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

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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 constitutes the second edition of deliverable 5.3, which provides the final assessment of the market performance using the newly developed designs and products, implemented within TradeRES project for the national/regional markets for carefully selected scenarios of energy transition targeting at (near) 100% renewable energy electric power systems. As in the first edition of D3.5, this assessment is performed by applying (key) market performance indicators (MPIs) previously defined within TradeRES 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 Central European national markets - EPEX SPOT: the Netherlands (case study B) and Germany (case study C), and one regional, related to the Iberian electricity market – MIBEL (case study D). The electricity markets' studies are conducted using different models and computational systems: Case study B was studied using COMPETES, EMlabpy and AMIRIS; Case study C by applying AMIRIS and finally, Case study D, by simulating the Iberian markets with MASCEM and RESTrade. Those models and simulation platforms were fully described in the deliverables produced within *WP 4 - Development of Open-access Market Simulation Models and Tools*.

Each national/regional case study of Task 5.3 dedicated itself to study different aspects of the electricity markets, and formulated research questions answered through the simulations performed within this Task, as presented below.

Dutch case study: The main research question addressed by the Netherlands case study B in this report are:

- ***To what extent can an energy-only market provide system adequacy for a renewable electricity system?***
- ***How do capacity mechanisms perform in a renewable electricity system?***

To answer these questions, 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-TNO will be used to obtain the reference system outcomes. 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.

The results indicate that an energy-only market design will not lead to an adequate level of investment in a future, low-carbon electricity market. One reason is that if such a market is to provide the level of reliability of power supply to which society currently is used, the volume of generation capacity and energy storage need to be dimensioned for a period with unusually low renewable energy generation and low temperatures (leading to high demand). This means that the rest of the time, this energy market will be somewhat over-dimensioned, which means that if the market is competitive, not all investment costs will be recovered.

A second, more general, reason why an energy-only market may fail to produce sufficient investment is that investors do not have perfect foresight while new projects take a number of years to complete. As a result, power shortages may not always be anticipated correctly, and the market is not able to relieve them immediately due to the construction time of new power plants. An important factor is that the use factor of controllable capacity will decline when the share of renewable energy generation increases. This makes the business case for controllable capacity increasingly dependent on short price spikes in an energy-only market design. This increases the investment risk and may therefore contribute to a lack of investment.

All investigated capacity remuneration mechanisms are able to improve welfare by improving system adequacy. A strategic reserve, however, distorts the merit order and has the most limited benefit. It is mainly useful as an instrument to keep unprofitable power plants in the market, e.g. to keep natural gas plants open during the transition until sufficient carbon-free controllable capacity has been built. A capacity market performs better but provides limited incentives for storage and demand response. Capacity subscription – essentially, a decentralized capacity market in which all consumers, including households, purchase capacity contracts – solves this problem, but has as a shortcoming that the length of contracts with households is limited to one year. One-year contracts do not provide sufficient investment risk reduction. Capacity markets can be designed to provide long-term contracts to new investments, as has been done in the UK. Another option is for a government-owned or controlled entity to purchase long-term capacity contracts from generators and sell them at cost as annual contracts to consumers. This entity therefore absorbs the volume risk, i.e. it bears the risk of over-contracting. If only carbon-free controllable capacity is purchased, this risk is small.

An interesting observation in this study is that future power prices will increasingly be determined by the willingness to pay of power consumers. In particular, if the demand for green hydrogen develops according to the current policy objectives, the price of electricity will be determined by the willingness to pay for electrolyzers for a large number of hours per year. In other words, electrolyzers may absorb a large part of the renewable energy surplus generation. This may offset the 'canibalization' effect – by which competition between renewable energy generators drives the price of electricity to zero – to a large extent. The degree to which this will actually happen will depend on the cost of electrolyzers, the ability to store hydrogen, and the demand for hydrogen.

German case study: The main research question to be addressed within the German case study included 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 compute and compare various MPIs across different scenarios. Different support instruments are considered and compared to a situation with no support for RES, namely: i) *fixed market premium* with fixed payments on top of market revenues ii) *one-way Contracts for Difference* with price-variable payments on top of market revenues; iii) *two-way Contracts for Difference* with price-variable payments on top of market revenues and an obligation to pay back in case of high prices; iv) *capacity premium* with payments per installed capacity; and v) *financial Contracts for Difference* with payments per installed capacity and a pay-back obligation for revenues generated by a reference plant.

The ***results of the German case study demonstrate a large range of market-based cost recovery rates for RES***. The cost recovery rates vary significantly depending on the scenario and policy instrument, ranging from 37% to 98% for PV and from 72% to 151% for onshore wind. Therefore, the results are highly dependent on the underlying assumptions of the scenarios. In particular, ***the flexibility of demand and the price of imported hydrogen have a significant impact on market outcomes***. It is evident that this has a considerably more pronounced effect on cost recovery rates than the support instruments themselves, given the nearly "ideal" parameterisation that underlies the analysis.

The German case study further reveals that ***the examined support schemes resulted in full cost recovery in all cases investigated, thereby reducing the risk associated with investments***. It is notable that two-way Contracts for Difference result in a greater level of vRES curtailment when compared to other support schemes. This leads to elevated prices and enhanced market-based cost recovery rates. Moreover, the findings indicate that instruments that do not distort dispatch (capacity premium, financial Contracts for Difference) result in a consistently higher level of wind offshore curtailment.

In terms of support costs one-way Contracts for Difference were found to perform worst due to the missing clawback obligation in months when market values exceed the production costs. For production-dependent Contracts for Difference, i.e., one-way and two-way Contracts for Difference, an over-support was found. This can be explained by two factors: monthly variations in income and an anticipation of clawback as well as a mismatch between *ex-ante* anticipated market values and realized *ex-post* market-values after curtailment. In terms of the total costs that need to be borne by end users, the production-independent financial Contracts for Difference is found to perform best.

Iberian case study: The main research question addressed in the Iberian case study is “***How can short-term markets be made more efficient in order to better integrate short-term vRES fluctuations****?”*. To answer this question, the agent-based models MASCEM and RESTrade are applied to different energy mixes, whose installed capacities were obtained by applying optimization models (work package 2), in energy transition scenarios comprising a time horizon from 2030 to 2050.

MIBEL market comprises two countries - *i.e.,* Portugal and Spain - among the ones with a higher penetration of vRES in the power system in Europe. To study MIBEL’s short markets behaviour five different scenarios were considered: one for 2030, taken as a reference scenario and four for 2050, with varied combinations of the i) percentage of vRES and ii) the degree of demand flexibility. For the 2030 scenario, two pricing vRES strategies were applied to explore the potential vRES benefits from the diversification of revenue streams: a *simple bidding* and a *strategy bidding*. Under the *simple approach*, the entire vRES power forecast is bid in the day-ahead market (DAM). In contrast, in the *strategy bidding* the agents allocate 20% of the vRES forecast power to the balancing market, with the remaining 80% being bid in the day-ahead market.

Additionally, a new market design, designated as period-ahead market (PAM), was analysed. This new design requires power forecasts for shorter time horizons (6 hours) when compared with DAM (24 hours) taking advantage of the reduced error forecast for shorter time horizons, thus benefiting vRES by reducing their imparities.

In the 2030 scenario, the economic MPIs show how different market designs and bidding strategies influence overall costs. While the *simple bidding* in the DAM offers lower operational costs, by allowing the participation of vRES in the ancillary services, the *strategy* bidding simulations can enhance higher vRES remuneration, thus may lead to higher market prices and overall systems costs. The strategic implementation in the PAM presents a more balanced situation between market efficiency and lower prices, especially beneficial for the large integration of vRES technologies into the electricity markets.

Technical MPIs show that Portugal achieves 100% RES-based electricity by 2050, while Spain reaches up to 97.2% in scenarios with highest flexibility. Higher demand flexibility reduces balancing needs and short-term uncertainties. Economic indicators show that scenarios with more demand flexibility (S2 and S4) have higher total system costs due to storage and vRES investments, but these scenarios present lower DAM prices. Socially, consumer welfare surpasses producer welfare across all scenarios. This difference reduces as the demand flexibility increases. Overall, more flexibility supports better vRES integration and reduces certain costs (e.g., penalties paid by vRES players in the balancing markets) but increases total system expenses. Although further work is required, the simulations conducted in the Iberian market enable to indicate that slight modifications in existing market designs - such shorter gate closure times as in the PAM simulated and promoting vRES participation in intraday and balancing mechanisms - facilitates the integration of these technologies in market environments, while alleviates the need to governmental derisking measures, *e.g.*, CfDs, under nearly 100% renewable power systems.

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List of acronyms

1-WAY-CFD	One-way contracts for difference
2-WAY-CFD	Two-way contracts for difference
ABM	Agent-based models
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
CfDs	Contracts for difference
CHP	Combined Heat & Power
CO2	Carbon dioxides
CM	Capacity market
COMPETES	Competition and Market Power in Electric Transmission and Energy Sector
CP	Capacity premium
CRM	Capacity remuneration mechanisms
CS	Capacity subscription
CSV	Comma separated values
DAM	Day-head market
DSR	Demand side response
EENS	Expected Energy Not Served
EM	Electricity market
EMLAB	Energy Modelling Laboratory
ENTSO-E	European Network of Transmission System Operators
EOM	Energy only market
EU	European Union
EV	Electrical vehicle
FIN-CFD	Financial contracts for difference
FIT	Feed-in tariff
G2V	Grid-to-vehicle
GHC	Greenhouse Gas
H_2	Hydrogen
HH	High hydrogen (price)
IDM	Intraday Continuous market
LCOE	Levelized Cost of Electricity
LH	Low hydrogen (price)
LOL	Loss of Load
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
NL	Net load
NONE	No support scheme
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
PAM	Period-ahead market
PHS	Pumped hydro storage
PLR	Peak Load Reduction
PV	Photovoltaic
RES	Renewable energy sources/systems
RF	Requested Flexibility
RQ	Research questions
SDAC	Single day-ahead coupling
SecR	Secondary reserve
SIDC	Single intraday coupling
SPRS	Starting Point Reference System
SPS	Starting Point Scenario
SR	Strategic reserve
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/systems
WP	Work package

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 (WPs) of this project, as illustrated by Figure 1.

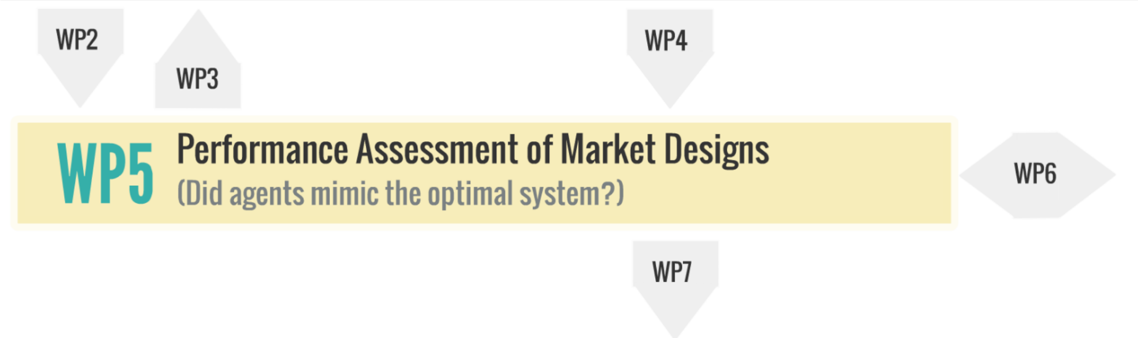

Figure 1. WP5 interactions within TradeRES project.

This report is the second edition of deliverable D5.3 of the TradeRES project. It aims to present and analyse the results of three studies investigating the performance of new designs bundles for national respectively European regional electricity markets. In the first edition of D5.3 [1], the results were preliminary and used mainly for testing, verification, and calibration of electricity market models to achieve close-to-real-world results. In this second edition, the focus is on the final market design bundles and products, using the latest version of the tools developed in WP 4, the TradeRES scenarios developed in WP 2 and the feedback from workshops and consultation to stakeholders achieved in WP6.

The work reported 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-TNO, 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, a brief overview of the main driving force behind the growing need to study current markets and analyse their outcomes are provided.

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. Conventional (fossil-fuelled) power plants connected to the transmission grid are increasingly being phased-out and, at the same time, non-traditional (variable renewable energy 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 vRES - 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, the scenario 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).

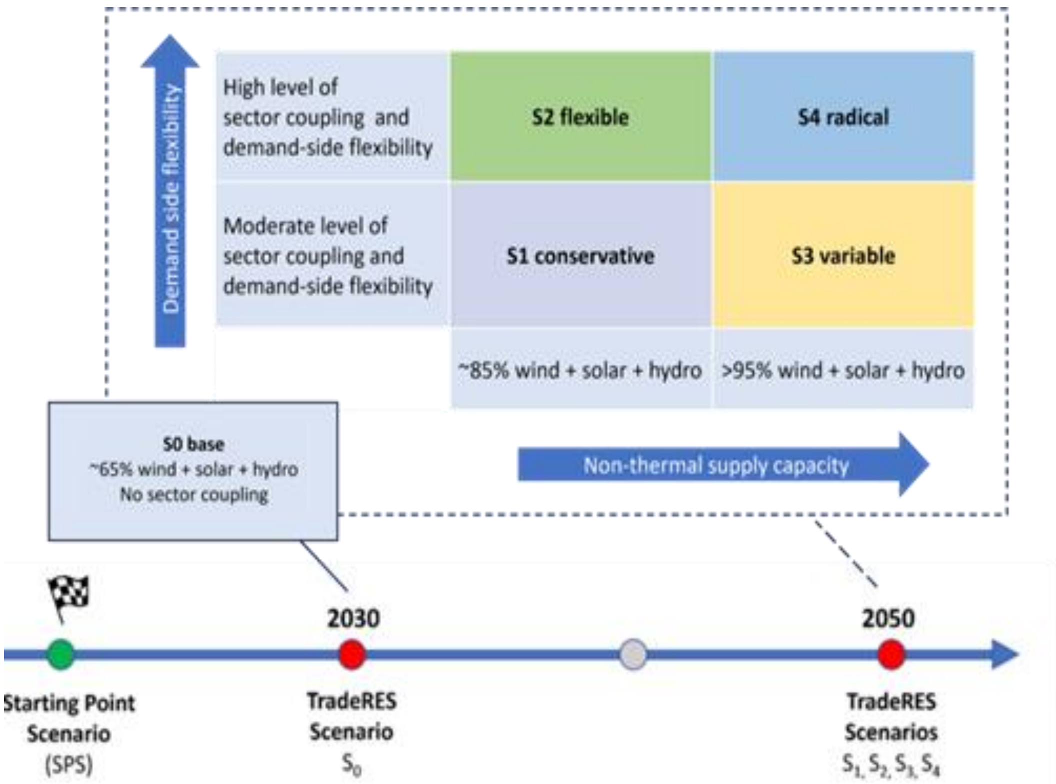

Figure 2. Allocation of TradeRES scenarios on the timeline.

The scenarios developed within TradeRES play a significant role on the process as they constitute the inputs fed to the models and consequently the outputs have a strong dependence of their assumptions. The scenario formation was developed under WP 2, where the TradeRES Scenarios were constructed using SPS – the starting point scenario - as a basis departure scenario, as depicted 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 identify an “optimal power system mix” 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) was populated with observed data from 2019 and this information used for benchmarking the agent-based models. The initial results for this SPS/SPRS scenarios were presented in the first edition of D5.3 [1].

The *Market Design Bundle* refers to the collection of market design options as identified in WP 3 and were implemented in the simulation tools developed in WP 4. The market design options 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.

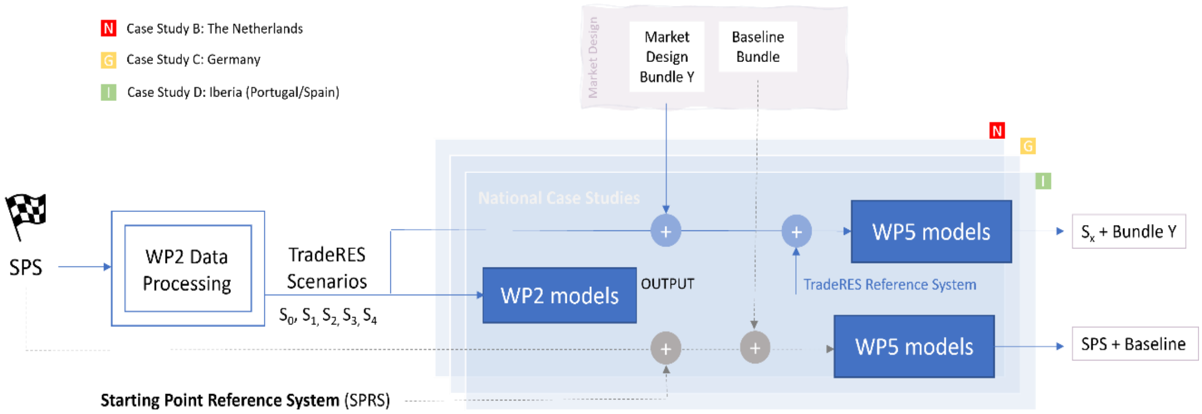

Figure 3. National/Regional case studies modelling process.

By summarizing the discussion around Figure 3, the usage of terms depicted in Box 1 is adopted.

Box 1: TradeRES Scenarios definitions

***Scenario** within TradeRES refers to a structured input data collection that encapsulate certain properties of the underlying future energy system.*

<u>TradeRES scenarios</u>:

- *SPS* - Starting Point Scenario (2019).

- 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.

- **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.

- **TRS - TradeRES Reference System** is the Reference System created by the optimization models for $S_0 - S_4$.

- **SPRS - Starting Point Reference System** 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 jointly evaluated 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 Dutch market (EPEX SPOT NL) and using the soft-linking AMIRIS-EMLabpy the aim is to analyse if an EOM will be sufficient to

[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 (European) Regional Markets; case study E - Pan-European wholesale electricity.

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 systems (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.

The results presented on this deliverable build on several other preceding deliverables and tasks for gathering inputs and identifying key aspects in a wide range of related subtopics, varying from newly developed and improved models, and their coupling to describe 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 Edition 2 [2], which follows up on D3.5 Edition 2 [3], by explaining new models used and developed within 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 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 [4]. As mentioned earlier, the models used are COMPETES-TNO, AMIRIS-EMLabpy, AMIRIS, MASCEM and RESTrade are shortly described below:

- **COMPETES-TNO:** 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 Spinetoolbox. 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 is an agent-based simulation model of short-term electricity markets. The coupled models together provide a realistic simulation of the behaviour of future decarbonized electricity markets under assumptions of imperfect foresight by the market actors.

- **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 as well as policy providers. The system is based on an open-source framework for agent-based energy system analysis (FAME)[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.

The remainder of this report is structured as follows. Section 2 describes TradeRES' research questions addressed in this deliverable and the market performance indicators (MPIs) selected and applied in this second edition of D5.3.

Section 3 describes the three case studies and includes 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). In section 4 is presented a summary of the main MPIs for the different case studies. Finally, in section 5, final remarks are drawn. Annex A provides a detailed description of the market performance indicators used in the deliverable to assess the different market designs and products. Annex B provides further information regarding the case study D – MIBEL.

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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)

The whole set of research questions TradeRES intends to contribute were presented in Annex A of the first edition of this deliverable [1]. In this edition, a reduced set of research questions were addressed in the national and regional market's case studies, Table 1. Different models/case studies will be in conditions to address different RQs. Those will be identified by the country acronyms: NL – Netherlands (case study B), GER- Germany (case study B) and Iberia (Portugal and Spain, from case study D) by the market acronym, MIBEL. Other case studies outside this Task address the local markets (case study A), here identified as "Local", and pan-European Market (case study E) as "pan-E".

- ***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; High 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.

This case study focuses on the energy-only market with a vRES capacity target and on the performance of capacity remuneration mechanisms (CRMs) with respect to enhancing the security of supply in a decarbonized electricity market.

Table 1. TradeRES research questions related to the 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
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	NL, MIBEL
ancillary services		What is the role/value of (variable) renewables for providing ancillary services?	Renewable producers / Short and long term	MIBEL
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	NL, MIBEL
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	all, but Local
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	NL
investment incentives for secure capacities (EOM or capacity mechanism)		Under which conditions will a future market enable the system adequacy?	Long term, short term	NL, MIBEL
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	all
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-) profitability and risk profiles?	Investor perspective / short and long term	all, but Local
investment incentives for renewables (EOM or capacity mechanism)		vRES support schemes (alternative market design): In case that no sufficient improvements to the wholesale market design can be identified and vRES 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	all, but Local

The questions that are addressed in the Dutch market case study are the following:

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, which type of capacity mechanism works and provides the lowest cost?

And, in these final simulations, the question addressed is:

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:

- *Are remuneration schemes for renewable energy sources (RES) needed and if so, how should they be designed?*
- *What effects do deviating scenario assumptions have on the refinancing of RES?*
- *What effects do deviating support instruments for RES have towards system effects expressed by central MPIs? Hereby compared to the first version of this deliverable, recent policy designs, such as Financial CfDs were also analysed and included in the comparison.*

In this edition of the deliverable, the focus is on assessing the need for renewable support schemes and their system effects. 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:

- Will (near) real-time trading/gate closure times enable vRES producers to maximize their profit and electricity markets to reduce structural imbalances?
- How to make short-term markets more efficient, in order to better integrate short-term vRES fluctuations?
- What is the value of new "flexibility" players/actors likely to appear up to 2050?
- 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?

- 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?

The main question addressed in this document is:

- ***How to make short-term markets more efficient in order to better integrate short-term VRES fluctuations?***

To address all the previous research questions, (key) market performance indicators (MPIs) were established in TradeRES project [5].

2.2 Market performance indicators for ~100% renewable power systems

The MPIs will enable to assess the performance of new market designs and products that were developed within 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 [5], [6]:

- *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 D5.1 [5].

Table 2. Summary of MPIs used in this deliverable for the different case studies (part 1).

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 [7].	✔	✔	✔
	#8: Load shedding	This MPI is related to security of supply. The MPI quantifies during how many hours there is not enough flexibility in the system and load shedding occurs, as well as how much load shedding occurs yearly in terms of energy.			✔
	#10: Use of demand side management and response	This MPI is related to secure, sustainable, affordable and competitive energy. Demand side management and response can increase competition, decrease the energy bill of consumers, increase the integration of RES, and avoid load shedding			✔
	#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.	✔	✔	✔
	#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.			✔

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

Domain	MPI Name (and acronym)	Detailed description	Case study: B – The Netherlands	Case study: C - Germany	Case study: D - MIBEL
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	✔	✔	✔
	#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.			✔
	#41: Volatility of electricity prices	This MPI is a key indicator in the risk management since it represents the price fluctuations over a 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.	✔	✔	✔
Social	#47: Social welfare	This MPI is related to country welfare, producer and consumer surplus per electricity consumed			✔

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 have conducted 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-TNO for running the reference scenario and generating the optimal ('benchmark') power system results.

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

This case study is structured in two main parts, each dedicated for the two mentioned models used to assess the Dutch market. The first part concerns the modelling for benchmark results with COMPETES-TNO. Firstly, a brief description of this model is provided in section 3.1.1. Subsequently, the scenario definitions assessed for the Dutch case study within the TradeRES scenarios framework are given in section 3.1.2. The reporting of the benchmark results is provided in section 3.1.3. The second part concerns the modelling with the AMIRIS-EMLabpy model.

The model description and implementation, as well as the different scenarios assessed are given in section 3.1.2.1, section 3.1.2.2 and section 3.1.2.3, respectively. Next, the respective results are reported in section 3.1.2.4. Finally, a comparison of the results of key MPIs between the benchmark results and the different results from the AMIRIS model, and final remarks are discussed in section 3.1.3.

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[3] Further details are available at: https://www.epexspot.com/en/about

3.1.1 COMPETES-TNO model

3.1.1.1 Model description

COMPETES-TNO 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-TNO 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 analyse least-cost capacity expansion under perfect competition formulated as a linear program to optimize generation capacity additions in the system;
- A unit commitment and economic dispatch module to determine and analyse 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-TNO 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-TNO has been used for many assignments and studies on the Dutch and European electricity markets.

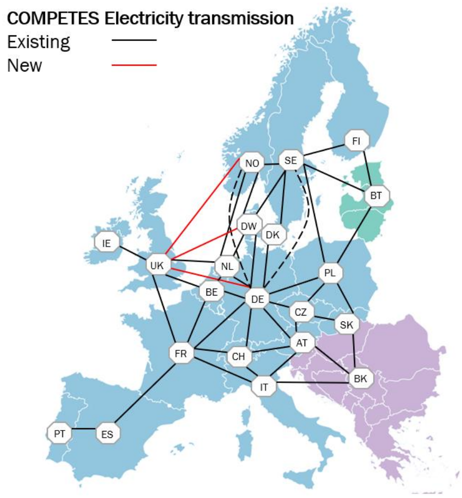


Figure 4. The geographical coverage of the COMPETES-TNO model.

[4] Over the past two decades, COMPETES-TNO 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.

For each scenario year, the significant inputs of COMPETES-TNO 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-TNO 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 - Compressed Air Energy Storage / Advanced);
  - Batteries (EVs, Li-ion, PB, VRB - Vanadium redox battery);
  - 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-TNO 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.

3.1.1.2 COMPETS-TNO: scenarios, input data and limits of the analysis

In COMPETES-TNO runs, the years 2030 and 2050 are optimized based on the TradeRES scenarios defined in the WP2 of the project[5] and the TradeRES database for data inputs of the initial capacities, demands and techno-economic parameters of the generation technologies.

The project scenarios for the year 2050 (i.e. S1, S2, S3, S4) defined in WP-2 have materialized under different considerations from the demand and the supply side:

- Demand side: the level of flexibility is adjusted across the scenarios through EVs, industrial hybrid boilers (electric/natural gas), residential heat pumps, and power-to-H2.
- Supply side: considers different remaining natural gas capacity assumed for the Netherlands and different levels of retrofit of the decommissioned gas capacities.

A more in detail description on the individual described considerations per scenario is shown below in Figure 5. A zero-emission constraint for the European system is enforced in the most pro-vRES scenarios (*i.e.*, S3 and S4). This constraint forces to achieve climate neutrality at the European geographical scope modelled in COMPETES-TNO.

Demand Side

Zero-emissions constraint activated?	No	Yes
• 25% flex for household power-to-heat; 50% flex for EVs; • Full flex for power-to-H2; • Full flex for industrial heat (electric/gas);	**S2 flexible**	**S4 radical**
• 0% flex for EVs, household power-to-heat; • 50% flex for power-to-H2; • 0% flex for industrial heat (fully electric)	**S1 conservative**	**S3 variable**
	• Natural gas capacity: ~5 GW left. • Max retrofit capacity: 50 % of the total NL capacity decommissioned by 2050 is assumed to be retrofitted (~10 GW) into H2 or biogas. • Investments in fossil-fired capacities coupled with CCS allowed.	• Natural gas capacity: 0 GW left. • Max retrofit capacity: 100% of the gas capacity is available for retrofit into H2 or biogas. • Investments in fossil-fired capacities coupled with CCS not allowed

Supply Side

Figure 5. Scenario design and inputs for the Netherlands case study.

[5] WP2- *Optimal electricity trading with ~100% RES: Generation of a reference power system, scenarios and input market data.*

The base case 2030 (S0) is optimized considering the initial installed capacities and energy demands of WP2 and provides a baseline for that year. The assumptions regarding flexibility of this scenario are more conservative compared to the 2050 scenarios, where 5% of heat pumps and 10% of EVs can provide demand response capabilities.

Given the different scopes of COMPETES-TNO and the ABM model, a comparison of results for relevant parameters and MPIs is done. The results obtained by COMPETES-TNO represent a benchmark to compare to the AMIRIS-EMLabpy results. In this regard, COMPETES-TNO simulated two situations for the Dutch power system: one variant including electricity trade with neighbouring countries (‘***connected-NL***’ case), and the other variant excluding trade (***‘isolated-NL’*** case). The latter provides the base inputs for the AMIRIS-EMLabpy runs and showcases the impact of including/excluding electricity trade on the performance of the NL power system.

3.1.1.3 COMPETES-TNO results and analysis

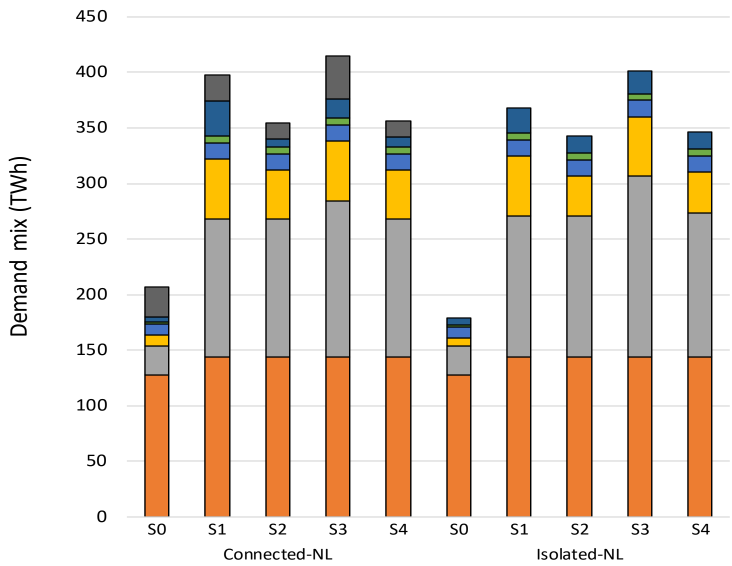
This section contains the benchmark results provided by COMPETES-TNO for the ‘connected-NL’ and ‘isolated-NL’ cases.

- ***Electricity demand***

Figure 6 shows the electricity demand across the different scenarios for both ‘connected-NL’ and ‘isolated-NL’ cases. Flexible demands from conversion technologies, notably Power-to-H2, represent an important share of the total electricity demand in all 2050 modelled scenarios. The ‘connected-NL’ and ‘isolated-NL’ cases present similar demands (with the exception of exports in the former). S3 presents the highest electricity demand, whereas S2 shows the lowest. Some main observations from the figure are:

- In S0, *i.e.*, the baseline scenario for 2030, the main part of total electricity load comes from conventional demand. A different demand pattern appears in S1-S4, showing that Power-to-X will be an important component of the future demand.
- Industrial Power-to-Heat amounts to less electrical demand in the more flexible scenarios (i.e., S2 and S4) due to the hybrid operation of e-boilers, allowing to use natural gas as fuel instead of electricity when the prices of the latter are relatively higher.
- Power-to-H2 demand reaches a minimum of 124 TWh in all scenarios in order to fulfil the EU directive that half of the H2 produced in the system is ‘green hydrogen’. For low flexible scenarios, half of this demand is inflexible (i.e., not responsive to price changes). In S3, the highest Power-to-H2 demand is found for both ‘connected-NL’ and ‘isolated-NL’. This is driven by the operation of power-generating H2 turbines which increases the demand for H2 production, as will be explained further on in the following subsections. This need for higher operation by the H2-fired units results mainly from the simulation of a CO2-free electricity system combined with low flexibility in S3.
- The total load-shifting demand from EVs and household heat pumps are the same across all scenarios, as these are demands that must be fulfilled in all cases, although – to some extent – this demand can be shifted on an hourly basis.

- Storage consumption in the ‘isolated-NL’ case is higher compared to the ‘connected-NL’ case, except for the S1 scenario. Overall, the lack of trade and its consequent flexibility results in the need for flexibility provided by battery operation.



