TradeRES

New Markets Design & Models for 100% Renewable Power Systems

Performance assessment of current and new market designs and trading mechanisms for national and regional markets

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1.0	28/11/2022	Public	This report will present and analyse the results obtained with the current and new markets designs of the national/regional case studies.

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Executive summary

The present deliverable was developed as part of the research activities of the TradeRES project *Task 5.3 – Performance assessment of current and new market designs and trading mechanisms for National and Regional Markets*. This report presents the first edition of deliverable 5.3, which provides an initial assessment of the market performance using the actually existing designs and products, implemented within TradeRES project in the models used in work package 5. This assessment is performed through (key) market performance indicators (MPIs) previously identified to address the research questions of the project in a quantitative manner.

Three computational studies focusing on national/regional electricity markets are analysed. Two related to the Central European market - EPEX SPOT: the Netherlands (case study B) and Germany (case study C), and one related to the Iberian electricity market – MIBEL (case study D). The studies are conducted using different models and computational systems: COMPETES, EMlabpy, AMIRIS, MASCEM and RESTrade that were fully described in the deliverables of *WP 4 - Development of Open-access Market Simulation Models and Tools*.

Dutch case study: The main research question addressed by the Netherlands case study in this report is "***To what extent can an energy-only market with/without variable renewable energy sources (vRES) targets provide system adequacy for a 100% RES system by 2030 and 2050?***". To answer this question, a coupled AMIRIS-EMlabpy model approach for a baseline scenario is used allowing to test different market design bundles. The power system optimization and economic dispatch optimization model COMPETES will be used to obtain the reference system outcomes in future editions of this deliverable. In this case study, the design bundles are: i) an energy-only market without vRES targets – *designated as EOM* – and ii) the energy-only market with vRES targets– *designated as EOM_VRES.* The results are obtained for the period between 2019 and 2050.

Broadly speaking, and despite some improvements needed before making recommendations for future market designs, preliminary results from the AMIRIS-Emlabpy approach highlighted that myopic profit-based investment decisions are not sufficient to incentivize a high share of renewable energy sources (RES). Furthermore, in long term an energy system with higher share of RES presented a lower supply ratio and thus worse security of supply despite the higher total installed capacity. Finally, we observed that although the market-based cost recovery was worse in the simulations with targeted investments (EOM_VRES), the costs to society were not much higher in this scenario in comparison to the EOM. These observations can be very different in future simulations when more realistic prices will be considered.

German case study: The main research question to be addressed in the German case study in this report is "***Are renewable energy sources (RES) remuneration support schemes needed and if so, how should they be designed?***". To answer this question, the agent-based model AMIRIS is used to analyse cost and revenue as well as economically induced curtailment situations. As a starting point scenario, the *status quo* of the German electricity sector is simulated based on the year 2019. A situation with support only in place for small rooftop PV plants is compared with different market design bundles, in this case support mechanisms, for vRES, namely: i) *fixed market premium* with fixed payments on top of market revenues ii) v*ariable market premium* with price-variable payments on top of market revenues; iii) *contracts for differences (CFD)* with price-variable payments on top of market revenues and an obligation to pay back in case of high prices; and iv) *capacity premium* with payments per installed capacity.

The simulations for this starting point scenario do neither reveal: i) substantial differences in the market performance for the different market design bundles; nor ii) a clear indication on how remuneration schemes should be designed. This result can be explained by the limited share of RES (nearly 34%), which is relatively low for having a systematic impact on the market prices. Results reveal that market revenues are not enough to cover the costs of RES. Depending on the RES technology around 28% (for PV) to 66% (for wind offshore) of total costs cannot be (re)covered at the day-ahead market.

Iberian case study: The main research questions addressed in the Iberian case study are "***How can short-term markets be made more efficient in order to better integrate short-term vRES fluctuations****?"* and *"****Are vRES remuneration support schemes needed and if so, how should they be designed****?*". To answer these questions, the agent-based models MASCEM and RESTrade are applied to a starting point scenario that was constructed considering the *status quo* of the Portuguese and Spanish power systems using historic data from the year 2019. Similarly to the German case study, different market design bundles for vRES producers are analysed, namely, i) fixed market premium, ii) variable market premium, calculated to ensure full cost recovery of the vRES investments; iii) One-way CfD; iv) two-way CfD; and v) capped premium.

The countries in the MIBEL market, *i.e.,* Portugal and Spain, are among the European countries with a higher penetration of vRES in their power systems. However, for the starting point scenario constructed and the simulations bundle addressed in this deliverable, the results indicate that only solar photovoltaic and conventional power plants (as nuclear and natural gas technologies) can recover their costs without remuneration support schemes. With the parameterizations assumed in the Iberian case study, Portugal and Spain reveal different market outcomes. For wind energy in Spain, none of the support schemes allows not wind investors recovering their (annualised) investment costs. For Portugal, the situation is slightly different, and only the two-way CfDs scheme does not enable players to obtain remunerations above the variable premium, used as a reference. Simulations conducted within MIBEL case study suggest that both countries may improve the allocation of their secondary reserve capacity, as the results indicate more capacity is reserved than the needed to balance the system considering all ancillary services.

The first set of simulations presented in this deliverable should be seen as preliminary, as they were used essentially for testing, verification and *calibration of* electricity market models, to obtain close-to real-world results. Due to the iterative nature of the project, some market design bundles presented in this version will be further investigated in the second edition of deliverable expected in Month 43. In the second edition results from the *WP 2 - Optimal electricity trading with ~100% RES: Generation of a reference power system, scenarios and input market data* that provide optimal energy shares for ~100% renewable electricity systems will be used. Additional research questions will also be addressed in the second edition of deliverable 5.3.

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List of acronyms

ABM	Agent-based models
AF	Activated Flexibility
AIMMS	Advanced Interactive Multidimensional Modelling System
AMIRIS	Agent-based Market model for the Investigation of Renewable and Integrated energy Systems
AS	Ancillary system
BRPs	Balance responsible parties
CAES/AA-CAES	Compressed Air Energy Storage / Advanced
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and sequestration
CfD	Contracts for differences
CHP	Combined Heat & Power
CO_2	Carbon dioxides
COMPETES	Competition and Market Power in Electric Transmission and Energy Sector
CP	Capacity premium
CSV	Comma separated values
DAM	Day-head market
DR	Demand response
DSM	Demand side management
EENS	Expected Energy Not Served
EMLAB	Energy Modelling Laboratory
ENTSO-E	European Network of Transmission System Operators
EOM	Energy only market
EU	European Union
EV	Electrical vehicle
FIT	Feed-in tariff
G2V	Grid-to-vehicle
GHC	Greenhouse Gas
KPIs	Key performance indicators
LCOE	Levelized Cost of Electricity
LMP	Local market price
LOLE	Loss of Load Expectation
LPM	Levelized Profit Margins
MAPE	Mean absolute percentage error
MASCEM	Multi-Agent Simulator of Competitive Electricity Markets
MIBEL	Iberian Electricity market
MPfix	Fixed market premium
MPI	Market performance indicator
Mpvar	Variable market premium
NB	Normalized bias
NL	Net load
NPV	Net present value
NRMSE	Normalized root mean square error
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
OMIE	Operador de Mercado Ibérico
OPEX	Operational Expenditure
P2G	Power-to-gas
P2H	Power-to-heat
P2h2	Power-to-hydrogen
P2M	Power-to-mobility
P2X	Power-to-X
PHS	Pumped hydro storage
PLR	Peak Load Reduction

PV	Photovoltaic
r	Discount rate
R&D	Research and development
RES	Renewable energy sources
RF	Requested Flexibility
RQ	Research question
RR	Refinancing ratio
SPRS	Starting Point Reference System
SPS	Starting Point Scenario
TC	Total costs
TR	Total revenues
TRS	TradeRES Reference System
TSO	Transmission system operator
UC	Unit commitment
V2G	Vehicle-to-grid
VRB	Vanadium redox battery
vRES	Variable renewable energy sources
WACC	Weighted average cost of capital
WMP	Wholesale market price
WP	Work package
WTG	Wind turbine generator

1. Introduction

The present deliverable was developed as part of the research activities of the TradeRES project *Task 5.3 – Performance assessment of current and new market designs and trading mechanisms for National and Regional Markets* under work package 5, "*Performance assessment of the market(s) design(s). Application of the open-access tools to characteristic case studies"* - a key work package that relates to all main work packages of this project, as illustrated by Figure 1.

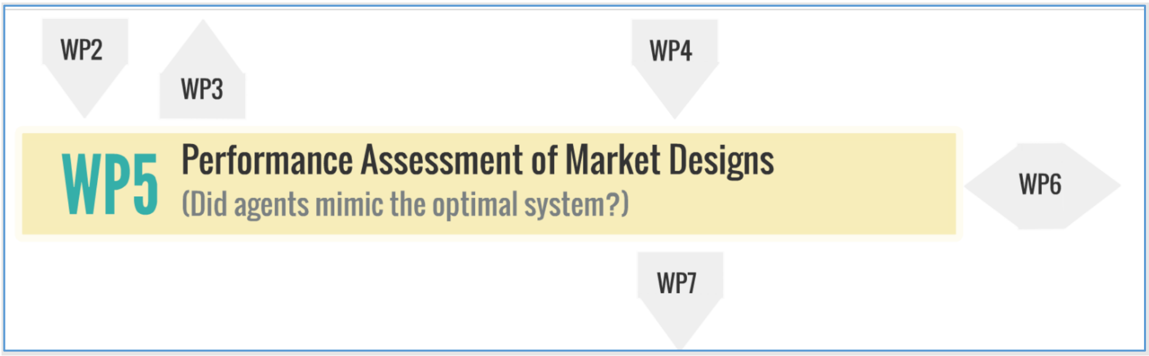

Figure 1. WP5 interactions within TradeRES project.

This report constitutes deliverable D5.3 of TradeRES project and its matter is to present and analyse the results of three studies staged to investigate the performance of new designs for both central and regional markets. The work was conducted in the context of task T5.3, which focuses on three computational studies, two related to the Central European market - EPEX SPOT, and one related to the Iberian electricity market - MIBEL. The studies were conducted with the help of different computational systems: COMPETES, AMIRIS, EMLabpy, MASCEM and RESTrade. To contextualize the report in terms of both market design and operation, particularly, the need to consider new market design elements, in the following, we give a brief overview of the main driving force behind the growing need to study current markets and analyse their outcomes.

The energy landscape is currently being shaped by three mega-trends, commonly referred to as the "three-D's"—Decarbonisation, Decentralization and Digitalization. In particular, renewable generation has grown significantly during the past decades, surpassing all expectations, and this growth is expected to continue during the coming years. Traditional (fossil-fuelled) power plants connected to the transmission grid are increasingly being phased-out and, at the same time, non-traditional (variable renewable systems – vRES) connected to the distribution grid are increasingly being part of the supply mix. In addition, distributed energy resources that can serve as both demand and supply or flexible demand (e.g., electric vehicles, batteries and heat pumps) are becoming market-ready and end users are increasingly transforming from passive consumers into prosumers.

The unique characteristics of renewable generation - more variable, less predictable and decentralized when compared to traditional generation - create unique challenges in the design and operation of electric energy markets. These include, among others, the following two key aspects: (i) the need to incentivize increasing levels of flexibility in a cost-effective way to manage the rising variability and uncertainty of the net load, and (ii) the need to ensure revenue sufficiency for achieving long-term reliability and re-investment. At present, it is unclear whether, or not, current markets based on the traditional and existing design will be able to evolve in a form adequate to mitigate the impact of the rising penetrations of renewables. Simply put, there is a growing need to study the operation and outcomes of current markets and to analyse the need to adapt current market rules to new market realities.

According to the developments of WP 2, the TradeRES scenarios that have been defined differ based on demand and supply side parameters. More specifically, which aims to capture a key milestone of the transition, foresees high penetration of renewable energy sources. The $S_1 - S_4$ anticipate very high to almost 100% shares of vRES and at the same time differ with respect to the level of demand flexibility and assumptions related to power generation (e.g. thermal capacity, hydrogen power plants, curtailment, etc.). These are the “Conservative” (S_1), the “Flexible” (S_2), the “Variable” (S_3) and the “Radical” (S_4) so called TradeRES Scenarios. The timeline shown in Figure 2 positions the scenarios to the key milestone years and also indicates the Starting Point Scenario (SPS) that refers to a year prior to the beginning of TradeRES project (*i.e.*, the year 2019).

Figure 2. Allocation of TradeRES Scenarios on the timeline.

The scenarios play a significant role on the modelling process as they constitute the inputs fed to the models and consequently there is strong dependence of the outputs. The scenario formation process under WP 2, where the TradeRES Scenarios were constructed using SPS as a basis, can be seen in Figure 3. For the National/Regional case studies specifically, as the figure shows, the WP 5 models need also inputs related to the Reference Systems and the Market Design Bundles.

The TradeRES Reference Systems refer to the outputs of the optimization models that are used in TradeRES to define a system in the long run under the TradeRES Scenarios. Such a Reference System can include but it is not limited to generation and storage capacities, *i.e.*, results of the optimal investment planning, and optimal operational outcome, e.g. dispatches, marginal prices, imports/exports, etc. For the SPS, instead of the optimization model outcomes, the corresponding Reference System, the so-called Starting Point Reference System (SPRS) is populated by using actual data from 2019 and used for benchmarking the agent-based models.

The *Market Design Bundle* refers to the collection of market design options as identified in WP3 and technically refined in WP 4 deliverables. The market design option that are considered to coexist are non-mutually exclusive, may refer to a different category and/or aspect and form the market design under consideration. The Baseline Bundle, which is to be used in conjunction with SPS and SPRS for setting up the benchmarking experiment, can contain the minimal and/or already implemented market design options.

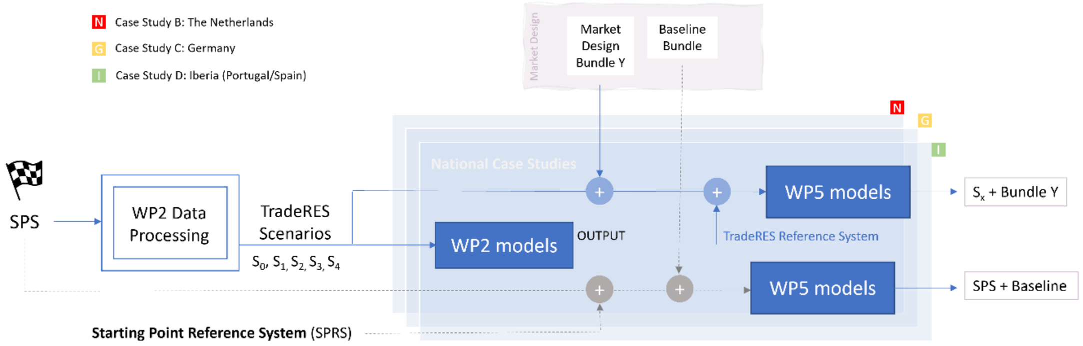

Figure 3. National/Regional case studies modelling process.

It should be noted that the full extent of the study with all the simulations described in Figure 3 is expected in the next version of this deliverable. Moreover, by summarizing the discussion around Figure 3, the following usage of terms is adopted.

- "Scenario" within TradeRES refers to a structured input data collection that encapsulate certain properties of the underlying future energy system
  - TradeRES Scenarios
    - S_0 – 60% vRES penetration (2030)
    - S_1 – the "Conservative" scenario; very high vRES shares (2050)
    - S_2 – the "Flexible" scenario; very high vRES shares (2050) and a highly flexible demand
    - S_3 – the "Variable" scenario; almost 100% vRES shares (2050)
    - S_4 – the "Radical" scenario; almost 100% vRES shares (2050) and a highly flexible demand
  - Starting Point Scenario (SPS) corresponds to year 2019
- "Reference System" within TradeRES refers to the structured collection of data that are complementary required by the agent-based models either for being explicitly used in the simulations or to be utilised as basis of comparison.
  - TradeRES Reference System (TRS) is the Reference System created by the optimization models for $S_0 - S_4$
  - Starting Point Reference System (SPRS) is the Reference System that uses data and conditions of 2019
- "Market Design Bundle" within TradeRES refers to a combination of Market Design Options that are to be studied and evaluated jointly in a case study.
  - Baseline Bundle is the specific Market Design Bundle that captures either minimal or already implemented the market design conditions.

Against this background, the main objective of this deliverable is to describe and analyse in detail the results of the following three computational studies:

- Study B[1] (the Netherlands): studying the Central European market (EPEX SPOT) and using the soft-linking AMIRIS-EMLabpy the aim is to analyse if an EOM will be sufficient to achieve the country vRES target and to analyse if a system that fulfils the investment targets can ensure security of supply.
- Study C (Germany): studying the German day-ahead market and using the agent-based model AMIRIS. The aim is to analyse the need and possible design of remuneration schemes for renewable energy sources (RES).
- Study D (Portugal/Spain): studying the Iberian market (MIBEL) and the agent-based models MASCEM and RESTrade. The aim is also to analyse new elements of market design mitigating the impact of the high variability and uncertainty of variable generation in the revenues of those power plants.

This deliverable builds on several other preceding deliverables and tasks for gathering inputs and identifying key aspects in a wide range of related subtopics, varying from existing models and their coupling to market design principles, as well as existing computational systems to model energy markets. Particularly, this deliverable heavily relies on information provided by WP3 and WP4 deliverables (see project website).

Especially noteworthy is deliverable D4.5 [1], which follows up on D3.5 [2], by explaining new models used and developed in this project for evaluating new market designs and changes in market rules. Specifically, D3.5 describes important market design choices at the wholesale and retail levels and D4.5 describes the modelling approach followed to include those new design features, including market changes to allow trading closer to real time, to stimulate flexibility options at all system levels, and the reduction of imbalances from variable renewable energy sources (vRES).

Also, in terms of revenue sufficiency for achieving long-term reliability, D4.5 describes the comparison of an energy-only market with a selection of capacity mechanisms to investigate the extent to which these mechanisms improve market performance with respect to system adequacy, investment risk and cost and risk to consumers. Furthermore, two main policy instruments – the European Emissions Trading System as a means of carbon pricing and different RES support schemes – are described, in order to simulate transition steps between the current situation and a zero-carbon system. Particularly, the renewable energy sources support schemes considered are feed-in premium, market premium, capacity-based support, and contract for differences. Finally, green origination certificates are also presented.

Regarding the computational platforms to simulate energy markets, in TradeRES project two types of models are used, namely agent-based and optimization models, which were described in deliverable D4.6 [3]. As mentioned earlier, the models used are COM-

[1] In this project, the case studies and respective reports are divided by spatial scope: case study A - Local Energy Communities; case studies B to D - National and Regional Markets; case study E - Pan-European wholesale electricity.

PETES, AMIRIS-EMLabpy, AMIRIS, MASCEM and RESTrade are shortly described below:

- **COMPETES:** Competition and Market Power in Electric Transmission and Energy Simulator developed by TNO, is a power optimisation system that seeks to minimise the total power system costs of the power market. The model can perform hourly simulations for two types of purposes: (i) least-cost unit commitment and economic dispatch, considering the technical constraints of generation technologies, and (ii) least-cost capacity expansion and economic dispatch to optimise generation and transmission capacity additions. It covers all EU Member States and some non-EU countries (e.g., Norway and Switzerland);
- **AMIRIS-EMLabpy**: Soft coupling of AMIRIS and EMLabpy in Spine toolbox. EMLabpy is a modular ABM that allows to analyse the impact of energy policies, such as capacity mechanisms, in the investment of generation capacity.
- **AMIRIS:** Agent-based Market model for the Investigation of Renewable and Integrated energy Systems, developed by DLR, is an agent-based system capable of simulating the day-ahead market. The agents comprise power plant operators, traders, demand/flexibility providers, prosumers and other dedicated groups of end-users and market operators. The system is based on an open-source framework for agent-based energy system analysis[2];
- **MASCEM:** Multi-Agent Simulator of Competitive Electricity Markets, developed by ISEP, is an agent-based system able to simulate day-ahead and intra-day markets, as well as the negotiation of bilateral contracts. The main market entities, implemented as software agents, include the market and system operators, producers and/or prosumers, aggregators, and consumers;
- **RESTrade**, developed by LNEG, comprises models of traditional power plants and variable renewable energy plants. This system can simulate the reserve markets and, also, the dynamic line rating of overhead power lines. The pricing methodology considered for the reserves market is based on the marginal pricing theory;

and are applied to the case studies and starting point scenarios described in this deliverable.

The remainder of this report is structured as follows. Section 2 describes TradeRES research questions and market performance indicators (MPIs) selected for this first version of D5.3. Section 3 describes the three computational studies and analyses the results. Specifically, subsection 3.1 describes case study B (the Netherlands), subsection 3.2 the case study C (Germany) and subsection 3.3 the case study D (Portugal/Spain). Section 4 presents a comparison of MPIs among the different case studies. Finally, in section 5, a synthesis of the results as well as future work that will be developed in the second version of this deliverable are provided. Annex A presents the relevant research questions for national/regional markets. Annex B provides a detailed description of the market performance indicators used in the deliverable to assess the different market designs and products.

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[2] Further details available at: https://gitlab.com/fame-framework/wiki/-/wikis/home

2. TradeRES' research questions and selected market performance indicators for ~100% RES power systems

2.1 Research questions addressed in the project

TradeRES project covers a wide range of subjects to be addressed. A deep and detailed exercise was conducted, not only to identify the ultimate research questions (RQ) whose answers the projects pursues, but also to cluster them within sub-themes, associated to the application of different models within the cases studied within WP5. Seven different main themes were identified and those are:

1. Improvement of short-term markets
2. Incentivizing distributed flexibility and local markets
3. Incentivizing demand response and sector coupling
4. System design and adequacy
5. investment incentives for renewables (EOM or support scheme) and for secure capacities (EOM or capacity mechanism)
6. Investment incentives for renewables (EOM or support scheme)
7. Investment incentives for secure capacities (EOM or capacity mechanism)

The whole set of research questions TradeRES intends to contribute to are presented in Annex A. In this first edition of the models' application in the national and regional market's case studies, a first reduced set of research questions, will be addressed. Those are presented in Table 1.

Different models/case studies will be in conditions to address different RQs. Those will be identified for each case study (B, C and D).

Table 1. TradeRES research questions addressed in the 1st iteration of simulations of national and regional case studies.

