TradeRES

New Markets Design & Models for 100% Renewable Power Systems

New market designs in electricity market simulation models

Deliverable number: *D4.5*

Work Package: *4*

Lead Beneficiary: *TU Delft*

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 864276

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Document information			
Version	**Date**	**Dissemination Level**	**Description**
1.0	August 31st 2021	Public	The new market designs and their implementations in the market models in subtask 4.2.2 will be featured in this report. (Initial version)
2.0	September 30th 2022	Public	The new market designs and their implementations in the market models in subtask 4.2.2 are featured in this report. (Final version)

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Disclaimer

Executive Summary

To integrate a high share of renewables in a future electricity system, the electricity market design choices of today must be questioned, and if needed, new market designs and/or new market rules must be proposed and implemented. This deliverable describes the modelling process and models for assessing and designing future electricity markets.

Preceding this deliverable are results of work package 3. The most relevant electricity market design aspects were identified from the literature and reported in (D3.5). Deliverable (D3.5) also outlines the main technical and economic challenges for the electricity systems with 100% variable Renewable Energy Sources (vRES) that should be addressed through market design. This deliverable, D4.5, follows up on (D3.5) by explaining new models for evaluating new market designs and changes in existing market rules.

The deliverable is organized according to different market segments, the modelling requirements to analyse new market rules are described and models with corresponding capabilities are outlined. The modelling efforts in task T4.2.2, which are taken to fulfil the modelling requirements and answer the main market design questions, are explained as well. The models reflect the scope of the main policy choices and are based on the strengths of the modelling capabilities of the consortium partners. Note that the model enhancements to represent the temporal, spatial and sectoral flexibility are reported in deliverables (D4.1) to (D4.3). For this reason, these topics are described only briefly in this deliverable.

The introduction summarizes the main market design challenges for 100% vRES systems. Sections 2-4 describe the market design choices at the wholesale and retail levels including ancillary services. The primary objectives for changes to these markets are to allow trading closer to real time, in order to reduce the imbalances from vRES, and to stimulate flexibility options at all system levels, in order to absorb the fluctuations in the output of vRES. The agent-based models are used to simulate the impacts of market improvements such as a higher time resolution in the wholesale market, shorter lead times for trading, the exposure of the demand side to real-time prices and the impacts of levies and subsidies. The way in which ancillary services are procured affects the costs and benefits of vRES. The analysis in TradeRES focuses on the following design variables: the symmetry of bids (upward and downward capacity), gate closure times, the market time unit, payment schemes and the minimum bid size.

The challenges with electricity network tariff regulation and congestion management are neither particular to vRES integration nor to fully renewable power systems and thus not within the narrower scope of TradeRES. Yet, network congestion and tariffs are considered in Section 5, but TradeRES does not research new congestion management methods or tariff schemes. The transmission network is modelled with single nodes per bidding zone, considering the physical constraints of cross-border capacity. Dynamic line rating as a means for increasing useable interconnector capacity is investigated.

The evaluation of system adequacy, as presented in Section 6, compares an energy only market with a selection of capacity mechanisms that are modelled to investigate the extent to which they improve the performance of the energy only market with respect to system adequacy, investment risk and cost and risk to consumers. Section 7 presents the modelling

choices for sector coupling. These choices may have a significant impact on system adequacy, as it influences not only overall electricity demand but also the volume and nature of flexibility options. The last two Sections, 8 and 9, describe the modelling of the two main policy instruments for decarbonizing the electricity system, the European Emissions Trading System as a means of carbon pricing and vRES support schemes. We include these representations in order to be able to simulate transition steps between the current situation and a zero-carbon system. vRES support schemes – such as feed-in premium, market premium, capacity-based support and contract for differences – are modelled. Furthermore, the impact of the price of the European Guarantee of Origin certificates is considered.

To simulate the market developments of future power systems, TradeRES uses two types of models, agent-based models (ABMs), and optimization models. ABMs allow capturing of strategic behaviour of market participants and interdependencies of multiple energy policies. Comparing their results against optimization models can reveal more insights into the variations in different market designs. Furthermore, optimization results can be taken as a reference for future scenarios and can provide data to ABMs for technologies that are not included in these models.

Table of Contents

List of Tables

List of Figures

List of Abbreviations

ABM. Agent-Based Modelling
aFRR. automatic frequency restoration reserve
AMIRIS. Agent-based Market model for the Investigation of Renewable and Integrated energy Systems
BM. Business Model
BRP. balancing responsible party
CFD. contract for differences
DER. distributed energy resources
DLR. dynamic line rating
DSO. distribution system operator
EOM. energy-only-market
EMLab. Energy Modelling Laboratory
ETS. Emission Trading System
ICAP. Installed Capacity
ISO. Independent System Operator
LSE. load serving entity
MASCEM. Multi-Agent Simulator of Competitive Electricity Markets
mFRR. manual frequency restoration reserve
MIBEL. Iberian Electricity Market
OHL. overhead line
PFS. Power Flow Service
RESTrade. Multi-agent Trading of Renewable Energy Sources
SLR. static line rating
TSO. Transmission System Operator
VAT. value-added tax
VOLL. value of lost load
vRES. variable Renewable Energy Sources

1 Introduction

This deliverable focuses on representing innovations in market designs and in market models to tackle the combined challenge of integrating vRES and ensuring a secure and reliable electricity system. Analysing these challenges requires methodological innovations in energy systems analysis, primarily in the way computer models of electricity systems are developed and used. This deliverable describes how both types of innovations, in market design and in research methodology, are developed in TradeRES.

Regarding innovations in market design, we distinguish three timeframes. One of the greatest challenges for low-carbon electricity systems is to maintain system adequacy, i.e., sufficient investment in controllable electricity generation capacity to maintain reliability, also during prolonged periods without variable renewable energy. A number of capacity mechanisms have been developed and tried in practice, but they have all shown drawbacks. We will test the main types of capacity mechanisms within TradeRES Work Package 5 and compare them to the benchmark energy-only market. Moreover, investigation of the merits of a less known solution called capacity subscription will be carried out. This market design puts the consumer at the centre, offering households and commercial consumers the opportunity to optimize between purchasing reliable power and providing their own solutions such as demand shifting and energy storage.

The second timeframe concerns short-term trade: the design of day-ahead and intra-day markets. Shorter lead times between trade and delivery, shorter trading blocks and a shift towards rolling time horizon trading may reduce imbalances caused by variable renewable energy sources without compromising reliability. The third timeframe is (near) real-time, the very short time frame within which the TSO is responsible for the provision of ancillary services, typically procured and scheduled in form of reserves ahead of time. Here, too, innovations are possible that facilitate the integration of vRES.

Well-designed competitive markets are needed more than ever in order to coordinate the operations of the vast numbers of decentralized resources, such as rooftop solar, load shifting and small-scale energy storage, and large-scale facilities, such as offshore wind parks, electrolysers and hydrogen gas plants. The challenge for the operational side of the market design is to ensure efficient system integration and remove barriers to vRES trading. Regarding the long-term aspect of market performance, there are legitimate concerns that electricity markets do not provide an optimal mix of investment in vRES and flexibility to provide long-term system adequacy. As existing solutions, such as strategic reserves and capacity markets, have significant drawbacks, the highly innovative concept of capacity subscription will also be investigated. This way, a market can be designed that provides both for efficient dispatch of all available resources and for sufficient investment in the right combination of new resources. A larger overhaul of European electricity markets would therefore not be necessary. Moreover, it would require an extremely challenging level of political coordination between the EU and member states, while the acceptance by stakeholders and consumers of a more fundamental redesign would be doubtful, in the absence of an apparent reason.

The main questions of electricity market design for 100% vRES generation can be summarized as (see (D3.5) for details):

- How can the design of the balancing markets be improved to facilitate variable renewable energy sources as well as all the potential forms of flexibility in future electricity systems?
- If the wholesale trading of electricity at Europe's power exchanges is moved closer to real time, how much will this reduce imbalances? In other words, how should wholesale market design evolve?
- Will power plant owners be able to recuperate their investments in energy-only markets? How does investment security improve with a strategic reserve, a capacity market and with capacity subscription?
- Will RES support schemes be needed and, if yes, which ones will perform better?
- Will the interplay of different policies provide enough incentives for the desired volumes of flexibility? How will different degrees of demand response impact the need and performance of flexible resources?

An overarching question is how a new market design will perform in the presence of increasing levels of renewable generation, more flexible technologies, sector coupling and flexible demand?

These questions lead to the following modelling requirements:

- Wholesale market models and ancillary service models need to be able to represent various trading time resolutions, different lead times for trading and different products in terms of quantity and duration.
- The market models need to represent temporal and cross-sectoral flexibility and real-time pricing for all demand.
- The market models need to be able to represent investment decision making process on an investment time frame under various market alternatives such as: energy only markets, strategic reserve, capacity markets, capacity subscriptions.
- The market models need to be able to capture the impacts of levies and subsidies on costs and revenues, in particular the European Emissions Trading System and vRES support schemes.

The expected insights from the models that are used in TradeRES are the following:

- By testing various energy and reserve product duration and sizes, TradeRES will identify the adequate set of products for ancillary services and wholesale markets for 100% vRES systems.
- By evaluating investment security under different arrangements, TradeRES will identify 1) if energy only markets are sufficient for investment recovery, and if not 2) what is the most suitable alternative for investment recovery.
- By modelling various flexibility options including sector coupling, as well as shorter market lead times and time units, TradeRES will quantify their impact on cost recovery of both dispatchable and vRES power plants.
- By modelling different market alternatives, TradeRES will provide advice on suitable market designs for several case studies (within the scope of work package 5).

- By contrasting Agent Based Models against the optimization models, TradeRES will be able to quantify the impact of myopic decision making and the effect of different strategic behaviours.

1.1 Scope of the deliverable

The deliverable explains the market design choices pursued by TradeRES, outlines modelling requirements for those design choices and explains how these market designs are modelled in the TradeRES project. Some are modelled within models of TradeRES partners, some by coupling models of TradeRES partners. Although the primary go-to approach is to use Agent-Based Modelling (ABM), some market design aspects are investigated with optimization models.

With respect to our TradeRES research method, we use agent-based modelling to test the performance of different market designs under realistic conditions such as imperfect behaviour, for instance myopic investment. We compare these results with baseline scenarios (obtained with optimisation models) to identify which market design can be expected to perform best.

A challenge of future electricity systems is that the flexibility that is necessary to integrate variable renewable energy sources can be provided at every system level, from large controllable generators to home batteries and load shifting. This poses a new challenge to electricity market modelling, which in the past was focused on wholesale electricity generation and typically used highly simplified representations of demand. In TradeRES, we explore the possibility of coupling models, such as the EMLab electricity market investment model and the AMIRIS model of short-term electricity trading (both of which are ABMs), to understand the impact of short-term flexibility on long-term security of supply. Model coupling is made to utilize the existing and already validated models.

The basis for models used in TradeRES analysis and design already exist (D6.2). Like the modelled markets, the models will evolve, as they require smaller or larger alterations and/or additions to comply with the modelling requirements listed above. This is not only a pragmatic choice; it is also an aim of our research to investigate to what extent existing models could be re-used, adapted and integrateed to reflect the rapid changes in the electricity markets without building a new, large European electricity market and system model from scratch.

The models that are used in TradeRES and the summary of their enhancements and newly developed market models within Subtask 4.2.2 are listed below. Each section of this deliverable will elaborate further on this list from the point of view of market design needs.

- To capture the investment decision-making process, Energy Modelling Laboratory (EMLab) is used. EMLab was originally developed in Java. Since the original Java model does not accurately represent flexibility options, we have used the model linkage toolbox to expand EMLab capabilities. In order to do so effectively, EMLab was recoded in Python language, giving its users more liberty to combine it with other models and giving the tool more modularity to include various of its features selectively. Therefore, as a part of Subtask 4.2.2, EMLab development in a modular struc-

ture is executed, leading to the representation of energy only markets, strategic reserves (under development), capacity markets and capacity subscription (under development) in a modular structure so that these market variants can be combined with short-term agent-based models. Besides the new capacity subscription module, a short-term investment module was added to represent investments that can be quickly installed, such as PV and batteries.

