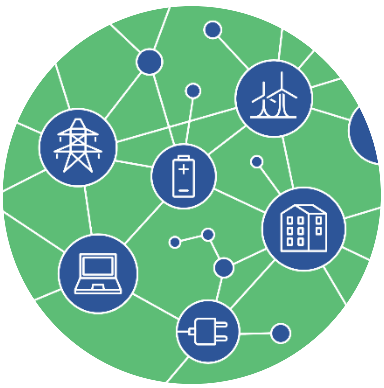
OSMOSE

OPTIMAL SYSTEM-MIX OF FLEXIBILITY SOLUTIONS FOR EUROPEAN ELECTRICITY

Quantitative analysis of selected market designs based on simulations

D2.4



Contact: www.osmose-h2020.eu

The project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 773406

Document properties

Project Information

Programme	**O**ptimal **S**ystem-**M**ix **O**f Flexibility **S**olutions For **E**uropean Electricity
Project acronym	OSMOSE
Grant agreement number	773406
Number of the Deliverable	2.4
WP/Tasks related	WP2/Tasks 2.3 and 2.4

Document information

Document Name	Quantitative analysis of selected market designs based on simulations
Date of delivery	28/02/2022
Status and Version	V2
Number of pages	86

Responsible

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Approver	Nathalie Grisey (RTE)

Dissemination Level

Type (distribution level)	☒ PU, Public ☐ CO – full consortium, Confidential, only for members of the consortium (including the Commission Services)

	☐ CO – some partners, Confidential, only for some partners (list of partners to be defined)

Review History

Version	Date	Reviewer	Comment
V1	28/02/2022	Nathalie Grisey	Version sent for review
V2	22/03/2022	Nathalie Grisey	Validated version after consideration of reviewer comments

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List of acronyms and abbreviations

In the table is listed the acronyms and abbreviations used in this document.

Acronym	Meaning
AS	Ancillary Services
CCGT	Closed Circuit Gas Turbine
CP	Clearing Price
DA	Day Ahead
DER	Distributed Energy Resource
DG	Distributed Generation
DN	Distribution Network
DSO	Distribution System Operator
EUR	Euro
GIS	Geographic Information System
GW	Giga Watt
HV	High Voltage
HHV	Extra High Voltage
ID	Intraday
LV	Low voltage
MVA	Mega Volt Ampere
OPF	Optimal Power Flow
OTC	Optimal Topology Control
PSH	Pumped Storage Hydroelectricity
PTDF	Power Transfer Distribution Factor
PV	Photovoltaic
RES	Renewable Energy Sources
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
VRE	Variable Renewable Energy

0 Executive summary

The electricity system is subject to significant ongoing structural changes on both the supply and demand side. In particular, the massive expansion of decentralized renewable energy is leading to increased variability and uncertainty, both in terms of time and space, making the balance of supply with demand more challenging. These changes are also affecting the electricity markets' ability to perform their different tasks: determining the short-term behaviour of power system assets, sending appropriate investment signals and ensuring assets can recover their investment costs.

The aim of OSMOSE's work package two is to evaluate the ability of different market designs to lead to an optimal mix of flexibility solutions, as well as operate it effectively. Deliverable D2.3 described the modelling used for this evaluation. This deliverable will now present the different case-study set-ups along with the detailed results of all the performed simulations.

RTE made use of their agent-based model ATLAS to simulate the fine details of the different steps in generator and consumer agents' decision making in the day-ahead and intraday markets. The model was used in two different case studies, looking at both a zonal and nodal market configuration in a 2030 setting. Covering the whole of Europe for a period of 24 hours, the simulation results highlighted (i) the significant differences between day-ahead and intraday market outcomes and hence asset revenues, (ii) the importance of interconnection to manage these differences, making congestions difficult to predict, and (iii) the need for further work to make quantified assessments of potential future market designs.

In a complementary, benevolent monopoly-based modelling approach, UDE used their tools, JMM and CEGrid, to simulate the operation of the European power system over a full year. Again, both a zonal and market configuration were considered. The analysis focussed specifically on the identification of the generation technologies most involved in adjusting their positions between the day-ahead and intraday markets. It also included an evaluation of the operational margin of a storage device on different nodes of central-western Europe.

EnSiEL used RTE's nodal case study as a basis to test their downscaling methodology, which simulates power system behaviour at the TSO/DSO interface, and evaluates whether distributed flexibility products can be activated on the ancillary services market while respecting local network constraints. Two planning strategies were used to determine how renewable capacity is spread on the distribution network, with notable impacts on the domain of feasible distributed flexibility product activation.

Comparing the different simulation results is the focus of Deliverable 2.5. It will also discuss the various recommendations that can be drawn from this work, both from a modelling and regulatory perspective.

1 Introduction

The overarching objective of the work package 2 is to simulate the short-term operation of future European power systems, under different market designs considering novel flexibility options and space-time downscaling. Deliverable 2.3 described the methodological frameworks developed by WP2 partners in their respective studies. In this document, we present the different case-study set-ups, along with the detailed results of all the performed simulations.