Cluster1	Cluster2	Research question /challenge to be addressed/answered by TradeRES models and simulations (one line per question)	Perspective/ Timeframe	WP5 Case Study/ Task	Requirements
improvement of short-term markets		How to make short-term markets more efficient in order to better integrate short-term VRES fluctuations?	Product design / short term	C, D	Capacity mix from EMLabpy or other model; Inform. on dependency between vRES forecast errors &lead times.
ancillary services		What is the role/value of (variable) renewables for providing ancillary services?	Renewable producers / Short and long term	D	n.a.
system design and adequacy		What is the optimal share of vRES generation on each market type/product that maximizes its profit enabling their participation without additional support?	Renewable producers / Short-term	A, B, C, D, E	1. vRES and hybrid techs. optimization models, 2. market models, 3. forecast methodologies 4. vRES and hybrid LCOEs, or CAPEX, OPEX and capacity factors, 5. vRES and hybrid techs. investments policy
system design and adequacy		Impact of no thermal capacity: How will it affect the market prices - what will determine the price, will there be more very high and very low prices? How will it affect capacity adequacy?	private investor and system perspective / long and short term	B, C, D, E	Thermal capacity alternatives in the scenarios

Cluster1	Cluster2	Research question /challenge to be addressed/answered by TradeRES models and simulations (one line per question)	Perspective/ Timeframe	WP5 Case Study/ Task	Requirements
investment incentives for secure capacities (EOM or capacity mechanism)		Are capacity mechanisms needed and if so, how should they be designed?	Producers, storages, consumers / long term and short term	B,C,D	Capacity mix from EMLabpy or other model + capacity mechanism schemes from WP 3
investment incentives for secure capacities (EOM or capacity mechanism)		Under which conditions will a future market enable the system adequacy?	Long term, short term	B,C,D	Couple EMLAB with models (ABM and optimization) that allows to integrate a more detailed dispatch algorithm and combine new market designs in the wholesale market, sector coupling and demand side response.
investment incentives for secure capacities (EOM or capacity mechanism)	investment incentives for renewables (EOM or support scheme)	Do actual market designs give sufficient and attractive incentives to capacity investments (in both vRES and conventional) technologies based only on energy trading without further incentives?	Renewable producers / Short and long term	A,B,C,D,E	1. vRES optimization models, 2. market models, 3. forecast methodologies, 4. vRES, LCOE, or CAPEX, OPEX and capacity factors
investment incentives for secure capacities (EOM or capacity mechanism)	investment incentives for renewables (EOM or support scheme)	Profitability (benchmark scenario and alternative scenarios and market designs): Does the wholesale market provide sufficiently high and secure revenues for private investors to invest in both intermittent renewables and dispatchable capacities under different scenarios and market designs? What are the underlying market dynamics driving (non-) profitablity and risk profiles?	Investor perspective / short and long term	B,C,D,E	Required output data: at least hourly prices for each bidding zone, hourly dispatch per technology and bidding zone, installed capacities per bidding zone, marginal plants
investment incentives for renewables (EOM or capacity mechanism)		VRE support schemes (alternative market design): In case that no sufficient improvements to the wholesale market design can be identified and VRE require financing in addition to wholesale market revenues: What is the impact of different financing instruments (market premium / bilateral contracts & CfD/ capacity-based premium) on (1) investment in renewables and (2) wholesale markets? To what degree should financing schemes be market-based	private investor and system perspective / long and short term	B,C,D, E	Modelling or assumptions on market behavior of renewables depending on support scheme; output data: at least hourly prices for each bidding zone, hourly dispatch per technology and bidding zone, installed capacities per bidding zone

- ***The Netherlands***

The Netherlands case study focuses on long-term market design options. The objective of long-term market design is to provide incentives for adequate and efficient investments. In the past, this only concerned dispatchable generation; in a future system, the objective is an optimal balance of variable renewable generation, controllable generation, storage and demand response, and an optimal combination between these market-driven investments and network capacity.

As discussed in the D3.5 of this project, mainly in section 5.4, it is uncertain whether an energy-only market design can provide an optimal investment mix of variable and controllable generation and energy storage technologies and enable sufficient demand response. Some reasons for this uncertainty are the substantial regulatory and technology risk as well as fuel and CO_2 price risk; vRES create price volatility and depress prices, reducing their own business case for dispatchable technologies; An increase on price volatility can reinforce the regulatory uncertainty; A lack of demand elasticity avoid scarcity prices to occur and therefore can diminish market-based cost recovery. Similarly, vRES create investment risk for controllable generation capacity, energy storage and demand response.

Due to the development stage of the models, this edition will focus on the energy-only market with a vRES capacity target. In the next iteration, a combination of VREs support mechanisms and capacity mechanisms will be investigated to find a market design that achieves sustainability goals while keeping the security of supply. In this project, the questions to be answered for the Dutch market are:

1) Does the wholesale market provide sufficiently high and secure revenues for private investors to invest in both intermittent renewables and dispatchable capacities under different scenarios and market designs?

2) If this is not the case, how should capacity mechanisms be designed? Are capacity mechanisms needed and if so, how should they be designed?

And in this first simulations' iteration, the question addressed will be;

> ***To what extent can an energy-only market with/without vRES targets provide system adequacy for a 100% RES system by 2030 and 2050?***

- ***Germany***

In the course of the project, the German case study seeks to answer the following research questions:

1. How to make short-term markets more efficient in order to better integrate short-term fluctuations from variable renewable energy sources (vRES)?
2. Which framework conditions incentivize flexibility options to contribute to an efficient dispatch?
3. Are remuneration schemes for renewable energy sources (RES) needed and if so, how should they be designed?
4. Are capacity mechanisms needed and if so, how should they be designed?
5. How can system adequacy be maintained in a ~100% RES electricity market?

In the first edition of the prevalent deliverable, the focus is on assessing the need for renewable support schemes. So, the main question addressed is:

> ***Are RES remuneration schemes needed and if so, how should they be designed?***

- ***Iberian market (MIBEL)***

In the course of the project, the MIBEL case study seeks to answer the following research questions:

1. Will (near) real-time trading/gate closure times enable vRES producers to maximize their profit and electricity markets to reduce structural imbalances?
2. How to make short-term markets more efficient, in order to better integrate short-term vRES fluctuations?
3. What is the value of new "flexibility" players/actors likely to appear up to 2030?
4. Cross-border trade: What are the benefits of cross-border trade and therefore of further market harmonization and/or measures such as dynamic line rating from a system perspective?
5. Does actual market design give sufficient and attractive incentives to capacity investments (in both vRES and conventional) technologies based only on energy trading without further incentives?
6. Are RES remuneration schemes needed and if so, how should they be designed?
7. Local Markets/Prosumage: How does incentivizing local markets and prosumage impact European wholesale markets?

In this first version of the deliverable, the focus is on assessing the need for renewable support schemes. Thus, the main questions addressed in this document are:

- ***How to make short-term markets more efficient in order to better integrate short-term VRES fluctuations?***
- ***Are RES remuneration schemes needed and if so, how should they be designed?***

To address all the previous research questions, (key) market performance indicators (MPIs) were established in TradeRES project [4].

2.2 Market performance indicators for ~100% renewable power systems

The MPIs will enable the assessment of the market designs' and products' performance under development in TradeRES. This assessment will support the identification of the most adequate configurations and products to address the project's research questions aiming to provide recommendations for future electricity market designs at local, national/regional and pan-European scales. The MPIs were classified using four domains: technical, economic, environmental, and social. In specific [4], [5]:

- *technical MPIs* assess aspects related to operating parameters and technical constraints.
- *economic MPIs* assess the viability and cost-effectiveness of the proposed solutions.

- *environmental MPIs* assess and evaluate the environmental impact of the proposed solutions.
- *social MPIs* are related to the stakeholders/end-users' willingness to participate in the new market products as well as the identification of the right incentives for motivating for instance load shifting of energy consumed according to the system needs.

A summary of the MPIs used in this deliverable is presented in Table 2, while a detailed description can be found in Annexe B.

Table 2. Summary of MPIs used in this deliverable for the different case studies.

Domain	MPI Name (and acronym)	Detailed description	Case study		
			B – The Netherlands	C - Germany	D - MIBEL
Technical	#1: Share of RES in the national demand	This MPI indicates the level of integration of RES, including wind, solar, biomass, biogas, concentrated solar power, hydro power plants, others in the power system under analysis.	✔	✔	
	#4: Loss of load expectation (LOLE)	Number of hours that secured capacity doesn't meet the demand (including imports and exports consideration) within a control region; simplified (no Monte Carlo simulation).	✔	✔	✔
	#5: Expected energy not served (EENS)	Amount of energy that cannot be provided during hours with loss of load (including imports and exports consideration) within a control region [6].	✔	✔	✔
	#6: Supply ratio	Relation of available supply capacity and demand. Different load curves scenarios will be analyzed with focusing on the average and extreme demand events (peak and percentiles 95th and 98th).	✔		
	#11: Peak Load Reduction	Comparison of absolute peak values between the initially demanded and the actually realized load in a period of time for indicating DSR effects.		✔	
	#12: Ancillary service(s) energy use	This MPI presents the dispatched energy of each ancillary service (AS) product and all ancillary services.			✔
	#13: Capacity procurement in the AS	This MPI presents the capacity procurement of each AS product and all ancillary services.			✔
	#14: Percentage of capacity use in the AS	This MPI presents the capacity of each ancillary service during time period effectively used in the AS.			✔
	#15: Share of demand participation in the AS	This MPI presents the share of demand participation in the AS.			✔
	#16: Share of vRES participation in the AS	This MPI presents the share of vRES participation in the AS.			✔
	#17: Market based curtailment	Market-based energy curtailed of vRES.		✔	✔
	#24: Normalized bias error (NB) of forecasts	This MPI intends to quantify the amplitude error related to the systematic tendency of a forecast. It allows assessing whether the forecasting methodology tends to underestimate or overestimate compared with the observed values.			✔

Domain	MPI Name (and acronym)	Detailed description	Case study		
			B – The Netherlands	C - Germany	D - MIBEL
	#25: Normalized root mean square error (NRMSE) of forecasts	This MPI intends to quantify the phase errors (related to temporal consistency and the capability to reproduce the temporal variability of a predetermined parameter) of the model.			✔
Economic	#26: Total system costs	This MPI is related to affordable and competitive energy. It represents the European power (and energy) system costs, including its investments and operation.			✔
	#27: System costs for dispatch	The overall costs of the power system modelled.		✔	✔
	#28: Costs to society	This MPI can be used to identify the total electricity price, the cost of the capacity market, and the cost of the renewable policy (if applicable) per unit of electricity consumed	✔		
	#29: Average day-ahead price	Volume-weighted average of hourly day-ahead market price for a year	✔	✔	✔
	#30: Energy scarcity duration	With more flexibility in the system the unserved energy can be reduced and extreme prices can appear when the system is under stress.		✔	
	#31: Support costs	The overall and specific amount of support pay out to RES operators		✔	✔
	#32: Market-based cost recovery	Relation of market-based revenues and expenses per technology (including storage) which indicates refinancing possibilities, cost coverage and support needs.	✔	✔	✔
	#33: Price convergence	Yearly percentage of hours with full, moderate and low price convergence measured by the yearly average day-ahead price differentials across European borders.			✔
	#36: Ancillary service(s) (AS) costs	This MPI presents the costs of each AS system and all ancillary services considering the price and quantity.			✔
	#37: Average market penalties	This MPI presents the penalties associated with the deviations between expected and observed power in the different electricity market products during a period. These penalties should be paid by the balance responsible parties (BRPs), considering that all players that deviated from the original program pay the entire AS costs.			✔
	#38: Average imbalances prices	This MPI presents the average imbalances prices for up and down deviations that should be paid by the balance responsible parties during a predetermined period.			✔
Environmental	#45: Power system emissions	This MPI is related to sustainable development and it provides the annual CO_2 emissions associated with fossil fuel energy generation. This indicator enables quantifying how much the different market designs reduce CO_2 emissions.		✔	✔

3. National and regional case studies

This section presents the results from the national and regional case studies.

3.1 Case Study B: The Dutch Market

The Netherlands is part of the EPEX SPOT market (together with twelve other countries[3]). The large-scale potential of wind offshore in the North Sea puts the Netherlands in a privileged position to accommodate large shares of vRES to meet both domestic and foreign electricity demand. TNO and TU Delft will conduct the performance assessment of a new market design for the Netherlands using the TradeRES novel tool – AMIRIS-EMLabpy for the baseline scenario and to test different market design bundles and COMPETES for the reference system.

COMPETES is an optimization model that identifies the least-cost energy mix configuration. AMIRIS-EMLabpy is an agent-based model that explores new market designs. The results of COMPETES will represent a power system's ideal configuration for optimal technical and economic performance concerning social welfare maximization. These results of AMIRIS Emlabpy will be compared against the reference system for evaluating the new market designs. Using two models underlying different goals and approaches, we can benchmark the results following different market designs against an optimal system configuration. This comparison will provide insights into the strengths and weaknesses of the new market designs.

3.1.1 Models used: COMPETES and AMIRIS- EMLabpy

COMPETES is a power system optimization and economic dispatch model that seeks to meet European power demand at minimum social costs (maximizing social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of power generation units and transmission interconnections across European countries and regions[4]. The model is implemented in the Advanced Interactive Multidimensional Modelling System (AIMMS).

COMPETES consists of two major modules that can be used to perform hourly simulations for two types of purposes:

- A transmission and generation capacity expansion module to determine and analyze least-cost capacity expansion under perfect competition formulated as a linear program to optimize generation capacity additions in the system;

[3] Further details are available at: https://www.epexspot.com/en/about
[4] Over the past two decades, COMPETES was originally developed by ECN Policy Studies – with the support of Prof. B. Hobbs of the Johns Hopkins University in Baltimore (USA) – but since 2018 it is used/developed commonly by the Netherlands Environmental Assessment Agency and TNO Energy Transition Studies.

- A unit commitment and economic dispatch module to determine and analyze least-cost unit commitment (UC) and economic dispatch under perfect competition, formulated as a mixed-integer program considering flexibility and minimum load constraints and start-up costs of generation technologies.

The COMPETES model covers all EU Member States and some non-EU countries – *i.e.*, Norway, Switzerland, the UK and the Balkan countries (grouped into a single Balkan region) – including a representation of the cross-border power transmission capacities interconnecting these European countries and regions (see Figure 4). The model runs on an hourly basis, *i.e.*, it optimizes the European power system over all 8760 hours per annum. Over the past two decades, COMPETES has been used for many assignments and studies on the Dutch and European electricity markets. In addition, it is used and regularly updated as part of the energy modelling framework for the annual Climate and Energy Outlook of the Netherlands (see, for instance, [7]).

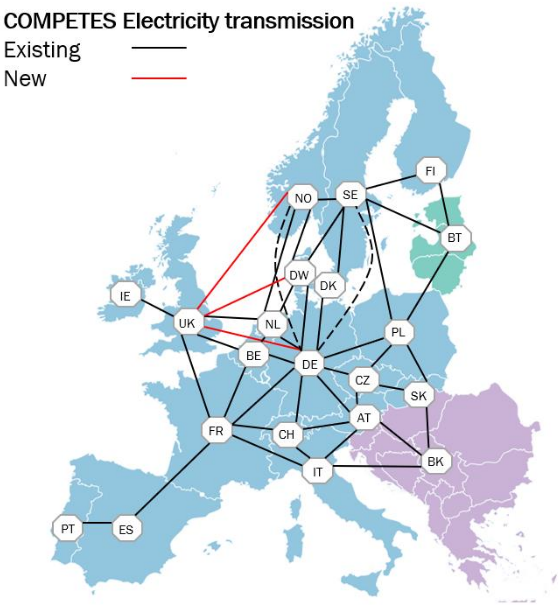


Figure 4. The geographical coverage of the COMPETES model.

For each scenario year, the significant inputs of COMPETES include the following:

- Electricity demand across all European countries/regions, including conventional power demand and additional demand due to further sectoral electrification of the energy system utilizing P2X technologies;
- Power generation technologies, transmission interconnections and flexibility options, including their techno-economic characteristics;
- Hourly profiles of various electricity demand categories and RES technologies (notably solar, wind and hydro), including the full load hours of these technologies;
- Assumed (policy-driven) installed capacities of RES power generation technologies;
- Expected future fuel and CO_2 prices;

- Policy targets/restrictions, such as meeting specific RE/Greenhouse gas (GHG) targets or forbidding the use of certain technologies (for instance, coal, nuclear or CCS).

As indicated above, COMPETES includes a variety of flexibility options:

- Flexible power generation:
  - Conventional: gas, coal, nuclear;
  - Renewable: curtailment of solar/wind;
- Cross-border power trade;
- Cross-border hydrogen trade;
- Storage:
  - Pumped hydro (EU level);
  - Compressed air (CAES/AA-CAES);
  - Batteries (EVs, Li-ion, PB, VRB);
  - Underground storage of hydrogen;
- Demand response:
  - Power-to-mobility (P2M): EVs, including grid-to-vehicle (G2V) and vehicle-to-grid (V2G);
  - Power-to-heat (P2H): industrial (hybrid) boilers and household (all-electric) heat pumps;
  - Power-to-gas (P2G), notably power-to-hydrogen (P2H2);

On the other hand, for each scenario year and each European country/region, the main outputs ('results') of COMPETES include:

- Investments and disinvestments ('decommissioning') in conventional and vRES power generation;
- Investments in interconnection capacities, both for electricity and hydrogen;
- Investments in storage;
- Hourly allocation ('dispatch') of installed power generation and interconnection capacities, resulting in the hourly and annual power generation mix – including related CO_2 emissions and power trade flows – for each European country/region;
- Demand and supply of flexibility options;
- Hourly electricity prices;
- Hydrogen prices;
- Annual power system costs for each European country/region.

AMIRIS-EMLabpy

AMIRIS and EMLabpy are both agent-based models (ABM). EMLabpy was inspired by EMLAb (Energy Modelling Laboratory), which is a model developed by TU Delft that allows to investigate the influence of policy on the investments of generation. The python version of EMLab was developed in a modular way, which allows to run parts of the model separately. This feature was essential, as the objective of the consortium is to exploit the capabilities of different models from the partners. Furthermore, EMLabpy was soft-linked with AMIRIS within the TradeRES-project to complement the model with AMIRIS' detailed representation of the electricity market that allows representing flexibilities and evaluating several RES-support mechanisms. In contrast, the original EMLab had a segmented representation of the load and couldn't represent flexibility, which will be essential in a future market. On the other hand, standalone AMIRIS is a model that focuses on investigating the influence of policies in the electricity market, but it lacks the possibility to model investments in generation. For a more detailed explanation of both models, refer to the user guides in D6.2.1 [8].

Both models were soft-linked with Spine-toolbox [9], which allows executing computational tasks in a flexible manner. An advantage of this soft-linking is that it has human-readable files as inputs. In this way the user can easily control the parameters, adding transparency to the simulations. Similarly, the outputs of both models are files that allow to change results between both models.

An overview of the workflow is presented in Figure 5. This workflow can be executed in a loop for the number of years defined by the user. The left blue symbols are the files with the input data. The pink symbols are the SQLite databases. The EMLabDB stores the information that is needed to run EMLabpy and the AMIRISDB stores the results from that model. The red symbols execute different model modules. The first module sets the year counter to zero. The second module assigns a unique number to the initial set of power plants to assign to each power plant the results from AMIRIS. The rest of the modules are executed in a loop and will be explained in the conceptual representation of the workflow in Figure 5.

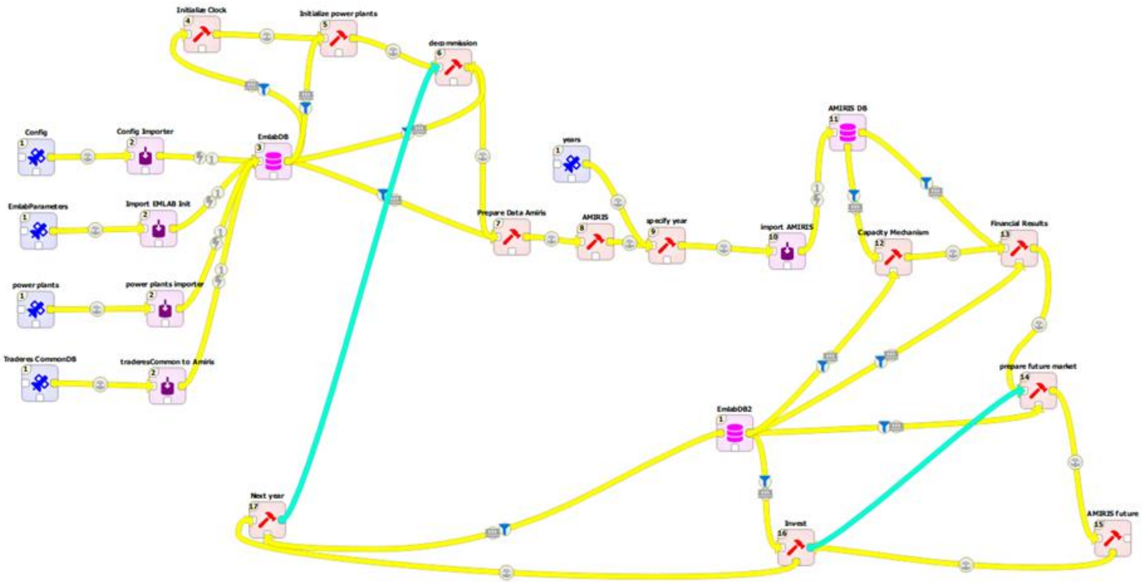


Figure 5. AMIRIS - EMLABpy workflow in Spinetoolbox.

After the year counter is increased by one year, the status of the power plants is updated. The unprofitable power plants that have passed their lifetime are being decommissioned. The average profits of three previous years' (without capital costs) are considered for the dismantling decisions. Next, the power plants that will be operational in the simulation year and the updated fuel prices are being written into an Excel file that is the input for the market to be cleared AMIRIS. Then, AMIRIS is executed for the current simulation year. The results of the market clearing are then used to estimate the bids of the power plants in a yearly capacity market. Finally, the financial results of the capacity mechanism and the market are considered to calculate the financial results of each plant and of the unique energy producer agent (owner of all power plants). In the final step, the market is evaluated for four years ahead, considering power plants in the pipeline. In each iteration, the candidate power plant with the highest net present value (NPV) is chosen to be invested in. This investment loop runs until there are no more power plants that will be profitable (positive NPV). To account for the subsidies in renewable energies, a target investor makes yearly investments in wind and solar energy as defined by the user. The vRES support is calculated as the missing profits needed to cover all the costs. In next edition of this deliverable, this targeted investment will be replaced by the vRES support mechanisms from AMIRIS, Figure 6. After each investment, the investment payments are registered for each power plant. In EMLab-py the equity payments are paid during the construction time (down payments) and the debt is paid during the power plant's lifetime (loans).

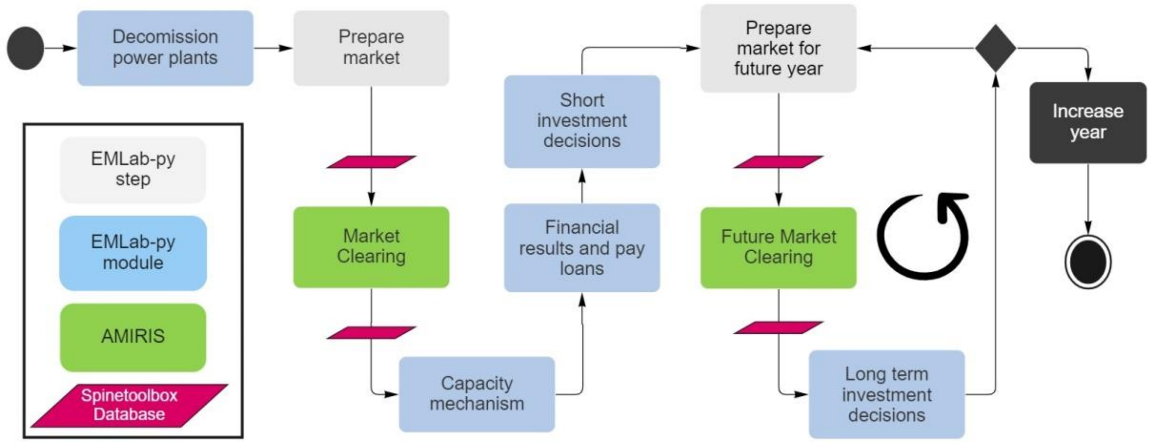


Figure 6: Conceptual workflow of AMIRIS-EMLabpy.

3.1.2 Scenarios, input data and limits of the analysis

Scenarios

In future COMPETES runs, we will optimize the 2030 based on the ENTSO-E scenario called 'Distributed Energy'[5] and 2050 based on TradeRES scenario defined in *WP 2 - Optimal electricity trading with ~100% RES: Generation of a reference power system, scenarios and input market data*. In this iteration we run the ABM model EMLabpy from 2019 until 2049. Its input data will be detailed later.