- Agent-based Market model for the Investigation of Renewable and Integrated energy Systems (AMIRIS) enables studying the impact of market designs and policy instruments on the strategic behaviour of energy-related actors and the emerging dynamics in the day-ahead electricity market. Within TradeRES, AMIRIS was significantly extended regarding demand-side flexibility (now depicting, e.g., load-shifting), remuneration options (now considering, e.g., contracts for difference), and its consideration of uncertainties (now covering, e.g., production uncertainties of variable renewable energy sources). In addition, AMIRIS was coupled to EMLab and MASCEM. In the first coupling AMIRIS supports EMLab in the assessment of investment options. In the latter coupling, MASCEM provides the capability of assessing complex day-ahead products to AMIRIS.
- The Multi-Agent Simulator of Competitive Electricity Markets (MASCEM), in turn, allows the study of restructured electricity markets with the potential to be used by entities of very different natures and scopes of study. Modelled agents correspond to various entities in the electricity market, such as Producers, Buyers, Brokers, Virtual Power Players, Market Operators, and System Operators. The main types of negotiations supported by MASCEM are day-ahead and intraday pool (symmetric or asymmetric, with or without complex conditions) markets, bilateral contracts, and forward markets. In MASCEM, it is possible to clear the market at any specified time interval, and market models can be executed for any horizon before delivery. MASCEM's enhancements in the scope of TradeRES include load shifting, load shedding, and real-time pricing mechanics (D4.1), EVs flexibility trading under different business models (BMs) (D4.2), spatial flexibility aiming to select the most suitable resources to solve foreseen network issues (D4.3), and new actor types regarding the new electricity market models (D4.4).
- Multi-agent Trading of Renewable Energy Sources (RESTrade) is an agent-based system that simulates the participation of traditional and new players in the ancillary system services. It uses models of Producers, Aggregators, Consumers, Coalitions, System Operators, Hybrid Power Plants, and Local Communities. RESTrade enables to simulate the participation of these agents in the automatic Frequency Restoration Reserve (aFRR) markets providing both capacity and energy reserve, and in the manual FRR (mFRR) energy market if they have the technical capability to do so. RESTrade uses both the traditional designs of these ancillary systems but also new designs, which enable more agents to participate in them (see Section 3 and Table 1). Their design changes comprise: i) postpone their gate closure to a time horizon close to the real-time operation, ii) rolling their gate closure, i.e., bids can be submitted to a single clearing period instead of a set of clearing periods, iii) shorter clearing periods, iv) shorter products, v) a separate procurement of both upward and downward reserves. Besides that, coupling ancillary services of different market

zones has been considered and a new dynamic procurement of aFRR capacity is under study.

1.2 Structure of the deliverable and relation to other deliverables

This deliverable describes activities in Subtask 4.2.2: “Representation of (new) market designs”. Each section describes one aspect of electricity markets. The sections that follow describe which market design aspect is handled by which model and in which way. The requirements are outlined in more detail. Section 2 describes how the models are improved to represent a wholesale market with shorter time units and shorter times between gate closure and delivery. In Section 3, design of ancillary service markets is targeted. Next, Section 4 contains the same for the retail/distribution network level. Section 5 states how transmission tariffs and congestion are represented. Section 6 discusses the key issue of system adequacy, while Section 7 describes the representation of sector coupling, an important feature of the future energy system. Sections 8 and 9 present how two important policy instruments, CO_2 policy and RES support, are modelled. Final remarks are given in Section 10. This deliverable is accompanied by a series of other deliverables from TradeRES Work Package 4, “Development of Open-access Market Simulation Models and Tools”. Please refer to these accompanying deliverables to gain deeper insights on their specific topics:

- Deliverable (D4.1) covers the model enhancements with respect to temporal flexibilities.
- Deliverable (D4.2) focuses on the implementation of sectoral flexibility within TradeRES models.
- Deliverable (D4.3) describes spatial flexibility options and their implementation in TradeRES models.
- Deliverable (D4.4) looks at new actor types in electricity market simulation models, starting with the given agent configurations of the ABMs.

2 Wholesale market design

The current day-ahead markets were designed for conventional dispatchable power plants, considering and accommodating the slow ramp rates and long start-up times of some technologies. However, as the power forecast of variable Renewable Energy Sources (vRES) and demand have significant errors for time horizons greater than six hours (Holttinen, et al., 2013), these resources would benefit from trade deadlines closer to real time. With the introduction of large volumes of vRES, wholesale markets also need to accommodate more flexibility. This can also be achieved by allowing trade to take place closer to real time (delivery time). Furthermore, bids of shorter time units and aggregated or hybrid vRES (a combination of vRES and dispatchable assets that is partially dispatchable), can also reduce forecast errors and therefore balancing needs. A major objective of the modelling efforts therefore is to investigate if such modifications to the wholesale market can reduce imbalances. A second objective of modelling wholesale markets is to assess generators' revenues and cost recovery. We want to analyse for both, vRES and dispatchable generators, how well they can be expected to recover their costs in a low-carbon energy-only market.

This section contains the high-level requirements for modelling these changes to market design. A more detailed description of the implementation of flexibility options is presented in (D4.1), (D4.2) and (D4.3).

2.1 Shorter lead times between market closure and delivery time

Shorter lead times, between market closure of day-ahead or intra-day markets and delivery can reduce forecast errors, especially from vRES, and demand. Thus, bringing market closure closer to real time can reduce balancing needs and also facilitate integrating providers of vRES. The current standard design of day-ahead wholesale markets in Europe entails a market closure time at noon for trade for the 24 hours of the next day. A simple - albeit important- option is to shift the market closure time to a moment later in the day. However, if all hours of the following day are traded at once, this still implies that the forecast errors will increase over the 24 hours of the traded period and that logically, the latter hours would be traded more than 24 hours before delivery. The current intraday auction designs also bring along the same drawback in terms of forecast errors, since clearing all 96 quarter-hours of the following day is carried out here. In some countries, however, the auctions are held closer to delivery time (3 pm of the previous day for AT, BE, DE and NL), though. Nonetheless, retaining some lead times and having a first (indicative) scheduling procedure enables the transmission system operators (TSOs) as system operators to retain a stable system.

As of now, a multi-stage decision making is used to tackle these issues. Continuous intraday trading provides market actors with the opportunity to improve their forecasts and trade until real close to delivery time or even until actual delivery time. Nonetheless, since improved information is available to all market participants in the intraday timescale and due to structural deviations between current day-ahead and intraday markets design (e.g.,

trading hours vs quarter-hours), outcomes may not be most efficient. Thus, one might rethink the day-ahead market design and its relation with intraday markets. However, since most models used in TradeRES do not contain an intraday market representation, we focus on adapting day-ahead market designs with a single auction-based market clearing. Nonetheless, the structural effects of potential multi-stage decisions are observed. Those were included in the discussion of our analyses where they can be relevant.

A second option to be investigated is to trade electricity in a rolling time-horizon market clearing process, in which the market is cleared per time unit, a fixed amount of time before real time. This would make it possible to reduce the forecast errors further and would eliminate the issue that the forecast error would increase over the 24-hour period. However, taking advantage of the updated information within that rolling time frame would require not only the intraday traders but also the wholesale traders to be active around the clock, rather than submitting their bids once per day.

The implementation of a rolling time-horizon market clearing process, will be tested within TradeRES project to assess the potential benefits in different case studies. Similarly, to shorter lead times, a rolling-time market clearing procedure instead of clearing all hours of the day-ahead market simultaneously could also improve the quality of information of traders. In MASCEM, it is possible to clear the market at any specified time interval; usually in periods of one hour, half-hour, 15 minutes, or 5 minutes; but not excluding any other periodicity that may be defined. MASCEM market models can also be executed for any horizon before delivery, usually day-ahead, hour-ahead, 15 and 5 minutes-ahead, but any other horizons can be simulated. See (D4.1) for a detailed description of the flexibility options that AMIRIS and MASCEM can or will simulate. Besides the shorter lead time and the rolling time horizon, these models can represent load shedding, load shifting, electricity storage and real time pricing.

Contribution to the electricity market models under development in TradeRES: provides insight in the benefits of wholesale market reforms for vRES integration, considering the full range of flexibility options, from large-scale generation and storage to demand response.

Input data: weather and demand forecasts and realizations, electricity supply data, future flexibility characteristics.

Output data: wholesale market clearing prices and balancing market results; The hypothesis is that the balancing volumes and prices decline with shorter lead times.

Models: AMIRIS, MASCEM

2.2 Shorter time units

Trading shorter time units facilitates actors who may only offer capacities within a limited time window. Examples are industrial demand response and energy storage units with a low stored energy to power ratio. Instead of the current hourly resolution of wholesale markets, wholesale trade could be conducted in blocks of 30, 15 or even 5 minutes. Shorter time units could also help facilities that have significant ramping constraints. Currently, the main ones are thermal power plants, but the flexibility of large industrial processes may also

be constrained by ramp rates and the same may be true of the electrolysers for hydrogen production in the future. In addition to shortening lead times, a harmonization across different market segments (day-ahead, intraday, balancing) can contribute to limiting the possibility to exploit information on inflexible operation patterns. In AMIRIS, the choice of product duration is flexible. The implementation of shorter lead times for the agent-based dispatch model AMIRIS is described in (D4.1).

Short-term intraday markets can be used to cover some of the deviations of market players, but they have limited liquidity. Several studies indicate that reducing the time unit of these markets to at least 15 minutes can substantially reduce the need for balancing reserve (IEA-RETD, 2015).

Contribution to the electricity market models under development in TradeRES: provides insight in the benefits of shorter trade time units for vRES integration, considering the full range of flexibility options, from large-scale generation and storage to demand response.

Input data: power and demand forecasts and realizations, electricity supply data, future flexibility characteristics.

Output data: wholesale market clearing prices and balancing market results; The hypothesis is that the balancing volumes and prices decline with shorter time units.

Models: AMIRIS, MASCEM

3 Ancillary services

Although vRES can cause more imbalances in the system and increase the ancillary services requirements, they can also provide some of these services (Algarvio, et al., 2019a). In this section, new market designs for ancillary services, to be modelled within TradeRES and studied in the context of the Iberian market (MIBEL), are described.

TradeRES (D3.3) pointed out some of the major challenges of the ancillary services for power systems with high shares of vRES. The problem starts with the long- to mid-term markets. Day-ahead markets close between 12 to 36 hours before delivery, when vRES and demand-side actors have to bid based on forecasts with substantial errors.

Gate closures closer to real-time operation, shorter time units (to at least 15 minutes), and improvements in the dispatchability of vRES are aspects that bilateral and spot markets can adapt to reduce the balancing needs (Algarvio, et al., 2019b; Energy Nautics, 2021; IEA-RETD, 2015). Short-term markets as intraday markets are used to cover some of the short-run deviations of market players, but they have limited liquidity (Algarvio, et al., 2019b). Furthermore, allowing bids of aggregated or hybrid vRES, making vRES (partially) dispatchable can also reduce their forecast errors and reduce the balancing needs. Following balancing market designs will be covered by RESTrade.

- **Gate closure**

As in spot markets, one of the main issues that increases the volume of automatic frequency restoration reserve (aFRR) capacity inefficiently is its gate-closure horizon. A gate closure long before real time decreases the forecast accuracy highly when predicting the maximum expected consumption or net-load, which conducts to an unnecessary increase of the aFRR capacity size (Algarvio, et al., 2019b; Holttinen, et al., 2013).

