D7.4 – Pan-EU Clearing market demonstration: final evaluation report, recommendations for European market upgrade

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Abstract
This Deliverable (D7.4) summarizes the progress of demo area 3 related to WP7 "Pan-EU Clearing Market demonstration". The report outlines an evaluation of the results obtained during the piloting and a presentation of key achievements, lessons learned, and connections to other deliverables.

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ACRONYMS AND ABBREVIATIONS

aFRR	Automatic Frequency Restoration Reserve
ANRE	Romanian Energy Regulatory Authority
ATC	Available Transfer Capacity
BEM	Balancing Energy Market
CCP	Consumer Clearing Price
CET:	Central European Time
DAM(PZU)	Day-ahead market
DEO	Distributie Energie Oltenia
DERs	Distributed Energy Resources
DRPs	Demand Response Programs
DSO	Distribution System Operator
ESSs	Energy Storage Systems
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EVs	Electric Vehicle
FCR	Frequency Containment Reserve
GAMS	General Algebraic Modeling System
IDM	Intra-day market
IEGSA	Integrated pan-European Grid Services Architecture
ITM	In-the-money
MCP	Market Clearing Price
mFRR	Manual Frequency Restoration Reserve
MIC	Minimum Income Condition
MILP	Mixed Integer Linear Program
OTM	out-of-the-money
PCR	Price Coupling markets of regions
PUN	Prezzo Unico Nazionale (National Uniform Pricing)
RES	Renewable Energy Sources
RNB	Romanian National Bank
SEE	Southeastern Europe
SSC	Scheduled Stop Condition
TSO	Transmission and System Operator
TYNDP	Ten-Year Network Development Plan

Executive summary

This deliverable D7.4 from Work Package 7 of the INTERRFACE project summarizes the progress and results of Demo Area 3 "Pan-EU Clearing Market demonstration" Demo. It is divided into two parts and includes Task 7.1 "DERs into Wholesale" Demo and Task 7.2 "Spatial aggregation of Local Flexibility" Demo. Within the context of Task 7.1, the methodological framework, the key assumptions, and the representative model outputs are summarized. Regarding Task 7.2, the deployment, the use cases, and the results evaluation of the demonstration, monitoring of key performance indicators are presented, along with conclusions and recommendations derived from both demonstrators .

From the perspective of Task 7.1, an applicable market platform, forming a specific feature in the IEGSA PLATFORM, has been developed for promoting DER participation in the wholesale market. The developed prototype reflects the modeling frameworks and technologies developed in WP3 and WP4 and makes use of numerous data from the TSOs, DSOs, market operators, and energy suppliers for its simulations. It provides an implementation of actual and realistic representation of the wholesale and retail markets in the examined South-East Europe (SEE) region, namely Romania, Bulgaria, and Greece. The real-world market operation scenarios take place in the future 2030 SEE power system, and its objective is to (i) produce clear price signals in the market coupling, (ii) incorporate DERs flexibility potential, and engage consumers/prosumers into electricity markets. Numerous combinations of scenarios and results enable the provision of robust conclusions and recommendations for marker development in the region.

From the viewpoint of Task 7.2, the spatial aggregation of local flexibility aimed at market setting delivers new market features. Refined spatial dimensions are introduced into the existing wholesale market design. The holistic mathematical optimization for market of local flexibilities –based on the pan-European day-ahead energy market coupling’s EUPHEMIA model – has been developed and configured to suit the demonstration’s requirements. The market design and functionality has been demonstrated in collaboration with local partners TRANS and DEO (Romanian TSO and DSO respectively) with demonstration partners. Out of this pilot, to include spatial dimension, it is considered that the zonal approach is the preferred way in the European markets, even in the case of DSO constraints, as a possible, manageable, gradual development of the EUPHEMIA-based wholesale market. In alignment with WP3 results, flexibility is defined partly as local flexibility capacity product for short-term congestion management services as its primary grid service. Also, the same auction-based platform within the intraday timeframe provides opportunity to trade energy in a finer, 15-min. time granularity while allowing pricing of internal congestions. This two product approach allows integration of global-TSO and the local-DSO dimension through a joint allocation. The single optimization of energy and local flexibility provides proper price signals, as an efficient way of solving grid related constraints regarding flexibility sources on DSO level. Effects of bidding zone market outcomes analyzed, including the introduction of cost-averaging pricing (PUN pricing) for the distribution of flexibility capacity procurement costs. Usually idle local flexibility is available for DSO demand but if not needed, flexibility is marketed on wholesale level. The platform supports different market participants to access the market easily. IEGSA accelerates and opens this possibility of flexibility marketing for different scales of aggregation, through cross-platform services from open access functions, such as Flexibility Register, TSO-DSO interface and single market interface for standardized market messages.

The unifying approach in both WP7 demonstrators allows various, currently disjoint market products’ pricing to be optimized. The same product for different services approach delivers proper alignment of the market flexibility resources cleared thus committed at the same timeframe, for the same delivery period. Multiple use cases can be performed using a single market platform, including local flexibility supply incetives, energy and capacity simoultaneous bidding with linking, TSO congestion management with market based energy product procurement.

This Deliverable summarizes the experience gained during the demonstration period and provides recommendations for improving the pan-European electricity market. The market effects from the active participation of DERs in the market operation are presented and evaluated in detail.

It also summarizes the market design, the realization of such a market auction, including the necessary optimization algorithm and IT tools of the market platform, and for the facilitation of a common approach for TSO-DSO-consumer coordination – realized by IEGSA – the prequalification steps leading to a successful market auction are described in detail. The evaluation is implemented in coordination with WP2 in customers' needs and WP3 on market design, providing recommendations on how the demo benefits satisfy the customer needs and will be channeled into future pan EU market evolution plan.

According to the work package plan, the objectives of the work are to:

- Demonstrate innovative market platforms that promote DERs participation in wholesale electricity markets.
- Illustrate market coupling scenarios among Romania, Bulgaria and Greece featuring clear price signals and DER flexibility potential.
- Simulate effects of DSO-usage of local flexibility resources on bidding zone market outcomes, by using shadow-prices to determine order clearing prices and EUPHEMIA algorithm.
- Evaluate the proposed market platforms to provide recommendations for the evolution of EU electricity markets.

The origin of both demonstrators is the proven and succesful day-ahead market integration algorithm, to be extended to SO-specific flexibility services.

Concerning Task 7.1, based on the results obtained, there is significant potential for DERs' market penetration. Apart from their participation in the balancing market, their role is also important in the coverage of operational congestion management capacity services at both TSO and DSO levels. With the detailed scenarios analysis for various market design and generation resource combinations, the results highlight the importance of power system development strategies. All EU member states shall carefully design their own energy mix based on the available resources and interconnection capabilities. However, it is important to stress that current market couplings necessitate a more systematic coordination of the overall EU electricity supply security measures, which must be executed through more systematic EU monitoring of the National Energy and Climate Plans' design to form complementary energy mixes to maximize the overall welfare. In addition, the increasing electrification of other complementary energy sectors (e.g., heating and transport) creates additional needs for significant RES investments, which go in line with the increased market participation of DERs.

As far as Task 7.2 is concerned, moving away from the disincentivizing copper-plate approach is the key result for future developments. With the spread of distributed energy sources, the socialization of the network constraints through system usage tariffs lead to inefficient markets. The advantage of the single market platform for different spatial dimensions is to have a unique trading platform with concentrated trading liquidity. Additional market design features, such as linked optimization of capacity and energy bids have been investigated, and considered and demonstrated to be readily implementable despite the algorithm complexity, in a exclusive linked order type. This feature however can be further progressed from this substitution model to a full co-optimization. Demonstration objectives addressing the key drawbacks are yet to be overcome in the current, wholesale focused and energy-only market design. New technology and power system specific constraints however are proved to be readily introduced into the current market coupling solution, the EUPHEMIA.

To summarize Demo Area recommendations, the existing, single and integrated European day-ahead auction framework is demonstrated to be suited as a base platform for solving further power system challenges. Increased DERs participation at a pan-European level requires harmonized product definitions and effective inter-operability among different markets to unlock DERs full flexibility potential. To achieve a single market solution, consideration of congestion management services shall be not treated as an additional market product, but product design shall be compatible with a multitude of use cases. DSO and DER specifics can be integrated with zonal representations into the existing, single day-ahead market auction framework (EUPHEMIA-type market optimization). The resulting single market framework is sensible and intelligible for all market players and includes the DSO specific congestion management services with well-known energy trading auctions. Key enabler of such complex market platforms is the unified data exchange platform: IEGSA.

Demonstrators also shed light on the current SO practices with flexibility demand. The firm delivery obligation prevalent in the electricity connection contracts resulted in limited need for active network management, at least in the case of the demonstration area of Romania. The traditional approach of investing in passive assets to meet worst case network demand is the sole business model of the system operators. Regulatory frameworks of the Demo Area strictly define responsibilities of each system operator, which discourages flexibilty innovations on the service demand side. Supply of market bids is also constrained, as the bidding of market players fully constitutes them as business sensitive processes with high value.

General regulatory limitations shall be lifted to enable demonstration in operational environment and TSO-DSO responsibilities shall be set to accept a cross-zonal platform in operation. TSO-DSO interoperability is enabled by IEGSA platform on the technical level Further legal and financial incentives are needed to move forward in delivering additional market solutions to the operational frameworks. Different market approaches of intraday market timeframe (auction based or continous trading dilemma) and slow adoptation of local flexibility services and products specific market regulations (cf. DSR Framework Guideline for Regulation) does not foster new flexibility solutions to be put in practice.

Further work with the sole aim of an integrated market and platform approach for the various TSO-DSO coordination schemes is required to have a specific common approach. A successful approach to solve the day-ahead energy market integrations issue was a single solution from the Central-Western Europe Region, where implicit auctions based integration provided the necessary common guide on the harmonization of the integration process. Single market platform for multiple grid services, distributed resource and location specific information integration along with the key IEGSA functions and the solution itself are an indispensable part of the commont single, collaborative System Operator market platform - according to the demonstrators results presented here – such solutions are taken forward by the the OneNet Horizon 2020 project.

1 Introduction

This Deliverable reports the demonstration description and pilot results of the Demos of the INTERRFACE project, which are a part of the activity of WP7 and in particular of Demo Area 3: "**Pan-EU Clearing Market demonstration**". The Deliverable refers to the activity of Tasks 7.1: **DERs into Wholesale** and 7.2: **Spatial aggregation of local flexibility**.

Within Task 7.1, a prototype has been developed, including an optimization and a forecasting toolbox. In particular, the optimization package successively solves the day-ahead (with an hourly time step) and the balancing market (with a 30-min time step) models taking into account as inputs the forecasting outputs, including electricity demand, PV, and wind generation forecasts. In addition, based on the modeling frameworks and technologies developed in WP3 and WP4, it considers additional services in the balancing market, such as operational congestion management capacity at both TSO and DSO levels, as well as different market designs reflecting various TSO-DSO coordination schemes. The demonstration takes place in the power systems of Greece, Bulgaria, and Romania.

The key day-ahead market (DAM) model results include: (i) Energy generation mix – DAM energy market schedule, (ii) System's marginal price, (iii) Interconnection flows, and (iv) CO_2 emissions. The key balancing market model results include: (i) Balancing market energy schedule, (ii) Activated upward and downward energy from each entity and the relevant market prices, and (iii) Reserve provision per type including upward and downward FCR, aFRR, mFRR, and operational congestion management capacity at both TSO and DSO levels and the relevant market prices.

As far as Task 7.2 is concerned, the spatial aggregation of the local flexibility demonstrator focuses on a wholesale market design that includes geolocational information to enable the collaboration of participants regardless of their size. Refined spatial dimensions are introduced into the existing wholesale market design with a holistic mathematical formulation for optimal market outcomes and optimal use of local flexibilities –based on the pan-European day-ahead energy market coupling's EUPHEMIA model – has been developed and configured to suit the demonstration's requirements. The demonstration takes place in Romania with local partners TRANS and DEO, (Romanian TSO and DSO respectively).

The EUPHEMIA-based market platform that includes a local flexibility resources tool, developed in part of the demonstration aiming towards Spatial Aggregation of Local Flexibility, aims to provide a new market platform-based tool to further enhance coordination of local energy and flexibility needs. Zonal aggregation representation of both TSO and DSO needs for both short-term and operational congestion services expressed in energy and flexibility (capacity-based) products has been selected, accordingly.

On this national auction-based platform, 15-min. energy products are traded (which allows BRPs to mitigate balancing cost). Compared to the currently predominant, continuously traded intraday market products, the advantage of this design is that internal TSO-DSO / DSO-DSO congestions are priced according to the requirements of Capacity Allocation and Congestion Management Network Code. Local flexibility is defined as an mFRR-like capacity product in alignment with WP3 results – as part of an operational congestion management service. To facilitate effective distribution of cost incurring from local flexibility procurement, PUN pricing is extended to include not only energy but flexibility capacity products as well.

The objectives of this work package are:

- Demonstrate innovative market platforms based on WP3 and WP4 work that promote DERs participation in wholesale electricity markets.
- Illustrate market coupling scenarios among Romania, Bulgaria, and Greece of clear price signals and DER flexibility potential.

- Simulate effects of DSO-usage of local flexibility resources on bidding zone market outcomes by using shadow prices to determine order clearing prices and the EUPHEMIA algorithm.
- Evaluate the proposed market platforms in order to provide recommendations for the evolution of EU electricity markets.

D7.4: Pan-EU Clearing Market demonstration: Final Evaluation report, lessons learnt, and recommendations for Market Upgrade (UPRC-M48)
This Deliverable will summarize the results of all the demonstrators in Demo Area 3. Specifically, the results will be reviewed in detail and evaluated. The results will be evaluated with regards to specific KPIs. Moreover, the Deliverable will include the evaluation of tested business use-cases, the validation of the proposed market framework and the assessment of the techno-economic impact.

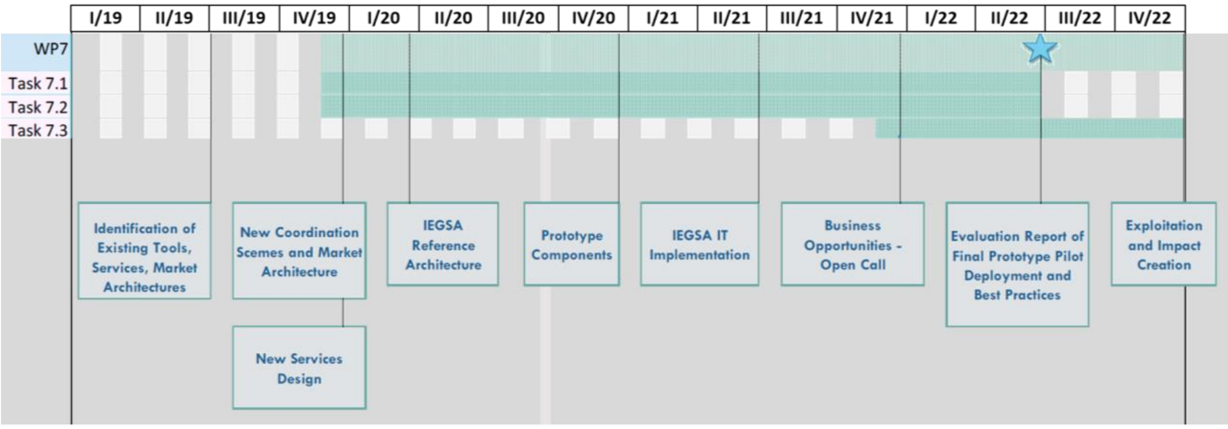

Figure 1: WP7 objectives and time plan

2 Evaluation of the results of the demonstrations

2.1 DERs into Wholesale

2.1.1 Introduction

The objective of the prototype developed is to illustrate market coupling scenarios among Romania, Bulgaria, and Greece by highlighting clear price signals and DER flexibility potential. The full model outputs have been structured in specific formats employed in the IEGSA architecture to allow elaboration and handling by the prototype and the plotting in the IEGSA environment. The real-world market operation scenarios take place in the South-eastern European (SEE) region, including the power systems of Romania, Bulgaria, and Greece region, aiming at: (i) provision of clear price signals in the market coupling, (ii) incorporating DERs flexibility potential, and engaging consumers/prosumers into electricity markets. The provision of numerous combinations of scenarios and results enables the provision of robust conclusions and recommendations for market development in the region.
The final prototype is split into three different modules, namely the Day-Ahead Market (DAM) model, the Balancing Energy Market (BEM) model, and the forecasting tools (PV, wind, and demand forecasting models). The optimization models are formulated as mixed-integer linear programming ones, and the General Algebraic Modelling System with the CPLEX solver will be used for their execution. The following **Figure 2** depicts the interlinkage of the developed methodological framework, including the integration of the Day-Ahead Market (DAM) model with the Balancing Energy Market (BEM) model considering the outputs of the forecasting tools (PV, wind, and demand forecasting models).

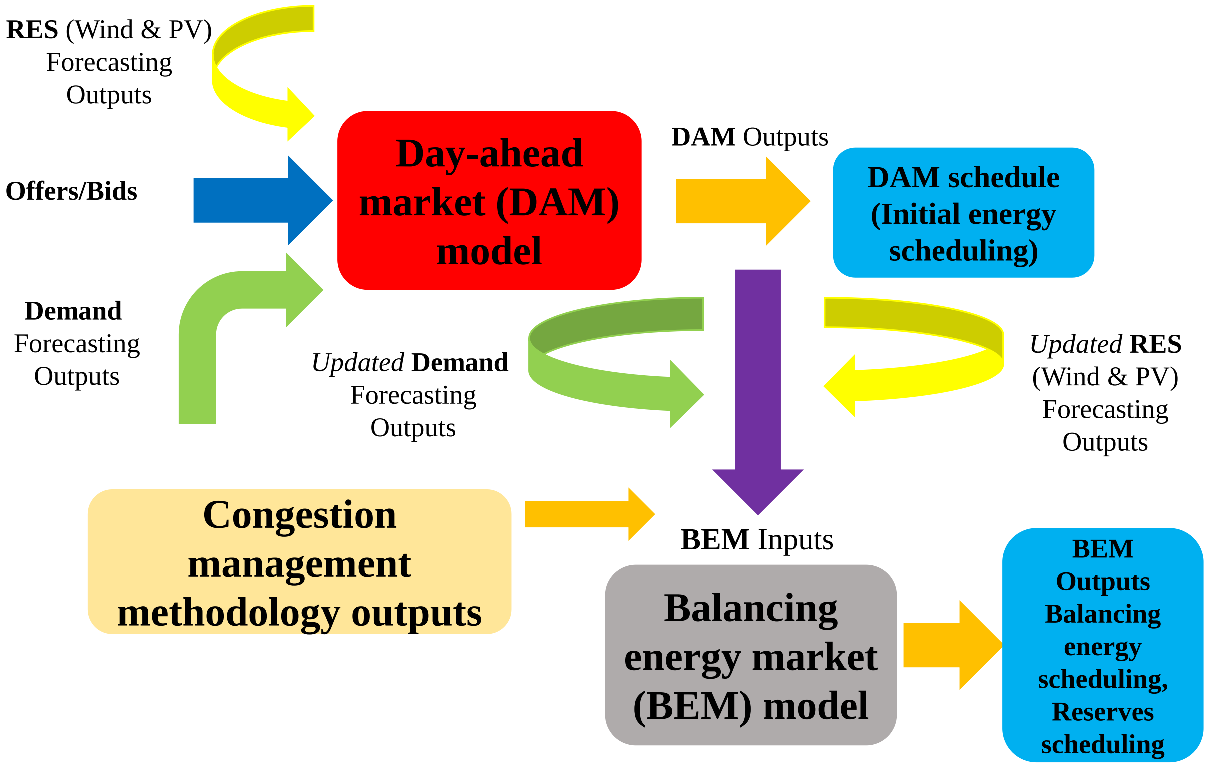

Figure 2: Integration of the Day-Ahead Market (DAM) model with the Balancing Energy Market (BEM) model considering the outputs of the forecasting tools

The initial forecasts of RES generation and demand from the relevant tools and the market participants' adopted strategy comprise the DAM model's initial input data. After the DAM model's successful execution, the model determines the initial energy market schedule, the cross-border electricity flows, and the resulting electricity price in each bidding area (Greece, Bulgaria, and Romania). Based on the updated data of the forecasting tools (demand and RES generation) and the Congestion Management methodology, the newly submitted bids of the market participants for the balancing market, and the thermal units' techno-economic data (technical minimums/maximums, synchronization, soak, desynchronization times, minimum uptimes and downtimes, reserve capability provision per reserve type, ramp-up and down limits, CO_2 emissions factor, etc.) the BEM model determines the optimal balancing energy and reserves scheduling. The balancing market products include: (i) upward and downward balancing energy and (b) several types of reserve capacity, including:

- ✓ FCR with an upward direction,
- ✓ FCR with a downward direction,
- ✓ aFRR with an upward direction,
- ✓ aFRR with a downward direction,
- ✓ mFRR with an upward direction,
- ✓ mFRR with a downward direction,
- ✓ Operational congestion management at a TSO level with an upward direction,
- ✓ Operational congestion management at a TSO level with a downward direction,
- ✓ Operational congestion management at a DSO level with an upward direction, and
- ✓ Operational congestion management at a DSO level with a downward direction.

2.1.2 DAM model

The DAM model is an optimization model that has been developed for the simulation of the EUPHEMIA Energy-only day-ahead market, according to its public description. The algorithm considers all the block and complex orders available in the European Power Exchanges, which have adopted the EUPHEMIA algorithm. The overall problem is formulated as a Mixed Integer Linear Programming (MILP) model. Its objective is the maximization of the overall social welfare (total load utility minus total energy supply cost). It is subject to a series of constraints, including demand balance and the constraints accounting for the representation of hourly offers/bids with complex orders, block orders, linked block orders, exclusive groups of block orders, and flexible hourly orders.

2.1.3 BEM model

The BEM model is an optimization model that has been developed for the simulation of the balancing market. It is a market-clearing approach that utilizes a detailed unit commitment model, enhanced by the specifications of the balancing market and the introduction of distributed energy resources (DERs). The developed Balancing Energy Model (BEM) is executed for the procurement of the following services: (i) upward and downward balancing energy, and (b) several types of reserve capacity, including upward and downward Frequency Containment Reserve (FCR), upward and downward Frequency Restoration Reserve with automatic activation (aFRR), and upward (spinning and non-spinning) Frequency Restoration Reserve with manual activation (mFRR), and upward and downward operational congestion management at both TSO and DSO levels. The objective function consists of several terms that determine the following costs: (i) net balancing energy cost, namely upward balancing energy cost minus downward balancing energy revenues at both TSO and DSO levels, (ii) FCR up reserve cost, (iii) FCR down reserve cost, (iv) aFRR up reserve cost, (v) aFRR down reserve cost, (vi) mFRR up reserve cost, (vii) mFRR down reserve cost, (viii) TSO operational congestion management up cost, (ix) TSO operational congestion management down cost, (x) DSO operational congestion management up cost, (xi) DSO operational congestion management down cost, (xii) Start-up cost, and (xiii) Shut-down cost.

2.1.4 Market design

Three (3) market design options are examined:

1. Market design A: No TSO-DSO coordination

Market design A has distinct requirements for operational congestion management services at both TSO and DSO levels. In both cases, these are treated as mFRR services.

2. Market design B: TSO-DSO coordination – Integrated Operational congestion management services at both TSO and DSO levels

In Market design B, the TSO and DSO levels' operational congestion management requirements are integrated into a shared requirement.

3. Market design C: TSO-DSO coordination – Integrated mFRR and Operational congestion management services at both TSO and DSO levels

In Market design C, the mFRR and operational congestion management requirements at both TSO and DSO levels are intégrâtes into a shared requirement.

2.1.5 Uncertain parameters

The modeling approach is complex and highly extensive, requiring plenty of assumptions, including economic, technical (operational), and environmental input data for each market participant and other system-wide related data. Apart from this, three national power systems (bidding areas) are considered, significantly increasing the computational effort and the required information. To address this issue and to facilitate the IEGSA platform users in constructing a desired scenario to be executed, a significant number of predetermined and illustrative scenarios (81 in total for each market design) have been executed, providing the option to the IEGSA platform users to plot various scenarios (inputs and outputs) from a wide range of a relevant model library. The input data are divided into the ones being common into all model executions (fixed) and others that vary in each scenario (variable), constructing in this way a rich set of solutions and results.

Consequently, four key indicators have been identified as the most critical, influencing the models' outputs, and three scenarios have been assigned to each. **Table 1** summarizes the selected critical inputs and the assumptions made for their assigned values. The Demo provides a set of different scenarios where IEGSA platform users will choose different combinations of:

1. *Demand patterns* and *climatic data*; therefore, different RES generation forecasting profiles. These two input parameters are collectively formed an integrated input, namely the net electricity demand. Three scenarios are assigned for the parameter of the net electricity demand, including low, medium, and high scenarios.
2. *CO_2 emissions price*; this parameter significantly affects the installed thermal units' operational variable cost. Three scenarios are assigned for the parameter of the CO_2 emissions price, including low, medium, and high scenarios.
3. *Natural gas fuel price*; this parameter significantly impacts the operational variable cost of the installed natural gas-fired units. This parameter is historically subject to extreme fluctuation, in contrast with the cost of the domestic (in each country-bidding area) lignite (brown coal) or hard

coal, whose price is more or less constant over time. Three scenarios are assigned for the natural gas fuel price parameter, including low, medium, and high scenarios.

4. *Cross-border interconnection capacities*; this parameter influences the cross-border electricity trade and, subsequently, the resulting energy mix in each bidding area to a significant extent. Three scenarios are assigned for the parameter of the cross-border interconnection capacities, including current, increased +, and increased ++ scenarios.

Table 1: Key variable input parameters in the different scenarios' formation

Input data	Scenario	Description
Net electricity demand	Low	Low net electricity demand (low demand scenario + high RES generation scenario)
	Medium	Medium net electricity demand (average demand scenario + average RES generation scenario)
	High	High net electricity demand (high demand scenario + low RES generation scenario)
CO_2 emissions price	Low	Low CO_2 emissions price levels (based on historical data)
	Medium	Average CO_2 emissions price levels (based on historical data)
	High	High CO_2 emissions price levels (based on future projections)
Natural gas fuel price	Low	Low natural gas fuel price levels (based on regional data)
	Medium	Average natural gas fuel price levels (based on regional data)
	High	High natural gas fuel price levels (based on regional data)
Cross-border interconnection capacities	Low (Current)	Current levels of the cross-border interconnection capacities (based on ENTSO-E data)
	Medium (Increased +)	Medium increased levels of the cross-border interconnection capacities (ENTSO-E's Ten-Year Network Development Plan scenarios)
	High (Increased ++)	Highly increased levels of the cross-border interconnection capacities (ENTSO-E's Ten-Year Network Development Plan scenarios)

2.1.6 Prototype outputs

The prototype has been executed and globally optimized using the CPLEX solver within the General Algebraic Modeling System (GAMS). An optimality gap of 0% has been achieved in all cases and scenarios of both DAM and BEM models' implementations. The timestep adopted is hourly for the DAM model outputs and half-hourly for the BEM ones.

