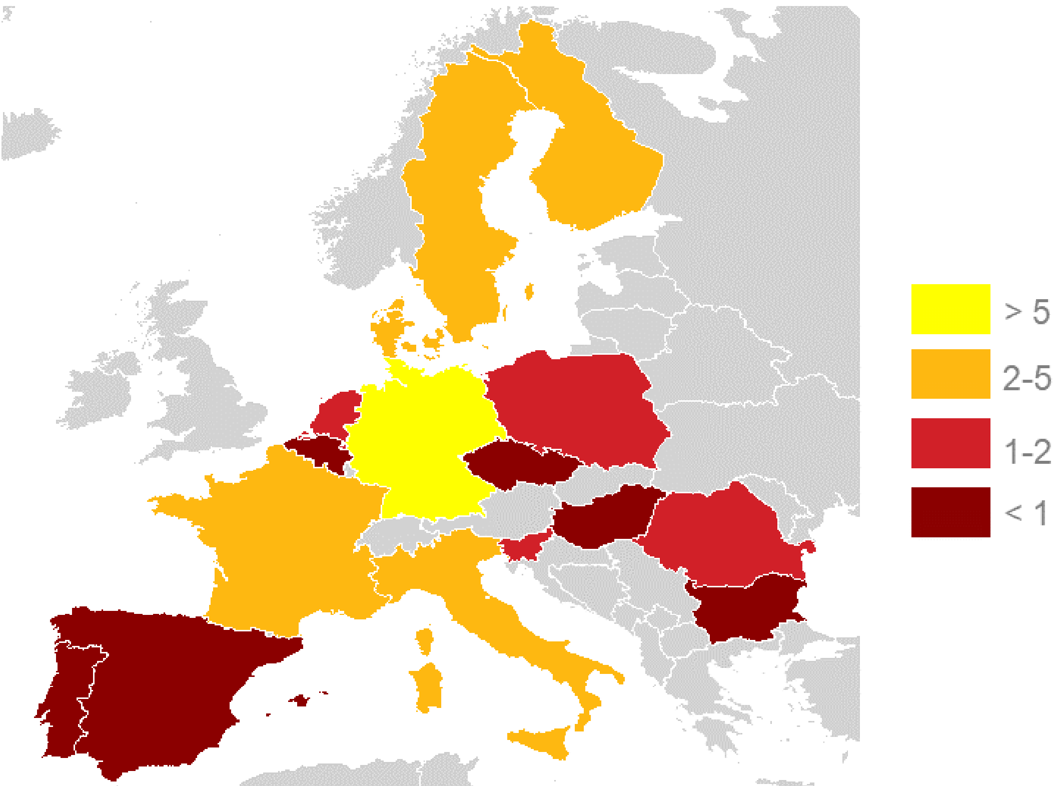
- short-term and medium-term hedging, related to operational needs and seasonal variations; and
- long-term hedging, related to the predictability of the profitability of an asset.

Liquidity is key to ensuring efficient hedging[26]. In some Member States, forward markets offer a relatively liquid platform to trade standard products of up to 1-3 years ahead of delivery. However, further in the future, forward markets are illiquid. Investors, which typically take a 20-year horizon to amortise their investments, will therefore face difficulties to hedge over this time horizon. Illiquid hedging tools may therefore create a hurdle for investments in low-carbon generation or flexibility sources. Hedging through long-term bilateral contracts (such as multi-year PPAs) is thus a commonly-used option to secure long-term financing for investors in some markets.

"... Volatility does not necessarily increase the average cost that the consumer pays over time."

Figure 24 shows varying liquidity in major European forward markets from 2016-2020, as expressed by the respective churn factors[27].

Figure 24: Liquidity of forward markets in major European forward markets (2016 - 2020)



Source: ACER-CEER Market Monitoring Report 2020.

Note: The figure includes only volumes traded or cleared at power exchanges and volumes traded through brokers. Colours are linked with the following churn factors: yellow – 5; orange - 2; red – 1; dark red – below 1.

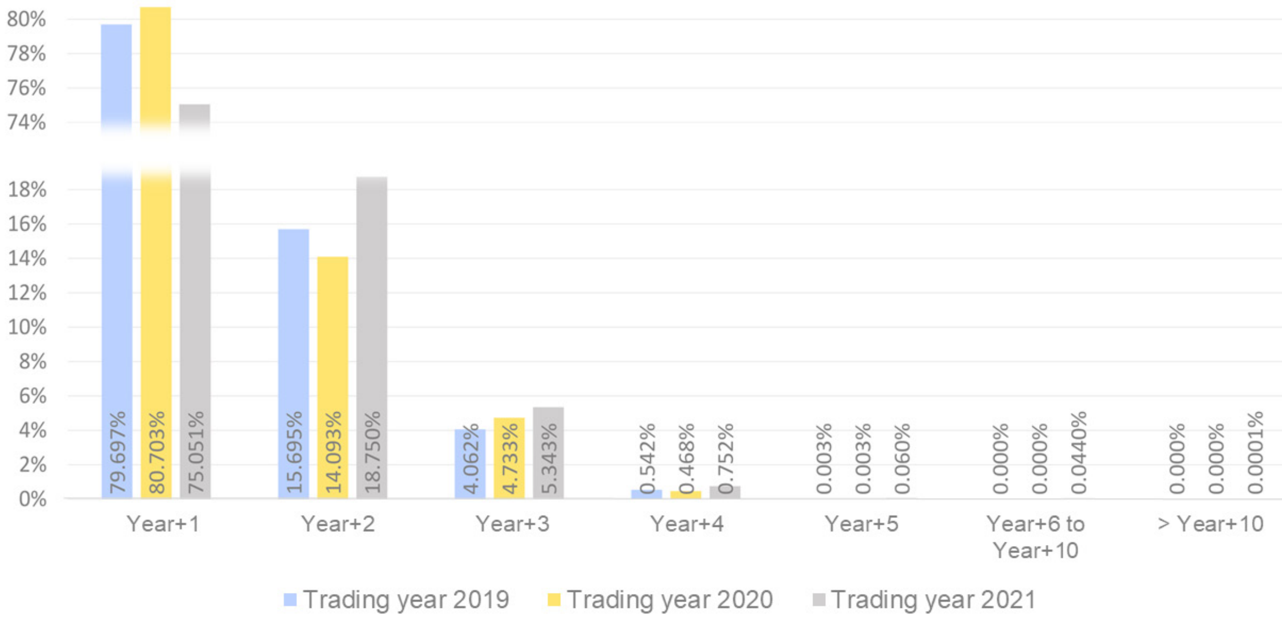
26 Liquidity refers to a sufficient amount of buyers and sellers regularly making transactions in a market.

27 The churn factor represents the overall volume traded through exchanges and brokers expressed as a multiple of physical consumption. It constitutes a common measure of liquidity.

As can be seen from the map, only Germany is averaging relatively high levels of liquidity. Another question though is the duration of the forward contracts on offer (irrespective of whether the market is liquid or not).

Figure 25 shows for Germany the long-term trading over products ranging from 1-20 years in the future. It shows that German market participants mainly trade up to two years in the future. Year-ahead trading accounts for over three-quarters of the traded volumes, with a slow increase in trading of longer-term products from 2019 to 2021.

Figure 25: Relative shares of trading volume per year in the future in Germany (2019 - 2021)



Source: ACER data.

Note: The blue, yellow and grey bars respectively sum up to 100% (over all timeframes). For 2020 (respectively 2021), Year +1 means products for delivery in 2021 (respectively 2022).

Beyond the liquidity of national markets, it is also crucial to ensure liquidity of cross-border hedging products to enable market participants to trade energy across borders in the long-term. Moreover, liquidity in long-term markets benefits from reducing market barriers (e.g. transaction costs).

Finally, in order to ensure properly functioning long-term markets, market participants need to trust the market to yield fair and competitive prices. The application of REMIT (the framework for detecting market manipulative behaviour across the EU) provides the necessary surveillance and enforcement across Europe to achieve this.

4.4. Which measures for policy makers to consider to further future-proof the EU's electricity market design?

Implementing key market integration measures that have already been agreed in EU legislation and beyond is vitally important (see Section 3 above). In addition, because of the changes ahead (e.g. accelerated investment needs and enhanced flexibility services provision) a number of measures should be put forward, in ACER's view, for consideration by policy makers.

4.4.1. Consider promoting and facilitating wider access to Power Purchase Agreements

Power Purchase Agreements (PPAs) are typically open to large investors (e.g. vertically integrated incumbents) and are mainly national. Enabling other actors to enter into such agreements would enlarge the PPA market, thereby stimulating investments in low-carbon generation and flexible resources.

Small suppliers often have limited access to PPAs, as they have difficulties to demonstrate their bankability and their ability to last over a long time period. They might also have varying time horizons or needs in terms of volumes to offtake. Opening PPAs up to a multitude of different actors would bring at least two benefits. First, developers would more easily sell the energy from their projects, as more possible buyers would be able to bid. Furthermore, smaller suppliers would benefit from the price predictability and hedging that PPAs enable.

Governments, other authorities and commercial entities can each play a role in improving the accessibility of PPAs. The EU's Renewable Energy Directive asserts that Member States need to remove regulatory and administrative barriers to long-term renewables PPAs and to describe in their national energy and climate plans how they will facilitate PPAs.

One way to ease access to PPAs would be to pool smaller sellers and buyers. For example, participation in PPAs could be opened up to groups of smaller consumers or suppliers. This approach would allow more market participants access to electricity, mostly from low-carbon generation, at a fixed price. In this case, the pool of buyers could be jointly responsible to tackle counterparty risk.

Supporting guarantees could be another way to stimulate PPAs. By taking over part of the guarantee and thus reducing risk and collateral requirements for private entities, a government could facilitate PPAs between smaller actors. Obviously, reducing the risk of high collateral requirements needs to be balanced with the risk of defaulting on the PPA's requirements themselves. Such guarantees should not discriminate or give price support specific to local industry. The box below describes credit guarantee schemes in Norway and Spain.

Case: The Norwegian credit guarantee scheme and the Spanish reserve fund for energy

The Norwegian Export Credit Guarantee Agency (GIEK) offers guarantees for PPAs. These guarantees support investments in renewable energy and enhance industrial companies' access to PPAs.

A guarantee to the electricity seller hedges against the risk of a buyer's failure to honour the agreement. A guarantee to the banks or other lenders hedges against the risk of the buyer defaulting on the repayment of loans. The guarantees are reserved for buyers registered in Norway active in wood processing, metal production or the production of chemical products.

Source: http://www.eksfin.no/en/produkter/power-guarantee

The Spanish Export Credit Insurance Company (CESCE) manages a guarantee reserve fund for electro-intensive entities (FERGEI). The fund gives a payment guarantee to large consumers who purchased at least 10% of their annual electricity demand via a renewable energy PPA. A guarantee to the electricity seller hedges against the risk of a buyer's failure to honour the agreement. Earlier this year, Spain approached the European Investment Bank to enquire as to whether the bank could consider providing similar financial guarantees for PPAs.

Source: https://www.cesce.es

4.4.2. Consider improving the efficiency of renewable investment support schemes, limiting their use to the needs assessed

When considering measures to underpin accelerated investment in renewable generation capacity, the choice and thus design of the support framework obviously matters.

There is no one-size-fits-all approach to such support frameworks. However, given the evolution of the electricity sector and the capacity needs further ahead, some rules-of-thumb seem warranted.

Based on the experience gained in the recent past, when designing mechanisms to steer renewable energy projects in particular, there seems to be a trade-off between promoting such projects ('build at scale and speed') and efficiently integrating them ('get the most out of the support rendered'). Also, based on even more recent experience, there seems to be a political premium in some quarters on ensuring that the revenue certainty provided to private operators by virtue of the support mechanism to underpin their investment is counterbalanced by mechanisms for feeding back unusually high market prices into the economy (e.g. to alleviate the impact of such prices for consumers). This is akin to an ex-ante excessive or 'windfall' profit taxation scheme.

Hence, if governments prioritise the build-out of new low-carbon generation at scale and at speed, whilst at the same time prioritising an overall ceiling on revenue that the generators thus supported can legitimately earn, opting for production-oriented schemes that remunerate equally each MWh produced would seem appropriate. This could be achieved e.g. by means of CfDs, noting the outcome could be somewhat equivalent to Feed-in-Tariff schemes.

If governments on the other hand prioritise the most efficient integration of new low-carbon capacity without necessarily considering ceilings for generators in times of high prices, opting for capacity-oriented schemes would seem more appropriate. This would mean, all things equal, that the support framework is less oriented towards the amount of electricity produced and more towards system value. When the emphasis is not only on total production, developers will take decisions at the time of the investment that increase the alignment between production and demand profiles in light of the market signals in place. Simply put, the most valuable projects would not necessarily be those that produce more electricity in total; the projects favoured would be those that produce more, where and when it is most valuable for the system. For systems with increasingly dominant shares of renewable generation, the rationale for moving in this direction seems strong.

Irrespective of which of the two approaches is favoured, there is a strong case for reviewing and, where relevant, updating the support scheme(s) in place commensurate with the broader objectives sought. The sheer volume of new generation investment needed across the EU to meet the decarbonisation goals will require not only a lot of investment, but also investment that is spent wisely, meaning on projects that deliver actual decarbonisation at scale (as opposed to generation that is curtailed or subject to vast network congestion) and that keep prices affordable for end-consumers. For both approaches, centralised auctions or tenders could be deployed as a tool to enhance competitiveness amongst offers.

4.4.3. Consider improving the liquidity of forward power markets

As explained above, liquid forward power markets help both buyers and sellers manage risks. Because of the benefits that hedging brings, increasing forward market liquidity (particularly beyond three years) is an important element to support investments in low-carbon and enhanced flexibility solutions.

Power exchanges have recently started to offer longer-term forward products on their markets, suggesting there may be demand for such products. Yet, additional efforts would seem to be needed to improve liquidity for these products. This can be achieved by further standardisation of products across Member States, by removing barriers for market participants to trade in forward markets (such as high fees) and by stimulating so-called 'market making'[28] in otherwise illiquid (long-term) markets. Such market making stimulation ideally originates from the power exchanges and brokers (for example by reducing fees for market makers), alternatively from governments or regulatory authorities. New Zealand offers one such example of market making stimulation.

[28] 'Market making' refers to certain traders submitting at the same time orders to buy and sell, in order to increase the amount of orders in the market. These orders will spur trading.

Case: Market making services in New Zealand

ASX, the wholesale market forward trading platform for New Zealand, introduced market making services on its platform in 2010. In the ASX New Zealand market, the four largest generator-retailers each provide market making services on a voluntary basis. In April 2021, the New Zealand Electricity Authority introduced a permanent mandatory backstop to the market making activities, meaning market making becomes mandatory when certain conditions are not fulfilled.

More specifically, the generators sign a contract with ASX to provide these services. ASX incentivises the market makers primarily through reductions on the platform's transaction fees. The New Zealand Electricity Authority monitors the market making.

Source: https://www.ea.govt.nz/

Governments could play a role in building up the necessary market liquidity. Such a role may take different forms. For example, regulators or other public authorities could open a call for tenders to designate a market maker for illiquid markets or by mandating market making. Governments and legislators could also mitigate the impact of very high collateral requirements which can act as a deterrent against engaging in longer-term markets. With unprecedented high prices, such collateral can represent substantial amounts of money and drives liquidity away from markets. Criteria to meet collateral requirements could be reviewed in light of such prices (e.g. criteria for market participants towards their banks). Moreover, in case of perceived market failure, central entities can also provide financial guarantees to reduce the costs related to collateral.

Products that enable the trade of electricity across borders, such as long-term transmission rights, may also provide an opportunity to improve liquidity in forward markets. Today, these products provide access to alternative hedging possibilities for market participants in smaller bidding zones with illiquid forward markets. This means that market participants can procure forward products in larger and more liquid markets, with transmission rights bridging the difference to their home market. However, such a hedging strategy may also lead to further shifts in liquidity from smaller to larger bidding zones, which is not necessarily optimal.

ACER believes that mandating TSOs to allocate long-term cross-zonal capacities in a way that enables the 'coupling' of national forward markets (as in the single day-ahead and intraday coupling), may provide an efficient pooling of liquidity in forward markets. Extending the time horizon for the allocation of cross-zonal capacities beyond one year would also stimulate liquidity in forward markets in longer horizons. A possible review by the European Commission of the Forward Capacity Allocation regulation could take on board such considerations. Finally, TSOs should maximise the long-term cross-zonal capacity, as a prerequisite for well-functioning and integrated forward markets.

4.4.4. Consider tackling non-market barriers and political stumbling blocks for enhanced coordination

Irrespective of the particular market design applied, tackling key non-market barriers will also be crucial. Enhanced grid infrastructure, such as transmission lines, will be key to enable the energy transition, e.g. connecting renewables generation and flexibility resources across wide geographic areas.

Numerous issues, especially related to permitting and local opposition, have delayed infrastructure rollout. For example, ACER's latest monitoring of the Projects of Common Interest finds that more than 40% of delays for electricity projects relate to permit granting. Part of the European Commission's REPowerEU Communication of March 2022 explicitly targets infrastructure bottlenecks, with the Commission calling for a simplification and shortening of permitting procedures.

Efficient grid development and operation, as well as energy efficiency measures, can reinforce the impact of flexibility sources or even substitute them (within and between Member States). Coordinated infrastructure planning, likely becoming increasingly complex in line with greater energy system integration, will thus become ever more important.

This challenge is not unique to grid deployment. A successful energy transition trajectory will rely on holistic policies that target both demand and supply and that focus on both the short-term and long-term.

Major decisions around power generation options, whether for new-build or retirement, can have major implications and create opportunities for other Member States. They may also impact significantly major investment decisions for electricity-consuming industry. Hence, enhanced coordination including across borders, visibility of planning and proactive involvement would seem to be a necessary feature of electricity generation policy going forward.

One pertinent illustration of such enhanced coordination needs is represented by the huge offshore wind resource endowments in the North Sea and the expressed desire to exploit these for sizeable shares of electricity demand across the European continent.

Offshore wind power: Scaling it up requires increased Member State collaboration

The countries in the North Seas Energy Cooperation (NSEC) recognise the importance of regional energy cooperation on a wide range of issues such as maritime spatial planning, grid planning, support schemes and tendering, financing, and the development and implementation of concrete projects[29].

[29] North Seas Energy Cooperation: 'Political Declaration on energy cooperation between the North Seas Countries and the EC on behalf of the Union', December 2021.

By way of example, the EU Energy Commissioner has expressed the importance of cooperation for the success of the project:

"NSEC is an outstanding example of how regional cooperation at sea basin level contributes to reach the EU Green Deal objectives, by setting a common direction and working together on ambitious cross-border offshore wind projects." (Ms Kadri Simson, EU Commissioner for Energy)

Recently, a Joint statement of European governments, power transmission operators, and industry on the expansion of offshore wind in Europe, signed on 6 April 2022, further emphasises the need for accelerating offshore wind deployment through coordination, proposing e.g. further visibility of respective offshore projects pipelines, removing barriers and streamlining consenting, coordination on planning, investing in research etc..

Coordination efforts amongst and between TSOs, Member States, regulators, project developers and others has built up over the past two decades. These include, but are not limited to, actions taken in the context of implementing the Ten-Year Network Development Plan, the EU-wide Network Codes and the European Resource Adequacy Assessment. Such coordination needs to be further enhanced. In an EU-wide context, coordination at the bilateral, regional or EU level can optimise investment decisions (such as the desired locations of renewables, flexibility or transmission assets), provide visibility about likely market entries and exits, and remove hurdles for speedy and efficient investments. Beyond the electricity sector, diversifying fuel supply would also likely require coordination, e.g. regarding where to build, how to operate LNG facilities as well as to ensure that they are connected to downstream markets.