- **Market time unit**

Another issue that increases the size of the aFRR capacity is its market time unit. This type of reserve was designed for a continuous use of 15 minutes (maximum), so it will be more efficient if the market time unit does not surpass this value (Algarvio, et al., 2019a).

Balancing products were designed for the participation of fast-responsive dispatchable power plants (e.g., hydro or gas plants that are capable of offering guarantee of power). Since vRES usually increase balancing needs, the design of markets should also enable and favour their effective participation in the trading process (within the range of their technical capabilities), to decrease the overall imbalances (Algarvio, et al., 2019b).

Against this background, a more efficient procurement of aFRR capacity will be tested in some studies involving (at least) MIBEL, by considering the vRES expected production, a separate procurement for upward and downward reserve, gate closures closer to real-time, and a shorter time unit.

- **Payment scheme**

Concerning the payment scheme of the aFRR capacity market, a pay-as-bid mechanism can reduce the aFRR costs while marginal pricing allows a non-discriminatory participation of all producers. The clearing of the market is exactly the same using both algorithms, the main difference is that while using marginal pricing all players receive the clearing price, using pay-as-bid they receive the price they bid. So, agents should adapt their behaviour

considering the payment scheme of each market. Pay-as-bid does not incentivize vRES participation based on their marginal prices, which can lead to an inefficient use of the free-of-cost vRES production, leading to curtailments and to the need of RES support schemes to guarantee their economic viability. Preliminary results (to be confirmed by the end of the TradeRES project) indicate that marginal pricing appears to be a more adequate mechanism to incentivize a non-discriminatory participation of all producers based on their marginal costs, as suggested by energy economics (Kirschen & Strbac, 2004). Otherwise, vRES may use strategic bidding that may not consider their optimal operation, reducing the general welfare of market participants.

Regarding aFRR energy markets, one of the main issues consists of the lack of competition in some countries. Another situation is that some electricity markets/control zones do not have an aFRR energy market, being the aFRR energy paid by the *manual frequency restoration reserve* (mFRR) energy price. This is not an efficient procedure since aFRR's participants may have different marginal costs when comparing with mFRR's participants. The TradeRES project will address alternatives for the electricity markets that may benefit from them, such as, coupled balancing markets between different market zones.

Against this background, the balancing markets should be coupled between different countries to increase competition and decrease the balancing needs. A good example of existing coupled balancing markets is the Nordpool (ENTSO-E, 2016).

- **Minimum bid size**

Another non-discriminatory change that can increase market participation and competition in the balancing markets with high amounts of vRES is the reduction of the minimum bid size to 0.1 MW and 0.1 MWh to capacity and energy markets, respectively. This change incentivizes the participation of demand-side players, medium-scale vRES, and hybrid power plants (Algarvio, et al., 2019b).

- **Procurement of aFRR capacity**

ENTSO-E suggested a symmetrical procurement of aFRRs capacity based on the maximum expected consumption (ENTSO-E, 2009; ENTSO-E, 2014). The use of symmetrical procurement for upward and downward capacity of aFRR increases operational costs and reduces efficiency. Some European countries updated this methodology by considering also the expected vRES production, decreasing the size of the required capacity (MIBEL Board of Regulators, 2018). Indeed, in power systems with increasing levels of vRES, using the maximum absolute value of the expected net load should be a better procedure than considering the maximum consumption. Some countries do not also use a symmetrical procurement of upward and downward capacity, changing their size to increase efficiency (MIBEL Board of Regulators, 2018). As this separate procurement for upward and downward capacity could be more efficient, TradeRES will address this aspect and analyse the impact of trading vRES in markets with high shares of renewables. A study involving (at least) MIBEL is foreseen at this phase of the project.

Most aFRR and mFRR energy markets already have a separate procurement for upward and downward energy. So, to increase the efficiency of these markets, closer to real-time gate closures are considered such as shorter time units (Algarvio, et al., 2019b). The mFRR energy market is more attractive than spot markets (Algarvio, et al., 2019a). Therefore, the

costs to have mFRR capacity markets can be suppressed (Algarvio, et al., 2019a). Table 1 presents the modelling approaches employed to upgrade the ancillary services considering future power systems with near 100% RES penetration addressed by RESTrade.

Table 1: Modelling approaches considered for ancillary services in RESTrade

Mechanism	aFRR capacity	aFRR energy	mFRR energy
Procurement	Separated upward and downward capacity based on expected maximum consumption, and vRES production	Separated upward and downward energy based on 5–15 minutes dispatch to cover frequency deviations	Separated upward and downward energy based on 15–60 minutes dispatch to cover frequency deviations
Payment scheme	Pay-as-bid / Marginal pricing	Marginal pricing / Pay-as-bid	Marginal pricing / Pay-as-bid
Trading procedure	Direct / Auction	Auction / Direct	Auction / Direct
Gate closure	2 hours-ahead	25 minutes-ahead	25 minutes-ahead
Time unit	5–15 minutes	5–15 minutes	15–30 minutes
Minimum bid size	0.1 MW	0.1 MWh	0.1 MWh

The TSO agent will be equipped with the modules containing the algorithms of each aFRR and mFRR balancing markets. The technical activation of these mechanisms has been studied in (D3.3) of this project. The representation of these markets will be harmonized with the whole of Europe, so they can be used in all case studies. Furthermore, TSOs will also be equipped with a harmonized imbalance settlement module, responsible to compute the penalties. This module is crucial due to the imbalance settlement fees that balancing responsible parties (BRPs) must pay in case of deviations, which derives from the system costs with balancing markets.

Contribution for the electricity models under development in TradeRES: Provides insight to the need for secondary (aFRR) and tertiary (mFRR) control such as the prices of their markets and their participants' dispatch. Investigates the effect of modifications to the ancillary services. It provides the penalties due to each BRP's deviation from schedules.

Input data: Receives all dispatch of all market players, considering the previous markets results. The aFRR capacity market receives a forecast of the maximum expected consumption and vRES production. During real-time operation, TSOs receive the instantaneous produced and consumed power, using the balancing reserves in case of frequency deviations. TSOs also receive the market participants' bids to these balancing markets.

Output data: TSOs should provide the aFRR capacity needs, each agent's dispatch in case of participating in the balancing markets, and each market's prices, capacity reserved and energy used in every balancing direction for the defined time-units (see Table 1). Furthermore, the penalties paid by BRPs due to their deviations will also be provided.

Model: RESTrade

4 Retail market design

Complementary to wholesale markets, retail markets also facilitate the active participation of demand in the market. While conventional electricity demand showed to be relatively inflexible in the past, new types of consumption such as the charging of electric vehicles and electric heating may be much more flexible, which facilitates their integration despite the large increase in demand that they cause. In order not to additionally burden consumers, their flexibility should only be called upon when it benefits the energy system. If flexible consumption can reduce network peaks and/or improve the utilization of vRES, this may reduce system cost. Consumers are exposed to a combination of financial incentives:

- **The price of electricity production**. As mentioned in (D3.5), in TradeRES, both time of use pricing and real time prices are considered.
- **Renewable energy support schemes for prosumers**, e.g., feed-in tariffs or net metering).
- **Taxes, levies, and subsidies** such as value-added tax (VAT) and renewable energy levies.
- **Network tariffs**. Network tariffs usually reflect consumers' variable costs for annual consumption and sometimes also a fixed component reflecting peak consumption. Yet, they typically do not reflect the real-time costs of network usage due to congestion, for instance. Proposals exist to make them flexible as a way to reduce congestion.
- **Potential payments from network congestion management**. If the network tariffs do not provide (sufficient) incentives to avoid congestion, additional instruments[1] can be implemented to handle it.

Renewable energy support schemes are discussed in Section 9 of this deliverable. The latter two topics, network tariffs and congestion management, will be discussed in Section 5.1. This section will therefore focus on the modelling of retail price of electricity and taxes and levies in markets with high shares of vRES. In addition, in Sections 4.3 and 4.4, two particular aspects of retail markets that influence their performance in a renewable system are presented, namely the roles of aggregators and prosumers.

4.1 The electricity price

Real-time pricing of electricity is the most accurate reflection of the momentary marginal cost or value of electricity generation to society and therefore in theory the best signal for indicating the need for flexibility. The market price coordinates the dispatch of flexible generation units, storage, and demand response by signalling at every moment the value of generation and/or social cost of demand reduction. Therefore, the flexibility incentive from real time pricing can be analysed in AMIRIS and MASCEM. Usually, real-time pricing is understood as passing the wholesale price of electricity, i.e., the day-ahead market price,

[1] These instruments may take the form of congestion pricing or of fixed payments/tariff reductions to consumers for being flexible. Congestion does not need to be managed with financial incentives, however, but may also be handled through technical control options, whose costs are socialized over all consumers.

on to small consumers. This is how it will be represented in TradeRES, e.g., in the AMIRIS model (see (D4.1)). Consumers may also be stimulated to participate in balancing markets; the options for this are presented in Section 3. Even though real-time pricing is likely to deliver the most efficient outcome from a pure cost perspective, a policy-relevant point of attention in our analyses will be how much risk this confers to consumers MASCEM can provide this analysis.

Contribution to the electricity market models under development in TradeRES: provides insight in the benefits of real-time pricing for vRES integration and the activation of demand-side flexibility resources

Input data: Demand response data (volumes, capacity, price response, maximum time that load can be shifted, etc.), demand response technology data

Output data: volume and capacity of load that is shifted, impact on system adequacy, wholesale prices

Model: AMIRIS, MASCEM, Backbone

4.2 Taxes and levies

Taxes such as VAT and levies for recovering the cost of renewable's support are common and may have a significant impact on the cost of electricity to consumers, which are particularly relevant when considering incentivizing demand response and sector coupling. They will therefore be included in the models that analyse the impact of prices on consumers. Taxes and levies can be implemented in multiple ways. VAT is implemented as a fixed cost per unit of electricity consumption, as are most other taxes and levies, and will be included in our analysis. In principle, energy taxes could also be charged as fixed annual payments, but this would be regressive with respect to income. Moreover, a common policy objective is to stimulate energy conservation, and then a fixed rate tends to be ineffective, as opposed to a per-unit rate. Therefore, we do not include this option.

A per-unit tax rate distorts the market, on the other hand, as the consumption price of electricity no longer reflects marginal cost. This may become an obstacle to efficient charging of batteries, whether stand-alone or of electric vehicles. A third option is therefore to define the tax or levy as a percentage of the market price, i.e. a percentage mark-up (Klein, et al., 2019). While this still distorts the market price, it has as an advantage that surpluses of renewable energy lead to lower prices, and shortages to higher prices, and therefore may incentivize consumer flexibility better. There are some design-related problems, though, such as a potential inefficient over incentive (Frontier & BET, 2016) or questions about liquidity deficits, surpluses and correction mechanisms (Nabe & Bons, 2014; Freier, et al., 2019).

Summarizing, the taxes and levies will be implemented in TradeRES models as follows:

- As a fixed rate per kWh of electricity consumption;
- As a percentage rate per kWh of electricity consumption.

AMIRIS already contains the option to pass volumetric taxes, levies, and subsidies to prosumers (see (D4.1)).

Contribution to the electricity market models under development in TradeRES: provides insight in the effects of charges on top of the electricity price on prosumer behaviour; demonstrates barriers to the efficient integration of small commercial and household consumers into the electricity market.

Input data: the price and structure of consumer taxes and levies on electricity

Output data: changes to prosumer behaviour with respect to the base case as described in Section 4.1

Model: AMIRIS, Backbone

4.3 Aggregation

Aggregation of distributed energy resources (DERs) has been among the very promising operations foreseen in the zero-carbon paradigm as it enables the exploitation of the full potential of those small and medium-sized resources connected at the distribution level.

In (D3.2), a separate aggregation layer was considered in the analysis of the actors' scene, with business entities such as suppliers, aggregators and virtual power plants engaging in aggregation activities. Based on the adopted classification, the suppliers are entities that buy electricity from the wholesale market or directly from the producers and sell it to the end users, while aggregators are entities that aggregate a number of end-users that own resources, like prosumers, producers or a mix of them, and engage as a single entity in markets.