The forecasting models' outputs include:

i. DAM electricity demand forecast in each hourly time period
ii. DAM wind power output forecast in each hourly time period
iii. DAM PV power output forecast in each hourly time period

iv. BEM electricity demand forecast in each half-hourly time period
v. BEM wind power output forecast in each half-hourly time period
vi. BEM PV power output forecast in each half-hourly time period

The DAM model outputs include:

i. DAM energy supply of each supply entity in each hourly time period
ii. DAM energy consumption of each load entity in each hourly time period
iii. DAM energy flow from each bidding zone to other in each hourly time period
iv. DAM State-of-energy level in each energy storage unit in each hourly time period
v. DAM charge power output of each energy storage unit in each hourly time period
vi. DAM discharge power output of each energy storage unit in each hourly time period
vii. DAM State-of-energy level in each EV type in each hourly time period
viii. DAM charge power output of each EV type in each hourly time period
ix. DAM discharge power output of each EV type in each hourly time period
x. Amount of renewable energy curtailed in each hourly time period

The BEM model outputs include:

i. BEM Power consumption of each demand entity in each half-hourly time period
ii. Power output of each entity in each half-hourly time period
iii. Power output of each entity during the desynchronization phase in each half-hourly time period
iv. Power output of each entity during the soak phase in each half-hourly time period
v. Balancing energy activation with a downward direction for each entity in each half-hourly time period
vi. Balancing energy activation with an upward direction for each entity in each half-hourly time period
vii. Contribution of each entity in Frequency Containment Reserve capacity with a downward direction in each half-hourly time period
viii. Contribution of each entity in Frequency Containment Reserve capacity with an upward direction in each half-hourly time period
ix. Contribution of each entity in automatic Frequency Restoration Reserve capacity with a downward direction in each half-hourly time period
x. Contribution of each entity in automatic Frequency Restoration Reserve capacity with an upward direction in each half-hourly time period
xi. Contribution of each entity in manual Frequency Restoration Reserve capacity with a downward direction in each half-hourly time period
xii. Contribution of each entity in manual Frequency Restoration Reserve capacity with an upward direction in each half-hourly time period
xiii. Contribution of each entity, belonging to either TSO or DSO level, in operational congestion management capacity with a downward direction in each half-hourly time period
xiv. Contribution of each entity, belonging to either TSO or DSO level, in operational congestion management capacity with an upward direction in each half-hourly time period
xv. Contribution of each entity in tertiary non-spinning reserve capacity in each half-hourly time period
xvi. Contribution of each entity in tertiary spinning reserve capacity in each half-hourly time period
xvii. State-of-energy level in each energy storage unit in each half-hourly time period
xviii. State-of-energy level in each EV type in each half-hourly time period

The key results have been structured in specific formats employed in IEGSA architecture to allow elaboration and handling by the prototype and plotting in the IEGSA environment.

2.1.7 Task 7.1 - Summary

Within the context of WP7 demonstrators, a prototype for promoting DER participation in the wholesale market has been materialized into an applicable market platform. This prototype incorporates the modeling frameworks and technologies developed in WP3 and WP4 and utilizes a large amount of data from the TSOs, DSOs, market operators, and participants. It provides an implementation of actual and realistic representation of the wholesale and retail markets in the examined South-East Europe region, namely Romania, Bulgaria, and Greece. A detailed description of the whole modeling framework can be found in Deliverable D7.1, as well as an analytical discussion of several prototype outputs has been highlighted in Deliverable D7.2. The most representative outputs of all scenarios and cases examined are structured in specific formats employed in IEGSA architecture to allow elaboration and handling by the prototype and the plotting in the IEGSA environment. The provision of numerous combinations of scenarios and results enables the provision of robust conclusions and recommendations for marker development in the region.

2.2 Spatial aggregation of Local Flexibility

2.2.1 Narrative of the demonstration

To specify the details of the demonstration, stakeholder requirements were identified in the early project phases, also to set the corresponding market designs in co-operation with WP2 and WP3. The benefits of such an approach for Spatial aggregation of Local Flexibility includes distribution of cost incurring from local flexibility procurement; PUN pricing is extended to include not only energy but flexibility capacity products as well. The resulting market model is tuned to incentivize local flexibility by enabling local participants to bid on a connected TSO-DSO level market. The connection of both global-TSO and local-DSO dimensions and the joint allocation of energy and local flexibility provides proper price incentives through coupling of different parts of trading. The actual benefits are shown in Deliverable D7.3. Also, market description has been elaborated to facilitate the documentation of the detailed work on the demonstration development. Focused work on the delivery of the IT solution of the standalone demonstration tool, based on the prototype has been successfully carried out, resulting in a standalone and IEGSA-connected software tool to carry out market operation.

The EUPHEMIA-based market platform including local flexibility resources tool aims to provide a new auction platform-based tool to further enhance coordination of local energy and flexibility needs. Zonal aggregated representation of both TSO and DSO needs for grid services expressed in energy and flexibility products has been selected to align the market algorithm to the existing EUPHEMIA-type common European Single Day-Ahead Coupling Solution.

This supplementary energy trading and market-based short-term and operational congestion management platform – that operates a daily run market auction on the intraday timeframe – provides opportunity to trade energy in a finer, 15-min. time granularity (allowing BRPs to mitigate balancing cost) while allowing pricing of internal congestions according to corresponding Capacity Allocation and Congestion Management Network Code. (Timing of gate closure of bid submission, auction runs and notification of participants: after the intraday scheduling process opened but before the first delivery periods of day D, preferably at D-1 22:00).

DSO demand of local flexibility is met with market bid matching in the demonstration as well. In alignment with WP3 results on the required services and market arrangement on TSO-DSO coordination it is defined as an mFRR-like (same ramp up, full activation time, etc.) but strictly not a balancing capacity product, and the market provides short-term congestion management services as its primary grid service, according to the stakeholder needs. To facilitate effective distribution of cost incurring from local flexibility procurement, PUN pricing is extended to include flexibility capacity products. With this approach, the price distorting effects of flexibility needs in a small (DSO) bidding zone can be mitigated.

Thus varying size of each DSO zones is equalized by the cost sharing feature enabled within the market by PUN pricing.
The resulting market model is tuned to incentivize local flexibility by enabling local participants to bid on an integrated marketplace, providing proper price incentives through coupling of different aspects of trading.
System use cases have been specified in detail to finalize IT architecture and align functional details of the demo specific IT prototype with the common IEGSA services. Five sub units, steps in the market processes have been set:

1. Prequalification
2. Order book management (aggregating and verifying market orders)
3. Bid matching, with market calculation algorithm
4. Post-matching (clearing result verification and result dissemination)
5. Settlement

IT platform planning has been carried out to realize IEGSA connection of the standalone demonstration. Standalone demonstration solution, custom developed in Python environment, handles bids and order book, and also provides an interface for aggregated bids. Excel order templates are developed to facilitate individual bidders. Automated runs of auctions are developed and deployed in a cloud-based input-output feeding structure. Results are interpreted separately for settlement, publication and individual bidder (bid and bidder ID management.)

Local implementation uses custom order book formats and standalone FSP bidding templates in Excel/.xml formats. Data conversion tools are used in productive deployment to map real-market datasets to the novel demonstrated market. Connection with IEGSA, and its functionalities, especially the flexibility register as the key functional layer element are fully covering the need of enabling complete TSO-DSO-consumer integration.

The standalone demo process developed is end-to-end deployed. Full-sized data based demonstration runs have been successfully carried out to fully verify its mathematical soundness and corresponding functionality. Interface integration and development with IEGSA and direct communication with market players (bidders on the market) is used to enhance prequalification process. Demonstration has been carried out and it was evaluated in 2022, and presented in Deliverable 7.3 of INTERRFACE.

2.2.2 Details of the market solution for local flexibilities

Spatial aggregation of local flexibility using market platform connecting wholesale and local flexibility with IEGSA TSO-DSO coordination interface ensures that orders and bids from market players are qualified from product perspective and grid connection perspective as well. TSO and DSOs qualify the resources, a unique identifier is assigned to validate locational information and capability of providing local flexibility (upon new request for qualifying new resource from a market player or during pre-defined open sessions for entering new flexi market players). Communication with TSO/DSO is done through IEGSA's TSO/DSO coordination interface. Qualified resources and their identifiers are stored in the Flexibility Register.

TSO and DSOs are initializing the local flexibility market setting basic topology and connectivity data. Local zones, boundaries are set through the TSO/DSO coordination and assigned to resources. The zonal configuration is the basis of the initialization of daily market runs.

During the daily auction steps, market players access the Market User Platform directly. Order book manager is initialized with predefined zonal configuration and cross-zonal capacities already agreed in the TSO/DSO coordination module. Key use case of the market platform is order book management, where market bidders can upload their bids in a pre-defined format; the orders are accessible and can be managed, their formats are checked against the requirements using IEGSA and the market platform functions. Pre-qualification requirements are cross-referenced to the Flexibility Register records (via a unique identifier). This platform aggregates and handles large number of market orders until gate closure. Participants submit market orders in preparation of the auction.

All market orders, bids and parameters are submitted via custom interfaces (either by file upload or through UIs / APIs) and it is ensured that a single set of input data, parameters and required settings are passed to the order matching process. Preliminary data filtering, handling format related inconsistencies, range and low complexity feasibility check is thus performed.

The key component of the system is the market auction algorithm, the operating optimization. This the acceptance of the orders, and clearing prices according to the objective function complying to the order pricing, balance and network constraints. This bid matching calculates all parameters to be published in the post matching process. As being a resource intensive computation with a strict running time limit, the solution first provides any feasible solution and then refine it to find the optimal solution. The framework is compatible with the current, already widely-known EUPHEMIA algorithm, used to permit easier distribution of the market design. The specialities include generalization of congestion pricing in hierarchical, stacked bidding areas, and the realization of an efficient way of solving grid related constraints through the usage of shadow prices (PUN pricing).

After the mathematical optimization is carried out, the market outcome is interpreted, and disaggregeted per each bidder. Market players' individual, bid-level results and positions of cleared and unmatched orders volumes are generated, along with general results of the auction (e.g. social welfare, market prices, cross-zonal exchanges). The specific algorithm ensures proper price signals for each area, both DSO and TSO levels, incentivizing flexibility resources to participate in a single, integrated platform. Congestion prices derived from market results provide signals for operational, short-term and long-term network transmission capacity management prioritization.

The settlement of the allocated market bids leads to actual realization of various market series. Final market results energy transactions are forwarded to the intraday scheduling process. The cost allocation in the financial settlement is novel in the demonstrator, as PUN concept is used to enable masking of underlying price differentiation for a selected market player (e.g. consumers) with market forces instead of tariff based cost distribution. Enhanced use cases (where TSO/DSO coordination is realized via priced market bids and channelled into the general market order book) are already available for internal congestion management with proper pricing of locations. Thus intraday redispatch, and market based counter trading is also possible with the demonstrated market tool. The developed tool enables the DSOs to use the intraday flexibility pool as a tool for internal congestion management via capacity procurement

Various future use cases can be supported using the developed auction based, multi-service, energy-local flexibility product joint optimizing solution, e.g.:

- Local (zonal) pricing to incentivize local flexibility supply, with increased DSO demand to 'pull' supply
- Possibility to bid simultaneously for two markets with a single resource for local FSPs
- Connection of local and "global" (TSO-level) segments of energy market – channelling liquidity into the smaller bidding zones – ensuring no small trade volume zones are isolated, as the key driver of market efficiency and robustness is liquidity
- TSO – congestion management via market based energy transactions
- Coordination on TSO-DSO congestion management – multiple combinations of market-based congestion management aimed balanced or imbalanced energy activation is possible – prices are aligned to the need of relieving local congestions
- Local flexibility is available for DSO demand but if not needed, flexibility is marketed on wholesale level, with capacity-energy linking

- Ex-ante (proactive) balancing by TSO, with scheduled energy product procurement
- BSPs have a possibility to balance their position on the 15-min. intraday auction market – this provides a base liquidity on the market

2.2.3 Market runs and scenarios

The spatial aggregation of local flexibility market approach is demonstrated on the Romanian market setting. To reach the full depth of complexity in such intraday market auctions, full historical bid-level datasets are used to generate up to hundred thousand of individual offers for each optimization run.

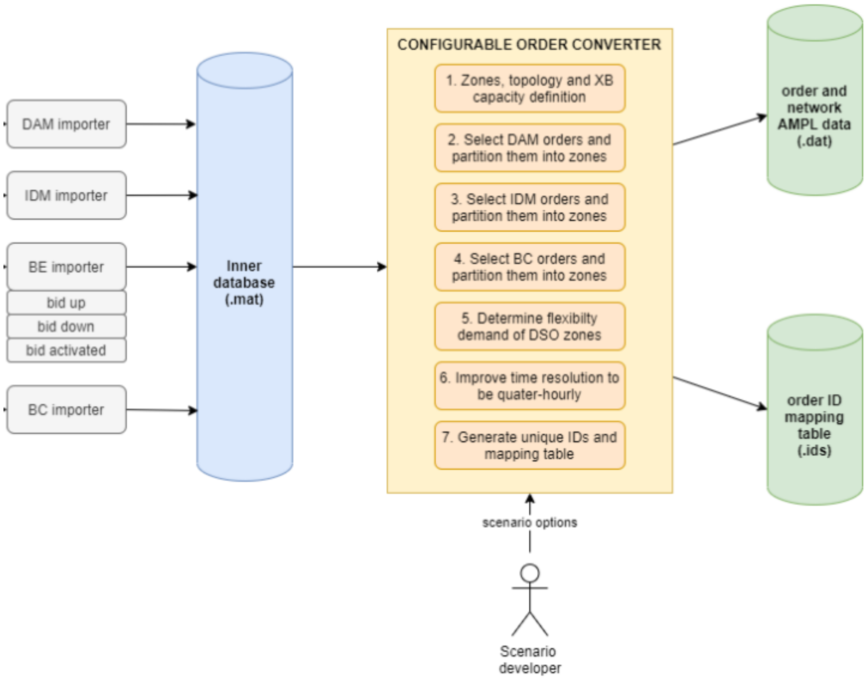

Figure 3: Market scenario forming in the demonstration execution – realistic market data-based scenarios

Scenario forming

The configurable order converter has multiple realistic options on handling alternative data-feeding options to the market simulation. This set of option can form the possible range of different scenario bases.

Based on the very wide-range of available, and consistent datasets, two distinct scenario sets are defined:

- D1: continuous dataset for demonstration (Jan-Dec 2020) to have a fixed market scenario
  - using DAM, IDM, Balancing energy market bids without constraining cross-zonal congestions
- D2: dedicated dataset for ceteris paribus scenario studies, to: explore and fine tune algorithm, market specifics and identify alternative use cases
  - M02 localbc: BC bidders along with their orders are matched to the DSOs.
  - M03 linkedcase: an extra energy supply bid is added to each upward BC bid in order to test the linked order type. The linked energy and upward bids are handled in an exclusive set, only one of them can be accepted.
  - M04 otmdam: only the out-of-the-money bids (meaning the bids that were not accepted at the DAM action) are used.

- M05 improvedidm: intraday orders are modified. Prices of demand bids are changed with [-2;+5] EUR/MWh, while prices of supply bids are changed with [-5;+2] EUR/MWh (using uniform distribution)
- M06 otmbc: only the out-of-the-money BC orders are used. (The demand for BC is again the half of the kept supplied volume.)
- M07 tso: TSO zone exists, 10% of the energy bids is sorted into the TSO zone.
- M08 congested: (TSO zone does not exist), ATC > 0 on each border, resulting in 30-50 constraint on zonal net position.
- M09 morecongested: (TSO zone does not exist), fixed ATC >> 0 on each border, resulting in 15-25 constraint on zonal net position.
- M10 morecongested: (TSO zone does not exist), fixed ATC = 0 on each border, resulting in totally decoupled DSOs.
- M11unbalanced: (TSO zone does not exist), DAM orders are rearranged to make low and high-price zones consistently and supply-demand is purposefully shifted to create more transmission demand
- M12unbalanced: M11 + TSO exists.

More details and summary, outlining the overall aims and purpose of the scenarios are discussed in D7.3 chapters 7.2, 7.3, 7.4.

2.2.4 Advantages of the integrated market auction – including spatial aggregation of local flexibilities

As part of INTERRFACE Demo Area 3, Pan-EU clearing market the Spatial Aggregation of Local Flexibility market demonstrator developed a new, EUPHEMIA-based market solution and corresponding market structure to engage local flexibility resources. A new market platform is developed, along with the necessary algorithm, and the demonstration was carried out in a single area, Romania.

The new intraday market setting demonstrated the feasibility of a combined, integrated, market auction-based solution for short-term and operational congestion management services, with integrated energy and capacity products, on a 15-min. (target model based) granularity of delivery periods. The zonal congestion management's disadvantages with small DSO-sized zones is offset with a local incentive to share cost burden. Uniform pricing (PUN) based cost averaging solution is used to provide a market-based solution to cover intra-zonal congestion cost markups by using cost averaging for certain type of bids (e.g. large demand). Thus a complete market solution is derived for the optimal use of local flexibility, resulting in introduction of small scale, locally procured flexibilities in the TSO-driven wholesale market design, while creating an efficient way of solving grid related constraints on DSO level. Stakeholder, system operator need underlined the issue of congestion management, that required an integrated mathematical formulation, a holistic market optimization in a single product based multi-service optimization, linking consumers – DSOs –TSOs.

The demonstrator aimed to and delivered a tool, to overcome key issues in the current market that does not fully meet the expectations of end-users, especially on the local scale. It is duly noted, that the devised market solution is compatible with the existing market framework. It uses the EUPHEMIA design, and the definitions, optimization framework and the products are either intraday energy or simple congestion management products, with standard auction based framework and zonal prices. Thus the introduction of local flexibilities resulted in an intelligible solution for market players. The tool is based on existing wholesale market products, channels liquidity to local zones using a proven concept.

As DSOs infrequently need active flexibility – generally idle local resources shall be offered to liquid markets, instead of standalone DSO-only markets. Optimal use of local flexibilities is thus ensured with the TSO-DSO common market auction. To ensure applicability for the DSOs, an efficient way of solving grid related constraints is delivered. The zonal approach is a simplified, but complete DSO-grid mapping solution for larger areas, which is not yet tractable to found a total nodal pricing approach. Existing zonal approach of European congestion management practices is thus used, with proven solutions. The required flexibility capacity for DSO to manage constraints is thus procured locally and activated by DSO.

The approach described is based on an optimization algorithm with complex functions. The demonstration proved that the holistic mathematical formulation approach is feasible, capable for delivering optimal market outcomes, linking consumers – DSOs – TSOs in a single and yet attainable market solution for flexibility on both TSO and DSO level. Some distinctive features are thus summarized:

- Flexibility definition of the market is twofold: energy and local capacity product
- Local flexibility is in focus, global flexibility as being capable for balancing services and already marketed directly on wholesale ancillary services is not targeted
- Aggregation to wholesale: Pulling demand for local flexibility only from DSOs is not enough, liquid energy market shall be reached and this is provided by the integrated market platform
- Spatial dimension: Zonal approach on congestion management in energy markets can be extended to include DSO level
- Pricing: Innovative application of PUN-like bid pricing helps alleviate cost distribution disincentives in low liquidity local zones

3 Monitoring of Key Performance Indicators

3.1 Introduction

Table 2 indicates the selected KPIs of the WP7 for both Demos. These include gathering the required data to eliminate generic assumptions (applicable to both Tasks), designing realistic scenarios to provide valuable recommendations (applicable to both Tasks), and the number of possible trades due to the new algorithm (applicable to Task 7.2).

Table 2: KPIs of the WP7

WP – Activities	Performance Indicator	Framework for Metrics	Target Values	Progress
WP7 - Pilot Deployment, Demonstration and Evaluation - Demo Area 3 (pan-EU Clearing Market)	7-1 Gathering of required data	7-1-1 Data gathering by involved partners to eliminate generic assumptions (over the requested data)	≥ 90%	Achieved
	7-2 Formation of realistic scenarios and recommendations	7-2-1 Co-design/feedback by partners on simulations and results (over the total number of scenarios)	≥ 60%	Achieved
	7-3 Number of possible trades due to the new algorithm	7-3-1 With the new approach such trades can bind which were not available before	>5 trade/area	Achieved

3.2 Task 7.1 – KPI 7-1 Gathering of required data

The applicability of the prototype has been tested on the integrated SEE power system, including the national power systems of Bulgaria, Greece, and Romania. In particular, the projected 2030 power systems have been modelled by taking into account each country's 2021-2030 integrated energy and climate plan.

The DAM input data include:

i. Maximum and minimum values of the minimum acceptance ratio of each submitted block order
ii. Maximum corridor flow between bidding zone in each hourly time period
iii. Energy supply cost of each block order
iv. Price of each block of the energy offer function of each supply entity pr in each hourly time period
v. Energy supply cost of each flexible hourly order
vi. Cost of each block of the energy offer function of each supply entity in each hourly time period t (€/MWh)
vii. Exclusive group containing block orders

viii. Maximum decrease gradient of each supply entity imposed by a Load Gradient Order

ix. Maximum increase gradient of each supply entity imposed by a Load Gradient Order

x. Parameter denoting if a child block is linked with its parental block under a tower-based relationship

xi. Quantity of available energy of each submitted block order in each hourly time period

xii. Total amount of required energy of each load entity in each block of its energy consumption function in each hourly time period

xiii. Total amount of available energy of each supply entity in each block of its energy offer function in each hourly time period

xiv. Maximum charge power output of each energy storage unit

xv. Maximum discharge power output of each energy storage unit

xvi. Maximum and minimum energy capacity of each energy storage unit

xvii. Quantity of available energy of each submitted flexible hourly order in each hourly time period

xviii. Maximum charge power output of each EV type

xix. Maximum discharge power output of each EV type

xx. Maximum and minimum energy capacity of each EV type

xxi. Number of electric vehicles per type in each system

The BEM input data include:

i. Scheduled DAM power consumption from the DAM of each demand entity in each hourly time period

ii. Scheduled DAM power output (DAM solution) of each entity in each hourly time period

iii. Cost of each block of the balancing energy offer function with downward direction of each power generating unit in each half-hourly time period

iv. Cost of each block of the balancing energy offer function with upward direction of each power generating unit in each half-hourly time period

v. Cost of the offer of each entity in each half-hourly time period for operational congestion management capacity at a DSO level with a downward direction

vi. Cost of the offer of each entity in each half-hourly time period for operational congestion management capacity at a TSO level with a downward direction

vii. Cost of the offer of each entity in each half-hourly time period for operational congestion management capacity at a DSO level with an upward direction

viii. Cost of the offer of each entity in each half-hourly time period for operational congestion management capacity at a TSO level with an upward direction

ix. Cost of the offer of each entity in each half-hourly time period for mFRR capacity with a downward direction

x. Cost of the offer of each entity in each half-hourly time period for mFRR capacity with an upward direction

xi. Cost of the offer of each entity in each half-hourly time period for FCR capacity with a downward direction

xii. Cost of the offer of each entity in each half-hourly time period for FCR capacity with an upward direction

xiii. Cost of the offer of each entity in each half-hourly time period for aFRR capacity with a downward direction

xiv. Cost of the offer of each entity in each half-hourly time period for aFRR capacity with an upward direction

xv. Maximum power consumption of each demand entity in each half-hourly time period

xvi. Minimum power consumption of each demand entity in each half-hourly time period

xvii. System-wide requirements for operational congestion management capacity with a downward direction at a DSO level in each half-hourly time period

xviii. System-wide requirements for operational congestion management capacity with a downward direction at a TSO level in each half-hourly time period

xix. System-wide joint requirements for operational congestion management capacity with a downward direction at a TSO-DSO level in each half-hourly time period

xx. System-wide joint requirements for mFRR and operational congestion management capacity with a downward direction at a TSO-DSO level in each half-hourly time period

xxi. System-wide requirements for operational congestion management capacity with an upward direction at a DSO level in each half-hourly time period

xxii. System-wide requirements for operational congestion management capacity with an upward direction at a TSO level in each half-hourly time period

xxiii. System-wide joint requirements for operational congestion management capacity with an upward direction at a TSO-DSO level in each half-hourly time period

xxiv. System-wide joint requirements for mFRR and short-term congestion management capacity with an upward direction at a TSO-DSO level in each half-hourly time period

xxv. System-wide requirements for FCR capacity with a downward direction in each half-hourly time period

xxvi. System-wide requirements for FCR capacity with an upward direction in each half-hourly time period

xxvii. System-wide requirements for aFRR capacity with a downward direction in each half-hourly time period

xxviii. System-wide requirements for aFRR capacity with an upward direction in each half-hourly time period

xxix. System-wide requirements for mFRR capacity with a downward direction in each half-hourly time period

xxx. System-wide requirements for mFRR capacity with an upward direction in each half-hourly time period

xxxi. Charging efficiency of each energy storage unit

xxxii. Discharging efficiency of each energy storage unit xxxiii. Charging efficiency of each EV type

xxxiv. Discharging efficiency of each EV type

xxxv. Shutdown cost of each entity

xxxvi. Minimum downtime of each entity

xxxvii. Minimum time duration that an entity can be assigned with two successive balancing energy activations with downward direction

xxxviii. Minimum time duration that an entity can be assigned with two successive balancing energy activations with upward direction

xxxix. Start-up cost of each entity

xl. Minimum uptime of each entity

xli. Maximum contribution of each entity in Frequency Containment Reserve capacity with downward direction

xlii. Maximum contribution of each entity in Frequency Containment Reserve capacity with upward direction

xliii. Maximum output of each entity when operating under Automatic Generation Control

xliv. Technical maximum of each entity

xlv. Minimum output of each entity when operating under Automatic Generation Control

xlvi. Technical minimum of each entity

xlvii. Power output of each entity when operating in soak phase

xlviii. Maximum charge power output of each energy storage unit

xlix. Maximum discharge power output of each energy storage unit

l. Maximum charge power output of each EV type

li. Maximum discharge power output of each EV type

lii. Total forecasted renewable power output per renewable energy technology in each half-hourly time period

liii. Energy storage level target at the end of the scheduling horizon of each energy storage unit

liv. Energy storage level target at the end of the scheduling horizon of each EV type

lv. Maximum energy capacity of each energy storage unit

lvi. Minimum energy capacity of each energy storage unit

lvii. Maximum energy capacity of each EV type

lviii. Minimum energy capacity of each EV type

lix. Maximum contribution of each entity in tertiary non-spinning reserve

lx. Maximum contribution of each entity in tertiary spinning reserve

lxi. Ramp-down rate of each entity

lxii. Ramp-down rate of each entity when operating under Automatic Generation Control

lxiii. Ramp-up rate of each entity

lxiv. Ramp-up rate of each entity when operating under Automatic Generation Control

lxv. System forecasted imbalances in each half-hourly time period

lxvi. Desynchronization time of each entity

lxvii. Soak time of each entity

lxviii. Synchronization time of each entity

lxix. Quantity of each power capacity block of the balancing energy offer function with downward direction of each entity in each half-hourly time period

lxx. Minimum amount of balancing energy activation with downward direction, offered by each entity in each half-hourly time period

lxxi. Quantity of each power capacity block of the balancing energy offer function with upward direction of each entity in each half-hourly time period

lxxii. Minimum amount of balancing energy activation with upward direction, offered by each entity in each half-hourly time period

lxxiii. Minimum time duration that each entity must provide balancing energy with downward direction

lxxiv. Minimum time duration that each entity must provide balancing energy with upward direction

The applicability of the prototype has been tested on the integrated SEE power system, including the national power systems of Bulgaria, Greece, and Romania. In particular, the projected 2030 power systems have been modeled by taking into account each country's 2021-2030 integrated energy and climate plan. Specifically, taking into account the existing energy mix and the current installed capacity of each system and in combination with the evolution of the system, the installed capacity was modeled on a unit basis of each system for the year 2030.

The data extraction and collection for the current installed capacity of each system was implemented in close cooperation with the involved partners to eliminate generic assumptions, as well as a thorough cross-check with the publicly available data on the ENTSO-E's Market Transparency Platform.

The operational data of each individual unit that was used are based on the relevant suggestions of the involved partners (each one for the system of the country they represent) as well as there was an additional cross-check so that they are representative of those published in the international literature (peer-reviewed papers). Representative data for each technology examined are also those available in the published ENTSO-E's Ten-Year Network Development Plan (TYNDP).

Regarding RES demand and availability data, detailed data was used for each country regarding demand forecasting (historical loads, historical temperatures, day-type information), wind forecasting (historical generations, historical wind speeds, historical wind directions), and photovoltaic production (historical generations, historical temperatures, historical irradiation). Also, based on each country's 2021-2030 integrated energy and climate plan, the total annual demand of each system for 2030 was taken into account, and the demand curve was normalized accordingly.