"... Coordination at the bilateral, regional or EU level can optimise investment decisions [...] and remove hurdles for speedy and efficient investments."

4.5. Consider structural measures that enhance the hedging potential of the system, thus helping to shoulder future periods of sustained high energy prices

Finally, as a more structural measure for the future, ACER points to a few options being debated in academic circles for enhancing the hedging potential of the current system. These are measures that policy makers may want to consider to guard against future periods of sustained high energy prices. Such measures are not immediate options to alleviate the extraordinary price pressures experienced here and now, but may alleviate concerns that even with an improved and adjusted electricity market design fit for the coming decade, one might need additional 'insurance' against future energy price shocks.

"... ACER points to a few options ... [that] may alleviate concerns that even with an improved and adjusted electricity market design ..., one might need additional 'insurance' against future energy price shocks."

Two specific measures are further explored below, namely a regulatory intervention inspired by financial hedging, and a 'relief valve' inspired by measures prevalent in certain electricity markets outside of the EU. In order for measures such as these to offer high degrees of regulatory stability, they should be implemented in a clear and transparent way, well in advance of those high energy price periods which they are designed to mitigate against. Should policy makers wish to move in this direction, ACER points out that each such measure has advantages and drawbacks, and advises that further analysis be done as to how they best fit with the jurisdiction in question.

Measures that exclude extreme risks from materialising, or mitigate the effects thereof if they do, can serve as insurance for certain groups of consumers. For example, a regulatory or other public entity may buy long-term hedging instruments on behalf of (groups of) consumers. This transfers the risk from consumers (who are usually risk-averse and have little means or knowledge to hedge properly) to electricity producers who can provide the hedge. Such a transfer, in turn, creates a need for producers to hedge themselves (for example by building flexible resources), thereby in turn increasing liquidity in long-term markets. Reliability options, 'affordability options' and cap-and-floor mechanisms constitute examples of such measures. They obviously come with a cost (no insurance is free), the allocation of which could be subject to different political considerations.

Reliability Options and Affordability Options

Reliability options, such as those implemented in Ireland or Italy, constitute a contract between capacity providers and a buyer (here a TSO). Each time the established reference market price rises above the strike price of the option, the seller pays the difference between the reference price and the strike price to the buyer. The main purpose of reliability options is for buyers to benefit from enhanced security of supply (adequacy). At the same time, the reliability option serves as a hedge against price spikes. Sellers of reliability options receive a regular payment for keeping capacity available.

So-called 'affordability options'[30] are measures introduced in anticipation of or as hedging against extreme price shocks in the future. They are subject to a centralised auction for long-term options, the execution of which depends on the average market price over a pre-defined period (e.g. a month)[31]. Only when the average price over the period exceeds the strike price, will the option be executed. Such options therefore maintain the exposure of consumers to shorter-term market signals but hedge them against sustained high prices and correspondingly high electricity bills.

[30] The 'affordability option' is described in Batlle et al (2022), Power Price Crisis in the EU: Unveiling Current Policy Responses and Proposing a Balanced Regulatory Remedy and in Batlle et al (2022), Power Price Crisis in teh EU 2.0+: Desparate times call for desperate measures. The measure proposes that a regulatory entity buys long-term Asian call options (which has a pay-off depending on the average over a time period rather than a single expiration date) from generators on behalf of the targeted consumers.

[31] These are also referred to as 'Asian call options'. Contrary to so-called 'European options' or 'American options' where the payment linked to the execution of the option depends on the price of the underlying asset at a specific point in time, the execution of 'Asian options' depends on the average market price over a pre-defined period.

A different mechanism which policy makers could also consider is the establishment ex ante of a temporary price limitation mechanism, triggered under clearly specified conditions (e.g. unusually high electricity price rises in a short period of time), the effect being to pause a return to full price formation for a specified period of time (e.g. a few weeks or a month). The measure would need to ensure that sufficient revenue is earned by generators and would require a compensation mechanism for those generators who are able to prove sourcing costs above the limitation ceiling[32].

Such a mechanism could prove a significant intervention in price formation, As such, it carries risks. However, this risk is partly mitigated by the advantage of giving regulatory stability provided the measure is implemented well in advance of the triggering events and provided its defining characteristics are clear and transparent. Should such a measure be deemed desirable, it would benefit from being coordinated at EU level, drawing on lessons from the jurisdictions where it has been implemented.

Temporary Relief Valve Mechanisms

So-called ‘relief valve’ mechanisms such as ERCOT's ‘Peaker Net Margin’ (Texas, United States) or ‘Cumulative Pricing Threshold’ in the National Electricity Market[33] (Australia) constitute examples of such a measure. Both markets foresee a normal market clearing, with regular price signals, including from price spikes, up to the point where sustained high prices have reached the mechanism’s pre-defined threshold.

The ERCOT ‘Peaker Net Margin’ measure calculates the accumulated profits over a year as a difference between the operating costs, defined by natural gas, and the real-time electricity price. The threshold is set at three times the cost of new entry of new generation plants. When the threshold is reached, the maximum price on the market is temporarily lowered and then, according to certain criteria, automatically raised again later on ensuring full price formation.

The Australian National Electricity Market imposes a so-called ‘Administered Price Period’ when the sum of the spot prices for the previous seven days reaches the ‘Cumulative Pricing Threshold’ (CPT) or when the sum of the ancillary service prices for a market ancillary service in the previous seven days exceeds six times the CPT. In 2019-2020, the CPT was equivalent to an average spot price of 658.04 AUD/MWh. The administered price cap during the administered price period is set at 300 AUD/MWh. The ‘Administered Price Period’ ends when the cumulative price has fallen below the CPT.

[32] See as an example of a 'temporary relief valve' M Hogan et al (2022), Price shock absorber: temporary electricity price relief during times of gas market crisis.

[33] See for example the Operation of the administered price provisions in the national electricity market briefing paper from the Australian Energy Market Operator (AEMO), July 2019.

5. Extreme price shocks leading to considerations of temporary, targeted measures

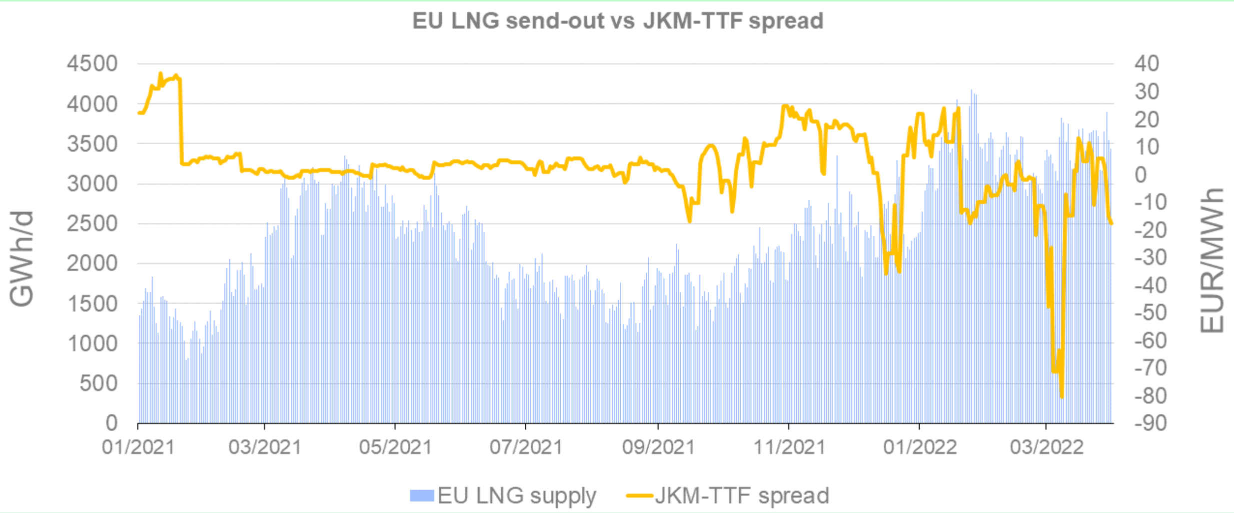
The extreme price situation as of end February 2022, described above as Phase 3 ('war emergency'), is the result of a rare, unexpected and difficult-to-mitigate energy price shock. It is exacerbated by high geopolitical tension and significant uncertainty around the energy supply outlook; this obviously linked to Russia's war against Ukraine and its possible consequences. The threat of war and the subsequent invasion gave rise to significant price rises and high price volatility, the former leading to increased LNG deliveries to Europe, as illustrated in the text box below.

Price signals delivered more spot LNG cargoes since the end of December 2021

In 2021, LNG volumes traded on a spot and short-term basis accounted for 38% of global LNG trade[34]. Spot LNG tends to flow to the region with the highest price. Due to growing, but still limited, contractual and end-point flexibilities, LNG cargoes are subject to short-term redirections and price arbitrages, making LNG deliveries more price responsive than in the past.

From December 2021 to March 2022, total LNG supply to Europe has significantly risen (+65% year-on-year, for the average of the fourth months) driven by the high European gas prices. This is exemplified in Figure 26, which compares the evolution of EU LNG supplies against the price spread between the European (TTF) and Asian (JKM) gas regions. The analysis shows that when, at the end of 2021, EU hub prices started to become higher than Asian ones (i.e. JKM-TTF price spread is negative in the graph), the total LNG supplies into the EU increased[35].

Figure 26: Total LNG supply to Europe (GWh/day) vis-à-vis European-Asian spot price (EUR/MWh) spreads (January 2021 - March 2022)



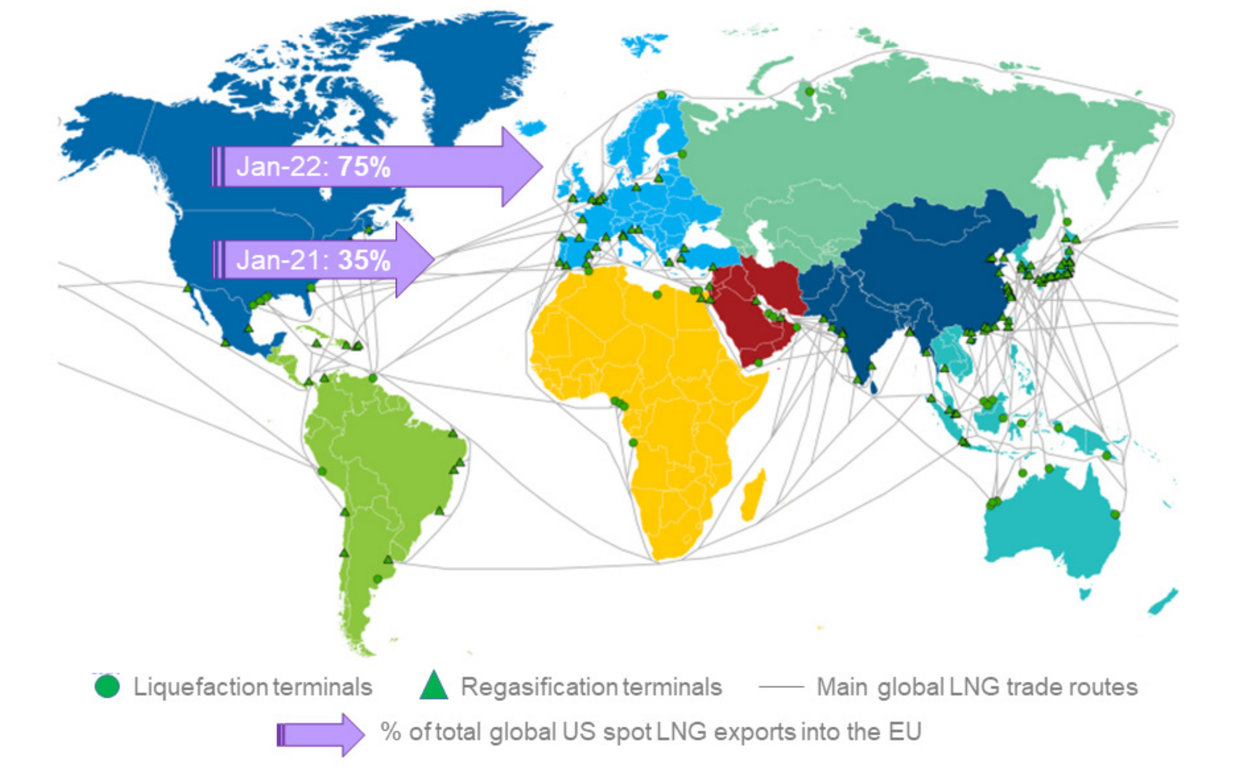
Source: International Gas Union and ICIS Heren.

[34] The figure refers to LNG volumes delivered up to three months from the transaction date. According to IEA estimates, that share was 30% in 2019.

[35] LNG supplies – i.e. gas regasified from the LNG terminals into the network - tend to relate well to total LNG imports, with some days of time-gap.

The major part of the increased EU LNG imports came from the US, which is the largest global spot LNG seller, accounting for 30% of total global spot LNG sales. As illustrated in Figure 27 below, 75% of the total global US spot LNG sales reached the EU in January 2022 (attracted by the higher European prices) in contrast to 35% one year earlier. In March 2022, US LNG deliveries accounted for 44% of total EU LNG imports, compared to 28% in 2021.

Figure 27: Share of global US spot LNG deliveries that reached the EU (January 2021 vs January 2022)



Source: International Gas Union and ICIS Heren.

With significant geopolitical tension and increased risk of gas supply impacts, EU prices have soared above Asian hub premium prices. As mentioned in Section 2, the current energy price shock and very significant price volatility stem less from physical shortages and more from perceived risks of and lack of clarity on potential significant disruptions of Russian gas flows going forward. This current situation has also given rise to decisions seeking to rapidly decrease the considerable reliance of many EU Member States on Russian gas and other energy commodities.

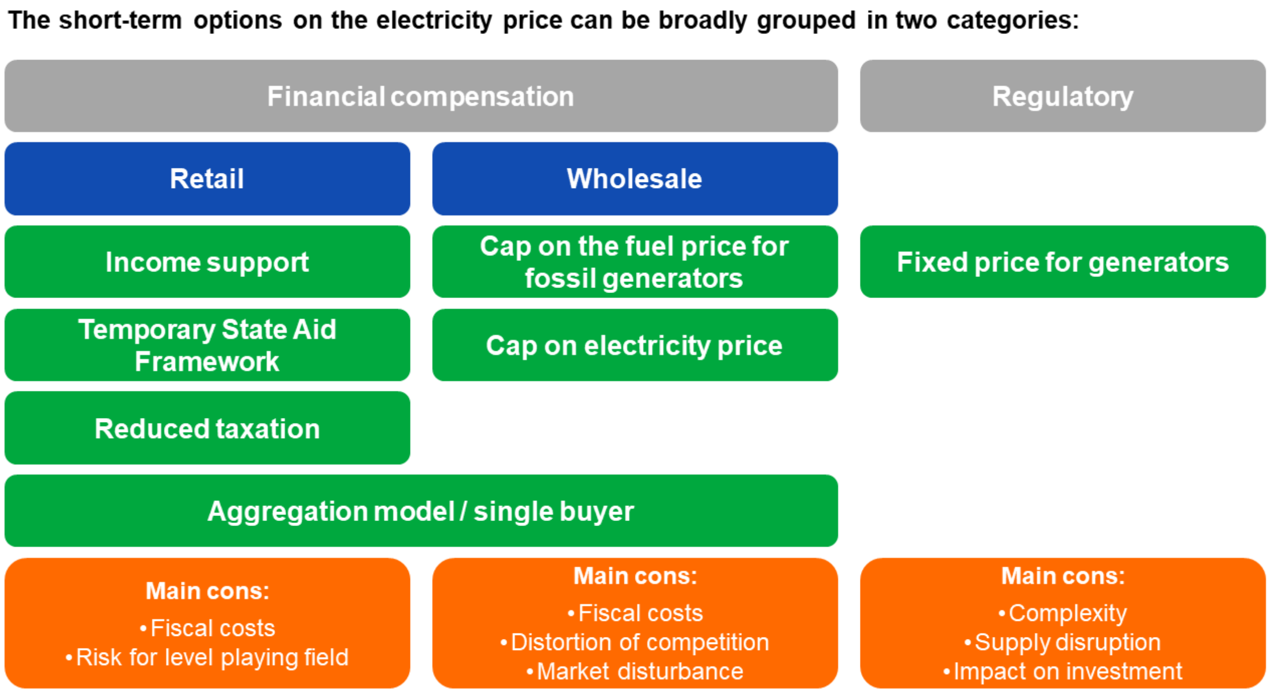
5.1. Differing political approaches to possible temporary measures

Well before the current emergency situation, over the autumn of 2021, several Member States introduced a variety of national measures to mitigate the effects of rising energy prices on households and businesses. These measures were in part informed by the European Commission's 'Toolbox' Communication of October 2021.

On 10 – 11 March 2022, following Russia's invasion of Ukraine, the EU heads of state invited the European Commission to propose a plan to phase out the EU's dependency on Russian fossil fuels. On 8 March, the Commission published its '[RePowerEU: Joint European action for more affordable, secure and sustainable energy Communication]'. This Communication outlined tentative measures to respond to rising energy prices in Europe and the need to replenish gas stocks ahead of next winter. It also pointed to the need to diversify the EU's sources of gas supply, to speed up the roll-out of renewable electricity sources as well as renewable gases, and to replace gas in heating and power generation. The Commission is expected to publish its detailed RePowerEU plan in May 2022. This will likely include options to optimise the electricity market design, following the publication of this ACER assessment.

On 23 March 2022, the Commission adopted [a follow-up Communication], touching upon e.g. common gas purchases and minimum gas storage obligations within the EU. It included a legislative proposal establishing a gas storage policy for the EU, seeking to ensure gas storage is filled to a minimum of 80% capacity by 1 November 2022, rising to 90% minimum gas storage obligations in the following years. In addition, the Communication grouped a number of ideas for short-term emergency measures as had been put forward by certain Member States to limit high electricity prices (see Figure 28 below). These ideas include intervening in the wholesale electricity market (e.g. via a cap on electricity prices or introducing a fixed price for fossil generators), intervening at retail level (e.g. via direct support or reduced taxation for specific consumer groups) or via introducing a so-called 'single buyer model' acting as intermediary between supply and demand.

Figure 28: European Commission's overview of short-term options to address high electricity prices (as per their 23 March 2022 Communication)



Source: European Commission Communication of 23 March 2022: 'Security of supply and affordable energy prices: Options for immediate measures and preparing for next winter', COM/2022/138 final.

The European Commission's Communication makes clear that all of the options outlined have costs and drawbacks. It concludes that the root cause of the electricity price crisis is the recent gas supply shock and its impact on gas prices. As such, it sets out options for interventions in the gas markets such as capping gas prices (or setting a price band) as well as ideas for an EU-level negotiation strategy with relevant suppliers so as to lower prices for LNG and/or pipeline gas deliveries.

In line with the European Commission's original tasking back in October 2021, this ACER assessment focuses on the benefits and drawbacks of the EU electricity market design, not least in terms of its ability to deliver the EU's decarbonisation trajectory over the next 10-15 years. At the same time, ACER of course acknowledges the significant political debate as to whether targeted extraordinary measures are needed on a temporary basis (e.g. to cushion the adverse impacts of high prices for particular groups and/or to structurally intervene in the energy market in the current emergency situation). Whilst the ACER assessment did not set out to tackle such issues, ACER takes the opportunity to offer its considerations on the use of such measures in order to address the current high energy price situation in the EU.