Although margins in the supply segment are considered relatively low due to high competition intensity, the buy-sell spread that is incorporated in the static or dynamic version of tariffs, which may even take the form of real time pricing, represents the costs of the offered retail services. The typical pricing approaches included static tariff plans that were designed given average wholesale prices. The main aim of such plans has been the maintenance of the sales volume ensuring certain revenue levels. In contrast to that, by triggering demand response, extra challenges arise, and higher profitability opportunities emerge as the role of the supplier may become more active, through the optimization services that are internalized.

Such challenges and opportunities are just a part of the optimization operations of an aggregator, a new market player that aims to optimise the use of any kind of distributed energy resources under a combination of business models. Distributed generation assets, energy storage systems and the controllable loads can be coordinated and operated together, forming a sufficient capacity for participation in markets and creating economies of scale conditions that make such value propositions viable. Additional business models may include the provision of services to distribution system operators (DSOs) for active network management, the provision of security of supply services during emergency conditions and the participation in local energy trading. This realization potential of aggregators in several market structures has been discussed in (D3.5), where the challenges around distribution network management and the value stack that emerges from business model combinations have been highlighted. Activities included in the aggregation operations are presented in Figure 1, which is an adapted schematic of the aggregator overview of (IRENA, 2019). Beyond the optimization routines that can lead to more efficient scheduling and coordination,

the adopted forecasting approaches for anticipating the demand, the supply and the system prices also play a vital role. This information can be either generated internally or acquired by third parties and used as is or refined since less bias is introduced, the closer to optimality the outcome gets. For the optimization part, a dynamic programming approach seems suitable, while different strategies may enable the consideration of different behavioural characteristics. Additionally, the temporal flexibility aspects related to load shifting and energy storage operations that take place on the aggregation level are discussed in (D4.1).

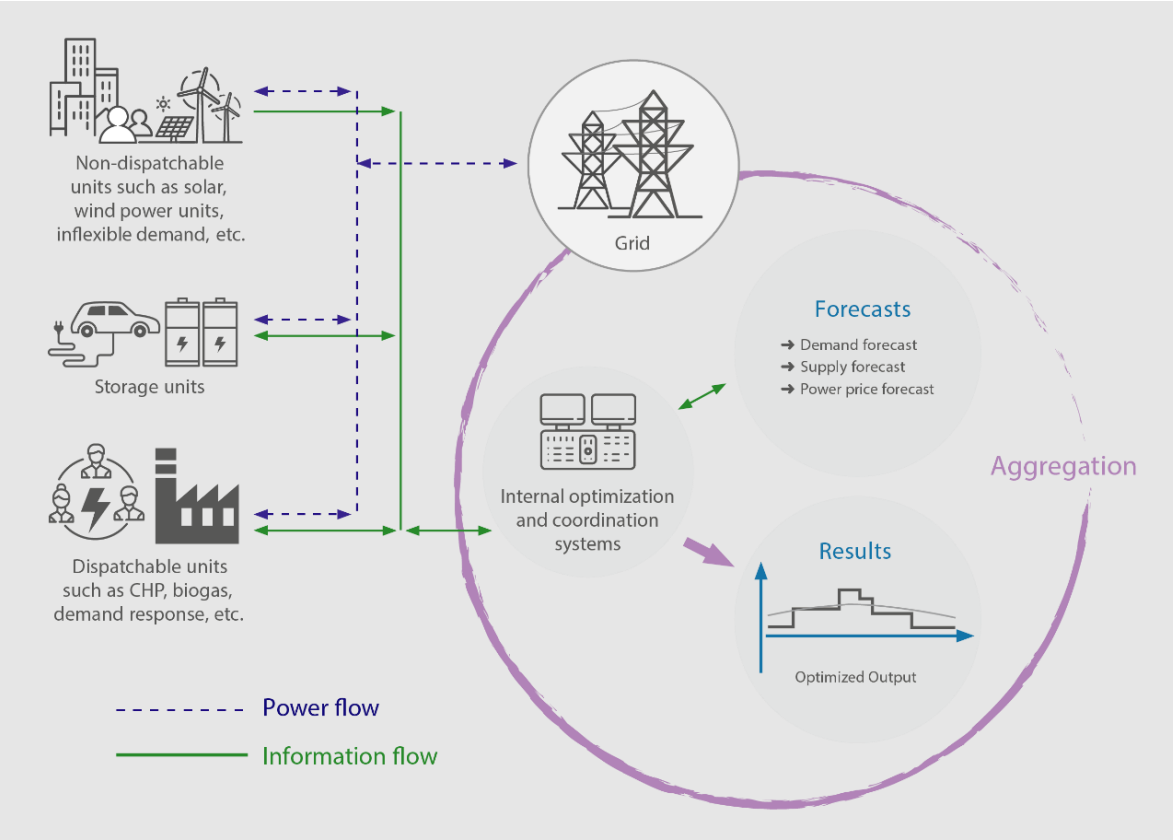

Figure 1: Aggregation operations, including forecasting, optimization, coordination activities

Given the bridge that aggregation offers between wholesale- and retail-scale sides, for its representation into models, certain key operational aspects of the micro-founded environment have to be considered. As mentioned in (D3.2), demand side operational characteristics related to the demand profiles, the load shedding actions and the demand side response representation (Shiftable fixed cycles, Continuously/discretized adjusted power) as well as storage (Min/Max energy limit, Charging/discharging power) and distributed generation (Generation profile, Curtailment action, Ramp limit, Up/down time) operational characteristics are among the important ones. As these characteristics are inherent to DERs, the asset portfolio is considered important, and its formation is dynamic in a competitive way, with coalitions being evolving over time. Of course, this level of detail is out of the scope of TradeRES and especially if the highly competitive environment of a retail market is considered, then the portfolios not being dynamic seems natural. Additionally, this does not prevent the incorporation of optimal portfolios and the consequent implicit or explicit

representation of aggregating entities. The former would include pre-aggregated resources under simplifications losing some low-level details, while the latter would analytically incorporate the several assets either under leasing schemes, or dynamic contracts and real-time pricing concepts. Versions of the implicit representation seem to suffice for studying the retail market side the relation that is developed with the energy and balancing markets.

A much more detailed consideration of aggregating agents is performed in (D4.4), where MASCEM and REStrade present current modelling approaches around agents and sketch modelling enhancements for the incorporation of emerging concepts. AMIRIS considers fixed technology portfolios but cannot represent more than one flexible agent at once.

Contribution to the electricity market models under development in TradeRES: allows to analyse the participation of flexible resources in the market through aggregators

Input data: characterization of aggregated demand with their willingness to pay / shift

Output data: Aggregated demand response volume and effects on adequacy

Models: MASCEM and RESTrade

4.4 Prosumers

Prosumers are the first class of actors defined in (D3.2) and by being the end-users and owners of distributed energy resources are in the heart of the retail market. Traditional consumers are also included in the prosumer class, as prosumers with zero generation and storage capacity, with the justification of the adopted convention being the fact that prosumers will prevail towards the 100% renewable generation era. Moreover, prosumers as the final users or groups of users consume, store, self-generate, and participate in flexibility or energy efficiency schemes, in a not primary commercial or professional way. They are distinguished based on their type to residential, enterprise, and industrial prosumers. At the same time, the group instance can be expressed through the community prosumer.

By owning assets of several technologies, which may be related to inflexible demand, controllable load (demand side response, electric vehicles, flexible heating, and cooling), energy storage systems (batteries, electric vehicles) and distributed generation (photovoltaics, wind turbines, combined heat and power, etc.), they incorporate the operational characteristics mentioned in the previous subsection. Their most dominant characteristic, which differentiates them from all other actors, is the utility maximization principle that governs their behaviour. Their needs have been the main driver for the establishment and evolution of the system as they set the demand side, while as the prioritization and shifting of loads enhances elasticity, short-term local storage adds extra time-coupling opportunities, offering further flexibility, and self-generation offsets the external energy requirements.

Prosumer agents may be related to inflexible, although curtailable, demand, which can be represented through input time series that follow the spatial and temporal resolution of the model. In its most simple form, these time series can be taken as static to study effects of static prosumer profiles on wholesale markets in an optimization model like Backbone. A more sophisticated approach would be to incorporate the part of the demand that can be shifted can either through assuming continuous or discretized power blocks or through fixed, deferrable cycles that represent certain devices and uses, as is shown in Figure 2,

with the former being characterised by its simplicity and the latter being closer to reality (Papadaskalopoulos & Strbac, 2016). Computation time can become a significant challenge in case of large systems, in which case a more aggregated approach may be necessary. A hybrid form, with continuous intervals instead of fixed cycles, but discretized states, is implemented in AMIRIS. A planning algorithm that implements a dynamic programming approach for load shifting is described in (D4.1). Energy storage systems, like the behind-the-meter batteries, constitute an extra source of flexibility that prosumers may use internally for reshaping their profile or lease its operation to an aggregating entity. Such assets may be incorporated via operating constraints that refer to their operating state of charge range, charging/discharging power limits and efficiencies. Regarding the flexibility emerging from sector coupling, electric vehicles and the space/water heating loads are among the technologies that are considered in the modelling, with a detailed analysis in (D4.2).

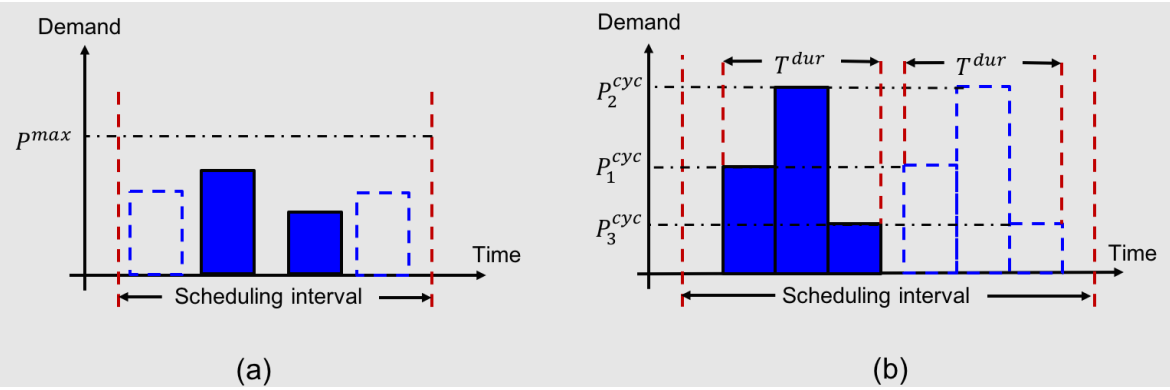

Figure 2: Flexible load modelling options (a) Continuously adjustable power and flexible shift intervals, (b) Fixed cycles and discretized power states

Regarding the explicit representation of prosumers, this can take place through representative agents that incorporate certain of the functionalities described, with the areal distribution being subject to the spatial resolution of the models. Multi-agent approaches are conceptually closer to the distributed representation of prosumers, while the alternative would include the consideration of prosumers after aggregation. The challenge that has been mentioned in (D3.5) about the loss of diversity into price-signal responses and the consequent concentration effects that may arise by the application of dynamic pricing are well known obstacles around the distributes form of demand side response that involves individual prosumers. A more in-depth consideration of the prosumer agent modelling principles and the enhancing directions proposed can be found in (D4.4).

Contribution to the electricity market models under development in TradeRES: Provides insights to the contributions of flexible prosumers to the system's demand side response and static prosumers to wholesale price formation

Input data: Characterization of prosumer load and production profiles as well as portfolios, similar to aggregators, cost and technology data for prosumer PV

Output data: Changes to load shifting/shedding and its effect on system adequacy and wholesale market prices, investment decisions in prosumer PV

Models: AMIRIS, MASCEM, Backbone

5 Electricity networks

Electricity networks aim to ensure electrical power transmission and distribution from generation to end consumers. Power networks can be split into two major subsections: transmission networks and distribution networks.