Market design bundles

To answer the research questions presented in section 2, the following market design bundles will be simulated with the AMIRIS-EMLabpy model, Table 3. Since the capacity

[5] More details available at: https://2020.entsos-tyndp-scenarios.eu/scenario-description-and-storylines/

market of the ABM model is still under development, we will test the energy-only market with and without vRES targets in this first iteration.

Table 3. Investigated market design bundles in this iteration.

Market design bundle	Energy Market	vRES targets	Name
Baseline	X		EOM
B1	X	X	EOM_VRES

Input data

In this first iteration, all the costs were considered fixed to the year 2030. The ABM model runs on a yearly basis. The initial set of power plants were the ones installed before 2019 and the plants planned to be commissioned until the year 2024. The set of power plants was from KEV 2022 [7] (see Figure 7).

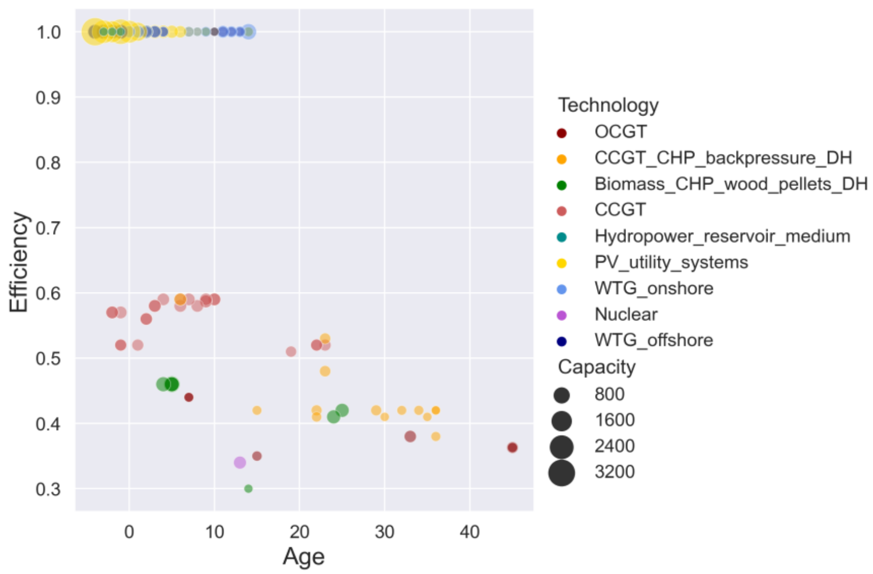


Figure 7. Initial set of power plants.

The investment costs, variable costs, fixed costs, efficiency, technical lifetime, and fuel costs were taken from the TradeRES database [9]. The candidate technologies to be installed are shown in Table 4.

Table 4. Capacities and permit and build years of technologies used in ABM.

Technology	Power capacity per unit (MW)	Permit and build years
Large PV systems	350	2
Wind onshore	220	2
Biomass CHP	100	4
OCGT	100	3
Wind offshore	500	2
CCGT	300	4

Lithium ion battery	100	3

Limitations of the analysis

A major limitation of these simulations is that fuel, CO_2 and technology prices were fixed for 2030. The CO_2 was fixed to the projected price of 2030 of 93 Euro/ton CO_2. This gives unrealistic results because, in reality, the capital costs of RES are expected to decrease and in contrast, fossil fuel prices are expected to increase. In future simulations, increasing CO_2 price, increasing fuel costs and decreasing capital costs will be considered. Finally, fixed costs of old power plants will be raised according to their age. For this reason, the following results are to be considered preliminary and the numbers are expected to change significantly in the next final deliverable. Once AMIRIS is able to consider dynamic CO_2 costs, the prices will be updated yearly. Secondly, AMIRIS will be adapted to consider yearly vRES support mechanisms power plants and this will replace the target investments of EMLabpy.

Due to the different scopes of COMPETES and the ABM model (most notably regarding sectors, technology options and countries), the ABM model needs to be further developed in order to provide insights from the comparison with COMPETES runs. Therefore, we will conduct COMPETES runs and make comparisons in future iterations. In this deliverable preliminary results from the ABM model are presented.

3.1.3 Simulation results and analysis

Two main simulation groups were executed in this subsection. One group with targeted investments in vRES that comply with yearly targets of installed capacity and the other group, without this forced investment in vRES.

- ***Technical MPIs***

With regard to technical MPIs, the simulations of the starting point scenario revealed the results presented below.

Although the amount of installed capacity kept increasing in the targeted simulations (see Figure 8), the share of RES in the annual generation (*MPI #1*), seemed to reach a limit of around 80% (see Figure 9) in terms of energy demand. Similarly, although investments in renewables continuously increase in the EOM, the share of RES in total energy demand stagnated at around 60%. This reveals that considering TradeRES capital costs for year 2030, an EOM profit-based capacity expansion cannot reach near 100% RES power system. Although RES technologies have a positive NPV, the simulation results indicate that the gas technologies present higher expected NPVs. No investments in offshore energy were seen in the profit-based (EOM) simulations. Wind onshore results are more profitable than offshore and these decrease the market value of candidate offshore technologies making them every time less profitable. Netherlands has strict geographical limitations so these are unrealistic results. In next bundle of simulations, the physical limitations affecting different technologies will be considered.

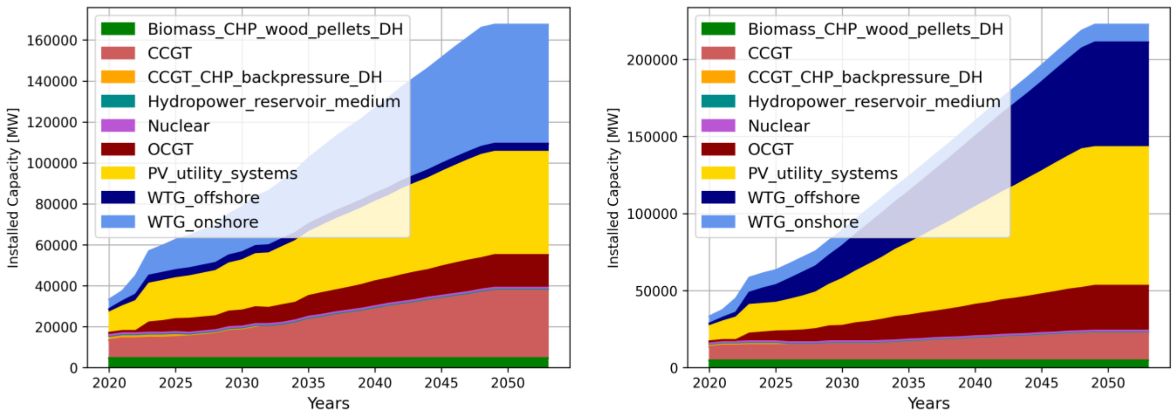


Figure 8. Installed capacity in EOM (left) in EOM_VRES (right).

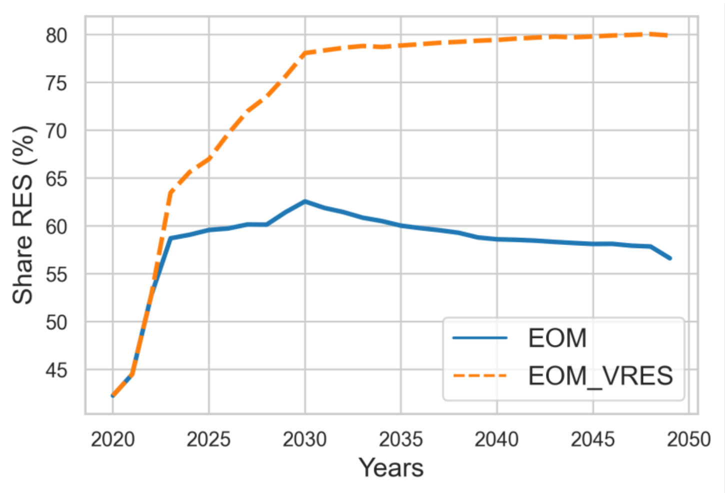


Figure 9. Share RES in the annual generation.

There were few decommissions under all market bundles. A couple of factors contribute to this result. First, demand is expected to increase rapidly associated with the electrification tendency of the economies; second, low extra fixed costs (for extending lifetime) were added according to the power plants' age to represent retrofit costs. These contributed to older power plants presenting positive profits, even if their lifetime was passed. For this reason, in future simulations the fixed costs will be assigned to higher retrofit costs as they pass their operational time, and/or their efficiency will be worsened.

MPI #4 - Loss of load Expectation (LOLE), MPI #5 – Expected Energy not supplied (EENS) and MPI #6 - Supply ratio: Even if some power plants "under construction" were considered in the initial set of power plants, there was a lack of capacity in the first three simulation years, as seen in Figure 10 to Figure 12. The reason for this is that the investment algorithm considers the future market four years ahead. Even if investments are made in the first year, the power plants take at least two years to be built. Hence, the loss of load and energy not supplied are unrealistic before year 2024. In the first three years, the LOLE was higher than 300 hours (see Figure 10). For this reason, only the results from 2024 will be analyzed. In the years 2032-2035, the EOM market presented the highest LOLE of 19-30 hours; this is because there was a decommission of 1500 MW of

CCGT, CHP and OCGT in the year 2032. From year 2035 onwards, the EOM presents a lower LOLE.

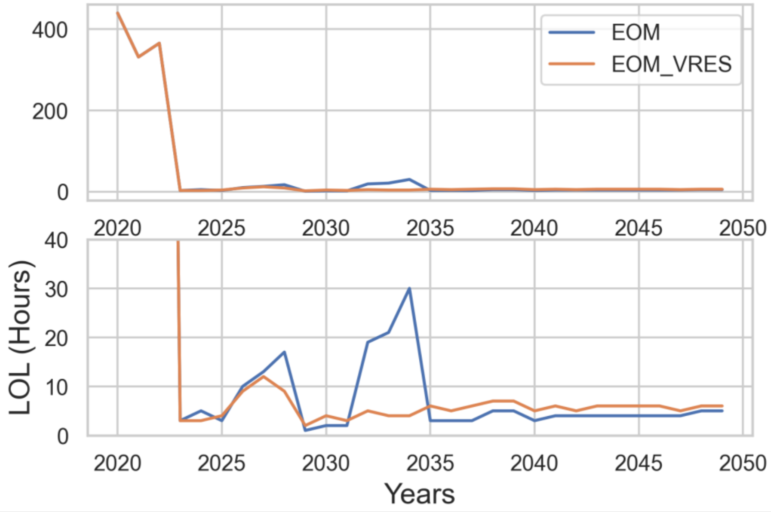


Figure 10. LOLE (lower plot with limited y-axis).

Similar to the LOLE, the EENS was highest in all market bundles in years 2020-2023 (see Figure 11). As expected, opposite trends were seen in the supply ratio (see Figure 12). In contrast to the EOM, in the targeted investment runs the LOLE and EENS did not peak in years 2033-2034. This was because no decommissions occurred after year 2026. With more vRES being installed every year, the installed gas plants continue being in use for longer times and avoid being dismantled.

With targeted investments in vRES, the LOLE remained lower than 10 hours. Until year 2035, the supply ratio (which was calculated as the minimum of hourly supply/ hourly demand) was higher than in the EOM scenarios. Nevertheless, from the year 2035 the supply ratio was worse with higher shares of vRES because fewer investments in dispatchable generation were made, originated by a lower projected NPVs. Hence, the share of RES can support the security of supply in some cases, but not always.

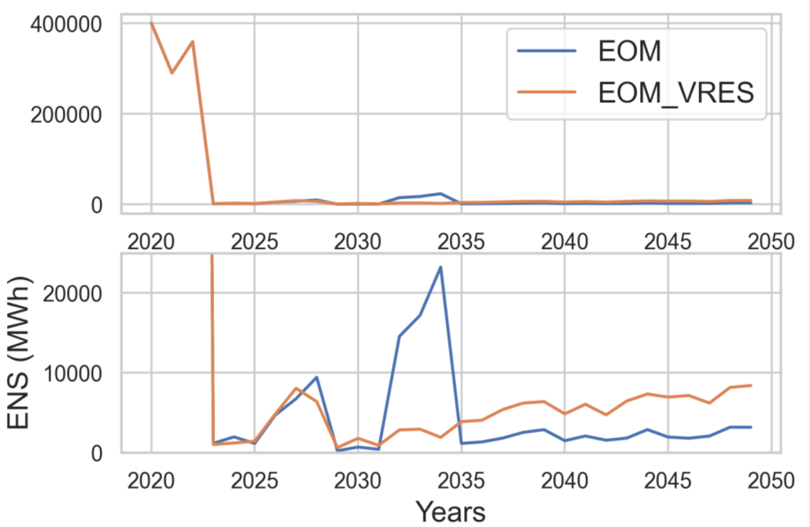


Figure 11. Expected energy not supplied. Lower plot with limited y-axis.

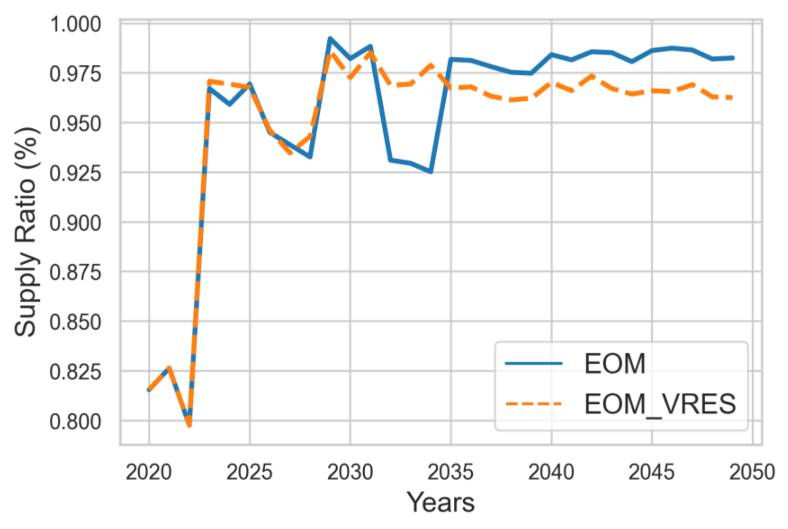


Figure 12. Supply ratio.

Analyzing operational power plants in the last year, Figure 13 indicates that the vRES do not increase the reliability of the system. Although the installed capacity in EOM_VRES is higher, the capacity of dispatchable technologies is slightly lower, this is the reason why the supply ratio is better in an EOM after year 2035. Furthermore, in the scenarios with a higher share of RES, the peak technologies (OCGT) are more dominant than the mid technology (CCGT). This was expected, as peak technologies are used more as RES share in the system increases. Less dispatchable installed capacity cause higher EENS, LOLE and lower supply ratio in the simulation with higher vRES, after year 2035. In the EOM scenario, the wind onshore energy was rapidly and extensively invested. In reality, the Netherlands might have stricter physical limitations, these will be accounted for in the next simulations.

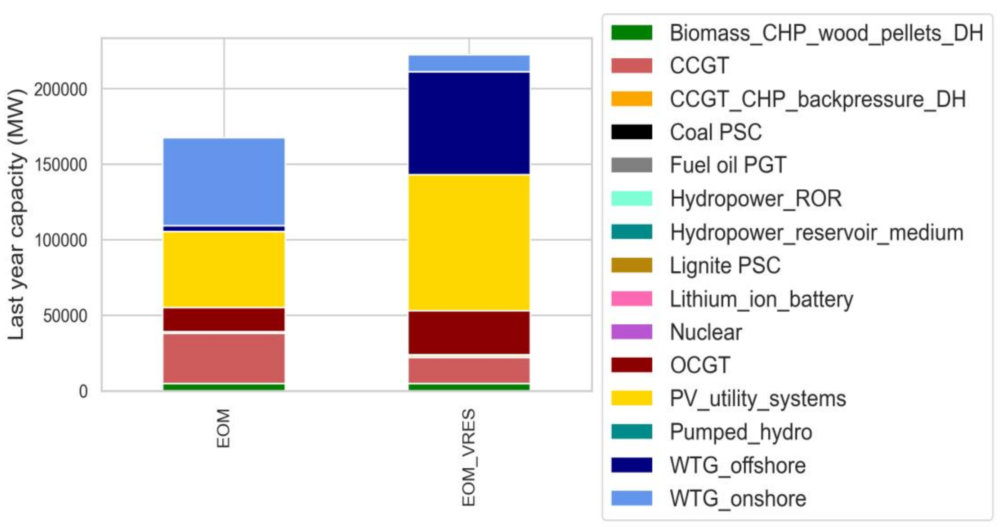


Figure 13. Last year installed capacity.

- ***Economic MPIs***

MPI #29: Average weighted electricity prices: Due to scarcity in the first years, the weighted-average electricity prices were extremely high in both market bundles, Figure 14. In the rest of the years, the electricity prices in the target renewable investments bundles, were approximately 20 Euro/MWh lower. This small difference can be explained by the fact that although hours with 0 Eur/MWh become more frequent, there were also frequent times of high electricity prices, where the gas peak plants set the market price.

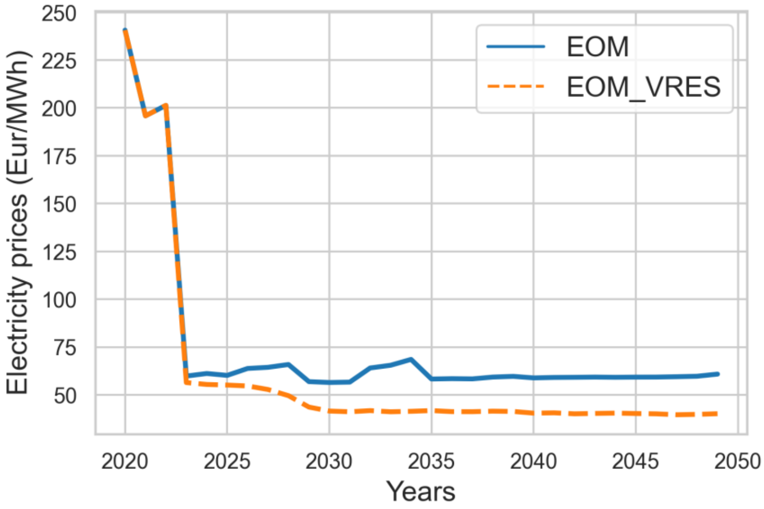


Figure 14. Electricity prices.

MPI# 32: Market-based cost recovery: The missing money caused by a higher share of RES leads to a lower market-based cost recovery in the markets with targeted vRES investments, Figure 15. The cost recovery for the EOM remains around 0 Euro, which means that the energy producer revenues enabled to recover the investments. In the last years of simulation, the recovery of the investments made is close to the end, increasing the wholesale market revenues and ensuring the market-based cost recovery. In contrast, the simulations with targeted RES investments reveal that these investments need financial support, as the wholesale market is not enough to cover the total costs. The gap between EOM and EOM_VRES is in the last years of around 11 billion Euro. In the next iteration of simulations, when higher CO_2 prices and a higher LCOE on RES technologies will be considered, more investments in these technologies should be seen in an EOM and the market-based cost recovery should be less negative.

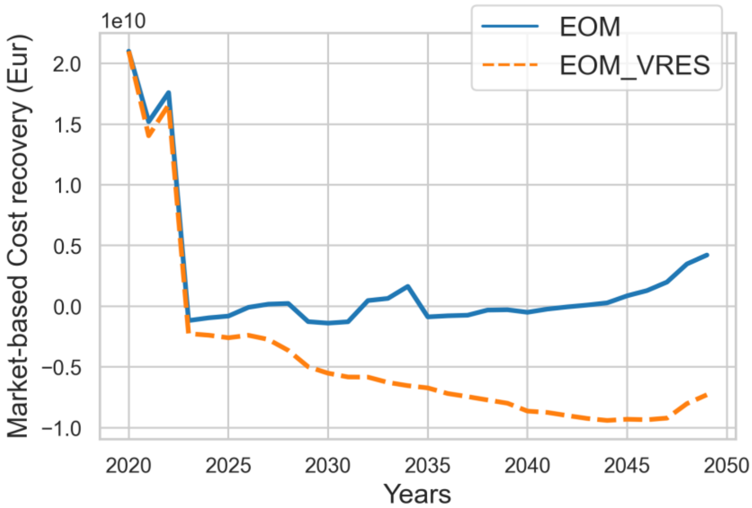


Figure 15. Market-based cost recovery.

Analysing the cash flow of the EOM and EOM_VRES (see Figure 16), it is visible that although the investment payments for new plants (vRES) were higher in the EOM_VRES bundle, a major reason for a lower cost recovery is due to much lower wholesale market revenues caused by lesser use of fossil fuels (commodities). This can also be seen in the annual generation Figure 17, where in the last year the annual generation from fossil fuel technologies was almost double in the EOM, in comparison with EOM_VRES bundle.

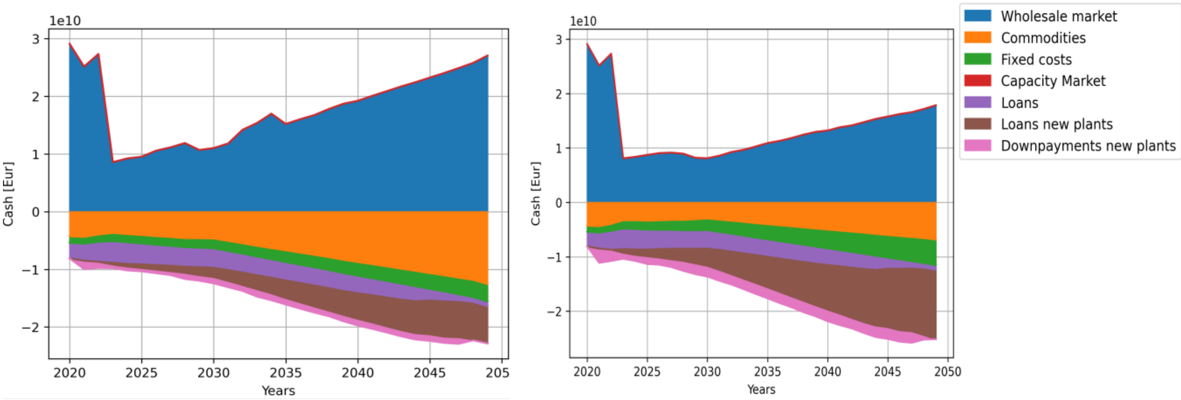


Figure 16. Example of cash flow in EOM (left) and EOM_VRES (right).

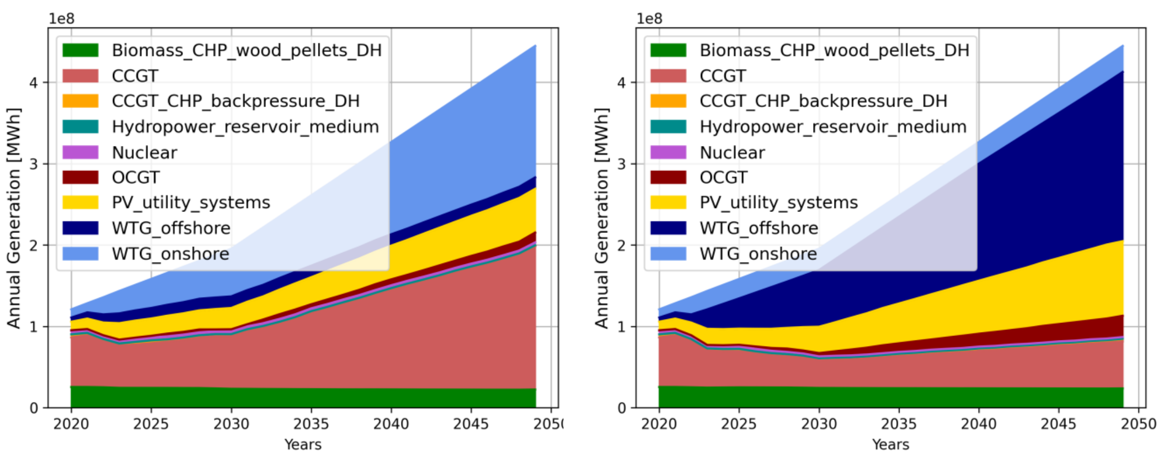


Figure 17. Annual generation in EOM (left) and EOM_VRES (right).