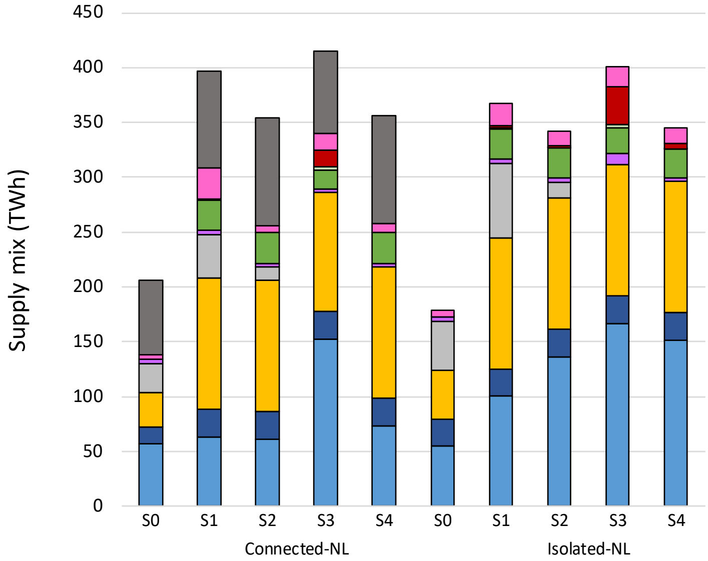
	Connected-NL S0	Connected-NL S1	Connected-NL S2	Connected-NL S3	Connected-NL S4	Isolated-NL S0	Isolated-NL S1	Isolated-NL S2	Isolated-NL S3	Isolated-NL S4
Exports	26	23	14	39	14	0	0	0	0	0
Storage (charge)	4	31	7	17	9	7	23	15	20	15
P2Mobility (EVs)	2	6	6	6	6	2	6	6	6	6
P2Heat (households)	10	15	15	15	15	10	15	15	15	15
P2Heat (industry)	10	54	44	54	44	7	54	37	54	37
P2Hydrogen	26	124	124	141	124	26	127	126	162	130
Conventional	128	144	144	144	144	128	144	144	144	144

Figure 6. Electricity demand in various scenarios run by COMPETES-TNO.

- ***Electricity supply***

Figure 7 shows for the respective scenarios the resulting supply mix to meet the previously described electricity demand. vRES generation represents the main part ot total electricity supply in both 2030 and 2050. The ratio between sun PV and wind offshore production varies across the scenarios. Overall, a trend can be seen where those scenarios with low flexibility in the system present more dispatch from wind offshore than the most flexible scenarios. Some main observations are:

- In S0, wind offshore plays a major role, followed by solar generation and natural gas production.
- Imports from neighbouring countries provide an important share of the supply mix for the ‘connected-NL’ scenarios, with around ~25% of the total mix. When these imports are not available (i.e. ‘isolated-NL’ case), the supply mix depends fully on generation from domestic sources, notably on wind offshore production.
- Storage production follows the trend already seen in the electricity demand subsection, with higher operation in the scenarios with low flexibility.



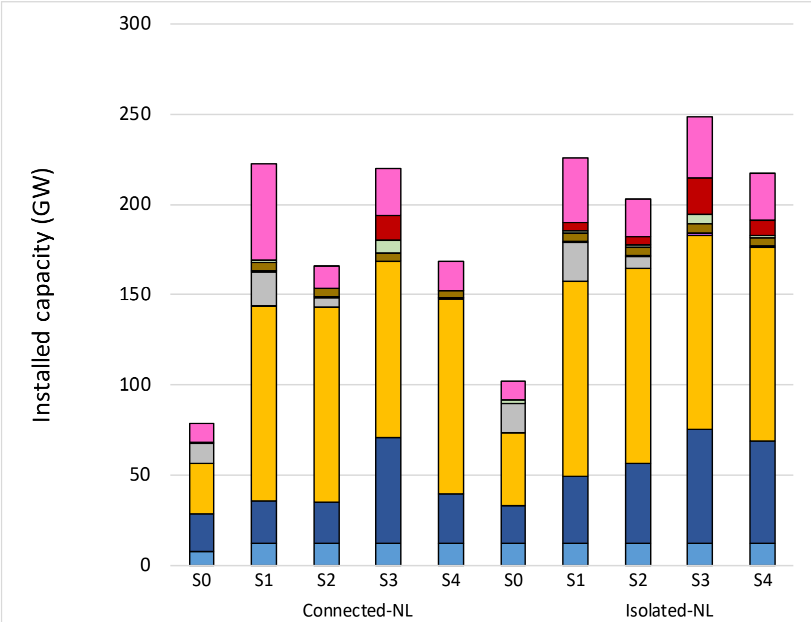
	Connected-NL S0	Connected-NL S1	Connected-NL S2	Connected-NL S3	Connected-NL S4	Isolated-NL S0	Isolated-NL S1	Isolated-NL S2	Isolated-NL S3	Isolated-NL S4
Imports	68	89	98	75	98	0	0	0	0	0
Storage (discharge)	4	28	6	15	8	6	20	13	18	14
H2-to-power	0	0	0	15	0	0	2	2	34	5
Biogas	0	1	0	4	0	0	1	0.3	3	0.4
Biomass	0	28	28	17	28	0	28	28	23	26
Nuclear	4	4	4	4	4	4	4	4	10	4
Gas	27	40	12	0	0	44	68	15	0	0
Sun PV	31	120	119	108	119	45	119	119	120	120
Wind onshore	16	25	25	25	25	25	25	25	25	25
Wind offshore	57	63	61	153	74	54	100	136	167	151

Figure 7. Electricity supply in various scenarios runs by COMPETES-TNO.

- The supply by dispatchable technologies varies according to the different scenario definitions. In S1 and S2, remaining gas capacity and investment in thermal capacities with CCS are allowed. The difference in assumptions regarding the flexibility of the system between S1 and S2 results in a different contribution of gas in the total domestic power generation in these scenarios. This contribution is higher in low flexibility scenario S1, both in the ‘connected-NL’ and ‘isolated-NL’ case, with a share of around 13% and 18% of the total power supply respectively.
  In the pro-vRES scenarios where no gas capacity is left in the system (i.e., S3 and S4), the power generation by gas-fired plants is replaced by other technologies. Across the two trade variants, the power production from H2 turbines, as well from biogas, is significant, notably in S3. Again, the S3 with low flexibility, presents a higher output from these dispatchable capacities compared to its scenario counterparts. The main dispatchable generation technology in 2050 is biomass. Its contribution to the supply mix is almost similar across all scenarios and trade-variants (i.e., about 26-28 TWh) but substantially lower in the two S3 cases (i.e., 17 and 23 TWh, respectively). This lower generation from biomass, notably in the ‘connected-NL’ case, is partially due to the higher wind offshore production in the scenario, reducing the need of output from biomass. A higher production from nuclear is seen in the ‘isolated-NL’ S3 scenario, i.e. about 10 TWh, compared to 4 TWh in all other scenarios. This is due to the capacity expansion of nuclear in this S3 scenario, as will be explained in the next subsection.

* ***Installed capacities***

Figure 8 shows the resulting installed capacities in the Netherlands from the optimization by COMPETES-TNO.



	Connected-NL S0	Connected-NL S1	Connected-NL S2	Connected-NL S3	Connected-NL S4	Isolated-NL S0	Isolated-NL S1	Isolated-NL S2	Isolated-NL S3	Isolated-NL S4
Storage	10	54	12	26	16	11	36	21	34	26
H2-to-power	0	0	0	14	0	0	4	4	20	8
Biogas	0	2	0	7	0	2	2	2	6	2
Biomass	0	4	4	4	4	0	4	4	5	4
Nuclear	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.4	0.5
Gas	11	19	5	0	0	16	22	7	0	0
Sun PV	28	108	108	98	108	40	108	108	108	108
Wind offshore	21	24	23	59	28	21	37	44	63	57
Wind onshore	7	12	12	12	12	12	12	12	12	12

Figure 8: Installed capacities in various scenarios run by COMPETES-TNO.

These capacities are heavily impacted by vRES technologies, notably sun PV, followed by wind offshore. Some main insights from the figure are:

* **Wind offshore capacities** vary across the different scenarios. The ‘isolated-NL’ scenarios present the highest wind offshore capacity compared to their ‘connected-NL’ counterpart. The highest capacities are seen in S3 of the ‘isolated-NL’ and ‘connected-NL’ cases. Low flexibility combined with a more restricted CO_2 system, results in a higher need for wind offshore.
* **Gas capacity** is part of the generation mix for S1 and S2 (see definition of the scenarios given in Figure 5). It is assumed that 5 GW of gas-fired plants will be remaining in 2050 under these scenarios. Note that the new investments in gas plants coupled with CCS amount to almost 17 GW and 16 GW in the ‘connected-NL’ and ‘isolated-NL’ S1 scenarios, respectively. When gas capacity is not allowed in the system (i.e., S3 and S4), other technologies fill that gap, namely H2 CCGT and biogas plants.
* **Nuclear capacity** remains the same across the scenarios with 0.5 GW capacity, except in S3 for the ‘isolated-NL’ case, with 1.4 GW installed. The 0.5 GW repre-

sents the current and only nuclear capacity in the Netherlands (Borssele nuclear plant). Recent political developments regarding nuclear power in the Netherlands point to an extension of the operation of this plant, as well as the potential for new nuclear capacity to be built. According to this, it is assumed that the operation of the existing Borssele plant will be extended beyond its current intended year of decommissioning (2033). In addition, the 'isolated-NL' S3 scenario is the only case where new nuclear capacity is invested by almost 1 GW. This is mainly due to the need to increase the baseload capacity to handle the lack of flexibility and the zero CO_2 emission restriction for 2040 and beyond.

- **Storage capacity** is most invested in the S1 cases with a maximum achieved of 54 GW in the 'connected-NL' case. The low flexibility of the system results combined with considerably high vRES generation (notably from solar) can result in high price volatility, favouring the business case for batteries.

- ***MPIs results***

Table 3 summarizes the selected MPIs for the different scenarios and trade variants. The main conclusions are:

- For both 'connected-NL' and 'isolated-NL', the highest vRES penetration in the system relative to the demand occurs for the most flexible scenarios (i.e., S2 and S4). In terms of total installed capacity, S3 scenario presents the highest vRES capacities, mainly due to higher electricity demand as shown in previous Figure 6.
- When power generation is not able to cover electricity demand, activation of load curtailment occurs, as measured by the indicators Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS). The lack of flexibility in the scenarios concerned prompts higher number of hours where LOLE episodes occur.
- The total system costs show that S1 and S3 present the highest costs. This indicates that lower flexibility in the system increases total costs.
- Curtailment of wind and sun reaches its highest annual value in the two S3 cases. S3 is characterized by its higher wind production compared to the other scenario variants, which combined with less flexibility in the system results in less capacity to integrate higher shares of variable production, and ultimately higher curtailment. It is also noticeable that the 'isolated-NL' case presents higher vRES curtailment than the 'connected-NL' case. The lack of flexibility to export surplus of vRES production exacerbates the need for vRES curtailment, most noticeable in the pro-vRES scenarios.
- For the 'connected-NL' case, high-flexible scenarios present lower weighted-average electricity prices compared to the low-flexible ones, with S4 reaching the lowest figure at 44.7 €/MWh. In general, the 'connected-NL' case presents lower prices compared to the 'isolated-NL' variant. An interesting observation is that under this variant with no trade, S4 does not present the lowest electricity price as in the connected-NL' case, but S3 does, mainly due to a higher wind offshore capacity and production combined with H2-to-power generation in the S3 isolated case.

Table 3: Results of key Dutch market MPIs for the different modelled scenarios in COMPETES-TNO.

MPI number and name	Unit	Connected-NL					Isolated-NL				
		S0	S1	S2	S3	S4	S0	S1	S2	S3	S4
MPI 1: Share of RES-E	%	75	76	91	89	95	70	74	90	83	93
MPI 4: Loss of load expectation	h	6	0	0	3	0	6	8	0	0	0
MPI 5: Expected energy not served	GWh	2.5	0	0	5.8	0	0	3.7	0	0	0
MPI 17: vRES curtailment	TWh	3.1	4.3	5.1	14.2	5.6	5.3	6.6	8.4	12.7	9.4
MPI 26: Total costs of the system	Bn €	7.4	13.1	8.0	16.7	8.4	8.2	18.7	15.1	19.5	15.9
MPI 27: System costs for dispatch	Bn €	1.8	2.4	0.5	1.1	0.1	2.6	4.2	0.7	1.2	0.2
MPI 29: Annual volume weighted average of hourly market-price	€/MWh	55.4	50.7	47.2	51.9	44.7	72.2	67.8	53.2	51.4	52.4
MPI 32: Market-based cost recovery	-	1.54	1.22	1.25	1.15	1.17	1.56	1.33	1.21	1.06	1.14
MPI 41: Volatility of electricity prices	-	24.7	58.1	29.2	292.0	29.2	294.7	304.4	39.5	78.3	43.1
MPI 45: Power system emissions	Mtons	5	-34	0	0	0	19	-0.1	-3	-5	-5

- The market-based cost recovery indicator is defined as total market revenues divided by total system cost, which reflects how market prices recover costs. In general, if the system is more flexible, the indicator will be closer to 1. The exception is S3 in the isolated-NL case, because of the extra flexibility provided by H2.
- The volatility of electricity prices is given as the standard deviation. More flexibility (i.e., in S2 and S4) helps to reduce the volatility of electricity prices.

3.1.1.4 Summary COMPETES-TNO results

- The flexibility level of the system impacts notably the generation and capacity mix of the scenarios. When more flexibility is available in the system, the total installed capacity decreases. From the technological point of view, flexibility allows to integrate more variable sources (i.e. sun and wind), and limits the investments from more dispatchable technologies.
- Peak generation technologies, such as H2-fired turbines and biogas units, were found not optimal in the scenarios with high-flexibility in the ‘connected-NL’ case.
- Domestic generation need increases in the ‘isolated-NL’ case due to lack of trade.
- Nuclear capacity is necessary when flexibility of the system is rather limited and CO2 -free electricity is desired, as in S3 of the ‘isolated-NL’ case.
- In general, higher flexibility achieves lower system costs and electricity prices.

3.1.2 AMIRIS-EMLabpy

3.1.2.1 The AMIRIS-EMLabpy model

In order to simulate the impact of bounded rationality on the performance of a future electricity market, a combination of the two agent-based models AMIRIS and EMLabpy was used. This part of the project evaluated the impact of limited foresight by market actors on generation investment decisions and the operational performance of a future power market as well as on investment decisions.

EMLabpy was co-simulated with AMIRIS within the TradeRES-project to complement EMLab’s simulation of myopic investment, and of the capacity remuneration mechanisms (CRMs) that might counter the resulting negative effects, with AMIRIS’ detailed simulation of the operational time scale of the electricity market that allows representing flexibilities and evaluating several RES-support mechanisms. AMIRIS includes two types of flexibility: consumers who reduce their load when the price reaches a certain level, represented by industrial load shedders in the model, and consumers who can shift their consumption over time, represented by electrolyzers (because it is assumed that the hydrogen that they produce can be stored).

EMLabpy was inspired by EMLab (Energy Modelling Laboratory), a model developed by TU Delft that simulates the influence of policy instruments (such as CRMs and CO_2 policy) on investment in generation [8]. The Python version, called EMLabpy, was developed in a modular way, allowing parts of the model to be run separately. The original EMLab represented load as time slices, which did not support the representation of flexibility, which will be essential in a future market. The use of AMIRIS greatly improved the representation of market operation, as AMIRIS simulates all hours of the year sequentially. Because AMIRIS lacks the possibility to model investments in generation, EMLab was used to add this feature. For a more detailed explanation of both models, see the user guides in D6.2.1 [9].

The AMIRIS-EMLabpy simulations are used to test the effects of different capacity remuneration mechanisms (CRMs) in a setting in which operational and investment decisions are based on realistic assumptions regarding the availability of information. An optimization model like COMPETES-TNO removes or underestimates the effects of myopic decisions in the short-term market (dispatch decisions) and in the long term (investment decision). Investors may not consider the risk of rare, adverse weather episodes (like a 'kalte Dunkelflaute' in northern Europe) or the fact that consumers and battery operators may not make optimal scheduling decisions. As a result, the reliability of the system may be overestimated in optimization models – in principle, reliability in these models will be optimal by definition – and the need for policy interventions may be consequently underestimated.

The additional realism regarding actor behaviour that the AMIRIS-EMLabpy simulation brings, comes at a cost of longer computation time and higher model complexity. It was therefore not possible to simulate cross-border trade with AMIRIS-EMLabpy and the long computation times limited the number of model runs that could be executed. Thus, AMIRIS-EMLabpy provides insight in the merits of policy interventions, while COMPETES-TNO provides more detailed insights in the interactions of different generation technologies and types of flexibility, including imports and exports, in a greater number of scenarios. Table 4 summarizes the main differences between the two models.

The results of the AMIRIS-EMLabpy simulations are not intended to represent forecasts of parameters such as the capacities of generation technologies, prices or market revenues, but to analyse market dynamics. Our model of a future power system is based on the Netherlands but does not consider imports and exports, which is a significant limitation in the representation of flexibility. COMPETES-TNO shows that with cross-border energy flows, the volume of generation capacity needed will be around 25% lower than in our results presented. Furthermore, risk aversion and market power are not considered, as these factors may impede market performance.

3.1.2.2 Implementation of the AMIRIS-EMLabpy model

The co-simulation of the AMIRIS and EMLabpy models was performed with the aid of the Spine Toolbox [10], which supports the execution of computational tasks by linked models in a flexible manner. This tool uses human-readable files as inputs, making it easy for the user to control the model parameters, adding transparency to the simulations. Similarly, the outputs of both models are files that allow to change results between both models.

Table 4: Comparison of COMPETES-TNO and AMIRIS-EMLabpy.

	COMPETES-TNO	EMLabpy AMIRIS
Method	Optimization	Agent-based
Scope	Europe wide, considers interconnections	One node, based on the Netherlands
Batteries	Optimized for whole year	Heuristic one-week demand forecast
Hydrogen	Endogenous price	Not modelled; hydrogen price is exogenous. Assumed stable hyd. price
	Cross border hydrogen trade	-
Technologies	Wider range of generation technologies. Different price for bioenergy investment costs.	Includes batteries (4 hours discharge time) and hydrogen OCGT.
Power2mobility	Optimized	Fixed exogenous demand
Power2heat	Optimized	Modelled as a load shifter with price cap
Power2gas	Optimized	Load shedder

An overview of the workflow is presented in Figure 9. This workflow can be executed iteratively for any number of years as defined by the user. The blue symbols on the left 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 next.

After the year counter is increased by one year, the status of the power plants in the model is updated. Unprofitable power plants (based on average profits of the three previous years, without capital costs) that have passed their lifetime are decommissioned. The power plants that will be operational in the simulation year together with the updated fuel prices are written in an Excel file that is input for AMIRIS. Then, AMIRIS is executed for the current simulation year. The results of this market simulation used to create power plants' bids in a capacity market that is simulated in EMLabpy. The financial results of the individual power plants are determined by adding the revenues from the capacity mechanism and from the market.

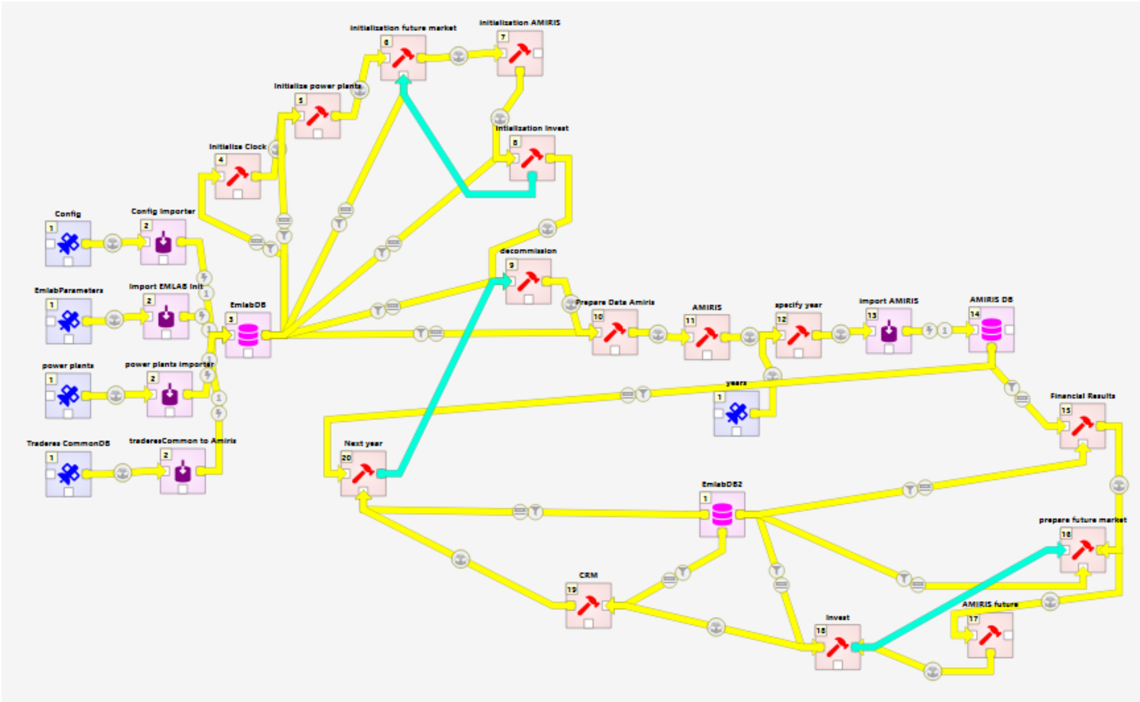


Figure 9. AMIRIS - EMLabpy workflow in the Spine Toolbox.

In the final step, investment opportunities are evaluated iteratively in EMLabpy by estimating supply and demand four years ahead and adding a potential power plant. Power plants that are in the construction pipeline are added to the estimate of the future supply curve. In each iteration, the net present value (NPV) of new power plants is estimated based on the estimated market revenues in the future year, the plant's operational costs (fuel, CO_2 and fixed operating and maintenance cost) and the amortized annual fixed costs. The candidate power plant with the highest present value (NPV is chosen for investment and added to the investment pipeline. This investment loop runs until there are no more power plants that have a positive expected NPV. The lifetimes of power plants can be extended, as long as they are profitable, until a maximum of years (see Table 5). This algorithm is the same for variable renewable energy technologies and for dispatchable technologies, but the latter may also receive revenues from a CRM. After each investment, the investment costs of the power plant are registered. In EMLabpy the equity payments are paid during the construction time (down payments) and the debt is paid during the power plant's lifetime (loans).

To test the performance of the different market designs, the realized weather is simulated with distinct weather years, while the investment decisions are based on a representative weather year. The year 2004 was used, as this was the year with a median total renewable energy production. Figure 10 describes the model. Sanchez *et al.* [11] provide a detailed description of the AMIRIS-EMLabpy model coupling.

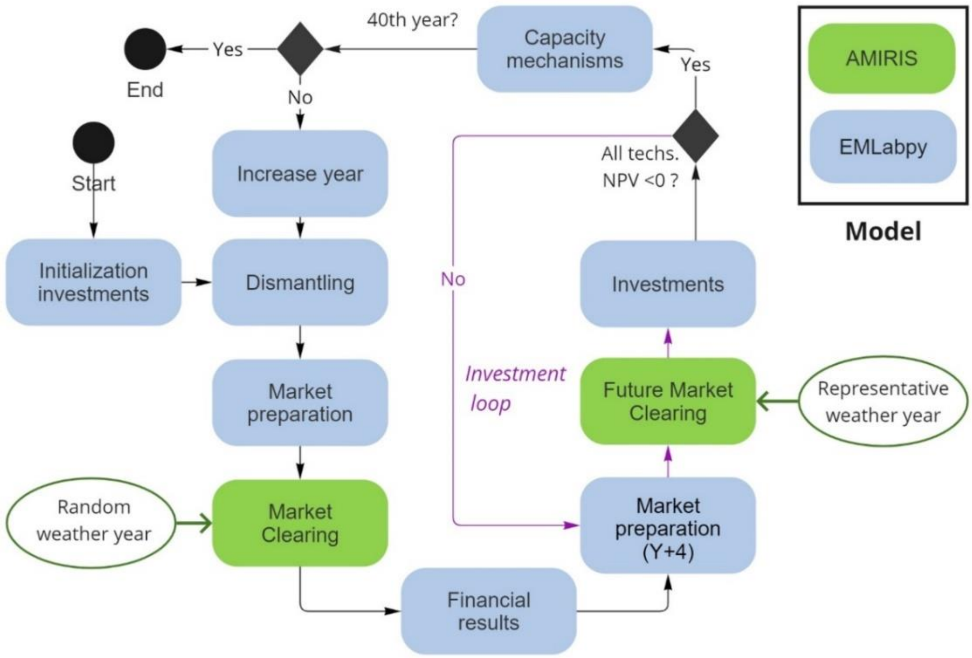


Figure 10. Conceptual workflow of AMIRIS-EMLabpy.

3.1.2.3 Scenario designs

Due to the long computation time of EMLab-AMIRIS, only the S3 and S4 scenarios are simulated. They differ with respect to the degree of flexibility of consumers that is assumed. The S1 and S2 scenarios that are not simulated are the ones that allow a limited volume of CO_2 emissions (or CCS), whereas S3 and S4 are fully renewable. While allowing some continued use of fossil fuels would reduce system cost, it is not expected to affect the relative performance of different types of CRMs, whereas the degree to which CRMs facilitate the integration of flexibility is a key issue regarding market performance.

The definition of the scenarios in AMIRIS-EMLabpy varies from the scenarios in COMPETES-TNO. In COMPETES-TNO, Scenario S3 is considered as the 'low-flex' scenario because it entails a high degree of electrification of industrial demand with limited possibility to shift from electricity to gas. AMIRIS-EMLabpy does not simulate the gas system. In In AMIRIS-EMLabpy, high industrial demand for electricity is assumed to come with higher demand flexibility. However, the 'low-flex' scenarios in COMPETES-TNO results in higher electrified industrial heat demand, which would correspond to the scenario with high industrial flexibility in our EMLabpy-AMIRIS, as higher industrial demand conveys higher flexibility. Similarly, COMPETES-TNO 'low-flex' scenarios have higher electrolyzer consumption to simulate less flexibility provided by its load-shedding capabilities. Again, in AMIRIS-EMLabpy, higher electrolyzers consumption enhances the flexibility within this modelling approach. In fact, in AMIRIS-EMLabpy the flexibility of electrolyzers is a key factor in determining market prices [11]. For this reason, instead of simulating a lower degree of flexibility (S3), a different hydrogen price was considered.

Three capacity remuneration mechanisms are simulated: a capacity market, a strategic reserve and capacity subscription. The first two options are chosen because they are currently the preferred market designs in the EU. The UK, Belgium, France and Italy have capacity markets, among others, as does much of the USA. This deliverable presents the results of a capacity market where only dispatchable technologies are allowed to participate. The current European regulation recommends a technology-neutral design that also remunerates flexible technologies.

The European regulation recommends implementing a strategic reserve before other capacity remuneration mechanisms and recommends dispatching the plants in the reserve at a market price cap. By withholding generators from the market, it forces flexible consumers to reduce their consumption even while these generators are available. For instance, if industrial consumers have a maximum willingness to pay between 1000 and 2000 Euros/MWh, they will curtail their demand when the price rises above this level, while the reserve generators are only dispatched when the market price cap of 4000 Euros/MWh is reached.

The third option, capacity subscription, has not been implemented. It is an innovation on the classic capacity market aiming to provide better incentives to consumers for flexibility by consumers and energy storage operators. In a capacity market, the TSO estimates the need for controllable generation capacity and buys enough to meet estimated demand. The costs are socialized. Flexibility can only be included in the form of 'negative generation', *i.e.*, electricity consumers with a predictable load sell the right to have their load curtailed when power is short. Other forms of flexibility are discouraged because the market always provides enough capacity, which naturally comes at a cost. In a market with capacity subscription, end consumers bid for dispatchable generation capacity contracts (capacity subscriptions) themselves, based on how much they are willing to pay for a certain volume of reliable supply. During shortages, they are either physically limited to this volume or they are exposed to spot prices for the part of their demand that is not covered by a subscription. See Doorman [12] and De Vries and Doorman [13] for a description of capacity subscription.

The performance of the different types of CRMs is compared to an energy-only market, which is the default market design in Europe and therefore the benchmark in this study. In an energy-only market, investment in generation capacity is driven by market incentives alone and there is no government intervention. Sanchez *et al.* [11] presents a simulation analysis of an energy-only electricity market with only renewable energy technologies, also made for the TradeRES Project. The article focuses on the impact of weather uncertainty and bounded rationality on system reliability. It presents a wider range of weather scenarios and a more detailed analysis of the impact of weather variability on electricity system adequacy. Other differences are that in that study, 5.6 GW of nuclear generation capacity was assumed to be built in the Netherlands, and the option of lifetime extension of power plants was not included. Despite the presence of nuclear power generators, the study showed that an all renewable energy-only market cannot be expected to provide system adequacy, even in the absence of external shocks like Covid, the 2022 gas crisis or the financial crisis of 2008.

Sanchez *et al.* [11] showed the important role of the willingness to pay of flexible demand in setting prices and thereby determining investment incentives. In that study, flexible demand was represented by the flexibility of electrolyzers, which constituted a large share of electricity demand and whose willingness to pay is a function of the market price of hydrogen. A higher hydrogen price was found to attract more investment in variable renewable energy (specifically offshore energy) but to increase the cost of hydrogen-based gas peak plant.

Due to the significant role of hydrogen, both a low hydrogen price (*LH*) and a high hydrogen price (*HH*) scenario are included for each market design tested. The LH scenarios use a hydrogen price of 1,5 Eur/kg, which is based on the renewable H_2 imports price in the TYNDP 2022 Scenario Report (global ambition scenario) [14] and is in line with the rest of the analyses in TradeRES. The HH scenario uses a price of 10 Eur/kg, based on more recent insights (TNO, 2024) [15]. However, this study does not consider economics of scale or technology advances which could lead to lower hydrogen prices. Thus, the following experiments are performed:

- Energy-only market (based case): EOM-LH and EOM-HH.
- Capacity market: CM-LH and CM-HH.
- Strategic reserve: SR-LH and SR-HH.
- Capacity subscription CS-LH and CS-HH.

The set of power plants at the start of the model simulation was taken from the results of COMPETES-TNO (Scenario S4 'isolated-NL'). The investment costs, variable costs, fixed costs, efficiency, technical lifetime, and fuel costs were taken from the TradeRES database [16]. The candidate generation technologies are shown in Table 5. In contrast to the TradeRES Data, hydrogen OCGT and lithium batteries with a depth of four hours were added as investment options.

Table 5. Characteristics of available technologies for investment and assumed, maximum lifetime of the technologies.

Technologies	Lifetime (years)	Maximal extension years (years)	Permit time (years)	Construction time (years)	Investment block capacity (MW)
Biofuel	25	6	1	3	300
Hydrogen OCGT	25	6	2	2	400
Hydrogen CCGT	25	6	2	2	400
Lithium ion battery 2h	25	1	0	1	300
Lithium ion battery 4h	25	1	0	1	300
Nuclear	40	10	2	5	500
Solar PV large	25	3	1	1	300
Solar PV rooftop	25	3	1	1	300
Wind Offshore	30	5	1	2	500
Wind Onshore	30	4	1	2	500

The capacity of the electrolyzers and the volume and capacity of industrial heat are provided by Scenario S4 of the COMPETES-TNO model results. An EOM was simulated to create an equilibrium mix of generation capacity, which was used at the start of the model runs to prevent large scarcities at the beginning of the simulations. Hourly heat pump demand was estimated from the hourly temperature and the temperature-dependent coefficient of production.

3.1.2.4 AMIRIS-EMLabpy results and analysis

Table 6 presents the results of the AMIRIS-EMLabpy simulations. Forty weather years were tested, as explained in section 3.1.4 and for present in this table the average and standard deviation from the 40 simulation years.

Table 6. MPIs of the 2050 Flex Scenario (based on COMPETES-TNO scenario S4).