The transmission network usually consists of high to very high voltage power lines designed to transfer bulk power from major generators to areas of demand; in general, the higher the voltage, the larger the transfer capacity. Only large customers are connected to the transmission network. The transmission networks' voltages are typically above 100 kV. These networks are designed to be extremely robust, so they can continue to fulfil their function even in case of several simultaneous network failures.

Distribution networks are usually below 100 kV (or 60 kV in some countries), and their purpose is to distribute power from the transmission network to customers. Distribution networks are less robust than transmission networks and their reliability usually decreases as voltage levels decrease. There is very little 'active' management of distribution networks. Rather, they assume a “fit and forget” philosophy, in other words, they are designed and configured based on extreme combinations of circumstances (for example, maximum demand in conjunction with high ambient temperatures, which reduce the capacity of overhead lines), to ensure that even in these extreme circumstances the network conditions experienced by customers are still within agreed limits.

The following section describes existing tariffs and congestion management for transmission networks and the solution proposed and developed within the TradeRES project. Section 5.2 details a dynamic line rating model developed for TSOs. Additionally, Section 5.3 presents a web-based service conceived in the scope of TradeRES for congestion and voltage management applicable to transmission and distribution networks.

5.1 Tariffs and congestion management

Transmission network tariffs usually consist of i) a fixed component (a connection cost), ii) a component that is related to consumption, i.e., a variable component (a charge per MWh of consumption), and iii) a peak component (a charge per MW of peak consumption). Currently, the consumption peaks of small consumers are not measured but this can be done by using smart meters. Volumetric and peak components may influence network usage directly. The fixed component can only be expected to influence the behaviour of network users at the time of investment decisions, or if consumers have a choice of alternative energy infrastructure.

To the best of our knowledge, there is no electricity network tariff design that provides optimal incentives to network users. One reason is that network expansion costs are ‘lumpy’: network expansion takes place in sizeable quantities, not in a continuous mode. As a result, the capital cost of a network increases in steps as network use increases, which means that the marginal cost of the network has extremely high spikes at the points where a step increase in capacity is needed. Marginal-cost pricing would therefore hit some consumers occasionally with extremely high prices: the marginal consumer causing the last unacceptable bit of congestion would be faced with the full cost of expansion, which is not

acceptable. A second reason is that marginal cost pricing has been proven to be insufficient for natural monopolies in the regulatory economics literature since their average costs are higher than the marginal costs. As a result, network tariffs do not reflect marginal cost (Vogelsang, 2005). Another reason for the lack of optimal network incentives is associated to its collective nature. Power flows, on the other hand, cause a quadratic increase in energy losses. As a result, the individual/marginal cost of every single transaction is affected by all the other transactions that occur simultaneously, making the cost of each transaction laborious to calculate (although not impossible).

Consequently, actual network tariffs may not provide grid users with sufficient incentives to avoid network congestion. Separate congestion management methods are therefore applied in Europe. The EU prefers flow-based market coupling for cross-border links (interconnectors), while the preferred method for solving temporal congestion is via re-dispatch and market splitting for structural intra-zonal congestion (The European Parliament, 2019)[2] The payments to re-dispatched generators can either be cost-based or market-based. Locational marginal pricing, which is applied in the USA, is considered to lead to more efficient dispatch decisions (Neuhoff, et al., 2013; Neuhoff, et al., 2011). This has not been implemented in Europe so far, although Poland is planning it (Hogan & Mackowiak-Pandera, 2019; Molestad & Czekanski, 2018). The result could be a step-wise approach, in which first the cross-border flows are determined through a zonal market clearing approach as is currently already done in the EU with EUPHEMIA, after which intra-zonal congestion is handled with locational marginal pricing (ENTSO-E, 2021). This approach is less efficient than clearing the entire market through a single integrated locational pricing algorithm but appears to be more feasible in the EU.

The design of network tariffs and congestion management methods requires careful balancing of conflicting objectives; cross-subsidies and economic inefficiencies tend to appear as inevitable. As this issue is not particular to an all-renewable energy market, no new solutions will be developed within the TradeRES project. However, the impact of network tariffs and congestion management on operation and investment on expansion planning cannot be ignored. Therefore, existing tariffs and congestion management methods will be included in the model analyses when they are expected to play a role.

In model studies that involve multiple countries, cross-border network constraints must be represented to avoid outcomes that rely on unrealistic cross-border flows. A full representation of network flows is elaborate and may not always be necessary. Instead, a common approach is to model bidding zones as single nodes and represent cross-border network capacity as fixed constraints. Cross-border congestion is handled as market coupling, leading to zonal price differences (Bhagwat, et al., 2014). In the TradeRES optimization models, Backbone and COMPETES, this approach will be adopted. Refer to Table 6 in (D2.2) for a complete overview of their spatial flexibility options.

[2] See also https://www.entsoe.eu/network_codes/cacm/implementation/sdac/.

5.2 Dynamic line rating

The limiting factors for the transmission capacity of overhead lines (OHLs), i.e., the maximum allowed current (usually called *ampacity*), are established based on two main criteria: maximum conductor temperature and minimum distance above ground – or clearance (Estanqueiro, et al., 2018). Usually, to accomplish these factors, TSOs use a static line rating (SLR) methodology to assess the lines' ampacity (Couto, et al., 2020). This methodology determines the line's capacity from constant weather conditions using: i) seasonal basis information or ii) conservative conditions. For example, the typical values applied by TSOs range between 0.50 - 0.61 m/s for wind speed (direction is neglected), 1000 – 1150 W/m^2 for solar irradiance. The temperature can be adjusted monthly and spatially in summer (Portugal case) or seasonally (Spain), according to the highest temperature expected for each region (Couto, et al., 2020).

Most of the time, these reference values (strongly) underestimate the real transmission capacity of OHLs, leading to vRES curtailment, grid congestion, namely, market splitting, and redispatch occurrences bringing economic losses to market participants. Grid reinforcements to reduce the occurrence of market splitting are costly and require long planning periods and complex approval procedures. Moreover, careful cost-benefit analyses of the investment costs against the benefit of reducing the occurrence of such events are needed. Therefore, new approaches to exploit the existing power network within the actual smart context assets are crucial.

One of the most promising approaches is the use of dynamic line rating (DLR) analysis. Considering the cooling and heating cable effect' and its inertia, the DLR analysis can estimate the ampacity value, which the OHLs may be operated at each time based on the weather conditions, Figure 3. This type of procedure led to the development of detailed numerical models such as the CIGRÉ (Iglesias, et al., 2014), which has been applied successfully to different geographical regions demonstrating that DLR has significant potential to increase the cable ampacity (IRENA, 2020). DLR can be applied to all OHL transmission lines, but according to the goals of this project, it will only be applied on the interconnection lines to (potentially) increase the cross-border capacity.

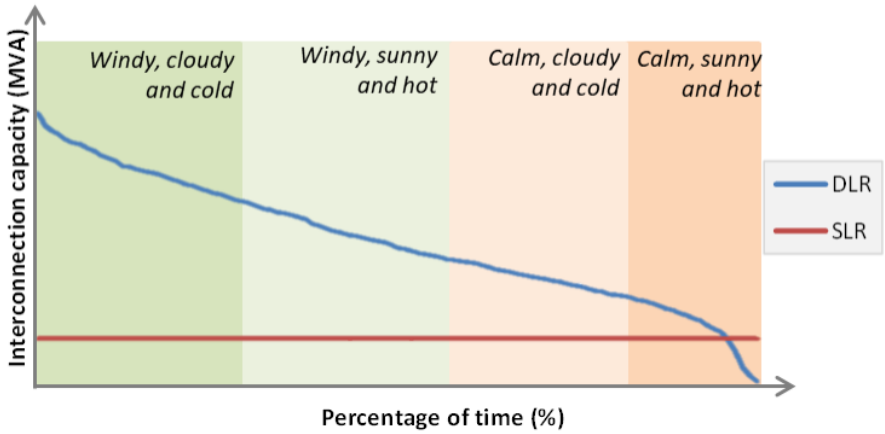

Figure 3: Interconnection capacity using a DLR analysis versus SLR analysis (Algarvio, et al., 2022)

According to several authors, the DLR enables to increase, on average, 10 to 30% of the thermal capacity over the capacity estimated using SLR without jeopardizing the cable characteristics (Estanqueiro, et al., 2018; Karimi, et al., 2018). Due to the synergy between the increased wind power generation and the line capacity (associated with the convective cooling effect) the DLR concept was initially applied in regions with high wind power potential. Nevertheless, recent studies highlight the benefit in regions with high solar potential and for interconnection power lines. Belgium's TSO, Elia, identified that the thermal capacity (due to wind cooling) of OHLs is more than 200% of the projected SLR (IRENA, 2020). Although, other transmission system assets (such as transformers and circuit breakers) that have lower ratings can reduce the benefit of applying DLR to OHLs. DLR can also provide a cost-effective generation dispatch (IRENA, 2020).

In TradeRES project, and for RESTrade and MASCEM models (and their application to MIBEL), the DLR analysis implemented in (Couto, et al., 2020) is used to feed the agent representing the TSO. A software module was created, as depicted in Figure 4. The module is based on CIGRÉ approach (Iglesias, et al., 2014).

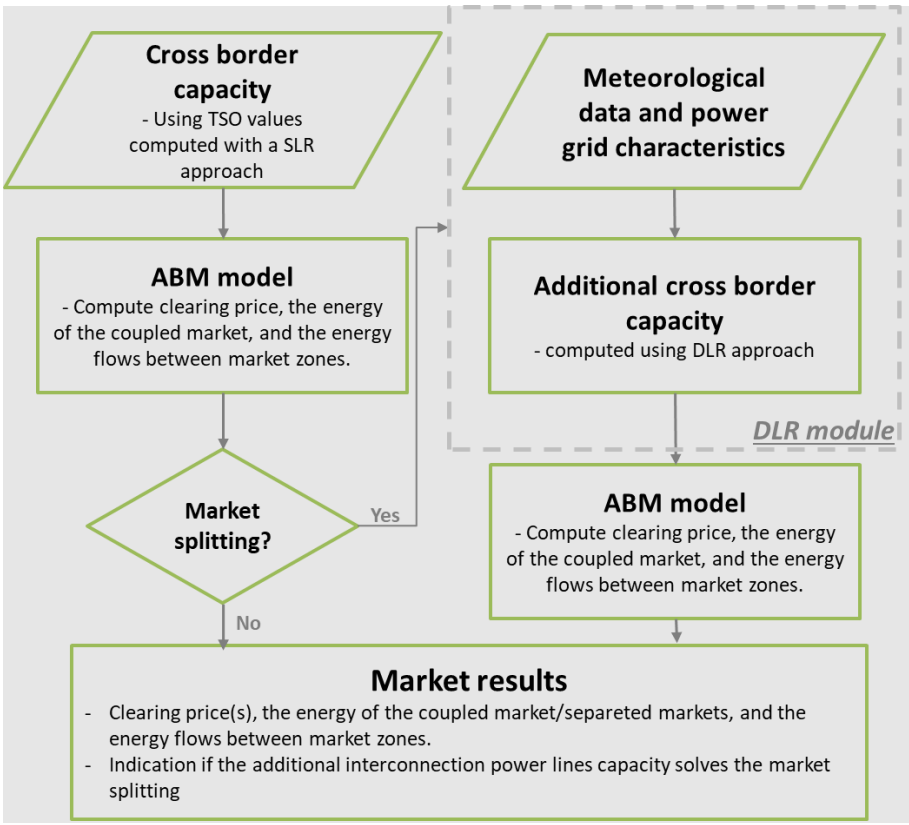

Figure 4: Main steps used to feed the TSO agent aiming to reduce the market splitting occurrences (Algarvio, et al., 2022)

The DLR module is applied for every hour where market splitting is identified in the day-ahead or intraday markets. For these hours, the DLR analysis is used to verify if there is an extra capacity for cross-border trade compared with the assumed SLR of each interconnection line. If an extra capacity is available, the interconnection capacity between regional power systems using the DLR result is recalculated. This information is then used by the

ABMs to compute the clearing price, the energy of the coupled market, and the energy flows between market zones for the different market products.