MPI #28 Costs to society*:* Surprisingly the total costs to society were very similar in both bundles, see Figure 18. The costs to society refer to the electricity prices and the vRES support costs per unit of electricity consumed. The low electricity prices in the EOM_VRES scenario were compensated by higher vRES support charges. The EOM scenarios had higher costs in the years 2027, 2028 and 2032 to 2035; in the rest of the years, the EOM_VRES scenarios presented higher costs to society. Nevertheless, the difference was only 5 Euro/MWh. This difference should be lesser when increasing CO_2 prices and lower capital costs are considered. This supports the fact that investing rapidly in renewable energies can be in the long term more cost optimal than a profit-based EOM market. Even if vRES capital costs don't decrease, CO_2 prices don't increase and the investments have to be made with subsidies, the total costs to society (including the vRES support subsidies) will not be significantly higher. If more renewable technologies are installed and these require extra subsidies, these extra costs to society could be compensated by lower average electricity prices that arise due to a reduced use of fossil fuels.

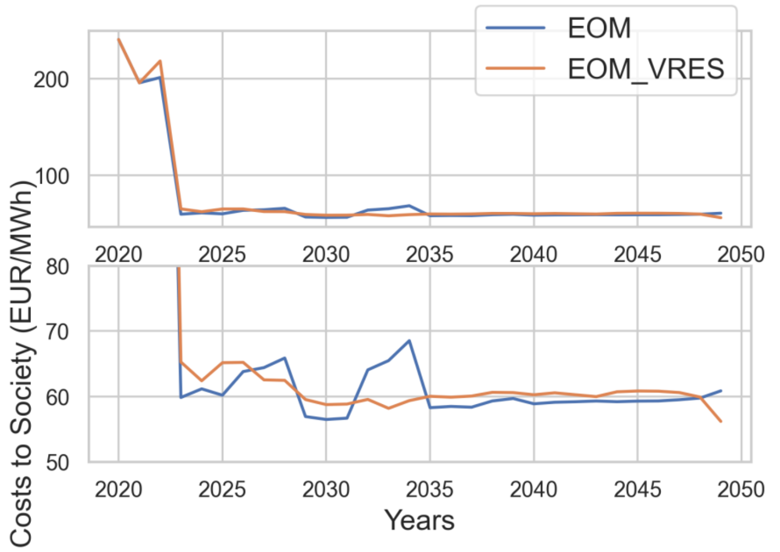


Figure 18. Costs to society (lower plot with limited y axis).

3.1.4 Final remarks and outlook

In the previous results extreme values were obtained for the first simulation years, due to the fact the algorithm presents numerical transients, thus needs to run for some years to achieve stable results. It should also be stated that, for this initial iteration of the application of the models, no imports and exports were considered. This could also contribute to the scarcity observed in the first simulation years.

In next step of the analysis, the numerical transient will be avoided and, furthermore, a shock of gas prices, as the one seen nowadays, will be considered to analyse the energy-only market-based cost recovery along with the other MPIs. Moreover, the vRES target investments will be replaced by the vRES support mechanisms of AMIRIS. Finally, COMPETES runs will be added to serve as a benchmark case.

3.2 Case Study C: German market

Germany is the country with the highest absolute feed-in of variable renewables within Europe. Nevertheless, the country is far from a ~100 % renewable power system. Thus, options for a new market design have to be studied carefully. In the first version of the prevalent deliverable, the German case study focusses on market design elements with regard to refinancing (v)RES.

3.2.1 Models used: AMIRIS and AMIRIS+ EMLabpy

There are two different models respectively model coupling workflows used:

- Dispatch-related analyses are carried out using the **A**gent-based **M**arket model for the **I**nvestigation of **R**enewable and **I**ntegrated energy **S**ystems (AMIRIS). AMIRIS simulates electricity prices endogenously based on the simulation of strategic bidding behaviour of prototyped market actors. This bidding behaviour does not only reflect marginal prices but can also consider effects of support instruments like market premia, uncertainties and limited information.

- Investment-related analyses in turn, combine the investment model EMLabpy-Generation with a detailed and iteratively run dispatch simulation using AMIRIS and integrated in a coupled workflow used for assessing investment strategies. A more extensive description can be found in section 3.1.1. Outcomes of the investment-related analyses will be presented in the second version of the prevalent deliverable.

For a description of the models used, please refer to deliverable D4.8 [10]. Further information on the open version of AMIRIS is available on https://gitlab.com/dlr-ve/esy/amiris/amiris or its landing page: https://dlr-ve.gitlab.io/esy/amiris/home/

3.2.2 Scenarios, input data and limits of the analysis

The dispatch-related analyses with AMIRIS each focus on comparing a situation with limited support with a range of remuneration schemes for renewable energy sources (RES). As a starting point scenario, the *status quo* of 2019 is simulated. This scenario is considered as "average" year with annualised costs and revenue situations for the respective year. Transformations pathways are not considered yet.

Input data for the starting point scenario is derived from various external sources. Capacities as well as time-series for demand, imports and exports reflect the status quo of 2019 and are based on ENTSO-E 2022 [11]. Values for cost and technical parameters of conventional power plants are taken from the UNSEEN project's 2018 scenario [12], which is based on a meta-analysis of various studies and primary data sources. Cost parameters for RES, instead, are taken from Kost *et al.* [13]. Different clusters of vRES are defined for the analysis that reflects the bandwidth of cost, especially capital expenditures. Fuel costs are derived from Destatis 2022 [14], feed-in profiles of RES from Bundesnetzagentur 2022 [15].

For the starting point scenario, pumped hydro storages are considered the only flexibility option. They are operated in a system cost minimizing way in AMIRIS. Table 5 summarizes the main input data underlying the starting point scenario.

For the analysis of remuneration schemes, the following support instruments have been implemented in AMIRIS (see D4.5 [1]):

- *Fixed market premium*: A fixed payment on top of market revenues and determined ex-ante. It is calculated to cover production costs.
- *Variable market premium*: An *ex-post* price-variable premium scheme. The difference between the production costs (or the "value to be applied") and the monthly, technology specific market value is calculated *ex-post* and paid to producers on top of market revenues. For fluctuating renewables, the monthly market value is the volume-weighted average of spot market revenues, calculated hourly on the basis for the technical feed-in potential for the respective energy carrier, neglecting curtailment. For other renewables, the base price is used.
- *Contracts for differences:* A two-sided variant of the variable market premium. The difference between the production costs (or the "strike price") and the monthly, technology-specific market value is calculated *ex-post* and paid to producers on

top of market revenues respectively reimbursed in the case, when market values are higher than the production costs.

- *Capacity premium*: A payment per installed capacity. The interval in which this premium is paid out is in principle flexible but aligned with the market premia respectively Contracts for Difference scheme and thus chosen to be monthly.

Table 5. Summary of inputs data for 2019 used in this deliverable for case study C - Germany.

Demand			
	Annual demand	TWh/a	527
	Peak demand	GW	88
Power generation capacities			
	Nuclear	GW	10
	Lignite	GW	18
	Coal	GW	22
	Natural gas	GW	24
	Other conventional	GW	4
	PV	GW	45
	thereof FIT-supported	GW	31
	Wind Onshore	GW	53
	Wind Offshore	GW	8
	Other RES	GW	13
Storage			
	Capacity	GW	8
	Energy	GWh	40
Average fuel / commodity prices			
	Nuclear	€/MWh	2
	Lignite	€/MWh	5
	Coal	€/MWh	11
	Natural gas	€/MWh	16
	CO_2	€/t	25

For their parameterisation, a pre-calculation with AMIRIS is conducted: In a first step, AMIRIS is iteratively run using a fixed market premium as a support instrument. Initially, these runs start with freely chosen technology-specific premia, which are subsequently adjusted run by run until the technologies cover their total costs and no excessive rents occur. Therefore, in each run, a so-called refinancing ratio (“RR”) is calculated which equals to the relation between the overall revenues and the total costs for a simulation year. To ensure a system which refinances the needed power plants and is efficient at the same time, this refinancing ratio should be close to 1. Hence, the fixed market premium is adjusted for each single agent until the refinancing ratio is within a tolerance interval of [0.99; 1.01].

$$RR = \frac{TR}{TC}$$

With RR being the refinancing ratio, TR the total revenues and TC the total costs.

Once the fixed market premia needed to ensure efficient refinancing are found, the production costs of the renewable plants are calculated by dividing the average annual costs by the realised generation, taking into account market-based curtailments. These production costs are in turn used to parameterise the value to be applied for a variable market premium resp. a contracts for differences scheme. For the capacity premium scheme, the total annual costs are divided by 12 to account for a monthly pay-out interval.

This approach ensures that each support instrument is parameterised to both ensure refinancing and prevent unnecessary payments.

Based on these assumptions and pre-calculations, five different cases for market design bundles are calculated for the starting point scenario based on aggregated capacities, costs and technical feed-in potentials of the year 2019. The cases differ in terms of applied support instruments to ensure the remuneration of renewable energy sources. All other data, especially input data, is equal for these five cases.

The market design bundle cases are denoted each after the dominating remuneration scheme – which is either the one currently in place for the Federal Republic of Germany, or one among those frequently discussed as a suitable alternative scheme. In all considered remuneration cases, an exception applies for 31 GW of rooftop-PV small units, which are assumed to be remunerated by fixed feed-in tariffs (FIT), since these units are considered as necessary investment incentives for private households. The FIT for rooftop-PV amounts to 110 €/MWh for the starting-point scenario and is designed to cover total costs of the units, assuming average weather conditions and related electricity generation.

The influence of demand response options is not considered in the first iteration.

Hence, results on MPIs will be presented in the next chapter for following market design bundle resp. remuneration cases in the starting point scenario:

- *No support ("None"):* A situation in which RES do not obtain any additional support payments besides revenues from the day-ahead market.
- *Fixed market premium ("MPfix"):* Fixed payments on top of market revenues.
- *Variable market premium ("MPvar")*: Price-variable payments on top of market revenues.
- *Contracts for differences ("CfD")*: Price-variable payments on top of market revenues. In the case of high market values price-variable obligations to pay back revenues exceeding production costs.
- *Capacity premium ("CP")*: Payments per installed capacity.

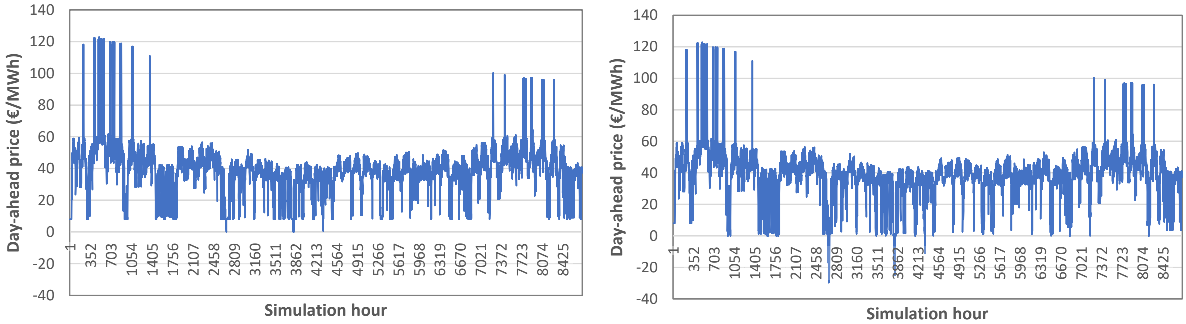
3.2.3 Simulation results and analysis

Before displaying the results for the MPIs, some fundamental simulation results are presented which help to understand the following indicators' characteristics.

First, the development of day-ahead market prices is depicted for the remuneration cases "None" and "MPvar", Figure 19. Note that price time series are identical for the remuneration cases "None" and "CP", as in these cases the bidding behaviour is equally not affected by policy instruments and very close for "MPvar", "MPfix" and "CfD".

For the "None" case, market prices vary between 0 and 123 €/MWh and amount to 40 €/MWh on an unweighted average. The price level is generally higher in the cold season. For "MPvar", prices vary between -30 and 123 €/MWh (unweighted average also equal to

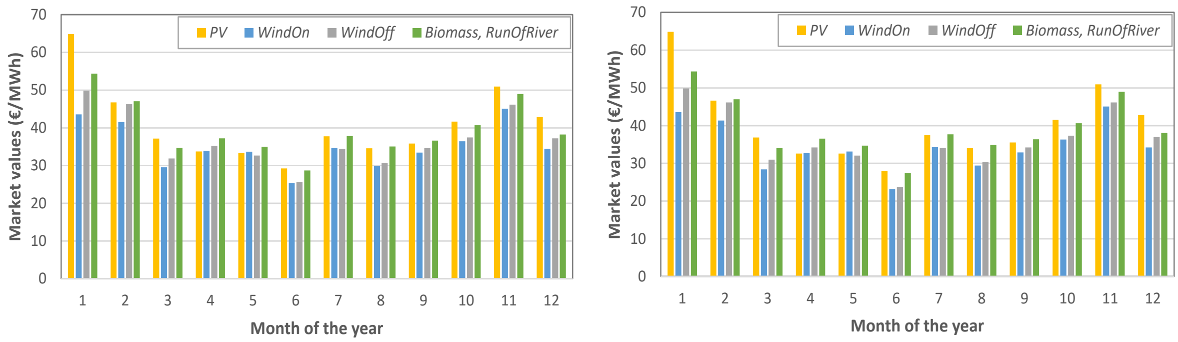
39 €/MWh). Prices are generally lower than for "None", as received market premia reflect the opportunity cost of the support instrument and thus result in lower (even negative) supply bids by RES traders (see also D4.5).



a) b)

Figure 19. Day-ahead market prices considering a) *"None"* case, and b) "*MPvar*" case.

Market values of RES for both cases are depicted in Figure 20. For the "None" case, they vary between 25 and 65 €/MWh depending on the technology. They tend to be highest for PV (due to coincidence with daily peak load). They are lower for wind power, as capacities are higher, resulting in stronger simultaneity and therefore, cannibalization, effects. A seasonal pattern can be observed with lower market values in summer. Market values for the "MPvar" case are slightly lower than for "None". Again, this is due to the incorporation of market premia in the supply bids of RES traders reducing market price levels – provided that RES set the price.



a) b)

Figure 20. Market value of RES considering a) *"None"* case, and b) "MPvar" case.

The values for accruing premia develop as follows (Figure 21):

- Throughout the remuneration cases, premia are lowest for PV. This reflects the low production costs of PV, especially compared to wind offshore, combined with generally higher market values and corresponding revenues for this technology.
- Average values for MPfix are 15 €/MWh for PV, followed by wind onshore (36 €/MWh) and wind offshore (73 €/MWh).
- For CP, monthly values amount to 1,118 €/MW for PV, 5,587 €/MW for wind onshore and 19,570 €/MW for wind offshore.
- Values for MPvar and CfD are updated on a monthly base. Across all technologies, MPvar values are lowest for PV (between 0 and 22 €/MWh) and are higher during summer, due to the lower market values as a result of the higher simulta-

neity effect in this period. For wind onshore, MPvar values range between 26 and 48 €/MWh and for wind offshore between 60 and 86 €/MWh.

- Values for CfD are identical to MPvar values for wind power plants. For PV, negative CfD premia are calculated for some months of the year. This is true for periods when market revenues for PV exceed their total costs.

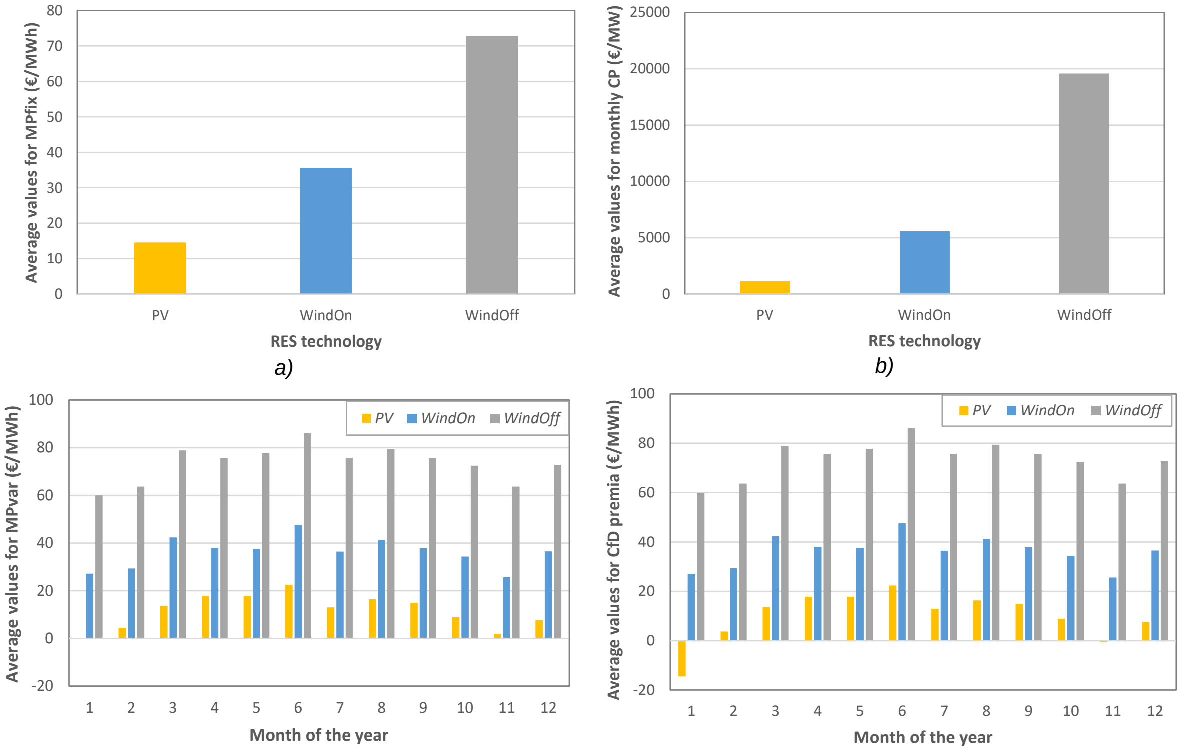


Figure 21. Average values for accruing premia considered for the vRES in the different remuneration cases: a) *MPfix; b) monthly CP; c) MPvar; and d) CfD premia.*

Results for the MPIs are given in the following section. Details on the calculation of these MPIs can be found in Annex B2.

- ***Technical MPIs***

With regard to technical MPIs, the simulations of the starting point scenario revealed the results presented below.

MPI #1 describes the share of RES in electricity consumption. For all five remuneration cases considered, it is about 34% with only low differences, Figure 22. The share is lowest for the “None” case as well as for “CP”. This is due to the fact that in these cases, RES have no incentive to sell electricity at prices that are lower than their marginal costs (apart from FIT-supported rooftop-PV). Hence, more market-based curtailment can be observed for “None” and “CP” than for the other cases (see also *MPI #17*). This, in turn, reduces the share of RES. In all other cases, the market premium is considered in the supply bids of RES traders; thus, electricity is also sold at prices that are lower than their marginal costs. Note that electricity consumption is constant for all five cases, as demand response is not yet considered in the analysis.

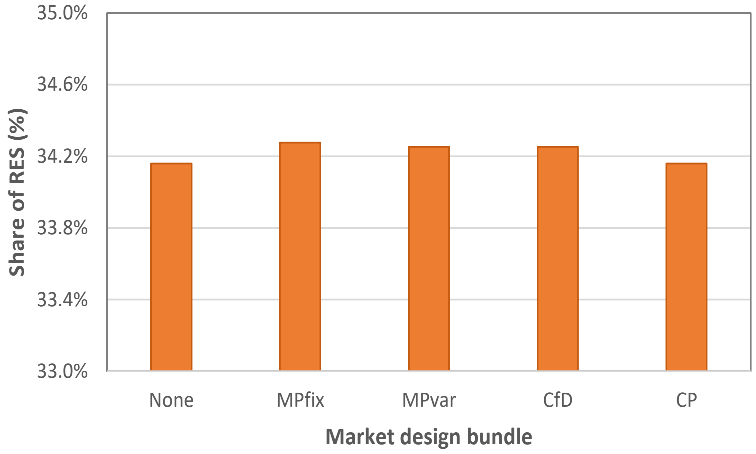


Figure 22. Share of RES in the electricity consumption for different support schemes.

MPI #4 addresses the loss of load expectation (LOLE). It is 0 for all cases, since the secured capacity meets the demand in all hours of the year. *MPI #5*, expected energy not served (EENS), is 0 correspondingly, since no loss of load is encountered in the simulations for the starting point scenario.

MPI #11, peak load reduction, describes the ratio of the realized demand peak and the planned demand peak. It is affected by forced load shedding (as an emergency measure in the case of real system shortage), voluntary shedding driven by (high) prices – which is not yet included in the analysis, but will be for the second iteration – and storage operation. For the starting point scenario, the relative peak load reduction is negative and amounts to –6% for all five cases, Figure 23. The peak load reduction is negative, as storages add to the demand and thus increases demand peaks in the simulations. Note that demand response is not yet considered in the simulations.

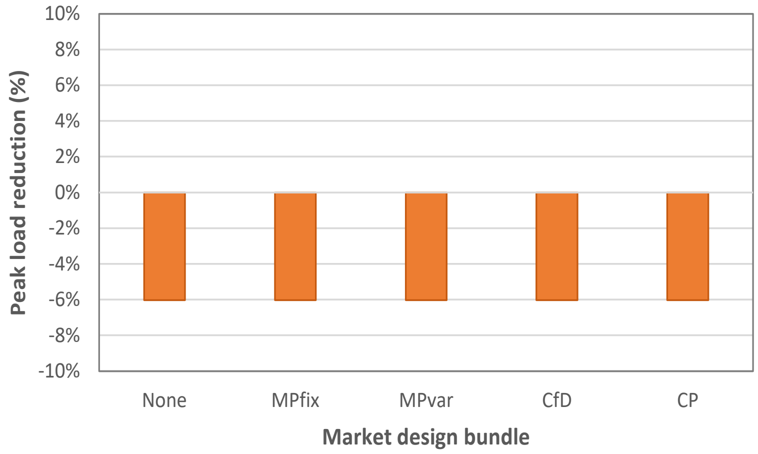


Figure 23. Peak load reduction (relative) under different support schemes.

MPI #17, market-based curtailment, is generally very low in the starting point scenario, Figure 24. This is mainly due to the limited share of RES in the scenario considered (see *MPI #1*). For the “None” and the “CP” case, vRES are curtailed if the market price is lower than their marginal costs (an exception applies for FIT-supported rooftop-PV, which sell electricity irrespective of the market price level). This applies to some degree to the feed-in of electricity from wind power plants, as their variable operational expenditures (OPEX) exceed the market prices in some hours of the year (see also spot market price levels below). As prices are never below zero in the “None” and “CP” case, PV is not curtailed.

This change for the other cases (“MPfix”, “MPvar” and “CfD”), where the value of the market premia is considered in the supply bids. RES traders are then willing to offer RES capacities at negative prices with an absolute value of the difference between the marginal costs and the anticipated market premium. In general, this leads to lower bids of vRES and hence lower curtailment. Nevertheless, due to respectively higher production costs market premia are relatively higher for wind than for PV. Thus, their negative price bids are lower than the negative PV bids. Accordingly, PV is curtailed earlier.