The data for the system requirements in each type of reserve (FCR, aFRR, mFRR) were listed by the involved partners (each for the system of the country it represents) and were calculated to 2030 based on the evolution of the installed capacity between 2021- 2030 with relevant literature methodology. Regarding the calculation of the requirements for operational congestion management capacity at both TSO and DSO levels, the findings of the relevant study of the Octane project in the framework of the Cascade funding of WP8 were utilized. Also, in some cases, proportional percentages of the system mFRR requirements were used.

The economic data used to design the units' offers are based on the assumptions of the scenarios designed regarding the evolution of the natural gas price and the prices of CO_2 emission allowances. Finally, the data related to the penetration of electric vehicles in each considered system and the interconnections of the systems between them were drawn from ENTSO-E's 10-year network development plan (TYNDP) 2020.

As a result of the above, more than 90% of data is based on real-world data gathered by involved partners to eliminate generic assumptions.

3.3 Task 7.1 – KPI 7-2 Formation of realistic scenarios and recommendations

Four key indicators have been identified as the most critical ones, influencing the models' outputs, and three scenarios have been assigned to each. These indicators include CO_2 emissions price, natural gas fuel price, net electricity demand (reference electricity demand minus forecasted RES generation), and interconnection capacities. In addition, three market designs have been adopted to represent the absence and different levels of TSO-DSO coordination. Consequently, 81 scenarios (all the possible combinations of the four uncertain parameters) have been executed for each market design; thus, 243 scenarios for the integrated SEE power system. The key results, together with representative data of all scenarios, have been structured in specific formats employed in IEGSA architecture to allow elaboration and handling by the prototype and plotting in the IEGSA environment. **Table 3** summarizes all the 81 scenarios examined for each national power system and market design.

Table 3: Implemented scenarios for each national power system and market design

Scenario	CO_2 price	NG price	Net demand	Interconnection capacities	IEGSA Code
Scenario 1	Low	Low	Low	Low	1111
Scenario 2	Medium	Low	Low	Low	2111
Scenario 3	Low	Low	Medium	Low	1121
Scenario 4	Low	Low	Low	Medium	1112
Scenario 5	Low	Medium	Low	Low	1211
Scenario 6	Medium	Low	Medium	Low	2121
Scenario 7	Medium	Low	Low	Medium	2112
Scenario 8	Medium	Medium	Low	Low	2211
Scenario 9	Low	Low	Medium	Medium	1122
Scenario 10	Low	Low	High	Low	1131
Scenario 11	Low	Low	Low	High	1113
Scenario 12	Low	Medium	Low	Medium	1212
Scenario 13	Low	Medium	Medium	Low	1221
Scenario 14	Low	High	Low	Low	1311
Scenario 15	High	Low	Low	Low	3111
Scenario 16	Medium	Low	Medium	Medium	2122
Scenario 17	Medium	Low	High	Low	2131
Scenario 18	Medium	Low	Low	High	2113
Scenario 19	Medium	Medium	Low	Medium	2212
Scenario 20	Medium	Medium	Medium	Low	2221
Scenario 21	Medium	High	Low	Low	2311
Scenario 22	Low	Medium	Medium	Medium	1222
Scenario 23	Low	Low	Medium	High	1123

Scenario 24	Low	Low	High	Medium	1132
Scenario 25	Low	Medium	Low	High	1213
Scenario 26	Low	Medium	High	Low	1231
Scenario 27	Low	High	Low	Medium	1312
Scenario 28	Low	High	Medium	Low	1321
Scenario 29	High	Low	Medium	Low	3121
Scenario 30	High	Low	Low	Medium	3112
Scenario 31	High	Medium	Low	Low	3211
Scenario 32	Medium	Medium	Medium	Medium	2222
Scenario 33	Medium	Low	Medium	High	2123
Scenario 34	Medium	Low	High	Medium	2132
Scenario 35	Medium	Medium	Low	High	2213
Scenario 36	Medium	Medium	High	Low	2231
Scenario 37	Medium	High	Low	Medium	2312
Scenario 38	Medium	High	Medium	Low	2321
Scenario 39	Low	Low	High	High	1133
Scenario 40	Low	Medium	High	Medium	1232
Scenario 41	Low	Medium	Medium	High	1223
Scenario 42	Low	High	Low	High	1313
Scenario 43	Low	High	Medium	Medium	1322
Scenario 44	Low	High	High	Low	1331
Scenario 45	High	Low	Medium	Medium	3122
Scenario 46	High	Low	High	Low	3131
Scenario 47	High	Low	Low	High	3113
Scenario 48	High	Medium	Low	Medium	3212
Scenario 49	High	Medium	Medium	Low	3221
Scenario 50	High	High	Low	Low	3311
Scenario 51	Medium	Low	High	High	2133
Scenario 52	Medium	Medium	High	Medium	2232
Scenario 53	Medium	Medium	Medium	High	2223
Scenario 54	Medium	High	Low	High	2313
Scenario 55	Medium	High	Medium	Medium	2322
Scenario 56	Medium	High	High	Low	2331
Scenario 57	Low	Medium	High	High	1233
Scenario 58	Low	High	Medium	High	1323
Scenario 59	Low	High	High	Medium	1332
Scenario 60	High	Medium	Medium	Medium	3222
Scenario 61	High	Low	Medium	High	3123
Scenario 62	High	Low	High	Medium	3132
Scenario 63	High	Medium	Low	High	3213
Scenario 64	High	Medium	High	Low	3231
Scenario 65	High	High	Low	Medium	3312
Scenario 66	High	High	Medium	Low	3321

Scenario 67	Medium	Medium	High	High	2233
Scenario 68	Medium	High	Medium	High	2323
Scenario 69	Medium	High	High	Medium	2332
Scenario 70	Low	High	High	High	1333
Scenario 71	High	Low	High	High	3133
Scenario 72	High	Medium	High	Medium	3232
Scenario 73	High	Medium	Medium	High	3223
Scenario 74	High	High	Low	High	3313
Scenario 75	High	High	Medium	Medium	3322
Scenario 76	High	High	High	Low	3331
Scenario 77	Medium	High	High	High	2333
Scenario 78	High	Medium	High	High	3233
Scenario 79	High	High	Medium	High	3323
Scenario 80	High	High	High	Medium	3332
Scenario 81	High	High	High	High	3333

Due to significant results data, a detailed discussion and results provision of all the scenarios examined, satisfying the requirements of KPI 7-2, are presented in the **Annex I** of that Deliverable.

3.4 Task 7.2 – Introduction

The realization of the previously described market design – a tailored intraday market with energy and capacity products and refined congestion zoning for both TSO and DSO-level congestion – was in the focus of this Task. Running the market algorithm with several specific scenarios for the Romanian demonstration area has been selected, and realigned as per the somewhat restricted availability of the market-specific but business sensitive datasets. Further datasets have been obtained during the demonstration runs, including full balancing market datasets. Nevertheless, the KPI 7-1-1 aiming towards eliminating generic assumptions has progressed well.

- Spatial aggregation of local flexibilities
  - Optimal use of local flexibilities: DSOs infrequently need active flexibility – generally idle local resources shall be offered to liquid markets
  - Develop a prototype introducing local flexibilities into the existing wholesale market - intelligible for market players
    - Platform based on existing wholesale market products, liquidity with proven concept, algorithm solutions
  - Create an efficient way of solving grid related constraints on DSO level
    - Complete DSO-grid mapping into existing zonal approach of European congestion management practices
    - Required flexibility capacity for DSO to manage constraints are to be procured locally and activated by DSO
  - Holistic mathematical formulation for optimal market outcomes, linking consumers – DSOs – TSOs
    - A single and yet attainable market solution for flexibility on both TSO and DSO level.
  - Distinctive features of the demonstrated EUPHEMIA-based market platform
    - Flexibility definition for market approach: energy and local capacity product

    - Local flexibility in focus, global flexibility already marketed directly on wholesale AS (balancing)
    - Aggregation to wholesale: Pulling demand for local flexibility only from DSOs is not enough, liquid energy market shall be reached!
    - Spatial dimension: Zonal approach on congestion management in energy markets can be extended to include DSO level
    - Pricing: PUN-like bid pricing helps alleviate cost distribution disincentives in low liquidity local zones
    - Innovative application of introducing new, consumer orders that are matched according to an average price
  - In Demo7.2 a feasible, computationally tractable yet unique mathematical approach is developed with the associated market design to solve the integration of local flexibility to the existing energy markets
  - Market platform is developed and deployed in the final host environment.
  - TSO/DSO connection is realized via IEGSA platform. The qualification results and current availability of resources are stored in the Flexibility Register
    - Prevents overbooking of flexible resources even if it participates in multiple markets (e.g. DAM, IDM)
    - Flexibility providers have a single system to report their availability
    - TSO/DSO have a single access point to reach the market platform for market-based congestion management services
    - Provides a standardized data exchange interface for the market messages

3.5 Task 7.2 - KPI selection, monitoring and assessment

As **Table 2** of WP7 KPIs state, along with data gathering, realistic scenarios, new trades are the key performance areas of the market demonstrator. For further monitoring of the demonstration solution, addicitonal metrics were defined to ensure effective and timely runs of local flexibility markets, with the new pricing schemes, further denoted az 'KPI 7-0' set for T7.2.

Market results were obtained, and various metrics are defined and calculated for the demo runs as presented in **Figure 4**. To present the demo run results, the following subsections discuss the key findings of the monitoring and evaluation.

Title	HorizontalAxis		Filter
	Tick	AxisLabel	
Energy clearing prices	t = 1..96	Price, EUR/MWh	Basecase
Energy clearing prices	t = 1..96	Price, EUR/MWh	Basecase
Additional capacity price	t = 1..96	Price, EUR/MWh	Basecase
Upward capacity clearing prices	t = 1..96	Price, EUR/MW/h	Basecase
Downward capacity clearing price	t = 1..96	Price, EUR/MW/h	Basecase
Welfare	d = 1..30	EUR	Basecase, Linkedcase
Calculation time	d = 1..30	sec	Basecase, Linkedcase
Energy trading volume	t = 1..96	Volume, MWh	Basecase
Allocated upward capacity	t = 1..96	Volume, MW	Basecase
Allocated downward capacity	t = 1..96	Volume, MW	Basecase
Energy trading volume	d = 1..30	Volume, MWh	Basecase, Linkedcase
Number of matched bids	d = 1..30	Count	Basecase
Cost of allocated upward capacity	t = 1..96	Cost, EUR	Basecase
Cost of allocated downward capac	t = 1..96	Cost, EUR	Basecase
System operator contribution	d = 1..30	Cost, EUR	Basecase
System operator contribution	d = 1..30	Cost, EUR	Basecase, Linkedcase
Net position of zones	t = 1..96	Volume, MWh	Basecase
COMPARE SCENARIOS			
Energy clearing prices	t = 1..96	Price, EUR/MWh	M01-M04
Additional capacity price	t = 1..96	Price, EUR/MWh	M01-M04
Welfare	d = 1..30	EUR	M01-M04
Calculation time	d = 1..30	sec	M01-M04
Number of matched bids	d = 1..30	Count	M01-M04
Cost of allocated upward capacity	t = 1..96	Cost, EUR	M01-M04
Cost of allocated downward capac	t = 1..96	Cost, EUR	M01-M04

Figure 4: The various metrics are defined and calculated for the demo runs

3.5.1 7-0 implicit KPIs of the realized market tool for monitoring

During the one-year demonstration 12 scenarios were studied, one scenario for each month. Due to the differences between them the results are not easily comparable from month by month. Detailed analysis of the results of the market demonstration have been concluded and presented in Deliverable 7.3, specific to the scientific results of the Spatial Aggregation of Local Flexibilities local grid services market platform. However, some further metrics have been defined and continuously monitored to check the performance and credibility of results:

1. **Calculation time** indicates whether there are any infeasibilities in the mathematical model. Although there were some extreme cases, as the time limit of the solver were set to 15 minutes (900 seconds), the solution was always found before it was exceeded – on the whole one-year period demonstrated.

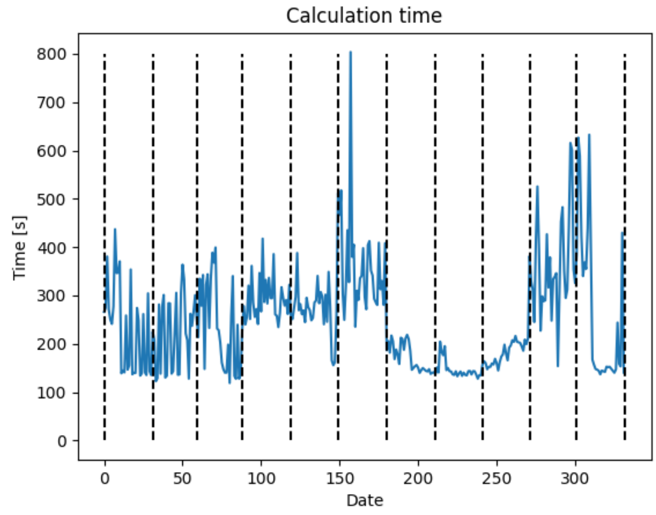

Figure 5: Calculation time of each market auction – all being in the 900 s time limit during the demonstration period

2. **Welfare** is the objective value of the optimization. As scenarios usually altered only slightly in the previous case, the welfare values were expected to be in the same magnitude. It was kept steady during the whole demonstration, as the following figure illustrates:

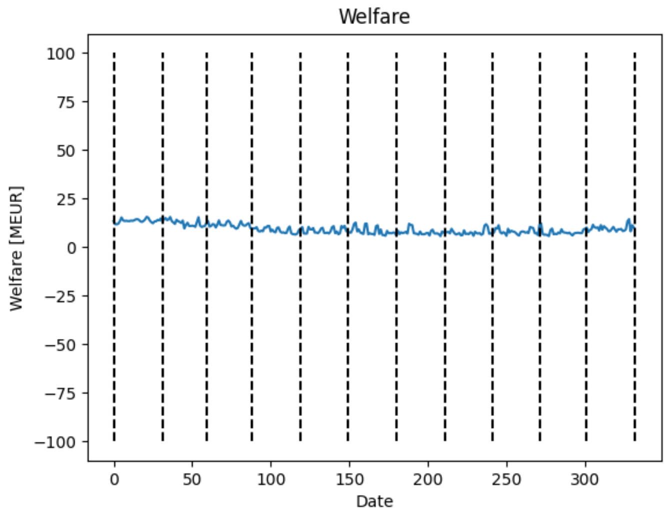

Figure 6: Figure Welfare of the daily market auctions

3. Feasibility of resulting energy market clearing price (MCP), including all stressed scenarios of various demand and supply extremities – in all cases the calculation converged and resulted in overall, quarterly energy prices (here represented without the local congestion price differentiation) still inside of acceptable price ranges, even in the cases of negative prices (as the basecase run is centered on Calendar Year 2020 market datasets, with low pandemic demand of the demonstrated area).

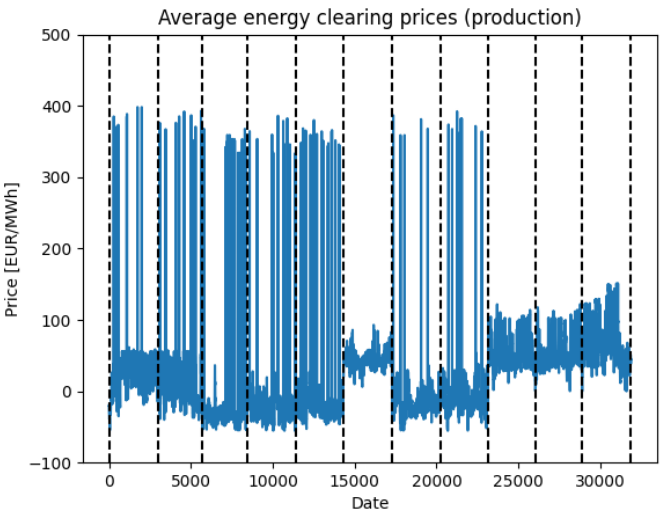

Figure 7: 15-min. clearing prices of all demonstrated runs of specific scenarios (M01-M12 – 35040 quarters of hour)

4. Finally, the **average additional capacity price (ACP)** is the last metric used for real-time monitoring. This price is indeed the most significant value of result to demonstrate the success of the project goal. With the exception of a few time units in the end of the simulation, the ACPs were always around 0-3 EUR/MWh.

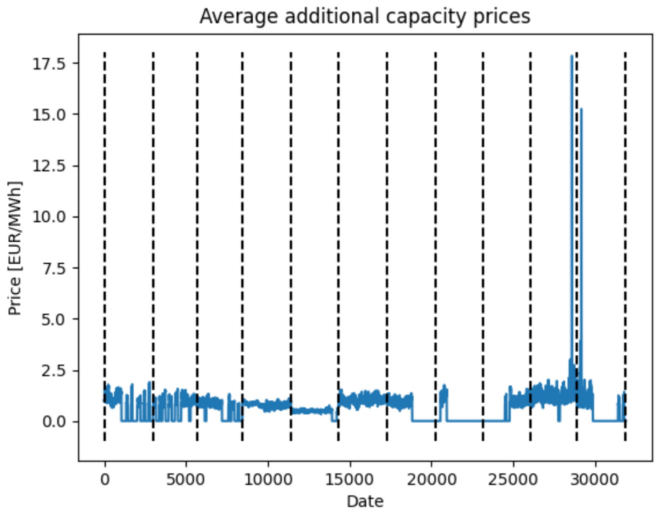

Figure 8: (PUN-pricing alike) Additional flexibility prices allocated to cleared consumer bids – mostly marginal payment increase observed

3.5.2 7-1 Gathering of required data

All data used for demonstration are obtained from the Romanian TSO, no simulations were used at all. However, some scenarios required additional data (e.g. location of order in the power system), that were not available at all due to privacy. These kinds of data were generated indeed but these assumptions did not influence the market structure. Further some stress scenarios were also defined to evaluate the robustness of market structure when the original base-case data were adjusted and modified accordingly. The scenario development along with the way of configuration was defined in T7.2's internal Scenario development document – circulated among TSO, DSO and market participant (aggregator generation company ALTEO) Demonstration Partners.

3.5.3 7-2 Formation of realistic scenarios and recommendations

Spatial Aggregation of Local Flexibilities market demonstrator relies on market scenarios, coordinated with demonstration partners. The general framework relies on the following principles and is specific, both for the basecase and the modified scenarios to ensure realistic market order book depth, bid granularity and all market specific ranges of parameters, based on parallel, existing market datasets:

- All the input data was formed from real market data of the Romanian day-ahead market, intraday market and balancing market. Only order transformation has been used that was necessary and inevitable to create an input for the advanced market with the new zonal feature.
- The Romanian DSO zones in the market simulation were created according to the current topology. Moreover, interconnections between DSO-DSO zones were defined according to the Romanian topology. TSO-DSO interconnections are not limited as usually in reality.
- The proposed market platform uses existing market concepts – it is auction-type as the current day-ahead market, and it can be fitted to the current electricity market timing: before the beginning of the current intra-day market on D-1, after the day-ahead, balancing and schedule formation.
- There is a prequalification process implemented if a new market player is willing to offer flexibility, similarly to the currently existing balancing market accreditation.
- There is a trading platform that has similar functionalities as the existing platforms – it provides bid managing and checking for market participants and it runs bid validity checks (e.g. format). System operators can provide information about available transmission capacities. The market algorithm runs also within the same time limits as the currently used ones provide solution in approximately 15 minutes.
- When price of input orders is changed, it is also implemented as it could have been given in reality. For example the order book contains most orders with the same demand and supply price as well as with equal quantity if they were paired immediately after placement.

Scenario name	Description
M01 basecase	Base case dataset for comparison.
M02 linked case	Special linked orders are generated to connect E/U/D products.
M03 otm DAM	Only out-of-the-money DAM orders are kept.
M04 improved IDM	Prices of IDM orders are modified to promote more trades
M05 local BC	BC orders are matched to zones by market participants, not randomly.
M06 otm BC	Only out-of-the-money BC orders are kept.
M07 TSO	TSO zone is demonstrated.
M08 congested	Network capacities are limited between DSO zones.
M09 congested ++	Network capacities are more limited between DSO zones.
M10 congested TSO	Network capacity is limited between DSO and TSO zones
M11 unbalanced	Energy orders are sorted to zones in an unbalanced way.
M12 unbalanced congested	Energy orders are sorted to zones in an unbalanced way, and network capacities are also limited.

Figure 9: Scenarios of Demonstration Spatial Aggregation of Local Flexibility market

As per the individual scenarios, specific considerations ensure the applicability and relevance of the configurations used in the Configurable Order Converter for the local market demonstrator, as follows:

- All scenarios test realistic assumptions but changing only one parameter at once according to the ceteris paribus method chosen, in order to investigate the effect of each of them on the outcome.
- There are cases with (M08-10, M12) and without network constraints. This as just like in reality – there are time periods without any congestions while there can be periods with congested network elements between zones.
- M01: base case: IDM orders are always submitted before 8PM D-1 according to the proposed timing of the developed market.
- M03: keeping only out-of-the-money DAM orders is justifiable supposing that only these orders would be present on such an extra market.
- M04 incorporates the modification of IDM orders as described above
- M05: balancing orders are matched to zones by market participants that is possibly realistic at the demo area. However other distribution of balancing bids were also tested to check its effect on the results.
- M06: It is also justifiable to keep only the BC orders, as the timing of the proposed market is after the day-ahead balancing market so it can be supposed that only these orders will be available for this zonal market.
- M07: a TSO zone is also implemented. It is realistic because flexibility generators can connect also to the TSO’s transmission grid and thus are less capable for DSO flexibility supply but accredited for system-level balancing (providing aFRR/mFRR or RR to the TSO).
- M08-10: the effect of different congestions is tested – limitation between DSO zones with two different extent as well as limitation between DSO and TSO zones.
- M11: Energy orders are sorted to zones in an unbalanced way. It tests the effect of uneven source distribution as can be in any real market and probably also in the Romanian demonstration area.
- M12: Simply to realistic attributes are mixed and tested together – uneven energy order distribution and limited network capacities.

However, some simplification and alignment was necessary to ensure a continuously operating demonstration in a novel market configuration. To ensure liquidity of DSO zones and the demonstration of the main novelty of the local market, the PUN-average based zonal pricing, balancing orders were sorted to DSO zones – individual, bid level generation pricing is not available due to business sensitivity reasons. This simplification still allows to test the market robustness and validity of pricing rules in a real market bid range. DSO flexibility demand was also exaggerated and proportionated according to zonal supply as current operational standards ensure smooth power supply without frequent grid congestions. These necessary adjustments were discussed and accepted among INTERRFACE participants and were ensured to form realistic scenarios among the basecase, one-year period of demonstration, to analyse the validity and applicability of the new local market products, bids and pricing rules.

3.5.4 7-3 Number of possible trades due to the new algorithm of PUN-like price averaging based solution

The main scientific novelty of the new clearing algorithm is the technique that makes it possible to redistribute some of the energy buyers’ expense to cover the costs of capacity (flexibility) requirements. This PUN-like technique operates in three conceptual steps:

1. the energy demand price is allowed to be higher than the energy supply price;
2. the incomes and expenses of all submitted orders are calculated;

3. the equality conditions of incomes and expenses are formulated including the crucial redistribution mentioned above.

The number of trades that are possible due to the new clearing algorithm is substantial. The entire capacity sub-market would be unavailable without this feature because it provides the necessary cost financing for accepted capacity bids. Consequently, every allocated capacity bid can be taken into account during this assessment.
It has to be noted that the capacity sub-market is one-sided in the algorithm; the demand side is represented by quantity constraints (leading to price-taker demand representation) instead of uniquely priced orders. For this reason, only the number of accepted supply bids is relevant. The total number of submitted and accepted upward supply orders in each month is depicted below:

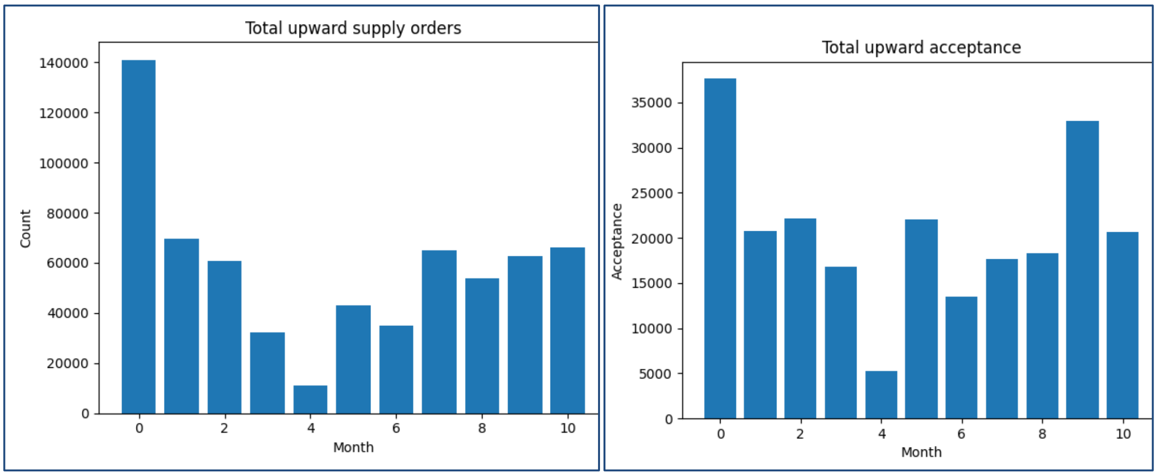

Figure 10: Total number of upward local flexibility orders – submitted and accepted

The aggregation of absolute number of orders can be represented to be scaled according to the demanded quantity. This results in a quasi-smooth acceptance rate of upward flexibility bid in each demonstration month (M2-M12 numbered from 0...10 on the next figure).