If the energy flows are higher than the cross-border capacity between market zones, even with the extra interconnection capacity attained with DLR, the markets are separated by the different market zones. In this case, the clearing price and energy are computed to each market zone, receiving as explicit supply (importing) or demand (exporting) bids the available energy for cross-border trades.

Due to the data requirements and specifications, this module will not be applied to all case studies foreseen in this project and will be only tested for the MIBEL case study.

Contribution to the electricity market models under development in TradeRES: Provides the hourly additional cross-border capacity based on a DLR analysis; It is only applied when market splitting occurs using the SLR approach.

Input data: It requires the identification of market splitting occurrences. To apply DLR, the following is necessary *i)* meteorological data – wind speed and direction, solar irradiance, and air temperature for the interconnection lines, and *ii)* transmission and distribution networks data – georeferenced layout and topology of the interconnection lines and their electrical characteristics (e.g., type of cable, number of cables, SLR, height above the sea level, etc.).

Output data: Hourly additional interconnection capacity based on a DLR analysis

Model: RESTrade, MASCEM, Backbone

5.3 Congestion in electrical networks

TradeRES has developed a Power Flow Service (PFS) with the purpose of validating the network feasibility of market results. This service supports any type of power network, including distribution and transmission networks, having a significant impact on system adequacy, RES remuneration, and balancing.

The PFS (Veiga, et al., 2021) is a web service built with Django, with the help of the pandapower Python library, to define and evaluate electrical networks from transmission to distribution grids. It encapsulates the pandapower tool in a REST API for agent-based studies and easy integration with other systems and services, allowing the modelling of real and simulated transmission and distribution grids for validation according to a given electricity market outcomes. PFS provides several types of requests, such as the definition and evaluation of a network, the evaluation of a saved network with new buses' loads and generators, and the retrieval of both the validation schemas for each one of the requests and the saved networks. The schemas built to validate the inputs of this service also allow different types of power flow algorithms, so that the user can choose the one that applies better to the scenario that needs to be tested. Service requests running a power flow analysis accept JSON or Excel files as input and allow the user to decide which type of output to receive (i.e., JSON or Excel). This consists of a very flexible and fast way of evaluating power networks, not requiring any programming knowledge, and permitting its integration into other applications and tools.

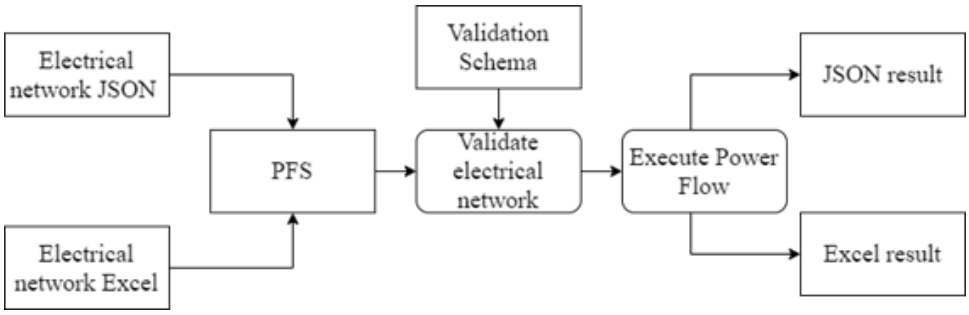

Figure 5: PFS information flow (Veiga, et al., 2021)

When distribution networks are congested, this can be managed through variable network tariffs, e.g., tariffs that increase in real time to reflect the level of congestion. Alternatively, if the network tariffs are constant, a separate congestion method may be applied.

As network tariffs do not reflect the marginal social cost of network usage, they cannot fully prevent congestion. Therefore, separate congestion management methods have been invented. There are two broad categories: i) congestion pricing and ii) flexibility markets. An example of the first is locational marginal pricing, in which local prices are varied in order to attract more generation and less consumption, or the other way around, and thereby adjust the network flows to fit the available network capacity. This method increases the price of network usage for market actors who cause the congestion and therefore yields revenues, but it has been shown that they should not simply accrue to the network operator as it provides an incentive to limit network capacity to increase revenues (Joskow & Tirole, 2000; Joskow & Tirole, 2005). In a flexibility market, the monetary flow is opposite: there, the DSO pays parties to relieve congestion. While this is easier to implement, local flexibility markets are highly susceptible to market power, e.g. in the form of inc-dec gaming (Hirth & Schlecht, 2019).

It is not in the scope of TradeRES to model possible distribution network tariffs and congestion management options.[3] The topic is large and complex, while it is not particular to a renewable electricity system. Therefore, in TradeRES, as a principle, the distribution network tariffs and congestion will not be modelled.

Contribution to the electricity market models under development in TradeRES: Power flow modelling and validation to ensure the feasibility of electricity transactions after the market clearing

Input data: network data, market outcome, mapping between market players and respective network buses

Output data: network power flow, voltage (magnitude and angle), power losses, and congestion and voltage validation (according to the network's voltage level)

Model: MASCEM, Backbone (cross border capacities)

[3] A project in which this is done is the STEP-UP Project, in which the TU Delft work package focuses on this precise problem. See https://www.stepupsmartcities.eu.

6 System adequacy

One of the leading research questions to be addressed by TradeRES models is whether an energy-only market provides sufficient incentives for investment in dispatchable power plant technologies to achieve adequacy in the future power system. With 'dispatchable' technologies, its meant all power plants that are capable of adjusting their power output to compensate for the power variability of vRES, e.g., from hydropower or biomass, energy storage and almost all conventional fossil-fuelled power plants. Demand side management and energy system integration (a.k.a sector coupling) may also play a role in adequacy, as conversion between different energy vectors may help to overcome challenges associated with vRES variable production. In the negative case, if the market does not provide enough investment in these flexible resources, the next question is, which capacity mechanism design is the most attractive for power systems with high shares of vRES. The second main question in this project, whether markets provide enough incentive to invest in vRES, is complementary to this one and will be discussed in Section 9 of this report.

The interactions between modifications to the wholesale market and capacity mechanisms will be evaluated. To evaluate capacity mechanisms, a situation of prolonged scarcity of wind and solar energy will be considered. Even when a power system is designed to have an annual average vRES capacity to supply the yearly average consumption, there will be energy deficit and surplus periods. The challenge will be to provide an optimal combination of energy storage, dispatchable generators and demand response in the system, i.e., a cost-optimal mix from a macroeconomic point of view. This requires designing the market and regulations to provide the socially desired volume of each of these technologies and services. The scenarios and the indicators to test the implementation of the model of capacity mechanisms to different case studies will be described in work package 5.

To simulate if investors will have enough incentives to invest in generation capacity, it is a requirement to consider that investors, in reality, do not have perfect foresight (of demand, the capacity planned by competitors, the regulation modifications, etcetera). Investment behaviour will be modelled with the ABM, EMLab. In EMLab, investments will only be made if the investor can have a reasonable expectation that the net present value of the investment will be positive, based on information that is available at the time of investment and the incentives, such as the prices of electricity and CO2.

One objective of the optimization models in the consortium (COMPETES, Backbone), by comparison, is to find the macroeconomic least-cost investment strategy. The ABM simulations will be compared with the results of the optimization models to determine the efficiencies of the different market design options and identify the optimal market options to be simulated in detail with ABM for different scenarios. The optimization models will indicate the best possible investments from the perspective of society. The ABMs will provide insight into realistically expected investment behaviour, given the market prices, the regulatory incentives, and the limited time horizon of investors.

To clear the short-term market, EMLab uses a segmented load duration curve which does not allow to model storage and flexible consumption. Hence, to analyse the impact of flexibility on investment decisions, the investment modules and capacity mechanisms modules of EM-Lab are soft-linked with a detailed short-term market model, AMIRIS. To enable

this model coupling, EMLab was rewritten to EMLab-py. Through the Spinetoolbox, the short-term market of AMIRIS will be run iteratively, and the results will be used for the investment decisions in EMLab.

6.1 Energy-only market

When assessing if the current energy-only market (EOM) provides sufficient incentives to achieve system adequacy, it is crucial to carefully model the price level and occurrence of peak prices in the energy-only market. In a power system mainly based on wind and solar energy, dispatchable technologies, such as storage facilities and hydrogen-based power plants, require a sufficient number of hours with high peak prices above their marginal costs to recover their long-term investment costs (Joskow, 2008). In theory, peak prices should reflect consumers' willingness to pay and thereby incentivize precisely the volume of dispatchable capacity that provides the level of security of supply desired by consumers, given the cost of these dispatchable technologies.

Therefore, for TradeRES, it is important to model demand-side flexibility as well as dispatchable generation in detail, both in the ABM simulations and in the optimization models. Particular aspects of flexibility resources that need to be considered in the models are:

- Capacity and energy volume that can be provided (by storage, hydrogen or biomass) or shifted (by demand);
- Cost (of generation and storage) and willingness to pay for secure supply or accept curtailment (of demand).

In AMIRIS, load shedding is represented by dividing the overall electricity demand time series into segments and providing each segment with a baseline demand time series as well as a value of lost load (VOLL) that reflects the consumer groups' willingness to pay. Demand-side bids are placed at this price by the demand trading agent. Thus, a more granular aggregated demand curve is intersected with the supply-side merit order. Load shifting is represented using a dynamic programming approach and accounting for shift times as well as load shift energy levels and the restrictions in terms of power, energy and shift times. Deliverable (D4.1) contains a description of the implementation. Backbone also allows the integration of load shedding units with different capacities and curtailment costs.

Besides the flexible resources and demand, the EOM will be analyzed with the increased flexibility that results from the modifications to the regulation of the market as described in Sections 2 and 3.

6.2 Capacity mechanisms

Several capacity mechanisms will be modelled in order to evaluate their impact on system adequacy and the cost of electricity to consumers. Many capacity mechanisms have been devised and tried out (Doorman, et al., 2016). We will focus on three types: yearly capacity markets, as centrally organized auction-based mechanisms, capacity subscriptions, as it is a promising innovation (see also (D3.5)); and a strategic reserve as it causes lower market impacts and is recommended in the Internal Market for Electricity, Regulation (EU) 2019/943. In the next subsections, the proposed implementation of the capacity mechanisms will be described based on their implementation in EMLab.

In Backbone, capacity mechanisms can be considered by adding a capacity margin constraint. This requires additional available capacity on top of the net load in all circumstances. This capacity can come from regular power plants, vRES (based on their availability), storage (to the extent they generate during peak net load events) and demand response (as they behave or according to their capacity depending on the modeller choice). It is presented in Equation (64) in (Helistö, et al., 2019).

6.2.1 Capacity market

Capacity markets have been introduced in many countries with the purpose of securing the reliability of the system by allowing generators to recover their fixed costs and generating investment incentives.

In EMLab, the yearly capacity market was modelled simplifying the New York Installed Capacity market (NYISO-ICAP) rules. In the NYISO-ICAP, the load serving entities (LSE) are responsible for procuring capacity credits. The capacity market is designed to meet the maximum energy demand plus an installed reserve margin (IRM). The demand curve is composed of a horizontal cap and a downward-sloping demand curve that reduces the price volatility. The price cap is set to 1.5 times the net cost of new entry (CONE). This is the cost of a new peaking power plant minus the expected revenues from energy and ancillary service markets. Without this slope, prices would result near zero when there is sufficient supply and near the market price cap when the supply is insufficient. The slope passes through a minimum installed capacity requirement that accounts for a reserve margin (Bhagwat, et al., 2017; Byers, et al., 2018).