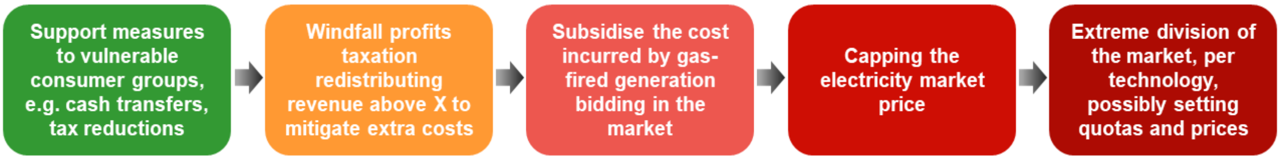
A spectrum of possible intervention measures are being tabled by different EU Member States. These range from the less interventionist measures that safeguard wholesale market functioning (such as targeted support for vulnerable customers) to the more interventionist (e.g. taxing windfall profits through to capping the price of the electricity market). As a rule of thumb, ACER considers that the more structural-interventionist a measure, the higher the potential to distort the market, especially in the medium to long-term. Hampering security of supply, distorting cross-border trade, jeopardising investor confidence are some of the risks ensuing from the more structural-interventionist measures being considered. Hence, prudent and careful consideration by policy makers at EU and national level would seem warranted before embarking upon such measures.

Firstly, interventionist measures carry the risk of rolling back, or perhaps even abolishing, the significant benefits already achieved by EU electricity market integration over the past many years (for details, see Section 3 above). Secondly, significant structural interventions in the market may make it more difficult to achieve the EU's ambitious decarbonisation objectives in the medium-term, especially if private investor confidence in an appropriate and stable market framework were to be negatively impacted. This is because lower private investor confidence would likely lead to a rise in 'political risk' premiums, making the decarbonisation trajectory more costly.

"As a rule of thumb, ACER considers that the more structural-interventionist a measure, the higher the potential to distort the market, especially in the medium to long-term."

Figure 29 is a stylised depiction of the spectrum of energy measures currently contemplated and/or advanced by different Member States across the EU. These measures are ranked according to the impact and level of structural interventionism.

Figure 29: Spectrum of possible structural-interventionist measures relevant for the EU electricity market (non-exhaustive)



Source: ACER.

Note: the further a measure is depicted to the right, the deeper the level of intervention and/or alteration of the market framework in ACER's view.

The first and least distortive category of measures (on the left hand side of the spectrum) are national measures to protect vulnerable consumers (e.g. through energy vouchers or direct cash transfers, efforts to reduce the overall energy bill, or to stimulate energy efficiency). As stated in ACER's Preliminary Assessment published in November 2021, such measures will be more effective if directed towards more vulnerable consumer groups, including the energy poor. Some Member States have opted for broad-based measures (e.g. lowering tax, lump sum payments) for all (or nearly all) consumers. Whilst of course in the end reflecting a political choice, such less-targeted measures generally end up being more costly and less effective.

A second category seeks to recover possible 'excessive' (also referred to as 'windfall') profits in a period of very high energy prices. Under some schemes in place in the EU today, companies are subject retrospectively to specific taxes on alleged 'windfall' profit, seeking to redistribute the impact of high prices from those who are deemed to earn the most to those who are suffering the most. The notion of excessive profit is the difference between the revenues from extraordinarily high electricity prices, and the 'standard profit' that a market participant could reasonably have expected (e.g. based on its generation costs, original investment costs, various risks and overall return-on-investment expectations).

Whilst redistributing welfare from generators to consumers in times of extreme high prices might intuitively seem fair and justified, such measures carry significant implementation challenges, as already witnessed in some jurisdictions. In particular, it is difficult to assess profits made vis-à-vis pre-contracted power volumes already sold at lower prices, e.g. through long-term markets. It might well be that generators did not earn the 'profits' being targeted, in which case the tax may render a loss for the generators in question. As a result, in such cases, 'windfall profit' interventions may risk jeopardising investor confidence or act as a disincentive to invest. Nonetheless, if such schemes manage to tackle genuinely extraordinary profits, the level of structural intervention seems lower than capping prices per se.

Whilst not necessarily framed as a 'windfall' profit redistribution scheme, other national measures may have similar effects and could thus have similar drawbacks. An example is mandatory long-term contracts for specific generators. If these aim at offering below-market prices for consumers (through administratively-set prices or limited competition on the buying side), they may well result in profit redistribution as well[36].

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[36] Some have argued that this type of measure would be appropriate in a market characterised by one or a few firms holding a dominant position. However, such measures may still lead to undesired effects ranging from an increase of perceived risks, in turn leading e.g. to higher financing costs, and to non-recoverable welfare losses for the system as a whole.

In principle, one could also envisage measures that target the price of gas power plants in the electricity merit order (the third box in Figure 29); this in light of the fact that gas can often be the price-clearing technology in the market, in particular in times of lower-renewable output. Lowering the bid price of gas-fuelled power plants (whilst still covering separately the higher gas sourcing costs for those power plants who end up in the merit order) would in principle reduce the impact of high gas prices on electricity prices. Such measures could be designed in different ways, all of them however carrying significant risks.

For example, besides numerous implementation challenges, these measures may jeopardise security of supply should cost-recovery be perceived as a risk; may significantly distort cross-border flows (as the artificially lowered prices may no longer reveal full scarcity); and would likely lead to inefficient dispatch decisions. In addition, such a measure carries significant direct costs, namely the difference between the (capped) bid price of the gas-fuelled power plant in question and its sourcing costs; costs which need to be carried by the government budget and thus indirectly paid for either by the taxpayer or the electricity consumer. Accounting for, monitoring and paying for these additional costs would also entail significant administrative burden.

In practice, and by way of comparison with the fourth box in Figure 29, lowering the bid price of gas-fuelled power plants would limit the electricity price for many hours, whenever the gas-fuelled units set the electricity price; however a direct cap on the electricity price would limit the electricity price for all hours, irrespective of the marginal technology. This would thus seem an even more extreme intervention in the market carrying greater risks.

Finally, one could imagine an even more structurally-interventionist measure in the form of a division of the electricity market into distinct technologies (the fifth box in Figure 29), perhaps with administratively-set production quotas and prices for each technology. ACER is not aware of any jurisdiction where such a mechanism has been recently implemented, in essence being more akin to 'war-time' measures (the analogy being e.g. manufacturing industry directed in war-time to produce certain equipment deemed essential with a certain revenue level being allowed). ACER has serious doubts as to whether such a model would be feasible in an EU context and whether it could secure supply, short of a quasi-nationalisation of the energy industry in question.

Broadly speaking, an important consideration of the measures briefly introduced above is how much they discriminate between generation technologies and/or among consumer segments. When a measure targets certain technologies only, it risks fragmenting the market, compromising competition and creating regulatory uncertainty about the potential for similar measures in the future. The more structurally ingrained a measure, the more likely it is to hamper innovation in future technologies and offerings, and accordingly the less likely it is to support investor confidence in new low-carbon investments. Moreover, if Member States implement such measures in a non-coordinated or non-aligned way, this might exacerbate the adverse impacts on cross-border trade and flows.

Overall, when addressing short-term needs, policy makers need to be careful about the negative medium- and long-term implications of the measures contemplated, such as the regulatory risk involved, the impact on future financing costs for private operators and the retention (or loss) of benefits hitherto accrued by way of current market functioning. In any case, Member State transparency on the measures being contemplated and a clear end-date or end-criteria for their expiry would seem particularly important. This reduces uncertainty and as such would likely have an immediate effect on longer-term market prices.

5.2. A different possible route; tackling the root causes (gas markets) rather than the symptoms (electricity prices)?

The aforementioned structural measures interfere in the EU wholesale electricity market, with those from the middle and towards the right of the spectrum outlined above likely having major distortive effects.

"Targeting the gas market and its price dynamics may well prove less distortive, given such a measure would not directly intervene in the electricity wholesale market functioning."

Should policy makers see a need to take immediate structural action under the current extraordinary energy price circumstances, a different possible route would be to target 'the root causes' of the situation, namely the very high price of gas, resulting from the considerable risk of and uncertainty around a severe gas supply shortage or disruption in the coming months; this rather than targeting 'the symptoms' (i.e. the high electricity prices).

Targeting the gas market and its price dynamics may well prove less distortive, given such a measure would not directly intervene in the electricity wholesale market functioning. Should governments seek to intervene in wholesale gas price-setting, they would need to make sure that the EU gas market remains sufficiently supplied (as otherwise, supply concerns and thus overall high price levels would risk being further exacerbated).

This means in particular that the EU market needs to remain attractive for flexible LNG shipments subject to increasing global competition (see also Section 6 below). Attracting sufficient LNG is of particular importance, as this is the main supply alternative to offset lower Russian supply over the coming months and years. Such a 'root cause' intervention would seem to require extensive dialogue with the main gas suppliers outside of the EU.

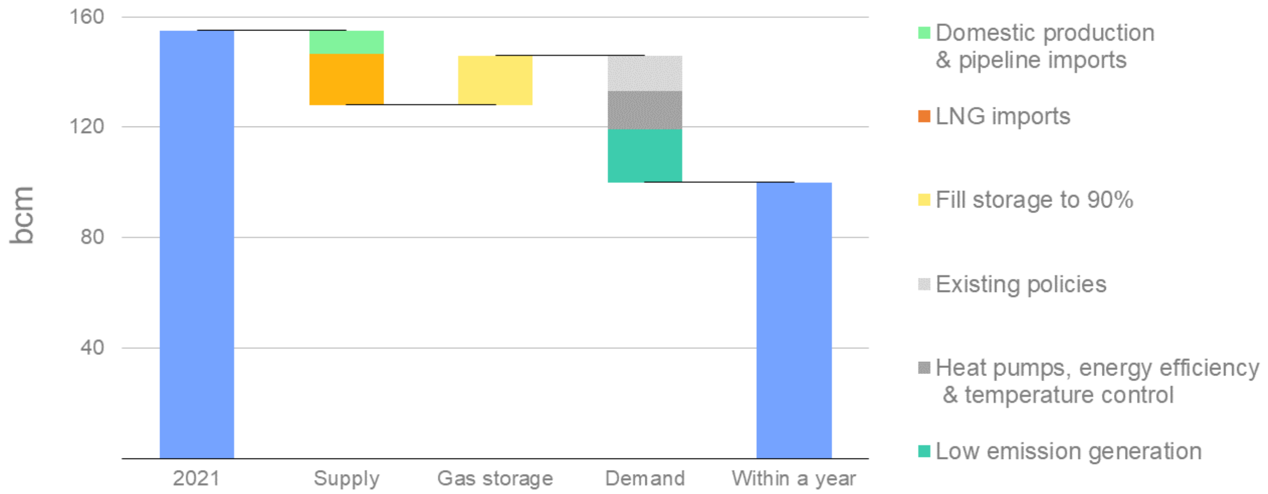
Finally, ACER notes that the current political debate has brought suggestions from some quarters to accompany this focus on gas market intervention with a particular price cap on gas being sold in the EU. At first glance, ACER finds it not fully clear what such a cap would contribute additionally to the aforementioned discussions with the main gas suppliers to the EU, noting once more the need in particular for LNG prices to remain competitive vis-à-vis alternative destinations for such cargoes.

Given that broader gas wholesale market functioning is not part of the European Commission's tasking in the aforementioned 'Toolbox' Communication, we will not pursue this avenue further in the context of this ACER assessment.

5.3. Getting better prepared for possible future supply or price shock events

Recent IEA analysis (depicted in Figure 30) has pointed to a number of near-term measures that could contribute significantly to lower EU dependency on Russian gas, thereby partly mitigating the impact of lower or uncertain future Russian gas supply on EU gas prices. No-regret measures to reduce dependency on Russian gas should include demand-side measures, fuel-switching efforts e.g. towards accelerated renewables deployment, and the diversification of gas supply sources. If implemented, such measures would also help the EU be better prepared for possible supply or price shocks in the future.

Figure 30: Breakdown of various measures lowering near-term EU gas supply dependency on Russia



Source: IEA.

Notwithstanding such near-term measures, the current extraordinary circumstances in which the EU finds itself, with adverse impacts on many consumer groups, suggests there is value in considering 'insurance options' to mitigate possible future periods of sustained high energy prices. These are not immediate options to alleviate the current extraordinary prices, but may alleviate concerns about future energy price shocks.

As further elaborated in Section 4 above, one such measure to be considered is a 'temporary relief valve' for when wholesale electricity prices rise unusually rapidly to high levels over a sustained period. Such a measure features in certain electricity markets outside of the EU. Another such measure is a financial option whereby pre-identified consumer groups via a regulatory intervention are hedged against sustained high prices occurring over a longer period above a certain threshold.

6. Mid-term prospects of gas markets

This section assesses the mid-term prospects of gas markets relevant for the likely impact on electricity prices over the coming years. In turn, this leads to some considerations about EU gas market design and contracting models going forward.

6.1. EU gas prices will become increasingly dependent on global LNG supply

The latest gas market outlook of the IEA[37] shows that under normal weather conditions EU gas demand is expected to decline by 6% in 2022, as an outcome of the high energy prices hampering economic activity alongside reinforced energy efficiency efforts and gas to coal switches in power generation.

LNG supplies will likely remain strong, as some previously offline capacity returns to the market along with the EU securing additional shipments (plus European forward prices remaining at premium to Asia through the rest of 2022). In this respect, the European Commission and Member States have stepped up their collective efforts to jointly acquire LNG from a variety of global gas producers and secure gas from more diversified sources (an EU Energy Purchase Platform has been set, to voluntarily coordinate common gas procurement[38]). For example, following a recent high-level EU-US agreement, the United States will strive to make available at least 15 bcm of additional LNG to Europe in 2022, with volumes expected to increase going forward.

"... In the absence of strong policies to curb demand, global gas supply tightness could well persist."

While this additional supply should help put moderate downward pressure on prices, it will not fully mitigate concerns about possible Russian supply disruptions. The need to refill depleted EU gas storages up to 80% by November of this year will create additional price pressures during the injection season, as also captured by the forward price curves in Figure 5.

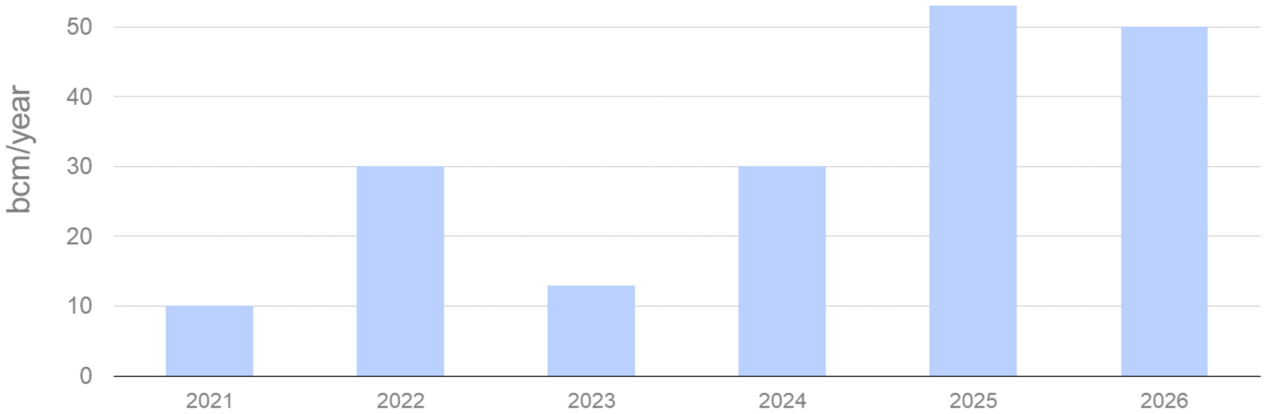
Over the coming years, as EU markets gradually shift away from Russian gas to more diversified supply sources, EU gas prices will be increasingly affected by regional and global price dynamics. Global gas demand is projected to grow steadily across the coming decade, with gas taking a leading role in meeting the growing energy needs of emerging economies, whilst helping to decarbonise their power sector, hitherto often reliant on coal generation.

[37] See the IEA's 'Gas Market Report, Q2 2022'.
[38] The EU Energy Purchase Platform will ensure cooperation in areas such as demand pooling, efficient use of infrastructure and international outreach.

As the EU aims at reducing its gas supply dependency from Russia, it will need to substantially increase LNG imports (with notional European Commission estimates referring to an additional 50bcm per year, approximately 10% of today's total LNG global supply[39]). Therefore, the IEA cautions that in the absence of strong policies to curb demand, global gas supply tightness could well persist[40].

A key factor in this regard is the expansion rate of LNG export capacity in the coming years. As Figure 31 shows, the bulk of this new LNG capacity is expected from 2025 onwards. Moreover, some of the additional supply coming online is likely to be more expensive than current gas pipeline supply originating from Russia, thus putting upward pressure on EU gas prices compared to 'normal' years in the recent past.

Figure 31: Start-up year of forthcoming global LNG (bcm/year) capacity (2021 - 2026)



Source: IEA.

6.2. The EU's 'pay as clear' electricity market design helps attract cleaner technologies, including low-carbon gas

The gradual phase-out of coal-fired power plants across the EU could further increase the prevalence of gas prices as a key driver of electricity prices in the coming years. In spite of recently announced life-time extensions of the nuclear fleet (e.g. in Belgium) or considerations to bring back otherwise mothballed or held-in-reserve coal-fired generation in some Member States, the impact of gas prices on electricity prices is likely to remain until various energy efficiency measures and/or new electricity capacity additions have taken hold.

That said, high gas prices and thus high electricity prices provide strong incentives for other solutions, such as demand-side response offerings and energy storage solutions, to participate in the electricity market. Such solutions, alleviating both gas demand and broader electricity system flexibility needs, would 'outcompete' gas by virtue of their increasingly competitive price bids in the electricity merit order should gas prices remain high. This is also discussed in Section 4 above.

[39] The figure is notionally assessed on the basis of the unused EU regasification terminals' and cross-border pipeline capacities in 2021. The extent to which these projections materialise will depend on the availability of additional global LNG and on the interplay of regional price signals. IEA's estimates halve the amount of LNG likely to be sourced to the EU, at least in 2022. Moreover, gas flows will need to substantially reroute if the EU system becomes increasingly independent from Russian supply, requiring reassessment of system operation and targeted infrastructure investment.

[40] The IEA estimates that global gas upstream spending is lower than what is required to achieve the most ambitious global decarbonisation scenarios. Despite the current record-high prices, new investments are still low relative to assessed needs; this not least due to investor uncertainty about the role of gas in the energy transition (a factor also leading to higher costs of investment capital).