MPI*		EOM_LH	EOM_HH	CM_LH	CM_HH	SR_LH	SR_HH	CS_LH	CS_HH
ENS [MWh]	Average	6375	13898	2268	727	2992	15302	3279	1400
	Std dev.	7577	21171	3909	2054	5157	21065	5059	4542
LOL [h]	Average	4.23	5.13	1.85	0.38	2.30	5.73	2.33	0.68
	Std dev.	4.77	6.17	2.55	0.84	3.29	6.26	3.41	1.77
Weighted average electricity prices [MWh]	Average	38.53	59.99	37.52	59.45	42.92	60.10	37.56	60.25
	Std dev.	4.47	11.21	3.80	11.18	8.02	11.28	3.74	11.23
Cost recovery [%]	Average	120.71	138.13	121.26	137.26	136.75	138.43	120.92	138.75
	Std dev.	8.26	22.15	6.87	21.78	19.66	22.32	8.27	22.15
Weighted average CRM Costs [Eur/MWh]	Average	0.00	0.00	1.00	1.04	0.74	0.04	1.27	0.55
	Std dev.	0.00	0.00	0.59	0.39	0.37	0.05	1.13	0.51
Cost to consumers [Eur/MWh]	Average	38.53	59.99	38.52	60.49	42.96	60.03	38.83	60.80
	Std dev.	4.47	11.21	3.88	11.23	7.50	11.40	4.10	11.28
Cost to society [mln. Eur]	Average	10304	21686	10217	21922	10354	21698	10331	21750
	Std dev.	572	694	579	641	607	687	565	761
CRM costs [mln. Eur]	Average	0	0	321	517	235	18	406	274
	Std dev.	0	0	188	190	112	22	363	247
Share VRES [%]	Average	96	87	96	87	96	87	96	88
	Std dev.	1	1	1	1	1	1	1	1

*average/std dev refer to a typical weather year based on data from 40 input years (see section 3.1.4)

- ***Energy only market***

In the scenarios with a high hydrogen price (i.e. HH scenario), the electricity price is higher and more volatile for two reasons. Firstly, as a result of the electrolyzer's higher opportunity cost, which is dispatched at 222 Eur/MWh instead of 33 Eur/MWh. Secondly, hydrogen turbines are dispatched at approximately 700 Eur/MWh due to high fuel price. In the HH simulation, electricity prices are 21.46 Eur/MWh higher than an EOM and with more than double volatility. This causes the cost recovery to be extremely volatile, and on average 17% higher than an EOM. Furthermore, the total costs to society increase to more than double from 10.5 to 22 billion, on average.

The cost increase of hydrogen turbines is sufficient for more nuclear energy to be installed. Figure 11 shows the impact of the hydrogen price on the generation mix. In comparison to EOM_LH, there are 21 GW more batteries, 13 GW more Nuclear, 2.1 GW more solar, 35.5 more wind offshore, and 19.6 GW less hydrogen turbines. The number of shortages remains at a similar level, but hydrogen production is much higher. Instead of 4.58 million tons, 11.67 million tons are produced on average. A higher hydrogen price implies that less hydrogen would be imported because the imports would probably have lower prices.

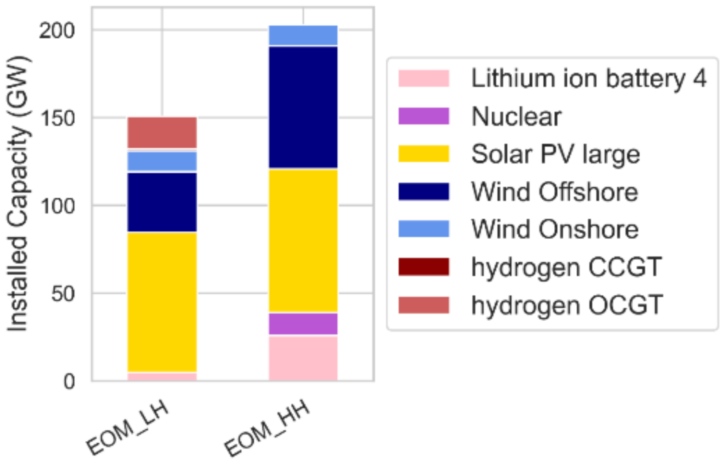


Figure 11. The impact of the hydrogen price on the generation portfolio in an energy-only market in 2050.

Figure 12 displays the Energy Not Served (ENS) and loss of load (LOL) results for all market mechanisms and scenarios. The ENS (left side) is categorized by curtailment type: DSR, with voluntary curtailment at 1500 Eur/MWh. Under the HH scenarios, an EOM led to a slight increase of shortages, with 5.13 h, instead of 4.23 h, and similarly higher and more volatile Energy Not Served (ENS), increasing from 6.3 GWh to almost 14 GWh on average. Meanwhile, the capacity market and capacity subscription presented the lowest shortages occurrences, with the former providing the highest reliability.

Figure 13 shows installed generation capacity in an energy-only market and with the investigated CRMs for the high hydrogen price scenario. The top part of the figure shows controllable generation capacity, the bottom part vRES. The top figure shows the declining volumes of controllable capacity in an energy-only market and with a strategic reserve. The capacity market consistently improves the reserve margin, while the market with capacity subscription developed an investment cycle, leading to lower security of supply in the latter part of the model run. Figure 14 shows the same for the low hydrogen price scenario. In this case, the differences in installed controllable generation capacity are not as pronounced, but we still see a lower reserve margin in case of an energy-only market and a strategic reserve and a strong investment cycle in case of capacity subscription.

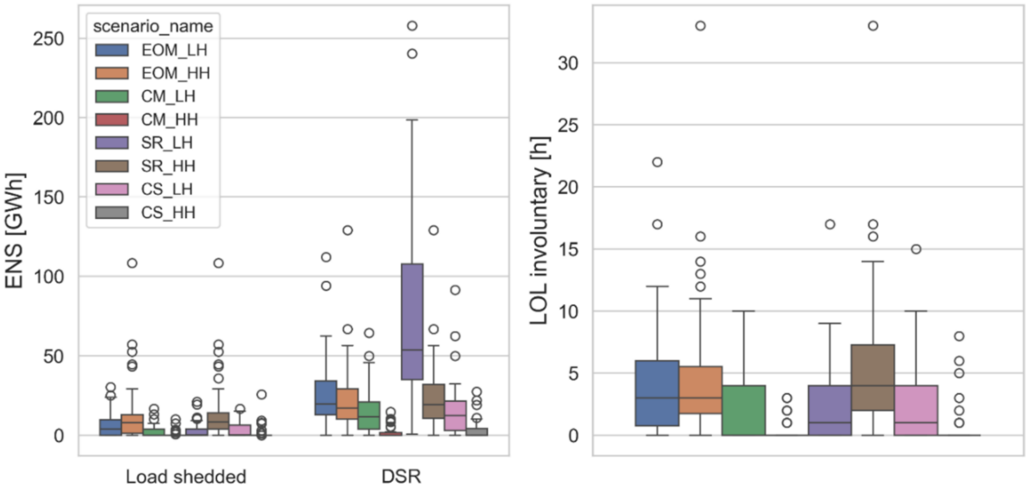


Figure 12. On the left, the Energy Not Served (ENS) from involuntary (load-shedded) and voluntary load shedding (DSR). On the right, the total Loss of Load (LOL) from involuntary load-shedding.

- ***Capacity market***

The hydrogen price influences the target volume for the capacity market. In the high hydrogen price scenario, more vRES is installed. Due to their coincidence, this causes their derating factors to be lower in this scenario. The de-rating capacity factor shall reflect the statistical degree to which the installed capacity of the reference technology is expected to contribute to resource adequacy when ENS occurs [17]. Nevertheless, the high cost of back-up hydrogen generators causes a lower level of controllable generation capacity. Table 7 shows the derating factors of selected technologies in both scenarios. The higher installed VRES in HH reduced the target volume to 19,200 MW, in contrast to the 20,000 MW in the CM_LH scenario.

Table 7. Derating factors in the low and high hydrogen price scenarios.

Hydrogen price	High hydrogen (HH)	Low Hydrogen (LH)
Lithium ion battery	4%	16%
Lithium ion battery 4	5.0%	25%
Wind Offshore	5.4%	6%
Solar PV large	0.5%	0%
Wind Onshore	11.9%	12%

A capacity market keeps the total installed capacity of dispatched technologies at a stable level (see Figure 13). Most CRM payments are given to nuclear plants, but the installed capacity of nuclear does not change. On the contrary, 6 GW of more H2-OCGT are installed. In the LH scenario (see Figure 14), 3 GW more of H2-turbines are installed, while the capacity of batteries and solar energy is reduced by a similar amount. In this way, the mechanism reduces the power shortages in LH and HH, as shown in Figure 12. The shortages are reduced to 0.38 hours in HH, which indicates that the CM could be slightly oversized. A capacity market reduces the costs to society by 256 million on average in HH scenarios, while increasing the costs to consumers by 0.5 Eur/MWh compared to the EOM.

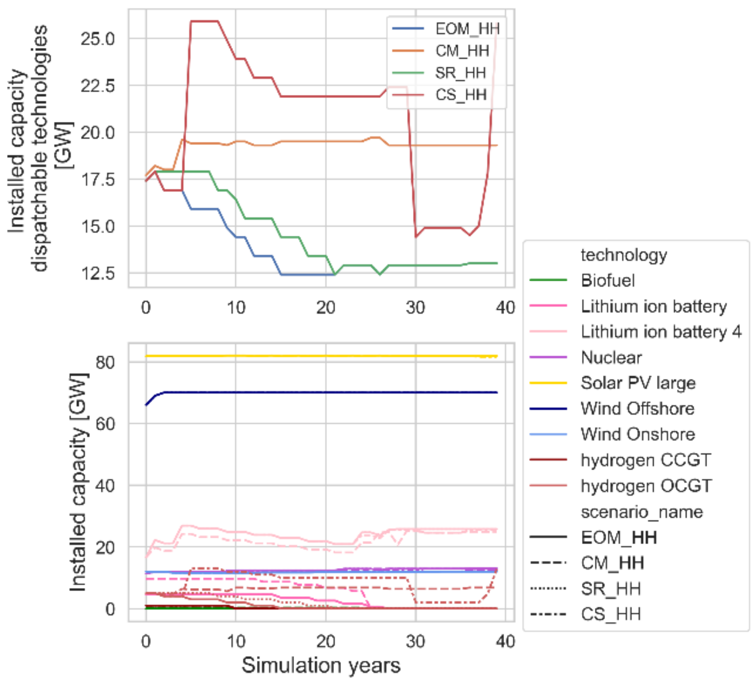


Figure 13. Installed capacity in the high hydrogen price scenario. The upper figure shows dispatchable capacity, the lower total installed capacity including vRES.

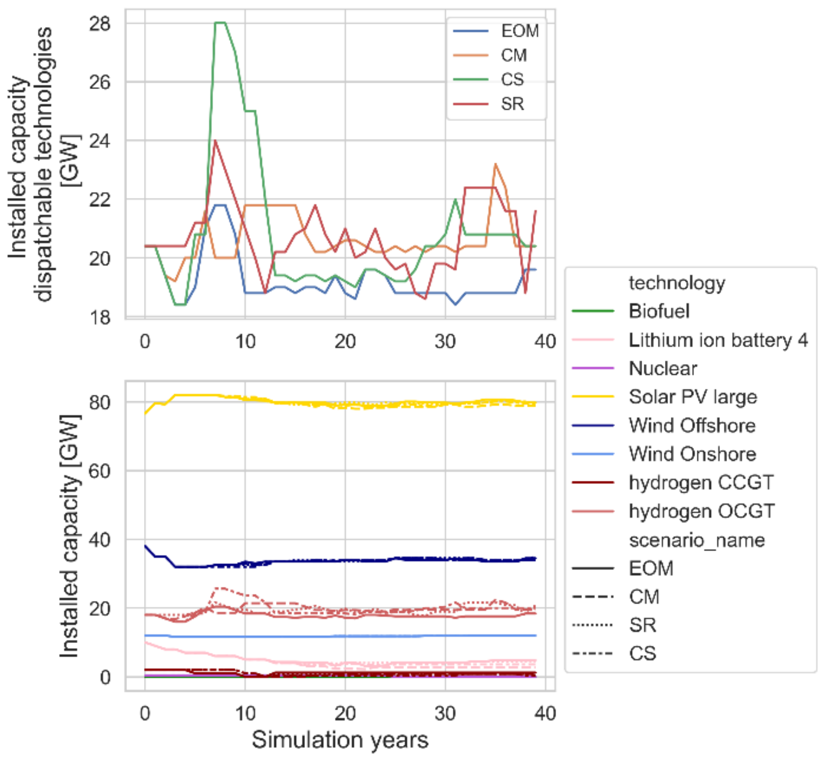


Figure 14 Installed capacity in the low hydrogen price scenario. The upper figure shows dispatchable capacity, the lower total installed capacity including vRES.

- ***Strategic reserve***

In general, a strategic reserve prolongs the lifetime of hydrogen turbines. The plants in the reserve were dispatched after the DSR, for this reason the average and the volatility of electricity prices increased. In the SR_LH scenario the electricity prices increase from 38.53 Eur/MWh to 42.92 Eur/MWh.

Nevertheless, in the HH scenario, the turbines become unprofitable and eventually, their share in the reserve is reduced to zero. Similarly, the biofuel plants are decommissioned after some years (see Figure 13). The model only includes old, unprofitable peak plants in the reserve. For this reason, after 20 years there are no more plants that could enter the reserve, so the reserve is phased out in the model and the effect of the mechanism is minimal. In reality, this would pose a dilemma of whether to build new back-up generators for the sole purpose of constituting a strategic reserve. This would be a costly solution, as these generators would be more efficiently dispatched in the regular market. In the HH scenario, higher scarcity prices were not enough to incentivize more H2 turbines or batteries.

- ***Capacity Subscription***

From the simulation years 30 to 38, installed capacities of H2-OCGT turbines become more volatile, with its installed capacity reduced by 7 GW (see Figure 13). This causes more shortages, which again increased the CS price and the installed capacity of H2 turbines. This investment cycle triggered from changing WTP of consumers was also observed in the LH scenario, although there the capacity remains relatively more stable. The costs to consumers increase in comparison to an EOM from 38.53 to 38.83 Eur/MWh in the LH scenarios and from 59.99 to 60.8 Eur/MWh in the HH scenarios.

3.1.2.5 Summary of the results of the AMIRIS-EMLabpy model analysis

Table 8 summarises the main findings of the market simulations with the AMIRIS-EMLab agent-based model. The energy-only market design is taken as a base case. Its shortcomings are periodic energy shortages that are associated with high prices. This leads to higher average prices, but the low frequency and unpredictability of these episodes still cause revenue certainty for generation companies to be low.

All investigated capacity remuneration mechanisms reduce the total cost to society (i.*e.*, the total cost of the power system plus the cost to society of power shortages). A capacity market reduces cost most in our simulations, even though capacity subscription creates a more efficient mix of dispatchable generation capacity, storage and demand-response. However, in our simulations, these benefits were offset by investment cycles that resulted from the short contract duration of capacity subscriptions. A strategic reserve appeared to work only as a partial and temporary solution, preserving old plants that are approaching decommissioning, but not providing long-term investment security nor damping consumer price volatility.

Table 8. Summary of the results of the agent-based model simulations considering LH scenarios.

	EOM	SR	CM	CS
Limiting shortages	- -	+ +[a)]	+++	++
Reducing costs to society	0	+	++	+
Reducing costs to consumers	0	- -	-	-
Revenue certainty for investors	- -	-	++[b)]	+
Avoidance of under/oversizing	+	-	-	+
Reducing electricity price volatility	0	- - -	++	+
Incentivizing demand response	+	++[c)]	-[c)]	+++

Footnotes:
a) Involuntary shedding was reduced but voluntary DSR increased.
b) Higher if payments are awarded in long-term contracts.
c) Higher if DSR can participate.

This analysis builds on Sanchez *et al.* [11], in which a more detailed analysis of the performance of an energy-only market with only renewable energy technologies is presented. This study showed that weather unpredictability affected both supply and demand in such a way that system adequacy could not be guaranteed by a market. The business case for investing in backup facilities that were needed during infrequent periods with high energy demand and low supply of renewable energy, such as cold and windless periods, was too low. Their capital costs would need to be recovered during the brief duration of such periods, while their frequency is uncertain. From a societal perspective, however, the cost of investing in these facilities is outweighed by the benefit of avoiding significant energy shortages.

The focus of this deliverable is on market designs that remediate the problem of insufficient investment. An energy-only market scenario is presented here as a reference case. The main findings of this study are as follows:

- A *capacity market* delivers the highest level of reliability because it provides the government with the most direct control over the level of generation capacity. A downside is that it will become increasingly difficult for central planners to determine the optimal volume of capacity due to the contributions of variable renewable energy sources, energy storage, demand response and imports and exports. Each of these factors may reduce the need for generation capacity, but it is difficult to quantify their contributions.
  A second disadvantage is that a capacity market does not provide intrinsic incentives for energy storage and demand response. It is possible to remunerate them by allowing them to sell capacity credits, but storage facilities need to receive derating factors that specify how long they are expected to operate before they are empty. Furthermore, demand can only participate if it has a clear baseline consumption pattern that can serve as a reference for their reduction efforts. Neither solution is optimal. With HH a capacity market was the mechanism that presented the highest capability to reduce shortages.

- A *strategic reserve* is politically attractive because it is easy to implement. However, it can distort the merit order of an energy system with demand flexibility. By keeping certain power plants in reserve and dispatching them at the market price cap (*e.g.*, the EPEX day-ahead bid cap), it forces demand response to become active before the power plants from the reserve are dispatched, even if the variable costs of the reserve are much lower than the cost of demand response. As a result, in the long run, a market with a strategic reserve has more frequent scarcity prices than a similar market without a reserve. These more frequent price spikes incentivize more investment in hydrogen turbines and batteries than the other market designs, leading to slightly higher costs to society than the other capacity mechanisms. Finally, a disadvantage of a strategic reserve is that it does nothing to stabilize end user prices. In the presence of a high hydrogen price, i.e. a large volume of flexible consumption with a relatively high willingness to pay, a strategic reserve is not so effective in reducing the shortages.

- *Capacity subscription* (CS) turns the reliability of electricity supply into a private good. (It does not affect service interruptions that are caused by network failures.) Both the strength and the weakness of this market design are the fact that all consumers, including households, decide on the level of firm generation capacity that they contract. The benefit is that this allows consumers to make an optimal balance between purchasing firm capacity and their own flexibility, including options such as installing energy storage behind the meter. The disadvantage is that this provides a less clear investment signal to generators than a capacity market. Small consumers cannot be expected to purchase capacity subscriptions with a duration of more than one year. Especially in the current phase of the energy transition, this does not provide sufficient investment security. Secondly, consumers may find it difficult to establish their willingness to pay and the volume of their demand for capacity. If they do not do this right, they may be unpleasantly surprised when a shortage period arises. This may lead to high capacity prices, potentially triggering an investment cycle, as was observed in our simulations. Therefore, small consumers may need help from retailer companies and perhaps even regulation of a minimum price and minimum volume of capacity.

3.1.2.6 Conclusions of the Dutch case study

The energy-only market design is not suitable for an electricity system with a high share of variable renewable energy. The business case for having sufficient controllable generation capacity to withstand rare periods of adverse weather conditions is too weak. Such periods would require back-up power plants (plus hydrogen production and storage facilities) that would operate only once per many years and would need to be remunerated through extremely high wholesale electricity prices during these periods. The frequency, duration and height of these price spikes is too unpredictable to stimulate sufficient investment.

A CRM will raise the cost of electricity to consumers slightly but will benefit them through higher security of supply and more stable energy prices by avoiding periodic energy shortages.

A capacity market is a mechanism most effective to reduce power shortages, thereby reducing the costs to society. Followed by a capacity subscription, which has the advantage of revealing the demand for back up capacity but has the risk that consumers will not consider extreme situations to declare their needed capacity, especially if they haven't experienced any electricity limitation in recent years.

The assessment of the impact of different market design options for the Dutch electricity market were studied with the AMIRIS-EMLabpy model. The results show that hydrogen price has a strong influence on the results. A high hydrogen price incentivizes more nuclear energy but doubles the total costs to society and makes the cost recovery more volatile.

The model COMPETES-TNO was used to offer benchmark results for an EOM simulation of the Dutch system. The results of that modelling effort showcased the effect of flexibility on the capacity and generation mix of the Dutch system from a cost-optimal point of view.

3.2 Case Study C: German market

Germany is the country with the highest absolute renewable electricity generation from vRES in Europe. Nevertheless, with around 52% RES share on electricity demand in 2023 [18], the country is still far from a ~100 % renewable power system, and therefore, large investments in vRES are required. It is currently unclear whether the necessary investments into vRES will be able to sufficiently recover their costs at the energy-only market - or whether financial support will be required for de-risking investment decisions [19]. The German case study assesses future market-based cost recovery of vRES, thereby taking into account the impact of different remuneration schemes.

3.2.1 Model used: AMIRIS

The German Case study was carried out using the **A**gent-based **M**arket model for the **I**nvestigation of **R**enewable and **I**ntegrated energy **S**ystems (AMIRIS).

In AMIRIS, actors and entities of the electricity markets are classified as agents and can be roughly divided into six categories: power plant operators, traders, marketplaces, policy providers, demand, and storage facilities. The model calculates wholesale electricity prices endogenously by simulating the strategic bidding behaviour of prototyped market actors.

An in-depth model description can be found in 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/.

For the analysis of remuneration schemes, the following support instruments have been implemented in AMIRIS (see D4.5 [2]):

i. Fixed market premium *(MPFIX)*: A fixed payment on top per MWh additional to market revenues, which is determined *ex-ante*.
ii. One-way contracts for difference (*1-WAY-CFD*): An ex-post price-variable premium scheme. The difference between the production costs, i.e. the strike price (or the “value to be applied”) and the monthly, technology specific market value which

serves as the reference price 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 of the technical feed-in potential for the respective energy carrier, neglecting curtailment. For other (controllable) renewables, the base price is used.

iii. Two-way CfD *(2-WAY-CFD):* A two-sided variant of the *1-WAY-CFD*. 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 of "clawback periods", when market values are higher than the production costs. In this variant, there is only one strike price, compared to another variant with a cap and floor price.

iv. Capacity premium *(CP)*: A payment is made on a per-installed-capacity basis, with the total amount equally distributed across the operational lifespan of the plant. Note that although future European regulation demands two-way CfDs or equivalent schemes [20] thus most likely involving some sort of clawback, this is not considered here. The instrument might be extended to do so. One possible extension is given in the form of a Financial CfD described in the following.

v. Financial CfD (*FIN-CFD*): A production-independent support instrument as proposed by [21]. Similarly, as in the case of *CP*, a payment is made on a per-installed-capacity basis. Additionally, the revenue generated by a reference plant must be reimbursed. Effectively, this can be seen as combining a capacity premium with a production-independent CfD with a strike price of zero [22]. The original proposal defines some options for choosing the reference plant [21]. For the prevalent analysis, the country average of all generation of the same technology is used.

In the German case study, the impacts of each support instrument are compared to a situation with no support (*NONE*). This case *NONE* assumes that vRES do not obtain any additional support payments besides revenues from the day-ahead market.

It is assumed that the day-ahead power market functions competitively, with no single market participant having the ability to exert significant market power. Therefore, the supply-side bids are generally derived from their marginal costs. Marketers of vRES factor in the payments they receive for the respective support instrument which might lead to bids deviating from their marginal costs for production-dependent support instruments. This can result in bids diverging from their marginal costs in case of production-dependent support. Note that in this study, support at negative prices is not considered what is in line with EU state aid guidelines [23]. Therefore, supply bids are capped at €0/MWh.

3.2.2 Input data

The German case study is carried out for the TradeRES scenarios S0 to S4. For each of the scenarios, a single snapshot year is simulated in hourly resolution.

The input data for AMIRIS is derived from the optimisation results of the Backbone model for Germany for each scenario. In particular, the following data sets are employed: installed power generation and storage capacities, their efficiencies, and load data. Moreover, import and export data from Backbone are used, along with the associated electricity prices.

Figure 15 presents the installed capacities for different technologies in Germany, as calculated by Backbone. Each technology is comprised of different types, such as ground-mounted and rooftop in the case of PV. The capacity mix is dominated by PV and batteries, particularly in the case of the scenarios S3 and S4 with high vRES shares. The less flexible scenarios (S1 and S3) require more backup capacity in the form of hydrogen turbines. The investment in wind turbines is relatively low across all scenarios compared to other recent scenarios, *e.g.*, [24], [25].

Furthermore, all other input data is aligned with the Backbone model, applied in WP2 of this project. This pertains to cost data (CAPEX, OPEX, annuity factors), fuel prices, CO_2 emission factors and certificate prices, as well as feed-in potentials of vRES.

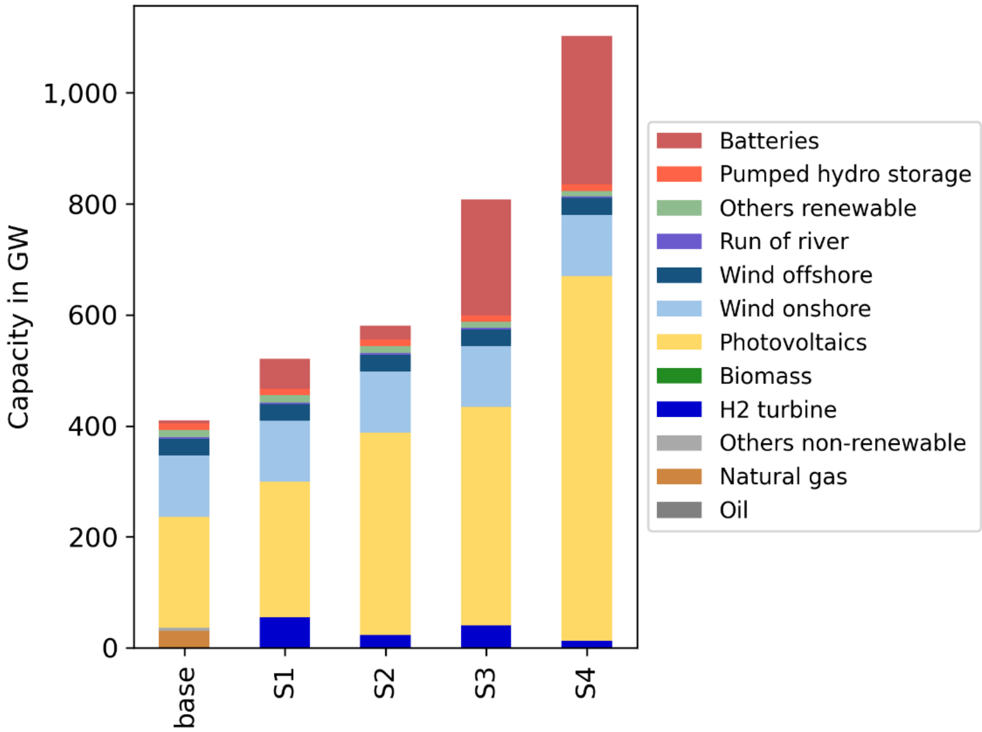


Figure 15. Installed power generation capacities in Germany per TradeRES scenario.

The dispatch of hydrogen electrolyzers as well as demand-side response, i.e. load shedding, is explicitly modelled in AMIRIS. However, the hourly dispatch of other flexibilities, such as storages, flexible heat pumps and electric vehicles, is extracted from Backbone and it is ensured that the same dispatch pattern is applied within AMIRIS. This is done because AMIRIS currently cannot accurately depict competing flexibility options.

The support schemes are parametrized nearly “optimal” in AMIRIS, ensuring that vRES operators recover their costs and that excessive rents do not occur. This is done to guarantee a system which refinances the necessary power plants in an efficient manner. To achieve this, a previous calibration workflow is carried out using AMIRIS, as described in the following.

In a first step, AMIRIS is iteratively run using *MPFIX* as a support instrument. Initially, these runs start with freely chosen technology-specific premia, which are subsequently adjusted run by run based on the resulting annual cost / revenue balance per vRES technology. This process is repeated until the technologies in question have covered their total costs within a 0.1% tolerance band. The next step is to align the parameterization of all other support instruments of interest to achieve full cost recovery as closely as possible. This is done by extracting the support payments and production cost by technology for *MPFIX* and calculating the respective premium parameters for the other support instruments individually.

Consider that the aforementioned support instruments are applied only to vRES, comprising PV, onshore wind and offshore wind. It is assumed that all electricity generated by vRES will be marketed at the day-ahead market. Hence, this analysis does not consider self-consumption, particularly in the case of rooftop PV.

3.2.3 Simulation results and analysis

The following section first presents the results for the TradeRES scenario S1 in detail. This scenario was selected as it represents an average scenario in terms of the most important MPI for the German case study, namely market-based cost recovery. Subsequently, the results are compared across the various TradeRES scenarios for the most relevant MPIs. Please note that for the *FIN-CFD* case, it is assumed that the feed-in potentials for the reference power plant equal those of the actual power plants.

3.2.3.1 Results for scenario S1

- ***Technical MPIs***

Regarding technical MPIs (see Annex A for definitions), the simulations of the S1 scenario revealed the results presented below.

MPI #1 describes the share of RES in electricity consumption (Table 9). Note that the focus is limited to the share of variable renewables, as the RES share is 100% for all constellations considered, because for Germany, there are no fossil generators in the system anymore in scenarios S1-S4. For all remuneration cases considered, the vRES share is about 73% showing only minor differences. The share is lowest for the *2-WAY-CFD* case. This is because of the clawback periods, and related higher market-based curtailment of vRES in this case (see also results on *MPI #17*, market-based curtailment).

Table 9. Share of vRES in electricity consumption across support schemes, scenario S1.

	NONE	**MPFIX**	**1-WAY-CFD**	**2-WAY-CFD**	**CP**	**FIN-CFD**
vRES share (**%**)	73.2	73.3	73.3	72.9	73.2	73.2

MPI #4 addresses the loss of load expectation (LOLE). It is zero 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 scenario S1. Note that this is driven by the given capacity mix from Backbone as well as the assumption of having sufficient capacity in the system, if needed provided by backup reserve plants.

MPI #11, the 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 exceeding willingness to pay, electricity exchange with neighbouring countries, and storage operation. For the S1 scenario, the relative peak load reduction is in some cases negative, up to -1.6%, which corresponds to an increase in peak demand (Table 10). During the planned demand peak, all demand can be met by vRES, creating an incentive for export of electricity in all cases except for *2-WAY-CFD*. This results in an increased realised demand peak in this hour, which also equals to the global demand peak in the simulation year. For the case of *2-WAY-CFD*, the demand peak is lower due to a higher domestic market clearing price resulting from a curtailment period for PV and onshore wind. This price exceeds that of exported electricity. Therefore, there is no export in this case, and the peak load reduction is effectively zero.

Table 10. Relative peak load reduction across support schemes, scenario S1.

	NONE	MPFIX	1-WAY-CFD	2-WAY-CFD	CP	FIN-CFD
Peak load reduction (%)	-1.6	-1.6	-1.6	0	-1.6	-1.6

MPI #17, market-based curtailment, reveals significant differences for the various support schemes, Figure 16. The figure presents the average results for each technology, aggregating the results for different sub-types (*e.g.*, rooftop and ground-mounted PV systems).

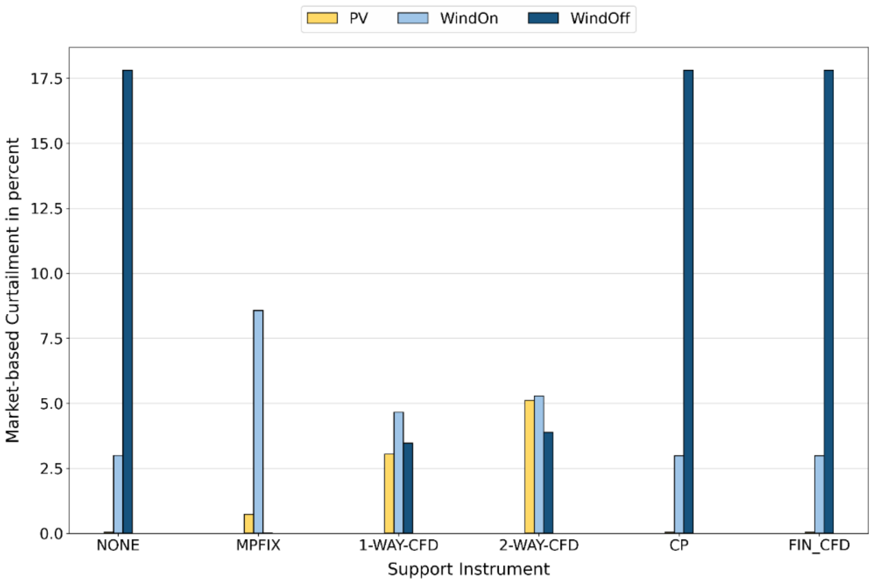


Figure 16. vRES market-based curtailment using different support schemes, scenario S1.