The capacity market is modeled as a uniform price auction where the bids are sorted in ascending order. In the NYISO-ICAP, there are more auctions each year, but in EmLab an annual auction is considered. Generators offer unforced capacity in a series of yearly auctions. The unforced capacity is calculated by factoring out the derating factor of the technologies to the installed capacity. The derating factor is established according to the historic unavailability of the technology. All technologies can participate, and power plants are awarded a one-year contract for the following year (Bhagwat, et al., 2017).

6.2.2 Strategic reserve

The European Commission has established in (The European Parliament, 2019) Article 21 (General Principles for capacity mechanisms) that the member states should evaluate if a strategic reserve is capable of addressing the resource adequacy concerns. Only if this is not the case, another mechanism may be implemented.

A strategic reserve is under the TSO's control, which designates a volume of generation capacity to be held in reserve. This capacity is kept out of all markets and is activated only in scarcity situations. The TSO covers the fixed costs of power plants that have a low probability of being called into the wholesale market to avoid mothballing. In case the plants are activated, the TSO keeps the difference between the market revenues and the plant's marginal costs to offset the reserve's cost. The European regulation enlists the requirements for the strategic reserve in Article 22 (Design principles for capacity mechanisms). These are: “the strategic reserve resources should be dispatched after the TSO exhausted their balancing resources; during imbalance settlement periods, imbalances in the market are to

be settled at least at the VOLL; the output of the strategic reserve should be attributed to balance responsible parties through the imbalance settlement mechanism; the resources of the strategic reserve should not participate in the wholesale and balancing markets for the contractual period…" (The European Parliament, 2019).

(Bhagwat, et al., 2016) implemented a strategic reserve in EMLab. They considered that the reserve price should be parametrized such that the revenues earned with the strategic reserve should be equivalent to the revenues from an EOM (to avoid changing the average electricity price for market parties). The parameters and rules of the strategic reserve in Emlab-py will align with the principles within (The European Parliament, 2019).

6.2.3 Capacity subscription

Capacity markets, in all their variants, have many drawbacks, such as complexity and various sources of economic ineffiencies. The effectiveness of a strategic reserve is disputed, while its property of making the system operator the generator of last resort also is a drawback. Capacity subscription is an innovative solution with very promising properties. It puts the consumer at the center, letting households as well as commercial consumers decide ex ante how much they are willing to pay for reliable power. This provides them with an optimal incentive for demand management while offering providers of reliable power a stable, low-risk market.

In a market with capacity subscription, consumers choose the level of reliability they prefer for scarcity situations by paying for a specific capacity, e.g. several kW per household, that they want to be able to consume. Under normal conditions, they may consume more, but during periods of energy shortage they will be limited to their maximal contracted capacity. The payments benefit the generation companies by providing a clear investment signal and a stable revenue for dispatchable capacity. This mechanism assumes that consumers are exposed to real-time prices.

To model capacity subscription, the main requirement is to parametrize the demand side response. The willingness to be shed can be differentiated according to consumer classes, considering their baseline consumption (MWh/h) and price thresholds (willingness to pay). The price of a subscription can be modelled as a function of the peak demand of the various consumers. To calculate the cost of the capacity subscription, the supply curve can be modelled with the bids of the power plants as in the capacity markets.

Contribution to the electricity models under development in TradeRES: Investigates the need for and performance of capacity mechanisms in a near 100% renew-able electric power system, considering future flexibility options; Capacity subscription is a promising, innovative mechanism that is included.

Input data: It requires forecasted revenues from the wholesale market (yearly unit production and average unit production price) fuel prices, fixed O&M costs, unit capacity, unit efficiency, parametrization of demand side response (for capacity subscription).

Output data: Assigned capacity mechanism support per unit, electricity price per time unit, total cost of electricity (including the cost of the capacity mechanism) to consumers, cost recovery, system adequacy.

Model: AMIRIS, EMLab

7 Sector coupling

The future power system will be characterized by a higher level of interaction between the industrial, transport and electrical sector. For example, the recent European plans for a green hydrogen strategy can enhance the system flexibility. Deliverable (D4.2) outlines the consortium agent-based modelling capabilities with respect to sector coupling (in particular heat pumps and electric vehicles) and its model enhancements. The enhancements of the sector coupling representation are outlined in (D2.2). So far, AMIRIS is not able to model hydrogen demand and supply. Nevertheless, the recent European plans consider the green hydrogen strategy as a central pillar to enhance the system's flexibility. This flexibility should be considered to estimate the need for installed capacity in scarcity situations. Hence, AMIRIS will consider the hydrogen demand from optimization models.

A deeper coupling of different energy sectors also has impacts on the different market aspects discussed in this report. In some cases, it might be beneficial to have multiple energy sources for a single purpose. For example, some heating solutions might be based on electricity *and* fuels – e.g. hydrogen in the future – as well as increased heat storage capacity. In such situations, the owner of the asset might need to consider multiple markets for different energy commodities and even markets for emission allowances to make a least cost decision. The design of the different markets should enable this kind of multi-market situation. Furthermore, an operational question might be whether it is more profitable to buy, sell or store energy which can be converted to and from various forms or other products, and the different commodities have their respective markets.

Although TradeRES models are not able to model all multi-market situations, the models are being enhanced to provide insights into specific markets. For example, MASCEM is being enhanced to consider the coordinated bidding of self-interest EV aggregators. These aggregators can also participate in local and wholesale electricity markets. AMIRIS is also being enhanced to represent flexible EV charging. Furthermore, it will consider time dynamic end-user tariffs to give insight into the participation of heat pumps. Albeit the flexibility of both agents (EV and heat pumps) cannot be represented in parallel.

System adequacy can be achieved through enough generation capacity that can always be dispatched at will. Energy sector integration involves the conversion of energy into different forms, some of which are more economical to store. This allows for more dispatchable generation. Energy sector integration should be considered as an option for increasing or maintaining power system adequacy.

Contribution to the electricity market models under development in TradeRES: ; model the impact of heat pumps and flexible vehicle demand on electricity prices; model the availability of hydrogen as a fuel for power generation; demand for hydrogen

Input data: cost and performance data of electrolysers; hydrogen demand; hydrogen network and storage data; heat technology parameters; electric vehicle load profiles

Output data: cost and quantity of hydrogen production; cost and quantity of hydrogen consumption for electricity generation

Models: AMIRIS, Backbone, MASCEM, COMPETES

8 Carbon policy

In an all-renewable energy system, there is no need for a carbon policy. In TradeRES, carbon policy will be included in model analyses of interim steps in the energy transition. The modelling of carbon policy will be based on the European Emission Trading System and possible changes to it.

The European Emission Trading System (ETS) is the main policy instrument in the European Union for reducing greenhouse gas emissions. It works according to the cap-and-trade principle, implementing a ceiling on total CO_2 emissions and allowing the trade of emission rights to allow for the most cost-efficient emissions reduction options. To stabilize the prices, the EU has introduced a Market Stability Reserve. In the past years, this mechanism has passed through several reforms. From 2021 onwards, the annual rate of emission allowances will reduce by 2.2%. On July 14th, 2021, the intermediate target for greenhouse gas reduction was set to 55% by 2030, compared to 1990, which asks for a stronger reduction rate.

Furthermore, a separate scheme for traffic and the heating sector not yet covered by the EU ETS shall be set up[4]. A more extensive explanation of the basic policy and its status and late evolution is outlined in (D3.5). In this subsection, we will focus on the modelling approach for this policy instrument.

At the most basic level, a CO_2 market can be implemented as an annual auction of CO_2 credits. The auction volume is set exogenously, as in reality, it is set by the government. The demand for CO_2 credits stems from the facilities that emit CO_2 – in our models, the power plants. Per power plant, the demand is equal to the expected emissions in the next year and the willingness to pay for CO_2 equals the expected market revenues minus operating costs. Thus, by dividing the expected operating margin by the associated emissions, a maximum price per ton of CO_2 is derived.

This method may lead to highly volatile CO_2 prices. Therefore, it is necessary to add a module that represents a forward market for CO_2. By simulating intertemporal arbitrage, CO_2 price volatility will be dampened to a more realistic level. The forward market for CO_2 should be based on a simulation of supply and demand in a future year. The supply of CO_2 credits is regulated (we will assume a reduction path in accordance with the EU Green Deal); the demand can be simulated by accounting for changes in energy demand and the electricity generation portfolio. If the future price of CO_2 is expected to increase, this will lead to a higher spot price given the opportunity cost of using credits. This will reduce the demand for credits (i.e., the current emissions), leading to more banked credits, which will help reduce the future shortage. The other way around, if a future surplus of credits is expected, this will depress the short-term price and lead to more emissions.

[4] Press release by the Commission: https://ec.europa.eu/commission/presscorner/detail/en/IP_21_3541, accessed 17.08.2021.

In some countries, a minimum price has been implemented to provide a stronger price signal for investment in decarbonization. By reducing the price risk of investments in decarbonization, they should take place sooner, thereby reducing CO_2 emissions as well as the average price of CO_2. This policy option will be included in the models.

The modelling of the ETS will be based on (Richstein, 2015) who implemented it in EMLab. The reduction options in EMLab were limited, however, to fuel switching and a few low-carbon generation technologies; in TradeRES, the much more refined market representation, as well as endogenous investment in vRES, will provide a significant improvement in the quality of the analysis.

Contribution to the electricity market models under development in TradeRES: provides insight into the impacts of the ETS and the options of a minimum and a maximum price on CO_2 reduction pathways

Input data: CO_2 policy settings: the ETS as it is now, or the addition of a minimum and possibly also a maximum price

Output data: CO_2 emissions, CO_2 prices, investment in CO_2 reduction

Model: EMLab, Backbone

9 RES support schemes

Analogous to the analysis of investment in dispatchable generation, the analysis of investment in vRES will start with an energy-only market without any financial support. If the wholesale market (and its modifications) does not provide sufficient revenues to invest in renewable energy technologies, we will investigate different support instruments, namely market premia, contracts for difference, feed-in premiums, and capacity-based support (CEER, 2021) in AMIRIS.

It is well known that a higher volume of a type of renewable energy in a market zone may cause its market value to decrease, as its generation occurs typically in a synchronized manner affecting large spatial areas and therefore usually dominates the local market trading in such periods (Hirth, 2013). This is often referred to as the vRES 'cannibalizing' effect (López Prol, et al., 2020), but fundamentally, it is a normal phenomenon in markets that the return-on-investment declines when supply increases. A particular issue with vRES is that wind and solar PV installations have similar marginal costs (close to zero), and are basically non-dispatchable, therefore tend to remain producing as long as they have primary energy resources and, as a result of which, they tend not to recover much of their investment when they feed in their highest volumes and are setting the market price.

A second challenge is weather uncertainty, as a result of which annual revenues of vRES may vary between years, which may contribute to investment risk, even in a long-term stable decarbonized market. An increase in flexibility may stabilize future electricity prices, as was explained in Section 5.1 of (D3.5), but the extent to which this will occur is uncertain. As a result, the need for financial support (e.g., acting as an environmental retrofit to RES) in an all-renewable electricity system is not clear at this time of the project, but we expect it will be known after the TradeRES case study simulations (in WP5).

It is a core objective of TradeRES to investigate this issue with its models. Therefore, the base case will be a market in which vRES need to recover its costs through the market (the wholesale market and possibly the balancing market). In addition, several types of renewable energy support instruments will be analysed. Firstly, we will model ***contracts for differences***, which are currently a common instrument, as well as two other forms of price support, namely, a ***feed-in premium*** and a ***market premium***. In addition, we will model ***capacity-based support***. Capacity-based support of vRES was applied at the end of 20th century in many western countries, mainly in the European Union. This way of supporting renewable technology had variable results, some reportedly negative. One of the main issues normally pointed out was the tendency to artificially increase the investment costs of projects by developers. Subsequently, it was concluded that renewable support-schemes should be aimed at the operation/efficiency of the units and not investment. This is now the established view and has been applied, e.g. in projects supported by NER300 European programme and Innovation Fund.[5] However, capacity-based support has as an interesting

[5] NER 300 programme | Climate Action (europa.eu), consulted on 28.07.2021.

feature, that it does not distort the short-term market incentives and may therefore contribute to more efficient market operation (Morales-España, et al., 2021).