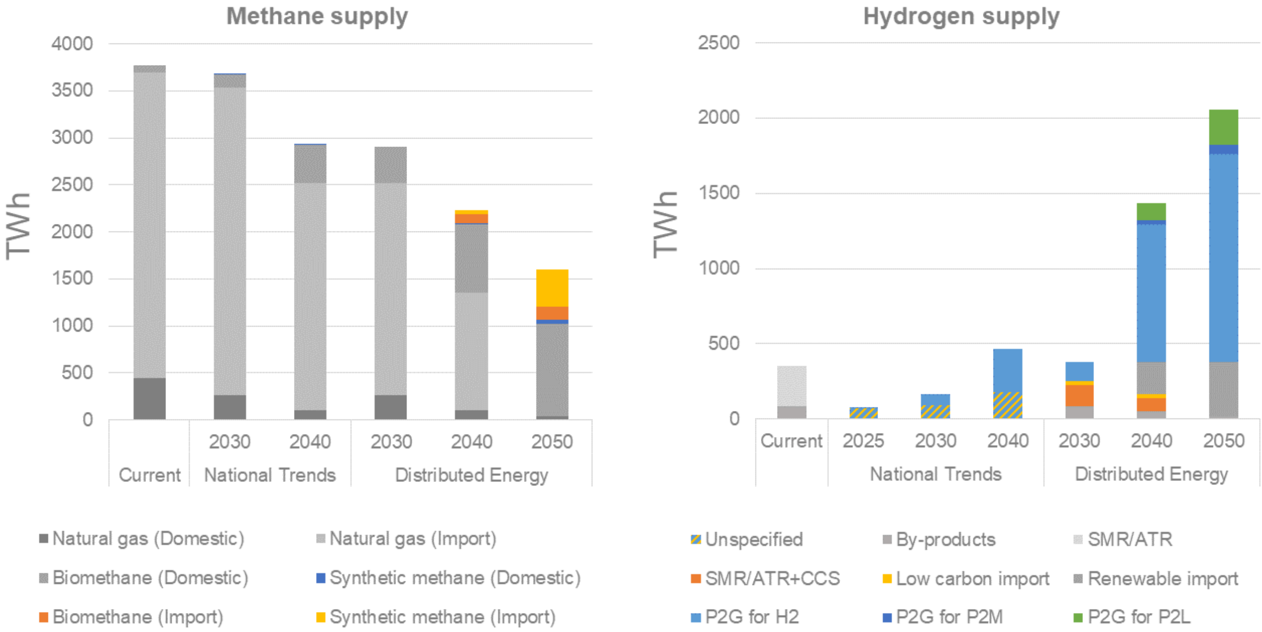
Importantly, the opposite is also likely to hold true. Without such a price incentive, the 'innovation or deployment incentive' for such technologies, competing with gas as to what ultimately clears at the margins and thus sets the overall clearing price, would be lower, thus impacting the uptake of these technologies.

Herein lies an important reason for policy makers, when contemplating extraordinary interventionist measures here and now, to consider prudently and carefully potential negative consequences of such measures in the medium- and long-term.

With the EU's ambitious decarbonisation trajectory, EU gas demand and supply patterns are likely to change. EU gas consumption is expected to decrease in the coming decades, driven not least by strong expansion of low-carbon electricity capacity and lower gas-based space heating requirements due to the electrification of heat, coupled to broader energy efficiency efforts. These pursuits have been given extra impetus by Russia's invasion of Ukraine and the ensuing need to lower the EU's energy dependency on Russia[41].

On the supply side, the transition towards domestically produced renewable and low-carbon gases will decrease the EU's external gas supply dependency. Cost reductions in technology (together with more efficient feedstock gathering and cheaper renewable power input) would make decarbonised gases more competitive. Nonetheless, their cost range is expected to be higher in the next couple of years compared to conventional natural gas prices of past years (though they may be competitive vis-à-vis the current record-high prices). Figure 32 shows two of the latest ENTSOG scenarios for bio-methane and hydrogen penetration. While there is ample technical potential to upscale such production, the cost-competitiveness of these technologies relative to conventional gas will be a crucial factor for their uptake rate. On balance, the EU's reliance on external gas supply is likely to remain high at least until 2040, amidst declining conventional EU domestic natural gas production.

Figure 32: EU methane and hydrogen supply (TWh/year) prospects (2030 - 2050)



Source: ENTSOG Ten-Year Network Development Plan 2022. Various scenarios.

[41] As an example, the European Commission's 'RePowerEU' Communication of March 2022 lists a 35 bcm biogas target in 2030, which would be equal to 25% of Russian piped gas supplies in 2021.

Gas supply patterns are also likely to evolve, mostly due to the more flexible operation of gas-fired power plants, meeting peak and/or seasonally contingent electricity demand as intermittent renewable generation increasingly dominates the electricity mix. In turn, this will likely reduce the revenues of gas-fired power plants over the longer-term. Hence, some of the current generation fleet might exit from the market, requiring other solutions and technologies to undertake that role. Once again, the price-setting mechanism of the current electricity market design provides relevant economic incentives in this respect.

6.3. What mechanisms can best limit gas price exposure whilst securing supply?

6.3.1. Long-term bilateral contracts will coexist with hub-trading

The current gas price situation in the EU has led to debates on the significance and structure of long-term gas supply contracts going forward. Despite the fact that these contracts have declined in recent years and will likely continue to do so, they still account for 75% of EU gas demand. Around 40% of these long-term volumes are signed with Gazprom.

When scarce flexible supply led to record-high gas prices in recent months, not only short-term hub prices but also the price of long-term supply contracts rose. This is because long-term contracts typically, though not exclusively, are linked to various hub-price references (the specific price increase being dependant on the time-lags and price formulas of the contract in question). Under the assumption that enhanced hub liquidity and competition puts downward pressure on prices, and to mitigate high energy prices for consumers, gas producers could further increase the supply volumes directly offered at hubs (hub prices are also crucial because they are the key reference used to determine the opportunity prices of the electricity bids of gas-fired power generators). Enhanced hub forward liquidity would help to better hedge prices and reduce price exposure.

ACER acknowledges, however, that views on this matter may differ. Several producers - as well as some buyers - could prefer to hold bilateral long-term contracts in order to ensure a secure return on production investments and/or lock deliveries in at possibly more stable prices. To the extent that new contracts are linked to the development of new gas fields and/or associated with substantial new infrastructure development (a well-established driver of long-term contracting), the prevalence of long-term contracts may remain.

All in all, the relative weight of long-term contracted versus direct hub-based supplies will be set by market participants' preferences, drawing lessons from the current tense supply situation. Individual portfolios are likely to contain mixed hedging strategies and price references and, on average, more diversified supply sourcing origins.

6.3.2. Higher gas storage stocks will benefit security of supply and flexible system operation

Another issue attracting attention relates to the future role of underground gas storages, key both to securing supply to meet seasonal demand swings (thus exerting downward pressure on prices during tight supply situations) and to supporting flexible system operation. The concerns about security of supply worsened in the aftermath of Russia's invasion of Ukraine, given uncertainty about Russian gas flows going forward. Such concerns have reinforced the supply security role of gas storage sites across the EU.

A key focus area here are the so-called Summer-Winter spreads which in the current high price situation provide little to no financial incentive for companies to fill storages over the summer. This is also acknowledged in the European Commission's Security of Supply and Affordable Energy Prices Communication of March 2022, which calls for EU storage sites to be filled to at least 90% of their capacity by 1 November each year (the target for the year 2022 being 80%, although some Member States may set it higher)[42].

Currently, underground gas storages are a key provider of seasonal flexibility for gas and for electricity (by way of example, storage withdrawals cover around 25% of gas consumption in winter). As such, storages are a crucial asset for hedging related forward prices. Moreover, the role of gas storage in enabling flexible short-term operation in both the gas and power system may increase in the coming years with the increase in intermittent renewable power generation. Hence, gas storages will need to find an optimal balance between these two operational time frames and market roles, i.e. between the provision of seasonal flexibility and shorter-term market balancing (noting this balance will also be influenced by the physical characteristics of the storage site in question).

Over time, low-carbon hydrogen – through storage and offtake of (renewable) electricity production – will likely complement the flexibility currently offered by underground gas storages, though views differ as to the expected rate of hydrogen uptake.

[42] The European Commission's legislative proposal for a regulation on gas storage, accompanying the aforementioned Communication in March, requires Member States to set a certain filling trajectory and measures to achieve the threshold. Discussions are taking place to determine the most effective approaches, taking into consideration solidarity principles but also the differences between Member States in terms of their respective storage availabilities relative to national demand.

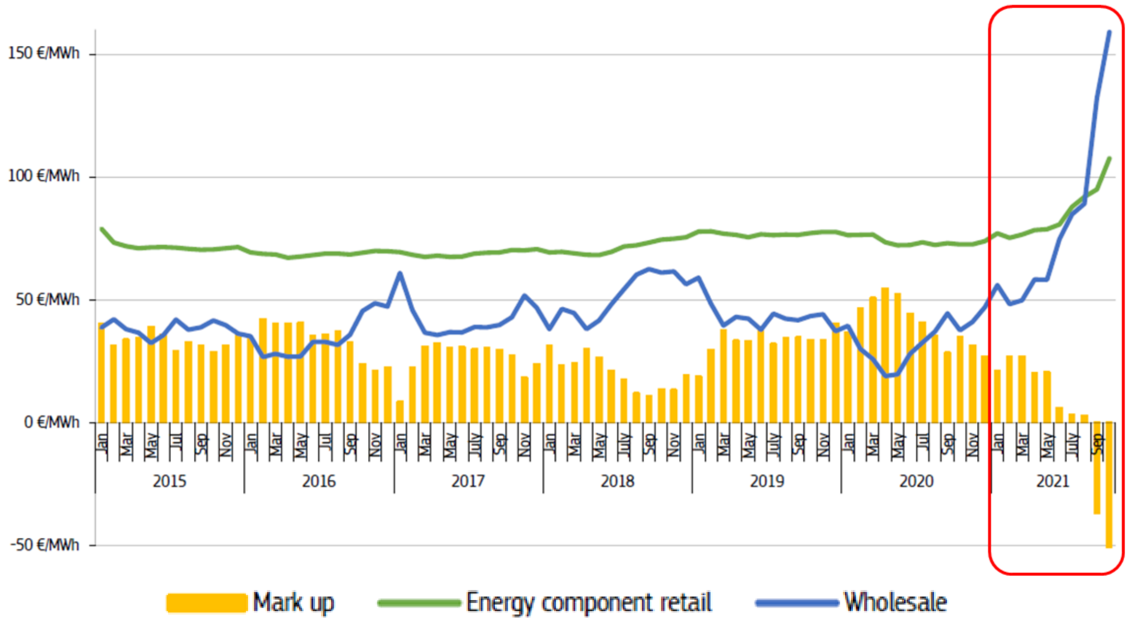
7. Retail energy markets and consumers

7.1. Record-high energy prices have negatively impacted consumers and retail suppliers

Following wholesale energy price increases of 200% (electricity) and 400% (gas), household energy prices in Europe increased sharply in 2021, reaching record levels (see Figure 33 below). Unfortunately, these price figures do not reveal the full story as it will continue to unfold.

As Figure 33 indicates, wholesale costs have been higher than the retail energy component. Ultimately, when wholesale costs are high over time, consumer prices must cover the costs of supply. Higher wholesale prices will ultimately be reflected in retail prices, although this may take time to pass through as retail suppliers may well have hedged or consumers may have signed fixed price contracts for a certain time period. Nonetheless, such differentials are unsustainable for suppliers in the longer term and it would thus seem likely that many energy consumers will see significant price increases in 2022.

Figure 33: European wholesale and retail electricity component prices (EUR/MWh) (2015 – 2021)

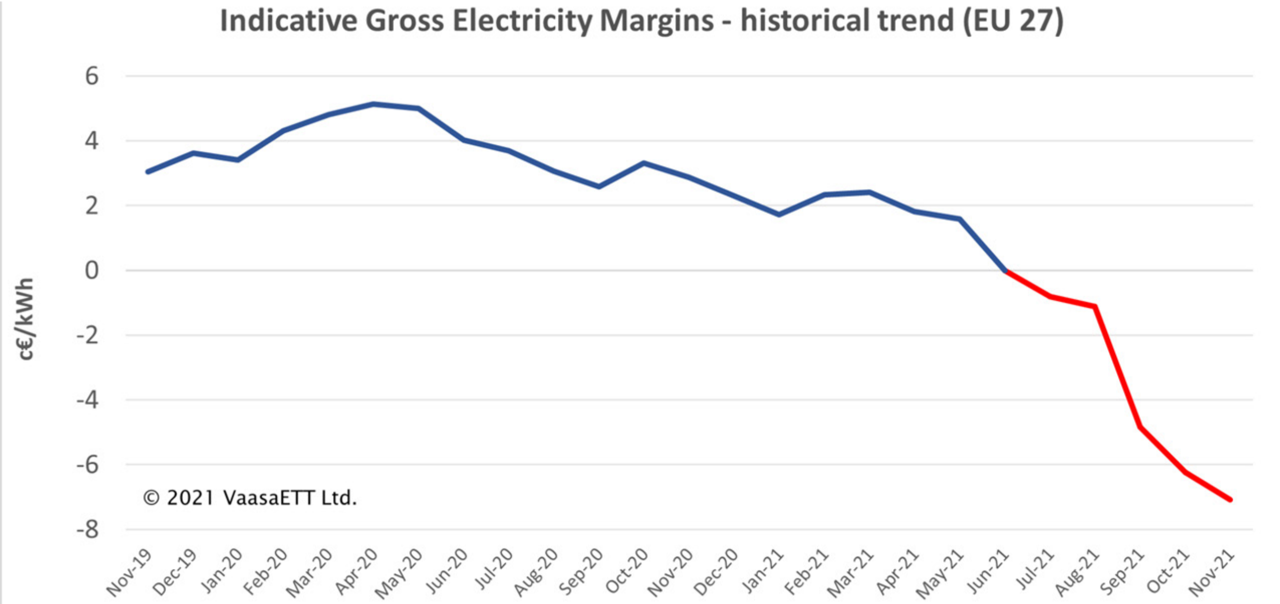


Source: European Commission: '[Quarterly Report on European Electricity markets Q3 2021](#)'.
Note: Mark-up refers to the difference between the wholesale energy component and the retail energy component.

Besides consumers, the increase in energy prices has significantly affected electricity and gas retail suppliers. With many retail suppliers exiting the market, and consumers concerned about their energy supply, the so-called Supplier of Last Resort mechanisms have been activated in many national markets. This mechanism is a reactive measure, which moves consumers to a fall-back supplier in the event of a supplier's exit. While the mechanism ensures continued supply to consumers, it does not protect them from facing higher costs associated with this transfer. The risk of a cost increase is particularly high in a period of high wholesale energy prices, as the new supplier has to buy the additional volumes of supply to secure demand for the transferred consumers; and this would be done (all things equal) at those higher prices. Some lessons from the workings of the Supplier of Last Resort mechanism in recent months are set out below.

In response to wholesale electricity price increases, retail profit margins have been negative since June 2021 on aggregate (see Figure 34 below). This shows the significant financial pressures placed on energy suppliers, leading to many retail supplier bankruptcies across Europe. While this pressure may have been mitigated by hedging efforts of certain suppliers, as with any business, consistently negative profit margins are unsustainable in the longer term.

Figure 34: Indicative supplier profit margin (Jan 2020 – Jan 2022)



Source: https://www.vaasaett.com/european-retail-energy-prices-reach-record-levels/.

Note: Indicative supplier gross-margins assess the difference between the energy price charged to household consumers and the actual power-procurement costs for retailers. Retailers' costs depend on procurement strategies. The financial losses are higher when solely considering short-term power purchasing.

Some EU consumers felt the impact of rising energy prices more rapidly depending on their retail tariff structure. In some cases, cost increases were immediately passed onto final consumers (via so-called dynamic-price contracts) whereas in other cases (fixed-price contracts), consumers were faced with price increases at a much slower rate. The opposite has also been true in the past: In some instances, those on dynamic price contracts immediately saw cost decreases when wholesale prices came down while those on fixed-price contracts were locked into a higher price for a period of time.

By way of example, in Spain during 2021, consumers on dynamic tariffs (PVPC tariff) were impacted immediately and significantly by increasing wholesale energy costs. On the other hand, prior to 2021, the PVPC tariff delivered an average of 12% savings to consumers when compared to the standard domestic rate[43].

[43] See table 16 of the '2019 Retail Electricity Market Monitoring Report' by CNMC.

7.2. Options to shield consumers from unwanted price volatility impacting affordability

With a few exceptions, retail energy consumers traditionally have little or no interaction with wholesale energy markets. Even if consumers today have more choice with regard to their energy supplier, many are unable to understand complex energy market risks. More self-consumption and aggregation may impact this dilemma as market interaction patterns may change, at least for some electricity consumers.

All in all, the past months of high energy prices provide a particular backdrop for considering the balance of risk between retail suppliers and retail consumers going forward. In particular, some measures could be considered that would reduce the likelihood of retail supplier failure and/or to mitigate the consequences of such failure.

Measures to reduce the likelihood of supplier bankruptcies could include introducing hedging requirements for retail suppliers. While the recent wholesale price increases are unprecedented, it is clear that some energy suppliers were quite unprepared for significant wholesale price volatility. This lack of financial resilience resulted in supplier bankruptcies in some Member States, transfer of consumers to a Supplier of Last Resort, and consumers seeing an increase in their energy price.

Hedging limits a supplier's exposure to price increases and thus lowers their risk of going bankrupt, which in turn can protect consumers from sudden price increases and contract terminations. Hedging also ensures some predictability regarding consumers' energy bills. Similarly, a minimum level of financial robustness (akin to MiFID-like requirements for financial markets) could be required for retail suppliers. Such considerations would benefit from further discussions between energy and financial regulators.

"... Some measures [...] would reduce the likelihood of retail supplier failure and/or ... mitigate the consequences of such failure."

As regards possible measures to mitigate the consequences of retail supplier failures, one could consider upfront financial guarantee requirements for suppliers. An alternative could be a broader consumer levy socialising the costs of certain suppliers exiting the market.

More specifically, requesting upfront financial guarantees or financial security from retail suppliers means that these guarantees could be used to mitigate negative consequences for energy consumers in the event of a sudden supplier exit from the market. Equally, in the event of a market exit without negative impacts on other suppliers or energy consumers, the guarantee would be returned to the exiting supplier.

A consumer levy mechanism could consist of common contributions to a fund to reduce the impact of cost increases borne by consumers impacted by a sudden supplier exit. In the event of a Supplier of Last Resort being appointed, such a fund would be drawn upon to limit the impact of cost increases on those consumers transferred to that new supplier. A consumer levy is not without significant costs and as such, may not be the most appropriate option for consideration.

Enhancing supplier responsibility: Financial Responsibility Principle - United Kingdom

The Financial Responsibility Principle (FRP) is an enforceable overarching rule requiring suppliers to minimise the costs to be borne by competitors in the event of failure. The FRP aims to ensure that suppliers act in a more financially responsible manner and take steps to bear an appropriate share of their risk.

The FRP expects that the supplier provides evidence that it has:

- plans in place to meet its financial obligations;
- effective processes, that are consistent with existing licence requirements, for example setting direct debit levels and for checking and returning customer credit balances;
- sustainable pricing approaches that allow it to cover its costs over time, or if it is pricing below cost that the risk sits with investors and not consumers;
- robust financial governance and decision-making frameworks; and
- the ability to meet its financial obligations while not being overly reliant on customer credit balances for its working capital.

Introducing this new principle allows Ofgem (the energy regulator) further regulatory powers, along with other tools such as milestone and dynamic assessments, to take enforcement action against irresponsible behaviours in the market. The FRP will help to ensure that suppliers adopt sensible practices in managing their costs.

Whatever the mechanism considered, it is important to recognise the trade-offs involved. Increased consumer protection comes at a cost, ultimately likely to be borne by consumers themselves.