The price limit for the curtailment of vRES installations is determined by their marginal costs and, where applicable, the opportunities from a production-dependent support payment, such as a market premium. Offshore wind is subject to significant curtailment, reaching 18% of its total generation potential in the *NONE* case and for cases where support instruments do not result in dispatch distortions, such as *CP* and *FIN-CFD*. This is due to the higher variable costs assumed for this technology compared to other vRES options.

If *MPFIX* is employed, vRES technology traders factor the value of the premium into their supply bids, which remain constant throughout the year. The opportunities associated with the support payments result in a reversal of the bidding order compared to the above cases. As a result, offshore wind becomes the technology with the lowest bids and is curtailed less. Onshore wind, on the other hand, which requires only a small premium to refinance, bids the highest and is therefore curtailed more.

There are notable differences in the curtailment between *MPFIX* and the production-dependent *CFD* schemes. In the latter cases, the premia and bids fluctuate throughout the year, resulting in a corresponding shift in the curtailment. These variations are particularly evident in the *2-WAY-CFD* case, which is subject to clawback regulations. In this case, when average market values are high in certain months, vRES traders place bids above their marginal costs to compensate of anticipated clawback payments, which ultimately results in an increase in market-based curtailment. Hence, the total vRES curtailment is highest in the *2-WAY-CFD* case.

- ***Economic MPIs***

MPI #27, the system costs for dispatch, reflect the sum of all variable costs, i.e., fuel costs, OPEX, and – where applicable – costs for CO_2 emission certificates. For the S1 scenario, the cost is estimated at on average €19.6 billion per year. The highest costs are incurred for the *2-WAY-CFD* scheme (€19.8 billion per year), which is in line with the lowest vRES share in this case (compare *MPI #1*), and higher production volumes of hydrogen and related costs. The lowest costs occur for cases when support payments do not distort the bidding behaviour of RES as they are either not given or production independent, i.e. for the cases *NONE*, *CP* and *FIN_CFD.* Note that the system costs for dispatch do not comprise cost of the support payments (see MPI #31) or any information regarding cost recovery (see MPI #32).

MPI #28 describes costs to society, Table 11. For the analysis, the electricity price payments and the support payments for end users as well as costs for backup provision are combined and evaluated on a per MWh basis. In terms of this indicator, the case *NONE* performs best, but as shown below for MPI #32 (Cost Recovery), it describes a situation where not all technologies can recover their full costs. Thus, it is not directly comparable in this regard, and rational investors would not be expected to make investments that are not able to break even. Similarly to MPI # 31 (RES Support cost), the *1-WAY-CFD* case also shows the highest costs to society. For the *2-WAY-CFD*, the high value is explained by the observed curtailment effects (MPI #17), which also contribute to the higher electricity price level (MPI #29).

Table 11. Costs to society (total average end-user costs), scenario S1.

		NONE	MPFIX	1-WAY-CFD	2-WAY-CFD	CP	FIN-CFD
Costs to society	€/MWh	91.5	97.1	101.5	98.9	97.5	96.5

MPI #29 describes the weighted average electricity price. The volume-weighted average electricity price at the day-ahead market amounts to between €65/MWh and €69/MWh, with the lowest values for *1-WAY-CFD* and the highest for *2-WAY-CFD* (Table 12).

Table 12. Volume-weighted average day-ahead electricity price, scenario S1.

		NONE	MPFIX	1-WAY-CFD	2-WAY-CFD	CP	FIN-CFD
Average price	€/MWh	65.8	65.5	65.4	69.2	65.8	65.8

For a more comprehensive overview of the distinctions between the support instruments, Figure 17 illustrates the duration curve of day-ahead market prices for the various remuneration schemes.

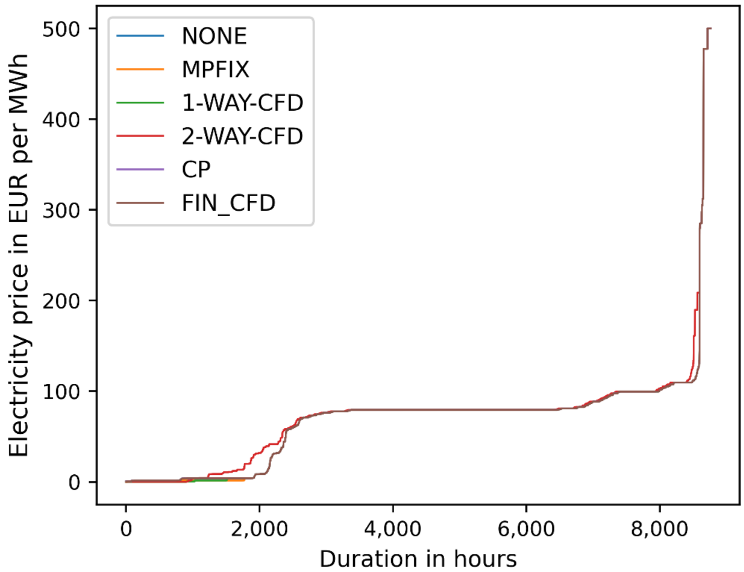


Figure 17. Duration curve of day-ahead market prices for different support schemes, scenario S1.

The price time series for the remuneration cases *NONE*, *CP* and *FIN-CFD* are identical, as in these cases bidding behaviour is not affected by policy instruments. In contrast, in the cases *MPFIX* and *1-WAY-CFD*, vRES traders factor opportunity costs of premium payments in supply bids, which results in slightly lower prices for some hours of the year. The *2-WAY-CFD* scheme has a more significant impact on prices. This is because vRES traders bid at higher prices in some months due to the payback obligations in clawback periods, which results in an increase in electricity prices.

MPI #31, RES support costs, reflect the sum of support that is paid to vRES operators. Results are shown in Figure 18. In specific terms (*i.e.*, total support costs divided by generation), support is highest for PV (€14-23/MWh as weighted average for ground-mounted and rooftop-PV, depending on the support instrument). The reason for this is that (1) PV exhibits a high level of simultaneity, which results in cannibalization of market revenues, and (2) there is a large share of rooftop PV plants (~100 GW) which have higher specific costs. To offset this, support payments must be made. In contrast, support costs for wind are significantly lower, amounting to €-4/MWh (*i.e.*, a net clawback) to €7/MWh for wind onshore, and to €4/MWh to €12/MWh for wind offshore.

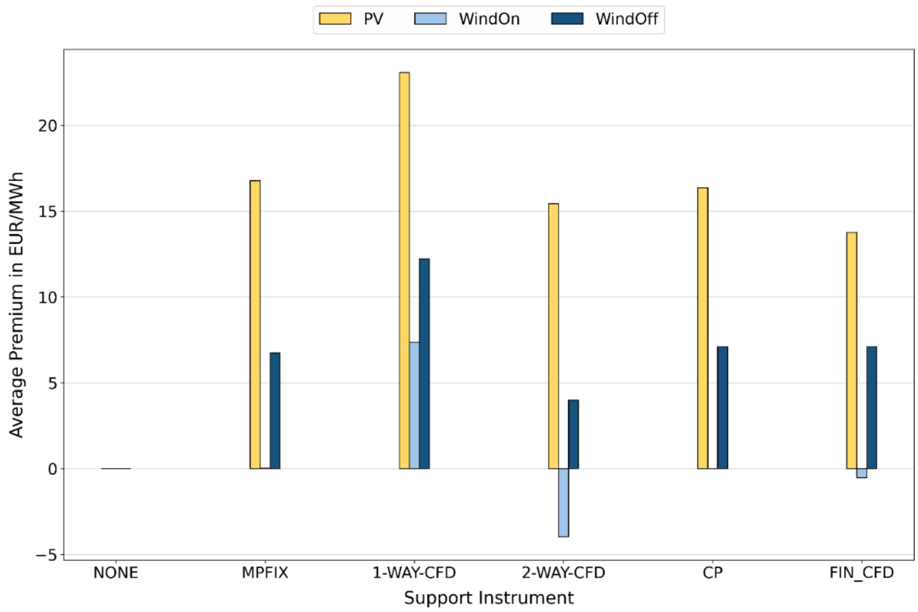


Figure 18. Average premium per vRES technology and support instrument, scenario S1.

There are notable discrepancies among the support instruments. In the cases of *MPFIX*, *1-WAY-CFD* and *CP,* vRES operators have the potential to generate revenues that exceed their total costs in periods with high market values, without being obliged to pay those back. Therefore, these excess revenues are not deducted from the premium payments in these cases. However, this is done in the *2-WAY-CFD* case. Here, excess revenues must be refunded, which reduces the net premium payments paid, eventually becoming negative for onshore wind. In the case of *FIN-CFD*, there is also an implicit obligation to refund excess revenues. The premium is set at a level that exactly covers the operator's costs.

In total, support for all vRES technologies adds up to €3 to €9 billion per year, depending on the support instrument (Table 13). The *1-WAY-CFD* scheme features the highest, whereas the *2-WAY-CFD* shows the lowest annual payments.

Table 13. Annual premium payments per vRES technology and support instrument, scenario S1.

		NONE	MPFIX	1-WAY-CFD	2-WAY-CFD	CP	FIN-CFD
PV	bn € /a	0	4.5	6.1	4.0	4.4	3.7
Wind Onshore	bn € /a	0	0.0	1.7	-0.9	0.0	-0.1
Wind Offshore	bn € /a	0	0.7	1.2	0.4	0.6	0.6
Total	bn € /a	0	5.2	9.0	3.4	5.0	4.2

MPI #32, market-based cost recovery, is depicted below for vRES technologies (Figure 19). The solid bars represent the cost recovery rate from market revenues, while the hatched bars represent the cost recovery rate from support payments.

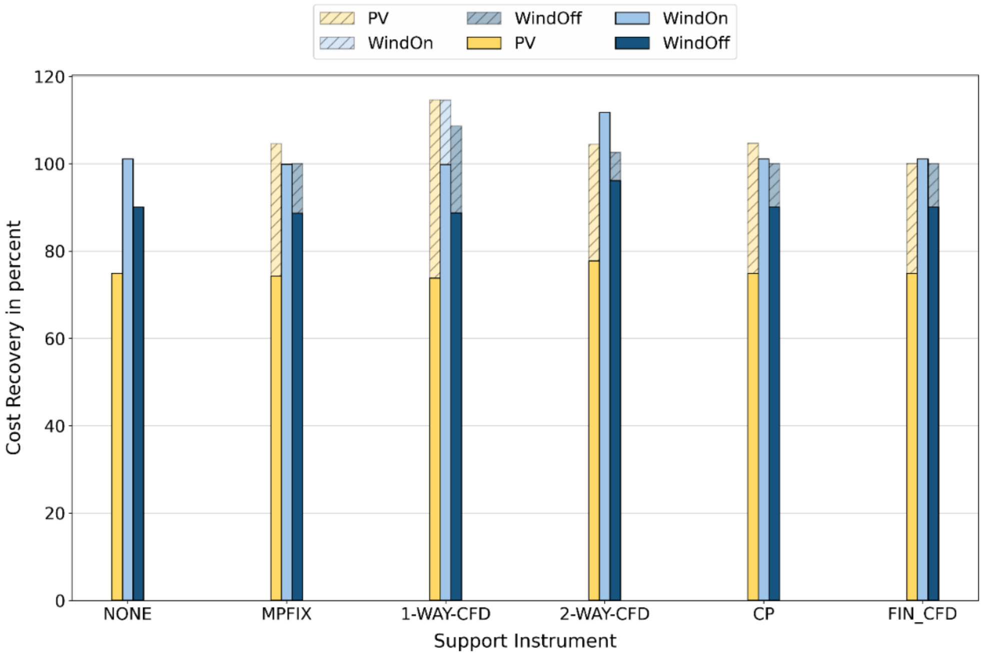


Figure 19. Cost recovery for different vRES technologies and support schemes, scenario S1.

In the considered scenario, market revenues generated by PV and offshore wind are insufficient to cover their total costs, regardless of variations caused by the support instrument. In particular, PV faces low market-based refinancing of around 75% on average, due to the high level of simultaneity and resulting lower market values, compared to wind. However, there are differences in the types of PV. Rooftop PV, which is more expensive, is at a disadvantage (55% market-based cost recovery in case *NONE*), while cheaper newly installed ground-mounted PV can cover its costs via the market (153%).

By contrast, market revenues for wind, particularly onshore wind, are closely at the point of covering costs. Market-based cost recovery rates for the case without support (*NONE*) are at 101% for onshore wind and 90% for offshore wind. The use of a *2-WAY-CFD* results in market revenues clearly exceeding total costs for onshore wind, due to higher electricity prices as a consequence of higher curtailment (see *MPIs #17* and *#29*).

Figure 19 also shows the total cost recovery for the renewable power plants, highlighted by hatched bars. By design, cost recovery is (at least) 100% in all scenarios with a support scheme. Overfinancing, *i.e.*, cost recovery rates above 100%, is possible for those support instruments that do not include a payback obligation for revenues exceeding total cost. This applies to *MPFIX*, *1-WAY-CFD* and *CP*.

It is notable that, despite the underlying concept of the instrument, overfinancing is also evident in the *2-WAY-CFD* case. This is because in this case, the premia are calculated according to the *predicted* generation of vRES, which does not yet consider market-based curtailment. However, the revenues generated for vRES operators are based on the *actual* generation, after curtailment. In this way, vRES operators avoid payback, which effectively increases their revenues and may even exceed their total costs.

As previously stated, for the *FIN-CFD* case, the feed-in potentials for the reference plant are assumed to be equal to those of the actual plant in this study. Consequently, this support instrument will result in 100% refinancing for all vRES technologies.

- ***Environmental MPI***

MPI #45, power system emissions, are zero for the S1 scenario, independent of the support instrument. This is because S1 considers a power system that relies on renewables and (green) hydrogen only.

3.2.3.2 Cross-scenario comparison

This subsection presents a comparison of the impact of varying scenario assumptions on selected relevant MPIs for the German case study.

- ***MPI #32, Market-based cost recovery***

Figure 20 shows the market-based cost recovery for PV (left) and onshore wind (right) across the scenarios S0 to S4. Depending on the scenario and policy instrument, the market-based cost recovery rates vary significantly, ranging from 37% to 98% for PV, and from 72% to 151% for onshore wind.

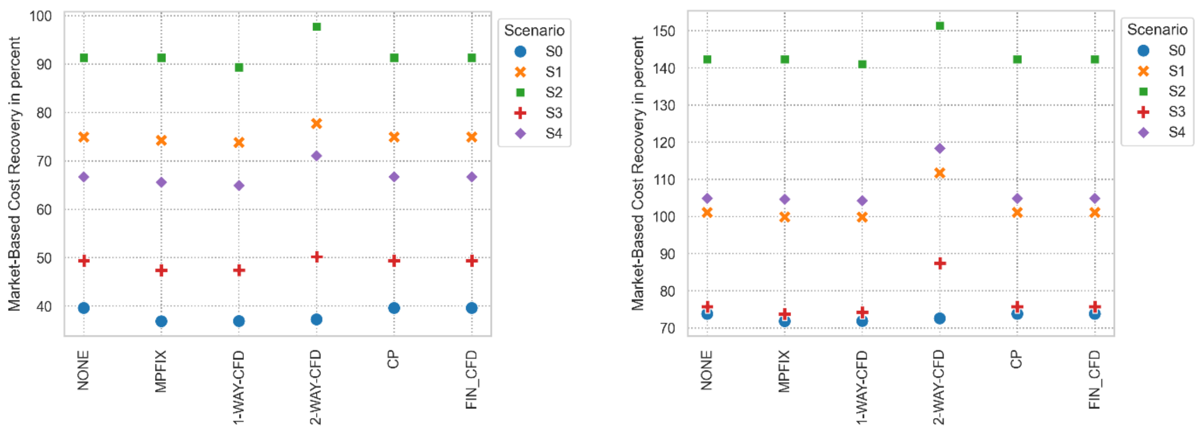


Figure 20. Market-based cost recovery for PV (left) and onshore wind (right) for different support schemes across TradeRES scenarios S0 to S4.

The S2 scenario, which has greater demand flexibility and high hydrogen prices, shows the highest market-based cost recovery rates. The higher hydrogen price lead to higher electricity prices at the day-ahead market, and thus higher market values for renewables, particularly in the winter months. In addition, the scenario-immanent high demand flexibility has a stabilising effect on market values. The latter results in relatively elevated refinancing rates in scenario S4, despite the hydrogen price being lower than in S2. In contrast, in scenario S3, which has the same hydrogen price as S1, the share of renewables is higher than in scenario S1. The merit order effect results in a lower price level, not being compensated by the relatively low use of flexibility in this scenario. Hence, market values, and therefore market-based cost recovery, are comparably low in this scenario.

The S0 scenario has the lowest share of renewables and limited sector coupling. The latter results in lower flexible demand which could stabilise the market values of renewables. Hence, this scenario demonstrates the lowest market-based cost recovery rates, as expected. Except for S0, the *2-WAY-CFD* scheme performs best across scenarios regarding the market-based cost recovery. This is due to the highest electricity prices for this support instrument, which are a consequence of the curtailment effects that occur during clawback periods, as described below. These results reveal that the scenario has a much stronger effect towards market-based cost recovery than the support instrument, given the nearly "ideal" parameterization assumed here.

- ***MPI #17, market-based curtailment***

Figure 21 shows the aggregated market-based curtailment for all vRES technologies across TradeRES scenarios and policy instruments. Values range from 1.3% to 7.4%. The highest level of curtailment is observed in S3. This is due to an imbalance between a relatively high share of renewables (compared to S0 and S1) and low demand flexibility. Scenario S2 shows the lowest level of curtailment.

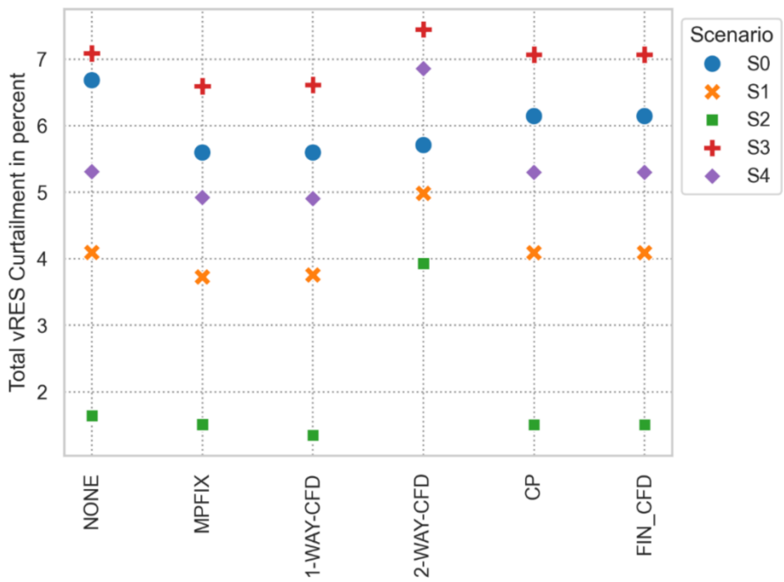


Figure 21. Total relative curtailment of vRES for different support schemes across TradeRES scenarios S0 to S4.

With respect to the policy instruments, the highest levels of total curtailment are observed for the *2-WAY-CFD* case for most scenarios. Therefore, the conclusion that this instrument results in a greater degree of curtailment due to payback obligations during clawback periods appears to be well-founded.

- ***MPI #31, RES Support cost***

Figure 22 depicts the total annual support cost paid to vRES operators. To compensate the low market-based cost recovery as described above, the highest level of support payments is associated with the S3 scenario for most support cases, reaching a total of EUR 21 billion for the *1-WAY-CFD* case. This is in line with the high-RES share in S3 while at the same time, a lack of flexibility compared to S2 and S4 leads to a lack of market value stabilization and thus the need for higher total support payments. The support payments in S4 for all cases but the *1-WAY-CFD* case are below those of S3 except for the much higher PV installations.

In general, the *1-WAY-CFD* scheme has the highest support payments across the scenarios. This is because this one-sided support scheme does not entail any payback obligations for vRES operators during periods with high market revenues. Conversely, this instrument results in high payments for vRES operators when market values are low in certain months, as is particularly the case for PV in S4. In contrast, support payments may become negative for two-sided support cases, reaching a total of EUR -6 billion for the *2-WAY-CFD* case in S2.

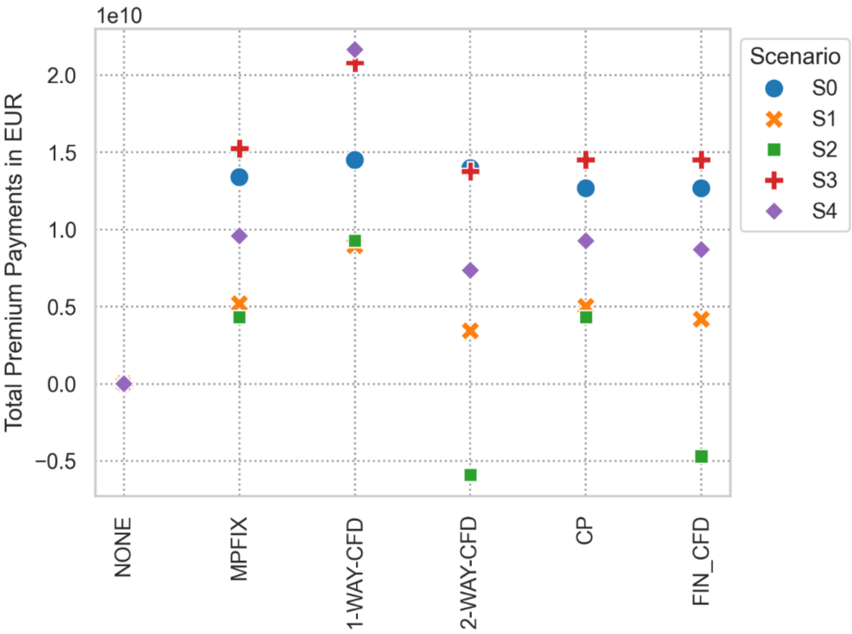


Figure 22. Total premium payments for different support schemes across TradeRES scenarios S0 to S4.

Figure 23 depicts the costs to society, given as the total average end user costs that include electricity prices as well as support payments and also a refinancing of backup capacity. Note that though this metric comprises all cost categories, the systems are not directly comparable as in the *NONE* case, there may be cases where not all costs are recovered. Also, note that the differences in the levels again are strongly driven by scenario assumptions and strongly correlate with assumed hydrogen prices of the scenarios.

Regarding the support instruments, it can be observed that the *1-WAY-CFD* shows the highest costs for society to be ultimately borne by end users, particularly driven by high support costs in this case. For the *2-WAY-CFD*, the second highest values can be observed due to high electricity costs for end users, except for the S2 scenario, which shows negative total support payments (see *MPI #31* above). The *FIN_CFD* shows the lowest values among the support instruments.

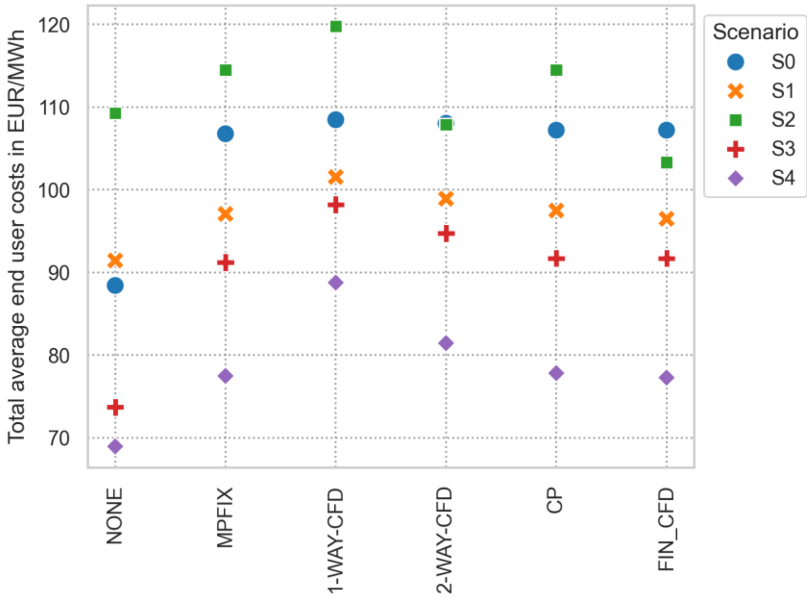


Figure 23. Total average end user costs (costs to society) for different support schemes across TradeRES scenarios S0 to S4.

3.2.4 Final remarks and outlook

The German case study has demonstrated the necessity for support instruments to mitigate the risks associated with vRES investments. This is particularly the case with rooftop PV, which has relatively high costs and cannot generate sufficient income at the market. However, it should be noted that no further opportunities have been accounted for regarding rooftop PV, such as, *e.g.*, the financial incentive for self-consumption for households with rooftop PV.

The results of the analysis reveal that the outcomes are highly sensitive to the underlying assumptions of the scenarios. In particular, the scenario-immanent flexibility of demand and the price of imported hydrogen have a significant impact on market outcomes. It has been found that this drives cost recovery rates to a much greater extent than the support instruments themselves, given the assumed nearly “ideal” parameterization.

All instruments considered guarantee at least 100% refinancing of vRES technologies. A significant finding is that two-way CfDs have the effect of increasing market-based curtailment, leading to higher market prices that benefit the refinancing of vRES, but must be borne by end users.

It should be noted that the parameterisation of all support instruments is based on the assumption of perfect information regarding the market performance of vRES, as reflected in the simulation results. In practice, however, such information is not available for ex-ante designed support instruments such as MPFIX. The parameterisation of the support instruments is therefore idealised in this case study; their efficiency is to be considered a benchmark that is difficult to achieve in reality. In this regard, the different instruments require ex ante prognoses of different parameters: *e.g.*, a CfD scheme requires for a prognosis of the total production costs, *i.e.*, the levelized costs of electricity, which can be prognosed with some degree of certainty, while for a capacity premium or a fixed market premium, an ex-ante prognosis of the cumulated market income over the lifetime is needed, which is highly insecure. These factors also have implications towards financing conditions and costs of capital [26] which is neglected in the prevalent analyses. Also, for the Financial CfD, the newly introduced base risk of deviating from the reference plant [27] is not considered by the simplifying assumption that the plants profile perfectly matches the reference profile. What is more, for instruments that do not foresee any clawback, market participants might factor in some higher additional (uncertain) revenues from markets and bid at lower prices in auctions for determining renewable energy support.

Further research is required to gain a deeper understanding of the deviating risk structures of support instruments and strategic bidding behaviour in auctions for renewable energy support. It would also be beneficial to study additional scenarios and the effect of multiple competing endogenous flexibility sources on market value stabilisation for variable renewable energy sources, considering the strategic behaviour of market actors.

3.3 Case Study D: Iberian market (MIBEL)

The Portuguese and Spanish governments worked together to create the Iberian Electricity Market (MIBEL) to foster the integration of their respective power systems. This European regional electricity market became a reality in July 1st, 2007 [28]. MIBEL comprises the day-ahead and intraday spot markets (based on a double auction mechanism), intraday continuous (based on a pay-as-bid scheme), and derivative markets (*e.g.*, forward and futures) [29]. Furthermore, the Iberian market governing bodies are also responsible for the ratification of all private bilateral agreements for electrical energy acquisition in this European region. Ancillary services in Portugal and Spain are operated independently of MIBEL and managed nationally, by each TSO.

In this second edition of deliverable D5.3, the Iberian market case study focuses on studying the impact of different market bundles (*e.g.*, existing day-ahead market and a (6-hour) period-ahead market – PAM [30]) on vRES performance, the diversification of the participation of renewable producers in different markets through an active strategy bidding in different markets, and the potential vRES participation in ancillary services trading [3].

3.3.1 Models used: MASCEM and RESTrade

TradeRES' Iberian case study uses the Multi-Agent System for Competitive Electricity Markets (MASCEM) and the Multi-agent Trading of Renewable Energy Sources (RESTrade) models and simulation tools. MASCEM models the main market entities and their interactions. Market entities are implemented as software agents, such as market and system operators, buyer and seller agents (consumers, producers, and/or prosumers), and aggregators. MASCEM accommodates the simulation models of three of the main European Electricity Markets (EM), including MIBEL's day-ahead market, the auction-based intraday market, and the continuous intraday market, as well as the double (symmetrical pool) and single-sided (asymmetrical pool) auction models.

RESTrade models the traditional power and energy reserve markets, supporting the participation of conventional dispatchable power plants, variable renewable energy systems, and demand players in the system balance. Furthermore, it also includes newly designed models for balancing markets and the imbalance settlement according to the new European legislation and other changes to improve the efficiency of these markets considering the: i) separate procurement, ii) marginal prices, iii) non-discriminatory access, and iv) fair cost distribution [31], [32]. Figure 24 illustrates the MASCEM-RESTrade coupling workflow.

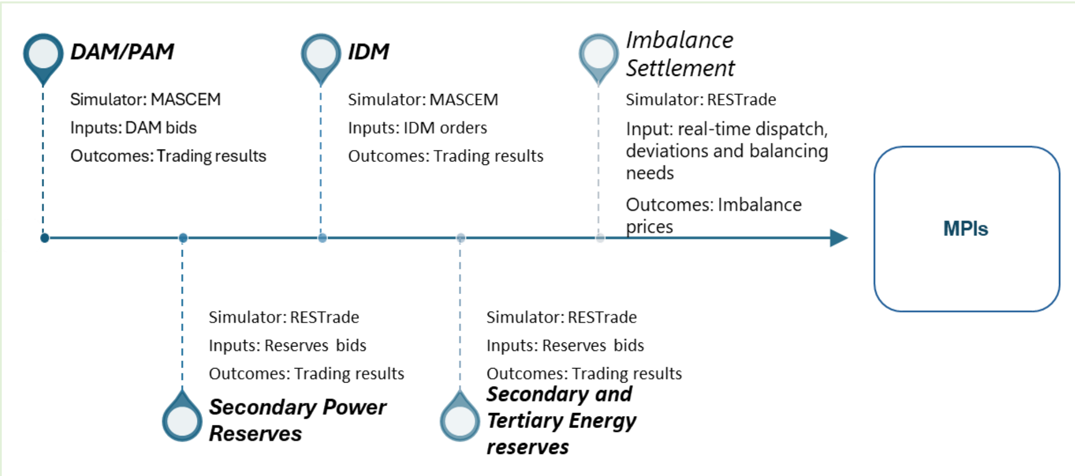


Figure 24. MASCEM-RESTrade coupling workflow.

For the analysis of market bundles, the strategic participation of RES producers, and the potential vRES participation in ancillary services trading, the following instruments have been considered:

- *Day-ahead market (DAM):* The current market design in use in Europe for the single day-ahead coupling (SDAC) [29].
- *Period-ahead market (PAM):* A new market design proposal to be compared with the current day-ahead market design [3]. This market design aims to support the integration of vRES by improving their power forecast accuracy [30], which in turn helps to reduce the balancing needs and overall system costs. Additionally, it can enhance the grid flexibility and the emergence of technologies/solutions capable of providing the necessary flexibility in short-term. In this case, PAM involves bidding for 6 hours ahead, with four updates throughout the day. The remaining configuration of this market is identical to the existing DAM.
- *Intraday Continuous market (IDM):* The current Iberian single intraday coupling (SIDC) model, which integrates MIBEL is a Pan-European intraday continuous cou-

pling [29]. This design provides low liquidity to vRES that tend to bid closer to each session end to avoid large forecast errors. After testing and presenting the results of the SIDC to the advisory board, it is considered continuous bidding but not trading, being the market cleared by the end of each session to give priority to vRES, using the SIDC pay-as-bid scheme.