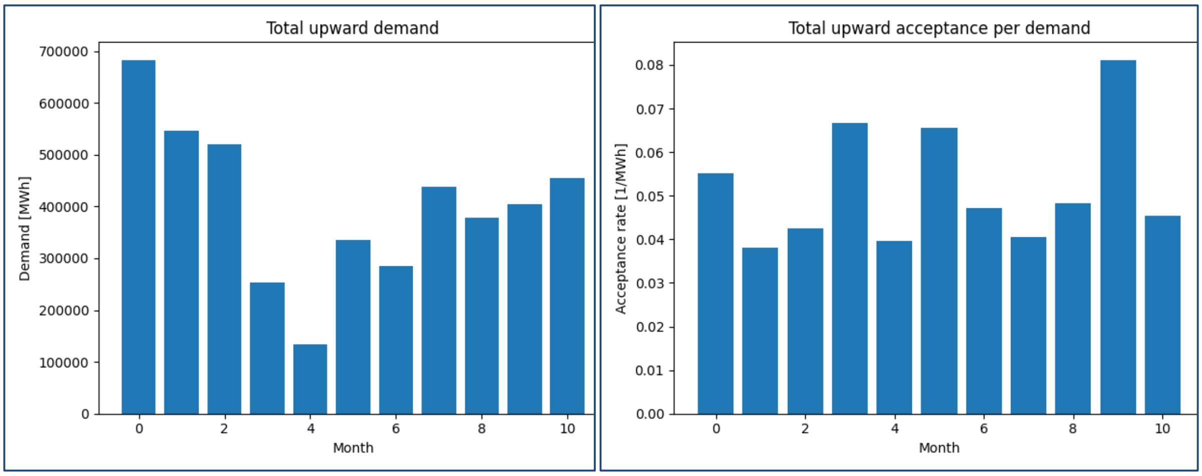

Figure 11: Upward local flexibility (capacity) product demand and the resulting number of accepted additional bids – renormed for demanded MWh – the indicator for new trades to be find and bound with the auction algorithm

4 Techno-economic analysis - Recommendations

4.1 Task 7.1

This Demo aims to develop a systematic modeling framework for the optimal operation of both DAM and BEM, including the participation of DERs in both energy and ancillary services provision. The following points are the main lessons learned from this demonstrator:

- Pilot has demonstrated a high potential for DERs participation in energy and reserve markets in high-RES power systems due to the significant flexibility capacity. Still, an increased DERs participation at a pan-European level -having different technology requirements and applications in the provision of flexibility- will potentially require harmonising product definitions and effective inter-operability among different markets to unlock DERs' full flexibility potential.
- On the other hand, dispatchable generation could also help the provision of balancing and congestion management services, as well as smoothing extreme fuel price fluctuations. The challenge for IEGSA replicability would be to accommodate whatever type of technology as per the generation/flexibility portfolio exists at different network locations. To this end, harmonized rules for aggregation should provide an effective way to cluster flexibility means for the optimal provision of services to System Operators.
- In scenarios of combined high fuel and CO_2 emission prices and/or low net demand, the role of DERs is further highlighted, facilitating the power system operation.
- The combination of extensive hydropower resources along with RES and DERs has the potential to result in zero-carbon power systems. Energy storage systems play a major role, among the DERs, in the provision of operational congestion management capacity, as well as the role of EVs is complimentary and noticeable in some scenarios.
- In the absence of significant hydropower resources, natural gas can act as a bridge for satisfying a share of aFRR, mFRR, and congestion management requirements. In general, thermal power units play a secondary role in operational congestion management capacity provision coverage. When this is combined with limited hydropower resources, DERs play a decisive role in the coverage of that service at both TSO and DSO levels.
- Thermal and nuclear power units, operating as baseload power plants, can guarantee robust power system operation in cases of extreme fluctuations of natural gas fuel price and/or peak loads, offering a share of FCR and mFRR services. However, one of the most crucial factors regarding the capability of nuclear power plants to participate in the balancing market is the amount of its technical minimum (compared to its technical maximum) as well as their capabilities in ancillary services provision. Unless there is flexibility potential, it runs the risk of being shut down in the balancing market.
- Additionally, during this pilot, extensive modeling and computational efforts were required. In terms of IEGSA scalability, computational performance and data handling capabilities should be carefully considered, as operational processes will compute a significant amount of data.
- Finally, data transparency requirements should also be defined to ensure optimal interaction among ENTSO-E Transparency Platform and other bodies to provide transparent and predictable information for current and future flexibility owners.
- The participation of all resources (thermal, hydropower, DERs) into the coverage of TSO-DSO shared requirements (Market Design C - Integrated TSO-DSO congestion management-mFRR service) leads to significant decreases in the market clearing prices of that service in comparison with the other cases (Market Designs A and B).
- Within the market coupling concept, more systematic coordination of the overall EU electricity supply security can be guaranteed through tighter EU monitoring of the National Energy and Climate Plans' design to form complementary energy mixes.

- In a zero CO_2 emissions world, single market integration will become of top priority in order to reach the climate and security of supply goals at a minimum cost. Completing the internal energy market and adopting the appropriate market design is of paramount importance.
- An increase in aggregated DERs supply is of considerable importance as even a minor rise is able to cause a disproportionate price impact because of the low short-run elasticities of electricity demand.
- Under the energy transition concept, there is a need for diversified energy mixes. The move towards greater electrification (sector coupling) and the investment pace in renewables, nuclear power, energy storage, network, and interconnections must be accelerated.

4.2 Task 7.2

The demonstration has been presented in detail in a dedicated Deliverable 7.3, to summarize the innovative elements, new services and market processes of the market design, the data flow and tools description in order to carry out the analysis results of the market runs. The specific takeaways are summarized in this section.

4.2.1 Year-round continuous run results

Based on the input, Romanian DAM/BAM/IDM actual market bids in a full order book with 15-min. granularity products are derived. The results show the interlinking of the various new features of the demonstrated market solution:

- differentiation of MCP and CCP – specific clearing prices, surcharges to cover flexibility need
- effect of local flexibility need on zonal clearing prices
- small mismatch of payments resulting in non-zero DSO contribution for the procured flexibility capacity
- favorable performance results on optimizing high-volume offer book acceptance ratios

The results show the underlying dynamics of the energy market, with accurate clearing price ranges of 0…80 EUR/MWh, for the historic 2019-2020 datesets. Specifically, Figure 12 shows a time series of boxplot distribution (upper/lower decile and quintiles, along with the averages) of one year results, ordered into a daily average figure.

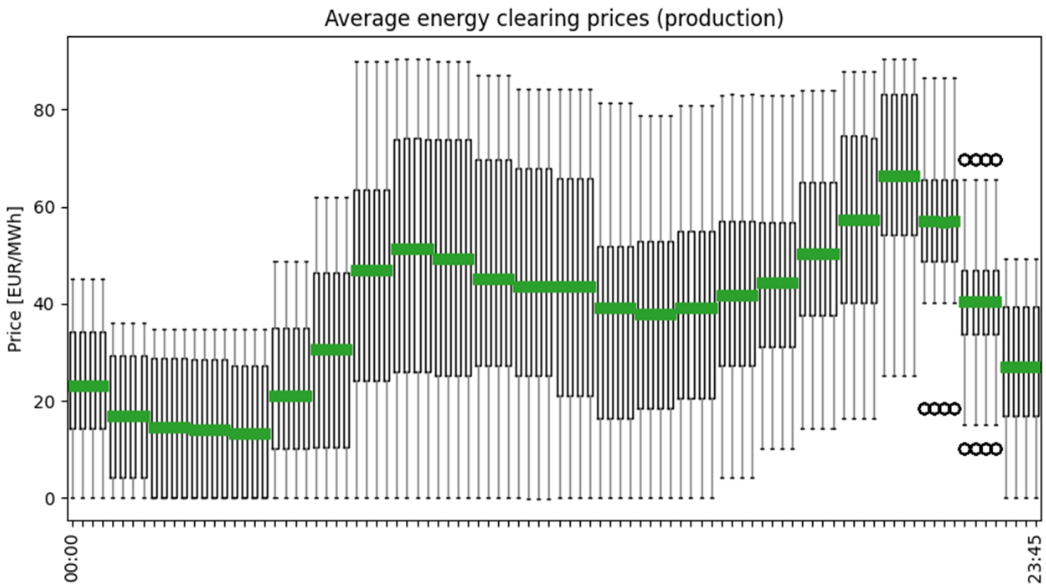

Figure 12: Distribution of quarter-hour energy clearing prices (MCP) – for M01 base case scenario

The average consumption energy clearing prices change where the CCPs of different zones deviate as expected, due to the different total cost allocated. TransN zone has the largest balancing capacity cost, therefore it is the most expensive for consumers to buy on the zonal market, even without cross-zonal congestions.

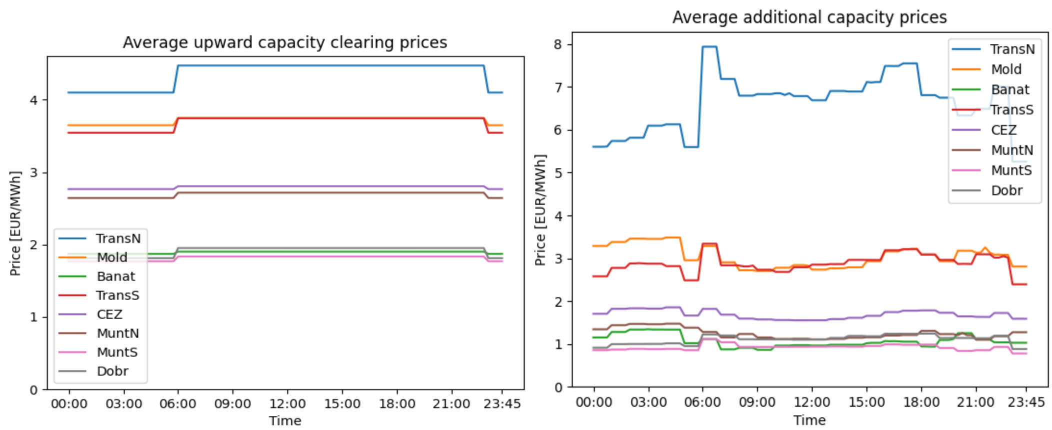

Figure 13: Daily average upward capacity clearing prices, and the resulting capacity fee component in the energy clearing prices – from one full year on M01 scn.

Also, Figure 13 presents the average upward capacity clearing prices and surcharges for each zone. As the flexibility supply is related to the BAM orders, its pricing is connected to its product structure of peak / off-peak timing distributions. TransN leads the average cost of additional quarter-hour cost among the various ones. The relations of zonal additional capacity prices – ACPs are similar to the relations of zonal CCPs. This also expected as the MCP on the supply side is identical. As these DSO zones are indeed quite small, there is a notable surcharge to the MCP, around 1-8 EUR/MWh for every MWh energy exchanged. This covers the need for local flexibility capacity procurement payments, to handle operational congestion management services needs. The summed payments of all participants of the market (= payment balance constraint), that also includes the total amount of DSO contribution to the flexibility demand show that in practice of 0…50 EUR/day. Thus with this unavoidable algorithmic relaxation this contribution is very small or even negligible (compared to the range of 4-8 million EUR total social welfare attained each day by the market auction in this scenario). This is expected and actually desired if the market is liquid enough, so the algorithm is demonstrated to provide a viable solution to the complex cost-averaging principle extension of the EUPHEMIA-algorithm based market auction.

4.2.2 Strained scenario runs (D2 set): M02…12 cases

Various differentiations of scenarios are set to underline one specific change in the market inputs, algorithm feature (such as linking of energy and capacity product on the individual supplier side) or network congestion and other variables for a sensitivity analysis. The most notable observations of each specific scenarios, focusing on the design variables.

1. *localbc:* The 10 BAM (mFRR/RR qualified) market players are specifically assigned to a specific zone thus the capacity demand/supply more greatly varies, approx. between 0…5 EUR/MW/h.

2. *linkedcase:* to test the energy and U/D reserve offers linking into exclusive sets - In this case new, conditional energy bids are strengthening the supply side of the energy products. The overall benecifical liquidity is notable, especially in MuntN (with larger consumption), the capacity cost is distributed among more energy demand bids, thus lower surpluses (ACPs) are needed. Matched energy consumption is higher, subsequently, due to lower CCPs. Zones where there are many capacity orders – especially MuntN – become exporters of their extra capacity. However, no notable differences were observed on the local flexibility market prices and volumes.

3. *otmdam:* only bids not cleared on the DAM are considered - Energy prices are substantially lower than in alternative scenarios, as the underlying energy order book is different. Negative prices occur in most hours during the day. This suggests that the energy demand is very small or sometimes even non-existent on the market. Average additional capacity prices are very high compared to the production prices (MCPs), due to very low cleared volumes. This result is specific to DAM and IDM liquidity on the Romanian market, as the latter is being outweighed by orders of magnitude in the demonstration period.

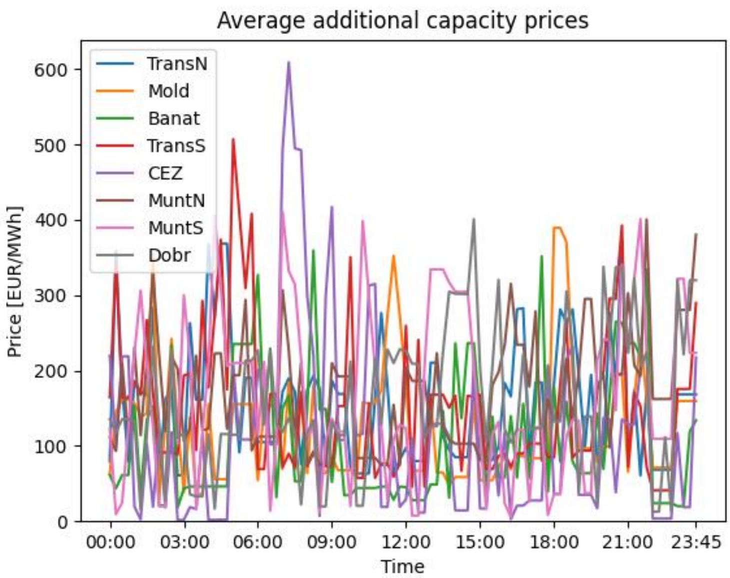

Figure 14: The daily average capacity surcharge in case of M04 – OTM DAM scenario

It is interesting to note, that in the objective function on several days of this scenario, the punishment term is larger than the surplus of the market. That results in some days to have negative welfare values. This necessity of SO contributions makes the clearing problems more difficult. This causes longer, but still manageable solution times, even in this extreme unbalanced supply-demand cases.

4. *improvedidm:* IDM bids are modified, differentiated with uniform distribution to find robustness effect of intraday forecasts on the market - even 2-5 EUR/MWh (>10%) modification has a small (<1 EUR/MWh) effect in zonal MCPs. The direction of the changes depends on secondary factors, such as underlying price distributions, net position of the zones, slopes of the price curves.

5. *otmbc:* not matched balancing energy market bids are part of the supply and demand consideration for flexibility need. The effect of capacity modifications is relatively small on the much larger energy market. The reduction in capacity cost makes it possible to accept slightly more expensive energy supply bids. This underlines the need of joining energy market products to flexibility market to have a more liquid and efficient market tool, also stabilizing resulting prices and market volatility.

6. *tso:* A disjunct TSO zone is formed to create an additional pool of flexibility available (10%), as a precursor for the following three congested, and the M12 scenarios. Yet no significant changes in prices, energy allocation or capacity allocation.

7. *congested:* All DSO interfaces are congested – 60% cross-zonal transfer reduction

8. *morecongested:* All DSO interfaces are congested – 80% cross-zonal transfer reduction

9. *decoupled:* All DSO interfaces are non-operational – 100% cross-zonal transfer reduction

Congestions occur in these three scenarios, deliberately, to test the algorithm capabilities, as illustrated in the following Figure:

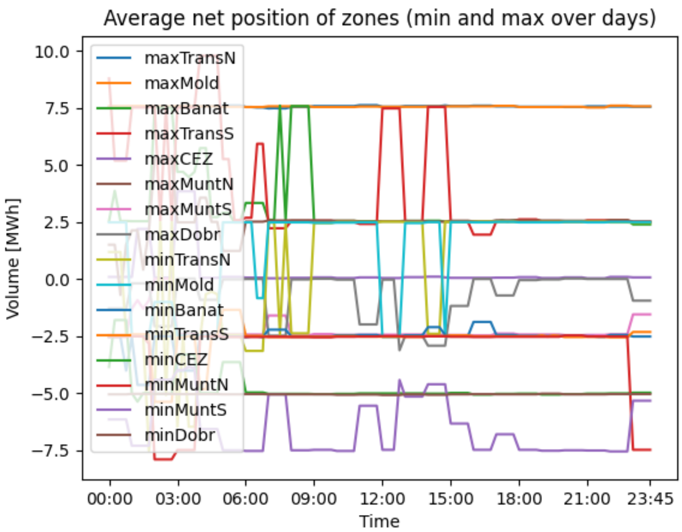

Figure 15: Net position of zonesin M09 scenario, with congested scheduled zonal positions (flat line)

For M08-M09-M10, the importing zones have ever smaller energy liquidity, therefore their ACPs become higher. The opposite is true for exporting zones.

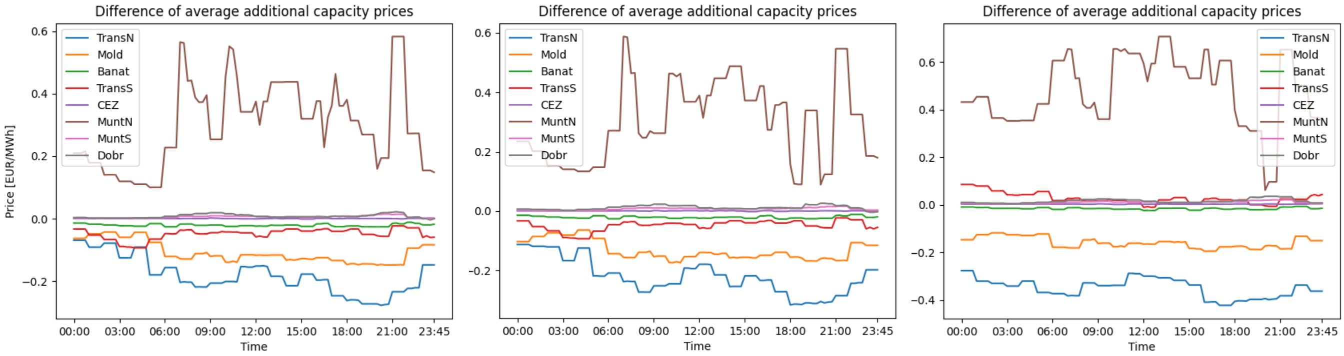

Figure 16: Comparison of capacity surplus fees in M08-M09-M10 scenarios, with increasing congestions

10. *unbalanced:* Different allocation of zonal configuration (modified recombing of offers, more to the first and last zones)

11. *unbalancedTSO:* A modified DSO allocation with a single TSO zone (M11+M07 combination)

The overall effect in these last two scenarios energy prices is small. The number of energy bids is reduced in MuntN and TransS, therefore the same capacity cost requires a larger ACP to cover it. The opposite is true for TransN and Mold with increased number of energy bids and smaller ACPs. MuntS and Dobr have larger amounts of energy bids but they have essentially no capacity allocation, therefore their ACPs remain zero. The distribution of energy bids is changed, therefore the consumption pattern is modified as well.

4.2.3 Aggregated results of all M01…12 scenarios

Performance of the market optimization platform for all scenario configurations

A specific part of the development was to carry out the optimization of the market algorithm. With the fine-tuning, several approaches were investigated, to tune the AMPL/CPLEX solver and the applied metaheuristics. Regular, basecase market situations do not necessarily result in difficult optimization problem, as the increased liquidity around the optimum point facilitates the solver progress showing a 'smooth' solution space. Average solution times, already presented in the monitoring section (Figure 5) were in the acceptable range for a auction typed energy market, even with realistic numbers of individual bids and complex constraints handling multiple products and dual variable (pricing) peculiarities of the demonstrated market design.

In details, as Figure 17 shows, even the most difficult M04 case, with hugely imbalanced supply-demand curves can be consistently solved by the optimization model of the demonstrator. Calculation times have substantial variance in between specific day and scenarios. It is important to underline, that performance can be improved with higher scale hardware environment, given the flexibility of the underlying general optimization (AMPL/CPLEX) platform used in the demonstrator. To derive the required performance, no high-performance, multi-core assets were necessary for these real-market complexity scenarios consisting of 60,000 – 100,000 bids with complex PUN based pricing rules per auction.

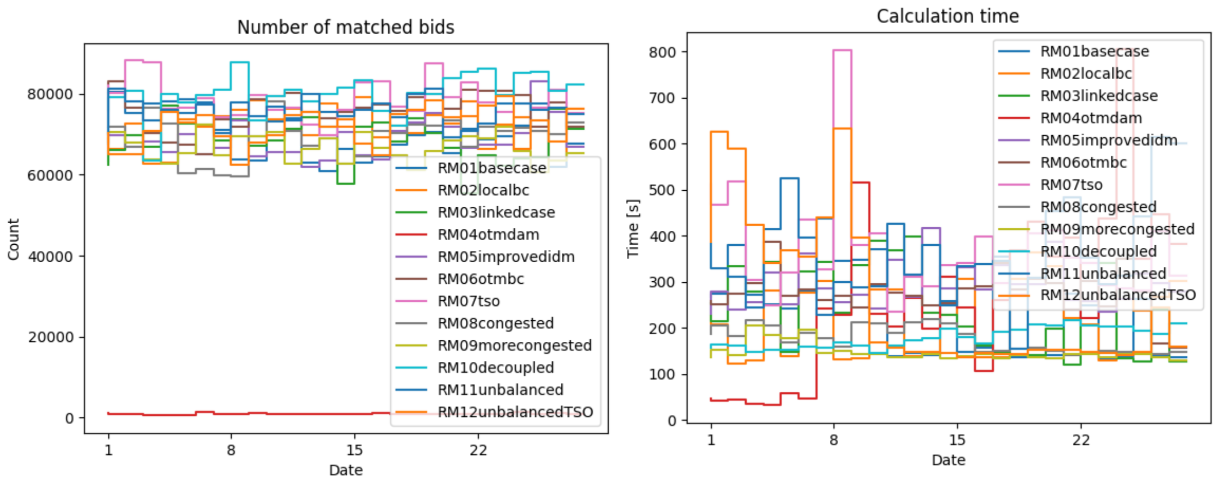

Figure 17: The number of matched bids and the required optimization calculation time in D2 scenario sets

COMPARISON OF THE MARKET RESULTS OF ALL SCENARIOS – PRICE AND COST INDICATORS

Comparing all 12 scenarios, the most striking difference is the final, production market prices, as some of the scenarios resulted in modified supply-demand balances. The OTMDAM scenario has a completely imbalanced aggregate curves, thus it results in significantly negative prices, and high supplementary price parameters to cover DSO flexibility requirements.

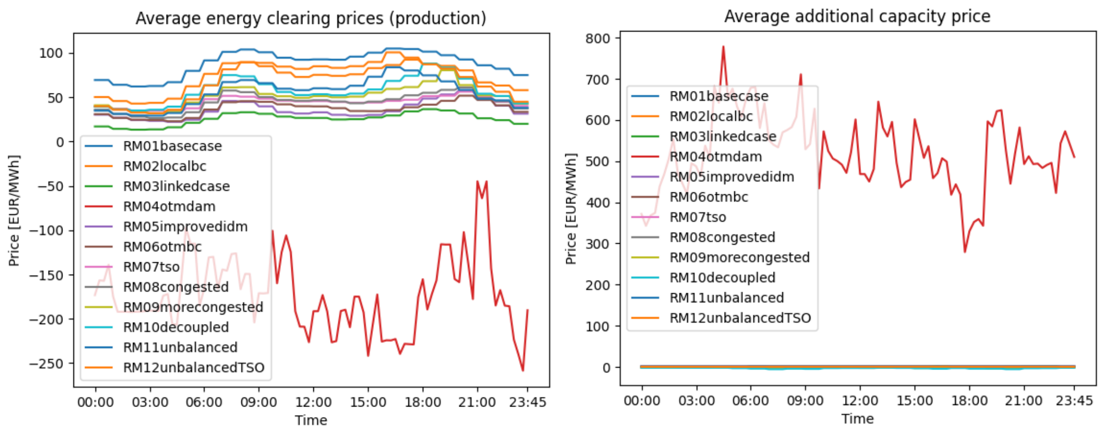

Figure 18: Average energy production clearing prices and capacity markup on energy bids in all scenarios

Another indicator of demand-supply mismatch is the total system operator contribution to the CCP-base clearing. As the allocation cannot find enough quantity as cost bearing volume, the M04 case skyrockets in the necessary operators' payments – up to 40.000 – 50.000 EUR/day, despite the penalty terms in the objective function. The result underlines the sensitivity of the market design to the total liquidity of the market.

4.2.4 Assessment of achieved indicators and results

The above inidicators and results underline the key achievements of the Demonstrators.

Market design: The connection of the global-TSO and the local-DSO dimension and the joint allocation of energy and local flexibility provides proper price incentives through coupling different slices of trading. The resulting market model is tuned to incentivize local flexibility by enabling local participants to bid on a connected TSO-DSO market. PUN pricing can be efficiently extended to have energy and flexibility capacity products to distribute costs incurred from local flexibility procurement. Out of this pilot, it is considered that the zonal approach is the preferred way in the European markets, even in the case of DSO constraints, as a possible, manageable, gradual development of the wholesale market.

Platform, software tool: A single framework is delivered that combines energy-only participants, TSO, DSO, and local flexibility providers in a holistic market approach. The platform supports different market participants to access the market easily. The IEGSA platform accelerates and opens the possibility for different scales of aggregation. The advantages of the common IEGSA platform:

- Prevents overbooking of flexibile resources even if they participates in multiple markets (e.g. DAM, IDM)
- Flexibility providers have a single system to report their availability
- TSOs/DSOs have a single access point to reach the market platform for market-based congestion management services
- Provides a standardized data exchange interface for the market messages

Stakeholder perspective: Price incentives are aligned, as multiple stakeholders observe single energy and capacity prices according to their location expressed in various congestion zones. According to the SO needs, the market provides short-term congestion management services as its primary grid service. It also offers the opportunity to trade energy in a more refined 15-min. delivery periods while allowing pricing of internal congestions according to corresponding Capacity Allocation and Congestion Management Network Code. Multiple use cases can be used using a single market platform, including local flexibility supply incetives, energy and capacity simoultaneous bidding with linking, TSO congestion management with market based energy product procurement. Usually idle local flexibility is available for DSO demand but if not needed, flexibility is marketed on wholesale level.
The advantage of using a single market platform for different spatial dimensions is to have a unique and integrated trading platform. The harmonization is based on the flexibility register and the common data structure that is required to apply. With this IEGSA based approach, a single solution is applied to the various grid users and system operators to register themselves to the market.
Price incentives are aligned, as multiple stakeholders observe single energy and capacity prices, according to their location expressed into various congestion zones. The same product for different services approach delivers proper alignment of the market flexibility resources cleared thus committed at the same timeframe, for the same delivery period. The coordination of TSO and DSO needs can be aligned with the usage of incentivizing price determination, capable of relieving the grid tariff cost burden from local flexibility markets.

Obstacles identified in further deployment: Current SO practices usually lead to small occurences of local flexibility demand, due to the firm delivery obligation prevalent in the electricity connection contracts. The general approach of investing in physical assets to meet worst case network demand lead to little experience in tight, congested network states, in the case of the demonstration area of Romania. Supply of possible flexibilities, however, can be channelled from the currently detached, parallel energy and balancing market workflows, as they have compatible product definitions with the demonstrated approach of the integrated two-product + multiple service based approach with holistic optimization.
Regulatory framework currently strictly define responsibilities of each system operator, which discourages flexibilty innovations to have a large scale demonstration, based on the service demand side. Supply of market bids also constrained, as the bidding of market players fully constitue as business sensitive processes with high value.

National regulatory barriers shall be lifted to enable demonstration in operational environment; TSO-DSO responsibilities shall be set, to accept a cross-zonal platform -in operation. While TSO-DSO interoperability is enabled by IEGSA platform on the technical level, legal and business 'push' is needed to move forward in delivering additional market solutions to the operational frameworks.
Regulatory barriers of intraday market timeframe (auction based or continous trading dilemma) and slow adoptation of local flexibility services and products and specific market regulations (cf. DSR Framework Guideline for Regulation has only been released by ACER in December 2022) does not foster the adoption of new flexibility solutions either.

5 Conclusions

This document provides a comprehensive summary of the WP7 of the INTERRFACE project and summarizes the progress and results of Demo Area 3 "Pan-EU Clearing Market demonstration" which includes Task 7.1 "DERs into Wholesale" and Task 7.2 "Spatial aggregation of Local Flexibility" Demos.

The objectives of the work package are to:

- Demonstrate **innovative market platforms** that promote DERs participation in wholesale electricity markets.
- Illustrate **market coupling scenarios** among Romania Bulgaria and Greece with **clear price signals and DER flexibility potential.**
- Simulate effects of DSO-usage of **local flexibility resources** on bidding zone market outcomes, by **using shadow-prices** to determine order clearing prices **and EUPHEMIA algorithm.**
- **Evaluate the proposed market platforms** to provide recommendations for the evolution of EU electricity markets.

5.1 Task 7.1

In this task, the experience gained during the demonstration period has been reviewed and evaluated to provide recommendations for improving the pan-European electricity market. The market effects from the active participation of DERs in the market operation are presented and evaluated. The evaluation in this task has been conducted in coordination with WP3 on market design to provide a detailed roadmap of how the demo benefits satisfy the customer needs and will be channeled into a future pan-EU market evolution plan.