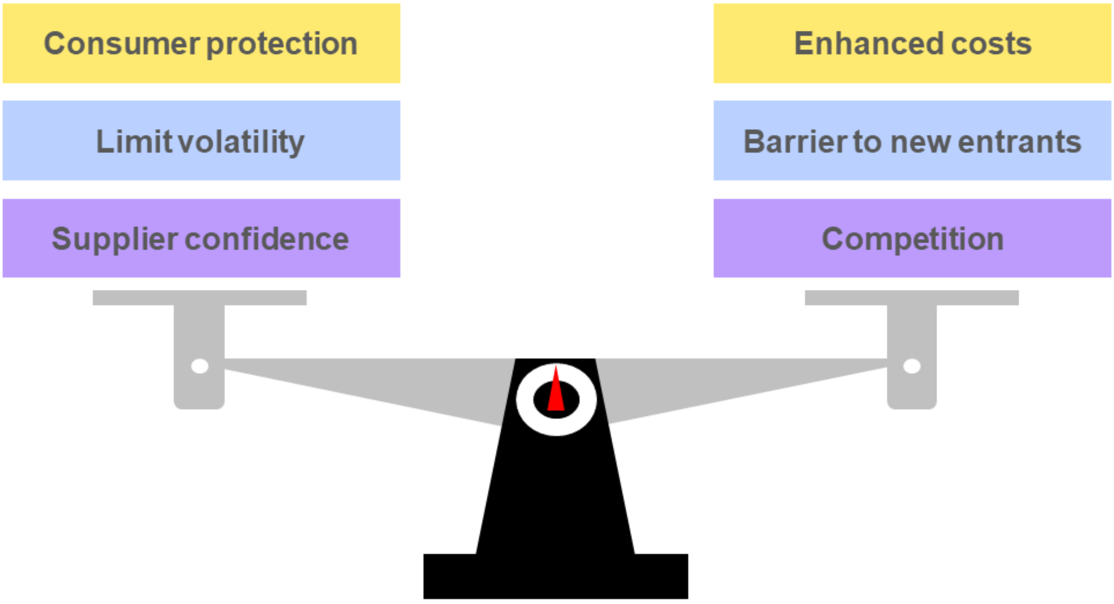
By way of example, expanding certain requirements for retail suppliers would likely limit entry of new market entrants and/or possibly hamper the introduction of innovative retail contracts. Under such approaches, vertically-integrated and more established suppliers will be in a stronger position to withstand additional financial requirements. Hence, a relatively closed supplier market of established (and likely big) incumbents would seem a probable development.

Similarly, broad-based consumer levies would socialise the cost of a poorly-managed supplier, perhaps giving undesirable (perverse) incentives towards unduly aggressive market behaviour, undertaken in the knowledge that a socialised fund would lower the risk of such behaviour. Hence, the drawbacks of such a measure likely outweigh the benefits.

"... It is important to recognise the trade-offs involved. Increased consumer protection comes at a cost, ultimately likely to be borne by consumers themselves."

There is thus a balance to be struck between on the one hand measures to enhance protection and confidence of consumers in case of high price volatility impacting affordability, and on the other hand to secure a competitive market for retail offerings, allowing new market players to enter without unnecessarily high barriers. This balance is more likely to be struck at national level rather than at EU level, given the different regulatory and market traditions prevalent across the EU. In any case, given the pressures energy suppliers currently face, it may be prudent to reflect on the appropriate timing to introduce additional measures, where deemed necessary.

Figure 35: Considering a balanced approach to protect consumers against price volatility impacting affordability



Source: ACER.

7.2.1. Consumer risks, consumer contracts and time-differentiated tariffs

In some ways, consumers are at the centre of the energy transition and are expected to take a more active role in their energy consumption. However, it is important that the consumer is both ready, capable, and willing to do so. Expecting that all domestic consumers will be active participants in their energy consumption may not be reasonable. While some consumers may be willing to become truly active, many consumers will likely manage their consumption (or generation) less actively.

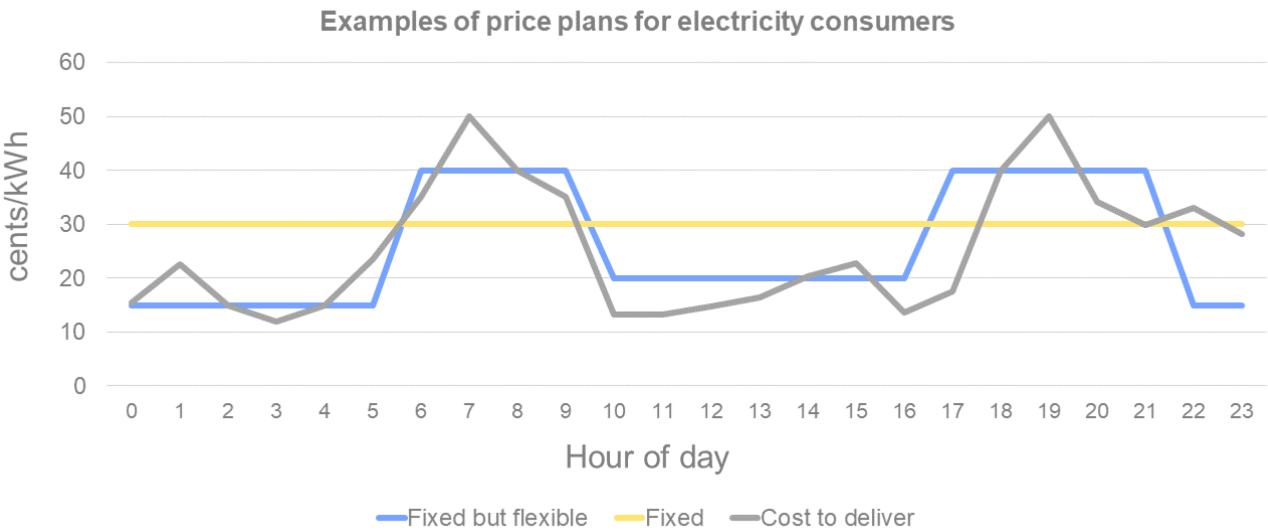
Similarly, consumers have access to a wide range of information. However, having access to such information does not necessarily mean that consumers are fully informed of the risks associated with each supply contract. While a consumer may decide upon the cheapest available contract, they may not be fully aware that they may be exposed to significantly higher bills in the event of an increase in wholesale energy costs. Even though information may in principle be fully available, it would seem appropriate not to operate with a 'default contract' containing significant risk. Rather, it may be seen as more acceptable to provide a level of predictability for certain categories of consumers and to approach 'default contract' options with this in mind.

Given the above, it may be appropriate to require, before a consumer subscribes to more flexible electricity supply contracts (e.g. contracts indexed to day-ahead market outcomes), that suppliers ensure that consumers are fully informed of the risks and benefits associated with such contracts. Where consumers are on dynamic-price contracts, it might also be appropriate for suppliers to provide regular updates regarding price variations. Such information could be provided via text messaging or similar, enhancing consumer awareness of both their consumption and current costs of energy.

Many consumers may wish to have a simple fixed price for the energy they consume, notwithstanding the cost of delivering energy varies over time. The costs to deliver energy to a home vary throughout the day based on the type of generation used to meet the consumer demand. As such, going forward, it is important to consider what retail pricing structures are most appropriate from a system point of view. Just operating with a default contract offering consumers a fixed price may not be the most appropriate in the future where the cost to deliver varies significantly. Such default pricing structures might of course differ for larger industrial energy users and smaller/domestic energy users.

Figure 36 below compares two potential price plans for electricity consumers[44]. Both provide consumers with a level of predictability regarding their energy consumption. Under the fixed price plan (yellow line), the consumer always pays the same price. The supplier also receives some certainty about future energy requirements. However, fixed prices do not 'nudge' the consumer towards adjusting their consumption patterns in line with the costs of delivering the energy at different times during a day (grey line). This can result in the system operators calling upon less efficient generation during periods of peak energy demand, increasing the cost of electricity. The fixed price contract should thus reflect this additional cost.

Figure 36: Fixed but flexible price example v fixed price example



Source: ACER.

On the other hand, a default fixed tariff that flexes (blue line) during the traditional peak hours of the day and for which the hourly price remains stable over a few months or years[45], could provide a balance between the flexibility needs of the system and the desire of the consumer for predictability. Consumers would be nudged towards consuming when it is more beneficial for the system as a whole, thus delivering significant savings.

[44] Default pricing structures may also differ between Member States. In some Member States the customer can chose the type of contract, including the supplier of last resort. Hence, where consumer choice exists, a fully fixed tariff contract should not be the default contract.
[45] The tariff may also consider predefined higher prices during a few days per year, in order to help manage system stress.

Overall, for less active customers who invest limited effort in adjusting consumption, a ‘system friendly’ default tariff could combine:

- Some predictability of the tariff into the future, providing certainty; and
- Some time-variation of the tariff, triggering demand-side response.

Finally, there is significant variation in the frequency of energy bills across the EU ranging from every two months to once a year. Suppliers and national regulatory authorities could encourage consumers to establish a monthly payment plan to manage their energy expenditure. This would reduce the impact of energy price volatility, e.g. in the winter heating period by spreading annual cost via a monthly payment. While such payment plans would not have prevented consumers being impacted following the wholesale price increases in 2021, they could cushion some of the price volatility for the consumer going forward.

7.2.2. Lessons learned from resorting to the Supplier of Last Resort

Numerous supplier exits over the past months have put the mechanism of Supplier of Last Resort to a considerable ‘stress test’. It is thus appropriate to draw some initial lessons.

With the rise in energy prices, some suppliers refused to become the Supplier of Last Resort, thereby also refusing additional customers, arguing that this would represent too big a challenge in current market circumstances. In other instances, the appointed Supplier of Last Resort in turn went bankrupt, meaning the consumers involved were transferred to yet another such last-resort supplier.

Timing issues are key with regard to the transfer of consumers under this mechanism. In particular, it would seem essential to ensure that the Supplier of Last Resort is responsible for supplying energy (and paying the related grid tariff) from the time the previous supplier exits the market to avoid costs incurred not being unaccounted for vis-à-vis the system operators.

While the Supplier of Last Resort mechanism overall seems to have worked, it did cause an economic burden on many designated last-resort suppliers due to the massive influx of new customers. Some national regulatory authorities report that consumers transferred to such a last-resort supplier faced higher prices than those paid by existing consumers of that supplier. While such increases were perhaps unavoidable in some instances given the wholesale cost increases which the last-resort supplier would need to cover, the strengthening of retail supplier resilience might limit the occurrence and impact of such developments.

Not surprisingly, given the different retail market approaches across the EU, experiences vary from one Member States to another. One particularly difficult phase of supplier exits occurred in the Czech Republic.

Case: Managing the transfer to a Supplier of Last Resort – ERU, the energy regulatory authority of the Czech Republic

In 2021, 16 energy suppliers failed in the Czech Republic resulting in 960,000 customers being transferred to a Supplier of Last Resort. This represented approximately 10% of the total energy consumers, an unprecedented amount for that mechanism. While the transfers overall were successful, some issues were observed during the process.

Customers faced extremely high prices as the supplier of last resort had to procure energy on a prompt basis; also, as the supply of last resort fell on the winter months, the bulk of heating customers' costs were spread across six months as opposed to the usual twelve months as amounts owed for consumption needed to be recouped within the time-limit for last resort supply. As a result, consumers saw an immediate and significant increase (4-5 fold) in their energy costs.

Furthermore, the extremely high and volatile wholesale prices limited the available offers for new customers and delayed the on-boarding of some consumer groups. This further prolonged the period for which consumers were faced with high energy costs.

In response to the sudden supplier market exit and subsequent transfer of consumers, ERU (the energy regulator) is reflecting on the balance between the risks shared by energy suppliers and consumers. For instance, the contract between the supplier and the consumer may give the supplier an undue advantage in changing supply conditions more easily. Another example is considerations as to who should bear the costs of supplier failings, including whether it is reasonable for those consumers losing their supplier to pick up all the costs.

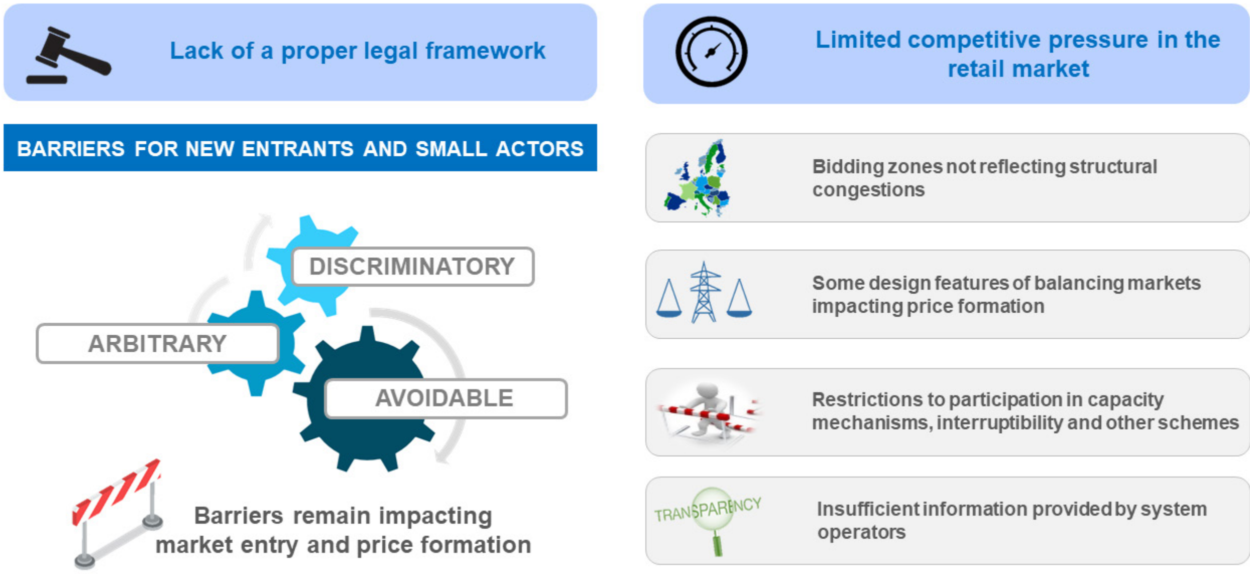
7.3. Pro-actively support demand-side response to help address volatility and solve system needs

The EU's electricity market will face new challenges as it seeks to deliver on Europe's ambitious decarbonisation trajectory. One objective of energy policy and supportive energy markets should be to allow consumers to avoid consuming during periods of higher prices, shifting demand instead to periods of lower prices. This allows consumers to lower their costs, and at the same time reduces overall system costs, facilitating the energy transition.

As further developed in Sections 3 and 4, with new intermittent generation capacity being added, the electricity system will be required to manage higher levels of volatility. Demand-side response should increase to assist energy systems in enabling enhanced renewable penetration. Demand-side response measures are currently in place in many Member States across the EU. However, most existing measures focus on the utilisation of demand-side response in specific circumstances, such as helping to tackle security of supply concerns.

To address this, Member States should consider focusing on the removal of barriers currently preventing the uptake of demand-side response. The most recent ACER-CEER Electricity Wholesale Market Monitoring Report provides an extensive overview of barriers to new market entry and small actor participation that are relevant for the further enhancement of demand-side response[46]. While barriers vary across Member States, barriers that limit retail competition, market entry and price formation are stifling the opportunities that demand-side response can provide to the power system and consumers. The removal of barriers is required to ensure the kick-starting of demand-side response products and services.

Figure 37: Overview of barriers possibly impeding demand-side response products and services



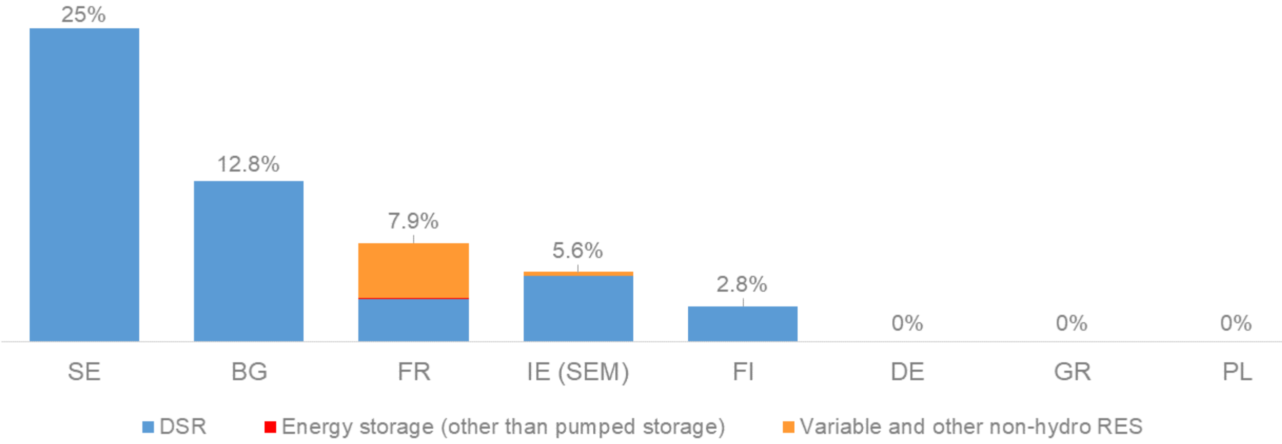
Source: ACER-CEER Electricity Wholesale Market Monitoring Report 2020.

By way of example, ACER identified that even though some national capacity mechanisms are theoretically open to demand-side response, certain requirements effectively hinder their entry and participation[47]. Figure 38 below shows the degree of demand-side response, energy storage and renewables remunerated through capacity mechanisms in 2020[48]. As can be seen, limited demand-side response is being awarded, showing scope for improvement in the coming years.

"The removal of barriers is required to ensure the kick-starting of demand-side response products and services."

[46] See Section 7 of the Electricity Wholesale Market Volume of the ACER-CEER Market Monitoring Report for the year 2020 (or '2020 MMR').
[47] See page 98 of the Electricity Wholesale Market Volume of the ACER-CEER Market Monitoring Report for the year 2020 (or '2020 MMR').
[48] See page 99 of the Electricity Wholesale Market Volume of the ACER-CEER Market Monitoring Report for the year 2020 (or '2020 MMR').

Figure 38: **Capacity of demand-side response, RES generation, and energy storage remunerated through capacity mechanisms in Member States**



Source: ACER-CEER Wholesale Electricity Market Monitoring Report 2020.

Lessons from certain jurisdictions outside Europe could prove instructive. As an example, the Australian demand-side response model provides an opportunity for large energy users to earn revenues while reducing their consumption during periods of peak demand, thus delivering a service to the electricity system.

Case: Demand-side response – Australia

Australia approved a wholesale demand-side response mechanism in June 2020, opening up the demand response market to consumers and aggregators as of October 2021. The focus is mainly on large customers (such as industry) capable of curtailing demand.