- Cross-border power flow validation and market splitting detection due to overhead power lines congestion was applied, considering the seasonal line rating in 2030 and dynamic line ratings in 2050 [33].
- Secondary Reserves: The current designs in both Portugal and Spain were simulated, but considering the separate procurement of upward and downward power and allowing the participation of vRES. This reserve was modelled and implemented using the procurement of power based on the ENTSO-E guidelines [34].
- Tertiary Reserves: The participation of vRES in this market was permitted in this case study. In Portugal, this is contrary to the current rules. In Spain, wind already participates actively in this market while solar PV participates only in a pilot project [35]. Both reserves have also been adapted to the PAM, closing after the PAM and trading in the same periods as the PAM.
- Imbalance Settlement: It has been considered that the Portuguese mechanism is applied in both countries. This mechanism passes all balancing costs to BRPs equally and independently of the balance direction.

It should be noted that the models used in this case study do not simulate or study investment 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].

3.3.2 Input data

The MIBEL case study is carried out for the TradeRES scenarios S0 to S4 (see Figure 2). For each of the scenarios, a single snapshot year is simulated in hourly resolution. The input data for the models used are derived from the optimisation results of the Backbone model for Portugal and Spain for each scenario. In particular, the following datasets are used: installed power generation, storage characteristics (capacities, generation and storage efficiencies), and real-time demand data. Moreover, cross border data capacities are also used within Backbone. The cross-border capacities in MIBEL are computed using seasonal line ratings in 2030 and dynamic line ratings in 2050 [36].

Figure 25 presents the optimized installed capacities for the different technologies in Portugal and Spain, as determined in WP 2 of the project, for the characteristics of the five scenarios (S0 – S4) developed in TradeRES project.

Figure 25 illustrates how different power generation technologies evolve and contribute to the energy mix as the scenarios progress towards a near 100% RES power system. The capacity mix is dominated by solar photovoltaic and wind (onshore) power generation, particularly in the case of scenarios S3 and S4 for Portugal, and S2 and S4 for Spain. Scenarios S2 and S4 require a higher installed capacity for Spain, while S3 and S4 present higher vRES capacities.

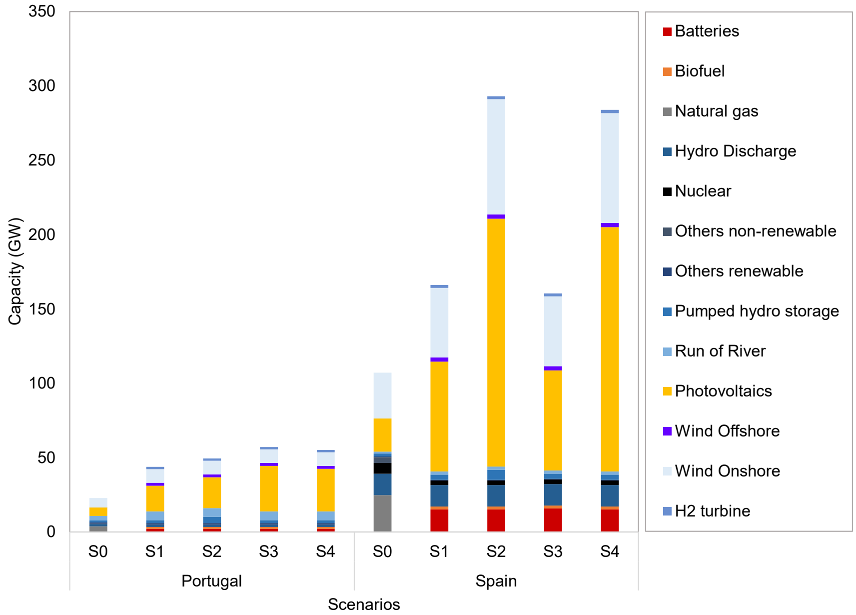


Figure 25. Installed power generation capacity by technology in Portugal (on the left) and Spain (on the right) per scenario.

The most significant investments in Portugal across all scenarios are in photovoltaic and wind-based (e.g., onshore and offshore) generation technologies. In turn, the most significant investments in Spain are in those technologies, but also in batteries. In all scenarios, both countries decommissioned natural gas (CCGT – combined cycle gas turbines), while Spain also decommissioned other still existing non-renewable technologies and part of nuclear capacity. These investments and disinvestments are reflected not only in the technologies' capacities, but also in the number of players per technology participating in each scenario.

The outcomes of the scenarios reflect the clear transition towards renewable energy technologies and a reduction in the reliance on fossil fuels in the future. Additionally, new capacity related to residential heating and cooling, as well as electric vehicles and electrolysers, will play an increasingly important role in the energy mix across all future scenarios. Details regarding the outcomes of the Backbone model can be found in the public deliverables and databases from TradeRES´ WP 2.

In addition to the Backbone data, in this case study, to generate bids that reflect the reality as close as possible, data from the DAM and IDM (*e.g.*, the total number of units bidding in a specific hour) have also been gathered from the Iberian market operator (OMIE) [29] and used in the simulations.

3.3.2.1 Bids generation in MIBEL case study

Given the competitive EM models provided by MASCEM, and aiming to reproduce as faithful as possible the Iberian reality, the market players' bids are generated having in mind the total amount of energy available per technology in each simulation scenario and ensuring that selling bid prices are always greater or equal to each technology's marginal costs. It should be noted that, using the marginal cost of each technology for the bid price would result in the same as having one player per technology bidding, hindering the competitive nature of the liberalized EMs and failing to properly reflect typical market operations.

One difference regarding the optimal solution provided by Backbone is that hydroelectric power plants bid based on the social value of water according to the reservoir level. The use of this value allows to mimic the behaviour of market participants using this technology, as they can strategically bid based on the abundance or scarcity of water in the reservoir. The social value of water has been modelled to be first in the market merit order than gas power plants (in 2030) and other dispatchable renewable generation (in 2050) where the reservoir level is above 50%. Furthermore, hydroelectric power plants can push out nuclear power plants from the market where the reservoir levels are above 90%. As the last resource to avoid forced load shedding, hydroelectric power plants are only used after demand side response when their reservoir content is below 10% [37].

Figure 26 presents the social value of water in Spain and Portugal during 2030, based on the observed national (mainland only) aggregated reservoir data from both TSOs for the year 2019.

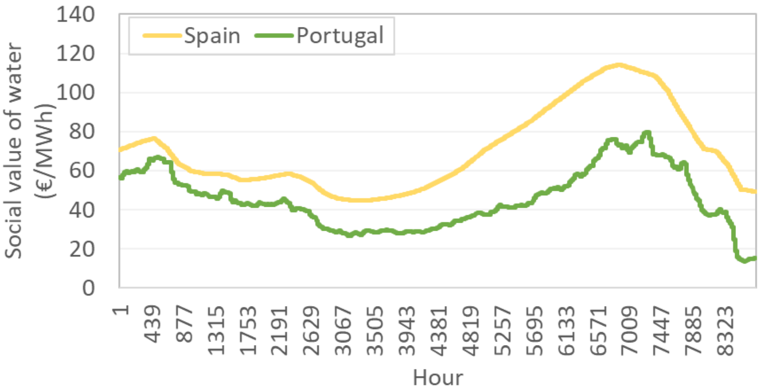


Figure 26. Illustration of the social value of water used in Portugal and Spain.

- ***Bids generation for DAM/PAM***

Regarding the generation of DAM/PAM bids, significant effort was given to produce input data as realistic as possible. To this end, OMIE's data from 2022 [38] was used to identify existing players, their units, and technologies. Equation 1 presents the mathematical formulation of the bid generator regarding the energy volume distribution.

$$Bid^{volume}_{(sce,tec,unit,p,d,m)} = \begin{cases} \dfrac{Bid^{Volume\ 2022}_{(tec,\ unit,p,d,m)}}{\sum_{unit=1}^{Ninit}\left(Bid^{Volume\ 2022}_{(tec,\ unit,p,d,m)}\right)} \times Volume^{sce}_{(tec,p,d,m)}\ if\ unit \in 2022 \\ \dfrac{Capacity^{sce}_{(tec,unit)}}{\sum_{unit=1}^{Ninit}\left(Capacity^{sce}_{(tec,unit)}\right)} \times Volume^{sce}_{(tec,p,d,m)}\ if\ unit \notin 2022 \\ Volume^{sce}_{(tec,p,d,m)}\ if\ unit\ has\ individual\ forecast \\ \forall sce \in Nsce, \forall unit \in Nunit, \forall p \in Np, \forall d \in Nd, \forall m \in Nm \end{cases} \quad (1)$$

where, sce identifies the scenario, $Nsce$ is the total number of scenarios, tec identifies the technology, $unit$ identifies the player's unit, $Nunit$ is the total number of units, p identifies the trading period, Np is the total number of periods, d identifies the day, Nd is the total number of days, m identifies the month, Nm is the number of months, $Bid^{volume}_{(sce,tec,\,unit,p,d,m)}$ represents the bid's energy volume per scenario, technology, unit, period, day, and month, $Bid^{Volume\ 2022}_{(tec,\,unit,p,d,m)}$ represents the bid's energy volume executed in 2022 per scenario, technology, unit, period, day, and month, $Volume^{sce}_{(tec,p,d,m)}$ represents the scenario's total energy volume available per technology, period, day, and month, and $Capacity^{sce}_{(tec,unit)}$ represents the scenario's capacity per technology and unit.

If a unit existed in OMIE's 2022 data, its bidding volume for a given scenario is set according to its bidding volume ratio in 2022. In the case of being a newly added unit, its bidding volume is set in accordance with the unit's capacity ratio within the given technology. Finally, are also considered renewable-based units with specific energy volume forecasts per trading period, day, and month are also considered.

Forecasts are based on the results reported in the second edition of D4.9 [30], and upscaled to each scenario's installed capacity. Data from several wind and solar PV power plants in Portugal and Spain were available, and the first step involved obtaining forecast data for each plant taking into account the nominal capacity in 2019. These forecasts were then upscaled proportionally to the installed capacity in each scenario. This approach allows the participation of vRES players with different generation profiles, and, consequently, diversifying bids in the MIBEL. Thus, all steps previously described allowed the diversification of the generated bids, aiming to replicate the bidding of renewable-based generators. In the strategy implemented across various simulations in this case study, vRES players bid based on their forecasts for DAM/PAM by: i) submitting the full hourly forecast values, or ii) bidding 80% of the forecast. In the latter case, the remaining 20% is reserved for participation in balancing markets. Equation 2 presents the mathematical formulation for the bid prices definition.

$$\begin{gathered} Bid^{price\ sce}_{(tec,\,unit,p,d,m)} = marginal\ cost_{(tec)} \times nrand\left(down_{(tec)}, up_{(tec)}\right) \\ \forall sce \in Nsce, \forall unit \in Nunit, \forall p \in Np, \forall d \in Nd, \forall m \in Nm \end{gathered} \tag{2}$$

where, $Bid^{price\ sce}_{(tec,\,unit,p,d,m)}$ represents the bid price per scenario, technology, unit, period, day, and month, $marginal\ cost_{(tec)}$ represents the technology's marginal cost, and $nrand\left(down_{(tec)}, up_{(tec)}\right)$represents a random number determined between the technology's upper ($up_{(tec)}$) and bottom ($down_{(tec)}$) limits.

Bid prices are determined by multiplying the respective technology's marginal cost or water value by a random factor within a specified range (+/-10%, batteries (charge and discharge), biofuel, electrolyser, gas, hydro discharge, load, nuclear, other non-renewable and renewable sources, as well as pumped hydro storage (PHS) for both charging and discharging). On the other hand, there are technologies with fixed factor, including demand side response (DSR), electric vehicles (EV), run-of-river hydro (ROR), solar CSP, solar PV (both residential and large-scale), wind (onshore and offshore), hydrogen turbines, and residential heating and cooling system. The corresponding range varies according to the unit's technology type. Thus, bid prices fluctuate within the same technology, aiming to introduce price volatility and competitiveness among players of the same technology, trying to represent real-world scenarios.

- ***IDM orders generation***

The generation of IDM orders, in turn, considers the untraded volume of the DAM, updated forecasts for PV and wind-based units, and the units allocated to the secondary reserves. For each simulation scenario, a forecast dataset and a list of units allocated to the secondary reserves are considered.

The units allocated to reserves may or not participate in the IDM, depending on the amount of energy volume allocated to the reserves markets. Solar and wind-based units adjust the energy traded in the DAM according to updated generation forecasts (closer to supply) and if they have surplus, they submit selling orders to IDM, otherwise, they submit buy orders to fulfil the volume traded in DAM that may lack. Load units also set their IDM orders based on updated consumption forecasts. Similarly, if these units have energy surplus, they submit selling orders to the IDM, otherwise, they submit demand orders to satisfy the required demand. The remaining units, only trade in IDM if they have untraded volume from the DAM.

IDM order prices also vary according to the technology and transaction type. Load units submit buying orders with the maximum allowed price, *i.e.*, 4000 EUR/MWh, to ensure the acquisition of the required demand. If selling, these units submit orders with prices varying between the DAM clearing price and 10% above. Power generation units, in turn, submit selling orders with prices set to 0 EUR/MWh, to ensure the energy dispatch. And, if buying, they set their orders' price between 10% below the DAM clearing price and the DAM clearing price. The approach previously described is also applied when the PAM is considered.

- ***Reserves orders generation***

Power bids to the secondary reserve (SecR) are based on the programmed dispatch of the DAM/PAM and the available capacity of each fast-response power plant. In the strategic scenarios (see section 3.3.3), vRES bids 20% of their expected deterministic power forecast for upward regulation and their DAM/PAM programmed dispatch for down-regulation. The value defined for upward regulation considered the almost certain real-time dispatch of vRES. Price bids are based on the real bids [39] used in the starting point scenario (2019) and presented in the first version of this deliverable.

Energy bids for the SecR are based on the clearing bids of the secondary power market. Price bids are based on the outputs of the DAM/PAM and the marginal prices of the power plants. Bids not cleared in the secondary market are carried over to the tertiary reserve (TR) market, along with bids from players who can only participate in the tertiary market due to their technical capabilities. Bids to the tertiary energy market are fixed after clearing the IDM.

3.3.3 Simulation results and analysis

Table 14 displays the market design variations studied in each simulation scenario of the Iberian case study, which were defined considering the research questions formulated for this case study.

Table 14. Market bundles studied per simulation scenario in the Iberian case study.

Scenario	Market Design	Simulation designation	Price Strategy	Energy Strategy
S0	DAM + SecR + IDM + TR	S0_DAM_Simple	Simple	NA
	PAM + SecR + IDM + TR	S0_PAM_Simple	Simple	NA
	DAM + SecR + IDM + TR	S0_DAM_Strategic	Strategic	✓
	PAM + SecR + IDM + TR	S0_PAM_Strategic	Strategic	✓
S1	DAM + SecR + IDM + TR	S1_DAM_Strategic	Strategic	✓
S2	DAM + SecR + IDM + TR	S2_DAM_Strategic	Strategic	✓
S3	DAM + SecR + IDM + TR	S3_DAM_Strategic	Strategic	✓
S4	DAM + SecR + IDM + TR	S4_DAM_Strategic	Strategic	✓

According with Table 14, the main scenario variations in the simulations performed within the Iberian case study are the:

i) **market design** (*DAM* or *PAM*) with changes in the trading/gate closure,
ii) **the price and energy** (*Simple* or *Strategic*) **strategies** used in the DAM/PAM bid generation that can be applied by market participants, and
iii) **the TradeRES scenarios**, which allow **the assessment of market performance under nearly 100% RES power systems**.

Concerning the optimal solution obtained in Backbone, the *simple* strategy bidding scenarios consider the social value of water, and a random value is applied to the marginal prices of each technology (as presented in equation 2). In the *strategic* bidding scenarios, that represent an active participation of vRES players, in addition to the previous assumptions, 20% of the DAM/PAM vRES hourly energy forecast is allocated to allow the participation of these players in the reserve markets, and the remaining energy (80%) is bid in the DAM/PAM. This assumption was based on preliminary work presented in [40].

The following section focuses on the MPIs analysis for scenario S0, where different market designs, price and energy strategies are analysed. Then, the results of the MPIs for scenarios S1 – S4 are presented. Details on the calculation of MPIs can be found in Annex A.

3.3.3.1 S0 results' analysis

To compare the different scenario variations according to combinations of market designs with price and energy bidding strategies, technical, economic, environmental, and social MPIs are analysed. From the MPIs list defined in the scope of the TradeRES project, only the ones adequate for MASCEM and RESTrade ABMs have been selected. The MPIs are presented for Portugal (PT) and Spain (ES).

- ***Technical MPIs***

The technical MPIs aim to compare the various market design options from a technical point of view to assess their performance.

MPI #1 indicates the level of integration of RES in electricity consumption as it is important to understand the position of the different energy mix scenarios analysed in the pathway for a nearly 100% RES power system, Figure 27.

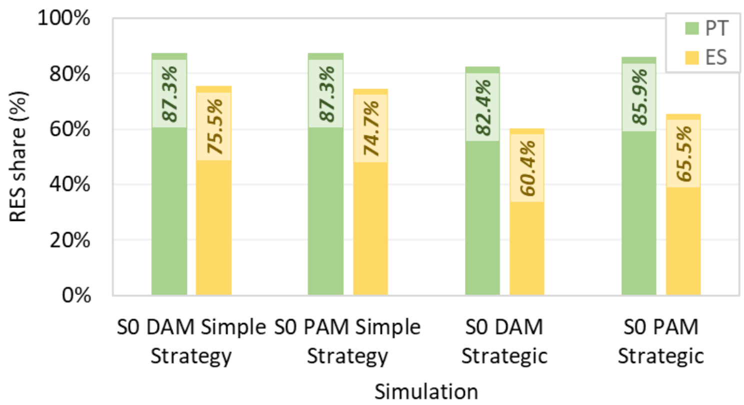
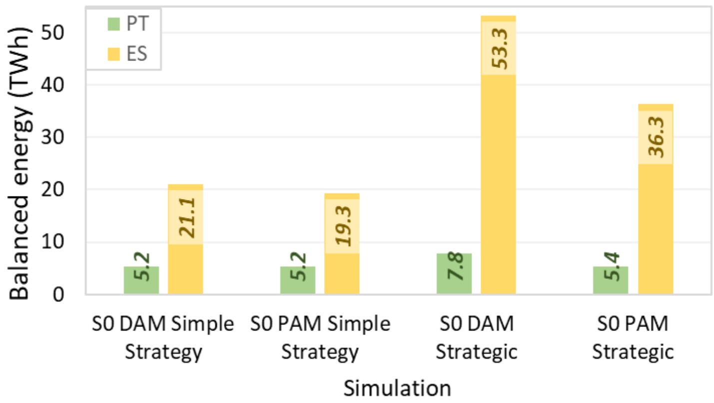


Figure 27. Share RES integration in the electricity consumption in Portugal and Spain.

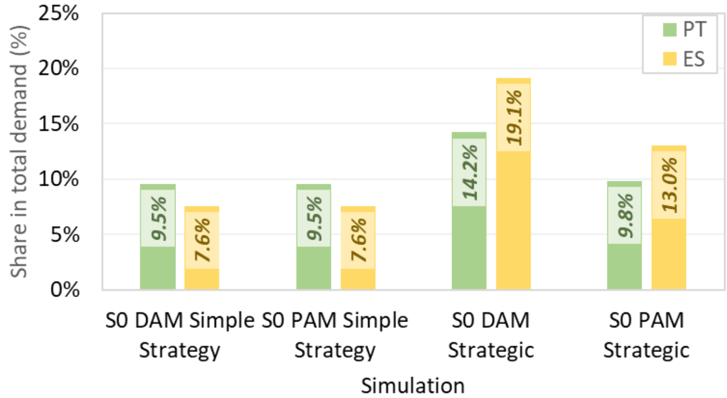
The results from the previous figure show RES share values ranging from 82.4% to 87.3% in Portugal and from 60.4% to 75.5% in Spain. In both countries, the *simple strategy* simulations consistently lead to higher RES share values. Nevertheless, in Portugal, the impact of this bidding strategy is relatively small, with differences of around 6%, while in Spain, the differences can reach up to 15%. In the *simple strategy*, vRES bid their full expected production, maximizing the RES share. However, when providing balancing services, vRES may need to curtail some of their power, reducing their overall share, as can be seen in the strategic simulations. Consequently, part of the 20% allocation for balancing reserves may remain unused. In the strategic PAM (compared with DAM), the balancing needs are lower due to the improvements in the power forecast accuracy. Therefore, vRES will provide less balancing energy, increasing their share. In Portugal, the sensitivity to *strategic behaviour* in the RES share is reduced. For Portugal, the RES share in the balancing services is lower (*MPI #16*) as well as the vRES curtailments (*MPI #17*), when compared to Spain.

MPI #4 (LOLE) and ***MPI #5*** (EENS) are 0 meaning that, even in scenarios with high share of RES both power systems analysed did not face periods with i) reduced security of supply and ii) LOLE and EENS values above the technically defined limits between 3 to 8 hours per year [41]. In addition, no load shedding event (***MPI #8***), usage of demand side response (***MPI #10***), or peak load reduction (***MPI #11***) occurred in these scenarios. Similarly to the description in the German case study, these results are influenced by the capacity mix provided by Backbone, as well as the assumption of having sufficient capacity in the system, which can be supplied by backup reserve plants if needed.

MPI #12 presents the results for energy procurement in ancillary services (AS) for the Iberian market (Figure 28), with the goal of assessing the impact of the two bidding strategies analysed in this case study.



a)



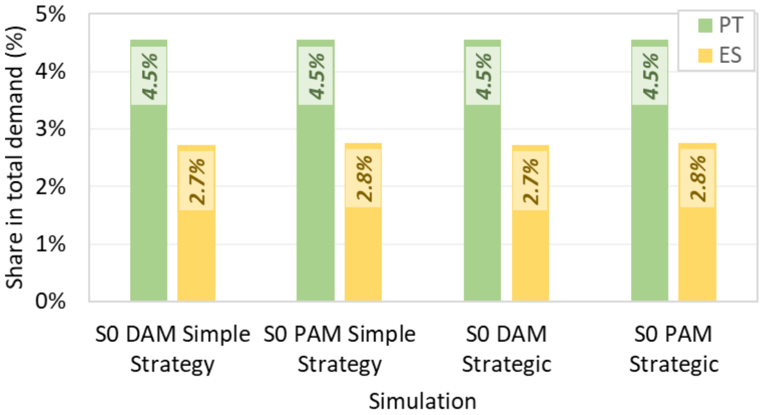
b)

Figure 28. Energy procurement in the ancillary services in the Portuguese and Spanish power systems: a) balanced energy, and b) share in the total demand.

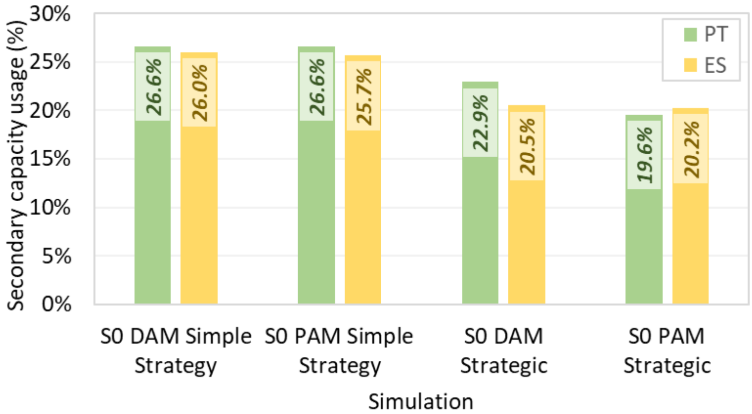
In addition to the energy procurement for AS, in this figure, the share that it represents in the total demand is also depicted, for a better comparison according to each country. Spain allows players to participate in imbalance resolution mechanisms, which occur after the continuous intraday markets and before balance control. Additionally, by permitting vRES to participate in AS, Spain can manage some of the vRES deviations, thereby reducing the overall need for curtailments. In this case study, it was assumed that in *simple strategy* simulations vRES cannot participate in the balancing markets, while in the *strategic* simulations they can.

In the *strategic* simulations, vRES are bidding only 80% of the deterministic forecast in the DAM/PAM, reserving 20% for providing (if needed) balancing services. Therefore, as depicted in Figure 28, the strategic behaviour leads to an increase in the balancing needs. This effect is particularly pronounced in the DAM, where the largest vRES power forecast errors are observed (see MPI #25).

MPI #13 analyse the capacity procurement in AS normalized to the total demand and the capacity usage (***MPI #14***) for the different simulations, Figure 29.



a)



b)

Figure 29. a) Capacity procurement in ancillary services relative to the total demand, and b) usage.

Regarding the capacity procurement, only a slight difference between the DAM and PAM scenarios occurs due to a better load forecast accuracy in the PAM scenarios. The simulation results depicted in Figure 29a) indicate that both countries are reserving more capacity in the SecR market than is really needed to balance the system. The typical procurement of secondary power (Figure 29b)) results in a capacity usage, on average, below 27% regarding the allocated power. These values are even lower in the *strategic* simulations, ranging from 19.6% (S0 PAM strategic in Portugal) to 22.9% (S0 DAM strategic in Portugal). Results highlight the inefficiencies of the existing approach, and, therefore, a more dynamic methodology should be developed to ensure system balance while maintaining sustainable resource usage and costs [33].

MPIs #15** and **#16 analyse the participation of demand and vRES in AS. While demand-side players (*MPI #15*) have a 0% share, as expected, only the *S0 DAM Strategic* and *S0 PAM Strategic* simulations - employing price and energy strategies - show vRES participation in ancillary services (Figure 30).

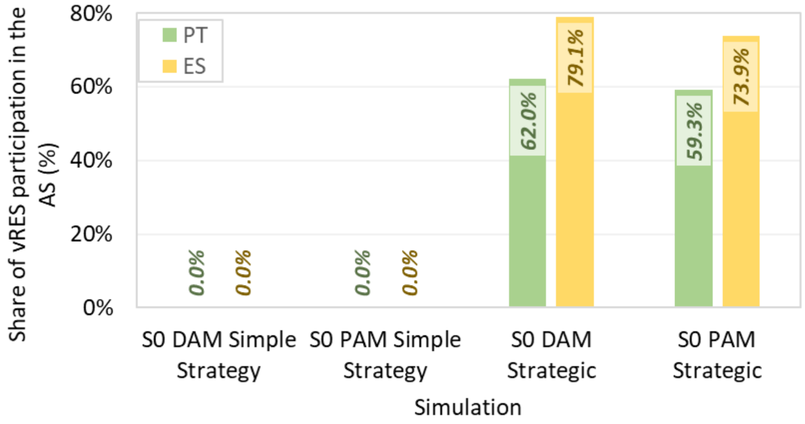


Figure 30. Share of vRES participation in the ancillary services in Portugal and Spain.

According to Figure 30 (*MPI #16*), in Spain, vRES participation ranges from 73.9% to 79.1% across secondary capacity, tertiary energy, and the imbalance resolution mechanism, respectively. For Portugal, these values are lower, ranging from 59.3% to 62.3%. The vRES participation is higher in the DAM scenario due to the balancing needs are also higher as can be seen in MPI #12. Is worth mentioning that vRES become the main provider of balancing services in the *strategic* simulations since they allocated 20% of their forecasts to support balancing mechanisms. This *strategic* behaviour influences the annual curtailment of market-based energy from vRES (***MPI #17***), Figure 31, *i.e.*, the amount of energy curtailed due to market-based incentives and/or limitations (*e.g.*, energy that cannot be balanced or that leads to grid congestion).

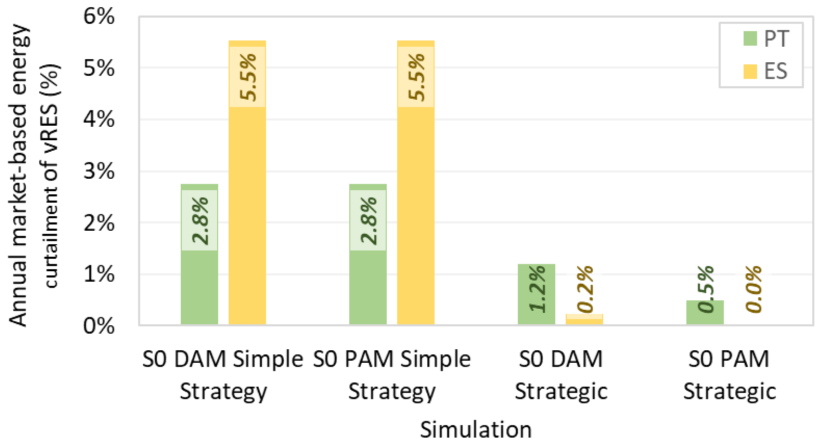


Figure 31. Annual curtailment of market-based energy from vRES.

The annual level of curtailment is significantly reduced in the *strategic* simulations for both countries, with a maximum value of 1.2% observed in Portugal in the *S0 DAM strategic* simulation. Through the active participation in balancing services, vRES avoid forced curtailments, reaching practically 0% in the PAM strategic simulation due to the improved forecast accuracy. This improvement can be quantified using the normalized root mean square error (NRMSE) of the power forecasts (***MPI #25),*** Figure 32. A detailed discussion of the forecast methodology and results can be found in D4.9 Ed. 2 [30]. The NRMSE are presented on a national aggregated scale for wind and solar PV technologies in Portugal and Spain. The normalization is computed based on the average of the observed power production values for each country.

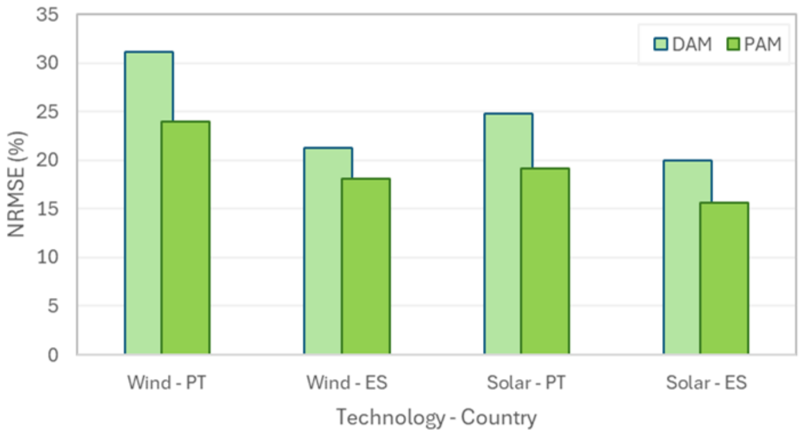


Figure 32. Normalized root mean square error (NRMSE) for wind and solar PV in Portugal and Spain.

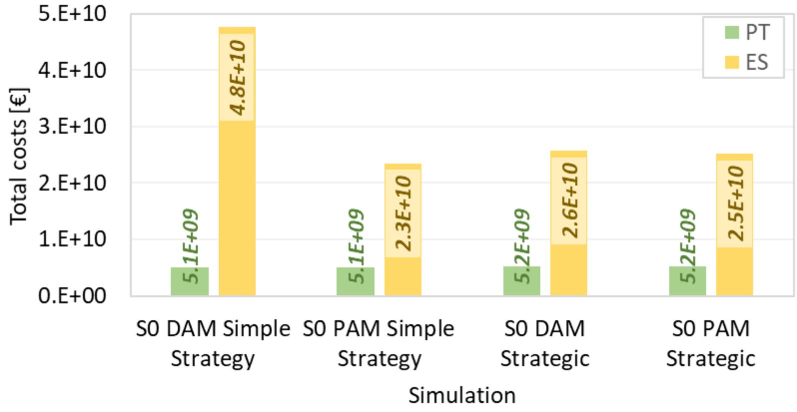
According to Figure 32, a decrease of over 7% in NRMSE was observed for wind power when PAM timeframes were used instead of DAM. The reduction was less pronounced for solar power but still exceeded, on average, 4 % in both countries. Thus, PAM design reduces the forecast errors when compared with the DAM design. Additionally, the results for Portugal showed lower performance compared to Spain. This can be partly attributed to the low wind and solar PV installed power capacity in Portugal, which reduces the potential benefits of power smoothing, thereby limiting improvements in forecast accuracy [42], [43].