Based on the results obtained, there is significant potential for DERs' market penetration. Apart from their participation in the balancing market by providing upward and/or downward through the charging-discharging cycle of both ESSs and EVs, their role is also important in the coverage of operational congestion management capacity services at both TSO and DSO levels. Depending on the net demand level of each system having an impact on the number and the operational capacity level of the online nuclear and hydrothermal power units, the amount of CO2 emission and natural gas fuel price affecting the economic competitiveness of the thermal power units, as well as the level of interconnection capacities providing flexibility for increased cross-border trading, DERs can play a decisive role on the coverage of the congestion management capacity services which can reach 100% of the total in several cases. In addition, in the absence of significant hydropower resources, the market participation of DERs is of paramount importance for the procurement of congestion management capacity services in future power systems with a high percentage of RES. Under cases of significant RES availability leading to days of very low net demand, the market participation of DERs is considered necessary for the full satisfaction of downward congestion management capacity services. In addition, when the interconnection capacities with the neighboring power systems are not very extensive, the participation of DERs in the TSO-based services creates the need for additional DERs' utilization at a DSO level in order to meet the congestion management requirements. Another important aspect concerns the value of CO2 emission and natural gas fuel price, which has an impact on the relevant economic competitiveness of thermal power units. This can result in either setting all these units offline, creating additional market space for DERs' penetration, or making those units operational at very low levels, close to their technical minimums, leading to increased downward services requirements to be supplied by DERs.

Last but not least, the operational mode of nuclear power units is of great significance to the power systems operation. If they continue to operate only for energy needs at their total capacity, as is currently the case in the SEE power system, they run the risk of getting offline in the balancing market of high RES power systems due to the high requirements for ancillary services. This includes even more opportunities for DERs' participation in the relevant markets.

To sum up, each EU country must carefully design its own energy mix based on the available resources and interconnection capabilities. However, it is important to stress that under the market coupling concept, more systematic coordination of the overall EU electricity supply security must be executed through more systematic EU monitoring of the National Energy and Climate Plans' design to form complementary energy mixes to maximize the overall welfare. In addition, the increasing electrification of other complementary energy sectors (e.g., heating and transport) creates additional needs for significant RES investments, which go in line with the increased market participation of DERs.

5.2 Task 7.2

As far as Task 7.2 is concerned, the zonal approach is the preferred way on the European markets, as the **spatial aggregation of local flexibility shall considers this method even in the case of DSO constraints**, as a possible, manageable, gradual development of the wholesale market – moving away from the disincentivizing copper-plate approach. With the spread of distributed energy sources, this uniform pricing approach does not lead to the desired, market-based functioning of short-term trading, as the socialization of the network constraints through system usage tariffs lead to inefficient incentives in market prices. Exact congestion locations do vary frequently, thus the applied zonal configuration shall be carefully considered. The advantage of using a single market platform for different spatial dimensions is to have a unique and liquid trading platform.

Zonal congestion management with PUN-like pricing has been demonstrated to provide a solution to system operators solving the local congestion issues and providing a way to participate in the wholesale market, simultaneously. **The connection of both the global-TSO and the local-DSO dimension and the joint allocation of energy and local flexibility provides proper price incentives through coupling different slices of marketing platforms and electricity products.**

The actual benefits are shown in the demonstration and further analysed to provide input of the concluding Deliverable D7.3. Also, market description has been elaborated to facilitate the documentation of the detailing work on the demonstration development. **Additional market design features, such as linked optimization of capacity and energy bids have been investigated, and considered and demonstrated to be readily implementable despite the algorithm complexity, in an exclusive linked order type.** This feature however can be further progressed from this substitution model to a full co-optimization.

Demonstration objectives addressed the key drawbacks that are yet to be overcome in the current, wholesale focused and energy-only market design. Too much complexity would have resulted in infeasible requirements for the animating algorithm and IT platform. New technology and power system specific constraints however are proved to be readiliy introduced to the almost decade-old integrated implicit cross-border auction based market coupling solution, the EUPHEMIA. Holistic mathematical formulation for optimal market outcomes, linking consumers – DSOs – TSOs is possible. The resulting market algorithm is demonstrated to be feasible and computationally tractable, with the added complexity, on real scale (~100.000 bids / auction), market, based on the liquid Romanian DAM, IDM and BAM markets' depth of order books.

5.3 Demo Area 3: Lessons learned and recommendations

- ✓ The preferred method to include spatial dimension and its resolution: Zonal representation is favoured to align the local flexibility and DER focused markets' algorithm to the existing, single day-ahead market auction framework (EUPHEMIA-type market optimization).
- ✓ The resulting single market framework is sensible and intelligible for all market players and includes the DSO specific congestion management services with well-known energy trading auctions.
- ✓ Consideration of congestion management services as additional market product, compatible with a multitude of use cases: single product – multiple (grid) services

- ✓ Increased DERs participation at a pan-European level requires the harmonisation of product definitions and effective interoperability among different markets to unlock DERs full flexibility potential
- ✓ Market algorithm scalability: leverage on existing auction platforms – additional technical constraints can be introduced
- ✓ IEGSA scalability: increased computational performance and data handling capabilities; operational processes will compute significant amount of data; suitable data plaforms are critical elements of energy markets.

The existing, single and integrated European day-ahead auction framework is demonstrated to be suited as a base platform for solving further power system challenges.

ANNEX I. Task 7.1 – Assessment of KPI 7-2 Formation of realistic scenarios and recommendations

Table 4 presents the TSO upward operational congestion management service mix and its daily average marginal price of the Greek power system in each scenario of Market Design A. DERs play a crucial role in several of the scenarios examined. In particular, they participate with a percentage of more than 15% of the total in the coverage of that service in Scenarios 34, 36, 46, 49, 51, 52, 62, 64, 66, 67, 71, 72, 75, 76, 78, 80, and 81. The highest share of 28% of the total is reported in Scenario 81. The common characteristic of most of these scenarios (34, 36, 46, 51, 52, 62, 64, 67, 71, 72, 76, 78, 80, and 81) is that net demand is high; thus, there is increased need for provision from additional resources. When net demand is medium (49, 66, 75), the values of CO_2 emission price and natural gas are at least medium (namely medium or high); thus, thermal power units lose part of their economic competitiveness. In those cases (medium net demand), the value of the interconnection capacities parameter is low, which means that there is more limited flexibility for energy exchanges with the other interconnected power systems.

Table 4: TSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design A

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	30%	70%	0%	2.87
2	31%	69%	0%	2.84
3	32%	68%	0%	3.07
4	19%	81%	0%	2.74
5	35%	62%	3%	2.91
6	32%	62%	7%	3.35
7	34%	66%	0%	2.68
8	30%	70%	0%	3.01
9	34%	63%	3%	3.25
10	42%	53%	6%	3.21
11	34%	66%	0%	2.65
12	35%	65%	0%	3.10
13	48%	52%	0%	2.97
14	29%	59%	13%	4.36
15	18%	82%	0%	2.92
16	19%	73%	8%	3.47
17	32%	53%	15%	3.69
18	35%	65%	0%	2.84
19	35%	65%	0%	3.09
20	30%	61%	9%	3.62
21	37%	57%	6%	3.88
22	46%	52%	2%	2.98
23	32%	68%	0%	2.76
24	42%	49%	9%	3.52
25	34%	66%	0%	3.17
26	27%	67%	6%	3.18
27	36%	56%	8%	3.79

28	33%	66%	1%	3.93
29	36%	57%	8%	3.53
30	22%	78%	0%	2.82
31	11%	89%	0%	3.05
32	21%	68%	11%	3.71
33	36%	61%	4%	3.24
34	33%	47%	20%	3.73
35	33%	64%	2%	2.94
36	11%	69%	20%	3.80
37	38%	58%	4%	4.04
38	36%	59%	5%	4.36

Continuation of **Table 4**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	41%	54%	5%	3.27
40	33%	67%	0%	2.80
41	43%	57%	0%	2.74
42	34%	53%	13%	4.39
43	34%	62%	4%	4.31
44	33%	55%	12%	3.77
45	29%	59%	12%	3.54
46	31%	50%	20%	3.62
47	23%	77%	0%	2.68
48	18%	82%	0%	3.16
49	26%	58%	16%	3.74
50	24%	76%	0%	3.92
51	33%	43%	23%	4.04
52	30%	48%	22%	4.12
53	31%	59%	10%	3.23
54	31%	60%	9%	3.89
55	43%	56%	1%	4.13
56	13%	87%	0%	3.62
57	32%	68%	0%	2.72
58	39%	59%	2%	3.92
59	38%	59%	3%	3.68
60	9%	77%	14%	3.75
61	34%	55%	12%	3.31
62	32%	47%	21%	3.94
63	23%	77%	0%	3.02
64	15%	65%	20%	3.83
65	9%	91%	0%	3.72
66	9%	73%	18%	4.63

67	41%	39%	20%	4.10
68	34%	61%	6%	3.72
69	34%	66%	0%	3.32
70	30%	66%	4%	3.62
71	10%	66%	24%	4.16
72	26%	50%	24%	4.12
73	25%	70%	4%	3.24
74	31%	69%	0%	3.84
75	33%	47%	19%	4.80
76	8%	73%	19%	4.25

Continuation of **Table 4**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	35%	65%	0%	3.39
78	15%	61%	24%	4.26
79	37%	57%	6%	3.65
80	11%	73%	16%	4.28
81	10%	62%	28%	4.72

Table 5 presents the TSO downward operational congestion management service mix and its daily average marginal price of the Greek power system in each scenario of Market Design A. DERs play a crucial role in several of the scenarios examined. In particular, they participate with a percentage of more than 30% of the total in the coverage of that service in Scenarios 1, 2, 5, 7, 8, 12, 14, 15, 19, 21, 25, 27, 31, 37, 42, and 54. The highest share of 48% of the total is reported in Scenario 42. The common characteristic of all these scenarios (1, 2, 5, 7, 8, 12, 14, 15, 19, 21, 25, 27, 31, 37, 42, and 54) is that net demand is low; thus, the online thermal and hydropower units operate close to their technical minimums and as a consequence, they have limited capability to provide downward services and there is increased need for DERs' participation.

Table 5: TSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design A

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	15%	53%	32%	5.98
2	11%	55%	34%	5.27
3	31%	47%	22%	6.27
4	27%	51%	22%	6.06
5	6%	57%	37%	5.38
6	35%	51%	15%	5.81
7	10%	58%	32%	5.30
8	8%	58%	34%	5.51
9	40%	45%	14%	6.24
10	37%	62%	1%	5.78
11	21%	58%	21%	5.97
12	1%	57%	42%	5.80

13	21%	72%	7%	6.21
14	2%	56%	41%	6.65
15	14%	52%	34%	5.08
16	40%	46%	14%	5.93
17	36%	62%	3%	5.47
18	20%	77%	3%	5.71
19	8%	61%	32%	5.66
20	35%	49%	16%	6.46
21	5%	51%	44%	6.84
22	27%	64%	9%	6.12
23	22%	73%	6%	6.12
24	44%	56%	0%	5.45
25	2%	55%	43%	5.58
26	33%	67%	0%	6.12
27	2%	60%	38%	6.62
28	14%	83%	3%	6.57
29	37%	51%	12%	5.77
30	18%	55%	27%	5.08
31	14%	53%	33%	5.49
32	45%	46%	9%	6.42
33	36%	64%	0%	5.73
34	36%	63%	1%	5.37
35	20%	69%	11%	5.85
36	47%	53%	0%	6.00
37	3%	50%	47%	7.21
38	17%	80%	2%	5.90

Continuation of **Table 5**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	37%	62%	1%	5.46
40	38%	62%	0%	5.53
41	27%	71%	2%	6.14
42	1%	51%	48%	7.23
43	21%	75%	4%	6.49
44	14%	86%	0%	6.57
45	41%	48%	11%	5.91
46	37%	63%	0%	5.55
47	32%	64%	4%	5.15
48	16%	54%	30%	5.51
49	36%	48%	15%	6.27
50	0%	100%	0%	4.03
51	27%	73%	0%	4.52
52	35%	65%	0%	5.83

53	27%	71%	2%	6.11
54	4%	58%	38%	6.98
55	15%	83%	2%	6.27
56	2%	98%	0%	4.26
57	29%	71%	0%	5.33
58	15%	82%	3%	7.12
59	8%	92%	0%	6.26
60	45%	46%	10%	6.23
61	28%	70%	2%	5.34
62	37%	63%	0%	5.22
63	30%	56%	14%	5.43
64	42%	58%	0%	5.83
65	1%	99%	0%	4.05
66	1%	99%	0%	4.35
67	21%	79%	0%	4.94
68	10%	89%	0%	5.60
69	7%	93%	0%	4.60
70	17%	83%	0%	6.55
71	35%	65%	0%	4.59
72	29%	71%	0%	5.66
73	33%	66%	0%	5.67
74	0%	100%	0%	4.12
75	2%	98%	0%	4.26
76	2%	98%	0%	3.18

Continuation of **Table 5**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	7%	93%	0%	4.59
78	25%	75%	0%	4.61
79	4%	96%	0%	3.44
80	1%	99%	0%	3.05
81	1%	99%	0%	2.75

Table 6 presents the DSO upward operational congestion management service mix and its daily average marginal price of the Greek power system in each scenario of Market Design A. This service is exclusively covered by DERs. In all of the cases, ESSs have a dominant role on covering that service accounting for around 97% of the total in all scenarios. The participation of EVs is reported in scenarios 17, 24, 34, 36, 39, 46, 51, 52, 62, 64, 67, 71, 72, 78, and 81. The highest share is recorded in scenario 34 with 28% of the total. The common characteristics of all these scenarios is that net demand is high; thus, ESSs are not adequate to cover alone that service and there is increased requirement for EVs' participation on supplementing on that service coverage. It is also worth mentioning that in the cases where EVs contribute to that service with a share less of 10% (with the exception of scenario 81 where they report a negligible share), the value of interconnection capacities is low, stressing again the flexibility provided by the transmission capacities and the increased role of DERs to locally cover the grid service's needs.

Table 6: DSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design A

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	8.18
2	100%	0%	0%	8.18
3	100%	0%	0%	8.18
4	100%	0%	0%	8.18
5	100%	0%	0%	8.99
6	100%	0%	0%	8.18
7	100%	0%	0%	8.18
8	100%	0%	0%	8.99
9	100%	0%	0%	8.18
10	100%	0%	0%	8.20
11	100%	0%	0%	8.18
12	100%	0%	0%	8.99
13	100%	0%	0%	8.99
14	100%	0%	0%	11.28
15	100%	0%	0%	8.18
16	100%	0%	0%	8.18
17	91%	9%	0%	8.29
18	100%	0%	0%	8.18
19	100%	0%	0%	8.99
20	100%	0%	0%	8.99
21	100%	0%	0%	11.28
22	100%	0%	0%	8.99
23	100%	0%	0%	8.18
24	76%	24%	0%	8.30
25	100%	0%	0%	8.99
26	100%	0%	0%	8.99
27	100%	0%	0%	11.28
28	100%	0%	0%	11.28
29	100%	0%	0%	8.18
30	100%	0%	0%	8.18
31	100%	0%	0%	8.99
32	100%	0%	0%	8.99
33	100%	0%	0%	8.18
34	72%	28%	0%	8.32
35	100%	0%	0%	8.99
36	91%	9%	0%	9.10
37	100%	0%	0%	11.28
38	100%	0%	0%	11.28

Continuation of **Table 6**

Scenario	ESSs	EVs	DRPs	Marginal price
39	75%	25%	0%	8.31
40	100%	0%	0%	8.99
41	100%	0%	0%	8.99
42	100%	0%	0%	11.28
43	100%	0%	0%	11.28
44	100%	0%	0%	11.28
45	100%	0%	0%	8.18
46	86%	14%	0%	8.30
47	100%	0%	0%	8.18
48	100%	0%	0%	8.99
49	100%	0%	0%	8.99
50	100%	0%	0%	11.28
51	76%	24%	0%	8.30
52	76%	24%	0%	9.12
53	100%	0%	0%	8.99
54	100%	0%	0%	11.28
55	100%	0%	0%	11.28
56	100%	0%	0%	11.28
57	100%	0%	0%	8.99
58	100%	0%	0%	11.28
59	100%	0%	0%	11.28
60	100%	0%	0%	8.99
61	100%	0%	0%	8.18
62	76%	24%	0%	8.31
63	100%	0%	0%	8.99
64	94%	6%	0%	9.02
65	100%	0%	0%	11.28
66	100%	0%	0%	11.28
67	79%	21%	0%	9.12
68	100%	0%	0%	11.28
69	100%	0%	0%	11.28
70	100%	0%	0%	11.28
71	76%	24%	0%	8.30
72	76%	24%	0%	9.12
73	100%	0%	0%	8.99
74	100%	0%	0%	11.28
75	100%	0%	0%	11.28
76	100%	0%	0%	11.28

Continuation of **Table 6**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	11.28
78	76%	24%	0%	9.12
79	100%	0%	0%	11.28
80	100%	0%	0%	11.28
81	99%	1%	0%	11.31

Table 7 presents the DSO downward operational congestion management service mix and its daily average marginal price of the Greek power system in each scenario of Market Design A. This service is exclusively covered by DERs. In all of the cases, ESSs have a dominant role on covering that service accounting for almost 100% of the total in all scenarios. The participation of EVs is reported in scenarios 12, 14, 21, 27, 37, 42, 54, and 65. The highest share is recorded in scenario 12 with 9% of the total. The common characteristics of all these scenarios is that net demand is low; thus, ESSs are responsible for providing also the corresponding TSO downward service due to the fact that hydrothermal power units operate close to their technical minimums. As a consequence, there is space in order for EVs to contribute to that service coverage.

Table 7: DSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design A

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	8.18
2	100%	0%	0%	8.18
3	100%	0%	0%	8.18
4	100%	0%	0%	8.18
5	100%	0%	0%	8.99
6	100%	0%	0%	8.18
7	100%	0%	0%	8.18
8	100%	0%	0%	8.99
9	100%	0%	0%	8.18
10	100%	0%	0%	8.18
11	100%	0%	0%	8.18
12	91%	9%	0%	9.07
13	100%	0%	0%	8.99
14	96%	4%	0%	11.32
15	100%	0%	0%	8.18
16	100%	0%	0%	8.18
17	100%	0%	0%	8.18
18	100%	0%	0%	8.18
19	100%	0%	0%	8.99
20	100%	0%	0%	8.99
21	96%	4%	0%	11.32
22	100%	0%	0%	8.99
23	100%	0%	0%	8.18
24	100%	0%	0%	8.18
25	100%	0%	0%	8.99

26	100%	0%	0%	8.99
27	96%	4%	0%	11.31
28	100%	0%	0%	11.28
29	100%	0%	0%	8.18
30	100%	0%	0%	8.18
31	100%	0%	0%	8.99
32	100%	0%	0%	8.99
33	100%	0%	0%	8.18
34	100%	0%	0%	8.18
35	100%	0%	0%	8.99
36	100%	0%	0%	8.99
37	97%	3%	0%	11.31
38	100%	0%	0%	11.28

Continuation of **Table 7**

Scenario	ESSs	EVs	DRPs	Marginal price
39	100%	0%	0%	8.18
40	100%	0%	0%	8.99
41	100%	0%	0%	8.99
42	98%	2%	0%	11.30
43	100%	0%	0%	11.28
44	100%	0%	0%	11.28
45	100%	0%	0%	8.18
46	100%	0%	0%	8.18
47	100%	0%	0%	8.18
48	100%	0%	0%	8.99
49	100%	0%	0%	8.99
50	100%	0%	0%	11.28
51	100%	0%	0%	8.18
52	100%	0%	0%	8.99
53	100%	0%	0%	8.99
54	97%	3%	0%	11.31
55	100%	0%	0%	11.28
56	100%	0%	0%	11.28
57	100%	0%	0%	8.99
58	100%	0%	0%	11.28
59	100%	0%	0%	11.28
60	100%	0%	0%	8.99
61	100%	0%	0%	8.18
62	100%	0%	0%	8.18
63	100%	0%	0%	8.99
64	100%	0%	0%	8.99

65	98%	2%	0%	11.30
66	100%	0%	0%	11.29
67	100%	0%	0%	8.99
68	100%	0%	0%	11.28
69	100%	0%	0%	11.28
70	100%	0%	0%	11.28
71	100%	0%	0%	8.18
72	100%	0%	0%	8.99
73	100%	0%	0%	8.99
74	100%	0%	0%	11.30
75	100%	0%	0%	11.29
76	100%	0%	0%	11.28

Continuation of **Table 7**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	11.28
78	100%	0%	0%	8.99
79	100%	0%	0%	11.28
80	100%	0%	0%	11.28
81	100%	0%	0%	11.28

Table 8 presents the TSO upward operational congestion management service mix and its daily average marginal price of the Bulgarian power system in each scenario of Market Design A. DERs play the dominant role in all of the scenarios examined. It is worth mentioning that in the majority of the scenarios examined they comprise the single resource for the coverage of that service. Their minimum share equals 63% of the total in scenario 42. This can be explained by the fact that nuclear power units are assumed that they do not participate in the ancillary services provision, due to the fact that their technical minimum equals their technical maximum, and as a consequence, the model determines their shut-downs in the balancing market leading to increased contribution from hydrothermal power units. This results in minimal capability on covering this upward service; thus, it is mainly met by DERs.

Table 8: TSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design A

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	9%	0%	91%	2.07
2	0%	0%	100%	1.91
3	0%	0%	100%	2.02
4	10%	0%	90%	2.07
5	0%	0%	100%	2.19
6	0%	0%	100%	1.93
7	0%	0%	100%	1.93
8	0%	0%	100%	2.04
9	4%	0%	96%	2.03

10	0%	0%	100%	2.34
11	10%	0%	90%	2.05
12	2%	5%	93%	2.49
13	0%	0%	100%	2.21
14	1%	27%	72%	2.53
15	0%	0%	100%	1.89
16	0%	0%	100%	1.96
17	0%	7%	93%	2.39
18	0%	0%	100%	1.92
19	0%	0%	100%	2.05
20	0%	0%	100%	2.07
21	1%	21%	78%	2.52
22	0%	0%	100%	2.18
23	4%	0%	96%	2.03
24	0%	0%	100%	2.07
25	0%	0%	100%	2.23
26	0%	0%	100%	2.16
27	0%	27%	73%	2.54
28	0%	21%	79%	2.50
29	0%	0%	100%	1.99
30	0%	0%	100%	1.89
31	0%	0%	100%	2.02
32	0%	0%	100%	2.08
33	0%	0%	100%	1.95
34	0%	0%	100%	2.11
35	0%	0%	100%	2.05
36	0%	0%	100%	2.18
37	0%	31%	69%	2.50
38	0%	17%	83%	2.46

Continuation of **Table 8**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	0%	0%	100%	2.07
40	0%	0%	100%	2.16
41	0%	0%	100%	2.19
42	0%	37%	63%	2.56
43	0%	30%	70%	2.48
44	0%	26%	74%	2.49
45	0%	0%	100%	2.07
46	0%	0%	100%	2.03
47	0%	0%	100%	1.89
48	0%	0%	100%	2.02

49	0%	0%	100%	2.17
50	0%	0%	100%	2.38
51	0%	0%	100%	1.96
52	0%	0%	100%	2.18
53	0%	0%	100%	2.05
54	2%	27%	72%	2.50
55	0%	26%	74%	2.48
56	0%	28%	72%	2.49
57	0%	0%	100%	2.17
58	0%	25%	75%	2.47
59	0%	30%	70%	2.49
60	0%	0%	100%	2.02
61	0%	0%	100%	2.03
62	0%	0%	100%	2.04
63	0%	0%	100%	2.02
64	0%	0%	100%	2.17
65	0%	24%	76%	2.48
66	0%	0%	100%	2.38
67	0%	0%	100%	2.07
68	0%	16%	84%	2.48
69	0%	25%	75%	2.48
70	0%	33%	67%	2.49
71	0%	0%	100%	2.03
72	0%	0%	100%	2.20
73	0%	0%	100%	2.13
74	0%	0%	100%	2.38
75	5%	15%	80%	2.48
76	0%	25%	75%	2.46

Continuation of **Table 8**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	0%	19%	81%	2.46
78	0%	0%	100%	2.02
79	3%	19%	79%	2.45
80	0%	18%	82%	2.47
81	0%	20%	79%	2.45

Table 9 presents the TSO downward operational congestion management service mix and its daily average marginal price of the Bulgarian power system in each scenario of Market Design A. As in corresponding upward service, DERs play the most crucial role in all of the scenarios examined. It is worth mentioning that in the majority of the scenarios examined they comprise the single resource for the coverage of that service. Their minimum share equals 98% of the total in several scenarios. This can be explained by the

fact that the hydrothermal power units are mainly responsible for covering the corresponding FCR, aFRR, and mFRR downward services; thus, DERs are kept responsible for meeting the TSO and DSO downward congestion management services.

Table 9: TSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design A

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	0%	0%	100%	1.89
2	0%	0%	100%	1.89
3	2%	0%	98%	1.89
4	0%	0%	100%	1.89
5	2%	0%	98%	2.02
6	0%	0%	100%	1.89
7	0%	0%	100%	1.89
8	0%	0%	100%	2.02
9	2%	0%	98%	1.89
10	2%	0%	98%	1.89
11	0%	0%	100%	1.89
12	2%	0%	98%	2.02
13	2%	0%	98%	2.02
14	2%	0%	98%	2.38
15	0%	0%	100%	1.89
16	0%	0%	100%	1.89
17	0%	0%	100%	1.89
18	0%	0%	100%	1.89
19	0%	0%	100%	2.02
20	0%	0%	100%	2.02
21	2%	0%	98%	2.38
22	2%	0%	98%	2.02
23	0%	0%	100%	1.89
24	2%	0%	98%	1.89
25	2%	0%	98%	2.02
26	2%	0%	98%	2.02
27	2%	0%	98%	2.38
28	2%	0%	98%	2.38
29	0%	0%	100%	1.89
30	0%	0%	100%	1.89
31	0%	0%	100%	2.02
32	0%	0%	100%	2.02
33	0%	0%	100%	1.89
34	0%	0%	100%	1.89
35	0%	0%	100%	2.02
36	0%	0%	100%	2.02
37	2%	0%	98%	2.38

38	2%	0%	98%	2.38

Continuation of **Table 9**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	2%	0%	98%	1.89
40	2%	0%	98%	2.02
41	2%	0%	98%	2.02
42	2%	0%	98%	2.38
43	2%	0%	98%	2.38
44	2%	0%	98%	2.38
45	0%	0%	100%	1.89
46	0%	0%	100%	1.89
47	0%	0%	100%	1.89
48	0%	0%	100%	2.02
49	0%	0%	100%	2.02
50	0%	0%	100%	2.38
51	0%	0%	100%	1.89
52	0%	0%	100%	2.02
53	0%	0%	100%	2.02
54	2%	0%	98%	2.38
55	2%	0%	98%	2.38
56	2%	0%	98%	2.38
57	2%	0%	98%	2.02
58	2%	0%	98%	2.38
59	2%	0%	98%	2.38
60	0%	0%	100%	2.02
61	0%	0%	100%	1.89
62	0%	0%	100%	1.89
63	0%	0%	100%	2.02
64	0%	0%	100%	2.02
65	0%	0%	100%	2.38
66	0%	0%	100%	2.38
67	0%	0%	100%	2.02
68	2%	0%	98%	2.38
69	2%	0%	98%	2.38
70	2%	0%	98%	2.38
71	0%	0%	100%	1.89
72	0%	0%	100%	2.02
73	0%	0%	100%	2.02
74	0%	0%	100%	2.38
75	0%	0%	100%	2.38
76	0%	0%	100%	2.38

Continuation of **Table 9**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	2%	0%	98%	2.38
78	0%	0%	100%	2.02
79	0%	0%	100%	2.38
80	0%	0%	100%	2.38
81	0%	0%	100%	2.38

Table 10 presents the DSO upward operational congestion management service mix and its daily average marginal price of the Bulgarian power system in each scenario of Market Design A. Although ESSs play the dominant role in the coverage of that service, EVs also provide a noticeable part contributing with a share higher than 30% of the total in scenarios 5, 10, 12-14, 17, 21, 22, 24-28, 34, 36, 37, 39, 41-43, 45, 49, 52, 54-59, 64, 69, 70, and 72. The highest share of 94% of the total for EVs is reported in scenario 12. The main reason for the increased service provision from EVs is the high share of DERs on the coverage of the corresponding TSO service; thus, there is an increased requirement from both ESSs and EVs.