In the cold season, the constant MPfix value is generally higher than the variable premia (MPvar and CfD, see above). Consequently, vRES operators are willing to sell electricity at lower prices for the “MPfix” case compared to “MPvar” and “CfD” in this period. Thus, market-based curtailment is lower for “MPfix” than for “MPvar” and “CfD”. This is especially true for wind power.

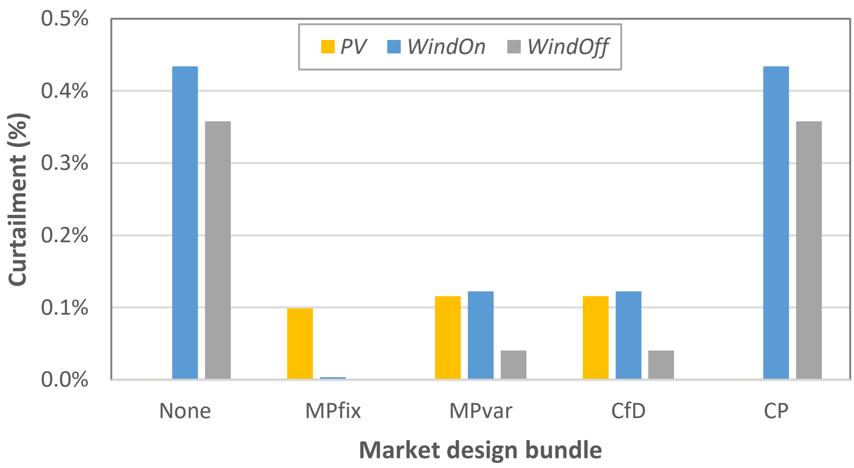


Figure 24. vRES market-based curtailment using different support schemes.

- ***Economic MPIs***

MPI #27: the system costs for dispatch reflect the sum of all variable costs, *i.e.*, fuel costs, OPEX, and costs for CO_2 emission certificates. For the starting point scenario, they amount to about 11.4 bn€/a, Figure 25. There are hardly any differences between the five cases according to the market design bundles, since production by RES is quite similar for all cases (compare *MPI #1*), and thus also conventional generation as well as related costs.

MPI #29 describes the weighted average electricity price. It ranges between 40.7 and 41.0 €/MWh for the five cases considered, Figure 26. Prices are generally lower for cases with market-premium-based support schemes (“MPfix”, “MPvar”, “CfD”), as market premia generally reduce the supply bids to negative values. Market prices are lower and become negative in periods when RES are able to cover demand.

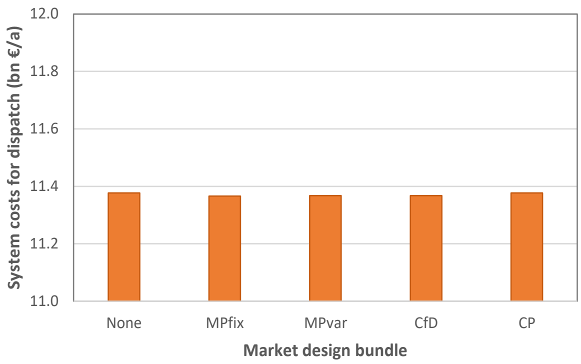


Figure 25. Systems costs for dispatch using different support schemes.

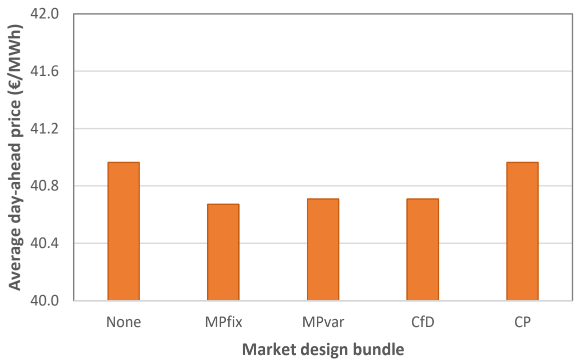


Figure 26. Average electricity price for different support schemes.

MPI #30, energy scarcity time period, is 0 in the starting point scenario, as there is no unserved energy demand in all cases considered.

MPI #31, RES support costs, reflect the sum of support that is paid to RES operators eligible for support. Support payments for PV units in a FIT scheme are included in the calculation of this MPI. Results are shown below in Figure 27 on an absolute and a specific base. In total, vRES support costs sum up to 2.1 bn €/a for the “None” case, which reflects the support paid to rooftop-PV in the FIT scheme. For all other cases, support for all vRES technologies adds up to 7.6 bn €/a. Total vRES support costs are highest for wind onshore and lowest for wind offshore, which reflects their share in the power plant portfolio (see section 3.2.1). No significant differences between the market design bundle cases, apart from “None”, are observed, Figure 27a). On a specific base (*i.e.*, total support costs divided by generation), support is highest for wind offshore (around 73 €/MWh), Figure 27b). Support costs amounts to about 55 €/MWh for PV (weighted average for ground-mounted and rooftop-PV) and 36 €/MWh for wind onshore.

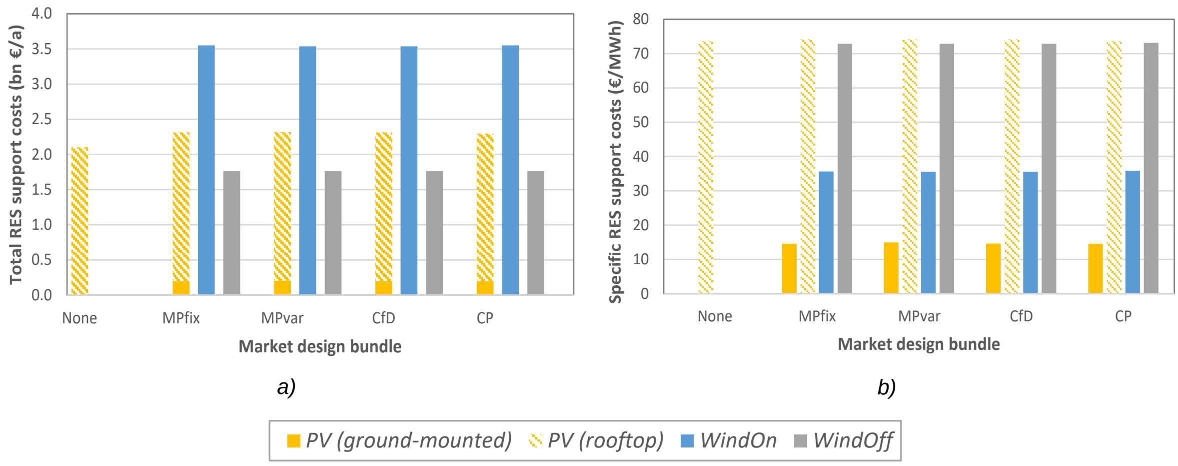


Figure 27. vRES support costs: a) total and b) specific for different technologies and support schemes.

MPI #32 market-based cost recovery, is depicted below for vRES technologies. Note that cost and revenues of rooftop-PV units that are remunerated by FIT are not included in the assessment of this MPI. Depending on the market bundle case, it amounts to 71% to 72% for PV, to 50% to 51% for wind onshore and to 34% for wind offshore, Figure 28. Values are generally higher for "None" and "CP" due to higher market values (see above).

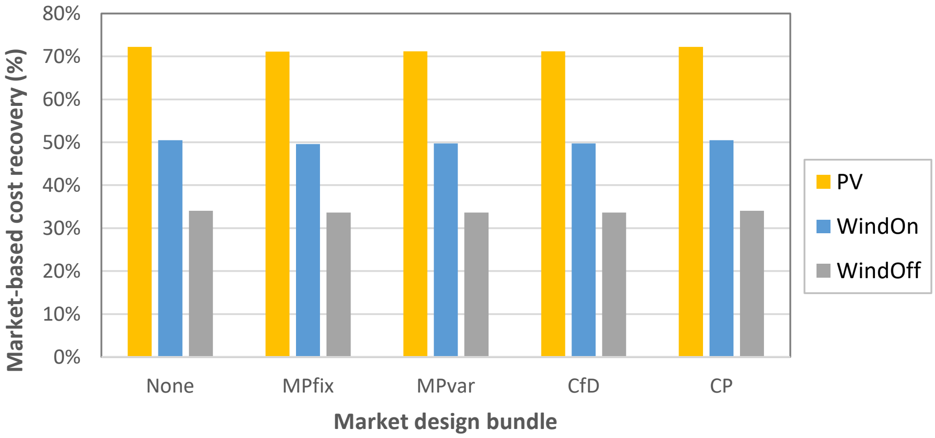


Figure 28. Market-based cost recovery for different vRES technologies and support schemes.

Not covering an MPI from the list in section 2 but being the core indicator for our main research question, is the total cost recovery of the renewable power plants. The case "None" reveals as well as in *MPI #32*, that a purely market-based cost recovery for renewables is not given in the starting point scenario with the underlying power plant park, commodity and CO_2 prices. Nevertheless, total cost recovery for PV is still about 94% for the "None" case, as a large share of the PV capacity is remunerated by a FIT with the purpose to cover total cost.

By design, cost recovery is (almost) 100% in all scenarios with a support scheme, Figure 29. Total cost recovery for PV considers cost and revenues for PV units supported by FIT and other support instruments and is about 99% on average. Given that in none of the cases the cost recovery exceeds 100%, the results confirm that the pre-calculated parameterisations of the support instruments meet their requirement to ensure refinancing as well as efficiency.

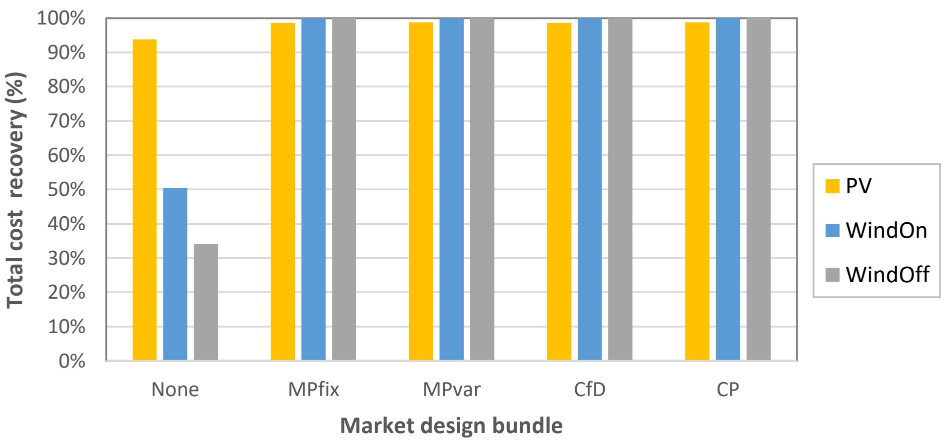


Figure 29. Total cost recovery for different vRES technologies and support schemes.

- ***Environmental MPI***

MPI #45 power system emissions, amount to 187 million t/a for the starting point scenario. As there are no significant differences in the dispatch of power plants for the five cases considered, there are hardly any differences in emissions either.

3.2.4 Final remarks and outlook

The simulations for the starting point scenario do not reveal significant differences in the market performance depending on the remuneration case. This is probably due to the limited share of RES in this scenario (approximately 34%, see *MPI #1*). Thus, RES are not yet very relevant for determining prices at the energy exchange.

However, differences prevail in the total cost recovery, revealing that in the "None" case refinancing of renewables is not sufficient.

Besides that, most of the results of the cases "None" and "CP" are equal for the starting point scenario. This can be explained by the identical microeconomic bidding behaviour in both cases, as the marginal cost-based bidding behaviour is not distorted by remuneration schemes. Furthermore, the bidding behaviour in the market design bundle cases "MPvar" and "CfD" is reflecting equal opportunity costs. The amount of revenues that must be paid back in the CfD scheme is very small for the starting point scenario. Hence, the outcomes of both remuneration schemes are very close to each other, too. At the same time, the results of the remuneration case "MPfix" slightly differ from the other premia-based schemes, as the fixed market premium deviates from the monthly changing values of the variable market premium.

Core indicators across the five market design bundle cases reveal: System costs for dispatch (*MPI #27*), volume-weighted average electricity prices (*MPI #29*) as well as the market-based cost recovery (*MPI #32*) and most other MPIs do not show significant differences between the five market design bundle cases. Main deviations occur in the market-based curtailment (*MPI #17*, not at a significant level, yet), the vRES support costs (*MPI #31*) and the connected total cost recovery. Regarding the latter, the results for the starting point scenario clearly show that RES remuneration schemes are needed, since market revenues are not high enough to cover the cost of RES. Depending on the RES technology, around 28% (for PV) to 66% (for wind offshore) of total cost cannot be covered at the day-ahead market.

Given, that in none of the cases the cost recovery exceeds 100%, the results confirm that the parameterisations of the support instruments meet their requirement to ensure refinancing as well as efficiency (see Chapter 3.2.2). However, the results do not give a clear indication on how remuneration schemes should be designed, as the market performance of all considered market design bundles is very similar. Note that, apart from the FIT for rooftop-PV, all support instruments considered in the starting point scenario are designed on the basis of perfect information regarding the market performance of vRES, considering the simulation results. In reality, in contrast, such information is not available for support instruments that are designed ex-ante such as MPfix. The parameterisation of the support instruments is therefore idealised in the starting point scenario; their efficiency is to be considered a benchmark that is difficult to achieve in reality.

It is likely that the market performance will change considerably with a higher share of RES in the power system and an accordingly needed increase in flexibilities. For the second iteration of this deliverable, a nearly carbon-neutral power system will therefore be simulated, amongst others with regard to the impact of temporal and sectoral flexibilities. Accordingly, the performance of the market design bundles will be assessed for such a RES-dominated scenario.

3.3 Case Study D: Iberian market (MIBEL)

The Portuguese and Spanish governments worked together to create the Iberian Electricity Market (MIBEL) with the intention of fostering the integration of their respective electrical systems [16]. The resulting effects were a crucial factor in creating an electrical market at the European level as well as in Iberia, which was a necessary first step in creating an internal energy market. This ongoing development started in 1998, and MIBEL was fully launched and brought to a successful Iberian electricity system on July 1st, 2007, providing a framework for granting access to all interested parties in accordance with the norms of equality, transparency, and impartiality, with the hope that its operation would benefit the consumers of both countries. MIBEL is composed of all spots (day-ahead and intraday auctions), intraday continuous, and deliberative markets. Furthermore, it is also responsible for the ratification of all private bilateral agreements for electrical energy acquisition in Iberia. Ancillary services of Portugal and Spain are independent of MIBEL and are managed by each TSO.

In this first version of deliverable D5.3, the Iberian market case study focuses on studying market bundles and the potential vRES participation in ancillary services trading.

3.3.1 Models used: MASCEM and MASCEM+RESTrade

The publicly available Spine Toolbox project[6] integrating MASCEM and RESTrade models was used to run MIBEL's case study. This project integrates MASCEM's wholesale market models with RESTrade's secondary and tertiary energy markets.

The MIBEL case study uses MASCEM's MIBEL wholesale day-ahead market model to run the day-ahead session of the Iberian electricity market and the RESTrade models to execute the ancillary services market after each day-ahead session. It should be noted that these models do not simulate nor study investments decisions. They aim, in turn, to simulate and replicate real spot market's operation as well as to test and study new market designs including vRES contribution to ancillary services. For further details about these models and their integration, please refer to deliverable D4.8 [10].

[6] https://github.com/TradeRES/mascem-restrade-demo

3.3.2 Scenarios, input data and limits of the analysis

This first version of the deliverable aims to tune and test the market models for the simulation of future market scenarios using real data from 2019. Thus, real day-ahead bids from the Portuguese and Spanish areas have been used to feed MASCEM. This data is made publicly available on the operator's (OMIE – Operador de Mercado Ibérico – Polo Español) web page [17]. The available data includes bid offers for each period of the day. Each offer has the following information: the date, hour, trading unit code, type of offer (*i.e.*, buy or sell), amount of energy to trade, price per MWh. Additionally, the available data also identifies if the bid offer has been accepted, or not, after market execution. This data is made available as daily comma separated values (CSV) files, *i.e.*, one per day-ahead session. Figure 30 presents a snippet of a publicly available CSV file, from OMIE's repository, from February 1st, 2019, used as input in MASCEM for the simulation of the Iberian day-ahead market.

Hora	Fecha	Pais	Unidad	Tipo Oferta	Energía Compra/Venta	Precio Compra/Venta	Ofertada (O)/Casada (C)
1	01/02/2019	MI	EGLEC2	C	103,1	180,30	O
1	01/02/2019	MI	ENDPC2	C	826,5	180,30	O
1	01/02/2019	MI	ENDE01	C	3.258,7	180,30	O

Figure 30. Snippet of MIBEL day-ahead publicly available data from February 1st, 2019.

The "***Hora***" column refers to the hour of the day (*i.e.*, the period number) and it assumes values in the interval [1, 25]. Since in Iberia there's a different summertime, the last Sunday of March considers only 23 hourly periods (as the hour moves forward) while the last Sunday of October regards 25 hourly periods (as the hour delays). The "***Fecha***" is the date in the Iberian format (*i.e.*, DD/MM/YYYY). "***Pais***" refers to the bidding area of this bid and it can assume three different values, namely: (i) "***MI***" – MIBEL; (ii) "***ES***" – Spain; "***PT***" – Portugal. It must be noticed that these files not only make available all bids submitted in the corresponding day-ahead session but, also, the session's outcomes. This said, if in the "**Pais**" column we have "PT" or "ES", it means that in this hourly period it was not possible to trade energy between both countries due to congestion issues, and the bidding area has been split in two, one per country. This means that each country is only able to trade energy internally without cross border transactions. The "***Unidad***" identifies the trading unit with its code. "***Tipo Oferta***" identifies if it is a buying bid ("***C***") or selling bid ("***V***"). The "***Energía Compra/Venda***" refers to the total amount of energy to buy ("***Compra***") or sell ("***Venta***") with this bid, in MWh. "***Precio Compra/Venta***" is the price per unit, *i.e.*, the price per MWh in EUR/MWh. And the "***Ofertada (O)/Casada (C)***" indicates if this is a submitted bid ("***O***") or a traded one ("***C***"). It must be noted that these files include all submitted bids in the top and the traded ones at the bottom. Finally, it must be stressed that the decimal and thousand numbers' separators are comma (",") and point ("."), respectively, due to the Iberian regional settings.

Forecast data for both solar PV and wind power have been computed for the Portuguese area [18] and have been collected for the Spanish area. The observed data of vRES have been collected in both areas. Real bids for the Portuguese ancillary services [19] have also been used to feed RESTrade. It enables us to tune the ancillary services models and obtain the results of the imbalance settlement, comparing them with the real results. Real bids for the Spanish ancillary services were not available at the current stage, being the Spanish imbalance settlement represented in the models using real costs of the ancillary services [20]. In future iterations of this market simulation, the actual modelling approach (and input data) of the Spanish control zone will replicate the presented for Portugal in this deliverable.

The Portuguese imbalance settlement considers that a balance responsible party (BRP) can be penalized by three times more in relation to other BRPs according to their degree of unbalance, *e.g.*, a BRP with a small imbalance while providing ancillary services will pay three times more than BRPs with imbalances concerning the spot market programmed dispatch. To use the complete model of this imbalance settlement the real-time imbalances of each power plant are needed, but only the imbalances of each BRP have been collected, containing aggregated data.

Although not directly computed with the models available for the Iberian case study, the share of RES in the national demand (*MPI #1)* was obtained using the observed data from 2019 to characterize this case study. The RES shares in the power system for Portugal and Spain are presented in Table 6 [20], [21].

Concerning vRES, both countries have a similar share, although the wind share is significantly higher than the solar share. A relevant investment in more solar PV capacity is expected in both countries until 2030 according to their national plans. In relation to the share of other non-variable renewables, in Portugal the share is substantially higher. However, in what concerns to hydro, its production is highly variable on the inter-annual time scale. Figure 31 presents the daily share of RES in the Portuguese demand for the starting point scenario (*i.e.*, 2019, the period simulated in this edition of the deliverable).

Table 6. Observed RES share in the Iberian power system.

	Wind (%)	Solar PV (%)	Solar Thermal (%)	Hydro (%)	Biomass (%)
Portugal	26.73	2.11	-	20.16	5.41
Spain	20.96	3.69	2.09	9.89	1.11

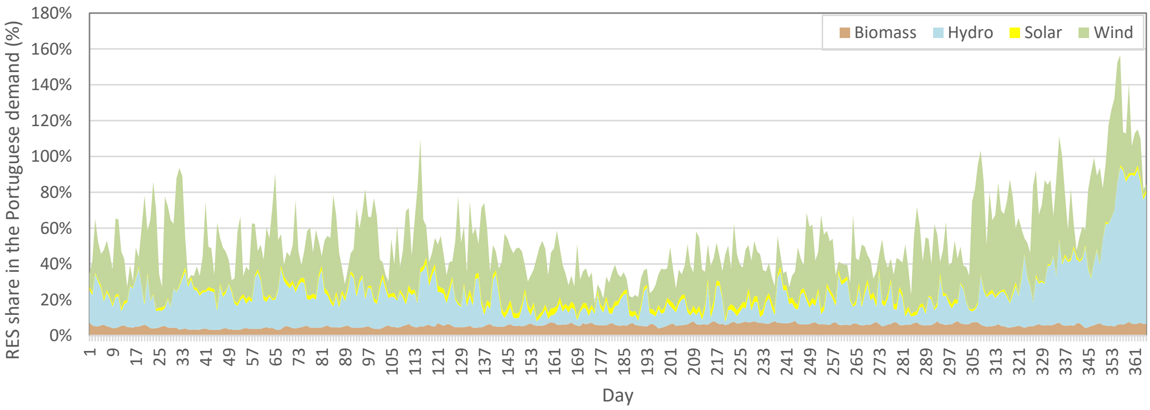


Figure 31. Observed daily average share of RES in the Portuguese demand.

Using the observed data for 2019 (Figure 31) is possible to verify that, on average, during several days the RES production was above the Portuguese demand. Curtailments are avoided by hydroelectric pumping and exports to Spain. Figure 32 presents the daily average share of RES in the Spanish demand during 2019.

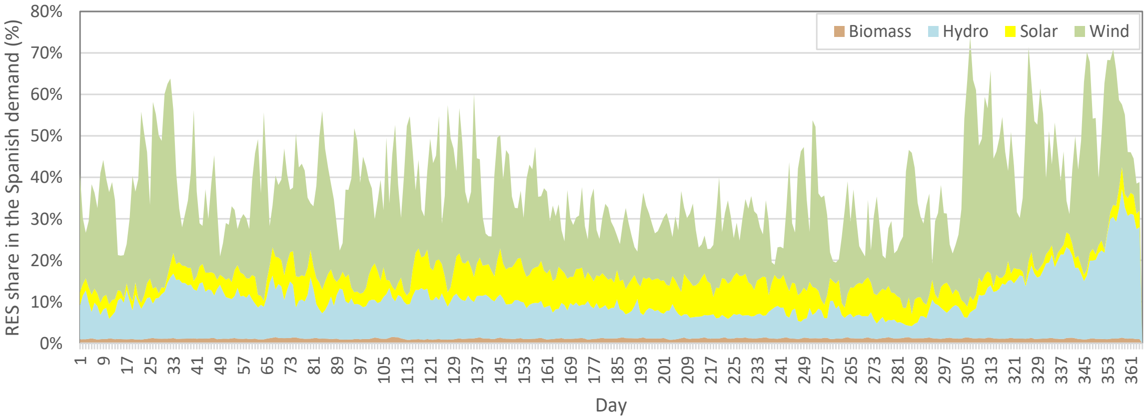


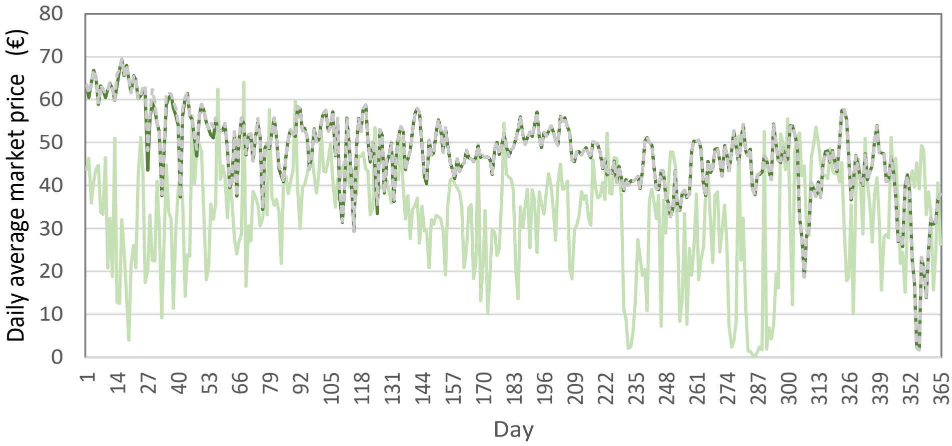
Figure 32. Observed daily average share of RES technologies in the Spanish demand.