- ***Economic MPIs***

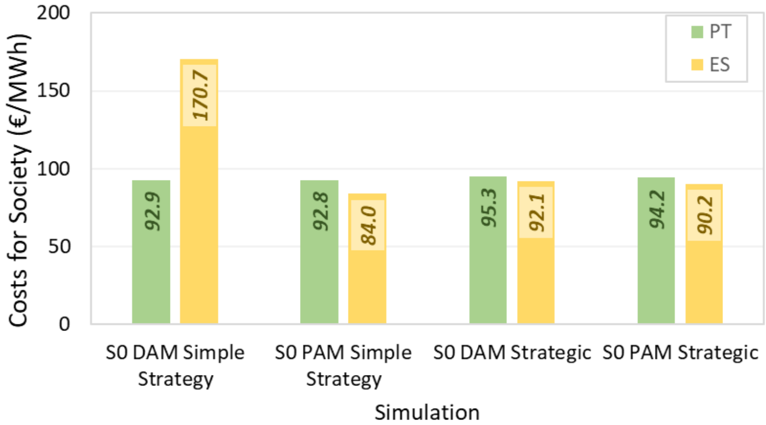
The economic MPIs aim to assess the economic efficiency of the different market designs proposed in the project.

MPI #26 and ***MPI #28*** enables to determine the total system costs and the costs for society, respectively (Figure 33). This MPI includes investment, O&M and fuel costs [44], that were extracted from the Backbone's database [16].

In the DAM *simple strategy* scenario more dispatchable power plants such as CCGT are used to provide balancing services, increasing the final costs. The costs of the PAM are lower than in the DAM *simple strategy.* In Spain due to the high dispatch costs associated with high level of gas production (see *MPI #27*). The *strategic* behaviour of vRES increases DAM/PAM and balancing prices, contributing to a global trend in market-based cost recovery for power plants. For Spain, the *strategic* behaviour reduces the system costs in the DAM but increases the remuneration of vRES. Despite the previous analysis, externalities factors such as support schemes should also be computed to fully assess the benefits of the strategic behaviour of vRES on the overall system costs.



a)



b)

Figure 33. a) Systems total costs and b) costs for society in Portugal and Spain.

MPI #27 provides the total costs for dispatch, including fuel, emissions, and load shift, Figure 34.

In the strategic scenarios, more power plants with higher marginal costs are used because 20% of the vRES energy is out of spot markets, and in the DAM simple strategy they are used to balance vRES, having the PAM *simple strategy* the lowest operational costs. In 2030, Spain has a substantial installed capacity for gas, whereas Portugal's gas capacity remains relatively low. Since gas and hydro are the primary providers of balancing services, relying on these technologies results in high dispatch costs, especially when addressing significant balancing needs in the DAM *simple strategy* scenario (see *MPI #12)*. To further understand the values achieved, ***MPI #29*** presents the annual average day-ahead/period-ahead prices weighted by the traded energy (VWAMP), Figure 35.

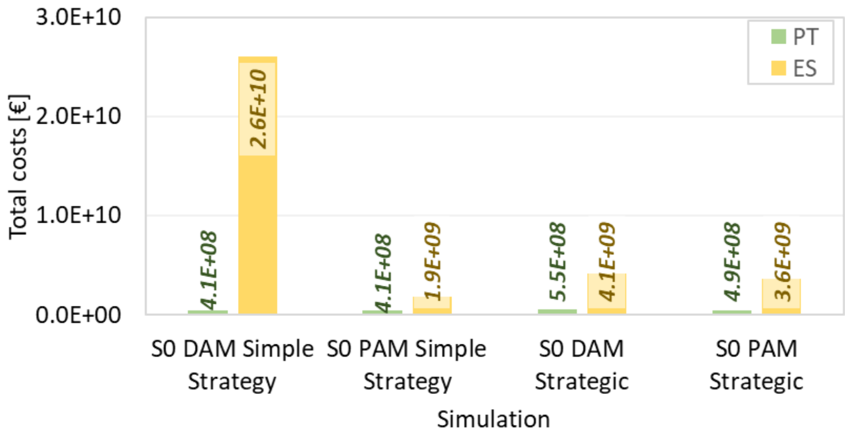


Figure 34. Total costs for dispatch.

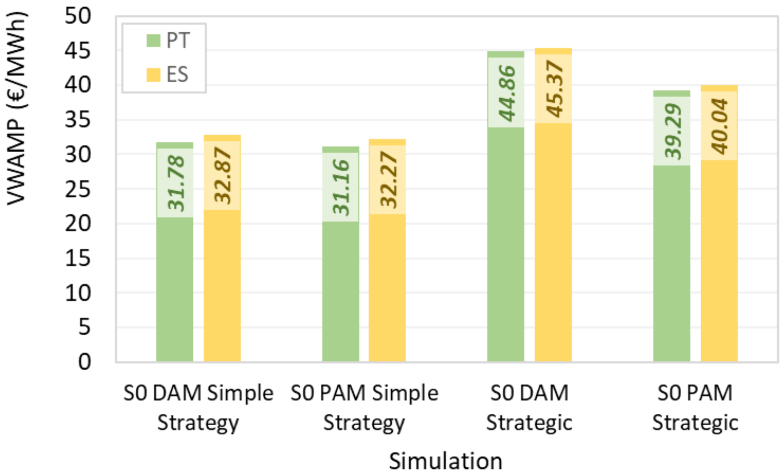
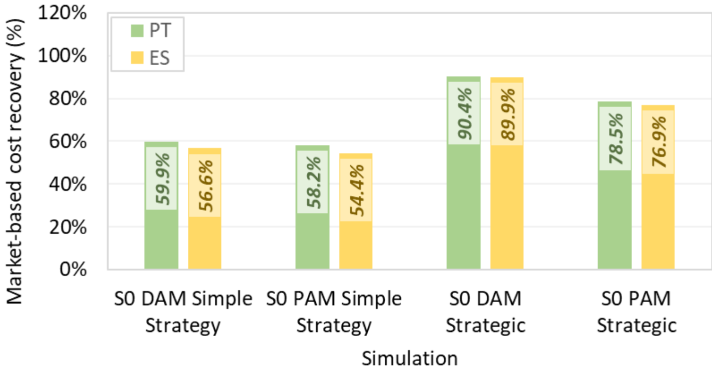


Figure 35. Annual average day-ahead/period-ahead prices weighted by daily traded energy.

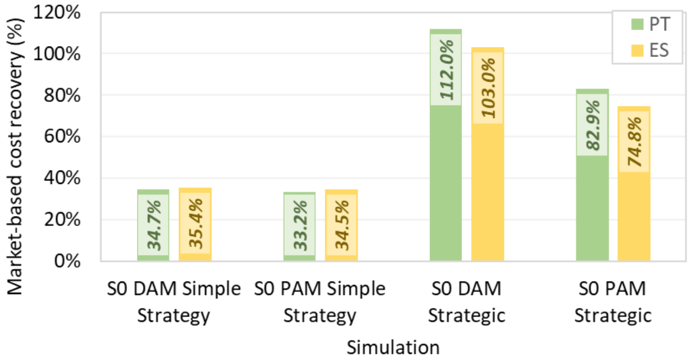
In S0, the highest VWAMP occurs in the *DAM strategic* variation and the lowest in the PAM simple strategic variant. From Figure 35 is also quite visible that using strategic behaviour increases market prices in relation to the *simple strategy* simulations, as previously discussed. Furthermore, in all four variants, the Portuguese VWAMP is slightly lower than the Spanish, which is a novelty when compared to the current prices. The result is explained by the higher share of RES (*MPI #1*), the low capacity of gas power plants (see Figure 25) and the lower water values/prices (see Figure 26) in Portugal, when compared with Spain.

MPI #32 provides the market-based cost recovery for wind and solar PV technologies in Portugal and Spain, Figure 36.

Due to the cannibalization effect associated with high shares of solar PV, in Figure 36 is possible to observe that, solar PV shows the lowest capacity to recover its investment costs in an electricity market environment, without strategic bidding from vRES. The *strategic* simulations increase vRES remuneration from the market due to the i) growth in the DAM/PAM prices and ii) the participation in balancing services. This allows vRES players to recover all (in the case of solar under the *S0 DAM strategic simulation*) or nearly all their investments. Nevertheless, these results are associated with a slight increase in overall system costs.



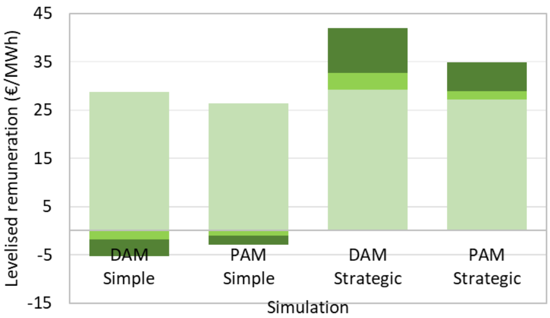
a) Wind



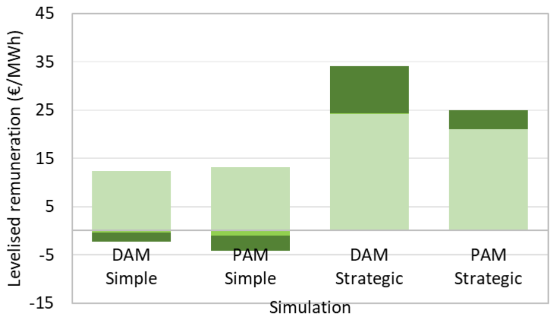
b) Solar

Figure 36. Market-based cost recovery of the: a) wind, and b) solar PV technologies for Portugal and Spain in S0 simulations.

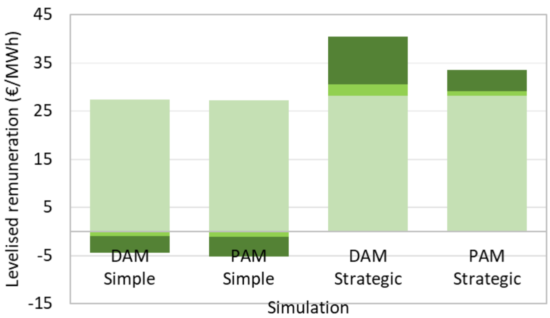
Figure 37 presents a detailed view of the levelized remuneration across different markets.



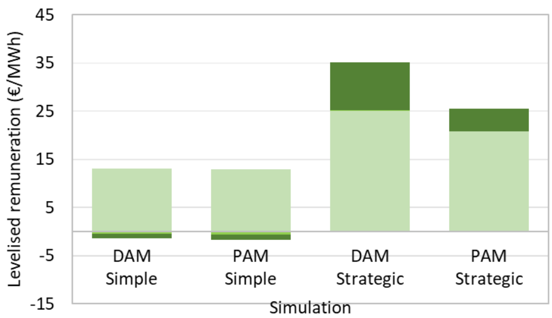
a) Wind Portugal



b) Solar PV Portugal



c) Wind Spain



d) Solar PV Spain

Figure 37. Levelized remuneration in the different markets for wind and solar PV technologies.

Figure 37 illustrates that in the *strategic* simulations, the remuneration from providing ancillary services AS is consistently positive, highlighting the advantages of diversifying participation across various markets. In contrast, the simple strategy does not show the same benefits.

MPI #33, the yearly price convergence, provides the price differential between bidding zones in each hour (trading period), *i.e.*, the annual price difference during hours when there is market split between Portugal and Spain. 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 and it is defined as low price convergence (more details are provided in the Annexe A). Figure 38 illustrates the price convergence between Portugal and Spain, including the number of market splitting hours per year, for the simulations in the scenario S0.

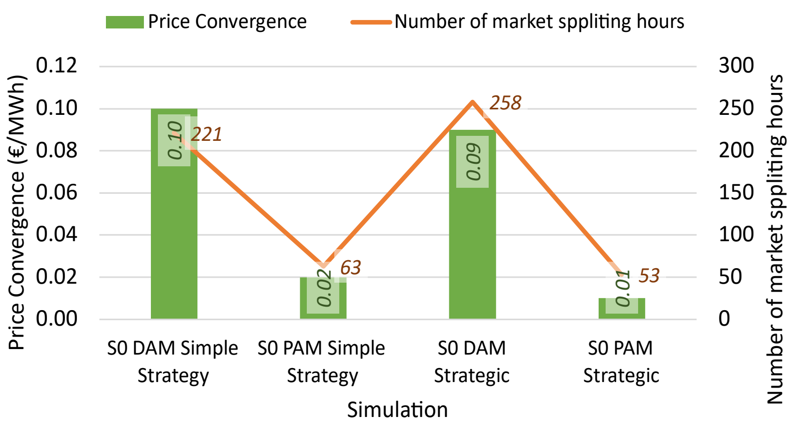


Figure 38. Price convergence between Portugal and Spain for S0 simulations.

Observing Figure 38, there is a full price convergence in all variations of simulation of S0 simulations. It is also clear that the trend of the price convergence in these simulations is supported by the number of hours with market splitting occurred between Portugal and Spain. vRES are causing more market distortions in the DAM and originating more market-splitting events due to "virtual" cross-border congestion. vRES bids to the PAM have lower forecast errors, reducing market distortions and market splitting events. Normally, market splitting originates price divergence as can be verified in the figure.

MPI #36 refers to the costs of AS, which are calculated in two ways: net costs and real costs. Net costs include the transaction costs between the players participating in ancillary services and the system operators, covering only the costs directly associated with ancillary services. The real costs also consider the balance responsible parties (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 15 presents the costs of the ancillary service.

Table 15. Costs of the AS services in Iberia.

Country	**Costs [€]**	**Simulation**			
		S0 DAM Simple Strategy	S0 PAM Simple Strategy	S0 DAM Strategic	S0 PAM Strategic
Spain	Net	1.2E+09	**1.3E+09**	-1.7E+09	7.1E+08
Portugal		**2.2E+08**	**2.2E+08**	-1.4E+08	1.1E+08
Spain	Real	**2.0E+09**	**2.0E+09**	4.9E+08	**2.0E+09**
Portugal		**2.7E+08**	**2.7E+08**	1.2E+08	2.4E+08

Results from Table 15 show that net costs are always lower than real costs or even negative, indicating an excess of vRES during most of the year that needs to be curtailed or downregulated. As expected, with increasing spot prices (MPI #29) and balancing needs (*MPI #32*) the strategic scenarios also increase the costs of the AS. In *strategic* simulation, the PAM, compared with DAM, has higher costs in Portugal and Spain. This occurs due to slightly highest period-ahead and balancing prices in the *PAM strategic* simulation (*MPI #29*) combined with a low decrease in the balancing needs (*MPI #12*), leading to increased balancing costs.

MPI #37 shows the average market penalties that BRPs must pay, Figure 39.

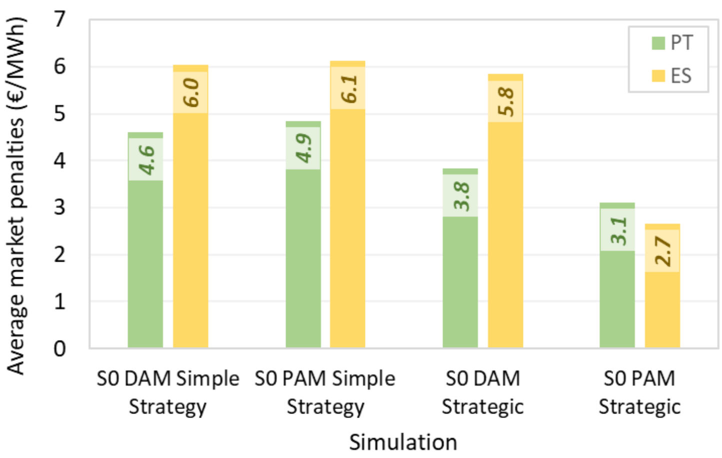


Figure 39. Average market penalties.

Analysing the Figure 39, the participation of vRES in balancing services enhances competition, leading to a reduction in the prices and in the average penalties paid by BRPs. Additionally, PAM has lower power forecast errors compared to DAM. The combination of these effects makes the *PAM Strategic Scenario* the one with the lowest penalties.

MPI #38 evaluates the average up and down imbalance prices. The relative differences between these prices and the day-ahead prices are presented in Table 16. From Table 16 it is clear that the absolute deviation costs for down deviations are higher than those observed for up deviations. With reduced penalties, the *strategic* scenarios have a lower difference between spot and imbalance prices.

Table 16. Imbalance costs in Iberia: upward and downward deviation.

Country	Deviation	Simulation			
		S0 DAM Simple Strategy	S0 PAM Simple Strategy	S0 DAM Strategic	S0 PAM Strategic
Spain	Up Absolute (€/MWh)	27.6	26.7	**39.5**	37.6
Portugal		28.9	28.0	**41.4**	37.1
Spain	Up Relative to DAM/PAM price* (%)	82.1%	81.4%	87.1%	**93.4%**
Portugal		86.2%	85.2%	91.5%	**92.3%**
Spain	Down Absolute (€/MWh)	39.6	39.0	**51.2**	42.9
Portugal		38.1	37.7	**49.1**	43.4
Spain	Down Relative to DAM/PAM price* (%)	117.9%	**118.6%**	112.9%	106.6%
Portugal		113.8%	**114.8%**	108.5%	107.7%

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

- ***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. It provides the annual CO2 emissions associated with fossil fuel-based electricity generation, allowing for the quantification of how different market designs contribute to reducing CO2 emissions. Figure 40 presents the CO2 emissions for Portugal and Spain across the various simulations per unit of consumed energy.

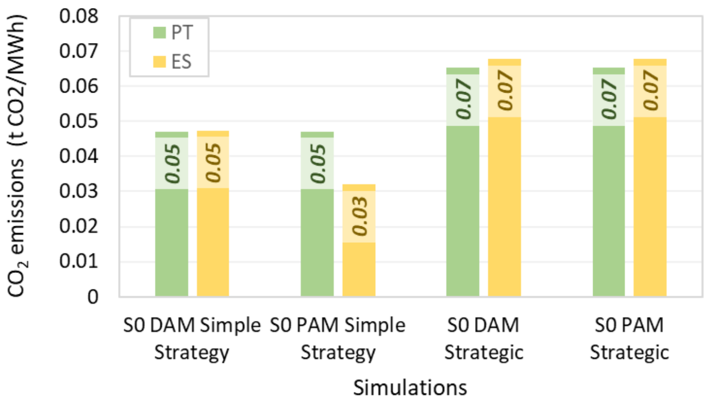


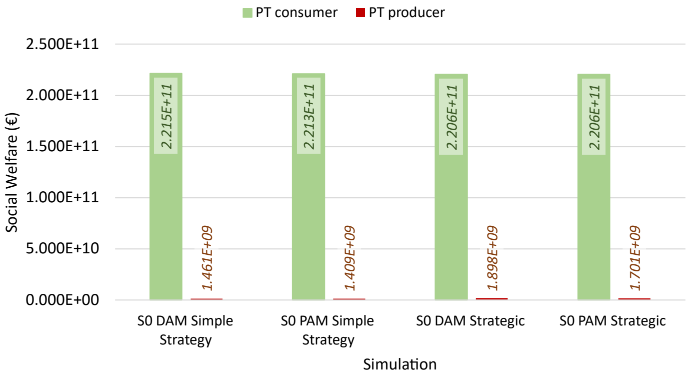
Figure 40. CO_2 emissions normalized by the consumed energy.

In the strategic scenarios, the lowest share of RES results in a greater reliance on other dispatchable polluting technologies to meet consumption needs. Consequently, the CO2 emissions increase in these scenarios. In the *PAM simple strategy* scenario the emission reduces in Spain because of a reduction in the production of gas power plants.

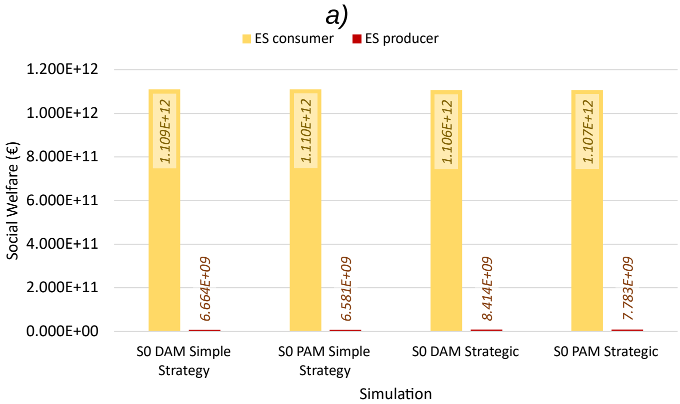
- ***Social MPIs***

The social MPIs aim to assess the social impact of the different market designs proposed in the project.

MPI #47 addresses the country's social welfare according to the consumers and producers' social welfare and surplus per electricity consumed, Figure 41.



a)



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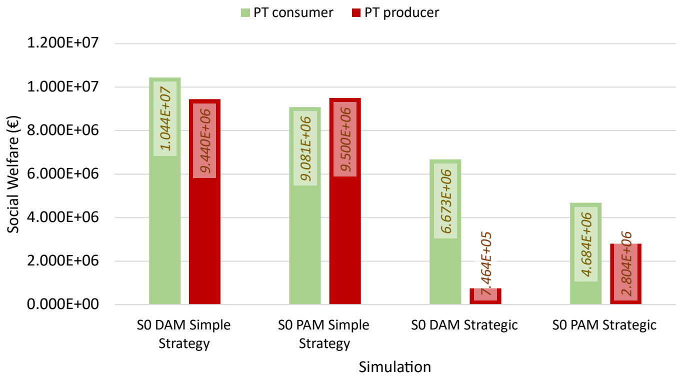

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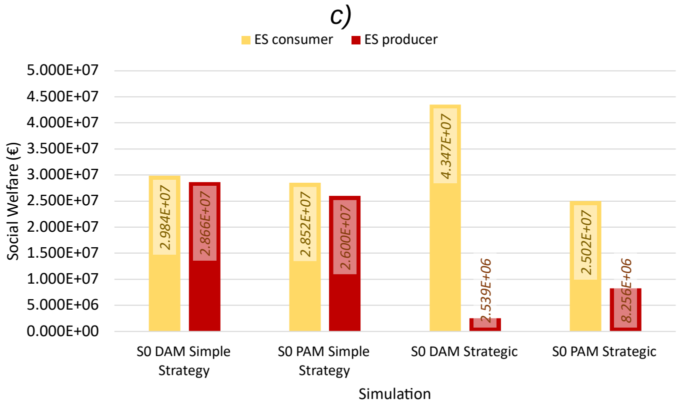


d)

Figure 41. a) Portuguese DAM and PAM social welfare, b) Spanish DAM and PAM social welfare, c) Portuguese IDM social welfare, and d) Spanish IDM social welfare for S0 simulations.

Figure 41a) presents the social welfare for Portugal DAM and PAM S0 simulations, Figure 41b) illustrates the social welfare for Spain DAM and PAM in S0 simulations, Figure 41c) shows the social welfare for Portugal IDM S0 simulations, and Figure 41d) introduces the social welfare for Spain IDM S0 simulations. The sum of the social welfare of consumers and producers is equal to the country welfare. The DAM/PAM significant difference between the social welfare of demand and supply means that demand is practically paying the marginal costs of supply, reducing the remuneration of supply to cover their investment costs. The social welfare of demand is also very high because it is practically only inflexible demand with bids equal to the market price-cap (4000 €/MWh). In the IDM the social welfare is closer because it only considers small adjustments concerning DAM bids. In annex B the surplus for consumers and producers normalised and presented in €/MWh for each country in both DAM/PAM and IDM are presented.

3.3.3.2 S1 – S4 results' analysis

This subsection presents a comparison of the impact of varying scenario assumptions on selected relevant MPIs for the MIBEL case study.

- ***Technical MPIs***

Figure 42 depicts the level of integration of RES in electricity consumption (***MPI #1)*** for scenarios S1-S4.

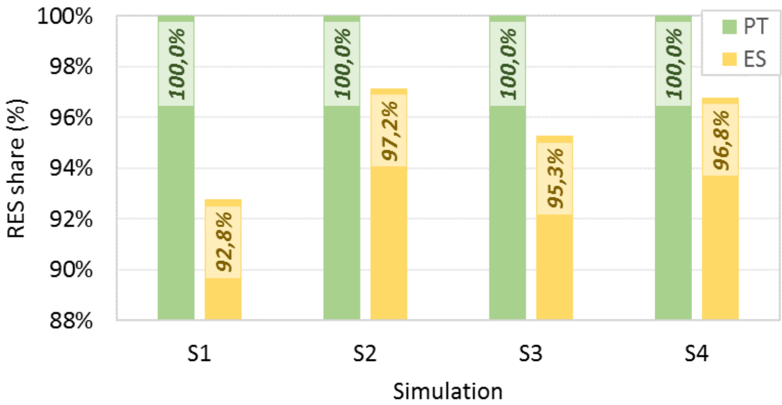


Figure 42. Integration of RES in electricity consumption for scenarios S1-S4 in MIBEL case study.

In the 2050 scenarios for Portugal, all electricity generation to satisfy the consumption is based on RES. In Spain, however, nuclear generation is still used, resulting in a RES share of final consumption ranging from 92.8% (S1) to 97.2% (S2). The scenarios with more flexible demand-side players (S2 and S4) can increase the RES share since the demand partly adapts its behaviour to consume energy during cheaper periods associated with a high share of vRES production.

Contrary to the S0 scenario, peak load reduction (MPI #11, as shown in Figure 43) and usage of demand side response (MPI #10) were observed in the two scenarios with lower demand flexibility: S1 and S3. Nevertheless, no load shedding events were identified for S1-S4 in the MIBEL case study. As a result, ***MPIs #4, #5, #8,*** and ***#9*** have no events.

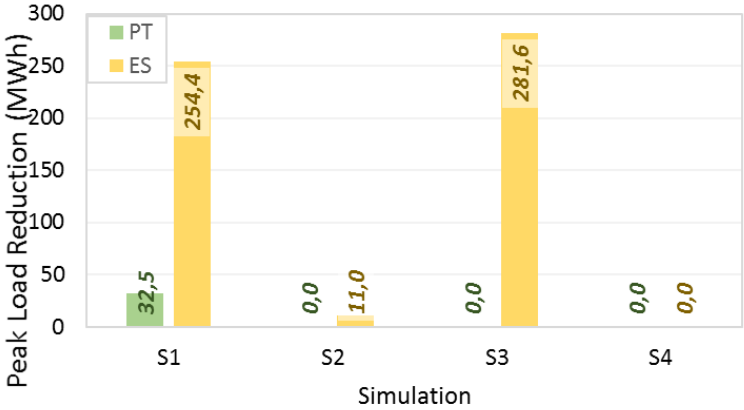


Figure 43. Peak load reduction for scenarios S1-S4 in MIBEL case study.

MPI #12 focuses on energy procurement and usage within AS and the results for the Iberian countries are presented in Figure 44. In addition to the energy procurement for AS, in this figure, the share that it represents in the total demand is also depicted, for a better comparison according to each country.

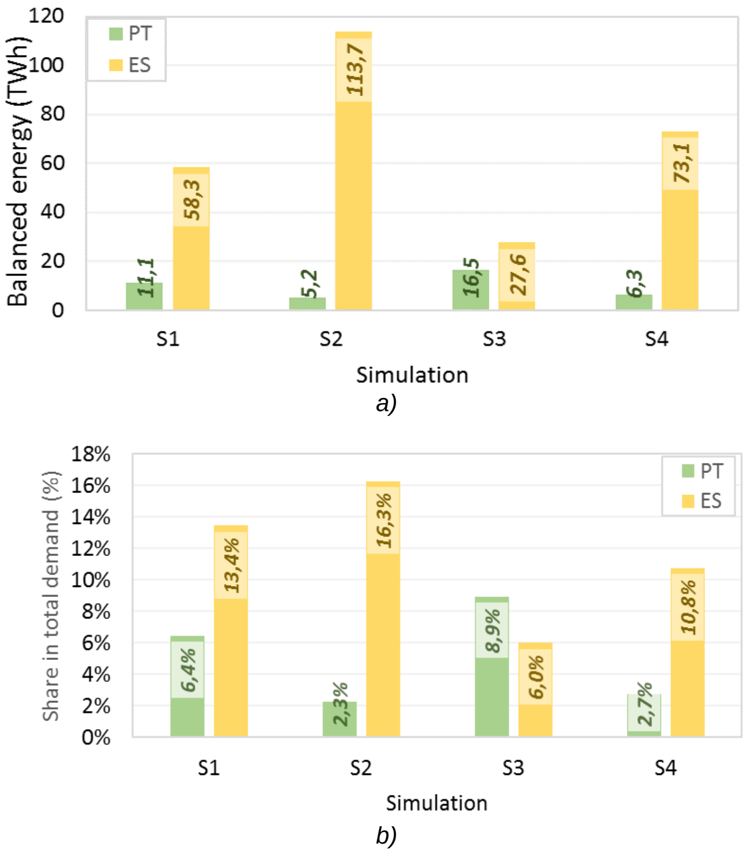


Figure 44. Energy procurement in the ancillary services in the Portuguese and Spanish power systems: a) balanced energy, and b) share in the total demand.

In Portugal, scenarios with low flexible demand (S1 and S3) have more balancing needs due to reduced flexibility available. The highest level of flexibility in Spain, in the scenarios with more flexible demand (S2 and S4), promote transactions closer to real-time operation, increasing the balancing needs. Furthermore, in proportion, Portugal has more demand flexibility than Spain, enabling to decrease its balancing needs in scenarios with higher demand flexibility (S2 and S4). Opposite, Spain has a more diversified supply portfolio, having lower balancing needs in scenarios with reduced demand flexibility (S1 and S3). ***MPI #13*** extends the analysis with the capacity procurement. In the case of the RESTrade models, only the SecR has capacity procurement. Similar to the previous MPI, the share of this capacity relative to the total demand has also been calculated, as shown in Figure 45.

Figure 45 reveals that a conservative approach to secondary capacity procurement leads to slightly higher costs in scenarios with more inflexible demand (S1 and S3). The variation in the share of total demand is more visible in Spain, ranging from 1.2% in S4 to 2.0% in S1, whereas in Portugal, it fluctuates between 1.0% in S4 and 1.5% in S1. ***MPI #14*** addresses capacity usage, with the results illustrated in Figure 46.

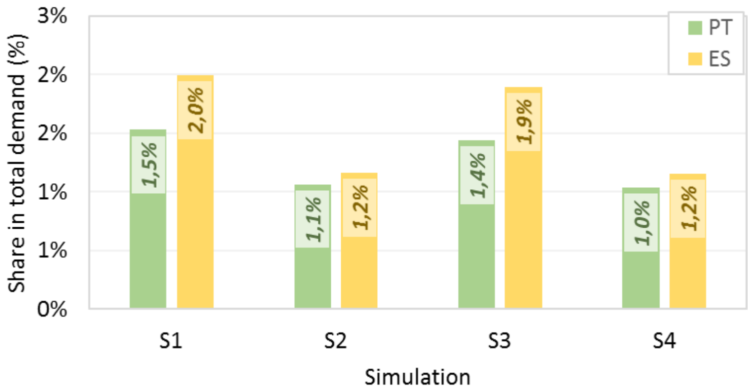


Figure 45. Share of capacity procurement in ancillary services in the total demand.