Table 10: DSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design A

Scenario	ESSs	EVs	DRPs	Marginal price
1	95%	5%	0%	1.99
2	100%	0%	0%	1.83
3	86%	14%	0%	1.95
4	94%	6%	0%	1.99
5	68%	32%	0%	2.11
6	97%	3%	0%	1.85
7	100%	0%	0%	1.85
8	100%	0%	0%	1.96
9	88%	12%	0%	1.95
10	21%	79%	0%	2.26
11	97%	3%	0%	1.97
12	6%	94%	0%	2.41
13	62%	38%	0%	2.12
14	59%	41%	0%	2.49
15	100%	0%	0%	1.81
16	100%	0%	0%	1.88
17	6%	94%	0%	2.31
18	100%	0%	0%	1.84
19	100%	0%	0%	1.96
20	100%	0%	0%	1.99
21	67%	33%	0%	2.47
22	69%	31%	0%	2.09
23	91%	9%	0%	1.95
24	62%	38%	0%	1.99

25	59%	41%	0%	2.15
26	70%	30%	0%	2.07
27	54%	46%	0%	2.50
28	68%	32%	0%	2.45
29	78%	22%	0%	1.91
30	100%	0%	0%	1.81
31	100%	0%	0%	1.94
32	89%	11%	0%	1.99
33	100%	0%	0%	1.87
34	62%	38%	0%	2.03
35	100%	0%	0%	1.96
36	67%	33%	0%	2.09
37	59%	41%	0%	2.47
38	74%	26%	0%	2.39

Continuation of **Table 10**

Scenario	ESSs	EVs	DRPs	Marginal price
39	65%	35%	0%	1.99
40	71%	29%	0%	2.08
41	66%	34%	0%	2.10
42	49%	51%	0%	2.53
43	65%	35%	0%	2.45
44	75%	25%	0%	2.43
45	60%	40%	0%	1.99
46	71%	29%	0%	1.95
47	100%	0%	0%	1.81
48	100%	0%	0%	1.94
49	68%	32%	0%	2.08
50	100%	0%	0%	2.28
51	95%	5%	0%	1.88
52	65%	35%	0%	2.09
53	95%	5%	0%	1.97
54	62%	38%	0%	2.47
55	65%	35%	0%	2.44
56	60%	40%	0%	2.46
57	70%	30%	0%	2.08
58	69%	31%	0%	2.43
59	62%	38%	0%	2.46
60	100%	0%	0%	1.94
61	71%	29%	0%	1.95
62	71%	29%	0%	1.96
63	100%	0%	0%	1.94

64	69%	31%	0%	2.08
65	72%	28%	0%	2.43
66	100%	0%	0%	2.28
67	100%	0%	0%	1.99
68	71%	29%	0%	2.42
69	69%	31%	0%	2.44
70	59%	41%	0%	2.47
71	71%	29%	0%	1.95
72	62%	38%	0%	2.11
73	74%	26%	0%	2.05
74	100%	0%	0%	2.28
75	80%	20%	0%	2.41
76	71%	29%	0%	2.42

Continuation of **Table 10**

Scenario	ESSs	EVs	DRPs	Marginal price
77	74%	26%	0%	2.40
78	100%	0%	0%	1.94
79	74%	26%	0%	2.39
80	74%	26%	0%	2.40
81	74%	26%	0%	2.39

Table 11 presents the DSO downward operational congestion management service mix and its daily average marginal price of the Bulgarian power system in each scenario of Market Design A. In all those scenarios, ESSs comprise the sole contributor of DSO downward operational congestion management service, since they constitute the most economical option for this and they have the full potential to satisfy it.

Table 11: DSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design A

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	1.81
2	100%	0%	0%	1.81
3	100%	0%	0%	1.81
4	100%	0%	0%	1.81
5	100%	0%	0%	1.94
6	100%	0%	0%	1.81
7	100%	0%	0%	1.81
8	100%	0%	0%	1.94
9	100%	0%	0%	1.81
10	100%	0%	0%	1.81
11	100%	0%	0%	1.81
12	100%	0%	0%	1.94
13	100%	0%	0%	1.94

14	100%	0%	0%	2.28
15	100%	0%	0%	1.81
16	100%	0%	0%	1.81
17	100%	0%	0%	1.81
18	100%	0%	0%	1.81
19	100%	0%	0%	1.94
20	100%	0%	0%	1.94
21	100%	0%	0%	2.28
22	100%	0%	0%	1.94
23	100%	0%	0%	1.81
24	100%	0%	0%	1.81
25	100%	0%	0%	1.94
26	100%	0%	0%	1.94
27	100%	0%	0%	2.28
28	100%	0%	0%	2.28
29	100%	0%	0%	1.81
30	100%	0%	0%	1.81
31	100%	0%	0%	1.94
32	100%	0%	0%	1.94
33	100%	0%	0%	1.81
34	100%	0%	0%	1.81
35	100%	0%	0%	1.94
36	100%	0%	0%	1.94
37	100%	0%	0%	2.28
38	100%	0%	0%	2.28

Continuation of **Table 11**

Scenario	ESSs	EVs	DRPs	Marginal price
39	100%	0%	0%	1.81
40	100%	0%	0%	1.94
41	100%	0%	0%	1.94
42	100%	0%	0%	2.28
43	100%	0%	0%	2.28
44	100%	0%	0%	2.28
45	100%	0%	0%	1.81
46	100%	0%	0%	1.81
47	100%	0%	0%	1.81
48	100%	0%	0%	1.94
49	100%	0%	0%	1.94
50	100%	0%	0%	2.28
51	100%	0%	0%	1.81
52	100%	0%	0%	1.94

53	100%	0%	0%	1.94
54	100%	0%	0%	2.28
55	100%	0%	0%	2.28
56	100%	0%	0%	2.28
57	100%	0%	0%	1.94
58	100%	0%	0%	2.28
59	100%	0%	0%	2.28
60	100%	0%	0%	1.94
61	100%	0%	0%	1.81
62	100%	0%	0%	1.81
63	100%	0%	0%	1.94
64	100%	0%	0%	1.94
65	100%	0%	0%	2.28
66	100%	0%	0%	2.28
67	100%	0%	0%	1.94
68	100%	0%	0%	2.28
69	100%	0%	0%	2.28
70	100%	0%	0%	2.28
71	100%	0%	0%	1.81
72	100%	0%	0%	1.94
73	100%	0%	0%	1.94
74	100%	0%	0%	2.28
75	100%	0%	0%	2.28
76	100%	0%	0%	2.28

Continuation of **Table 11**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	2.28
78	100%	0%	0%	1.94
79	100%	0%	0%	2.28
80	100%	0%	0%	2.28
81	100%	0%	0%	2.28

Table 12 presents the TSO upward operational congestion management service mix and its daily average marginal price of the Romanian power system in each scenario of Market Design A. Due to the significant hydropower resources of that system, hydropower units satisfy almost all the requirements in all scenarios, with a very minor contribution from thermal power units and DERs. With regard to DERs, their share does not exceed 5% of the total in any of the scenarios.

Table 12: TSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design A

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	1%	99%	0%	2.65
2	0%	100%	0%	2.65

3	2%	98%	0%	2.87
4	1%	99%	0%	2.65
5	0%	100%	0%	2.65
6	0%	100%	0%	2.65
7	0%	95%	5%	2.88
8	0%	100%	0%	2.65
9	1%	99%	0%	2.83
10	1%	99%	0%	2.65
11	0%	100%	0%	2.65
12	0%	100%	0%	2.65
13	4%	96%	0%	2.65
14	2%	98%	0%	2.65
15	0%	100%	0%	2.65
16	0%	100%	0%	2.65
17	2%	98%	0%	2.65
18	0%	100%	0%	2.67
19	0%	100%	0%	2.65
20	0%	100%	0%	2.65
21	1%	99%	0%	2.65
22	1%	99%	0%	2.70
23	2%	98%	0%	2.65
24	3%	97%	0%	2.68
25	0%	100%	0%	2.71
26	0%	100%	0%	2.65
27	3%	97%	0%	2.65
28	0%	100%	0%	2.65
29	0%	100%	0%	2.88
30	0%	100%	0%	2.65
31	0%	100%	0%	2.65
32	0%	100%	0%	2.65
33	0%	100%	0%	2.71
34	1%	99%	0%	2.65
35	0%	100%	0%	2.68
36	1%	99%	0%	2.65
37	0%	100%	0%	2.74
38	0%	100%	0%	2.83

Continuation of **Table 12**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	2%	98%	0%	2.65
40	0%	100%	0%	2.70
41	1%	99%	0%	2.75

42	3%	97%	0%	2.65
43	0%	100%	0%	2.65
44	0%	100%	0%	2.65
45	0%	96%	4%	2.88
46	1%	99%	0%	2.65
47	0%	100%	0%	2.65
48	0%	95%	5%	2.90
49	0%	100%	0%	2.65
50	0%	98%	2%	3.39
51	2%	98%	0%	2.65
52	1%	99%	0%	2.65
53	0%	95%	5%	2.91
54	0%	100%	0%	2.65
55	0%	100%	0%	2.88
56	0%	100%	0%	2.89
57	0%	100%	0%	2.65
58	0%	100%	0%	2.65
59	0%	100%	0%	2.67
60	0%	98%	2%	2.90
61	0%	100%	0%	2.65
62	1%	94%	5%	2.88
63	0%	100%	0%	2.67
64	1%	99%	0%	2.65
65	0%	98%	2%	3.28
66	0%	100%	0%	2.71
67	0%	100%	0%	2.65
68	0%	100%	0%	2.65
69	0%	100%	0%	2.95
70	0%	100%	0%	2.65
71	0%	100%	0%	2.65
72	1%	99%	0%	2.65
73	0%	95%	5%	3.04
74	0%	99%	0%	3.39
75	0%	100%	0%	2.85
76	1%	94%	5%	2.94

Continuation of **Table 12**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	0%	100%	0%	2.71
78	1%	94%	5%	2.90
79	0%	100%	0%	2.82
80	0%	100%	0%	2.76

81	1%	96%	3%	2.94

Table 13 presents the TSO downward operational congestion management service mix and its daily average marginal price of the Romanian power system in each scenario of Market Design A. Although hydropower units are again the most significant provider in all these scenarios, the role of DERs is essential, with a share higher than 10% of the total in the scenarios with low net demand (1, 2, 4, 5, 7, 8, 11, 12, 14, 15, 18, 19, 25, 27, 30, 31, 35, 37, 42, 47, 48, and 63).

Table 13: TSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design A

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	2%	73%	25%	4.09
2	2%	82%	16%	4.07
3	5%	94%	1%	3.67
4	2%	67%	32%	4.29
5	1%	76%	23%	3.99
6	0%	100%	0%	2.85
7	1%	71%	28%	4.10
8	3%	78%	19%	4.21
9	3%	97%	0%	3.69
10	7%	93%	0%	3.29
11	1%	68%	31%	4.29
12	2%	77%	22%	4.12
13	14%	86%	0%	3.11
14	4%	69%	28%	4.31
15	4%	80%	16%	3.98
16	0%	100%	0%	2.73
17	2%	98%	0%	2.85
18	1%	72%	28%	4.03
19	1%	82%	17%	4.20
20	0%	100%	0%	3.25
21	1%	97%	2%	3.39
22	8%	92%	0%	3.15
23	7%	93%	0%	3.81
24	6%	94%	0%	3.11
25	1%	74%	25%	4.08
26	7%	93%	0%	3.13
27	6%	66%	28%	4.42
28	1%	99%	0%	2.69
29	0%	100%	0%	2.65
30	3%	84%	13%	3.75
31	3%	79%	18%	3.90
32	0%	100%	0%	3.11
33	1%	99%	0%	3.16

34	0%	100%	0%	2.65
35	0%	73%	27%	4.37
36	1%	99%	0%	2.82
37	0%	90%	10%	3.68
38	0%	99%	1%	2.80

Continuation of **Table 13**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	2%	94%	4%	3.10
40	3%	97%	0%	3.59
41	14%	84%	2%	3.72
42	4%	68%	28%	4.58
43	2%	98%	0%	3.24
44	0%	100%	0%	2.91
45	0%	100%	0%	2.65
46	1%	99%	0%	2.78
47	1%	71%	28%	4.15
48	3%	76%	22%	4.10
49	0%	100%	0%	2.82
50	0%	99%	1%	3.09
51	1%	99%	0%	2.78
52	0%	100%	0%	2.85
53	0%	100%	0%	3.40
54	0%	93%	7%	3.53
55	1%	99%	0%	2.65
56	0%	100%	0%	2.78
57	2%	98%	0%	2.92
58	1%	99%	0%	3.25
59	0%	100%	0%	3.21
60	0%	100%	0%	2.73
61	0%	100%	0%	2.78
62	0%	100%	0%	2.65
63	2%	80%	18%	3.98
64	2%	98%	0%	2.65
65	0%	96%	4%	3.68
66	0%	100%	0%	2.65
67	0%	100%	0%	2.74
68	1%	99%	0%	2.65
69	1%	99%	0%	2.84
70	5%	95%	0%	3.10
71	1%	99%	0%	2.72
72	0%	100%	0%	2.83

73	1%	99%	0%	3.64
74	0%	99%	1%	3.09
75	0%	100%	0%	2.65
76	0%	100%	0%	2.65

Continuation of **Table 13**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	2%	98%	0%	2.88
78	1%	99%	0%	2.91
79	0%	100%	0%	2.65
80	0%	100%	0%	2.65
81	0%	100%	0%	2.65

Table 14 presents the DSO upward operational congestion management service mix and its daily average marginal price of the Romanian power system in each scenario of Market Design A. Although ESSs play the dominant role in the coverage of that service, EVs also play an important role in some cases providing a percentage higher than 10% of the total in scenarios 9, 13, 22-24, 39, and 41. The highest share of 27% of the total for EVs is reported in scenario 39. The common characteristic of all scenarios is that net demand is either medium or high; thus, the system needs are higher than the other resources, and there is a requirement for EVs' services.

Table 14: DSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design A

Scenario	ESSs	EVs	DRPs	Marginal price
1	94%	6%	0%	7.97
2	95%	5%	0%	7.95
3	93%	7%	0%	8.10
4	93%	7%	0%	7.99
5	100%	0%	0%	8.32
6	95%	5%	0%	7.97
7	95%	5%	0%	7.96
8	100%	0%	0%	8.30
9	75%	25%	0%	8.13
10	95%	5%	0%	8.00
11	91%	9%	0%	8.00
12	100%	0%	0%	8.32
13	86%	14%	0%	8.40
14	96%	4%	0%	9.36
15	100%	0%	0%	7.92
16	97%	3%	0%	7.95
17	95%	5%	0%	7.97
18	95%	5%	0%	7.97
19	100%	0%	0%	8.30
20	93%	7%	0%	8.34

21	100%	0%	0%	9.32
22	81%	19%	0%	8.42
23	82%	18%	0%	8.12
24	77%	23%	0%	8.10
25	100%	0%	0%	8.32
26	95%	5%	0%	8.36
27	99%	1%	0%	9.36
28	98%	2%	0%	9.36
29	100%	0%	0%	7.92
30	100%	0%	0%	7.92
31	100%	0%	0%	8.29
32	96%	4%	0%	8.33
33	95%	5%	0%	7.98
34	97%	3%	0%	7.97
35	100%	0%	0%	8.30
36	98%	2%	0%	8.33
37	100%	0%	0%	9.32
38	100%	0%	0%	9.32

Continuation of **Table 14**

Scenario	ESSs	EVs	DRPs	Marginal price
39	73%	27%	0%	8.07
40	91%	9%	0%	8.37
41	76%	24%	0%	8.44
42	98%	2%	0%	9.36
43	93%	7%	0%	9.39
44	95%	5%	0%	9.38
45	100%	0%	0%	7.92
46	100%	0%	0%	7.92
47	100%	0%	0%	7.92
48	100%	0%	0%	8.29
49	100%	0%	0%	8.29
50	100%	0%	0%	9.32
51	95%	5%	0%	7.96
52	97%	3%	0%	8.33
53	97%	3%	0%	8.37
54	100%	0%	0%	9.32
55	100%	0%	0%	9.32
56	100%	0%	0%	9.32
57	95%	5%	0%	8.35
58	98%	2%	0%	9.36
59	96%	4%	0%	9.38

60	100%	0%	0%	8.29
61	100%	0%	0%	7.92
62	100%	0%	0%	7.92
63	100%	0%	0%	8.29
64	100%	0%	0%	8.29
65	100%	0%	0%	9.32
66	100%	0%	0%	9.32
67	98%	2%	0%	8.32
68	100%	0%	0%	9.32
69	100%	0%	0%	9.32
70	99%	1%	0%	9.39
71	100%	0%	0%	7.92
72	100%	0%	0%	8.29
73	100%	0%	0%	8.29
74	100%	0%	0%	9.32
75	100%	0%	0%	9.32
76	100%	0%	0%	9.32

Continuation of **Table 14**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	9.32
78	100%	0%	0%	8.29
79	100%	0%	0%	9.32
80	100%	0%	0%	9.32
81	100%	0%	0%	9.32

Table 14 presents the DSO downward operational congestion management service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design A. ESSs solely cover that service in all scenarios since they have the potential for that due to their limited participation in the corresponding TSO-level downward service.

Table 15: DSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design A

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	7.92
2	100%	0%	0%	7.92
3	100%	0%	0%	7.92
4	100%	0%	0%	7.92
5	100%	0%	0%	8.29
6	100%	0%	0%	7.92
7	100%	0%	0%	7.92
8	100%	0%	0%	8.29
9	100%	0%	0%	7.92

10	100%	0%	0%	7.92
11	100%	0%	0%	7.92
12	100%	0%	0%	8.29
13	100%	0%	0%	8.29
14	100%	0%	0%	9.32
15	100%	0%	0%	7.92
16	100%	0%	0%	7.92
17	100%	0%	0%	7.92
18	100%	0%	0%	7.92
19	100%	0%	0%	8.29
20	100%	0%	0%	8.29
21	100%	0%	0%	9.32
22	100%	0%	0%	8.29
23	100%	0%	0%	7.92
24	100%	0%	0%	7.92
25	100%	0%	0%	8.29
26	100%	0%	0%	8.29
27	100%	0%	0%	9.32
28	100%	0%	0%	9.32
29	100%	0%	0%	7.92
30	100%	0%	0%	7.92
31	100%	0%	0%	8.29
32	100%	0%	0%	8.29
33	100%	0%	0%	7.92
34	100%	0%	0%	7.92
35	100%	0%	0%	8.29
36	100%	0%	0%	8.29
37	100%	0%	0%	9.32
38	100%	0%	0%	9.32

Continuation of **Table 15**

Scenario	ESSs	EVs	DRPs	Marginal price
39	100%	0%	0%	7.92
40	100%	0%	0%	8.29
41	100%	0%	0%	8.29
42	100%	0%	0%	9.32
43	100%	0%	0%	9.32
44	100%	0%	0%	9.32
45	100%	0%	0%	7.92
46	100%	0%	0%	7.92
47	100%	0%	0%	7.92
48	100%	0%	0%	8.29

49	100%	0%	0%	8.29
50	100%	0%	0%	9.32
51	100%	0%	0%	7.92
52	100%	0%	0%	8.29
53	100%	0%	0%	8.29
54	100%	0%	0%	9.32
55	100%	0%	0%	9.32
56	100%	0%	0%	9.32
57	100%	0%	0%	8.29
58	100%	0%	0%	9.32
59	100%	0%	0%	9.32
60	100%	0%	0%	8.29
61	100%	0%	0%	7.92
62	100%	0%	0%	7.92
63	100%	0%	0%	8.29
64	100%	0%	0%	8.29
65	100%	0%	0%	9.32
66	100%	0%	0%	9.32
67	100%	0%	0%	8.29
68	100%	0%	0%	9.32
69	100%	0%	0%	9.32
70	100%	0%	0%	9.32
71	100%	0%	0%	7.92
72	100%	0%	0%	8.29
73	100%	0%	0%	8.29
74	100%	0%	0%	9.32
75	100%	0%	0%	9.32
76	100%	0%	0%	9.32

Continuation of **Table 15**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	9.32
78	100%	0%	0%	8.29
79	100%	0%	0%	9.32
80	100%	0%	0%	9.32
81	100%	0%	0%	9.32

Table 16 presents the integrated TSO congestion management-mFRR up service mix and its daily average marginal price of the Greek power system in each scenario of Market Design B. Since this service is integrated with the mFRR one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A. In general, the participation of DERs in the coverage of that service is limited, exceeding the share of 10% of the total only in scenarios 51, 71, 72, and 78. The

common characteristic of those four scenarios is that the net demand in each one of them is high, justifying the increasing need for additional resources.

Table 16: Integrated TSO congestion management-mFRR up service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design B

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	15%	85%	0%	2.74
2	15%	85%	0%	2.71
3	15%	84%	0%	3.20
4	15%	85%	0%	2.65
5	21%	79%	0%	3.17
6	17%	82%	2%	3.16
7	15%	85%	0%	2.70
8	15%	85%	0%	2.89
9	15%	85%	0%	3.03
10	21%	79%	0%	3.08
11	15%	85%	0%	2.65
12	22%	78%	0%	2.89
13	22%	78%	0%	2.97
14	20%	73%	7%	4.27
15	15%	85%	0%	2.74
16	16%	81%	2%	3.21
17	16%	82%	3%	3.31
18	15%	85%	0%	2.70
19	15%	85%	0%	2.95
20	16%	79%	5%	3.54
21	21%	76%	3%	3.43
22	21%	79%	0%	2.92
23	15%	85%	0%	2.88
24	21%	77%	2%	3.27
25	22%	78%	0%	2.99
26	15%	82%	4%	2.96
27	20%	76%	4%	3.89
28	20%	78%	1%	3.93
29	18%	80%	2%	3.23
30	15%	85%	0%	2.73
31	15%	85%	0%	2.79
32	17%	80%	3%	3.47
33	15%	84%	1%	2.96
34	16%	78%	6%	3.65
35	15%	85%	0%	2.67
36	16%	76%	8%	3.71
37	18%	79%	3%	3.90
38	17%	82%	1%	4.41

Continuation of **Table 16**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	21%	79%	0%	3.00
40	15%	82%	4%	3.01
41	21%	79%	0%	2.65
42	20%	73%	7%	3.73
43	18%	82%	0%	4.00
44	14%	81%	5%	3.52
45	18%	79%	3%	3.35
46	16%	75%	9%	3.60
47	15%	85%	0%	2.84
48	15%	85%	0%	2.80
49	17%	78%	5%	3.62
50	15%	85%	0%	2.81
51	21%	66%	14%	3.61
52	16%	75%	10%	3.77
53	15%	85%	0%	3.01
54	19%	81%	1%	4.17
55	18%	82%	0%	3.72
56	14%	86%	0%	3.09
57	14%	86%	0%	2.73
58	17%	82%	0%	3.44
59	15%	84%	1%	3.55
60	15%	78%	7%	3.63
61	15%	85%	0%	2.90
62	16%	75%	10%	3.64
63	16%	84%	0%	2.97
64	16%	77%	7%	3.69
65	19%	81%	0%	3.42
66	23%	70%	7%	4.38
67	21%	73%	7%	3.87
68	20%	78%	2%	4.41
69	14%	86%	0%	3.29
70	15%	85%	1%	3.50
71	18%	68%	14%	3.67
72	16%	74%	10%	3.89
73	15%	84%	1%	3.04
74	19%	81%	0%	3.26
75	22%	69%	8%	4.40
76	22%	72%	6%	4.14

Continuation of **Table 16**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	14%	86%	0%	3.14
78	19%	67%	14%	3.77
79	22%	74%	4%	3.73
80	22%	74%	3%	4.06
81	21%	69%	10%	4.50

Table 17 presents the integrated TSO congestion management-mFRR down service mix and its daily average marginal price of the Greek power system in each scenario of Market Design B. Since this service is integrated with the mFRR one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A. The supply of that service from DERs stands for more than 10% of the total in scenarios 1, 2, 4, 5, 7, 8, 12, 14, 15, 19, 21, 25, 27, 30, 31, 37, 42, 48, 50, and 54. The common characteristic of all these scenarios is that the net demand in each one is low; thus, fewer hydrothermal power units are online, and there is limited capability for downward services.

Table 17: Integrated TSO congestion management-mFRR down service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design B

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	24%	57%	18%	5.51
2	19%	59%	22%	5.13
3	48%	45%	8%	6.20
4	30%	59%	11%	5.63
5	15%	55%	31%	5.26
6	50%	47%	3%	5.68
7	25%	59%	16%	5.17
8	23%	59%	18%	5.37
9	51%	46%	2%	6.08
10	40%	60%	0%	5.43
11	24%	71%	5%	5.19
12	6%	60%	35%	5.13
13	37%	60%	3%	5.92
14	12%	61%	27%	6.24
15	24%	58%	17%	5.01
16	51%	47%	2%	5.72
17	38%	62%	0%	5.38
18	34%	61%	5%	5.57
19	25%	61%	14%	5.43
20	51%	47%	2%	6.15
21	12%	65%	24%	6.03
22	30%	68%	2%	5.37
23	29%	71%	0%	5.63
24	46%	54%	0%	5.23
25	8%	59%	33%	5.29
26	33%	67%	0%	5.63

27	12%	59%	29%	6.72
28	20%	79%	0%	6.04
29	49%	49%	2%	5.61
30	26%	60%	14%	5.01
31	23%	58%	19%	5.42
32	52%	47%	1%	6.14
33	38%	62%	0%	5.34
34	39%	61%	0%	5.26
35	27%	70%	2%	5.31
36	38%	62%	0%	5.50
37	12%	68%	21%	5.86
38	22%	78%	0%	5.69

Continuation of **Table 17**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	36%	64%	0%	5.00
40	43%	57%	0%	5.63
41	28%	72%	0%	5.37
42	12%	59%	29%	6.60
43	21%	78%	1%	6.28
44	15%	85%	0%	5.99
45	52%	46%	2%	5.65
46	40%	60%	0%	5.42
47	27%	65%	9%	5.00
48	28%	59%	13%	5.40
49	50%	47%	3%	6.19
50	29%	58%	13%	5.38
51	32%	68%	0%	4.45
52	38%	62%	0%	5.49
53	34%	66%	0%	5.84
54	12%	68%	20%	6.73
55	23%	76%	1%	5.98
56	12%	88%	0%	3.72
57	28%	72%	0%	4.93
58	18%	82%	0%	6.19
59	15%	85%	0%	5.76
60	53%	47%	1%	6.12
61	30%	70%	0%	5.11
62	39%	61%	0%	5.09
63	32%	64%	4%	5.16
64	33%	67%	0%	5.62

65	1%	99%	0%	3.90
66	10%	90%	0%	4.02
67	26%	74%	0%	4.56
68	18%	82%	0%	5.31
69	13%	87%	0%	4.09
70	14%	86%	0%	5.55
71	28%	72%	0%	4.39
72	27%	73%	0%	5.60
73	35%	65%	0%	5.61
74	0%	100%	0%	3.64
75	12%	88%	0%	3.99
76	12%	88%	0%	3.02

Continuation of **Table 17**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	12%	88%	0%	4.03
78	18%	82%	0%	4.54
79	12%	88%	0%	3.22
80	12%	88%	0%	2.96
81	12%	88%	0%	2.72

Table 18 presents the DSO upward operational congestion management service mix, and its daily average marginal price of the Greek power system in each scenario of Market Design B. ESSs account for almost 100% of that service satisfaction. However, EVs highlight their presence in some scenarios with a percentage higher than 10%, such as in 24, 34, 36, 39, 46, 51, 52, 62, 67, 71, and 78. The common characteristic of all these scenarios is that the net demand of each one is high, and the EVs' participation is deemed necessary for that service coverage.