9.1 No vRES support

This reference option entails all vRES selling the bulk of their electricity generation through the day-ahead market. In reality, they also may sell their output through specific long-term contracts; currently, power purchasing agreements are popular. However, in an all-renewable energy market, there will be no bonuses for renewable energy, as it likely is the only energy source, and it may be expected that the price of long-term contracts will approximate the average price that the generators would have received in the short-term market. For wind and solar PV generators, this price – called the (energy carrier-specific) market value – will be lower than the average market price because this price will be lower when more of their generation is available (see 'canibalization' effect above). In addition to market performance indicators, such as market-based cost recovery, the market value will be monitored in the model runs to evaluate the cost recovery of all RES, variable or not.

Most TradeRES models (including AMIRIS, RESTrade, MASCEM) allow for vRES generation being marketed without support. In this case, the RES feed-in potentials are marketed at their marginal costs. Hence, traders marketing the vRES generation are not willing to accept prices below the marginal costs and would curtail the generation in this case.

The optimization models within TradeRES can be applied to model wholesale price dynamics and their effects on the revenues of vRES at the pan-European level, providing a reference for ABMs. Certain vRES support schemes will also be modelled explicitly.

9.2 Contracts for Difference

Large renewable projects are currently supported with contracts for difference (CFD) in a number of European countries. This instrument pays renewable generators the difference between a reference price and their market revenues. A payback obligation in case the market revenues exceed the reference price or a limit on the total amount of support per MWh of energy production may also be implemented, as well as a restriction to hours in which the market price is not negative, in order to avoid an incentive to keep producing when there is a surplus of energy. Usually, the amount of support is determined in a state-administered auction scheme. Thus, producers of RES bid competitively for the support, which is therefore awarded to the producer who needs the lowest level of support, i.e., bids to the lowest reference price. Producers bid before they build their RES installations. In case of offshore wind parks, they usually bid for a package that includes permits and the network connection in addition to the subsidy.

Model implementation will hinge on the determination of the reference price. It may not be easy to emulate the bidding process, as producers' bids are determined by a number of factors such as the estimated costs of the vRES plant, financing costs and risk premia resp. risk aversion. In principle, not considering risk premia and market imperfections, the reference price should reflect the levelized cost of electricity. This is therefore a suitable starting point for model implementation.

The payments are simply the difference between this reference price and the received market price. As mentioned above, they may be limited to a maximum payment per MWh, to hours in which the market price is not negative and to a maximum number of hours per year.

In summary, as a departing point, CFD will be modelled as follows:

- The **reference price** will be set equal to the levelized cost of electricity of RES generation, i.e., the average cost of new RES generation units;
- The **payments to the vRES** generators will be equal to the difference between the reference price and the market price; payments are made per unit of produced electricity. Optionally, the payments may be restricted to:
    - Hours with non-negative prices;
    - A maximum payment per MWh;
    - A maximum number of operational hours per year;
    - Whether or not to let generators pay back when the market price exceeds the reference price.

In AMIRIS, CFDs have been added as a support instrument for RES support building on the previous architecture. This architecture contains a central support policy agent who is attributed with all the necessary information for determining support pay-outs. This also comprises projected or, at a later stage, potentially modelled levelized cost of electricity estimates for vRES. A trading agent markets the technology-specific aggregated RES capacity infeed whereby the price depends on the opportunity costs resulting from the support instrument and its limitations (e.g., no support after a given number of hours with negative prices, caps for capacity or full-load hours). RES units are aggregated to sets of portfolios for the particular trading agent. Parameterization as well as generalization of the approach are still work in progress and to be addressed within the TradeRES case studies of WP 5.

Furthermore, there is an implementation of the variable market premium scheme in AMIRIS which can be classified as a one-sided CFD since there is no payback obligation in case the market revenues exceed the reference price. The market premium amount paid is dependent on the energy carrier-specific market value which is determined ex-post for a given period. It is defined to be the difference between the reference price and the respective market value. Thus, the trader is willing to offer RES capacities at negative prices with an absolute value that is smaller than the difference between the (near zero) marginal costs and the expected market premium since this does reflect the opportunity cost of the support instrument.

9.3 Capacity-based support

Capacity-based support of renewable energy generators does not distort the short-term market incentives. It is easy to model: generators receive a subsidy per installed MW of generation capacity. The main question is how to determine this level in the model, also in view of providing fair support for different types of renewable generation.

For AMIRIS, capacity premiums have been added as a support instrument for RES. A previous implementation of a prior AMIRIS version has been built upon (Reeg, 2019). Parameterization is done in the course of the TradeRES WP 5 case studies. This includes the

design question on how to distribute the payout of the capacity premium over time. In the optimization model Backbone, a capacity premium can be implemented by reducing investment costs of renewables accordingly. The main difference of capacity-based support and the capacity mechanisms from Section 6.2 is in the targeted technologies to which they apply. While the capacity mechanisms are in most cases technology agnostic and award controllable capacity from generation, consumption and storage side, the capacity-based support of vRES is intended to incentivize deployment of controllable renewable generation.

9.4 Feed-in Payments

A feed-in tariff provides a fixed amount of money per unit of electricity generation. A feed-in premium in turn, is referred to as a fixed payment on top of market revenues. Concerning variable feed-in premia, see Section 9.2 “Contracts for Difference”.

A single, technology-unspecific payment would increase the overall investment in renewable energy, while the differences in cost and output characteristics between the different technologies would lead to an efficient dispatch of technologies. Furthermore, technology neutral designed payments entail the threat of ending up with lock-ins (Leprich, et al., 2013). For AMIRIS, it is planned to model technology-specific fixed feed-in premiums.

A variant of a feed-in premium is a fixed market premium. In this case, the renewable energy generator receives a fixed premium on top of the electricity price. It may be implemented with a lower limit to guarantee the economic viability of the technologies’ installations and an upper limit (floor and cap prices). Spain used this option until 2010, considering a reference premium of 30.99 €/MWh, with a lower limit of 75.41 €/MWh, and an upper limit of 89.87 €/MWh.

The main difference of vRES behaviour regarding a fixed feed-in tariff vs. a fixed market premium or a CFD appears to be that with a fixed feed-in premium, they have the incentive to produce and sell as much kWh as possible, while with a fixed market premium or a CFD they would consider the current market price and cap production at the negative price equal to the level of a market premium (considering operational costs). In the case of a mere capacity-based premium, rational vRES producers would cap their production at any price below their marginal cost since they would not receive any revenue from that. This behaviour will be analysed within the agent-based model simulations in our project. In the optimization model Backbone, the impact of this behaviour on European wholesale prices can be studied by representing a feed-in premium as negative O&M costs in contrast to regular O&M costs for scenarios with CfDs.

Contribution to the electricity market models under development in TradeRES (10.1-10.4): provides insight into the effects of different vRES support instruments on the refinancing and development of vRES, on investment risk in vRES and the effect of different support schemes on wholesale market prices

Input data: vRES support instrument parameters and conditions (specification of how much support is issued under which circumstances)

Output data: investment in vRES, vRES operation, including curtailment, vRES market values and capture prices (received market prices by vRES generators), cost of vRES support

Model: AMIRIS – EMLab, Backbone

9.5 Green Origination certificates

In Europe, energy providers are obliged to publish the renewable share of their purchased energy. Since electricity is a homogeneous good, tradable green origination certificates were introduced in Europe in 2001 to allow for a distinction between renewable and "grey" energy on an annual-sum-level. Particularly, they allow producers of renewable energy to issue a certificate for each "green" MWh produced to a national registry and sell this certificate to a provider of electricity that wishes to demonstrate its renewable electricity share with green certificates. Historically, origination prices were low, and therefore, did not provide a very attractive source of income to renewable providers (Wimmers & Madlener, 2020). However, with increasing ambitions of particularly industrial customers to become climate-neutral, there is an increase in demand in demonstrating one's "green" electricity supply, even to the extent that it is in real-time and not only in terms of its annual sum. Therefore, this additional source of income for renewables will be investigated by modelling green origination as an input to be used by renewables with a negative, possibly time-variant input price in the optimization model Backbone.

Similarly to the tender procedures to model the required support amount, the tender process for green origination certificates is out of scope for the TradeRES modelling activities. Thus, prices for green origination certificates will be depicted using an approximation of certificate prices that might be realized. Possibly this certificate price will be assumed to be negatively correlated with current available renewable production in order to capture the real-time value of green energy.

Contribution to the electricity market models under development in TradeRES: provides insight on the effects of an additional source of income for vRES on investments in vRES as well as its impact on wholesale market prices

Input data: assumptions on future certificate prices

Output data: investment in vRES, vRES operation, vRES market values, wholesale market prices

Model: Backbone

10 Final remarks

Together with the other deliverables of Work Package 4, this deliverable outlines the scope and model conceptualization of the models that will be run in Work Package 5. As the models are continuously further implemented, their documentation will be refined. This document outlines the main modelling choices that have been, are currently being or will be, implemented in the suite of models that is under development within the TradeRES project. System adequacy – the ability of the electricity system to meet demand under all circumstances – is a key aspect. As it depends on the availability of generation, storage and demand response at all system levels, on network capacity and on sector coupling, ideally it would require a detailed operational analysis of the full integrated system. However, because this is not feasible, a modular modelling approach is applied to handle the large scope and computational complexity of the analysis as described. This approach of coupling models extends the state-of-the-art in integrated energy system modelling.

Various policy options for system adequacy will be modelled, with the energy-only market as the reference case. Improved flexibility options will be included, with the question of whether they will provide sufficient stability to the market or whether a capacity mechanism will improve the performance of the market in terms of adequacy and price stability. Existing as well as new capacity mechanisms, such as the capacity subscription, will be analysed. Contrary to existing analyses, their performance will be tested in the context of an all-renewable energy system with innovative flexibility options. The contribution of more flexibility from the wholesale market (as described in Section 2) and from aggregators (as described in Section 4) to the energy-only market and to different capacity mechanisms (as described in Section 6) will be evaluated, as well as the impact of sector coupling (Section 7).

The second main question that is addressed in this project is the degree to which variable renewable energy sources will be able to recover their costs in a future electricity market. Again, the energy-only market is the base case, while various policy support instruments will also be modelled (Section 9). And again, a key modelling question is to what degree future improvements to system flexibility will be able to absorb the fluctuations in renewable energy generation and thereby support their business case. The impact of carbon policy – the ETS and possible modifications to it, as described in Section 8 – will be included in analyses of interim steps towards full decarbonization.

This project provides methodological innovations that are needed for researching long-term market design innovations. Both the questions of the economic viability of market-driven investment in vRES and the question of long-term system adequacy in a low-carbon electricity system depend on the stability and predictability of electricity prices in such a future system. This, in turn, depends on the available flexibility options, from household demand response to large-scale energy storage, and how well these options are integrated in the energy system. To model the interactions between decentral generation, storage and demand flexibility and the wholesale market, where large wind farms and back-up plants sell their power, TradeRES uses model coupling. Thus, cutting-edge new market designs are investigated with cutting-edge modelling approaches.

In this deliverable, the enhancements to temporal flexibilities in the models were mentioned briefly, as (D4.1) enlist their details. Similarly, innovations to the governance of consumers are captured in (D4.4). With respect to transmission networks, an innovative approach to maximize the capacity is dynamic line rating, which will be evaluated in the MIBEL case study.

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