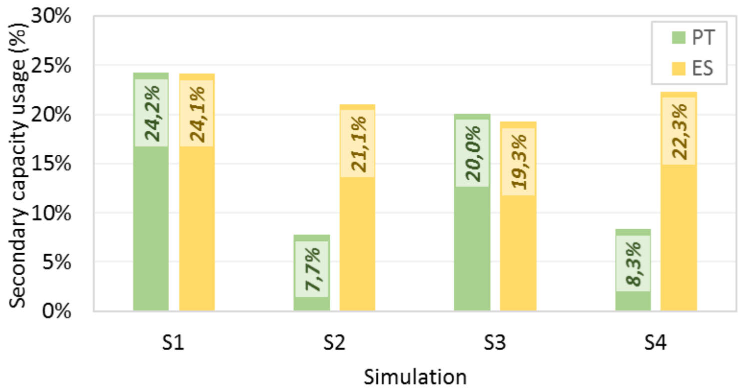


Figure 46. Capacity usage regarding its procurement for scenarios S1-S4.

The efficiency of capacity usage drops significantly in high flexible demand scenarios in Portugal. This reflects the effective value of demand-side players in responding to vRES production, which mitigates very short-term uncertainties and reduces the need for activating SecR. In Spain, the impact of demand-side flexibility is less evident due to the more diversified supply portfolio and relatively lower investments in storage infrastructure (see Figure 25).

Regarding the participation of demand and vRES in AS (***MPIs #15** and **#16),*** the values are similar to S0 *strategic* simulations, establishing vRES as the primary providers of balancing energy across both countries. In Spain, the contribution of vRES to ancillary services ranges from 72.6% (S3) to 80.6% (S1). For Portugal, these values are lower, with vRES contributing 52.4% in S4 and 72.9% in S2. Thus, as observed also in S0 scenarios vRES are the primary providers of balancing energy across both countries. With this participation, vRES avoid forced curtailments (***MPI #17***)*,* Figure 47. Indeed, practically any quantities except for Portugal in the S3 "variable" scenario with high vRES investment but low demand-side flexibility is observed. This result highlights the demand flexibility is not enough to accommodate all vRES generation.

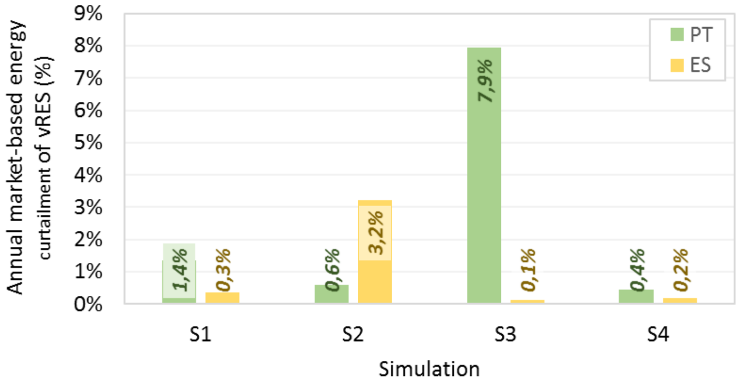


Figure 47. Annual curtailment of market-based energy from vRES.

- ***Economic MPIs***

MPI #26 the total system costs, the total costs for dispatch (***MPI #27)***, the costs for society (***MPI #28)*** and the VWAMP (***MPI #29)*** for scenarios S1-S4 are presented in Figure 48.

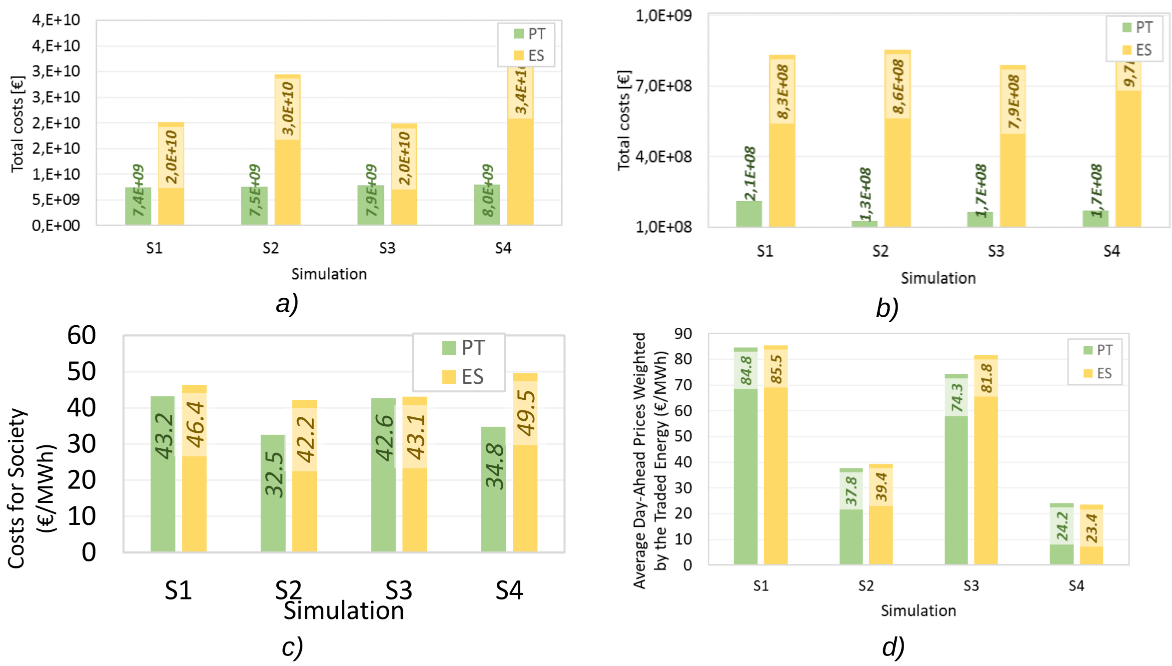
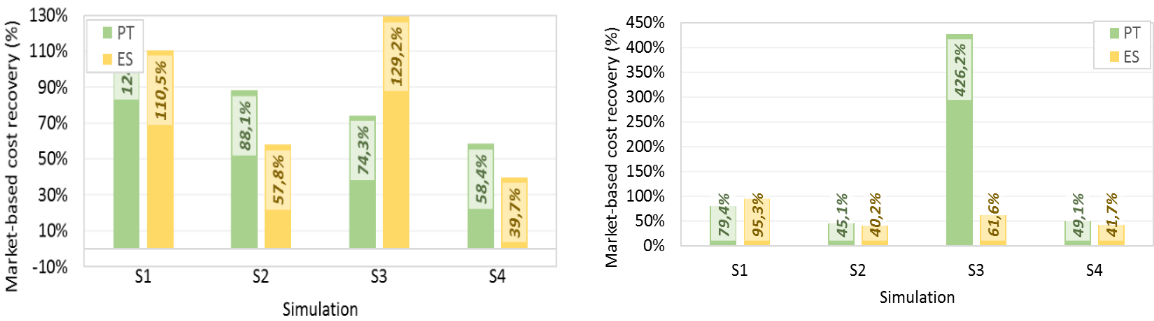


Figure 48. a) Systems total costs, b) total cost for dispatch, c) costs for society and d) VWMP in Portugal and Spain for S1-S4 scenarios.

Figure 48a) shows that scenarios with greater demand-side flexibility (S2 and S4) also involve higher investments in vRES, resulting in higher overall costs compared to scenarios with lower investments in storage. However, an exception is seen in Portugal, where scenario S3 shows greater investment in vRES than scenario S2. Operational costs are significantly lower than in 2030 due to the phasing out of gas power plants, Figure 48b). The S4 scenario, with more flexible demand and vRES, has higher dispatch costs. The costs increase due to a high level of storage and energy conversion, associated with batteries and electrolysers, instead of a direct consumption in real-time. In Portugal, society's costs (MPI #28) presented in Figure 48c) are significantly lower in the most flexible scenarios (S1 and S2) because of the increased demand of electrolyzers and batteries for similar total costs in all scenarios (MPI #26). While demand flexibility in Portugal is beneficial, in Spain, it shall be further analysed if the value of that demand (e.g., the H2 price) can provide a positive return considering the significant increase of its total costs in scenarios S2 and S4 (MPI #26).

The highest VWAMP d) occurs in scenario S1 while the lowest occurs in scenario S4. As expected, scenarios S2 and S4 present the lower VWAMPs due to the high level of sector coupling and demand-side flexibility. Scenario S4 is the only one where Spain achieved a lower VWAMP than Portugal. This is due to the high investment in vRES. In turn, S1 and S3 consider moderate levels of sector coupling and demand-side flexibility leading to high VWAMPs. The results for scenarios S1 and S3 reflect the lower demand flexibility to respond to vRES production, which affect the wind and solar PV market-based cost recovery (***MPI #32***), Figure 49.



a) Wind *b) Solar PV*

Figure 49. Market-based cost recovery of the: a) wind, and b) solar PV technologies for Portugal and Spain in S1-S4 scenarios.

The scenarios with more demand-side flexibility decrease the market-based recovery of vRES because they adapt to vRES behaviour, *i.e.*, consume more where vRES produce more, decreasing market prices. Onshore wind can recover all or a significant level of its investment in the scenarios with low flexibility. Only the Portuguese solar PV can recover its costs because of extreme events in S3, where the balancing prices are at the maximum (4000 €/MWh) for upward regulation or in the minimum (0 €/MWh) for downward regulation during daytime, highly increasing the remuneration of Solar PV. The inefficiency of the balancing services to balance all required energy in S3 can be confirmed in the level of vRES curtailments (*MPI #17*) in Portugal. This problem may be solved if vRES allocates more power to balancing services than the 20% power of deterministic forecasts.

Figure 50 illustrates the price convergence between Portugal and Spain for the scenarios S1-S4 (***MPI #33***), including the number of market splitting hours per simulation year.

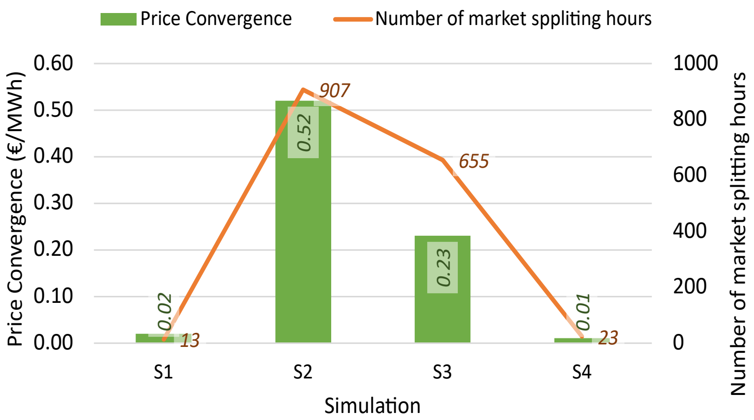


Figure 50. Price convergence between Portugal and Spain for S1-S4 simulations.

Observing Figure 50, there is a full price convergence in all scenarios throughout the year. Again, it is also clear that the trend of the price convergence in these scenarios is supported by the number of hours in the simulation year that market splitting occurred between Portugal and Spain. However, it should be noted that although S1 has a price convergence slightly higher than S4, scenario S4 presents ten additional hours with market splitting when compared to S1. Such reflects that, during market splitting hours, in scenario S1 there are less occurrences of full convergence hours (i.e., 6 in 13) than in S4 (i.e., 12 in 23). Moreover, S1 has also low price convergence (only 7 hours), while S4 has only 5 hours of low price convergence being the remaining 6 hours of moderate price convergence. The conservative S1 scenario is the most comparable with the S0 DAM scenarios, having almost 20 times less market splitting events. Therefore, using dynamic line rating enables a significant reduction in the number of market splitting events.

MPI #36, the costs of ancillary services for scenarios S1-S4, is presented in Table 17.

Table 17. Costs of the ancillary system services in MIBEL for S1-S4.

Country	Costs [€]	Simulation			
		S1	S2	S3	S4
Spain	Net	-4,2E+09	-2,9E+09	-1,5E+09	-1,58E+09
Portugal		6,5E+08	-1,3E+07	-7,2E+08	-5,04E+07
Spain	Real	2,1E+09	1,2E+09	6,0E+08	-5,35E+08
Portugal		7,3E+08	7,3E+07	4,8E+08	-1,59E+07

Net costs are always lower than real costs or even negative, which means that there is an excess of vRES during the majority of the year, being it curtailed or downregulated. One of the most interesting results is the lower prices of balancing services concerning the DAM in the S4 scenario with more demand flexibility and vRES generation. This situation occurs because a significant quantity of energy is left for trading closer to real-time, reducing its value. A similar situation occurs nowadays in the IDM. Intraday markets tend to have lower prices than day-ahead markets because inflexible demand is already satisfied, and flexible demand only wants energy considering an opportunity price lower than DAM prices [45]. As in the S4 scenario, the demand flexibility is high, on average, it originates lower prices in the balancing services than in the DAM.

- ***Social MPIs***

MPI #47, the social welfare for DAM and IDM S1-S4 simulations, is depicted Figure 51. The surplus results for consumers and producers normalised and presented in €/MWh for each country in both DAM/PAM and IDM are presented in annexe B.

Analyzing Figure 51a) and b), which correspond to DAM results for each country, there is a significant difference between the social welfare values for consumers and producers. In both countries and across all scenarios consumers exhibit higher social welfare values. This indicates that demand (consumers) is covering the marginal costs of supply, which in turn reduces the remuneration available for producers to cover their investment costs. In both cases, the results are consistent with the previous comparison, showing that consumers are covering the marginal costs of supply. The IDM surplus (annex B) for consumers and producers in both countries, consumers maintain highest surplus values than the one observed for producers, but the difference is smaller compared to the DAM results. This reduction is due to the smaller volumes of energy traded in the IDM sessions. In both countries, scenarios with higher levels of flexibility (S2 and S4) show lower surplus values compared to S1 and S3. This occurs due to the adjustment of demand and supply by flexible players, leading to reduced surplus for both consumers and producers.

3.3.4 Final remarks and outlook

Portugal and Spain have both a high penetration of vRES in their power systems, above 60% and 93% of the total 2030 and 2050 annual consumption thus constituting a very relevant case study for TradeRES project. In the S0 scenario, that simulates the year 2030, Portugal had the demand served by more than 82% of RES and Spain by more than 60%. In the 2050 scenarios, Portugal satisfies its demand with a share of 100% RES and Spain with a share that varies between 93% and 97%, being higher in the scenarios with more flexible demand (S2 and S4). According to market results, both countries have means to improve the allocation of secondary capacity, due to the obtained reduced utilization of the reserves committed. A more dynamic procurement of secondary capacity has been tested, contributing for reducing vRES integration costs and the maintenance of power systems stability and robustness, at lower costs.

Figure 51. a) Portuguese DAM welfare, b) Spanish DAM social welfare, c) Portuguese IDM social welfare, and d) Spanish IDM social welfare for S1-S4 simulations.

The participation of vRES in balancing markets leads to a reduction in their imbalances, which can be verified by comparing the forecast errors between the Simple and Strategic S0 scenarios. In all Strategic scenarios, vRES are the main supporters of balancing services. The PAM also reduces balancing needs, penalties and vRES curtailments. For vRES players, the strategic bidding simulations revealed a potential benefit of enhancing market-based remuneration through diversified revenue streams. However, a slight increase in overall system costs was also observed. In relation to market-based cost recovery, results showed that several vRES do not recover their production costs without support schemes, in the scenarios with more demand flexibility. The scenarios with low demand flexibility have higher costs and balancing needs, increasing the remuneration of vRES as the main providers of balancing services.

The results presented in the Iberian case study are based on two different strategies for pricing definition, as mentioned throughout the explanation of the results. To create the pricing strategies, it was necessary to use, and in some cases assume, a marginal cost value for each technology. For instance, for technologies considered vRES (i.e., wind and solar PV), a reference price of 0 €/MWh was used. The assumption that market players bid at 0 €/MWh has a critical impact on the results and requires further investigation. In practice, vRES market players without support schemes, will not bid with a value of 0 €/MWh (unless necessary) but rather with a value that ensures financial returns. In future markets with high penetration of vRES (as can be seen in the results regarding 2050 scenarios where RES reached a 93% share), these participants may raise their bid prices to ensure profitability. This could lead to more expensive technologies entering the market if they submit lower bids, potentially reducing the share of vRES in the energy mix. Even if vRES aims to optimize for revenue, their higher bid prices could open the door for other technologies to compete, which might reduce their intended impact. This highlights the complexity of integrating high vRES shares while ensuring market efficiency. More detailed modelling and analysis of bidding behaviours in these future scenarios are still needed.

On the other hand, in this case study, the main difference between the two pricing strategies (*simple* or *strategic*) is the allocation of 20% of the forecast vRES production for participation in reserves (first in the secondary power, and the non-allocated in the tertiary energy). Considering the strategic price definition, allocating 20% of the forecasted production of vRES for participation in reserves means that less of this production is directly available for the DAM. This leads to a reduced vRES availability, potentially lowering their market share into DAM negotiations, as showed in the outcomes of this case study. With less vRES bidding in the DAM, other more expensive and pollutant generation sources (like natural gas) might be needed to meet demand, which could increase the DAM prices. Nonetheless, allocating a portion of vRES production, like wind and solar, to reserves could improve grid stability and flexibility and help manage fluctuations associated with vRES generation and/or load consumption.

4. Summary of market performance indicators

This section summarizes the main outcomes obtained for the three national/regional case studies: B-Netherlands, C-Germany and D-MIBEL for the TradeRES scenarios and market design bundles presented in section 3 of this deliverable. The market performance indicators adopted within project TradeRES and relevant for the national and regional markets were calculated. The 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, and simulated in work package 5.

Some selected MPIs are presented in Table 18 to enable an overall characterization of the performance of the national electricity markets studied in this Task, and quantify the results obtained within the project. Additional MPIs can be found in the main list presented in section 2 (Table 2).

Table 18. MPIs relevant for characterizing the performance of national markets.

MPI number	MPI name
1	Share of RES-E
4	Loss of load expectation
5	Expected energy not served
26	Total costs of the system
27	System costs for dispatch
29	Average day-ahead market price
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[6]. *MPI #29* enable to assess the costs of electricity from the society's perspective. *MPI #32* translates the cost recovery of different technologies from energy-only markets and thus discloses the need for RES support schemes.

[6] aka "integration costs of vRES".

MPI #45 refers to the CO_2 emissions and partially reflects the RES penetration on each power system. Within this section, *MPIs #1* have been normalized by the consumption (or production as applicable) of each national power system.

- **Dutch Market**

In this section, a summary and a comparison between the benchmark results obtained from COMPETES-TNO and the results from AMIRIS-EMLabpy for their Energy Only Market simulations (EOM), given that COMPETES-TNO can only model an energy-only market, are provided. The objective of this comparison is to shed some light on how it compares a cost-optimal system against the simulation of an agent-based model such as AMIRIS. For this purpose, two sets of results are selected: the 'S4-Isolated NL' from COMPETES-TNO scenarios, and the EOM_LH scenario from AMIRIS-EMLabpy. The reason behind contrasting these two cases is to reduce the comparison burdens given by the different capabilities of both models.

The 'isolated NL' cases from COMPETES-TNO allow to align better to AMIRIS-EMLabpy results, as no electricity trade is considered. Moreover, some data from EOM_LH was based on the S4 scenario from COMPETES-TNO, such as the electrolyzers capacity and the industrial heat demand. The rest of the data from both simulations was taken from the TradeRES, which makes them comparable. To realize this comparison, some MPIs were selected to contrast both scenario results, which are reported in Table 19. It is important to notice that the MPIs from the EOM_LH reported for comparison correspond to the average of the different weather years, and therefore differ from COMPETES-TNO results, where only one weather year is optimized.

Overall, both scenarios present similar penetration of vRES in the power system, following the storyline of scenario S4, representing more than 90% of the final share of vRES supplying the final electricity demand.

The LOLE parameter from the AMIRIS scenario presents that (on average), 4.23 of the year involuntarily-curtailment of demand must be performed, which conveys around 6.4 GWh of ENS. In the case of COMPETES-TNO, the domestic supply under the 'S4-Isolated NL' is enough to cover all demand at all hours of the year.

In the ABM used; the investments are done until the level that the expected profitability of an additional capacity stops being profitable. For this reason, higher shortages were expected in comparison to an optimization model and confirm that it is a suitable methodology to investigate market designs that aim to reduce the power curtailments.

The resulting total system costs from COMPETES-TNO present a higher value than AMIRIS-EMLabpy. This can be due to several factors. The capital costs are an important part of the total system costs. In the case of S4-Isolated NL, there is a total of 218 GW of generation capacity installed, whereas the EOM_LH scenario presents roughly 150 GW. COMPETES-TNO presents 28 GW more of solar energy, 22 GW more of offshore energy, 21 GW more of solar energy, and 6 GW more of bioenergy. AMIRIS-EMLabpy resulted in a higher capacity of OCGT turbines, which were not considered as an option in the optimization model. A potential explanation for installed capacities could be differed by the different flexible capabilities between the models. COMPETES-TNO can model a higher degree of flexibility of the system, with its associated electricity demand, which can lead to a higher introduction of capacities.

The market-based cost recovery from the two models does not differ significantly and indicates a relatively good cost recovery for the investments (as the values are greater than 1). It is, however, calculated on the system level. A detailed calculation of the individual technologies is possible but falls out of the scope of this comparison. The incentives for the investments are best shown by the results of AMIRIS-EMLabpy as described in previous sections. The volatility of electricity prices shows a significant deviation between the two. Again, they are not completely comparable as they are aimed to show different things. COMPETES-TNO shows the volatility of prices in one year, while AMIRIS-EMLabpy shows the volatility of average prices across all the analysed years.

It is important to notice that comparison corresponds to the outcomes of two very different models, with different scopes, objectives and capabilities, as summarized previously in Table 20. Therefore, it is always a complex task to draw conclusions from results with different models. In this particular case, the comparison of the performance of the models is understood as an acknowledgment of the different capabilities of the models, as well as a form to classify them for future market studies, their limitations in each application and possible future needs of improvement.

Table 19. Summary of the results for case study B: Dutch case study.

MPI number: name	**Unit**	**COMPETES-TNO**	**AMIRIS-EMLabpy**
		S4- Isolated NL	**EOM_LH**
1: Share of RES-E	-	93%	96%
4: Loss of load expectation	h	0	4.23
5: Expected energy not served	GWh	0	6.4
26: Total costs of the system	Bn €	15.9	10.5
29: Annual volume weighted average of hourly market-price	€/MWh	52.4	38.5
32: Market-based cost recovery	-	1.14	1.21
41: Volatility of electricity prices	-	43.1	4.47

Table 20. Installed capacities (in GW) for case study B: Dutch case study.

	AMIRIS-EMLabpy	**COMPETES-TNO**
BESS	4.8	26
Solar PV large	79.8	108
Wind Offshore	34.5	57
Wind Onshore	12	12
Hydrogen CCGT	1.2	8
Hydrogen OCGT	18.4	0
Biogas	0	2
Biomass	-	4
Nuclear	-	0.5
Total	150.7	213

- **German Market**

In the case study for Germany, the remuneration of renewable electricity generation in electricity-only markets has been at the focus. A total of five different support instruments plus a situation without any support have been simulated. An in-depth comparison of MPIs for different support instruments has been done for scenario S1. This scenario is characterized by a comparatively low RES share and a low level of flexibility, but indicates an average scenario in terms of the market-based cost recovery which is one of the most important MPIs for the German case study. Also, a cross-scenario comparison of selected MPIs has been done.

Table 21 presents the main MPI results of the German case study. The ranges of results across different support instruments are shown for each of the five scenarios considered. Note that MPI #1 represents the vRES shares as the RES share is at ~100% for all cases.

The results show that the effect of the scenario assumptions, inter alia the degree of flexibility in the system, has a much higher impact on results, when compared to the support instrument in place. Some scenarios, esp. S0 and S3 showed no sufficient market-based cost recovery (MPI #32) for RES. This especially holds for PV and here in turn for rooftop solar plants and can be explained by their high simultaneity (of production) and a pronounced cannibalisation effect induced by this. They end up at a cost recovery rate of roughly 75% (average across all PV technologies) for S1. Note that self-consumption was not considered which might be an option especially for rooftop solar plants to operate them in an economically viable manner.

Table 21. Summary of the results for case study C: German market.

MPI	Units	MPI value				
		S0	S1	S2	S3	S4
1	%	73	73	94	92	99
4	h	0	0	0	0	0
5	MWh	0	0	0	0	0
27	€ bn/a	16.7 to 16.8	19.5 to 19.8	8.5 to 8.8	8.2 to 8.6	3.3 to 3.9
29	€/MWh	57.6 to 59.0	65.4 to 69.2	73.9 to 79.1	44.3 to 48.1	46.5 to 51.4
31	€/MWh	37 to 43 (PV), 17 to 21 (onshore wind), 19 to 21 (offshore wind)	14 to 23 (PV), -4 to 7 (onshore wind), 4 to 12 (offshore wind)	2 to 18 (PV), -23 to 6 (onshore wind), -15 to 8 (offshore wind)	23 to 33 (PV), 7 to 20 (onshore wind), 19 to 29 (offshore wind)	13 to 24 (PV), -6 to 14 (onshore wind), 0 to 18 (offshore wind)
32	%	37 to 40 (PV), 72 to 74 (onshore wind), 73 to 75 (offshore wind)	74 to 78 (PV), 100 to 112 (onshore wind), 89 to 96 (offshore wind)	89 to 98 (PV), 141 to 151 (onshore wind), 122 to 128 (offshore wind)	47 to 50 (PV), 74 to 87 (onshore wind), 65 to 73 (offshore wind)	65 to 71 (PV), 104 to 118 (onshore wind), 95 to 106 (offshore wind)
45	t/a	56	0	0	0	0

Concerning the support instruments, all of them can achieve to recover the full costs of renewables in case they are nearly “ideally” parameterized as it is assumed. Some support instruments either do not foresee a clawback, such as a fixed market premium or a capacity premium, or the payback obligation is bound to the actual infeed which may deviate from the anticipated one, for the two-way CfD with a monthly reference period. Thus, total cost recovery rates may exceed 100%. The mechanisms without payback obligations also lead to higher RES support costs (MPI #31).

In the case of the two-way CfD without any limits to the clawback obligation, significantly higher market-based curtailments of renewables (MPI #17) are observed. This results in higher volume-weighted average electricity prices (MPI #29), which in turn tends to stabilize the market value of renewables. Ultimately, higher system costs for dispatch (MPI #27) must be balanced with lower RES support costs (MPI #31) in the case of the two-way CfD.

- **Iberian Market**

The Iberian case study focused on testing new market designs and rules to make short-term markets more efficient in order to better integrate short-term vRES fluctuations. The current set market designs do not allow vRES to participate without causing market distortions, as they cannot regulate their generation as easily as conventional dispatchable technologies.

Day-ahead markets close at least 12 hours ahead of the first commitment hour, resulting in significant forecast errors, being the continuous intraday market the best solution to fix those errors by 1-hour ahead of real-time operation. However, it operates continuously, which means that to obtain better forecast accuracy, vRES shall trade closer to its gate closure, when most of the trades already occurred. Against this background, the (6-hour) period-ahead market (PAM) has been introduced. This market design benefits from improved power forecasts, with accuracy increasing by over 7% for wind power and 4% for solar PV at the national aggregate level in both Portugal and Spain. These improvements help reduce market distortions, as highlighted in the results. The PAM also increases the share of vRES by reducing their forced voluntary energy curtailments, decreasing balancing needs and penalties.

In the intraday market, has been coupled the best features to vRES of the European intraday marginal and continuous markets (SIDC). The simulated intraday market considers the pay-as-bid scheme of the SIDC being only cleared on its gate-closure like marginal markets, introducing the rule of giving priority to vRES in the first in, first out mechanism of the SIDC. This change allows for increasing its liquidity and vRES trades, reducing balancing needs and penalties.

Regarding balancing markets, it has been considered the separate procurement of upward and downward regulation and the participation of vRES, significantly reducing vRES forced curtailments and increasing competition and vRES remuneration.

Table 22 and Table 23 present a summary of the market indicators calculated within the MIBEL case study for Portugal and Spain, respectively, using the *strategic* simulations in scenarios S0-S4. The observed yearly RES share is high in all scenarios being above 80% in all cases for Portugal. For Spain, the values are slightly lower ranging from 60% to 97%. In the 2050 scenarios all production in Portugal and Spain is renewable or carbon-neutral, which means the CO_2 emissions are 0 (MPI #45). For the conditions imposed to obtain the optimized scenarios, both Iberian countries that constitute MIBEL market do not present risks of having LOLE events with EENS (*MPIs #4* and *#5*) as it is to be expected.

Concerning *MPI #27*, the dispatch costs obtained within MIBEL significantly decreased from 2030 to 2050 with a strong influence from the retirement of gas power plants. Regarding day-ahead prices (*MPI #29*) and investment recovery (*MPI #32*), inflexible-demand scenarios tend to have higher prices and recover the investment in wind onshore and solar PV. Demand flexibility makes demand-side players adjust to vRES production, decreasing market prices and the vRES return. This means that in the demand-flexible scenarios vRES need support schemes.

Table 22. Summary of the results for case study D: Portugal.

MPI	**Units**	**MPI value**					
		S0		**S1**	**S2**	**S3**	**S4**
		DAM	PAM	DAM	DAM	DAM	DAM
1	%	82.4	85.9	100	100	100	100
4	h	0	0	0	0	0	0
5	h	0	0	0	0	0	0
27	10^8 €	5.48	4.88	2.12	1.29	1.66	1.70
29	€/MWh	44.86	39.29	84.79	37.83	74.27	24.19
32	%	112.0 (solar PV), 90.4 (onshore wind)	82.9 (solar PV), 78.5 (onshore wind)	79.4 (solar PV), 124.4 (onshore wind)	45.1 (solar PV), 88.1 (onshore wind)	426.2 (solar PV), 74.3 (onshore wind)	49.1 (solar PV) 58.4 (onshore wind)
45	t/a	3.57E+06	3.13E+06	0	0	0	0

Table 23. Summary of the results for case study D: Spain.

MPI number	**Units**	**MPI value**					
		S0		**S1**	**S2**	**S3**	**S4**
		DAM	PAM	DAM	DAM	DAM	DAM
1	%	60.4	65.5	92.8	97.2	95.3	96.8
4	h	0	0	0	0	0	0
5	h	0	0	0	0	0	0
27	10^8€	41.28	35.98	8.33	8.55	7.89	9.70
29	€/MWh	45.37	40.04	85.52	39.39	81.79	23.40
32	%	103.0 (solar PV), 89.9 (onshore wind)	74.8 (solar PV), 76.9 (onshore wind)	95.3 (solar PV), 110.5 (onshore wind)	40.2 (solar PV), 57.4 (onshore wind)	61.6 (solar PV), 129.2 (onshore wind)	41.67 (solar PV), 39.67 (onshore wind)
45	t/a	1.89E+07	1.71E+07	0	0	0	0

5. Final remarks

This report presents the second edition of deliverable 5.3, which provides a final assessment of the designs and products developed in TradeRES project for national/regional electricity markets. Three markets are analysed in this report through computational studies: the Netherlands market, in case study B; the German market in case study C; and the Iberian (Portugal and Spain) market MIBEL in case study D.

From ***the Dutch case study*** some conclusions may be drawn. Based on this market's simulation of a steady-state scenario for a fully decarbonized energy system in which demand, fuel prices, and CO2 prices were stable, investment cost recovery was uncertain due to the large impact of inter-annual weather variability.

The impact of weather uncertainty was compared with the uncertainty from stochastic demand growth and observed that, even in a very flexible system, shortages were higher in scenarios with weather variability. In the simulations performed, the inter-annual variability of cost recovery increased more than three-fold, and the annual variability of weighted-average electricity prices more than ten-fold, in comparison with a scenario without weather uncertainty.