Table 18: DSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design B

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	8.18
2	100%	0%	0%	8.18
3	100%	0%	0%	8.18
4	100%	0%	0%	8.18
5	100%	0%	0%	8.99
6	100%	0%	0%	8.18
7	100%	0%	0%	8.18
8	100%	0%	0%	8.99
9	100%	0%	0%	8.18
10	100%	0%	0%	8.20
11	100%	0%	0%	8.18
12	100%	0%	0%	8.99
13	100%	0%	0%	8.99

14	100%	0%	0%	11.28
15	100%	0%	0%	8.18
16	100%	0%	0%	8.18
17	92%	8%	0%	8.28
18	100%	0%	0%	8.18
19	100%	0%	0%	8.99
20	100%	0%	0%	8.99
21	100%	0%	0%	11.28
22	100%	0%	0%	8.99
23	100%	0%	0%	8.18
24	84%	16%	0%	8.30
25	100%	0%	0%	8.99
26	100%	0%	0%	8.99
27	100%	0%	0%	11.28
28	100%	0%	0%	11.28
29	100%	0%	0%	8.18
30	100%	0%	0%	8.18
31	100%	0%	0%	8.99
32	100%	0%	0%	8.99
33	100%	0%	0%	8.18
34	73%	27%	0%	8.34
35	100%	0%	0%	8.99
36	86%	14%	0%	9.10
37	100%	0%	0%	11.28
38	100%	0%	0%	11.28

Continuation of **Table 18**

Scenario	ESSs	EVs	DRPs	Marginal price
39	73%	27%	0%	8.34
40	100%	0%	0%	8.99
41	100%	0%	0%	8.99
42	100%	0%	0%	11.28
43	100%	0%	0%	11.28
44	100%	0%	0%	11.28
45	100%	0%	0%	8.18
46	90%	10%	0%	8.25
47	100%	0%	0%	8.18
48	100%	0%	0%	8.99
49	100%	0%	0%	8.99
50	100%	0%	0%	8.99
51	88%	12%	0%	8.32
52	83%	17%	0%	9.13

53	100%	0%	0%	8.99
54	100%	0%	0%	11.28
55	100%	0%	0%	11.28
56	100%	0%	0%	11.28
57	100%	0%	0%	8.99
58	100%	0%	0%	11.28
59	100%	0%	0%	11.28
60	100%	0%	0%	8.99
61	100%	0%	0%	8.18
62	79%	21%	0%	8.31
63	100%	0%	0%	8.99
64	99%	1%	0%	9.01
65	100%	0%	0%	11.28
66	100%	0%	0%	11.28
67	90%	10%	0%	9.11
68	100%	0%	0%	11.28
69	100%	0%	0%	11.28
70	100%	0%	0%	11.28
71	85%	15%	0%	8.32
72	95%	5%	0%	9.06
73	100%	0%	0%	8.99
74	100%	0%	0%	11.28
75	100%	0%	0%	11.28
76	100%	0%	0%	11.28

Continuation of **Table 18**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	11.28
78	87%	13%	0%	9.09
79	100%	0%	0%	11.28
80	100%	0%	0%	11.28
81	100%	0%	0%	11.28

Table 19 presents the DSO downward operational congestion management service mix, and its daily average marginal price of the Greek power system in each scenario of Market Design B. ESSs are capable of meeting 100% of that service satisfaction since they comprise the most economically competitive DER resource.

Table 19: DSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design B

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	8.18
2	100%	0%	0%	8.18

3	100%	0%	0%	8.18
4	100%	0%	0%	8.18
5	100%	0%	0%	8.99
6	100%	0%	0%	8.18
7	100%	0%	0%	8.18
8	100%	0%	0%	8.99
9	100%	0%	0%	8.18
10	100%	0%	0%	8.18
11	100%	0%	0%	8.18
12	100%	0%	0%	8.99
13	100%	0%	0%	8.99
14	100%	0%	0%	11.28
15	100%	0%	0%	8.18
16	100%	0%	0%	8.18
17	100%	0%	0%	8.18
18	100%	0%	0%	8.18
19	100%	0%	0%	8.99
20	100%	0%	0%	8.99
21	100%	0%	0%	11.28
22	100%	0%	0%	8.99
23	100%	0%	0%	8.18
24	100%	0%	0%	8.18
25	100%	0%	0%	8.99
26	100%	0%	0%	8.99
27	100%	0%	0%	11.28
28	100%	0%	0%	11.28
29	100%	0%	0%	8.18
30	100%	0%	0%	8.18
31	100%	0%	0%	8.99
32	100%	0%	0%	8.99
33	100%	0%	0%	8.18
34	100%	0%	0%	8.18
35	100%	0%	0%	8.99
36	100%	0%	0%	8.99
37	100%	0%	0%	11.28
38	100%	0%	0%	11.28

Continuation of **Table 19**

Scenario	ESSs	EVs	DRPs	Marginal price
39	100%	0%	0%	8.18
40	100%	0%	0%	8.99
41	100%	0%	0%	8.99

42	100%	0%	0%	11.28
43	100%	0%	0%	11.28
44	100%	0%	0%	11.28
45	100%	0%	0%	8.18
46	100%	0%	0%	8.18
47	100%	0%	0%	8.18
48	100%	0%	0%	8.99
49	100%	0%	0%	8.99
50	100%	0%	0%	8.99
51	100%	0%	0%	8.18
52	100%	0%	0%	8.99
53	100%	0%	0%	8.99
54	100%	0%	0%	11.28
55	100%	0%	0%	11.28
56	100%	0%	0%	11.28
57	100%	0%	0%	8.99
58	100%	0%	0%	11.28
59	100%	0%	0%	11.28
60	100%	0%	0%	8.99
61	100%	0%	0%	8.18
62	100%	0%	0%	8.18
63	100%	0%	0%	8.99
64	100%	0%	0%	8.99
65	100%	0%	0%	11.29
66	100%	0%	0%	11.29
67	100%	0%	0%	8.99
68	100%	0%	0%	11.28
69	100%	0%	0%	11.28
70	100%	0%	0%	11.28
71	100%	0%	0%	8.18
72	100%	0%	0%	8.99
73	100%	0%	0%	8.99
74	100%	0%	0%	11.29
75	100%	0%	0%	11.29
76	100%	0%	0%	11.28

Continuation of **Table 19**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	11.28
78	100%	0%	0%	8.99
79	100%	0%	0%	11.28
80	100%	0%	0%	11.28

81	100%	0%	0%	11.28

Table 20 presents the integrated TSO congestion management-mFRR up service mix, and its daily average marginal price of the Bulgarian power system in each scenario of Market Design B. DERs comprise the most significant resource in meeting that service since they supply an average of 81% of the total needs in all scenarios. Their share is above 50% of the total in 79 of 81 scenarios. It is also worth mentioning that in scenarios 13, 22, 26, 40, 41, and 57 which are characterized by low CO_2 emission and medium natural gas fuel price, the DERs share in the coverage of that service equals 100%.

Table 20: Integrated TSO congestion management-mFRR up service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design B

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	43%	0%	57%	1.91
2	41%	0%	59%	1.91
3	12%	0%	88%	2.03
4	40%	0%	60%	1.96
5	5%	1%	95%	2.48
6	10%	0%	90%	1.93
7	41%	0%	59%	1.91
8	25%	0%	75%	2.05
9	15%	0%	85%	1.99
10	0%	15%	84%	2.39
11	44%	0%	56%	1.97
12	8%	0%	92%	2.23
13	0%	0%	100%	2.19
14	1%	77%	22%	2.65
15	6%	0%	94%	1.89
16	27%	0%	73%	2.00
17	15%	12%	73%	2.39
18	35%	0%	65%	1.92
19	23%	0%	77%	2.06
20	10%	0%	90%	2.10
21	6%	24%	70%	2.54
22	0%	0%	100%	2.40
23	15%	0%	85%	1.99
24	4%	0%	96%	2.34
25	8%	0%	92%	2.25
26	0%	0%	100%	2.17
27	1%	40%	59%	2.55
28	0%	27%	73%	2.49
29	23%	0%	77%	1.91
30	6%	0%	94%	1.89
31	6%	0%	94%	2.02
32	10%	0%	90%	2.08

33	26%	0%	74%	1.94
34	13%	11%	76%	2.39
35	24%	0%	76%	2.04
36	18%	7%	75%	2.49
37	0%	40%	59%	2.67
38	0%	17%	83%	2.46

Continuation of **Table 20**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	8%	0%	92%	2.09
40	0%	0%	100%	2.24
41	0%	0%	100%	2.19
42	2%	78%	20%	2.66
43	0%	25%	75%	2.49
44	0%	35%	65%	2.51
45	12%	0%	88%	2.07
46	10%	0%	90%	2.06
47	6%	0%	94%	1.89
48	6%	0%	94%	2.02
49	22%	0%	78%	2.04
50	6%	0%	94%	2.02
51	10%	0%	90%	1.97
52	18%	10%	72%	2.50
53	17%	0%	83%	2.13
54	0%	25%	75%	2.53
55	0%	27%	73%	2.48
56	0%	25%	74%	2.53
57	0%	0%	100%	2.22
58	0%	25%	75%	2.47
59	0%	22%	77%	2.49
60	6%	0%	94%	2.18
61	17%	0%	83%	1.93
62	13%	0%	87%	2.08
63	6%	0%	94%	2.02
64	10%	0%	90%	2.20
65	4%	0%	96%	2.38
66	10%	0%	90%	2.38
67	14%	0%	86%	2.08
68	0%	21%	79%	2.47
69	0%	28%	72%	2.50
70	0%	29%	71%	2.55
71	9%	0%	91%	1.89

72	10%	0%	90%	2.20
73	12%	0%	88%	2.02
74	4%	0%	96%	2.38
75	10%	21%	69%	2.49
76	10%	23%	67%	2.49

Continuation of **Table 20**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	0%	25%	75%	2.49
78	10%	0%	90%	2.02
79	10%	0%	90%	2.38
80	10%	24%	66%	2.49
81	17%	0%	83%	2.42

Table 21 presents the integrated TSO congestion management-mFRR down service mix, and its daily average marginal price of the Bulgarian power system in each scenario of Market Design B. Thermal power units together with DERs almost equally cover that service in total in all scenarios. The DERs' share exceeds the percentage of 50% of the total in scenarios 2, 6-8, 15, 16, 18-20, 29-33, 35, 45, 47-51, 53, 60, 61, 63, 65-67, 71, 73-75, 78, 79, and 81. In all these scenarios, the value of CO_2 emission price is medium or high.

Table 21: Integrated TSO congestion management-mFRR down service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design B

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	75%	0%	25%	1.89
2	23%	0%	77%	1.89
3	83%	0%	17%	1.89
4	75%	0%	25%	1.89
5	84%	0%	16%	1.98
6	24%	0%	76%	1.89
7	23%	0%	77%	1.89
8	24%	0%	76%	2.02
9	83%	0%	17%	1.85
10	84%	0%	16%	1.85
11	75%	0%	25%	1.89
12	83%	0%	17%	2.02
13	84%	0%	16%	1.98
14	84%	0%	16%	2.32
15	0%	0%	100%	1.89
16	25%	0%	75%	1.89
17	70%	0%	30%	1.89
18	22%	0%	78%	1.89
19	24%	0%	76%	2.02
20	24%	0%	76%	2.02
21	83%	0%	17%	2.38

22	84%	0%	16%	1.98
23	81%	0%	19%	1.89
24	84%	0%	16%	1.85
25	83%	0%	17%	2.02
26	84%	0%	16%	1.98
27	84%	0%	16%	2.32
28	84%	0%	16%	2.32
29	2%	0%	98%	1.89
30	0%	0%	100%	1.89
31	0%	0%	100%	2.02
32	24%	0%	76%	2.02
33	24%	0%	76%	1.89
34	71%	0%	29%	1.89
35	24%	0%	76%	2.02
36	72%	0%	28%	2.02
37	84%	0%	16%	2.32
38	84%	0%	16%	2.32

Continuation of **Table 21**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	84%	0%	16%	1.85
40	84%	0%	16%	1.98
41	84%	0%	16%	1.98
42	84%	0%	16%	2.32
43	84%	0%	16%	2.32
44	84%	0%	16%	2.32
45	1%	0%	99%	1.89
46	70%	0%	30%	1.89
47	0%	0%	100%	1.89
48	0%	0%	100%	2.02
49	1%	0%	99%	2.02
50	0%	0%	100%	2.02
51	27%	0%	73%	1.89
52	72%	0%	28%	2.02
53	27%	0%	73%	2.02
54	84%	0%	16%	2.32
55	84%	0%	16%	2.32
56	84%	0%	16%	2.32
57	84%	0%	16%	1.98
58	84%	0%	16%	2.32
59	84%	0%	16%	2.32
60	0%	0%	100%	2.02

61	2%	0%	98%	1.89
62	72%	0%	28%	1.89
63	0%	0%	100%	2.02
64	71%	0%	29%	2.02
65	24%	0%	76%	2.38
66	26%	0%	74%	2.38
67	37%	0%	63%	2.02
68	84%	0%	16%	2.32
69	84%	0%	16%	2.32
70	84%	0%	16%	2.32
71	24%	0%	76%	1.89
72	71%	0%	29%	2.02
73	1%	0%	99%	2.02
74	24%	0%	76%	2.38
75	24%	0%	76%	2.38
76	70%	0%	30%	2.38

Continuation of **Table 21**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	84%	0%	16%	2.32
78	25%	0%	75%	2.02
79	24%	0%	76%	2.38
80	71%	0%	29%	2.38
81	44%	0%	56%	2.38

Table 22 presents the DSO upward operational congestion management service mix, and its daily average marginal price of the Bulgarian power system in each scenario of Market Design B. ESSs account for around 73% of that service satisfaction in all scenarios, followed by EVs, which represent 27% of the total in all scenarios. The share of EVs surpasses 60% of the total in scenarios 5, 10, 14, 17, 22, 24, 34, 36, 42, and 52, where the value of CO_2 emission price is low or medium.

Table 22: DSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design B

Scenario	ESSs	EVs	DRPs	Marginal price
1	74%	26%	0%	2.01
2	100%	0%	0%	1.83
3	86%	14%	0%	1.95
4	83%	17%	0%	1.98
5	20%	80%	0%	2.40
6	95%	5%	0%	1.85
7	100%	0%	0%	1.83
8	97%	3%	0%	1.96
9	82%	18%	0%	1.96
10	6%	94%	0%	2.31

11	79%	21%	0%	2.01
12	59%	41%	0%	2.14
13	65%	35%	0%	2.10
14	11%	89%	0%	2.73
15	100%	0%	0%	1.81
16	94%	6%	0%	1.92
17	6%	94%	0%	2.31
18	100%	0%	0%	1.84
19	100%	0%	0%	1.97
20	89%	11%	0%	2.01
21	59%	41%	0%	2.49
22	40%	60%	0%	2.32
23	85%	15%	0%	1.96
24	14%	86%	0%	2.26
25	55%	45%	0%	2.16
26	69%	31%	0%	2.08
27	58%	42%	0%	2.53
28	65%	35%	0%	2.45
29	100%	0%	0%	1.83
30	100%	0%	0%	1.81
31	100%	0%	0%	1.94
32	89%	11%	0%	1.99
33	100%	0%	0%	1.86
34	6%	94%	0%	2.31
35	100%	0%	0%	1.96
36	6%	94%	0%	2.41
37	52%	48%	0%	2.62
38	74%	26%	0%	2.39

Continuation of **Table 22**

Scenario	ESSs	EVs	DRPs	Marginal price
39	62%	38%	0%	2.01
40	59%	41%	0%	2.15
41	65%	35%	0%	2.10
42	31%	69%	0%	2.71
43	65%	35%	0%	2.45
44	59%	41%	0%	2.49
45	72%	28%	0%	1.99
46	66%	34%	0%	1.98
47	100%	0%	0%	1.81
48	100%	0%	0%	1.94
49	100%	0%	0%	1.96

50	100%	0%	0%	1.94
51	91%	9%	0%	1.90
52	6%	94%	0%	2.42
53	90%	10%	0%	2.05
54	60%	40%	0%	2.49
55	65%	35%	0%	2.44
56	62%	38%	0%	2.48
57	60%	40%	0%	2.14
58	69%	31%	0%	2.43
59	71%	29%	0%	2.44
60	71%	29%	0%	2.09
61	100%	0%	0%	1.86
62	59%	41%	0%	2.00
63	100%	0%	0%	1.94
64	66%	34%	0%	2.11
65	100%	0%	0%	2.28
66	100%	0%	0%	2.28
67	100%	0%	0%	2.00
68	71%	29%	0%	2.42
69	67%	33%	0%	2.45
70	62%	38%	0%	2.50
71	100%	0%	0%	1.81
72	65%	35%	0%	2.11
73	100%	0%	0%	1.94
74	100%	0%	0%	2.28
75	68%	32%	0%	2.44
76	68%	32%	0%	2.45

Continuation of **Table 22**

Scenario	ESSs	EVs	DRPs	Marginal price
77	67%	33%	0%	2.45
78	100%	0%	0%	1.94
79	100%	0%	0%	2.28
80	69%	31%	0%	2.45
81	100%	0%	0%	2.32

Table 23 presents the DSO downward operational congestion management service mix, and its daily average marginal price of the Bulgarian power system in each scenario of Market Design B. ESSs exclusively cover that service in all scenarios examined.

Table 23: DSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design B

Scenario	ESSs	EVs	DRPs	Marginal price

1	100%	0%	0%	1.81
2	100%	0%	0%	1.81
3	100%	0%	0%	1.81
4	100%	0%	0%	1.81
5	100%	0%	0%	1.94
6	100%	0%	0%	1.81
7	100%	0%	0%	1.81
8	100%	0%	0%	1.94
9	100%	0%	0%	1.81
10	100%	0%	0%	1.81
11	100%	0%	0%	1.81
12	100%	0%	0%	1.94
13	100%	0%	0%	1.94
14	100%	0%	0%	2.28
15	100%	0%	0%	1.81
16	100%	0%	0%	1.81
17	100%	0%	0%	1.81
18	100%	0%	0%	1.81
19	100%	0%	0%	1.94
20	100%	0%	0%	1.94
21	100%	0%	0%	2.28
22	100%	0%	0%	1.94
23	100%	0%	0%	1.81
24	100%	0%	0%	1.81
25	100%	0%	0%	1.94
26	100%	0%	0%	1.94
27	100%	0%	0%	2.28
28	100%	0%	0%	2.28
29	100%	0%	0%	1.81
30	100%	0%	0%	1.81
31	100%	0%	0%	1.94
32	100%	0%	0%	1.94
33	100%	0%	0%	1.81
34	100%	0%	0%	1.81
35	100%	0%	0%	1.94
36	100%	0%	0%	1.94
37	100%	0%	0%	2.28
38	100%	0%	0%	2.28

Continuation of **Table 23**

Scenario	ESSs	EVs	DRPs	Marginal price
39	100%	0%	0%	1.81

40	100%	0%	0%	1.94
41	100%	0%	0%	1.94
42	100%	0%	0%	2.28
43	100%	0%	0%	2.28
44	100%	0%	0%	2.28
45	100%	0%	0%	1.81
46	100%	0%	0%	1.81
47	100%	0%	0%	1.81
48	100%	0%	0%	1.94
49	100%	0%	0%	1.94
50	100%	0%	0%	1.94
51	100%	0%	0%	1.81
52	100%	0%	0%	1.94
53	100%	0%	0%	1.94
54	100%	0%	0%	2.28
55	100%	0%	0%	2.28
56	100%	0%	0%	2.28
57	100%	0%	0%	1.94
58	100%	0%	0%	2.28
59	100%	0%	0%	2.28
60	100%	0%	0%	1.94
61	100%	0%	0%	1.81
62	100%	0%	0%	1.81
63	100%	0%	0%	1.94
64	100%	0%	0%	1.94
65	100%	0%	0%	2.28
66	100%	0%	0%	2.28
67	100%	0%	0%	1.94
68	100%	0%	0%	2.28
69	100%	0%	0%	2.28
70	100%	0%	0%	2.28
71	100%	0%	0%	1.81
72	100%	0%	0%	1.94
73	100%	0%	0%	1.94
74	100%	0%	0%	2.28
75	100%	0%	0%	2.28
76	100%	0%	0%	2.28

Continuation of **Table 23**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	2.28
78	100%	0%	0%	1.94

79	100%	0%	0%	2.28
80	100%	0%	0%	2.28
81	100%	0%	0%	2.28

Table 24 presents the integrated TSO congestion management-mFRR up service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design B. Hydropower units supply the vast majority of that service, and the DERs' share is almost negligible, reporting less than 5% of the total service supply in some scenarios.

Table 24: Integrated TSO congestion management-mFRR up service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design B

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	1%	99%	0%	2.65
2	0%	100%	0%	2.65
3	11%	89%	0%	2.77
4	4%	96%	0%	2.70
5	7%	93%	0%	2.65
6	0%	100%	0%	2.67
7	0%	100%	0%	2.65
8	0%	100%	0%	2.65
9	12%	88%	0%	2.65
10	1%	99%	0%	2.65
11	1%	98%	0%	2.93
12	5%	95%	0%	2.68
13	0%	100%	0%	2.65
14	1%	99%	0%	2.65
15	0%	100%	0%	2.77
16	0%	100%	0%	2.65
17	4%	96%	0%	2.65
18	0%	100%	0%	2.65
19	0%	100%	0%	2.65
20	0%	100%	0%	2.65
21	1%	99%	0%	2.65
22	0%	100%	0%	2.66
23	8%	91%	0%	2.89
24	5%	95%	0%	2.73
25	3%	97%	0%	2.65
26	0%	100%	0%	2.65
27	2%	98%	0%	2.65
28	0%	100%	0%	2.65
29	0%	100%	0%	2.65
30	0%	100%	0%	2.74
31	0%	100%	0%	2.65
32	0%	100%	0%	2.65

33	0%	100%	0%	2.65
34	1%	99%	0%	2.65
35	0%	100%	0%	2.67
36	6%	94%	0%	2.65
37	0%	100%	0%	2.65
38	0%	100%	0%	2.82

Continuation of **Table 24**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	5%	95%	0%	2.65
40	0%	100%	0%	2.65
41	1%	99%	0%	2.65
42	2%	98%	0%	2.65
43	0%	100%	0%	2.65
44	0%	100%	0%	2.65
45	0%	99%	1%	2.88
46	6%	94%	0%	2.65
47	0%	100%	0%	2.65
48	0%	100%	0%	2.66
49	0%	98%	2%	2.90
50	0%	98%	2%	2.90
51	3%	97%	0%	2.65
52	1%	99%	0%	2.65
53	0%	100%	0%	2.65
54	0%	100%	0%	2.71
55	0%	100%	0%	2.77
56	0%	100%	0%	2.87
57	0%	100%	0%	2.65
58	0%	100%	0%	2.65
59	0%	100%	0%	2.72
60	0%	100%	0%	2.77
61	0%	100%	0%	2.65
62	3%	95%	2%	2.88
63	0%	100%	0%	2.65
64	6%	90%	4%	2.90
65	0%	99%	1%	3.07
66	0%	100%	0%	2.70
67	3%	97%	0%	2.65
68	0%	100%	0%	2.65
69	0%	100%	0%	2.69
70	0%	100%	0%	2.65
71	3%	97%	0%	2.65

72	3%	97%	0%	2.65
73	0%	98%	2%	2.90
74	0%	96%	4%	3.13
75	0%	100%	0%	2.65
76	5%	95%	0%	2.65

Continuation of **Table 24**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	0%	100%	0%	2.68
78	3%	97%	0%	2.65
79	0%	100%	0%	2.75
80	3%	97%	0%	2.69
81	3%	97%	0%	2.66

Table 25 presents the integrated TSO congestion management-mFRR down service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design B. Although hydropower units continue to be the major supplier, DERs highlight their presence in scenarios 4, 5, 11, 12, 14, 18, 25, 27, 35, 42, and 47, where their share exceeds 10% of the total provision and the net demand in all these scenarios is low.

Table 25: Integrated TSO congestion management-mFRR down service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design B

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	9%	81%	10%	3.82
2	5%	90%	5%	3.82
3	7%	93%	0%	2.98
4	11%	74%	15%	4.29
5	8%	77%	14%	4.15
6	0%	100%	0%	2.72
7	6%	88%	6%	3.79
8	6%	89%	5%	3.98
9	7%	93%	0%	3.21
10	20%	80%	0%	3.05
11	10%	73%	17%	4.05
12	3%	85%	12%	3.87
13	20%	80%	0%	3.05
14	19%	65%	16%	4.42
15	6%	90%	4%	3.99
16	0%	100%	0%	2.65
17	5%	95%	0%	2.65
18	8%	77%	15%	4.26
19	7%	87%	7%	4.07

20	0%	100%	0%	2.85
21	6%	92%	2%	3.83
22	21%	79%	0%	3.19
23	6%	94%	0%	3.47
24	21%	79%	0%	3.05
25	5%	81%	14%	3.98
26	20%	80%	0%	2.97
27	19%	63%	18%	4.42
28	20%	80%	0%	2.65
29	0%	100%	0%	2.65
30	7%	88%	5%	3.92
31	4%	92%	4%	3.58
32	0%	100%	0%	2.87
33	1%	99%	0%	3.08
34	3%	97%	0%	2.78
35	7%	80%	13%	4.09
36	4%	96%	0%	2.65
37	3%	95%	2%	3.68
38	20%	80%	0%	2.65

Continuation of **Table 25**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	19%	81%	0%	2.98
40	20%	80%	0%	2.86
41	21%	79%	0%	3.37
42	19%	69%	12%	4.56
43	20%	80%	0%	2.65
44	20%	80%	0%	3.08
45	0%	100%	0%	2.72
46	2%	98%	0%	2.72
47	7%	80%	13%	4.00
48	3%	96%	2%	3.51
49	0%	100%	0%	2.68
50	7%	87%	6%	4.04
51	1%	99%	0%	2.78
52	3%	97%	0%	2.65
53	0%	100%	0%	3.02
54	3%	95%	2%	3.24
55	20%	80%	0%	2.65
56	20%	80%	0%	2.77
57	20%	80%	0%	2.83
58	20%	80%	0%	3.00

59	20%	80%	0%	3.08
60	0%	100%	0%	2.65
61	1%	99%	0%	3.26
62	2%	98%	0%	2.72
63	6%	89%	5%	3.93
64	3%	97%	0%	2.73
65	0%	99%	1%	3.24
66	0%	100%	0%	2.65
67	2%	98%	0%	2.73
68	20%	80%	0%	2.65
69	20%	80%	0%	2.70
70	20%	80%	0%	2.86
71	0%	100%	0%	2.65
72	1%	99%	0%	2.82
73	0%	100%	0%	3.20
74	0%	99%	1%	3.09
75	0%	100%	0%	2.65
76	1%	99%	0%	2.65

Continuation of **Table 25**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	20%	80%	0%	2.72
78	1%	99%	0%	2.73
79	0%	100%	0%	2.65
80	2%	98%	0%	2.65
81	2%	98%	0%	2.65

Table 26 presents the DSO upward operational congestion management service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design B. ESSs account for around 97% of that service satisfaction in all scenarios, followed by EVs, which represent 3% of the total in all scenarios. The share of EVs surpasses 10% of the total in scenarios 9, 13, 24, 39, and 41, where the value of CO_2 emission price is low.