Analysing Figure 32 it can be verified that in the best case the RES share in the Spanish demand achieves a value of around 70%.

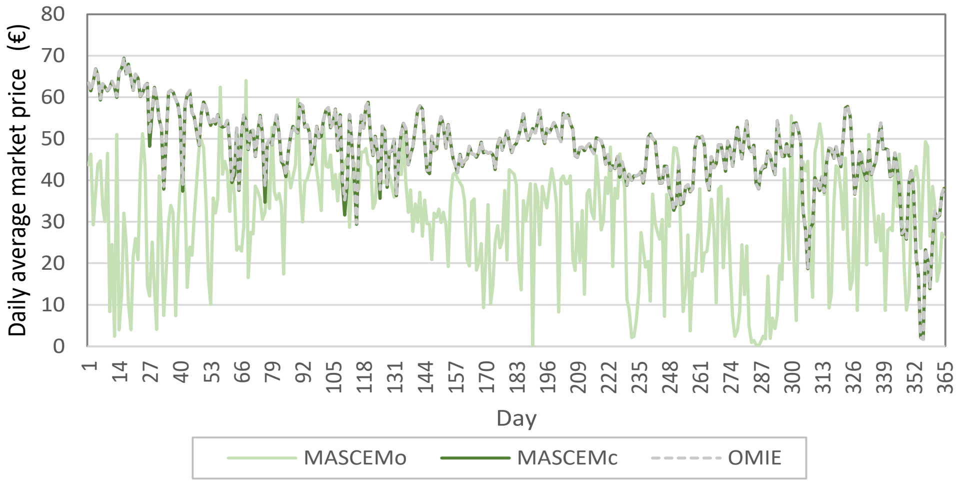
3.3.3 Simulation results and analysis

Using real data to feed and tune the market models, enables to simulate and compare the simulation results with the real-world results. However, it must be stressed that the data publicly available at OMIE's repository disregards the players' strategic bidding. In MIBEL markets (*i.e.*, day-ahead, and intraday wholesale markets), players can submit complex conditions along with their bids, with a strategic approach trying to increase profits if they are selling or decrease costs if they are buying. These restrictions allow players to leave the market if they are not respected, meaning that players are not interested in participating unless those conditions are met. In what concerns the day-ahead market, only sale bids can be submitted along with complex conditions. Day-ahead complex bids incorporate complex sale terms and conditions including at least one of the technical or economic constraints (for further details regarding complex bids see [22]). Thus, if the submitted complex conditions are not met for a particular seller, his supply may be curtailed or removed from trading, requiring the renegotiation of the respective period or day-ahead session. Therefore, using OMIE's publicly available data to simulate MIBEL in MASCEM, without having the details about the player's strategic bidding, can affect the outcomes significantly, resulting in a deviation from the real-world market prices and amount of traded energy.

On the other hand, as stated in subsection 3.3.2, the publicly available data identifies the traded bids and the amount of each bid's traded energy. One possible solution to simulate MIBEL and have similar outcomes to the ones achieved by OMIE is to use the traded bids. Fundamentally, it is the same as gathering simple bids after applying complex conditions. This way, it is possible to use these bids to simulate MIBEL in MASCEM as if players were submitting their strategic constraints. Figure 33 presents the average market prices for Portugal (a) and Spain (b) in MIBEL's day-ahead session, comparing the market prices gathered from OMIE's public repository with the ones obtained by simulating it in MASCEM with the submitted bid offers ($MASCEM_O$), and with the traded bid offers ($MASCEM_C$), for the year 2019.



a)



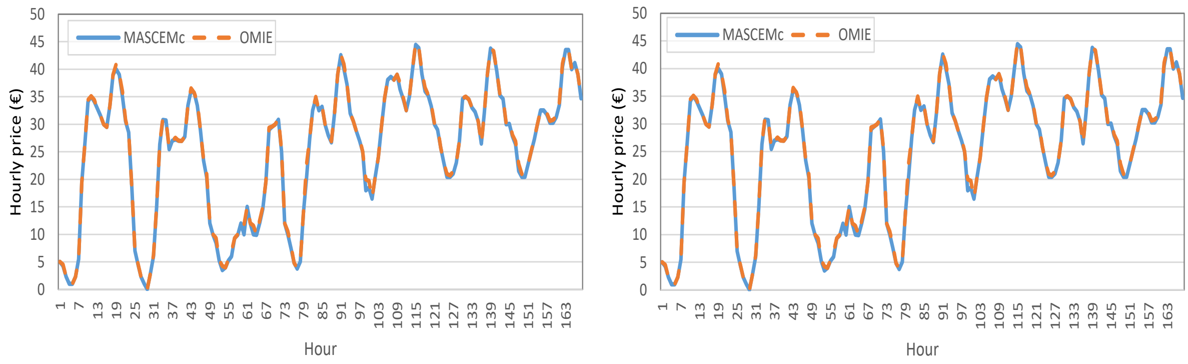
b)

Figure 33. Daily average market prices comparison in a) Portugal and b) Spain.

Observing Figure 33, $MASCEM_C$ (in dark green) results are practically the same as the OMIE's (dashed line), while $MASCEM_O$ (ligh green) outcomes are significantly different. The mean absolute percentage error (MAPE) of the $MASCEM_C$ scenario is 0.345% for Portugal and 0.442% for Spain, indicating that when considering the complex conditions, MASCEM can emulate OMIE's outcomes. MAPE is computed as follows:

$$MAPE = \frac{100\%}{T} \sum_{t=1}^{T} \left| \frac{p_t - \widehat{p_t}}{p_t} \right|$$

Where T is the number of periods, p_t, the observed price and $\widehat{p_t}$ the simulated price per period t. Figure 34 presents a randomly selected week with a comparison of hourly market prices from OMIE and $MASCEM_C$, for Portugal and Spain, respectively.



a) *b)*

Figure 34. Hourly market prices comparison: OMIE and MASCEMc for a)Portugal and b)Spain.

Again, the selected week's results demonstrate the close accuracy of running MIBEL in MASCEM after complex conditions apply. It is possible to submit the complex conditions of MIBEL players in MASCEM along with their bid offers. However, the OMIE's repository doesn't disclose the strategic bidding of its players, hardening MASCEM's proof of concept.

The real Portuguese secondary and tertiary reserve markets published the real bids and dispatch needs, which are submitted to RESTrade, enabling us to simulate their markets. The 2019 simulations clearly replicated those markets obtaining a mean absolute percentage error (MAPE) of 0% in both markets.

The imbalance settlement depends on the results of all market mechanisms. Real data has been used to test these mechanisms avoiding the propagation of errors in the case of using simulated results from the day-ahead and ancillary services. The MPIs were computed considering the simulation of the Iberian day-ahead market (MIBEL), the Portuguese ancillary services and both countries' imbalance settlement. The Spanish ancillary services consider observed data. The Portuguese imbalance settlement considers that BRPs can have different degrees of penalization. In RESTrade this procedure has been simplified due to the lack of real-time dispatch data for each power plant. Therefore it is considered that all players have the same levelized penalty, obtaining a MAPE of 6.74% and 16.89% in the computation of the up and down imbalance prices, respectively (see Figure 35).

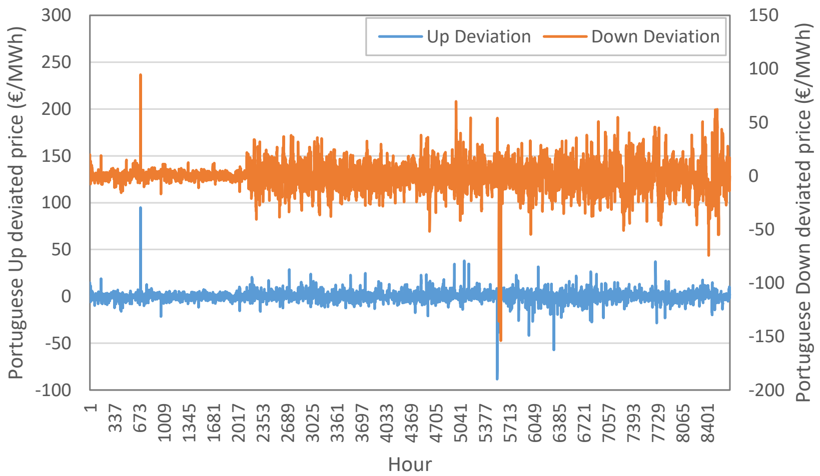


Figure 35. Upward and downward deviated prices for Portugal.

RESTrade includes a similar model of the Spanish imbalance settlement computing its imbalances prices with a MAPE of 0% (see Figure 36).

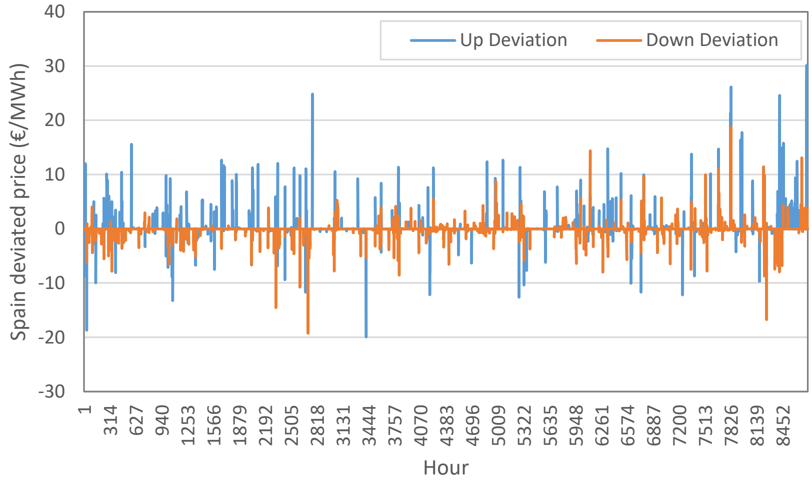


Figure 36. Upward and downward deviated prices for Spain.

- ***Technical MPIs***

With regard to technical MPIs, the simulations of the starting point scenario revealed the results presented below.

MPI #4 and *MPI #5* are 0 concerning the LOLE and EENS, respectively, as expected for the simulated starting point scenario. In future scenarios with vRES penetrations closer to 100%, due to their inherent variability, power systems may face periods with reduced security of supply and periods with LOLE and EENS above the technically defined limits between 3 to 8 hours per year may occur [23].

MPI #12 addresses energy procurement/use in ancillary services and the results for the Iberian countries are presented in Table 7. While the Portuguese ancillary services have been simulated using model RESTrade, at this phase of the work, the information of the Spanish ancillary services consists of real data. Concerning the formulation presented in Deliverable 5.1, besides the 2019 energy procurement for ancillary services, the share that it represents in the total demand was computed, for a better comparison according to each area/country.

Table 7. Energy procurement in MIBEL ancillary services.

	Balanced energy (TWh)	Share in total demand (%)
Portugal	2.28	4.53
Spain*	*7.79*	*3.11*

**Spanish data source* [20].

Spain allows players to participate in the imbalance resolution mechanisms, which close after the continuous intraday markets and prior to balance control. Besides that, by allowing the participation of vRES in the ancillary services, Spain can control part of the vRES deviations, reducing the need of ancillary services. Thus, by having a more mature and less restrictive market design, Spain required less quantities of energy in relative values [24], a feature of markets that will be addressed in future MIBEL simulation scenarios.

MPI #13 considers capacity procurement in ancillary services. In the case of the RESTrade models, only the secondary reserve has capacity procurement. Concerning Deliverable 5.1, besides the total 2019 capacity procurement, it has also been computed the share of that capacity in relation to the total demand, Table 8.

Table 8. Capacity procurement in ancillary services (Iberia).

	Secondary Capacity (TW)	Share (%)
Portugal	2.49	4.94
Spain*	*9.55*	*3.82*

**Spanish data source* [20].

According to the results of the simulation (Portugal) and the OMIE observed data (Spain), both countries are reserving more capacity in the secondary capacity market than the energy they need to balance the system considering all ancillary services. Thus, can be concluded that the conservative approach of system operators for computing the balance capacity needs can lead to excessive costs when compared with its real-time needs. A more dynamic methodology should be designed to guarantee the balance of security at sustainable usage and costs.

MPI #14 considers the capacity usage in ancillary services, and the results are presented in Table 9.

Table 9. Secondary capacity used (Iberia).

	Secondary capacity usage (%)
Portugal	20.26
Spain*	*27.73*

**Spanish data source* [20].

Both countries have an inefficient procurement of balance capacity. On average, Portugal and Spain allocate almost five and four times more secondary balance capacity than they need, respectively. These results support the need for a better design of the balance capacity procurement of secondary reserve [25].

MPIs #15 and *#16* consider the share of demand and vRES in the ancillary services. In the starting point scenario (year 2019) in the Portuguese control zone, vRES market players are prevented from participating in the ancillary services markets. In Spain, only wind power plants can do it, what occurred for the simulated starting point year share of 0.35%, 8.29% and 8.50% on the secondary capacity, tertiary energy and the imbalance resolution mechanism, respectively. All the other players and services have a share of 0%. In future scenarios, apart from simulating ancillary services markets, both in Portugal and in Spain, the participation of demand players in these markets will also be included.

MPI #17 addresses the annual curtailment of market-based energy of vRES, *i.e.*, the amount of energy curtailed due to market-based incentives and/or limitations. For the year 2019, there was no vRES energy curtailed in Portugal, according to MIBEL market data.

Although in most European countries the vRES energy that exceeds system needs is usually curtailed, in Portugal, that energy usually is directly used by pumped hydro storage plants (PHS) to store energy in their upper reservoirs [26]. Unlike Portugal, Spain usually curtails excess wind generation and has applied its first PV curtailment in July 2022. Although not all pumping by PHS was powered by vRES, in Portugal, during 2019, the total amount of energy consumed by pumped storage hydropower was 1.83 TWh, representing nearly 3.5% of the annual electricity generation and 12.6% of the yearly vRES-based electricity generation [21], what gives an idea of the dimension of this sector, and its impact on the costs of the power system.

In Portugal, it was considered the vRES forecasts to day-ahead markets computed using the approach presented in D4.9 [18]. In Spain, it was considered the deviations in relation to the final hourly operational programmed dispatch (after the imbalance resolution mechanism[7]) to compute the forecast error. Spanish wind power plants can participate in the imbalance resolution mechanism which closes after the continuous intraday market, a few minutes ahead of real-time operation and in the ancillary services, significantly reducing their deviation in relation to the day-ahead market.

MPI #24 considers the computation of the normalized bias (NB) error of forecasts for the period covering the day-ahead market, being in the case of Portugal 6.06% and 2.11% for wind and solar PV, respectively. Concerning the Spanish forecasts for their final dispatch, computed only a few minutes ahead of real-time operation, the NB errors are 0.99% and 0.77% for wind and solar PV, respectively. The error of vRES day-ahead forecasts (Portugal) is significantly higher than the error of participating in close to real-time markets (Spain) as can be verified in *MPIs #24* and *#25*.

MPI #25 considers the computation of the normalized root mean square error (NRMSE) error of forecasts. Considering day-ahead forecasts in Portugal, the NRMSE is 7.09% and 4.89% for wind and PV, respectively. Considering close to real-time forecasts in Spain, the NRMSE is 1.37% and 1.58% for wind and PV, respectively.

[7] *This programme includes the transactions in the organized market and through bilateral contracts which were technically validated, the mobilizations of Provisional Reserve Programme (PPR) and all other programming changes relating to processes for the resolution of technical constraints and to ancillary services* [19].

The same justification of the NB can be applied to the NRMSE. The more interesting result is that by participating in the Spanish ancillary services wind power plants obtain a lower NRMSE when compared with the solar PV.

- ***Economic MPIs***

MPI #26 considers the total system costs, including investment, O&M and fuel costs [27]. The investment costs consider two scenarios with a discount rate (r) of 4% and 6%, as presented in Table 10.

Table 10. MIBEL systems total costs for the two scenarios with different discount rate.

	Total costs (r=4%) [10^9 €]	**Total costs (r=6%) [10^9 €]**
Portugal	2.98	3.01
Spain	12.41	12.56

MPI #27 considers the total costs for dispatch, including fuel, emissions, and load shift. Results of this MPI for Portugal and Spain are provided in Table 11.

Table 11. Total costs for dispatch (Iberia).

	Total Costs 10^9 €
Portugal	1.30
Spain	4.41

MPI #29 addresses the annual volume-weighted average of hourly day-ahead market price. Table 12 provides the average day-ahead market prices for both Portugal and Spain for the year 2019.

Table 12. MIBEL annual volume-weighted average day-ahead.

	EUR/MWh
Portugal	50.24
Spain	50.14

The annual volume-weighted average day-ahead market price for Portugal was 50.24 EUR/MWh, while for Spain it was 50.14 EUR/MWh.

MPI #31 focusses on the computation of the vRES support schemes costs in 2019. It is considered that the support schemes will support vRES investment for 12 years considering two scenarios with a discount rate of 4% and 6%, respectively. The variable premium is the support scheme that recovers all the investment in wind power plants for a given discount rate. It is computed considering the payment of a variable value according to the production costs of the technology. The goal is to compensate the difference between production costs and the market remuneration of wind power. The fixed premium is calculated to compensate for the deficit between the expected production costs and market remuneration during the support scheme duration. The capped fixed premium is exactly like the previous method but considers a minimum and maximum remuneration price. CfDs consider a strike price equal to the levelized expected production costs during the support scheme duration. In the one-way CfDs, vRES are compensated when the strike-price is lower than market prices and in two-ways CfDs vRES always receive the strike-price. Figure 37 presents the simulated Spanish costs with each support scheme to wind power plants during 2019.

During 2019 the productivity of the Spanish wind power plants was below the average, which means that all support schemes give a lower remuneration when compared to the variable premium, preventing investors to recover their yearly investment costs. Figure 38 presents the Portuguese costs with wind power plants support schemes.

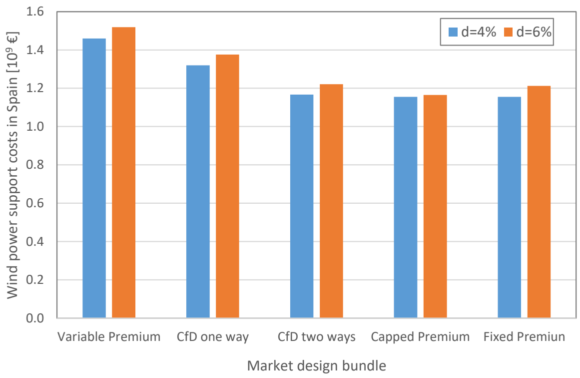


Figure 37. Costs with wind power plants in Spain for different support schemes.

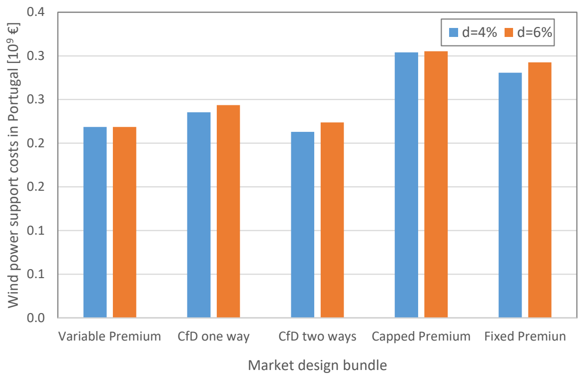
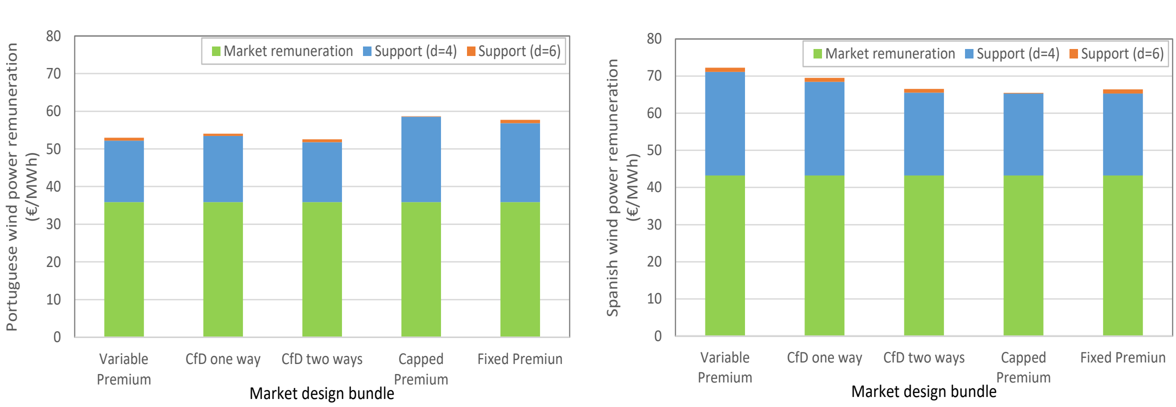


Figure 38. Costs with wind power plants in Portugal for different support schemes.

In Portugal, the 2019 wind power productivity (wind index) was above the average. This high level of production increases the wind power producers' remuneration above the variable premium for all support schemes, except in the case of two ways CfDs scheme.

Figure 39 presents the levelized weight of the support in the total remuneration of each support scheme in Portugal and Spain, respectively.



a) *b)*

Figure 39. Levelized weight of the support in the total remuneration of each support scheme in: a) Portugal and b) Spain.

MPI #32 has the goal of computing the 2019 market-based cost recovery of each technology, as presented in Figure 40 for Spain and in Figure 41 for Portugal.

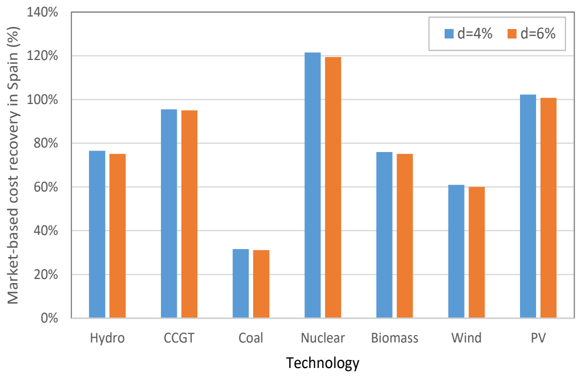


Figure 40. Market-based cost recovery of the technologies in Spain.