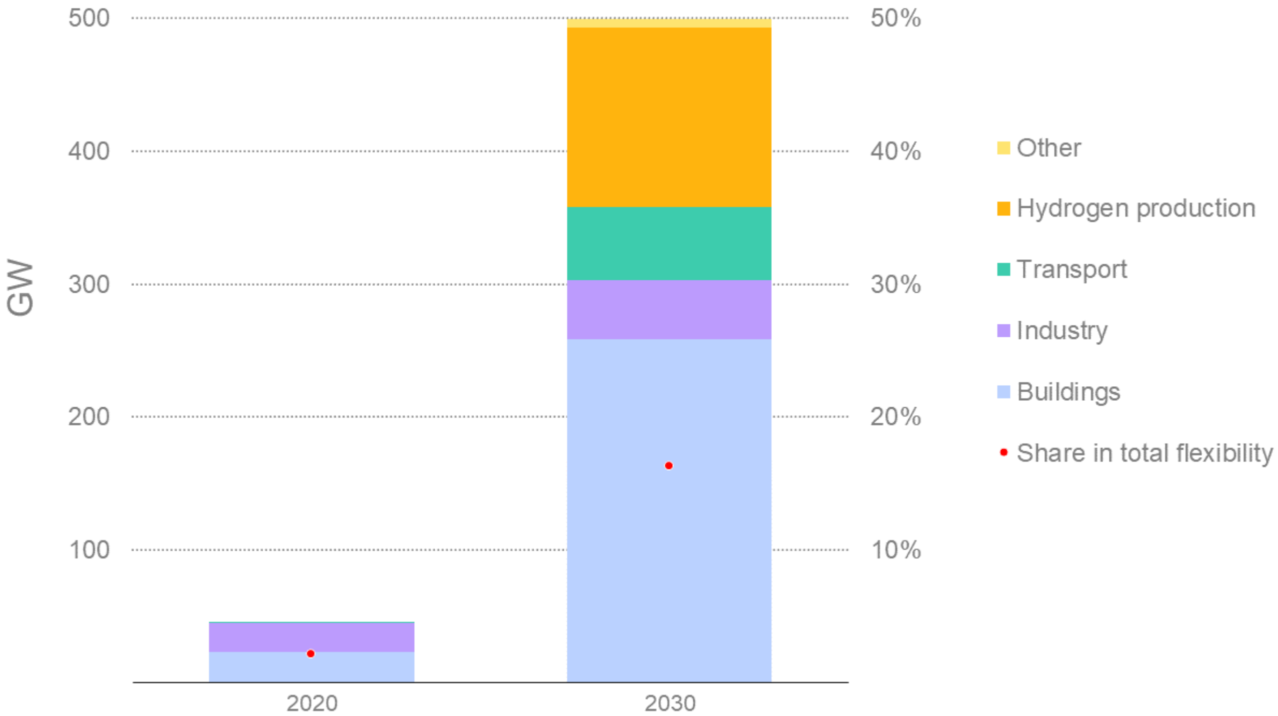
The wholesale demand-side response mechanism allows consumers to bid their willingness to consume electricity at different prices into the wholesale market, thus reducing dispatch costs. The mechanism requires consumer loads to be controllable for the purposes of scheduling and predictable for the purposes of baselines.

For small customers, a number of opportunities emerge under the current arrangements. However, it was decided that extending this mechanism to small customers would significantly increase complexity (and thus cost and implementation time) of the mechanism, while providing limited additional benefits at this stage.

It is no coincidence that the Australian model focuses on large consumers. As previously identified by the IEA, industrial and large commercial customers today represent the majority of demand-side response capacity available for use[49]. Figure 39 shows the potential opportunities for demand side response as identified by the IEA.

[49] See the IEA 'World Energy Outlook 2018'.

Figure 39: **Worldwide potential for demand-side response**



Source: IEA[50].

While smaller consumers should be permitted to participate in demand-side response, the larger potential in the near- to medium-term is likely to remain with the bigger energy usage segments (industry, buildings, and increasingly transportation, including aggregators of such segments). Given the limited roll-out of smart metering for smaller electricity consumers in some Member States, it may well be more appropriate for the purpose of facilitating demand-side response at scale to focus on larger energy consumers initially.

The increased electrification e.g. of transport and heating needs will further change the electricity demand curve in the future. The impacts of such changes are likely to be managed both by policies and by behavioural shifts. Businesses and households should be incentivised e.g. to avoid charging electric vehicles during peak demand periods to reduce peak loads, network congestion and the requirement for network reinforcement. The implementation of time-differentiated distribution network tariffs can be an important tool in this regard.

At present, average EU electricity consumption is 3,500KWh per household per year. In contrast, where electrification of heat and transport is more widespread (e.g. in some Nordic countries), average domestic consumption is close to 16,000KWh per annum. While at present, there may be limited opportunities for the household consumer to participate in demand response, in the future the potential benefits for consumers in reducing costs will likely be substantially higher. Tariffs can play a role in this as discussed above.

[50] A significant majority of the buildings-related potential comes from space heating, water heating or cooling (see 'IEA Demand Response Tracking Report' (November 2021).

8. Conclusions

This ACER assessment examines the benefits and drawbacks of the current EU electricity market design. It seeks to determine whether the current market design is fit-for-purpose in order to deliver on the EU's ambitious decarbonisation trajectory over the next 10-15 years.

Overall, ACER finds that whilst the current market design is worth keeping, some longer-term improvements are likely to prove key in order for the framework to deliver on this decarbonisation trajectory, and to do so at lower cost whilst ensuring security of supply.

As such, the assessment identifies several areas where policy makers could put further emphasis to ensure the EU wholesale electricity market design is fit for purpose. These areas fall under 6 broad headings, covering a combined total of 13 measures, each having various advantages and drawbacks. An overview of these measures is captured in the following table.

Table 1: ACER's assessment of the key challenges, measures for policy makers to consider and their respective advantages and drawbacks

Challenge	Measures to consider	Advantages and drawbacks
Making short-term electricity markets work better everywhere		
Currently, only a share of the potential benefits of EU electricity market integration are realised	 **1. Speed up electricity market integration, implementing what is already agreed:** National regulatory authorities and Member States should implement what is already agreed, focusing in particular on four areas: i) meet the 'minimum 70% target' (for enhancing electricity trade between Member States) by 2025; ii) roll out flow-based market coupling in the Core and Nordic regions as soon as possible; iii) finalise the integration of national balancing markets; iv) review the current EU bidding zones to improve locational market price signals, leading to a decision in 2023. See Section 3.3.	+ The listed measures contribute to mitigate price volatility, enable efficient cross-border trade and enhance security of supply. - Meeting the 70% target (action i) is a pre-condition to unlock most of the benefits underlying actions ii and iii. Currently, uncoordinated approaches and varying degrees of commitment to meet the 70% target exist.
Driving the energy transition through efficient long-term markets		
Trigger massive investments in low-carbon generation	 **2. Improve access to renewable Power Purchase Agreements (PPAs):** Member States should improve access to PPAs provided commercially in the market, e.g. through public guarantees or pooling smaller sellers and buyers. See Section 4.4.1.	+ Reduces costs for smaller renewable developers by making it easier to secure funding. Access to long-term contracts helps smaller developers manage their risks. + A public guarantee covers the counter-party risk, thereby reducing the risk premium covered by market participants. + Moves more renewables away from (costlier) support mechanism and towards commercially-driven PPAs. + The long-term contract hedges consumers against future price volatility. - Managing smaller actors with access to PPAs increases complexity and raises need for coordination. - Public guarantees do not solve the risk that some actors might default on the PPA requirements.

ACER

Challenge	Measures to consider	Advantages and drawbacks
How to get best value for money when driving investments	**3. Improve the efficiency of renewable investment support schemes:** Member States should decide whether and how to support particular technologies. Member States should review and, where relevant, update the support scheme(s) in place per their broader objectives. Prioritising build-out of new generation at scale and at speed, whilst prioritising a revenue ceiling for generators, may well point to 'Contracts for Difference'-type schemes. On the other hand, if most efficient integration of new low-carbon capacity is the priority, opting for capacity-oriented schemes may be more appropriate. See Section 4.4.2.	+ Centrally-steered support speeds up investment, whereas market-led investments drive efficiency and competition between technologies. + Hedges against some price volatility. - Risk that certain contracts, e.g. based on fixed remuneration for the energy produced, unduly limit exposure to market prices, negatively impacting short-term efficiency and demand-side response - Centralised procurement may transfer too much risk to the central entity
Limited liquidity in long-term markets, in particular beyond three years	**4. Stimulate 'market making' to increase liquidity in long-term markets:** Member States, power exchanges and brokers should consider stimulating liquidity through 'market-making' in an effort to help independent companies, traders etc. compete with large established firms e.g. via tenders, mandatory measures or (financial) incentives. See Section 4.4.3.	+ Market-making improves electricity market liquidity which in turn attracts more entrants, increases competition and ensures a level-playing field between vertically integrated companies and independent companies. - Market-making can be costly to incentivise.
	5. Better integrate forward markets: The European Commission should consider reviewing the Forward Capacity Allocation regulation with a view to further integrate forward markets, thereby enhancing liquidity in these markets. See Section 4.4.3.	+ More efficient, wider access to hedging. - Heavy implementation and operational efforts (similar to those undertaken for coupling short-term markets).
	6. Review (and potentially reduce, if warranted) collateral requirements: The European Commission should, together with the European Securities and Markets Authority (ESMA), financial regulators, etc. monitor needs for potentially reducing certain collateral requirements for trading in long-term wholesale electricity markets, particularly in times of rapidly increasing requirements. See Sections 4.3. and 4.4.3.	+ Frees up cash flow for the actual trading of electricity. - Increases the risk of being exposed to market participants failing on their obligations. - In extreme situations, possibly aggravates contagion risks.
Increasing the flexibility of the power system		
Need for increased flexibility in the system	**7. Preserve the wholesale price signal and remove barriers to demand resources providing flexibility:** Free, competitive price signals best denote true flexibility needs, and are thus efficient instruments for driving investments in flexibility resources, including those providing seasonal flexibility. Hence, national regulatory authorities and system operators should focus on the rapid removal of barriers to utilising such resources. See Sections 4.1. and 7.3.	+ Eases market integration of intermittent renewable generation and helps deliver on the EU's decarbonisation trajectory. - None.

Protecting consumers against excessive price volatility whilst addressing inevitable trade-offs		
Shield consumers from excessive price volatility	**8. Shield those consumers that need protection the most from price volatility:** Member States and national regulatory authorities should protect vulnerable consumers in times of high prices, where needed, whilst not limiting the ability of e.g. energy communities or aggregators to provide innovative energy services for the benefit of the system and consumers. Furthermore, Member States and national regulatory authorities should ensure that retail suppliers provide consumers with simple and clear information about their retail contract, in particular regarding the risks and benefits related to dynamic contracts. See Sections 7.2.1 and 7.3.1.	+ Protects the consumers most in need. + Enables consumers to take informed decisions. - Broader measures may prove inefficient and result in retail market concentration.
Mitigate the negative impact of retail energy supplier bankruptcies on end consumers	**9. Tackle avoidable supplier bankruptcies, getting the balance right:** Member States and national regulatory authorities should strike a balance between ensuring the financial responsibility of retail energy suppliers, and keeping the market open for new responsible suppliers. See Section 7.2.	+ Retains consumer confidence throughout the energy transition. + Supports responsible supplier behaviour. - Increasing retailers' collateral/hedging responsibilities increases costs, which ultimately are paid by consumers. - Difficult balance to strike, potentially jeopardising retail services innovation.
Tackling non-market barriers and political stumbling blocks		
Need for enhanced coordination and communication	**10. Tackle non-market barriers, ensuring generation and infrastructure is build at pace:** Member States should consider enhanced coordination and an increased focus on cross-border perspectives, as a prerequisite for efficient and accelerated roll-out of low-carbon generation and grid infrastructure, and for supporting security of supply. See Section 4.4.4.	+ Leads to more efficient decisions in the longer-term and faster deployment of projects. - Requires increased investment and greater attention to cross-border perspectives and needs, supplementing national perspectives
Preparing for future high energy prices in 'peace time'; being very prudent towards wholesale market intervention in 'war time'		
Keep bills relatively affordable during periods of sustained high energy prices	**11. Consider prudently the need for market interventions in situations of extreme duress; if pursued, consider tackling 'the root causes':** Member States should accelerate gas demand reduction (efficiency efforts, fuel switching) and deploy efforts that put downward pressure on gas prices (e.g. new supply or cheaper supply coming to Europe, considering the use of the new common Energy Purchase Platform), whilst retaining prices that secure LNG delivery. See Section 5.2.	+ Retains the benefits of current electricity market functioning. + Promotes savings of the fuel source aggravating the current situation. + Tackles the 'root cause' and mitigates potentially negative knock-on effects. - Can be difficult to deploy in a coordinated manner in a short period of time.

	 **12. Consider public intervention to establish hedging instruments against future price shocks:** Taking inspiration from financial options, Member States could consider an intervention whereby predefined consumer groups are hedged against sustained high wholesale prices (above a certain threshold, dubbed ‘affordability options’). See Section 4.5.	+ Hedges vulnerable consumers against sustained high prices arising in the future. + May create cascading needs to hedge (as generators providing the hedging tools would likely need to hedge their own positions), thereby increasing the liquidity of long-term markets. - Hedging comes with a cost for the ones who pay for the option. - It might be difficult to identify sufficient generators that would provide such hedging at moderate cost.
	 **13. Consider a 'temporary relief valve' for the future when wholesale prices rise unusually rapidly to high levels:** Member States could consider establishing ex-ante a temporary price limitation mechanism kicking in automatically under clearly specified conditions (e.g. unusually high electricity price rises in a short period of time), pausing the return to full price formation for a specified period of time (e.g. a few weeks or a month). The measure would need to ensure significant revenue is earned by generators and would retain compensation for generators who can prove sourcing costs above the limitation ceiling. See Section 4.5.	+ Predefined threshold and framework for normal and temporary relief conditions. + Limits the impact of sustained high prices, thus indirectly also setting boundaries for perceived excessive profits. - Risks market exit or requests for financial compensation. - Threshold-setting may prove difficult. - Risks endangering security of supply, if generators who prove sourcing costs above the limitation ceiling are not compensated adequately. - Risks dampening signals for demand-side response.

EU Agency for the Cooperation of Energy Regulators (ACER)

ACER, the EU Agency for the Cooperation of Energy Regulators, contributes to Europe's broader energy objectives, including the transitioning of the energy system at lower cost, by:

- Developing competitive, integrated energy markets across the EU via common rules and approaches, thereby enabling reliable and secure energy supply at lower cost;
- Contributing to efficient trans-European energy infrastructure and networks, enabling energy to move across borders, thus enabling energy choices at lower cost and furthering the integration e.g. of renewables;
- Monitoring the well-functioning and transparency of energy markets, deterring market manipulation and abusive behaviour.

ACER was established in March 2011 and is headquarted in Ljubljana, Slovenia, with a small liaison office in Brussels. Over time, the Agency has received additional tasks and responsibilities relevant for the further integration of the European internal energy market and for monitoring how energy markets are working.

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Department for
Energy Security
& Net Zero

GB Wholesale Electricity Market Arrangements

Government response to consultation on re-coupling GB auctions for cross-border trade with the EU at the day-ahead timeframe

August 2023

Any enquiries regarding this publication should be sent to us at: pxconsultation@energysecurity.gov.uk

Contents

Introduction

Executive summary

1. On 30 September 2021, the government published a consultation to seek views on the current arrangements for trading electricity on power exchanges in the Great Britain (GB) wholesale electricity market and to outline proposals to support efficient cross-border trading[1]. The consultation was originally open for four weeks until 28 October 2021. To facilitate as many responses as possible this was extended by an additional week with the consultation formally closing on 3 November 2021.

2. We are grateful to those who were able to respond to the consultation for their responses on how to improve current GB wholesale electricity market arrangements.

3. The responses have been analysed to identify the common themes and most frequently expressed views. Following this analysis, we have concluded that a single GB clearing price in the day-ahead timeframe would be highly beneficial in supporting the United Kingdom (UK) to discharge its obligations under the UK-EU Trade and Cooperation Agreement (TCA), as well as deliver broader benefits to the GB wholesale electricity market and its participants in trading electricity cross-border as efficiently as possible as part of and in any case in advance of multi-region loose volume coupling (MRLVC).

4. Given no substantive progress has been made towards a voluntary solution to date, and taking full account of the consultation responses and our conclusion on the benefits, we intend to legislate to achieve a single GB clearing price, subject to engagement with the Specialised Committee on Energy (SCE), industry and stakeholders.

5. Before progressing with legislation, we will engage with the SCE to discuss the benefits of a single clearing price in our respective day-ahead markets and to ensure both Parties have a shared understanding of how a single GB clearing price will support us in meeting our shared obligations under the TCA. The SCE is designed to ensure the proper functioning of the Energy Title (Title VIII) in the TCA and is the appropriate forum to discuss these matters. We will update stakeholders on the outcomes of these discussions through appropriate industry forums in due course.

6. In parallel we plan to engage with industry and stakeholders to explore and understand how the recoupling of the two hourly day-ahead GB auctions, offered by European Power Exchange EPEX Spot SE's (EPEX) and Nord Pool AS's (NP) at 09:20 and 09:50 respectively, can be successfully designed and implemented. We are disappointed that these arrangements have not progressed in a voluntary manner, particularly given the strong consensus of industry, and would strongly encourage the two power exchanges to work collaboratively to help ensure a solution resulting in a single GB clearing price is developed and implemented as soon as possible.

[1] https://www.gov.uk/government/consultations/re-coupling-great-britain-electricity-auctions-for-cross-border-trade

7. Our engagement with the SCE, industry and stakeholders will ensure we are well placed to make a final decision on progressing legislation to implement a single GB clearing price (subject to parliamentary scrutiny).

8. Given the potential benefits of including North Sea Link (NSL) within any future recoupling arrangements, namely in preventing fragmentation of liquidity in the GB wholesale market and helping maximise efficient cross-border electricity trade over interconnectors, we shall encourage stakeholders to consider how NSL could be involved in the recoupling of the two hourly day-ahead GB auctions.

Background information

9. Following the UK's exit from the European Union (EU), electricity is no longer traded through the EU market coupling regime established through the Capacity Allocation and Congestion Management (CACM) Regulation[2]. As a result, the EU market coupling process no longer determines prices for EPEX and NP's respective day-ahead GB markets that were previously coupled. Instead, interconnector capacity is sold to the market separately and independently of electrical energy through explicit auctions. EPEX and NP are now operating fully separated day-ahead markets, settling and clearing at different and independent prices.

10. The UK and the EU agreed the TCA on 24 December 2020, and it was applied provisionally from 1 January 2021 until formally entering into force on 1 May 2021. Implementation of the TCA will enable efficient electricity trade over electricity interconnectors and the relevant energy provisions[3] will specifically support and strengthen the UK and EU's respective energy and climate ambitions whilst ensuring our respective markets are sufficiently compatible to enable efficient electricity trading to take place in an open and fair manner.

11. The TCA commits the UK and EU to ensuring the efficient use of electricity interconnectors and to coordinate the development of arrangements for robust and efficient outcomes for all relevant timeframes[4]. The TCA sets out the basis for these new arrangements in the day-ahead timeframe as an implicit[5] MRLVC trading model, with the objective of maximising the benefits of trade.

12. Annex 29 of the TCA sets out the requirements for MRLVC. These include that interconnector flows should be calculated via an implicit allocation process by applying a specific algorithm. The inputs into the algorithm should include commercial bids and offers for the day-ahead market timeframe from 'relevant day-ahead markets'[6] in the UK, and network capacity data and system capabilities determined in accordance with the

[2] Electricity Network Codes and Guidelines (Markets and Trading) (Amendment) (EU Exit) Regulations 2019 revoked Commission Regulation (EU) 2015/1222 CACM to the extent it applied in GB as retained EU law.
[3] Part 2 – Title VIII – Energy - Trade and Cooperation Agreement
[4] For example, Article 311 of the Trade and Cooperation Agreement
[5] Implicit trading is where the capacity on the interconnector and the energy product are bought together in a single auction.
[6] The consultation proposed that for the purposes of Annex 29 of the TCA these should be the two hourly day-ahead GB auctions which currently take place at 09:20 and 09:50.

procedures agreed between Transmission System Operators (TSOs). If the inputs into the algorithm include network capacity or system capabilities that do not reflect the physical ability to trade power between the ‘relevant day-ahead markets’ in the UK and relevant connected EU bidding zones, MRLVC may not calculate the most efficient interconnector flows.

13. Efficient cross-border electricity trading arrangements are critical to realising the benefits of interconnection and multi-purpose interconnectors.