Table 26: DSO upward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design B

Scenario	ESSs	EVs	DRPs	Marginal price
1	93%	7%	0%	7.97
2	95%	5%	0%	7.95
3	93%	7%	0%	8.15
4	95%	5%	0%	7.97
5	100%	0%	0%	8.29
6	97%	3%	0%	7.97
7	95%	5%	0%	7.97
8	99%	1%	0%	8.31

9	87%	13%	0%	8.13
10	95%	5%	0%	8.00
11	95%	5%	0%	7.95
12	100%	0%	0%	8.32
13	83%	17%	0%	8.42
14	100%	0%	0%	9.36
15	100%	0%	0%	7.92
16	95%	5%	0%	7.95
17	95%	5%	0%	7.97
18	95%	5%	0%	7.97
19	100%	0%	0%	8.30
20	98%	2%	0%	8.34
21	100%	0%	0%	9.32
22	94%	6%	0%	8.39
23	93%	7%	0%	8.03
24	79%	21%	0%	8.10
25	100%	0%	0%	8.35
26	95%	5%	0%	8.36
27	100%	0%	0%	9.36
28	98%	2%	0%	9.36
29	100%	0%	0%	7.92
30	100%	0%	0%	7.92
31	100%	0%	0%	8.29
32	96%	4%	0%	8.33
33	96%	4%	0%	7.95
34	96%	4%	0%	7.97
35	100%	0%	0%	8.30
36	98%	2%	0%	8.32
37	100%	0%	0%	9.32
38	100%	0%	0%	9.32

Continuation of **Table 26**

Scenario	ESSs	EVs	DRPs	Marginal price
39	73%	27%	0%	8.06
40	95%	5%	0%	8.36
41	78%	22%	0%	8.44
42	100%	0%	0%	9.36
43	98%	2%	0%	9.35
44	95%	5%	0%	9.38
45	100%	0%	0%	7.92
46	100%	0%	0%	7.92
47	100%	0%	0%	7.92

48	100%	0%	0%	8.29
49	100%	0%	0%	8.29
50	100%	0%	0%	8.29
51	96%	4%	0%	7.96
52	98%	2%	0%	8.33
53	95%	5%	0%	8.33
54	100%	0%	0%	9.32
55	100%	0%	0%	9.32
56	100%	0%	0%	9.32
57	95%	5%	0%	8.35
58	97%	3%	0%	9.36
59	94%	6%	0%	9.39
60	100%	0%	0%	8.29
61	100%	0%	0%	7.92
62	100%	0%	0%	7.92
63	100%	0%	0%	8.29
64	100%	0%	0%	8.29
65	100%	0%	0%	9.32
66	100%	0%	0%	9.32
67	98%	2%	0%	8.32
68	100%	0%	0%	9.32
69	100%	0%	0%	9.32
70	93%	7%	0%	9.39
71	100%	0%	0%	7.92
72	100%	0%	0%	8.29
73	100%	0%	0%	8.29
74	100%	0%	0%	9.32
75	100%	0%	0%	9.32
76	100%	0%	0%	9.32

Continuation of **Table 26**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	9.32
78	100%	0%	0%	8.29
79	100%	0%	0%	9.32
80	100%	0%	0%	9.32
81	100%	0%	0%	9.32

Table 27 presents the DSO downward operational congestion management service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design B. ESSs account for 100% of that service satisfaction in all scenarios.

Table 27: DSO downward operational congestion management service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design B

Scenario	ESSs	EVs	DRPs	Marginal price
1	100%	0%	0%	7.92
2	100%	0%	0%	7.92
3	100%	0%	0%	7.92
4	100%	0%	0%	7.92
5	100%	0%	0%	8.29
6	100%	0%	0%	7.92
7	100%	0%	0%	7.92
8	100%	0%	0%	8.29
9	100%	0%	0%	7.92
10	100%	0%	0%	7.92
11	100%	0%	0%	7.92
12	100%	0%	0%	8.29
13	100%	0%	0%	8.29
14	100%	0%	0%	9.32
15	100%	0%	0%	7.92
16	100%	0%	0%	7.92
17	100%	0%	0%	7.92
18	100%	0%	0%	7.92
19	100%	0%	0%	8.29
20	100%	0%	0%	8.29
21	100%	0%	0%	9.32
22	100%	0%	0%	8.29
23	100%	0%	0%	7.92
24	100%	0%	0%	7.92
25	100%	0%	0%	8.29
26	100%	0%	0%	8.29
27	100%	0%	0%	9.32
28	100%	0%	0%	9.32
29	100%	0%	0%	7.92
30	100%	0%	0%	7.92
31	100%	0%	0%	8.29
32	100%	0%	0%	8.29
33	100%	0%	0%	7.92
34	100%	0%	0%	7.92
35	100%	0%	0%	8.29
36	100%	0%	0%	8.29
37	100%	0%	0%	9.32
38	100%	0%	0%	9.32

Continuation of **Table 27**

Scenario	ESSs	EVs	DRPs	Marginal price
39	100%	0%	0%	7.92
40	100%	0%	0%	8.29
41	100%	0%	0%	8.29
42	100%	0%	0%	9.32
43	100%	0%	0%	9.32
44	100%	0%	0%	9.32
45	100%	0%	0%	7.92
46	100%	0%	0%	7.92
47	100%	0%	0%	7.92
48	100%	0%	0%	8.29
49	100%	0%	0%	8.29
50	100%	0%	0%	8.29
51	100%	0%	0%	7.92
52	100%	0%	0%	8.29
53	100%	0%	0%	8.29
54	100%	0%	0%	9.32
55	100%	0%	0%	9.32
56	100%	0%	0%	9.32
57	100%	0%	0%	8.29
58	100%	0%	0%	9.32
59	100%	0%	0%	9.32
60	100%	0%	0%	8.29
61	100%	0%	0%	7.92
62	100%	0%	0%	7.92
63	100%	0%	0%	8.29
64	100%	0%	0%	8.29
65	100%	0%	0%	9.32
66	100%	0%	0%	9.32
67	100%	0%	0%	8.29
68	100%	0%	0%	9.32
69	100%	0%	0%	9.32
70	100%	0%	0%	9.32
71	100%	0%	0%	7.92
72	100%	0%	0%	8.29
73	100%	0%	0%	8.29
74	100%	0%	0%	9.32
75	100%	0%	0%	9.32
76	100%	0%	0%	9.32

Continuation of **Table 27**

Scenario	ESSs	EVs	DRPs	Marginal price
77	100%	0%	0%	9.32
78	100%	0%	0%	8.29
79	100%	0%	0%	9.32
80	100%	0%	0%	9.32
81	100%	0%	0%	9.32

Table 28 presents the integrated TSO-DSO congestion management-mFRR up service mix, and its daily average marginal price of the Greek power system in each scenario of Market Design C. Since this service is integrated with the mFRR and the DSO one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A and the integrated TSO congestion management-mFRR up service of Market Design B. DERs provide an average of 18% of the total needs in all scenarios. Their lowest share is 17%, and their highest one is 27% of the total.

Table 28: Integrated TSO-DSO congestion management-mFRR up service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design C

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	16%	67%	17%	2.65
2	16%	67%	17%	2.73
3	16%	67%	17%	2.79
4	16%	67%	17%	2.67
5	22%	61%	17%	2.71
6	17%	66%	17%	2.93
7	16%	67%	17%	2.67
8	16%	67%	17%	2.68
9	16%	67%	17%	2.88
10	22%	61%	17%	2.83
11	16%	67%	17%	2.65
12	23%	60%	17%	2.88
13	24%	60%	17%	2.87
14	23%	61%	17%	3.32
15	16%	67%	17%	2.65
16	16%	66%	18%	2.98
17	16%	66%	17%	3.15
18	16%	67%	17%	2.66
19	16%	67%	17%	2.65
20	17%	64%	19%	3.35
21	22%	61%	17%	3.42
22	24%	60%	17%	2.87
23	16%	67%	17%	2.65
24	22%	61%	17%	3.01
25	22%	61%	17%	2.87
26	16%	65%	19%	2.93
27	21%	60%	18%	3.71

28	18%	66%	17%	3.33
29	17%	64%	19%	3.23
30	16%	67%	17%	2.79
31	16%	67%	17%	2.67
32	16%	64%	20%	3.45
33	16%	67%	17%	2.68
34	17%	63%	20%	3.79
35	16%	67%	17%	2.69
36	17%	62%	21%	3.60
37	20%	62%	19%	3.73
38	18%	66%	17%	3.54

Continuation of **Table 28**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	22%	61%	17%	2.88
40	16%	65%	19%	2.93
41	22%	61%	17%	2.67
42	21%	59%	19%	3.55
43	16%	67%	17%	3.32
44	16%	64%	20%	3.01
45	18%	64%	18%	3.12
46	17%	61%	21%	3.47
47	16%	67%	17%	2.68
48	16%	67%	17%	2.72
49	17%	64%	19%	3.30
50	20%	63%	17%	3.05
51	21%	51%	27%	3.59
52	17%	60%	23%	3.77
53	16%	67%	17%	2.81
54	18%	64%	18%	3.32
55	17%	66%	17%	3.40
56	16%	68%	17%	2.96
57	16%	68%	17%	2.65
58	18%	66%	17%	3.25
59	15%	68%	17%	3.02
60	16%	63%	20%	3.43
61	16%	67%	17%	2.71
62	17%	61%	22%	3.53
63	16%	67%	17%	2.67
64	17%	62%	21%	3.59
65	20%	63%	17%	3.14
66	24%	56%	20%	4.06

67	22%	58%	20%	3.18
68	18%	65%	17%	3.13
69	15%	68%	17%	2.77
70	16%	66%	18%	3.33
71	19%	54%	27%	3.62
72	17%	60%	24%	3.63
73	16%	67%	17%	2.65
74	20%	63%	17%	3.24
75	24%	54%	22%	4.18
76	24%	57%	19%	3.92

Continuation of **Table 28**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	15%	68%	17%	2.93
78	20%	53%	27%	3.81
79	23%	58%	19%	3.35
80	23%	59%	17%	3.83
81	22%	55%	22%	4.11

Table 29 presents the integrated TSO-DSO congestion management-mFRR down service mix, and its daily average marginal price of the Greek power system in each scenario of Market Design C. Since this service is integrated with the mFRR and the DSO one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A and the integrated TSO congestion management-mFRR up service of Market Design B. DERs provide an average of 31% of the total needs in all scenarios. Their lowest share is 28%, and their highest one is 50% of the total. Their share exceeds 40% of the total in scenarios 5, 12, 14, 21, 25, 27, 42, and 54, where the net demand is low, the CO_2 emission price is low or medium, and the natural gas fuel price is medium or high.

Table 29: Integrated TSO-DSO congestion management-mFRR down service mix (percentage terms) and its daily average marginal price (€/MW) of the Greek power system in each scenario of Market Design C

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	17%	45%	38%	5.28
2	18%	44%	38%	4.89
3	38%	34%	28%	5.54
4	24%	44%	31%	5.44
5	13%	39%	48%	4.96
6	37%	35%	28%	5.32
7	22%	44%	34%	4.94
8	19%	44%	37%	5.17
9	37%	35%	28%	5.50
10	30%	42%	28%	5.28
11	18%	49%	32%	4.98
12	6%	44%	50%	5.06
13	27%	45%	28%	5.07

14	11%	43%	46%	5.66
15	19%	43%	38%	5.01
16	38%	35%	28%	5.19
17	24%	48%	28%	4.57
18	22%	50%	28%	4.87
19	22%	45%	33%	5.20
20	37%	35%	28%	5.64
21	11%	46%	43%	5.53
22	21%	51%	29%	4.61
23	18%	54%	28%	5.72
24	31%	41%	28%	4.88
25	6%	44%	50%	4.98
26	21%	51%	28%	4.65
27	11%	43%	46%	6.16
28	15%	57%	28%	4.95
29	36%	36%	28%	5.16
30	25%	44%	30%	4.63
31	19%	44%	37%	5.37
32	37%	35%	28%	5.43
33	22%	50%	28%	4.94
34	25%	47%	28%	4.69
35	20%	52%	28%	4.92
36	25%	48%	28%	5.22
37	11%	49%	40%	6.40
38	14%	58%	28%	4.33

Continuation of **Table 29**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	24%	48%	28%	4.61
40	29%	43%	28%	4.86
41	17%	55%	28%	3.92
42	11%	43%	46%	5.67
43	16%	56%	28%	5.55
44	12%	60%	28%	4.83
45	37%	35%	28%	5.17
46	25%	47%	28%	4.85
47	23%	48%	29%	4.71
48	23%	44%	33%	5.15
49	37%	35%	28%	5.93
50	0%	72%	28%	3.75
51	22%	50%	28%	4.24
52	25%	47%	28%	5.00

53	18%	54%	28%	5.29
54	11%	48%	40%	5.53
55	13%	59%	28%	4.38
56	11%	61%	28%	3.32
57	18%	54%	28%	3.97
58	13%	59%	28%	4.92
59	11%	61%	28%	4.42
60	38%	35%	28%	5.77
61	17%	55%	28%	4.86
62	24%	48%	28%	4.85
63	24%	48%	28%	4.97
64	21%	51%	28%	5.17
65	2%	71%	28%	3.41
66	9%	63%	28%	3.50
67	17%	55%	28%	3.90
68	14%	58%	28%	4.14
69	11%	61%	28%	3.09
70	12%	60%	28%	5.02
71	18%	54%	28%	4.14
72	16%	56%	28%	4.80
73	15%	58%	28%	4.51
74	0%	72%	28%	3.14
75	11%	62%	28%	3.55
76	11%	61%	28%	2.82

Continuation of **Table 29**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	12%	60%	28%	3.40
78	10%	62%	28%	4.25
79	11%	61%	28%	2.96
80	11%	61%	28%	2.82
81	11%	61%	28%	2.67

Table 30 presents the integrated TSO-DSO congestion management-mFRR up service mix, and its daily average marginal price of the Bulgarian power system in each scenario of Market Design C. Since this service is integrated with the mFRR and the DSO one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A and the integrated TSO congestion management-mFRR up service of Market Design B. DERs play the most decisive role since they provide an average of 81% of the total needs in all scenarios. Their lowest share is 33%, and their highest one is 100% of the total.

Table 30: Integrated TSO-DSO congestion management-mFRR up service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design C

Scenario	Thermal power	Hydropower	DERs	Marginal price

1	41%	0%	59%	1.93
2	44%	0%	56%	1.91
3	13%	0%	87%	2.03
4	43%	0%	57%	1.91
5	5%	0%	95%	2.47
6	14%	0%	86%	1.97
7	36%	0%	64%	1.93
8	27%	0%	73%	2.05
9	17%	0%	83%	1.96
10	10%	3%	87%	2.39
11	44%	0%	56%	1.90
12	8%	10%	82%	2.49
13	0%	0%	100%	2.23
14	1%	65%	34%	2.65
15	7%	0%	93%	1.89
16	28%	0%	72%	2.00
17	16%	5%	79%	2.39
18	37%	0%	63%	1.92
19	25%	0%	75%	2.05
20	11%	0%	89%	2.10
21	6%	60%	33%	2.66
22	0%	0%	100%	2.19
23	15%	0%	85%	1.97
24	4%	0%	96%	2.34
25	9%	0%	91%	2.24
26	0%	0%	100%	2.17
27	1%	33%	65%	2.53
28	0%	20%	80%	2.53
29	29%	0%	71%	1.89
30	7%	0%	93%	1.89
31	7%	0%	93%	2.02
32	11%	0%	89%	2.08
33	27%	0%	73%	1.94
34	14%	6%	79%	2.39
35	25%	0%	75%	2.04
36	15%	0%	85%	2.17
37	0%	64%	36%	2.66
38	0%	14%	86%	2.47

Continuation of **Table 30**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	9%	0%	91%	2.08

40	0%	0%	100%	2.23
41	0%	0%	100%	2.19
42	1%	47%	51%	2.67
43	0%	22%	78%	2.49
44	0%	29%	70%	2.51
45	7%	0%	93%	1.89
46	11%	0%	89%	2.07
47	6%	0%	94%	1.89
48	7%	0%	93%	2.02
49	24%	0%	76%	2.03
50	4%	0%	96%	2.38
51	11%	0%	89%	1.96
52	19%	7%	75%	2.49
53	4%	0%	96%	2.04
54	0%	20%	80%	2.51
55	0%	22%	78%	2.48
56	1%	56%	44%	2.67
57	0%	0%	100%	2.22
58	0%	21%	79%	2.47
59	0%	35%	64%	2.55
60	7%	0%	93%	2.02
61	18%	0%	82%	2.04
62	10%	0%	90%	2.05
63	6%	0%	94%	2.02
64	11%	0%	89%	2.18
65	4%	0%	96%	2.38
66	11%	0%	89%	2.38
67	15%	0%	85%	2.08
68	0%	17%	83%	2.48
69	0%	21%	79%	2.50
70	0%	28%	72%	2.49
71	10%	0%	90%	1.89
72	11%	0%	89%	2.20
73	12%	0%	88%	2.02
74	4%	0%	96%	2.38
75	11%	0%	89%	2.38
76	11%	18%	71%	2.47

Continuation of **Table 30**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	0%	28%	72%	2.50
78	11%	0%	89%	2.02

79	11%	0%	89%	2.38
80	11%	20%	70%	2.49
81	19%	0%	81%	2.39

Table 31 presents the integrated TSO-DSO congestion management-mFRR down service mix, and its daily average marginal price of the Bulgarian power system in each scenario of Market Design C. Since this service is integrated with the mFRR and the DSO one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A and the integrated TSO congestion management-mFRR up service of Market Design B. DERs play a key role since they provide an average of 46% of the total needs in all scenarios. Their lowest share is 20%, and their highest one is 100% of the total. The share of 100% is achieved in scenarios 15, 30, 31, 45, 47, 48, 60, and 63, where the value of the CO_2 emission price is high.

Table 31: Integrated TSO-DSO congestion management-mFRR down service mix (percentage terms) and its daily average marginal price (€/MW) of the Bulgarian power system in each scenario of Market Design C

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	77%	0%	23%	0.94
2	25%	0%	75%	1.89
3	80%	0%	20%	0.85
4	77%	0%	23%	0.95
5	80%	0%	20%	0.87
6	27%	0%	73%	1.89
7	25%	0%	75%	1.89
8	27%	0%	73%	2.02
9	80%	0%	20%	0.89
10	80%	0%	20%	0.85
11	78%	0%	22%	0.95
12	80%	0%	20%	0.87
13	80%	0%	20%	0.87
14	80%	0%	20%	0.93
15	0%	0%	100%	1.89
16	28%	0%	72%	1.89
17	79%	0%	21%	1.82
18	24%	0%	76%	1.89
19	27%	0%	73%	2.02
20	27%	0%	73%	2.02
21	80%	0%	20%	0.93
22	80%	0%	20%	0.87
23	80%	0%	20%	0.90
24	80%	0%	20%	0.85
25	80%	0%	20%	0.87
26	80%	0%	20%	0.87
27	80%	0%	20%	0.93
28	80%	0%	20%	0.93

29	5%	0%	95%	1.89
30	0%	0%	100%	1.89
31	0%	0%	100%	2.02
32	27%	0%	73%	2.02
33	27%	0%	73%	1.89
34	80%	0%	20%	1.83
35	27%	0%	73%	2.02
36	80%	0%	20%	1.92
37	80%	0%	20%	0.93
38	80%	0%	20%	0.93

Continuation of **Table 31**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	80%	0%	20%	0.85
40	80%	0%	20%	0.87
41	80%	0%	20%	0.87
42	80%	0%	20%	0.93
43	80%	0%	20%	0.93
44	80%	0%	20%	0.93
45	0%	0%	100%	1.89
46	80%	0%	20%	1.85
47	0%	0%	100%	1.89
48	0%	0%	100%	2.02
49	1%	0%	99%	2.02
50	27%	0%	73%	2.38
51	30%	0%	70%	1.89
52	80%	0%	20%	1.89
53	27%	0%	73%	2.02
54	80%	0%	20%	0.93
55	80%	0%	20%	0.93
56	80%	0%	20%	0.93
57	80%	0%	20%	0.87
58	80%	0%	20%	0.93
59	80%	0%	20%	0.93
60	0%	0%	100%	2.02
61	2%	0%	98%	1.89
62	80%	0%	20%	1.85
63	0%	0%	100%	2.02
64	79%	0%	21%	1.98
65	27%	0%	73%	2.38
66	30%	0%	70%	2.38
67	42%	0%	58%	2.02

68	80%	0%	20%	0.93
69	80%	0%	20%	0.93
70	80%	0%	20%	0.93
71	28%	0%	72%	1.89
72	80%	0%	20%	1.98
73	1%	0%	99%	2.02
74	27%	0%	73%	2.38
75	27%	0%	73%	2.38
76	79%	0%	21%	2.32

Continuation of **Table 31**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	80%	0%	20%	0.93
78	28%	0%	72%	2.02
79	27%	0%	73%	2.38
80	80%	0%	20%	2.32
81	49%	0%	51%	2.38

Table 32 presents the integrated TSO-DSO congestion management-mFRR up service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design C. Since this service is integrated with the mFRR and the DSO one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A and the integrated TSO congestion management-mFRR up service of Market Design B. DERs play a noticeable role since they provide an average of around 15% of the total needs in all scenarios. Their lowest share is 15%, and their highest one is 18% of the total.

Table 32: Integrated TSO-DSO congestion management-mFRR up service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design C

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	4%	81%	15%	2.70
2	0%	85%	15%	2.65
3	13%	73%	15%	2.65
4	5%	81%	15%	2.65
5	8%	78%	15%	2.75
6	0%	85%	15%	2.65
7	0%	85%	15%	2.77
8	0%	85%	15%	2.65
9	12%	74%	15%	2.65
10	2%	84%	15%	2.67
11	4%	82%	15%	3.01
12	5%	80%	15%	2.70
13	1%	85%	15%	2.65
14	2%	84%	15%	2.65
15	0%	85%	15%	2.65

16	0%	85%	15%	2.65
17	5%	80%	15%	2.65
18	0%	85%	15%	2.65
19	0%	85%	15%	2.65
20	0%	85%	15%	2.65
21	0%	85%	15%	2.65
22	1%	84%	15%	2.65
23	10%	76%	15%	2.65
24	5%	80%	15%	2.65
25	5%	80%	15%	2.67
26	0%	85%	15%	2.65
27	3%	83%	15%	2.65
28	0%	85%	15%	2.65
29	0%	85%	15%	2.65
30	0%	85%	15%	2.77
31	0%	85%	15%	2.65
32	0%	85%	15%	2.65
33	0%	85%	15%	2.65
34	1%	84%	15%	2.66
35	0%	85%	15%	2.65
36	6%	79%	15%	2.65
37	0%	85%	15%	2.65
38	0%	85%	15%	2.71

Continuation of **Table 32**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	5%	81%	15%	2.65
40	0%	85%	15%	2.65
41	1%	84%	15%	2.65
42	3%	83%	15%	2.65
43	0%	85%	15%	2.65
44	0%	85%	15%	2.65
45	0%	85%	15%	2.65
46	7%	79%	15%	2.65
47	0%	85%	15%	2.77
48	0%	85%	15%	2.65
49	0%	84%	16%	2.90
50	0%	85%	15%	2.96
51	3%	82%	15%	2.65
52	0%	85%	15%	2.65
53	0%	82%	18%	2.90
54	0%	85%	15%	2.65

55	1%	85%	15%	2.77
56	0%	85%	15%	2.65
57	0%	85%	15%	2.65
58	0%	85%	15%	2.65
59	0%	85%	15%	2.65
60	0%	85%	15%	2.65
61	0%	85%	15%	2.76
62	3%	82%	15%	2.65
63	0%	85%	15%	2.65
64	7%	79%	15%	2.65
65	0%	85%	15%	2.65
66	0%	85%	15%	2.65
67	3%	82%	15%	2.65
68	0%	85%	15%	2.65
69	0%	85%	15%	2.83
70	0%	85%	15%	2.65
71	3%	82%	15%	2.65
72	3%	82%	15%	2.65
73	0%	84%	16%	2.90
74	0%	85%	15%	2.65
75	0%	85%	15%	A
76	6%	79%	15%	2.65

Continuation of **Table 32**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	0%	85%	15%	2.72
78	3%	82%	15%	2.77
79	0%	85%	15%	2.71
80	3%	82%	15%	2.68
81	3%	83%	15%	2.65

Table 33 presents the integrated TSO-DSO congestion management-mFRR down service mix, and its daily average marginal price of the Romanian power system in each scenario of Market Design C. Since this service is integrated with the mFRR and the DSO one, it is more significant in requirements in comparison with the TSO upward congestion management service of Market Design A and the integrated TSO congestion management-mFRR up service of Market Design B. DERs play a noticeable role since they provide an average of around 17% of the total needs in all scenarios. Their lowest share is 15%, and their highest one is 29% of the total. They surpass the level of 20% of the total in scenarios 1, 4, 5, 7, 11, 12, 14, 18, 25, 27, 35, 42, and 47, where the net demand is low.

Table 33: Integrated TSO-DSO congestion management-mFRR down service mix (percentage terms) and its daily average marginal price (€/MW) of the Romanian power system in each scenario of Market Design C

Scenario	Thermal power	Hydropower	DERs	Marginal price
1	8%	71%	21%	3.82
2	3%	80%	17%	3.33
3	6%	79%	15%	2.79
4	11%	64%	25%	4.22
5	9%	67%	24%	4.14
6	0%	85%	15%	2.72
7	8%	68%	24%	3.94
8	4%	78%	18%	3.62
9	5%	80%	15%	3.23
10	22%	63%	15%	2.92
11	10%	62%	28%	4.05
12	5%	71%	24%	3.92
13	21%	64%	15%	2.86
14	21%	52%	27%	4.27
15	5%	80%	16%	3.46
16	0%	85%	15%	2.65
17	6%	79%	15%	2.65
18	9%	66%	25%	4.05
19	5%	78%	17%	3.72
20	0%	85%	15%	2.68
21	7%	78%	15%	2.94
22	21%	64%	15%	2.79
23	5%	80%	15%	3.10
24	22%	63%	15%	3.00
25	4%	70%	26%	3.90
26	21%	64%	15%	2.78
27	20%	51%	29%	4.42
28	21%	64%	15%	2.65
29	0%	85%	15%	2.65
30	4%	80%	16%	3.29
31	5%	77%	18%	3.74
32	0%	85%	15%	2.73
33	1%	84%	15%	3.00
34	3%	82%	15%	2.65
35	8%	69%	23%	4.04
36	6%	79%	15%	2.65
37	4%	81%	15%	3.09
38	21%	64%	15%	2.65

Continuation of **Table 33**

Scenario	Thermal power	Hydropower	DERs	Marginal price
39	21%	65%	15%	2.92
40	21%	64%	15%	2.80
41	21%	64%	15%	2.97
42	21%	55%	24%	4.57
43	21%	64%	15%	2.65
44	21%	64%	15%	2.82
45	0%	85%	15%	2.72
46	3%	82%	15%	2.65
47	8%	69%	23%	3.92
48	3%	82%	15%	3.30
49	0%	85%	15%	2.73
50	0%	85%	15%	2.65
51	1%	85%	15%	2.72
52	3%	82%	15%	2.65
53	1%	85%	15%	3.23
54	4%	81%	15%	3.45
55	21%	64%	15%	2.65
56	21%	64%	15%	2.65
57	21%	64%	15%	2.76
58	21%	64%	15%	2.67
59	21%	64%	15%	2.96
60	0%	85%	15%	2.65
61	0%	85%	15%	3.19
62	2%	84%	15%	2.65
63	5%	78%	18%	3.75
64	3%	82%	15%	2.65
65	0%	85%	15%	2.94
66	0%	85%	15%	2.65
67	3%	83%	15%	2.65
68	21%	64%	15%	2.65
69	21%	64%	15%	2.65
70	21%	64%	15%	2.79
71	0%	85%	15%	2.72
72	0%	85%	15%	2.65
73	0%	85%	15%	3.13
74	0%	85%	15%	2.80
75	0%	85%	15%	2.65
76	3%	82%	15%	2.65

Continuation of **Table 33**

Scenario	Thermal power	Hydropower	DERs	Marginal price
77	21%	64%	15%	2.68
78	0%	85%	15%	2.65
79	0%	85%	15%	2.65
80	2%	83%	15%	2.65
81	2%	83%	15%	2.65