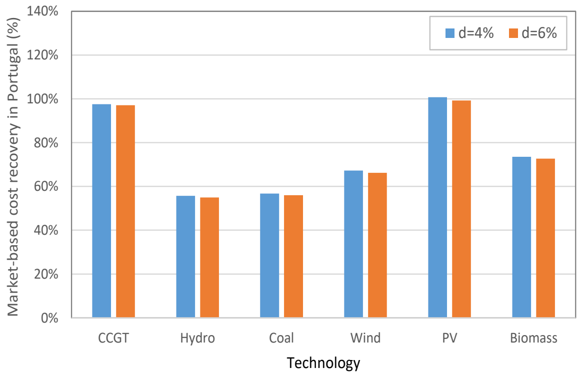


Figure 41. Market-based cost recovery of the technologies in Portugal

Analysing the previous two figures (Figure 40 and Figure 41) can be concluded that only solar PV and thermal-based technologies (CCGT and nuclear) can recover their yearly production costs. All the other technologies need support mechanisms to recover their costs. Analysing the figures can be verified that only nuclear technology can recover all costs and obtain a significant return from the market. Solar PV and CCGT technologies have a remuneration close to their yearly production costs. The low power factor of coal power plants led them to a significant deficit between their market remuneration and costs.

MPI #33 regards the yearly price convergence, calculated by the price differential between bidding zones of each hour (*i.e.*, the trading period). Full price convergence is defined by a price differential between 0–1 EUR/MWh. Moderate price convergence is within the interval 1–10 EUR/MWh. Above 10 EUR/MWh, it is defined as low price convergence. In this first iteration of MIBEL's case study, the price convergence between Portugal and Spain is 0.13316 EUR/MWh, *i.e.*, full price convergence.

MPI #36 refers to the costs of the ancillary services. They are computed in two ways: net or real costs. The net costs consider the transaction costs between the players participating in the ancillary services and system operators, *i.e.*, only the ancillary services costs. The real costs also consider the BRPs deviations in the transaction costs, *i.e.*, the spot markets costs and the difference (penalties) between these costs and the ancillary services costs paid by BRPs. Table 13 presents the costs of the ancillary service.

Table 13. Costs of the ancillary system services in Iberia.

	Absolute Costs		**Costs relative to Power System Size (*)**	
	Net [10^9 €]	Real [10^9 €]	Net [€/MWh]	Real [€/MWh]
Portugal	0.05	0.06	1.08	1.132
Spain	0.22	0.15	0.88	0.61

(*) The ancillary system services relative costs are normalized by dividing the absolute costs by the balancing traded energy.

While in Portugal the real costs are higher than the net costs, in Spain the opposite situation occurs. These preliminary results - although not straightforward comparable, as the Portuguese are simulated and the Spanish were assessed at OMIE - indicate that, the ancillary services prices in Portugal are normally higher than in Spain. The reason behind that occurrence is unclear but, may be associated with the conservative approach followed in the Portuguese control zone, by not allowing the participation of vRES in ancillary services provision, as well as less competitivity in the Portuguese market for these services.

MPI #37 has the goal of computing the average market penalties that BRPs must pay. While in Portugal its average price is 9.32 €/MWh, in Spain it is 10.69 €/MWh, which reflects the difference between the imbalance settlement and the opportunity for the use of the imbalance resolution mechanism in Spain. While in Portugal all BRPs pay for their deviations, in Spain, only the net deviations are paid [28]. Furthermore, the imbalance resolution mechanism and the participation of wind power plants in the Spanish ancillary services allow players to adjust their programming dispatch closer to real-time operation, meaning that BRPs, which do not use these mechanisms, pay higher penalties when comparing to Portugal.

MPI #38 has the goal of computing the average up and down imbalance prices. Furthermore, the relative differences between these prices and the day-ahead prices are computed and presented in Table 14.

These results reflect the same as the previous MPI. Notwithstanding that, the Portuguese ancillary services are more costly in relative terms; the costs of the Spanish ancillary services are not divided by all BRPs with deviations. Thus, in Spain, the players who pay for deviations will pay more than in Portugal.

Table 14. Imbalance costs in Iberia: upward and downward deviation.

	Upward deviation price		**Downward deviation price**	
	Absolute (€/MWh)	Relative to DAM price** (%)	Absolute (€/MWh)	Relative to DAM price** (%)
Portugal	45.91	96.19	49.54	103.81
Spain	43.18	90.72	51.53	108.26

(**) The relative prices are calculated by dividing the imbalance prices by the DAM prices (set as 100%).

Figure 42 presents the difference between the DAM and the imbalances prices in Portugal.

From Figure 42, it is possible to conclude that exist a few events when the penalties are significant, leading BRPs to pay when injecting more energy into the grid.

Figure 43 presents the difference between the DAM and the imbalances prices in Spain. In Spain, there is an hour with a huge high imbalance price for down deviations of 1296 €/MWh. However, compared to Portugal, in Spain, extra injected energy in the grid is never paid. These results reflect the differences between the Imbalance Settlement mechanisms of both countries.

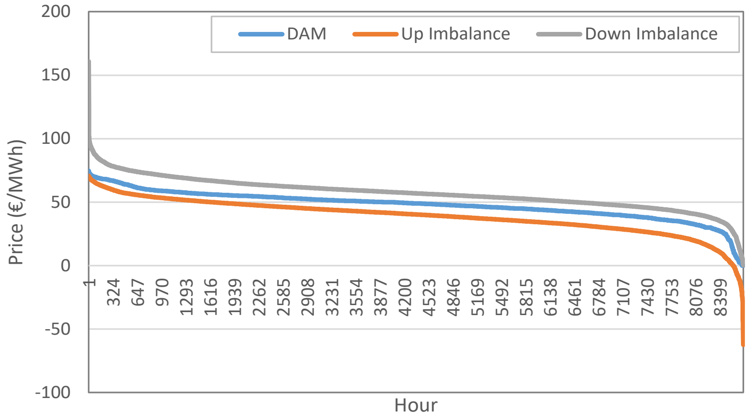


Figure 42. DAM and imbalances prices in Portugal.

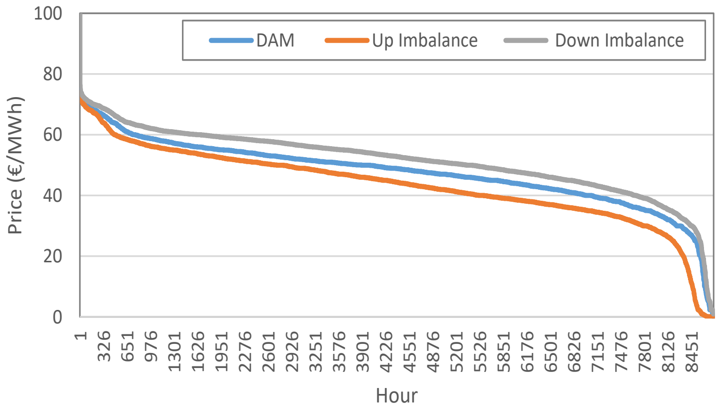


Figure 43. DAM and imbalances prices in Spain.

- ***Environmental MPI***

MPI #45 addresses the power system emissions. This MPI is important to characterize the sustainability of the power sector studied and its position in the energy transition's pathway by providing the annual CO_2 emissions associated with fossil fuel electrical energy generation. This indicator enables quantifying how much the different market designs reduce CO_2 emissions. However, in this first iteration of the case study, this MPI supplies a baseline value to be compared in future iterations. **Error! Reference source not found.** presents the CO_2 emissions of Portugal and Spain for 2019 considering different fossil fuels.

In 2019, in Portugal, the amount of electricity generated with recourse to natural gas was significantly higher than with coal, explaining the higher CO_2 emissions of natural gas. In Spain, in turn, in 2019, the use of coal to produce electricity produced more CO_2 emissions than natural gas. However, when comparing the tons of CO_2 emissions per consumed energy (Figure 44) is possible to see that Spain has less emissions, mainly because of using nuclear power plants and more modern coal power plants than Portugal.

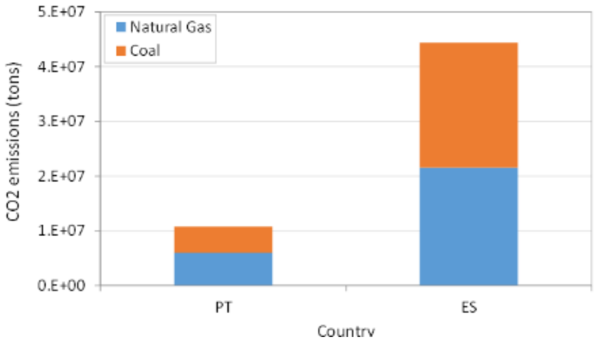


Figure 44. Iberian CO2 emissions for 2019.

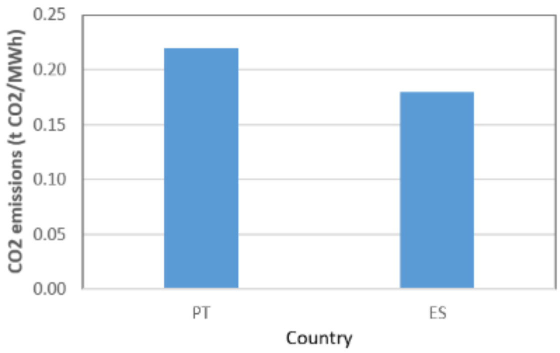


Figure 44. Iberian CO_2 emissions for 2019 normalized by the consumed energy in each country.

3.3.4 Final remarks and outlook

Portugal and Spain have both a high penetration of vRES in their power systems, above 25% of the total annual consumption thus constituting a very relevant case study for TradeRES project. In the starting point scenario, that simulates the year of 2019, Portugal had the demand served by 54% RES and Spain by 38%. Despite a visible difference in the conventional RES share – essentially due to hydro - both countries have very similar vRES participations, as 29% of supplied energy in 2019 was originated by vRES in Portugal, and 25% in Spain. Furthermore, Portugal experienced several hours with RES production above the demand, using hydroelectric pumping and exporting to Spain to avoid vRES curtailments.

According to market results, although preliminary, both countries appear to have means to improve the allocation of secondary capacity, due to the obtained reduced utilization of the reserves committed. In the next iteration of models application (and edition of this deliverable) a more dynamic procurement of secondary capacity will be tested, which has the goal of contributing for reducing vRES integration costs and the maintenance of power systems stability and robustness, at lower costs.

In relation to market-based cost recovery, results showed that (taking into account DAM only) several technologies do not recover their production costs without support schemes, with the exception of nuclear, CCGT, and PV plants. In subsequent simulations of this case study and under higher RES participations, it will be tested if all mature technologies can be remunerated from energy-only markets or if they replicate 2019 and continue to need additional economic support [29].

The participation of vRES in close-to real-time markets leads to a reduction in their imbalances, which can be verified by comparing the forecast errors between Portuguese and Spanish vRES [25].

4. Summary of market performance indicators

This section summarizes the main outcomes obtained for the three case studies: B-Netherlands, C-Germany and D-MIBEL for the starting point scenarios and the bundle of simulations presented in section 3. Particularly, the market performance indicators adopted within project TradeRES and defined for national and regional markets were calculated, whenever possible.

Some selected MPIs are included to provide a general characterization of the results presented in this first edition of deliverable 5.3. Those indicators are presented in Table 15. Further MPIs can be found in the main list presented in section 2 (Table 2). The ultimate objective of the MPIs' definition within project TradeRES is to enable the quantification of market performance of the different designs and products (developed within work packages 3 and 4) that will be simulated within work package 5. At the actual preliminary stage of the simulations, this reduced set of MPIs was selected due to the different parameterizations among case studies. In the second edition of this deliverable, a higher harmonization of the MPIs will be pursued aiming to highlight the pros and cons of the different market designs and products for the three national/regional case studies under analysis in this task.

Table 15. MPIs relevant for characterizing the starting point scenarios.

MPI number	MPI name
1	Share of RES-E
4	Loss of load expectation
5	Expected energy not served
6	Supply ratio
27	System costs for dispatch
28	Costs to society
29	Average day-ahead market price
31	RES support costs
32	Market-based cost recovery
45	CO_2 emissions

MPI #1 calculates the RES share in each country's demand, which is a relevant form to identify each country's stage in relation to the European goal of power systems with 100% of RES.

MPIs #4 and *#5* are important to identify the suitability of the power systems' installed capacity to comply with the expected demand. Results presented in the previous section show that, for the starting point scenario simulated, neither Germany, Portugal, nor Spain present risks of having LOLE or EENS above the acceptable limits.

MPI #27 enables to characterize the dispatch costs of power systems[8]. *MPI #28, MPI #29* and *MPI #31* enable to assess the costs of electricity from the society's and the consumer's perspectives, respectively.

MPI #32 translates the cost recovery of different technologies from energy-only markets and thus discloses the need for RES support schemes.

MPI #45 refers to the CO_2 emissions and partially reflects the RES penetration on each power system.

Within this section, *MPIs #1, #27, #3*1 and *#45* have been normalized by the consumption (or production as applicable) of each national power system.

- **Dutch Market**

Table 16 presents the indicators obtained for the Dutch market starting point scenario.

Table 16. Summary of the results for case study B: Dutch market.

MPI name (units)	Year	EOM	EOM_vRES
4	2030	2	4
	2049	5	6
5	2030	669	1760
	2049	3152	8387
32	2030	-1.39	-5.52
	2049	4.21	-7.29
6	2030	98%	97%
	2049	98%	96%
1	2030	63%	78%
	2049	57%	80%
28	2030	56	59
	2049	61	56
29	2030	56	42
	2049	61	40

EMLabpy must run for 4 years (or the user-defined look-ahead years) to give stable results. In these first simulations, we observed high scarcity in the first 3 simulation years. This caused extreme MPI values for the initial year, as described in section 3.1.3. In next iteration, the simulations will be triggered from an earlier year to be able to be compared with other case studies.

[8] aka "integration costs of vRES".

At this stage, AMIRIS is being developed to take as input yearly vRES support, fuel prices and CO_2 prices. For this reason, it is not yet possible to consider multi-year simulations with vRES support. In the Dutch case, the national vRES targets are considered to achieve investments in these technologies. The vRES support is calculated as the financial gap for these investments. This is a rough estimation and not comparable with the VRES support mechanisms as modelled in the other case studies.

- **German Market**

In the case study for Germany, five different remuneration cases have been simulated. Probably due to the limited share of RES in this scenario (approximately 34%, see *MPI #1*) the results do not reveal significant differences: System costs for dispatch (*MPI #27*) are at 11.4 bn €/a, respectively at 21.6 €/MWh, volume-weighted average electricity prices (*MPI #29*) range between 40.7 €/MWh and 41 €/MWh and the market-based cost recovery (*MPI #32*) is at 72% for PV, 50% for onshore wind and 34% for offshore wind.

Main deviations between the cases without and with support instruments occur in the vRES support costs (*MPI #31*). In the cases with support 15 €/MWh are paid for PV, 36 €/MWh for onshore wind and 73 €/MWh for offshore wind. Results for the market based cost recovery (*MPI #32*, see above) show that market revenues are not high enough to cover the cost of RES. Depending on the RES technology, around 28% (for PV) to 66% (for wind offshore) of total cost cannot be covered at the day-ahead market.

Given, that in none of the cases the cost recovery exceeds 100%, the results confirm that the pre-calculated parameterisations of the support instruments meet their requirement to ensure refinancing as well as efficiency (see chapter 3.2.2). Note that all support instruments in this case study are designed based on perfect information regarding the market performance of vRES. The parameterisation of the support instruments is therefore idealised in the starting point scenario; their efficiency is to be considered a benchmark that is difficult to achieve. Table 17 presents the main results of the German market.

Table 17. Summary of the results for case study C: German market.

MPI number	MPI value
1	34%
4	0 h
5	0 MWh
27	21.57 €/MWh
29	40.7 - 41.0 €/MWh
31	15 €/MWh (PV), 36 €/MWh (onshore wind), 73 €/MWh (offshore wind)
32	72 % (PV), 50% (onshore wind), 34% (off-shore wind)
45	0.35 t CO_2/MWh

- **Iberian Market**

Table 18 presents the market indicators calculated for this first iteration of the Iberian market (MIBEL) simulation considering an observed yearly RES share of 54% in Portugal and 36% in Spain. For the conditions of the starting point scenarios, both Iberian countries that constitute MIBEL market do not present risks of having LOLE events with EENS (*MPI #4* and *MPI #5*) as it is to be expected.

Concerning *MPI #27*, the dispatch costs obtained within MIBEL are different – higher for Portugal than in Spain. This result is expected for the scenario simulated (2019), since Portugal still had in operation coal power plants (decommissioned in the meanwhile) with higher marginal costs, when compared with the Spanish thermal energy mix, constituted by nuclear power plants and modern coal power plants with lower CO_2 emissions. This difference in the dispatch cost is also reflected in *MPI #29*, where it is possible to observe that the average day-ahead price in Portugal is slightly higher than in Spain.

Table 18. Summary of the results for case study D: Iberian market.

MPI number	MPI value (Portugal)	MPI value (Spain)
4	0 h	0 h
5	0 MWh	0 MWh
27	25.82 €/MWh	17.64 €/MWh
29	50.24 €/MWh	50.14 €/MWh
31	0 €/MWh (PV), 19 €/MWh (onshore wind)	0 €/MWh (PV), 24 €/MWh (onshore wind)
32	101 % (PV), 98% (natural gas), 74% (biomass), 67% (onshore wind), 57% (coal), 56% (hydro)	122% (nuclear), 102 % (PV), 95% (natural gas), 77% (hydro), 74% (biomass), 61% (onshore wind), 32% (coal)
45	0.22 t CO_2/MWh	0.18 t CO_2/MWh

In the Iberian countries, however, wind generation (onshore) still needs support schemes to be economically sustainable as can be seen in *MPI #31*. Concerning *MPI #45*, Portugal has slightly higher weighted CO_2 emissions than Spain due to the already mentioned fact of having older/higher emission thermal technologies. Large-scale PV power plants can recover their production costs from the DAM at MIBEL, due to the abundant solar resource in southern Europe.

5. Syntheses and future work

This report presented the first version of deliverable 5.3, which provides a first assessment of the market designs and products developed in TradeRES project. Three computational studies are analysed: study B (the Netherlands); study C (Germany); and study D MIBEL (Portugal/Spain).

In the Dutch case, the EOM seemed to be insufficient to give enough incentives to invest in a high volume of renewables. In these first simulations, we simulated a high share of RES with investments according to national Dutch targets, instead of only considering profit-based investments. Although the total installed capacity was higher, the resource adequacy was not improved in the long term, as indicated by the supply ratio, as well as the LOLE and EENS. Finally, it was observed that although the market-based cost recovery was lower with a higher concentration of renewables, the costs to society were not higher, in that market bundle. In the long term, the costs in a system with high vRES penetration caused by subsidies could be compensated by lower average electricity prices.

These first simulations of AMIRIS-EMlabpy for the case study B should be seen as preliminary as there are many improvements still to be made before making recommendations for a future market design. In the next iteration of case study simulations, in terms of input data, the capital costs will be decreased, similarly, the CO_2 costs and fuel costs will be increased. In these runs, few decommissions were seen, in next simulations, higher fixed costs (or lower efficiency) will be assigned to older power plants. Furthermore, the physical limits for installed capacity per technology, should be accounted for. The current gas market has much higher prices than the one that was taken for this simulation. In future simulations, a shock of gas prices will be considered to analyse the market-based cost recovery along with the rest of the market performance indicators (MPIs). Moreover, the vRES target investments will be replaced by the vRES support mechanisms of AMIRIS. Finally, COMPETES runs will be added to serve as a benchmark case.

In the German case study, as a starting point scenario, the German electricity sector in 2019 was simulated, with a RES share of 34% according to the simulations. A situation with support only for small PV rooftop plants was compared with different market design bundles for RES. For most MPIs, no significant differences were found between support instruments that are ideally designed. Nonetheless, in terms of market-based cost recovery, we find that for the starting point scenario and the given commodity and CO_2 prices, renewables are not able to fully recover their full costs on a pure market basis which shows the need for support. It is likely that the market performance will change considerably with a higher share of RES in the power system and an accordingly needed increase in flexibilities. For the second iteration of this deliverable, a nearly carbon-neutral power system will therefore be simulated, amongst others with regard to the impact of temporal and sectoral flexibilities. Accordingly, the performance of the market design bundles will be assessed for such a RES-dominated scenario.

The 2019 simulations of the Iberian market of electricity (MIBEL) and the Portuguese and Spanish ancillary services and imbalance settlements have the goal of calibrating the MASCEM and RESTrade models to obtain close-to real-world results. All results have low errors compared to real-world results, with exception of the Portuguese imbalance settlement due to lack of data. Portugal already has a relevant share of RES on its demand, with RES generation above the total demand during several hours. The practices of Portugal and Spain (MIBEL) allow to defining the set of priorities for the second iteration when will be considered a power system with nearly 100% RES during the whole year:

- Increase the power system flexibility to embed high and low vRES production;
- Test the strategic bidding of vRES according to their support schemes;
- Test a dynamic procurement of the secondary capacity according to the power system net load;
- Study the impact of allowing vRES and demand players' participation in the ancillary services;
- Test a fairer imbalance settlement mechanism.

In this deliverable, preliminary results from the market design bundles are presented and they will be further investigated in the second version of deliverable 5.3 (expected in Month 43 of the project). In the second version, the outcomes from the *WP 2 - Optimal electricity trading with ~100% RES: Generation of a reference power system, scenarios and input market data* that provide optimal energy shares for ~100% renewable electricity systems will be used as reference systems to evaluate different market designs' performance. Further research questions and market designs will also be addressed in the second edition of the deliverable.

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Annex A – Relevant research questions for National/Regional Markets

1. Improvement of short-term markets

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	Perspective / Time frame	MPIs
Will (near) real-time trading/gate closure times enable VRE producers to maximize their profit? And electricity markets to reduce structural imbalances?	Renewable producers / Short term	Increase in renumeration; System costs; Market prices.
How to make short-term markets more efficient in order to better integrate short-term VRES fluctuations?	Product design / short term	System costs; Market prices and transparency
What are the effects of shorter lead times between market closure and delivery (DAM) in the volume of procured/dispatched reserves?	Power system/ short term	Balancing costs

2. Incentivizing distributed flexibility and local markets

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	Perspective / Time frame	MPIs
Will (near) real-time trading/gate closure times enable VRE producers to maximize their profit? And electricity markets to reduce structural imbalances?	Renewable producers / Short term	Increase in renumeration; System costs; Market prices.
How to make short-term markets more efficient in order to better integrate short-term VRES fluctuations?	Product design / short term	System costs; Market prices and transparency
What are the effects of shorter lead times between market closure and delivery (DAM) in the volume of procured/dispatched reserves?	Power system/ short term	Balancing costs

3. Incentivizing demand response and sector coupling

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	**Perspective / Time frame**	**MPIs**
What is the value of new "flexibility" players/actors likely to appear up to 2030?	All but rigid generation / Short and long term	VRE penetration; Storage share; Balancing needs; Market prices; Demand-response participation; Sector coupling share; Balancing costs; Curtailments; CO2 emissions.
Which framework conditions incentivize flexibility options to contribute to an efficient dispatch?	Technological flexibility options, esp. Demand response / short term	System costs; Market prices and transparency
Demand Response (alternative scenarios and wholesale market design): Which market designs can effectively incentivize demand response? How do the different resulting levels of demand response impact measures of profitability and system efficiency on the European scale?	system and investor perspective / long and short term	NPVs, variance of annual returns, installed capacities, system costs
Impact of different kinds of flexible demand from sector coupling on market prices (energy and ancillary services) - is the concern about too low prices valid and are the ancillary service markets going to be a lot bigger part of future revenue. What the market designs should be to incentivize demand side investments that provide cost optimal outcomes.	private investor and system perspective / long and short term	investment decisions (system optimal vs. actor-based) and consequent differences in total system costs, emission reductions

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	**Perspective / Time frame**	**MPIs**
How can we remunerate the value of distributed flexibility in reducing the low-carbon generation investments required for the achievement of carbon targets?	DERs / long-term	Market prices and transparency; Capacity mix; Demand-response participation
Which are the most effective mechanisms for the interaction of local energy markets with national (wholesale energy and ancillary services) markets?	Prosumers, Aggregators/ Short term	Market prices and transparency
What is the value of new "flexibility" players/actors likely to appear up to 2030?	All but rigid generation / Short and long term	VRE penetration; Storage share; Balancing needs; Market prices; Demand-response participation; Sector coupling share; Balancing costs; Curtailments; CO2 emissions.