Consultation proposals

14. The consultation proposed the introduction of arrangements between the ‘relevant day-ahead markets’ to support the formation of a single GB clearing price, so that the commercial bids and offers input into MRLVC can be matched, cleared, and settled in line with the MRLVC process to determine interconnector flows, and in any case to support the GB market and GB market participants in trading cross-border electricity as efficiently as possible in advance of MRLVC.

15. The consultation proposed that the ‘relevant day-ahead markets’ for the purposes of Annex 29 of the TCA should be the two hourly day-ahead GB auctions which currently take place at 09:20 and 09:50. These two auctions were previously coupled by EPEX and NP for purposes of trade with the EU (when the UK was part of the Internal Energy Market). The use of the commercial bids and offers from these auctions would most likely maximise the benefits of cross-border trade by providing the most reliable market signals.

16. Although the consultation was primarily focused on identifying the ‘relevant day-ahead markets’ that would be used for the purposes of Annex 29 of the TCA and the proposal to re-establish a single GB clearing price by coupling those specific hourly day-ahead GB auctions, stakeholder views were sought on a number of further related issues regarding:

    - further governance arrangements and processes (once new trading arrangements with the EU are operational), and the role of Ofgem in those governance processes;
    - possible further policy proposals relating to the operation of power exchanges in the GB wholesale market across other timeframes; and
    - possible further policy proposals relating to the operation of power exchanges in the GB wholesale market across other borders.

Summary of responses to the consultation questions

17. The consultation received 25 individual written responses while the consultation was open. Two responses were received after the extended consultation period closed. These proposals have not been counted in this summary of responses. The evidence provided in these late submissions has been noted as part of the government's consideration of this issue.

18. Responses were received from a range of respondents including power exchanges, energy companies, trade associations, energy and commodity traders, energy solution providers, transmission system operators and energy system operators.

19. All responses have been recorded and the government has analysed the common themes that emerged to obtain an indication of the most frequently expressed points of view.

20. In reporting the overall response to each question, we have used a number of terms:

- 'Majority' and 'most' indicates the clear view of more than 50% of respondents to that question.
- 'Minority' and 'few' indicates the clear view of fewer than 50% of respondents to that question.

21. Not all responses answered every question. The number of responses each question received is noted in brackets. This number excludes those who stated they had no opinion or comment to give on the question. Any percentage cited in favour or opposition to a question excludes those who had no opinion or comment to give on the question or said 'don't know'.

22. Analysis has shown that the majority of respondents were supportive of the proposals set out in the consultation. This summary of stakeholder responses is organised with each question presented in the order they appeared in the original consultation.

Questions on approach to forming and implementing a single GB clearing price:

Question 1: (20 responses) What has been the impact (financial or otherwise) of power exchanges ceasing to couple their auctions in the day-ahead timeframe and not producing a single GB clearing price? Please provide details and estimates of the impact.

23. Respondents who commented on this question highlighted a variety of concerns and impacts as a consequence of the power exchanges ceasing to couple their hourly day-ahead auctions in GB. We have set out the key themes which were raised by respondents:

- Reduced liquidity in each power exchange's respective hourly day-ahead timeframe auctions.
- Higher costs for market participants as a consequence of:
    - managing the risks of price divergences between the two power exchanges;
    - trading on two different platforms; and
    - traders attempting to arbitrage between the two auctions.
- Increased operational complexity due to needing to manage additional auctions at different times.
- Increased number of instances of flows against price differential for imports and exports over electricity interconnectors.

24. Several respondents considered divergences in the clearing prices between the two power exchanges are greatest on 'tight days', this is typically defined as where the cushion of spare capacity on the electricity system is low, and not attributable to market fundamentals.

25. However, two respondents noted their view that the effect of the divergence in prices between the two exchanges was minimal.

Question 2: (24 responses) Do you agree with the proposal for the two day-ahead auctions noted in paragraph 22 to be used as the 'relevant day-ahead markets' for the purposes of Annex 29 of the TCA?

26. The majority of respondents (88%) agreed with the proposal. The reasons for this support varied, but several respondents expressed the view that the two hourly day-ahead auctions described in paragraph 22 of the consultation are the most liquid and see the largest traded volumes in the day-ahead timeframe.

27. However, a minority of respondents considered that although it would be possible to use these auctions as the 'relevant day-ahead markets', it wasn't strictly necessary for MRLVC.

Question 3: (24 responses) Do you agree that the coupling of the 'relevant day-ahead markets' is necessary to provide the appropriate market arrangements to support efficient trade of electricity over interconnectors, as part of and in any case in advance of MRLVC? Please provide supporting evidence for this necessity.

28. The majority of respondents (88%) agreed, acknowledging the inefficiencies highlighted in the consultation document and noting that the proposal should be implemented promptly, describing it as a 'no-regrets' solution.

29. Some respondents elaborated on this and raised concerns as to whether, in the absence of a single GB clearing price, there would be a fair or efficient basis to allocate interconnector flows determined under MRLVC.

30. However, a minority of respondents disagreed with the question. Several respondents expressed their view that recoupling of the two hourly day-ahead GB auctions is not necessary for trade to take place efficiently over the electricity interconnectors.

Question 4: (23 responses) Do you agree with the proposal that legislative intervention is necessary to enable the formation of a single GB clearing price in the 'relevant day-ahead markets' to ensure efficient electricity trading over interconnectors, now and as part of MRLVC? Do you have evidence to support this proposal? Do you have any alternative proposals with supporting evidence?

31. The majority of respondents (74%) agreed that legislative intervention is necessary to enable the formation of a single GB clearing price in the 'relevant day-ahead markets' to ensure efficient electricity trading over interconnectors, now and as part of MRLVC.

32. Within this group there were some further nuances as one respondent considered that it would be important to ensure any future legislation relating to a single GB clearing price would be applicable to any new market entrants. Some respondents gave their view that any intervention should set out a more detailed framework clearly setting out roles and responsibilities regarding the sharing of order books and market operator functions.

33. Those respondents that disagreed about the need for legislative intervention expressed views that:

- A single GB clearing price could be achieved voluntarily without legislative intervention or implemented through existing GB competition law frameworks.
- There should be simultaneous reciprocity in mandating market coupling of both timeframes.

Question 5: (24 responses) Do you agree with our outcomes in paragraph 27 against which the market operators should re-couple their 'relevant day-ahead markets'? Are there additional outcomes that should be required in the recoupling of the 'relevant day-ahead markets'?

34. The majority of respondents (83%) agreed with the outcomes noted in paragraph 27 of the consultation, against which market operators should recouple their 'relevant day-ahead markets'.

35. Within this group a minority of respondents highlighted additional outcomes which they considered should be required in the recoupling of the 'relevant day-ahead markets' including but not limited to:

- Clear requirements for any market coupling operator role.

- Other non-EU borders.
- Fallback procedures if coupling between the two power exchanges were to fail.
- Expansion of the third outcome so that it reads, "allows for future interaction with, and amendment as necessary to support efficient trade of electricity over interconnectors and in particular facilitate MRLVC".
- The efficient functioning and development of the GB clearing price methodology and cross-border clearing arrangements.

36. The minority of respondents who disagreed with the outcomes made the following points:

- One respondent noted that, in their view, the outcomes referred to in the fourth bullet point of paragraph 27 (fair and non-discriminatory in the treatment of the relevant electricity market operators, TSOs, and wider market participants) cannot be achieved by the proposals as laid out in the consultation and would end up being undermined by them.
- One respondent, although agreeing with the outcomes described in the first bullet point (results in a single GB clearing price across the two 'relevant day-ahead markets') and fourth bullet point (is fair and non-discriminatory in the treatment of the relevant market operators, TSOs, and wider market participants) of paragraph 27, felt the other outcomes need to be clarified further and made more specific.

Question 6: (20 responses) Taking account of the UK's obligations under the TCA, with particular reference to those provisions in Annex 29, do you agree with the proposed timeframe for making operational the new mechanisms for a single GB clearing price?

37. A majority of respondents (90%) agreed with the proposed timeline for making operational the new mechanisms for a single GB clearing price ahead of the MRLVC technical procedures entering into operation. However, there was some uncertainty with several respondents expressing their disagreement with the question.

Question 7: (20 responses) Do you agree with our proposal for the costs of re-coupling the 'relevant day-ahead markets' be borne by the operators?

38. Of those respondents who commented there was no clear consensus with views evenly distributed (50%) between those who agreed that the operators should bear the costs and those who disagreed with the proposal and put forward different approaches, or did not express a clear view in favour or opposition to the proposal.

39. A broad range of views were expressed by respondents with regards to the costs of recoupling and who should be responsible for those costs:

- The power exchanges should be able to recover the costs as they are being asked to fulfil a natural monopoly type role.

- The costs incurred by the power exchanges should instead be distributed through Transmission Network Use of System Charges (TNUoS).
- Costs should be recovered in the same way they previously were under the CACM regulation.
- Any cost recovery mechanism should be the same as proposed for MRLVC.

Question 8: (13 responses) What do you estimate to be the costs of implementing the proposal for either or both operators and the industry more widely? Please provide details and estimates of any relevant activities required to transition from the current arrangements to the new arrangements laid out in the proposal.

40. There were a notable number of submissions which did not provide an answer to this question. We would like to thank those respondents who were able to provide or offered to produce a cost estimate for implementing the proposal on a confidential basis.

41. A majority of respondents (83%) considered the implementation costs and personnel resource associated with the proposal would likely not be material, with responses commenting on both industry-wide costs and/or costs for their individual organisation.

42. A minority of respondents expressed the view that as the specific details of the proposal were not yet known it would be difficult to provide an accurate cost estimate.

Question 9: (19 responses) What do you estimate to be the impacts (financial or otherwise) to operators and market participants from adopting the new arrangements laid out in the proposal? What are the impacts of not implementing the proposal? Please provide details and estimates of the relevant costs and benefits.

43. Respondents who commented on this question highlighted a variety of concerns and impacts from adopting the new arrangements. We have set out some of the key themes which were raised by respondents:

    - Adopting the new arrangements could help resolve the issues raised in response to Question 1 of the consultation.
    - Adopting the new arrangements would outweigh any costs incurred by operators and market participants.
    - Failing to implement the proposed arrangements could hinder the implementation of MRLVC and lead to continued upward pressure on wholesale prices which would ultimately be passed on to consumers.

44. Several respondents noted they would not be able to recover the subscription fees already paid to access both power exchanges’ services if there was a recoupled auction but noted the benefits of a recoupled auction (e.g. access to pooled liquidity) would outweigh this loss.

45. However, several respondents highlighted in their view that:

- There could be a cost for those entities operating the 'relevant day-ahead markets' given customers would be able to procure services from one power exchange and benefit from the pooled liquidity of a recoupled auction.
- There could be significant impacts in terms of system designs and related changes to adopt these new arrangements.

Question on regulation of a single GB clearing price:

Question 10: (20 responses) To what extent do you agree with our proposals for regulating the new mechanism for a single GB clearing price? Should these obligations be capable of enforcement by Ofgem as if they were a relevant requirement on a 'regulated person' for the purpose of the Electricity Act 1989?

46. A majority of respondents (90%) agreed with the proposals, noting that Ofgem should have regulatory oversight and enforcement powers over any new mechanism for a single GB clearing price. One respondent went further and stated that Ofgem should have regulatory oversight over any arrangement which saw the introduction of a single GB clearing price even if it were implemented voluntarily.

47. A minority of respondents disagreed with the proposals and Ofgem's role in regulating a single GB clearing price, expressing the following views:

- Legislative intervention is not required to establish a single GB clearing price, as a result the establishment of the status of a regulated person also isn't necessary.
- A new regulatory framework should be established for power exchanges in GB to ensure their roles and responsibilities are placed on a proper legislative footing, rather than deeming power exchanges to be a 'regulated person' for the purpose of the Electricity Act 1989.

Questions on future governance arrangements:

Question 11: (20 responses) To what extent do you agree with the proposal for a designation process enabling eligible persons (including existing market operators) to apply to undertake MRLVC functions rather than establishing a new entity for this purpose?

48. Most respondents who commented on this question expressed agreement with the proposed designation process enabling eligible persons to undertake MRLVC functions rather than establishing a new bespoke entity.

49. Respondents who agreed with the proposals for a designation process expressed views that:

- The two power exchanges have experience of performing the market operator function and would be able to provide a high quality and reliable service.
- The designation process previously used for the purposes of CACM was successful.
- The proposal for a designation process will enable competition.

50. However, of those respondents that disagreed their views were that:

- Given the technical procedures for MRLVC are yet to be developed, it is too early to consider this issue in detail.
- The proposal would likely require additional resource and time with limited opportunities to encourage new entrants in a way that creates additional value.

Question 12: (18 responses) To what extent do you agree Ofgem should be responsible for assessing entities against any future designation criteria and approving the designation of entities who undertake coupling activities under MRLVC? What do you think any such designation criteria and process should look like?

51. A majority of respondents (89%) agreed with the proposal that Ofgem should be responsible for assessing entities against any future designation criteria and approving the designation of entities who undertake coupling activities under MRLVC.

52. Around 25% of respondents expressed the view that any designation process itself should closely mirror the CACM regulation, a process which is already well known by market participants. A respondent stressed the organisational capability and financial strength of any entities seeking to undertake coupling activities under MRLVC should be carefully considered as part of any assessment by Ofgem.

53. However, of those respondents that disagreed their views were:

- This question is premature, so cannot be answered in an informed way given that MRLVC technical procedures have not been developed yet.
- Legislative intervention and designation of a regulated person is not necessary to establish a single GB clearing price.

Question 13: (14 responses) An alternative legislative option would be to licence those entities who wish to undertake market coupling under MRLVC relating to 'relevant day-ahead markets' for the purposes of Annex 29 of the TCA. It would be beneficial to obtain stakeholders thoughts on this alternative approach.

54. We note that a number of respondents did not provide a response to this question. Of those which did, there was no clear consensus with views evenly distributed between those who

agreed licencing was a potential alternative approach and those who disagreed with the proposal. We have set out some of the key themes which were raised by respondents.

55. Several respondents who agreed with licensing as an approach expressed the view that licensing offers flexibility allowing requirements to be amended as necessary.

56. Those respondents who disagreed with licensing as an approach expressed the views that:

- They did not view this alternative approach as being better.
- A relatively light-touch designation process has been sufficient to date in the presence of two competing, technically capable market operators.
- They did not see the benefit of adding this additional requirement given this was not necessary when a single GB price was first established under CACM.

Questions on possible future interventions across other trading timeframes:

Question 14: (23 responses) Are there similar issues and concerns, as set out in this consultation for the 'relevant day-ahead markets', for the intraday trading timeframe?

Question 15: (15 responses) What are those issues and concerns, do they relate to domestic or cross-border trade between the UK and the EU, and do you have evidence of the associated impacts?

57. A majority of respondents (65%) expressed the view that there are similar issues and concerns, for the intraday trading timeframe, with several respondents highlighting the risks of inaccurate price signals and a reduction in market liquidity.

58. Respondents outlined what they considered to be the potential benefits of addressing the intraday timeframe:

- Ensuring the flows of renewable energy can be efficiently managed.
- Supporting the optimal allocation of capacity in the day-ahead timeframe.
- Increased efficiency and liquidity.

59. A minority of respondents did not consider there to be similar issues for the intraday timeframe expressing the views that:

- Coupling the intraday timeframe could be more complex to deliver compared to the day-ahead timeframe.
- Unlike the day-ahead timeframe where there was previously a single GB clearing price, the situation has not changed in the intraday timeframe.

Question 16: (21 responses) The proposed intervention spans the specific auctions noted in paragraph 22 which we propose should be used as the 'relevant day-ahead markets' for the purposes of Annex 29 of the TCA. However, we would welcome views as to what extent you agree that a similar mechanism is needed to produce a single GB clearing price across existing intraday trading mechanisms?

60. There was no clear consensus between respondents with views evenly distributed between those who agreed a similar mechanism is needed across existing intraday trading mechanisms and those who disagreed. We have set out some of the key themes which were raised by respondents.

61. Respondents who agreed that a similar mechanism is needed expressed views that:

- Such arrangements would help improve liquidity and market efficiency in the longer term.
- Any mechanism that reduces the costs for GB consumers would be welcomed.

62. Within this group respondents shared different views as to when such a mechanism should be introduced:

- The intraday timeframe should continue to be explored once the day-ahead timeframe has been resolved.
- The intraday timeframe should be developed in parallel with the day-ahead timeframe or as soon as possible.

63. Respondents that disagreed expressed views that:

- Implementing a similar mechanism across intraday and other timeframes would involve greater risks compared to the day-ahead timeframe, as day-ahead arrangements are already well understood and have been successfully implemented in the past.
- Coupled intraday auctions would interrupt and undermine intraday market liquidity.
- Without clarity on an intraday market arrangement (such as a target model) it is not possible to take any view as to the concerns or interventions required in this timescale.

Questions on possible future interventions across other trading borders:

Question 17: (20 responses) Do you agree that there are interactions between UK-EU trading and other UK trading borders, specifically with Norway? What are those interactions, and what are the associated impacts?

64. A majority of respondents (85%) expressed the view that there are interactions between UK-EU trading and other UK trading borders, specifically NSL, and similar issues exist.

- Respondents felt the most efficient way to avoid inefficiencies and market distortions would be for the proposed single GB clearing price arrangements to apply to NSL as well.
- Respondents raised concerns about the operation of a separate day-ahead auction in GB allocating capacity over NSL. It was noted this could result in a failure to optimise flows across the interconnector.
- Respondents stated that NSL would benefit from being part of the pooling of GB volumes in the day-ahead timeframe under the proposed GB coupling arrangements.

65. Not all respondents shared these views, with a minority noting existing agreements should be sufficient to mitigate the risks of having separate arrangements in operation over NSL. Other respondents noted the importance of having equivalent arrangements in place for the intraday timeframe, which should be implemented at the same time as any day-ahead arrangement to maximise efficient trade over NSL.

66. A respondent noted the current gate closure time allows market participants in Norway to first participate in the NSL auction and then in the Single Day-ahead Coupling (SDAC) process, thereby maximising liquidity. They expressed the view that, depending on the timing of any GB recoupled auction, this could change and could result in Norwegian market participants needing to choose whether to participate in the NSL auction or SDAC, which could reduce liquidity over NSL.

Question 18: (20 responses) Considering either day-ahead or intraday timeframes, to what extent do you consider that it would be beneficial for a new mechanism for a single GB clearing price to apply to all UK-EU and UK-Non-EU interconnection? What would be the impact (financial or otherwise) of having different arrangements in place on different borders?

67. Most respondents expressed the view that they support more efficient trading over electricity interconnectors but differ as to how/when those targets can/should be achieved.

68. The majority of respondents (90%) noted that in due course it would be beneficial to have a single GB price applicable to all UK-EU and UK-Non-EU interconnection across both day-ahead and intraday timeframes. Views expressed by respondents included that such an approach would simplify both domestic and cross-border trade, increase liquidity and promote less price volatility. Several respondents expressed the view that having different arrangements in place on different trading borders could lead to market distortions.

69. However, several respondents noted what they viewed as the importance of recognising that different jurisdictions have different regulatory arrangements which could impact the benefits of a single GB clearing price. In their view, careful co-ordination between jurisdictions would be necessary to support the introduction of a single GB clearing price.

Government response and forward proposal

Government proposals

70. We are grateful to those who were able to respond to the consultation for their responses on how to improve current GB wholesale electricity market arrangements.

71. Having carefully considered the consultation responses, we have decided to take forward the majority of the proposals outlined in the consultation to support the efficient trade of electricity over interconnectors, as part of and in any case in advance of MRLVC.