An interesting finding of the Dutch case study was the impact of the weather year that investors use for deciding upon new generation capacity. It was demonstrated that if investors based their investments on a weather year with very low vRES, thereby ensuring the reliability of the system for the worst weather years, they would be unable to recover their investments. On the other hand, if they would base their investment decisions on a more optimistic vRES yield, they would invest less and receive excessive returns, but this would come at the cost of lower system reliability and higher electricity prices. ***Results enable to conclude that in a system with variable supply, investors have insufficient incentive to ensure reliability, and therefore a capacity remuneration mechanism will be needed to ensure enough backup capacities.***

In view of those results. the performances of a capacity market, a strategic reserve, and capacity subscription were studied in a climate-neutral, high vRES version of the Dutch electricity system. The first two options have been implemented in other countries; capacity subscription is an instrument that promises to involve consumers (both household and industrial ones) better, but this instrument has not been tried in practice. All three of the reviewed capacity remuneration mechanisms can reduce the cost to society in a low-carbon power system with a high reliance on vRES, *e.g.*, solar and wind energy. Capacity markets and capacity subscription schemes offer a choice of whether to remunerate all or only dispatchable generation technologies. The latter appears to be the better choice, because imperfectly estimated derating factors of vRES and batteries can distort the market, and remunerating for capacity could reduce the exposure of these technologies to market signals, depending on the design of Capacity Remuneration Mechanisms (CRM). Total costs to consumers remained at similar levels as in an EOM (Energy Only Market), while reducing shortfalls in volume and duration, thus reducing the total system costs.

From the results, it was observed that ***using strategic reserves incentivized more investments in hydrogen turbines*** than the other CRMs in our model. It ***also caused***

volatile and high day-ahead/short-term electricity prices, mainly due to the dispatch of the reserve at the price cap. Its benefits appear to be limited to cases in which unprofitable plants need to be kept available for a period, *e.g.*, gas plants that would need to remain available until replacements would have been built. ***Both a capacity market and capacity subscription are able to provide security of supply and stable electricity bills to consumers***. In a capacity market, a central entity determines the capacity demand curve and other parameters. With capacity subscription, consumers purchase yearly subscriptions that ensure that their electricity supply will not be limited below the subscribed level during periods of scarcity. In the model of capacity subscription used for the Dutch case study, consumers base their willingness to pay on experienced shortages, and generators base their investments on the capacity subscription price. Because the contract duration was one year and the assumed limited "memory" of consumers and generators, periodic scarcity events occurred and caused investment cycles. Larger investment cycles were observed when consumers and generators do not have any "memory" regarding past shortages, ignoring the risk of extreme weather events. Capacity subscription could limit investment cycles by offering long-term contracts for capacity. ***During the energy transition, an intermediary agent (regulated entity on behalf of the government) could contract capacity long-term from generators and sell it in annual contracts to consumers***. The advantage over a capacity market remains the incentive for consumers to develop flexible solutions behind the meter and the fact that the net demand for dispatchable capacity is revealed.

In ***the German case study***, RES remuneration has been analysed for the TradeRES scenarios S0-S4 as well as for different support instruments. Most notably, ***the effect of different scenario assumptions towards the market-based cost recovery of renewables and other MPIs has been found to be much stronger than the differences resulting from various support instruments.*** Thus, it is seen as ***a challenge to plan robust policy designs that can adapt to different future developments***, including negative developments in terms of market values and cost recovery rates. Also, ***it has been found that compared to wind, it is more challenging for PV, especially rooftop plants, to recover their costs on the electricity market***. Nonetheless, options not considered in the analyses such as self-consumption could be employed here.

Regarding the support instruments, the Financial CfD is found to exactly recover the costs, given the plants profile exactly matches the reference generation. In the case of two-way CfDs with a monthly reference period and no limits imposed on the clawback, distortions during clawback periods can be observed, resulting in significantly higher market-based curtailment of renewables as well as higher electricity prices. One-way Contracts for Difference were found to perform worst in terms of support costs due to the missing clawback obligation in months when market values exceed the production costs. For production-dependent Contracts for Difference, i.e. one-way and two-way Contracts for Difference, an over-support was found. This can be explained by two factors: monthly variations in income and an anticipation of clawback as well as a mismatch between *ex-ante* anticipated market values and realized *ex-post* market-values after curtailment. In terms of the total costs that need to be borne by end-users, the production-independent financial Contracts for Difference is found to perform best. Nonetheless, it should be mentioned that a nearly “ideal” parameterisation of the support instruments was assumed in this analysis. However, the support instruments differ regarding associated *ex-ante* prognoses risks, which shall be addressed in future research.

The ***Iberian case study focused on changes to actual designs and rules that can better integrate vRES*** without considering support schemes and taking into account TradeRES scenarios S0-S4. This was studied in MIBEL case study by i) exploring market designs that enable closer-to-real-time trading, and/or ii) using bidding strategies that allow a diversification of the revenue streams.

The annual RES share is high across all scenarios analysed, consistently above 80% in Portugal. In Spain, it ranges from 60% to 97%. By 2050, all electricity generation in Portugal and Spain will be either renewable or carbon-neutral, resulting in zero CO2 emissions. Under the optimized scenarios of TradeRES, both Iberian countries in the MIBEL market show no risk of loss of load expectation or expected energy not served. Dispatch costs significantly decreased from 2030 to 2050, driven by the phase-out of gas power plants. Inflexible-demand scenarios show the highest day-ahead market prices and capacity to enable the market-based recovery for wind onshore and solar PV. On the other hand, demand flexibility allows demand-side players to adjust to vRES production, lowering market prices and reducing vRES returns, indicating that vRES would need support schemes in scenarios with high demand-flexible.

Findings from this case study show that vRES cause significant market distortions in the DAM since their day-ahead forecasts have significant errors. Therefore, the market prices that reflect real wholesale electricity prices consider the sum of DAM prices and high balancing penalties. ***The (6 hours) period-ahead market (PAM) offers a solution by reducing these distortions***, minimizing real-time balancing needs, and lowering penalties for vRES players.

The intraday continuous market (SIDC) should change its design, as tested in this case study*.** vRES are the players more interested in using SIDC to adjust their DAM programming dispatches. However, their forecast accuracy improves significantly when updates are made closer to the SIDC gate closure. Since the current "first in, first out" mechanism can penalize late bids expected from vRES players, the results suggest shifting SIDC to a clearing process at the gate closure***, by the end of each session, ***giving priority to vRES and using the SIDC pay-as-bid scheme.***

In ***balancing markets was found that is important to separate the procurement of upward and downward regulation. This separation would enhance competition and better reflect the dynamic value of these services.*** As vRES increasingly replace dispatchable technologies, adapting balancing mechanisms to the inherent variability of these technologies is crucial to maintaining system resilience. This adaptation also enables vRES to diversify their revenue streams through strategic bidding in the different markets. Developing dynamic approaches to procuring secondary reserve can contribute to optimize efficiency and ensure that resources are allocated effectively in real time. The imbalance settlement mechanisms shall consider the real-time balancing price of the energy used to balance BRPs. This approach incentivizes BRPs to self-balance in the case of high balancing prices in their imbalance direction. Furthermore, it also incentivizes BRPs to increase their imbalance if that benefits the power system (a negative penalty).

In conclusion, new market designs should avoid mechanisms that lead market distortions, ensure non-discriminatory practices, and be based on marginal prices. They must also be adapted to accommodate the variability and reduced predictability of vRES, which will be the primary energy sources in future carbon-neutral power systems. ***While further work is still needed***, e.g., in developing more dynamic and market-dependent strategic bidding for vRES players, ***the market designs explored in the Iberian market presented examples of how flexible and adaptive models, such as PAM with shorter gate closure times and refined intraday and balancing mechanisms, can help unlock the full potential of vRES*** while enhancing the efficiency ***within market environments in nearly 100% renewable power systems***.

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Annex A – Market Performance indicators: a detailed description

In this annex, each MPI used in this version the D5.3 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.*, [7], [46].
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 [7].
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 #8	
Name (and acronym)	Load shedding
Detailed description	This MPI is related to security of supply. During how many hours there is not enough flexibility in the system and load shedding occurs, as well as how much load shedding occurs yearly in terms of energy.
Measuring the MPI/Unit	h, # of events.
Mathematical formulation	Expressed in the number of hours and events during a year when shedding happened as well as a percentage value of the annual consumed (or traded) energy within a pre-defined spatial domain/control zone/electricity market.
Target and optimal value (when applicable)	Compare optimization results with ABM results, as well as results between market designs.

MPI #10	
Name (and acronym)	Use of demand side management and response (DSM/DR)
Detailed description	This MPI is related to secure, sustainable, affordable and competitive energy. Demand side management and response can increase competition, decrease the energy bill of consumers, increase the integration of RES, and avoid load shedding. How much electric vehicles, heat pumps, etc. provide flexibility/demand response in different markets (or how much of that is activated)?
Measuring the MPI/Unit	Dimensionless, number of start-ups and shutdowns
Mathematical formulation	$$DR_{use} = \frac{\sum_{t=1}^{T} Controlled\ consumed\ energy_t}{\sum_{t=1}^{T} Total\ consumed\ or\ traded\ energy_t}$$ where t is the time steps when the demand response is activated.
Target and optimal value (when applicable)	Compare optimization results with ABM results, as well as results between market designs

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.

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 #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 [47].
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 #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 [48]). 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 [49].
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 $i, j \epsilon I$
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 #41	
Name (and acronym)	Volatility of electricity prices
Detailed description	Key indicator in the risk management since it represents the price fluctuations over a period.
Measuring the MPI/Unit	Dimensionless
Mathematical formulation	The volatility index can be calculated from daily average prices as follows: $$X_i = log_{10}P_{dayT} - log_{10}P_{DayT-1}$$ X_i denotes the logarithmical difference of the daily average prices of two consecutive trading days, $$\overline{X_d} = \frac{\sum_{i=1}^{d} X_i}{d}$$ *d* denotes the number of trading days observed and X_d denotes the averages of X_i-s over a period of *d* trading days. The annualised volatility can be calculated as follows, $$VOL_{(T-d+1,T)} = 100 * \sqrt{N} * \sqrt{\frac{\sum_{i=1}^{k}(X_i - \bar{X})^2}{d}}$$ where *N* is the number of trading days for a year. For electricity markets, it is recommended to eliminate the weekend prices. Lower trading volumes might cause higher daily price variations, so an average monthly 21 trading day period and yearly 252 days period is recommended. To construct regional and European level volatility indices from the regional sub-indices, the methodology suggests to calculate the weighting factors for each market on each trading day and *t*, and then aggregate the daily logarithmic differences. From these values then calculate the standard deviation, and multiply the results by the annualisation factor and by 100. The weighting coefficient would be $$Wci = \sum_{T-d+1}^{T} Dci$$ *Dci* is the daily traded volume of day-ahead contracts on a given market on a given trading day. The daily logarithmic differences are aggregated as weighted arithmetical averages, $$X_{EUi} = \frac{\sum Wci * Xi}{\sum Wci}$$ Further details are provided in [50].
Target and optimal value (when applicable)	Low volatility is more preferable.

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	$$CO2Emissions = \sum_{k=1}^{K} \sum_{t=1}^{T} \left(CO2perMWh_{k,t} \times Generation_{k,t}\right)$$ 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.

MPI #47	
Name (and acronym)	Country welfare, producer and consumer surplus per electricity consumed
Detailed description	Different measures of hourly producer and consumer surplus per electricity consumed by country can give insights on welfare as well as risk distribution across countries: Hourly rent of producer located in a country per electricity consumed in a country: Difference between hourly revenues per electricity produced in a country (market price plus other premia, such as renewable support schemes or some form of capacity payments) and marginal costs times hourly generation divided by the country's hourly consumption Hourly consumer surplus by country: Average difference between hourly willingness to pay and prices of electricity consumption (market price plus taxes, levies, charges…) of consumer groups Total welfare per electricity consumer by country: adding the two measures: a. The numbers should be compared in terms of: Measures of welfare distribution Their annual sum of all producers/consumers in a country The standard deviation of this annual sum across countries b. Measures of risk distribution: The variance of hourly values For a graphical definition of producer and consumer rent in an electricity market context please see [7].
Measuring the MPI/Unit	€/kWh

MPI #47	
Mathematical formulation	Hourly producer surplus per consumption: $\frac{\sum_{k=1}^{K}(p_{it}+s_{ikt}-mc_{ikjt})q_{ikt}}{c_{it}}$ Hourly consumer surplus per consumption: $\sum_{c=1}^{C} wtp_{ict} - p_{it} - t_{ict}$ With: - p_{it} as wholesale market price - s_{ijt} as relevant support/subsidy for producer *k*, - mc_{ijt} as *k*'s marginal costs, - q_{ijt} as *k*'s generation, - c_{it} as a country's total electricity consumption - wtp_{ict} as willingness to pay of consumer group *c* and - t_{ict} as its relevant taxes/levies/charges/subsidies - in country *i* - in hour *t*.
Target and optimal value (when applicable)	High annual sums, but low standard deviation and variance are desirable.
Case studies	Pan-European, LEC.

Annex B – MIBEL additional results

This section presents additional results from the simulation performed for the S0 scenario, considering DAM and PAM designs with both *simple* and *strategic* price definitions. The Figure B1 presents the average daily prices for four different strategies: "S0 DAM simple strategy", "S0 DAM strategy", "S0 PAM simple strategy", and "S0 PAM strategy".

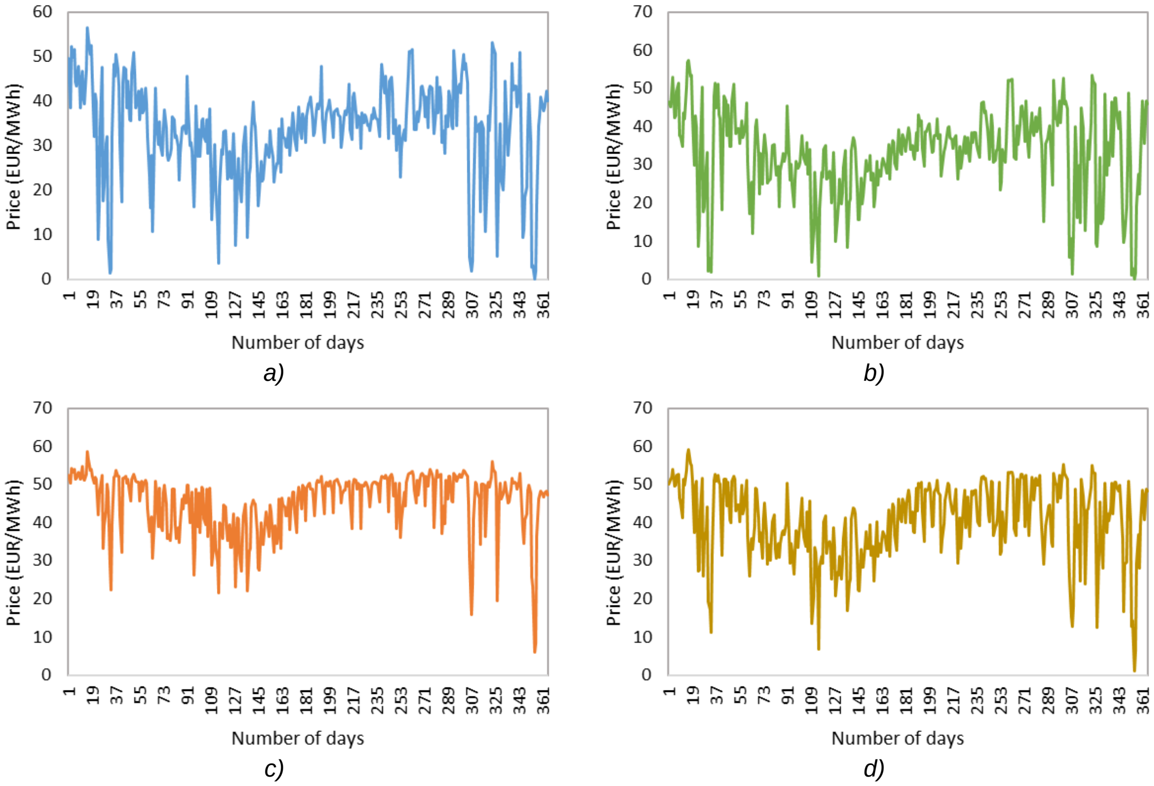


Figure B1. Daily average prices: a) – DAM & simple strategy, b) - PAM & simple strategy, c) - DAM & strategy, and d) PAM & strategy.

When examining average clearing prices, the results indicated an approximate average of 35.51 €/MWh for the S0 DAM simple strategy, 39.73 €/MWh for the S0 DAM strategy, 42.80 €/MWh for the S0 PAM simple strategy, and 44.90 €/MWh for the S0 PAM strategy. The S0 PAM strategy exhibited greater stability in its market prices, while the S0 DAM simple strategy showed significant fluctuations, reflecting its less effective pricing mechanisms. Similarly, the S0 PAM simple strategy demonstrated price instability.

The Figure B2 presents key trading metrics for four distinct strategies. These metrics include total traded volumes, total offered demand, and total offered supply.

In terms of total traded volumes, the S0 PAM simple strategy led with 352,320.07 GWh, indicating the highest level of trading activity, followed closely by the S0 DAM simple strategy at 351,895.41 GWh. Both S0 DAM and S0 PAM strategies present lower volumes of 346,920.79 GWh and 349,236.80 GWh, respectively.

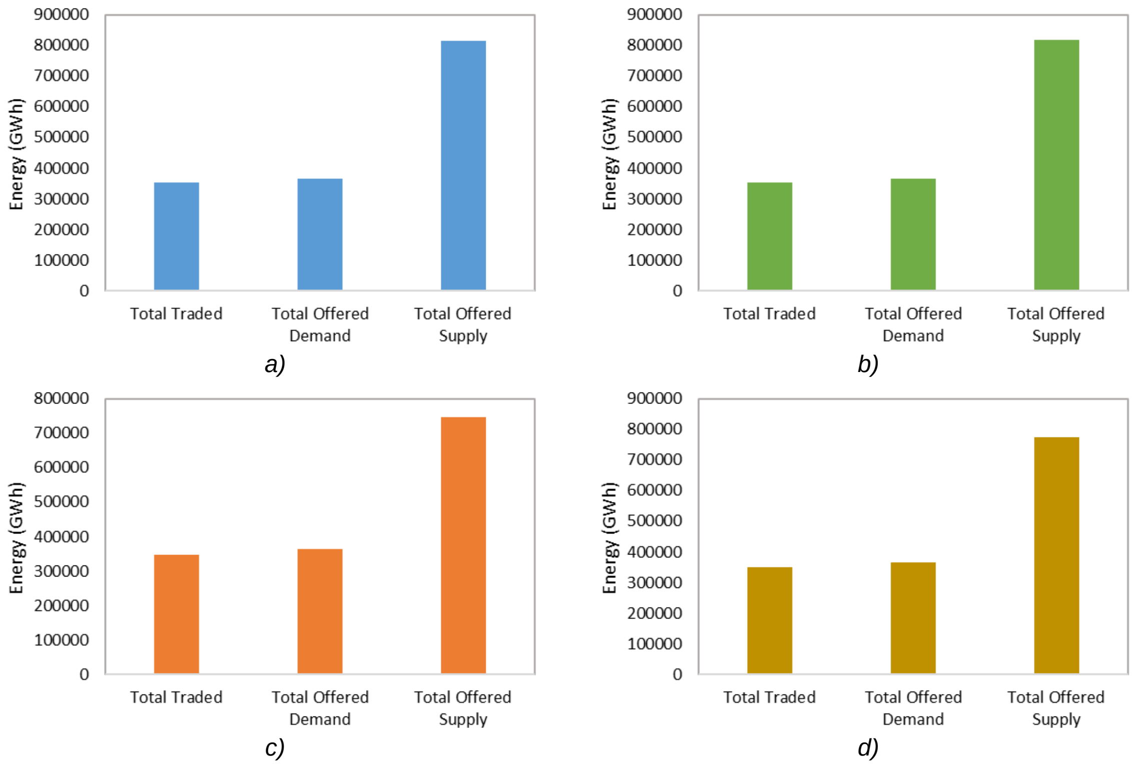


Figure B2. Offered and traded energy: a) – DAM simple strategy, b) - PAM & simple strategy, c) - DAM & strategy, and d) PAM & strategy.

The Figure B3 presents the total traded energy by various technologies under different strategies. Natural gas shows substantial variations, with the highest trading volume under the S0 DAM strategy at 78,252.38 GWh, indicating that more complex strategies leverage this resource effectively. Hydro Discharge also peaks at 16,210.63 GWh under the S0 DAM strategy. Nuclear energy trades highest at 59,529.61 GWh in the S0 DAM strategy, while Pumped Hydro Storage (PHS) shows higher trades in PHS discharge. Solar PV residential notably increases in volume to 61,170.80 GWh under the S0 PAM strategy. Wind offshore shows minimal trades in simple strategy scenarios but surges in the S0 PAM strategy. Conversely, wind onshore performs well in simple strategy scenarios but drops significantly in the strategy scenarios.

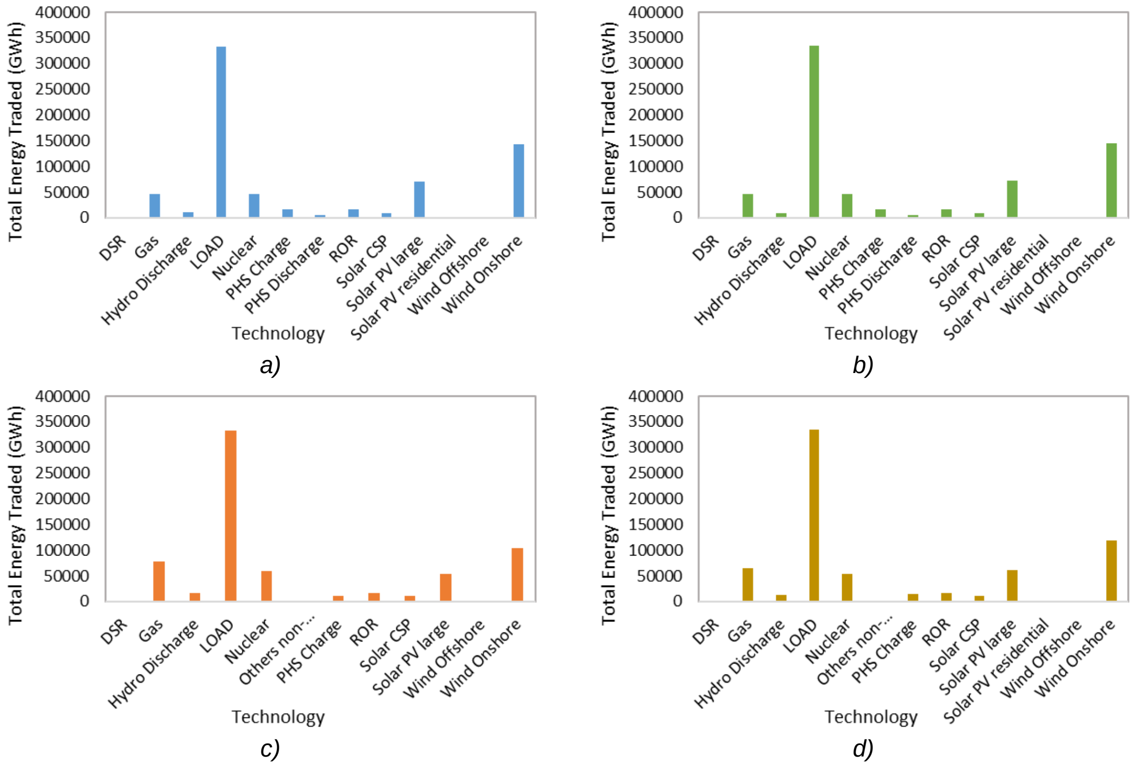
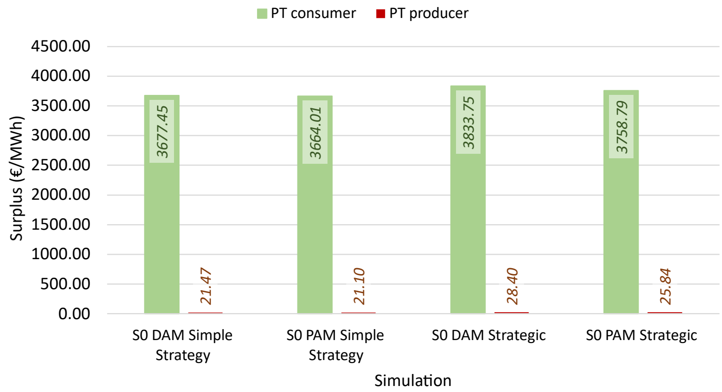


Figure B3. Traded energy by technology: a) – DAM simple strategy, b) - PAM simple strategy, c) - DAM strategy, and d) PAM strategy

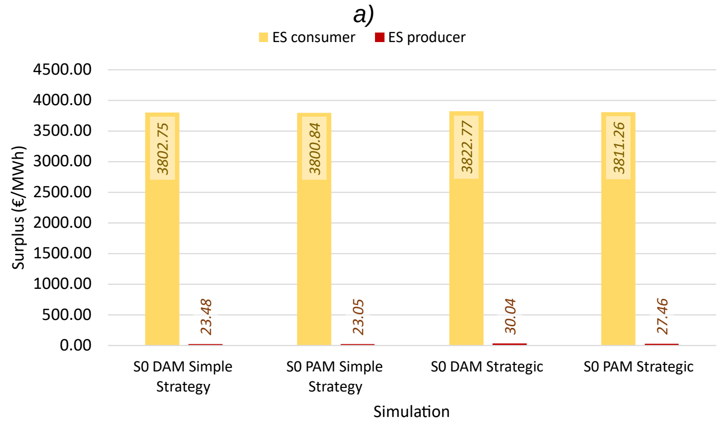
B.1 – S0 simulations

Figure B4 presents the surplus for consumers and producers normalised and presented in €/MWh for each country in both DAM/PAM and IDM.

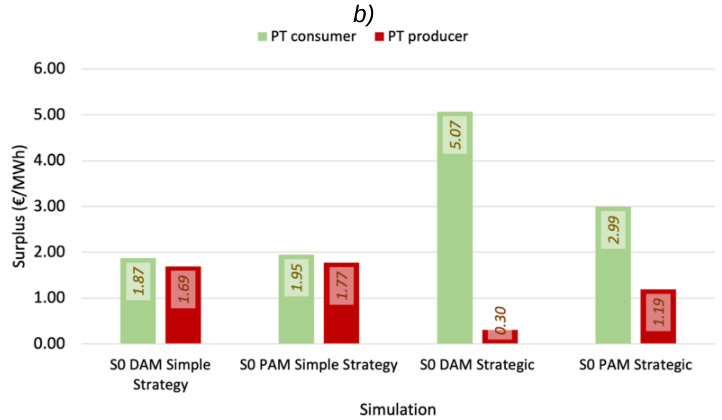
For Figure B4a) and b), the results align with the MPI #47 results for this scenario, showing that consumers (demand) largely support the marginal costs of prosumers, which in turn reduces the remuneration for suppliers, affecting their ability to recover investment costs. Analyzing the results of Figure B4c) and d), a similar behavior is observed as in the previous analyses. In the case of the IDM, the surplus values of consumers and producers are closer, due to the smaller adjustments made in the energy balance.



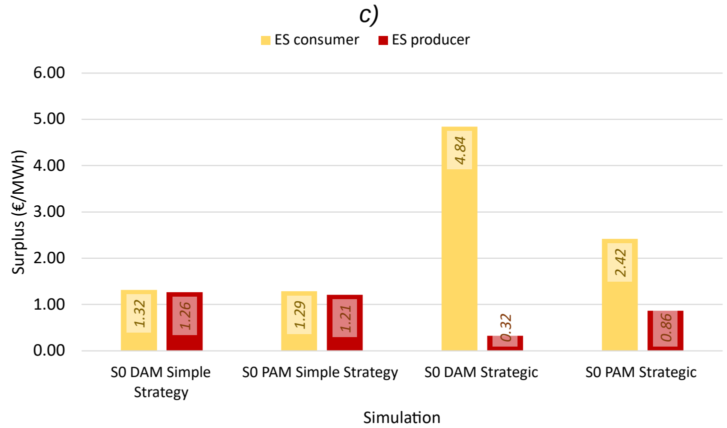
a)



b)



c)

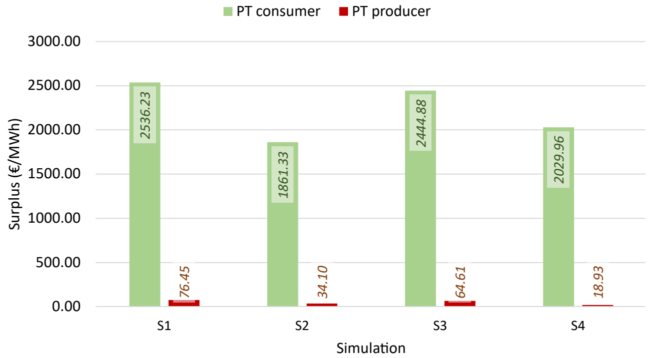


d)

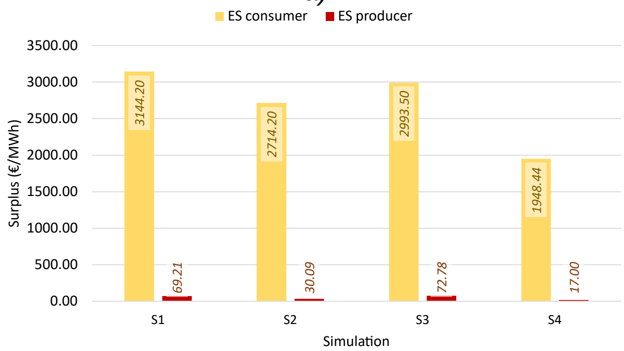
Figure B4. a) Portuguese DAM and PAM surplus, b) Spanish DAM and PAM surplus, c) Portuguese IDM surplus, and d) Spanish IDM surplus for S0 simulations.

B.2 – S1-S4 scenarios

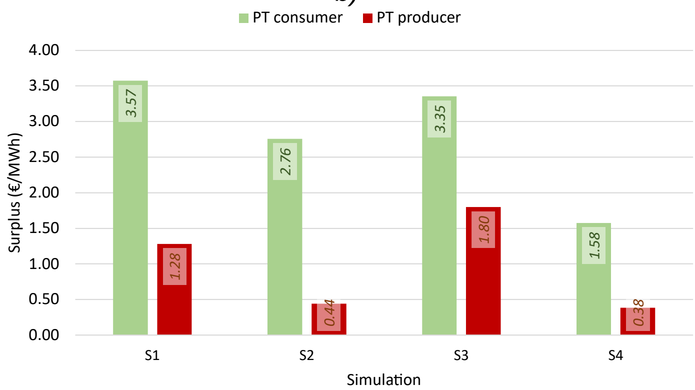
The Figure C5 presents the surplus for consumers and producers normalised and presented in €/MWh for each country in both DAM/PAM and IDM for S1-S4 scenarios.



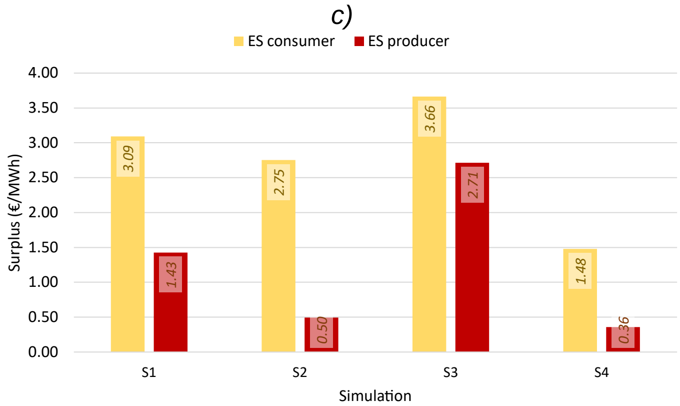
a)



b)



c)



d)

Figure C5. a) Portuguese DAM surplus, b) Spanish DAM surplus, c) Portuguese IDM surplus, and d) Spanish IDM surplus for S1-S4 simulations.