4. System design and adequacy

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	Perspective / Time frame	MPIs
What is the optimal share of vRES generation on each market type/product that maximizes its profit enabling their participation without additional support?	Renewable producers / Short-term	vRES/RES penetration; maximize RES renumeration/value; Energy system costs; Market prices and transparency; Curtailments; CO2 emissions.
How to measure the adequacy of an energy system with 100% RES, where higher flexibility will characterize the power system?	long term	security of supply; performance indicators; fairness
Cross-border trade (benchmark scenario and alternative scenarios): How much cross-border trade occurs in the benchmark scenario? What are the benefits of cross-border trade and therefore of further market harmonization from a system perspective?	system perspective / long and short term	price convergence, cross-border trade volumes, installed capacities, price volatility, system costs
other commodities (benchmark scenario): How do the CO2-price and H2-price evolve on the path to the transition to a carbon-neutral energy system and what is their impact on wholesale market prices?	investor and consumer perspective / short term	CO2 Prices
Impact of no thermal capacity: How will it affect the market prices - what will determine the price, will there be more very high and very low prices? How will it affect capacity adequacy?	private investor and system perspective / long and short term	market prices, load shedding, use of DR, investments
Can national imbalances be cancelled out throughout Europe and which levels of cross border capacity can drive a social optimum mix of assets?	Capacity mix/ Long term	System costs; Adequacy measures; Market prices; Capacity mix; VRE Curtailments

5. investment incentives for renewables (EOM or support scheme) and for secure capacities (EOM or capacity mechanism)

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	Perspective / Time frame	MPIs
Does actual market designs give sufficient and attractive incentives to capacity investments (in both vRES and conventional) technologies based only on energy trading without further incentives?	Renewable producers / Short and long term	vRES/RES penetration; System costs; Market prices and transparency; Demand-response participation; Balancing costs; VRE Curtailments
Profitability (benchmark scenario and alternative scenarios and market designs): Does the wholesale market provide sufficiently high and secure revenues for private investors to invest in both intermittent renewables and dispatchable capacities under different scenarios and market designs? What are the underlying market dynamics driving (non-)profitability and risk profiles?	Investor perspective / short and long term	NPVs of different technologies in different countries, variance of annual returns, variance/distribution of monthly/daily/hourly returns, price volatility, price duration curves, marginal plants
Aggregation of storage and generation (alternative scenario): What is the impact of aggregation / portfolio optimization on private investor profitability?	private investor perspective / long and short term	NPVs, variance of annual returns, installed capacities, system costs
Risk preferences (alternative scenario): What is the impact of different risk preference of producers on wholesale market outcomes?	private investor perspective / long and short term	NPVs, variance of annual returns, installed capacities, system costs

5a. Investment incentives for renewables (EOM or support scheme)

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	**Perspective / Time frame**	**MPIs**
Are RES remuneration schemes needed and if so, how should they be designed?	Renewable producers / long term and short term	vRES/RES penetration; System costs; Market prices / Market values and transparency; VRE Curtailments
VRE support schemes (alternative market design): In case that no sufficient improvements to the wholesale market design can be identified and VRE require financing in addition to wholesale market revenues: What is the impact of different financing instruments (market premium / PPA & CfD/ capacity-based premium) on (1) investment in renewables and (2) wholesale markets? To what degree should financing schemes be market-based?	private investor and system perspective / long and short term	NPVs, variance of annual returns, installed capacities, price volatility

5b. Investment incentives for secure capacities (EOM or capacity mechanism)

Research question/challenge to be addressed/answered by TradeRES models and simulations (one line per question)	**Perspective / Time frame**	**MPIs**
Are RES remuneration schemes needed and if so, how should they be designed?	Renewable producers / long term and short term	vRES/RES penetration; System costs; Market prices / Market values and transparency; VRE Curtailments
VRE support schemes (alternative market design): In case that no sufficient improvements to the wholesale market design can be identified and VRE require financing in addition to wholesale market revenues: What is the impact of different financing instruments (market premium / PPA & CfD/ capacity-based premium) on (1) investment in renewables and (2) wholesale markets? To what degree should financing schemes be market-based?	private investor and system perspective / long and short term	NPVs, variance of annual returns, installed capacities, price volatility

Annex B – Market Performance indicators: a detailed description

B.1 – MPIs detailed identification

In this annexe, each MPI used in this first version of this deliverable is presented in a consistent way using the following descriptors:

- **Name (and acronym):** Identification of the MPI and (when applicable) an acronym is provided.
- **Detailed description:** Detailed description of the MPI, indicating its objective and motivation to be analysed in the project. When applicable bibliographic references and common/reference values mentioned in the literature are also provided.
- **Measuring the MPI/Unit:** Indication how the MPI can be measured. When applicable the units of the MPI are also presented.
- **Mathematical formulation:** Identification of the mathematical formulation to compute the MPI.
- **Target and optimal value (when applicable):** Indicate the target and optimal value of the MPI. In this case, the information can be generic (*e.g.*, increase the annual share of vRES generation). When applicable the optimal value will be provided.

Below the description of each MPI is provided.

MPI #1	
Name (and acronym)	Share of renewable energy sources (RES) in the national demand.
Detailed description	This MPI indicates the level of integration of RES, including wind, solar, biomass, biogas, concentrated solar power, hydro power plants, others in the power system under analysis. Important to understand the position of the different energy mix scenarios analysed in the TradeRES project in the pathway for a near 100% RES power system.
Measuring the MPI/Unit	%
Mathematical formulation	$$RES_{share} = \frac{\sum_{k=1}^{K}\sum_{t=1}^{T} RES\_Generation_{k,t}}{\sum_{t=1}^{T} Demand_t}$$ where $RES\_Generation$ is the generation from the *k-th* RES asset/technology at *t-th* time step. $Demand_t$ is the total electricity demand.

MPI #4	
Name (and acronym)	Loss of Load Expectation (LOLE)
Detailed description	Number of hours that secured capacity doesn't meet the demand (including imports and exports consideration) within a control region; simplified (no Monte Carlo simulation); see, *e.g.*, [6], [30].
Measuring the MPI/Unit	h/year
Mathematical formulation	$LOLE = \sum_{t=1}^{T} 1_{\{Residual\ load_t > Peak\ capacity_t\}}$
Target and optimal value (when applicable)	0

MPI #5	
Name (and acronym)	Expected Energy Not Served (EENS)
Detailed description	Amount of energy that cannot be provided during hours with loss of load (including imports and exports consideration) within a control region [6].
Measuring the MPI/Unit	MWh/year
Mathematical formulation	$EENS = \sum_{t=1}^{T} Net\ load_t - Peak\ capacity_{t_{\{Net\ load_t > Peak\ capacity_t\}}}$
Target and optimal value (when applicable)	0 (optimal value).

MPI #6	
Name (and acronym)	Supply ratio
Detailed description	Relation of available supply capacity and demand (similar to D3.1 [31]). For comparison between the different scenarios load curves will be analyzed with focusing on the average and extreme demand events (minimum, peak and percentiles 95th and 98th).
Measuring the MPI/Unit	Dimensionless.
Mathematical formulation	$\text{Supply ratio}_t = \frac{Supply\ capacity_t}{Electricity\ demand_t}$
Target and optimal value (when applicable)	>= 1 (for every hour)

MPI #11	
Name (and acronym)	Peak Load Reduction (PLR)
Detailed description	Comparison of absolute peak values between the initially demanded and the actually realized load in a period of time for indicating DSR effects.
Measuring the MPI/Unit	%
Mathematical formulation	$$PLR_T = \left(1 - \frac{Peak_{realized,T}}{Peak_{initial,T}}\right) * 100$$ where $Peak_{x,T} = \max_{t \in T} D_{x,t}$
Target and optimal value (when applicable)	Not applicable.
Case studies	All

MPI #12	
Name (and acronym)	Ancillary service(s) energy use
Detailed description	This MPI presents the dispatched energy, e_o, of each ancillary service (AS) product (o) and all ancillary services (O).
Measuring the MPI/Unit	MWh
Mathematical formulation	$\sum_o^O \lvert e_o \rvert$
Target and optimal value (when applicable)	0

MPI #13	
Name (and acronym)	Capacity procurement in the AS
Detailed description	This MPI presents the capacity procurement, c_o, of each AS product (o) and all ancillary services (O).
Measuring the MPI/Unit	MW
Mathematical formulation	$\sum_o^O c_o$
Target and optimal value (when applicable)	0

MPI #14	
Name (and acronym)	Percentage of capacity use in the AS
Detailed description	This MPI presents if the capacity, c_o, of each (o) and all ancillary services (O) during time period ,h, are effectively used in the AS.
Measuring the MPI/Unit	%
Mathematical formulation	$\sum_o^O \frac{c_o}{he_o} \times 100$
Target and optimal value (when applicable)	100 %

MPI #15	
Name (and acronym)	Share of demand participation in the AS
Detailed description	This MPI presents the share of demand participation, q_o^D, in the AS, i_D^{AS}.
Measuring the MPI/Unit	%
Mathematical formulation	$i_D^{AS} = \sum_o^O \frac{p_o q_o}{q_o^D} \times 100$
Target and optimal value (when applicable)	> 0 %

MPI #16	
Name (and acronym)	Share of vRES participation in the AS
Detailed description	This MPI presents the share of vRES participation,q_o^{vRES}, in the AS, i_{vRES}^{AS}.
Measuring the MPI/Unit	%
Mathematical formulation	$i_{vRES}^{AS} = \sum_{o=1}^O \frac{p_o q_o}{q_o^{vRES}} \times 100$
Target and optimal value (when applicable)	> 0 %

MPI #17	
Name (and acronym)	Market-based energy curtailed of vRES
Detailed description	Amount of energy curtailed due to market-based incentives to do so.
Measuring the MPI/Unit	MWh/year
Mathematical formulation	$RES\ curtailment = \sum_{k=1}^{K} \sum_{t=1}^{T} (RES\_Generation\_Potential_{k,t} - RES\_Injection_{k,t})$ where, $RES\_Generation\_Potential$ is the available generation and $RES\_Injection$ is the energy used for the k-*th* asset/technology and t-*th* the time step.
Target and optimal value (when applicable)	Not applicable.

MPI #24	
Name (and acronym)	Normalized bias error (NB) of forecasts
Detailed description	This MPI intends to quantify the amplitude error related to the systematic tendency of a forecast. It allows assessing whether the forecasting methodology tends to underestimate or overestimate compared with the observed values. The normalization by the nominal power capacity ($NominalPower$) of the power plants enables a proper comparison among different case studies.
Measuring the MPI/Unit	%
Mathematical formulation	$NB = 100 \times \frac{\frac{1}{T} \sum_{t=1}^{T} Forecast_t - Observed_t}{NominalPower}$ $Forecast_t$ and $Observed_t$ correspond to the forecast and observed data for the *t-th* time step.
Target and optimal value (when applicable)	0 %

MPI #25	
Name (and acronym)	Normalized root mean square error (NRMSE) of forecasts
Detailed description	This MPI intends to quantify the phase errors (related to temporal consistency and the capability to reproduce the temporal variability of a predetermined parameter) of the model. As appointed by several authors, such errors cannot be easily removed by using linear corrections as it is usual for amplitude-related errors (*e.g.*, NB). Thus, a forecasting approach with lower phase errors is preferred rather than a forecast with reduced amplitude errors [32].
Measuring the MPI/Unit	%
Mathematical formulation	$$NRMSE = 100 \times \frac{\sqrt{\frac{\sum_{t=1}^{T}(Forecast_t - Observed_t)^2}{T}}}{NominalPower}$$ $Forecast_t$ and $Observed_t$ correspond to the forecast and observed data for the *t-th* time step.
Target and optimal value (when applicable)	0 %

MPI #26	
Name (and acronym)	Total system costs
Detailed description	This MPI is related to affordable and competitive energy. It represents the European power (and energy) system costs, including its investments and operation.
Measuring the MPI/Unit	€
Mathematical formulation	$$Total\ Costs = Investment\ costs + O\&M\ costs + cycling\ costs + fuel\ costs + load\ shedding\ costs$$
Target and optimal value (when applicable)	Compare optimization results with ABM results, as well as results between market designs

MPI #27	
Name (and acronym)	System costs for dispatch
Detailed description	The overall costs of the power system modelled.
Measuring the MPI/Unit	€/year
Mathematical formulation	$Dispatch_{cost} = Cost_{fuel} + Cost_{emissions} + Cost_{loadshift}$
Target and optimal value (when applicable)	Not applicable.

MPI #28	
Name (and acronym)	Costs to society
Detailed description	The sum of the electricity price, the cost of the capacity market, and the cost of the renewable policy (if applicable) per unit of electricity consumed
Measuring the MPI/Unit	€/MWh
Mathematical formulation	$Costs\ to\ consumers = average\ electricity\ price + \frac{costs\ of\ capacity\ market + VRES\ Support\ costs}{electricity\ consumed}$
Target and optimal value (when applicable)	Lower costs are desirable. It can be calculated per year or as an average of all simulation years.

MPI #29	
Name (and acronym)	Average day-ahead market price
Detailed description	Volume-weighted average of hourly day-ahead market price for a year
Measuring the MPI/Unit	€/MWh
Mathematical formulation	Power prices: Intersection of demand and supply curve; dual value of demand coverage constraint Volume-weighted average
Target and optimal value (when applicable)	Sub-target: low price level for affordability, high price level for cost recovery

MPI #30	
Name (and acronym)	Energy scarcity time period
Detailed description	With more flexibility in the system the unserved energy can be reduced and extreme prices can appear when the system is under stress.
Measuring the MPI/Unit	*h* (period length).
Mathematical formulation	Number of consecutive hours with values above a pre-determined price threshold.
Target and optimal value (when applicable)	Not applicable.

MPI #31	
Name (and acronym)	RES support costs
Detailed description	The overall and specific amount of support pay out to RES operators
Measuring the MPI/Unit	€/year; €/MWh
Mathematical formulation	$$RES_{support} = \sum_{i=1}^{n} support\_payment_i$$ Where $support\_payment_i$ is the money paid to renewable generator i and n is the number of RES receiving support.
Target and optimal value (when applicable)	Lowest possible.

MPI #32	
Name (and acronym)	Market-based cost recovery
Detailed description	Relation of market-based revenues and expenses per technology (including storage) which indicates refinancing possibilities, cost coverage and support needs (similar to D3.1 [31]). With more flexibility in the system, the volume of unserved energy can be reduced. Instead, scarcity may be indicated by prices only. Some scarcity prices are necessary, among others to signal the need for investment. The system-level cost recovery can indicate if there are enough market incentives. If prices are structurally higher than average cost, however, the system may be considered as not being adequate. It can be applied at a system level or per technology or per company.
Measuring the MPI/Unit	Dimensionless
Mathematical formulation	$$Market_{income} = \frac{\sum_{t=1}^{T} Revenues_t}{\sum_{t=1}^{T} Expenses_t}$$ where t is the temporal time available. *Revenues* represent the gains due to the participation on the different market products. $Expenses$ represent all expenses of participating in the different electricity market products. For the system-level cost recovery: $$Cost\ recovery = \frac{total\ market\ revenues}{total\ system\ costs}$$
Target and optimal value (when applicable)	Optimal value for the average price is the average cost of electricity, considering a normal return on investment.

MPI #33	
Name (and acronym)	Price convergence
Detailed description	Yearly percentage of hours with full, moderate and low price convergence measured by the yearly average day-ahead price differentials across European borders with: - Full price convergence defined as 0-1€/MWh price differential - Moderate price convergence defined as 1-10€/MWh price differential - Low price convergence defined as >10€/MWh price differential Further details are provided in [33].

MPI #33	
Measuring the MPI/Unit	€/MWh
Mathematical formulation	Price differential: $\Delta p_{ij}^{DA} = \sum_{t=1}^{T} \frac{(p_{it}^{DAM} - p_{jt}^{DAM})}{t}$ for hours t and bidding zones $i, j \in I$
Target and optimal value (when applicable)	Hard to determine optimal level as 100% full price convergence would mean overinvestment in the grid. Comparison to current ones.

MPI #36	
Name (and acronym)	Ancillary service(s) (AS) costs
Detailed description	This MPI presents the costs (C_o) of each AS system (o) and all ancillary services (O) considering the price, p_o, and quantity q_o. The quantity can be in power capacity (MW) or energy (MWh).
Measuring the MPI/Unit	€
Mathematical formulation	$\sum_o^O C_o = \sum_o^O p_o q_o$
Target and optimal value (when applicable)	0

MPI #37	
Name (and acronym)	Average market penalties
Detailed description	This MPI presents the penalties associated with the deviations between expected and observed power in the different electricity market products during period T. These penalties should be paid by the balance responsible parties (BRPs), considering that all players that deviated from the original program, q_{dev}, pay the entire AS costs.
Measuring the MPI/Unit	€/MWh
Mathematical formulation	$\bar{P}_{PEN} = \frac{\sum_{t=0}^{T} \frac{\sum_o^O p_{o,t} q_{o,t}}{q_{dev,t}}}{T}$
Target and optimal value (when applicable)	0

MPI #38	
Name (and acronym)	Average imbalances prices
Detailed description	This MPI presents the average imbalances prices for up, p_{imb}^{up}, and down, p_{imb}^{down}, deviations that should be paid by the balance responsible parties during period T.
Measuring the MPI/Unit	€/MWh
Mathematical formulation	$\bar{P}_{imb.}^{up} = \frac{\sum_{t=0}^{T} P_{DAM\,t} - P_{PEN\,t}}{T}$ $\bar{P}_{imb.}^{down} = \frac{\sum_{t=0}^{T} P_{DAM\,t} + P_{PEN\,t}}{T}$ where P_{DAM} is the day-ahead market price.
Target and optimal value (when applicable)	Optimal value is the average day-ahead market price.

MPI #45	
Name (and acronym)	Power system emissions
Detailed description	This MPI is related to sustainable development and it provides the annual CO_2 emissions associated with fossil fuel energy generation. This indicator enables quantifying how much the different market designs reduce CO_2 emissions. It can be used in some scenarios as constraint equal to 0.
Measuring the MPI/Unit	tons
Mathematical formulation	$CO2Emissions = \sum_{k=1}^{K} \sum_{t=1}^{T} (CO2perMWh_{k,t} \times Generation_{k,t})$ where k is the asset/technology and t represents the time step.
Target and optimal value (when applicable)	Compare optimization results with ABM results, as well as results between market designs.

B.2 – German MPIs additional comments

For the German case, the MPIs are calculated as follows:

MPI	Additional information
#1 Share of renewable energy sources (RES) in the national demand.	The annual realized generation of renewable generators is divided by the overall demand of that year. Values are below 100% even in a ~100% RES scenario as backup generation is needed. In the case of a ~100% RES scenario, this backup generation is exclusively taken from green hydrogen, thus also renewable.
#4 Loss of Load Expectation (LOLE)	LOLE is defined as the number of hours that secured capacity doesn't meet the demand (including imports and exports consideration) within a control region. To calculate the secured capacity (or firm capacity), a deterministic approach is used and it is referred to the "Leistungsbilanzbericht 2019" of German TSOs and the assumed unavailability factors, which are 40% for biogas, 72% for run of river and 20% for pumped hydro storage (thus assuming a dry period) as well as 50% for other (controllable) RES. In a rather conservative approach, variable renewable energy sources are assumed not to contribute to secured capacity, i.e., they are assumed to have a firm capacity rate of 0. The residual load is calculated by subtracting realized generation of fluctuating RES (i.e. generation after market-based curtailment) from the planned demand (i.e. the demand before curtailment, storage or any other flexibility measures).
#5 Expected Energy Not Served (EENS)	EENS is the energy that is not met during periods, when there is LOLE, i.e. the difference between the residual load and the secured capacity.
#9 Average duration of load shedding events	For calculating the average duration of load shedding events, all hours in which load shedding was active are divided by the number of load shedding events (see MPI #8).
#10 Use of demand side management and response (DSM/DR)	For the first iteration of this deliverable, no load shifting is considered, but it will be for the second iteration. Thus, MPI #10 was not yet calculated and won't be displayed.
#11 Peak Load Reduction (PLR)	For assessing the peak load reduction in AMIRIS, the realized demand peak was compared to the planned demand peak. For the first iteration of this deliverable, the realized demand peak can be smaller than the planned demand peak in the case of shedding while shifting is not (yet) considered. A bias occurs since the overall demand is used in the calculation. Since storages may also place demand-side offers, demand peaks might also be increased which is found for the considered cases.
#17 Market-based energy curtailed of vRES	For calculating absolute market-based curtailments (energy in MWh), the sum of the realized generation per vRES plant is subtracted from the energy production potential per vRES plant. For calculating relative shares, the energy curtailed is divided by the sum of the energy production potential.

MPI	Additional information
#27 System costs for dispatch	The dispatch system costs are defined to be the sum of all variable costs, comprising costs for fuel, operation and maintenance costs, emissions costs as well as costs for load shifting. The latter will only be contained in the second version of this deliverable. The hourly values are summed up for calculating overall annual system costs for dispatch. Thus, the indicator only comprises operational expenditures, no capital expenditures.
#29 Average day-ahead market price	The average day-ahead price is calculated as a volume-weighted average. Also, for informatory purposes, an unweighted average is calculated since this reflects what is referred to as the "base price" in real markets.
#30 Energy scarcity duration	The energy scarcity duration is defined as the number of hours with the price over a pre-defined threshold. Since it is non-trivial to define one single scarcity threshold and this is highly dependent on commodity prices and other exogenous factors, different price levels are studied to get an idea of the price distribution "in the extreme range". The number of hours with prices exceeding 500 €/MWh, 1,000 €/MWh resp. 3,000 €/MWh is considered.
#31 RES support costs	The overall RES support costs are calculated as the sum of support that is paid to RES operators eligible for support on an annual basis. For the prevalent analyses, support for the major vRES sources, i.e. solar photovoltaics plants, wind onshore and wind offshore is evaluated. The payments are given per energy carrier and per support instrument. Total values are obtained by summing up the support payments made by the SupportPolicy agent. Specific values on a per MWh basis are calculated by dividing the overall support payments by the realized generation. For units in a FIT scheme, a fixed tariff is paid out, but the costs occurring are only the ones not obtained by marketing these units (which is done price-independent by the German TSOs). Hence, to calculate the support payments for FIT units, the market revenues have to be subtracted from the overall support that is paid out.
#32 Market-based cost recovery	Market-based cost recovery is calculated per renewable energy carrier by the quotient of received market revenues and total costs. Hereby, the total costs are given on an annuised basis and include both, operational and capital expenditures (also refer to the production costs calculation in chapter 3.2). Because prices might become negative, losses might occur from marketing RES generation. Hence, in very extreme constellations, market-based cost recovery might also be negative.
#45 Power system emissions	The overall power system emissions are calculated by summing up all the emissions caused by the dispatch of fossil generators on an annual basis. Thus, only direct emissions are included while indirect ones are out of scope, but nonetheless very important to consider.