72. This section is broken down to reflect each of the questions raised in the consultation document.

Dealing with day-ahead markets: multi-region loose volume coupling

73. With the aim of ensuring the efficient use of electricity interconnectors and reducing barriers to trade between the EU and UK, the TCA requires the development of arrangements to deliver robust and efficient outcomes for all relevant timeframes (forward, day-ahead, intraday and balancing[7]). For the day-ahead timeframe specifically, the TCA goes further and specifies details[8] for developing new cross-border arrangements according to a new model of trade: MRLVC. The technical details of the trading model are to be jointly developed by the relevant UK and EU Electricity System Operators and Interconnector TSOs for submission to the SCE[9].

74. The TCA is clear that the SCE, as a matter of priority, should be progressing work on the new efficient electricity trading arrangements. At the SCE meeting on 30 March 2022, both the UK and EU affirmed that, while the timeline in Annex 29 to the TCA has not been met, they remain committed to discharging the SCE's obligations under TCA Articles 312 and 317 as a matter of priority. The UK set out its significant concern about the delays to date to the TCA's timetable and called for accelerated engagement on this issue. At the SCE meeting on 28th September 2022, both the UK and EU reiterated their commitment to discharging the SCE's obligations under TCA Articles 312 and 317(2), as well as Article 321 as a matter of priority. On 24 March 2023, the UK-EU Partnership Council confirmed both parties' commitment to progressing work on MRLVC.

75. As required by the TCA, the UK and EU TSOs undertook and published the Cost Benefit Analysis[10] (CBA) for MRLVC in April 2021. It identified that a single GB clearing price at the day-ahead timeframe is highly desirable for the effective implementation of MRLVC, which will underpin efficient trading arrangements between the UK and EU. The CBA further

[7] Article 311(1)(f) of the Trade and Cooperation Agreement
[8] Annex 29 – Part 1 of the Trade and Cooperation Agreement
[9] Article 311(1)(f), Article 312(1), Article 317 of the Trade and Cooperation Agreement
[10] Annex 29 – Part 1(1) & Part 2 of the Trade and Cooperation Agreement

noted that the lack of the single GB clearing price, with GB power exchanges independently calculating separate prices through separate auctions, may create issues in the effective implementation of MRLVC. These issues could include incomplete optimisation, a negative impact on price formation and increased complexity of fallback arrangements and coordination procedures. Therefore, the TSOs recommended a single GB clearing price as a common feature in all MRLVC design options.

76. In response to the CBA, market participants and trade associations highlighted the importance of the single GB clearing price in supporting the TCA's objectives and the effective functioning of the newly proposed implicit trading model. Similar views were raised in response to this consultation with agreement among the majority of respondents about the potential inefficiencies that could occur if cross-border trade under MRLVC were to take place with uncoupled hourly day-ahead GB auctions. For example, one submission noted that:

> *"there would appear to be no fair or efficient basis to allocate the interconnector flows determined under MRLVC to the respective exchanges subsequently in the presence of two separate exchanges. Any attempt to do so could lead to unnecessary and unpredictable price divergence between the two exchanges…[t]he result would fragment liquidity in the day-ahead markets and further undermine forward market liquidity."*

77. Submissions more broadly demonstrated the inefficiency and real-world impact on trading with two hourly day-ahead GB auction prices. One consultation response provided a useful example highlighting the problems price divergences between the exchanges can cause. The respondent explained the difficulty in determining efficient interconnector flows between GB and the EU. The submission noted that if:

> *"the N2EX GB auction clears at £40/MWh for one hour; and the EPEX SPOT GB auction clears at £50/MWh; while the power price in France in that same hour is €46/MWh; then it is not clear whether it is most efficient to schedule the 3GW of interconnection to France to flow from France to GB in that hour or to flow from GB to France. While it is possible to correct uneconomic flows in the intraday timeframe…it would likely be significantly more cost-effective if the day-ahead timeframe enabled the interconnectors to be scheduled in the correct direction in the first instance."*

78. The consultation proposals were not universally supported, with one submission stating the current trading arrangements have had a minimal impact on electricity prices overall, presenting a low risk for GB consumers. The respondent stated that:

> *"…since 1st January 2021 [to October 2021], the average price spread between the two GB day ahead auctions operated by EPEX Spot at 9:20am and N2EX at 9:50am has been less than £5/MWh across 71.6% of all hourly trading periods, and less than £10/MWh across 90.5% of all hourly trading periods."*

79. However, this illustrates that there can be divergences in price between the exchanges, which other respondents consider to be significant (£10/MWh or more). Several respondents cited multiple impacts this price divergence can have on electricity trading, including challenges in establishing the most efficient way to schedule interconnector flows and avoid uneconomic flows. Further to this, we understand that on 'tight days'[11], where there are periods of low domestic generation when GB would benefit from efficient interconnector imports, market participants have experienced significant price divergences between the two exchanges which has also made it difficult for market participants to manage risk.

80. The existence of a price differential between the two hourly day-ahead GB auctions contributes to unclear price signals making it difficult for market participants to make most efficient use of cross-border trade of electricity. The introduction of a single GB clearing price would therefore support more efficient trade of electricity over interconnectors, as well as deliver broader benefits to the GB wholesale electricity market in trading electricity cross-border as efficiently as possible as part of and in any case in advance of MRLVC.

81. Submissions noted a number of domestic impacts from the decoupling of EPEX and NP's day-ahead GB auctions. While domestic impacts are an ongoing cause for concern and we will continue to engage with industry, the primary focus of the consultation is the implementation of efficient cross-border trade with the EU.

Definition of 'relevant day ahead markets'

82. The majority of submissions agreed that the 'relevant day-ahead markets' for the purposes of Annex 29 of the TCA should be the two hourly day-ahead GB auctions which currently take place at 09:20 and 09:50. This is primarily because each auction sees the largest traded volumes out of the available day-ahead GB auctions, and therefore would support the efficient trade of electricity over interconnectors, as part of and in any case in advance of MRLVC. Submissions also noted that these auctions were previously coupled for the purposes of participating in SDAC.

It is the government's view that it would be highly beneficial for the UK to introduce a single GB clearing price by recoupling the two hourly day-ahead GB auctions, supporting the UK to discharge its obligations under the TCA. A single GB clearing price would support the efficient trade of electricity over interconnectors, as well as deliver broader benefits to the GB wholesale electricity market in trading electricity cross-border as efficiently as possible as part of and in any case in advance of MRLVC.

Given no substantive progress has been made towards a voluntary solution to date, and taking full account of the consultation responses and our conclusion on the benefits, we intend to legislate to achieve a single GB clearing price, subject to engagement with the SCE, industry and stakeholders.

[11] See footnote 7.

Before progressing with legislation, we will engage with the SCE to discuss the benefits of a single clearing price in our respective day-ahead markets and to ensure both Parties have a shared understanding of how a single GB clearing price will support us in meeting our shared obligations under the TCA. The SCE is responsible for ensuring the proper functioning of the Energy Title in the TCA and is the appropriate forum to discuss these matters. We will update stakeholders on the outcomes of these discussions through appropriate industry forums in due course.

In parallel we plan to engage with industry and stakeholders to understand how the recoupling of the two hourly day-ahead GB auctions can be successfully designed and implemented.

Our engagement with the SCE, industry and stakeholders will ensure we are well placed to make a final decision on progressing legislation to implement a single GB clearing price (subject to parliamentary scrutiny).

Treatment of costs

83. The consultation proposed the associated costs of recoupling the two hourly day-ahead GB auctions offered by EPEX and NP at 09:20 and 09:50 respectively be borne by the relevant electricity market operators.

84. We note there was an almost even split between those respondents who agreed and disagreed with the consultation proposal. Respondents noted it would be reasonable for the relevant electricity market operators to bear the costs. However, concerns were raised by some respondents who highlighted there should be appropriate regulatory oversight over the costs incurred and the recovery mechanism.

85. Having carefully considered the responses to this consultation we propose to move away from the assumption that costs shall be distributed through arrangements such as TNUoS or similar mechanisms. We believe the associated costs of any future recoupling of the two hourly day-ahead GB auctions offered by EPEX and NP at 09:20 and 09:50 should be borne by the relevant electricity market operators.

86. We believe the two power exchanges are uniquely positioned to drive this process. They have the relevant industry knowledge and expertise to not only ensure costs are minimised but also to recover those costs as efficiently as possible on a commercial basis through their fees charged to their users (i.e. market participants) should they wish.

We believe the relevant electricity market operators should bear the associated development, implementation and operational costs of any future recoupling of the two hourly day-ahead GB auctions offered by EPEX and NP at 09:20 and 09:50 respectively, with any costs incurred efficiently and recovered on a commercial basis should they wish.

Legislation – Arrangements for a Single Clearing Price[12]

87. Secretary of State Guidance published in January 2021[13] on the application of the TCA noted it would be appropriate for the previous arrangements that resulted in a single GB clearing price be replicated at the earliest opportunity. In response to the CBA carried out by UK and EU TSOs, industry noted the importance of the single GB clearing price in supporting the TCA's objectives and the effective functioning of MRLVC, describing the implementation of such arrangements as 'no-regret' work that will also improve the efficiency of the explicit trading arrangements currently in place. Despite these recommendations, no substantive progress has been made towards a voluntary solution to support the formation of a single GB clearing price at the day-ahead timeframe.

88. The consultation sought views on whether legislative intervention is necessary to enable the formation of a single GB clearing price in the 'relevant day-ahead markets' for the purpose of electricity trading over interconnectors and whether such arrangements should be regulated by Ofgem.

89. There was significant support for legislative intervention to secure a single GB clearing price and to ensure Ofgem has appropriate powers to regulate the new mechanism for a single GB clearing price.

We note there was significant support for legislative intervention to secure a single GB clearing price and for Ofgem to have appropriate powers to regulate any new arrangements for a single GB clearing price.

Given no substantive progress has been made towards a voluntary solution to date, and taking full account of the consultation responses and our conclusion on the benefits, we intend to legislate to achieve a single GB clearing price, subject to engagement with the SCE, industry and stakeholders.

Before progressing with legislation, we will engage with the SCE to discuss the benefits of a single clearing price in our respective day-ahead markets and to ensure both Parties have a shared understanding of how a single GB clearing price will support us in meeting our shared obligations under the TCA. The SCE is responsible for ensuring the proper functioning of the Energy Title in the TCA and is the appropriate forum to discuss these matters. We will update stakeholders on the outcomes of these discussions through appropriate industry forums in due course.

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[12] Please note there are no plans to regulate the cross-border market coupling function at this stage. The submission responses will be taken into account when considering further legislation to support the implementation of MRLVC in the future.

[13] Electricity trading arrangements - published in January 2021 and available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/958195/secretary-of-state-electricity-trading-arrangements-guidance.pdf

In parallel we plan to engage with industry and stakeholders to explore and understand how the recoupling of the two hourly day-ahead GB auctions, can be successfully designed and implemented.

Our engagement with the SCE, industry and stakeholders will ensure we are well placed to make a final decision on progressing legislation to implement a single GB clearing price (subject to parliamentary scrutiny).

Possible future interventions across other timeframes

90. The efficient use of electricity interconnectors is a key focus of the energy title in the TCA which extends beyond the day-ahead timeframe. It requires the development of arrangements to deliver robust and efficient outcomes for all relevant timeframes being forward, day-ahead, intraday and balancing[14]. However, the immediate focus is on the day-ahead timeframe given the priority placed on it by the TCA.

91. A number of submissions acknowledge the priority must be the recoupling of the day-ahead GB markets and reaching an agreement with the EU on the implementation of MRLVC, while noting the possible future benefits of taking action in the intraday timeframe, particularly the continuous intraday market.

92. Submissions stated that the intraday timeframe experiences many of the same issues as the day-ahead timeframe, such as inaccurate price signals and a reduction in market liquidity. These respondents were of the view that action in the intraday timeframe, such as the sharing of order books in the continuous intraday market, could be beneficial in terms of improving liquidity, market efficiency and in the longer-term help ensure efficient cross-border electricity trade over interconnectors is maximised particularly as we transition our energy system towards more intermittent renewables. Not all submissions agreed with this, stating that in their view, action in the intraday timeframe represents a greater unknown compared to the day-ahead timeframe and may be more complex to implement.

In accordance with the terms of the TCA the day-ahead timeframe should remain the priority. However, development of efficient arrangements in other timeframes should continue to be kept under review to ensure efficient cross-border electricity trade over interconnectors is maximised.

Possible future interventions across other borders (NSL Specifically)

93. The arrangements and proposed interventions set out in the consultation were primarily concerned with the trading of electricity between the UK and EU. However, concerns have been raised regarding the interactions and implications of UK-EU electricity trading on other borders, specifically between GB and Norway and the allocation of capacity on the NSL interconnector. The consultation sought views about the interactions between UK-EU and

[14] Article 311(1)(f) of the Trade and Cooperation Agreement

UK-Norway trading, and whether any future interventions are necessary to support those trading arrangements.

94. Overall, the majority of respondents raised concerns about the operation of a separate day-ahead auction in GB allocating capacity over NSL. It was stated that this could result in a failure to optimise flows across the interconnector with respondents being of the view that NSL would benefit from being part of the pooling of GB volumes in the day-ahead timeframe under the proposed GB coupling arrangements.

95. NSL's capacity is currently allocated by NP, as the presently appointed power exchange, at the 9:50 day-ahead auction (one of the 'relevant day-ahead markets' for the purpose of the consultation). Respondents noted the current gate closure time allows market participants in Norway to first participate in the NSL auction and if not successful participate in the SDAC process, maximising liquidity. We understand that depending on the timing of any recoupled auction, liquidity over NSL could be adversely affected as Norwegian market participants may need to choose between participating in the NSL auction or SDAC process. Respondents noted that any changes to the auction timing would need to be carefully considered before implementation.

96. Some respondents noted that current agreements should be sufficient to mitigate the risks of having separate arrangements in operation over NSL. Others noted the importance of having equivalent arrangements in place for the continuous intraday market which should be implemented at the same time as any day-ahead arrangement to maximise efficient trade over NSL.

We want to see a recoupling solution that helps maximise cross-border trade between the UK-EU, supports our treaty obligations and prevents fragmentation of liquidity in the GB wholesale market.

Taking full account of the responses to this consultation and the agreement reached between Norway and the UK in September 2021[15], we recognise the benefits of including NSL's capacity in any day-ahead GB recoupling arrangements.

It is the government's view that any day-ahead GB recoupling arrangements should be capable of supporting the inclusion of NSL's capacity to help maximise efficient cross-border electricity trade over interconnectors and to help prevent the fragmentation of liquidity in the GB wholesale electricity market.

[15] Article 5(a) of the Agreement between the Kingdom of Norway and the United Kingdom of Great Britain and Northern Ireland on cross-border trade in electricity and cooperation on electricity interconnection aiming to promote efficient electricity trade and minimise barriers to electricity trade.

Possible future interventions across other borders (Single Price All Borders)

97. Views were sought on the extent to which it would be beneficial to provide a mechanism for a single GB clearing price in either the day-ahead or intraday timeframe, which would be applicable to all UK-EU and UK-Non-EU interconnection.

98. Most respondents are aligned in terms of wanting ever more efficient trading over electricity interconnectors but differ as to how/when those targets can/should be achieved. Almost all submissions acknowledged there would likely be a benefit in having a single GB clearing price across both day-ahead and intraday timeframes, applicable to all UK-EU and UK-Non-EU interconnection. Such an approach would simplify both domestic and cross-border electricity trade, increasing liquidity and promoting less price volatility.

99. As set out above, the day-ahead timeframe should remain the priority in accordance with the TCA. However, we hope to see continued cooperation between parties across all timeframes to ensure the development of a system which supports our future electricity needs.

In accordance with the terms of the TCA the day-ahead timeframe should remain the priority. However, development of efficient arrangements in other timeframes should continue to be explored to ensure efficient cross-border electricity trade over interconnectors is maximised.

Future Governance Arrangements

100. The consultation was primarily focused on identifying the 'relevant day-ahead markets' that would be used for purposes of Annex 29 of the TCA and the proposal to re-establish a single GB clearing price. However, views were also sought on a number of other issues set out below.

Designation process for market operators of MRLVC

101. Most submissions agreed that any future designation process should allow eligible persons, including existing market operators, to apply to undertake MRLVC functions rather than establishing a new entity for this purpose.

Future assessment of market operators of MRLVC

102. Submissions broadly agreed that Ofgem should be responsible for assessing eligible persons against any future designation criteria, as well as approving the designation of eligible persons to undertake coupling activities under MRLVC. One respondent expressed the view that Ofgem should assess the organisational and financial capability of entities undertaking coupling operations.

103. A majority of submissions were of the view that the designation process should be as similar as possible to the previous processes which operated in GB under CACM to ensure efficient operability of arrangements. There was a general consensus that establishing a new entity to perform MRLVC functions would likely impact the implementation timescales,

and that the existing market operators (e.g. the two GB power exchanges) had the experience to successfully deliver these functions.

Licensing of market operators of MRLVC

104. There was not a clear majority in favour of supporting licensing entities who wish to undertake market coupling under MRLVC. The most common argument made against licensing was that the entities undertaking market coupling functions under CACM were not licenced, and that relatively light-touch designation was sufficient to regulate the two commercially competitive power exchanges operating in GB.

105. The most common argument in favour of licencing was that licence conditions could be amended relatively flexibly in the future (e.g. to facilitate MRLVC). Certain submissions were in favour of licencing power exchange activities in GB (including coupling activities and MRLVC operation).

These views have been noted and will be taken fully into account during the development of MRLVC.

Next Steps

- We have made clear that we consider a single GB clearing price in the day-ahead timeframe to be highly beneficial in supporting the UK discharge its obligations under the TCA. A single GB clearing price would support the efficient trade of electricity over interconnectors, as well as deliver broader benefits to the GB wholesale electricity market and its participants in trading electricity cross-border as efficiently as possible, as part of and in any case in advance of MRLVC.
- Given no substantive progress has been made towards a voluntary solution to date, and taking full account of the consultation responses and our conclusion on the benefits, we intend to legislate to achieve a single GB clearing price, subject to engagement with the SCE, industry and stakeholders.
- Before progressing with legislation, we will engage with the SCE to discuss the benefits of a single clearing price in our respective day-ahead markets and to ensure both Parties have a shared understanding of how a single GB clearing price will support us in meeting our shared obligations under the TCA. The SCE is designed to ensure the proper functioning of the Energy Title in the TCA and is the appropriate forum to discuss these matters. We will update stakeholders on the outcomes of these discussions through appropriate industry forums in due course.
- In parallel, we plan to engage with industry and stakeholders to understand how the recoupling of the two hourly day-ahead GB auctions, can be successfully designed and implemented. We are disappointed that these arrangements have not progressed voluntarily, particularly given the strong consensus of industry, and would strongly encourage the two power exchanges to work collaboratively to help ensure a solution

resulting in a single GB clearing price is developed and implemented as soon as possible.

- Our engagement with the SCE, industry and stakeholders will ensure we are well placed to make a final decision on progressing legislation to implement a single GB clearing price (subject to parliamentary scrutiny).
- Given the potential benefits of including NSL within any future recoupling arrangements, namely in preventing fragmentation of liquidity in the GB wholesale market and helping maximise efficient cross-border electricity trade over interconnectors, we shall encourage stakeholders to consider how NSL could be involved in the recoupling of the two hourly day-ahead GB auctions.
- The Review of Electricity Market Arrangements (REMA) is currently underway and we shall continue to monitor and consider possible interactions with our recoupling proposals and the TCA.

This consultation is available from: www.gov.uk/government/consultations/re-coupling-great-britain-electricity-auctions-for-cross-border-trade

If you need a version of this document in a more accessible format, please email alts.formats@energysecurity.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.