Each partner's work will successively be described: RTE (Section 2), UDE (Section 3) and EnSiEL (Section 4). RTE's work on the impact of topological actions will then briefly be discussed (Section 5). Comparing the different simulation results is the focus of Deliverable 2.5, which will also discuss the various recommendations that can be drawn from this work, both from a modelling and regulatory perspective

2 PROMETHEUS and ATLAS model results

2.1 Introduction

The aim of the work presented in this section is to simulate the short-term operation of a power system, with a specific focus on the gradual reveal of load- and VRE-related uncertainty to market participants and its impact on their decision making. To do so, we used the PROMETHEUS and ATLAS-based methodology described in section 4 of deliverable D2.3, which allows the agent-based simulation of a sequence of day-ahead and intraday market sessions. This methodology was applied to two different settings, one with a zonal market configuration, the other with a nodal one.

Load- and VRE-related uncertainty, modelled using the methodology described in deliverable D2.1, can lead to important changes in net load forecasts (see Figure 1) between the day-ahead and intraday horizons[1]. Considering the time required to turn certain generation technologies on and off, this forces market agents to make their decisions gradually. This has a significant impact on the resulting power system dispatch; being able to model the difference steps of a market sequence is hence crucial to understanding the details of short-term power system operation.

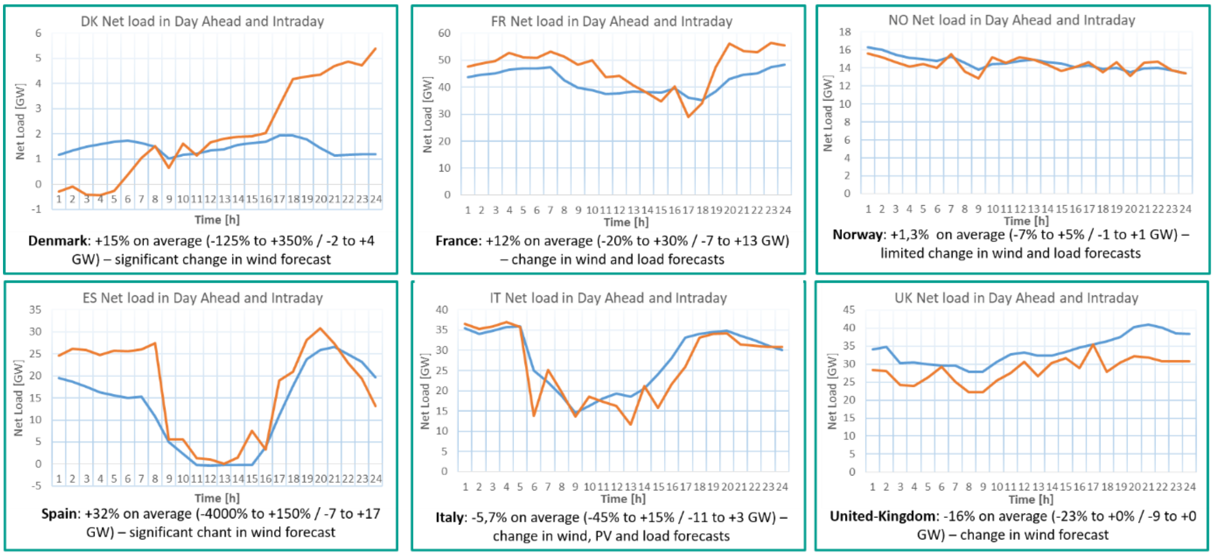

Figure 1: For the zonal study, net load forecasts for the Day-Ahead (blue) and Intraday (orange) markets, shown for Denmark, France, Norway, Spain, Italy and the United-Kingdom

The zonal and nodal simulations are based on different case studies, however their overreaching logic and the nature of their input data format is the same: they both build upon Antares simulations. Note that these Antares simulations have the same network representations as their ATLAS counterparts: one zonal and one nodal. As described in

[1] Note that for methodology used to generate the load and VRE generation forecast errors (see deliverable D2.1) does not express geographical and temporal correlations to be kept. This explains why the Intraday (orange) net load curves are far less smooth than their day-ahead counterparts, or than historical data. This issue may have a significant impact on some of our results, and will be discussed when relevant.

deliverable D1.3, Antares simulates the dispatch of a power system for several weather years at full hourly resolution. The size of the problem requires many assumptions to be made, notably that of a benevolent monopoly (a single centralised entity makes social welfare maximising decisions) and that of perfect foresight (for each weekly sub-problem, this centralised entity knows exactly the values load and VRE generation will take).

In the work presented in this section, our more detailed modelling allows us to go beyond these assumptions. To maintain tractability, our scope must however be limited to a single day of power system operation. In practice, Antares simulations provide installed capacities and the hourly price forecasts on which the strategy of market agents is based.

We will start by describing the case studies to which the zonal and nodal methodological frameworks are applied, before illustrating the impact of each market stage on the decisions market agents must make. We will then move on to more in-depth analyses, exploring the impact of market stages on the flexibility provided by different solutions, on network congestion and on flexibility solution revenue.

2.2 Case studies description

2.2.1 Zonal market case study

The zonal analyses are based on the detailed simulation of the short-term operation of a power system proposed by OSMOSE WP1: the 2030 intermediate point of the “current goals achieved” scenario. This system covers 33 European countries, each represented by a single node (see Figure 2). It has a total annual demand roughly equal to that of 2015 and 2020 (2580 TWh), and much increased VRE capacity: 208 GW, 54 GW and 218 GW of solar, offshore and onshore wind respectively (for further details, refer to WP1 deliverables).

As previously mentioned, the input data to our methodological framework mostly consists of that of the WP1 Antares study: installed capacities of all generation, storage and interconnector assets. The hourly zonal prices generated by the Antares simulations are also key inputs to our study, as they are used as a basis for the market agents’ buy- and sell-order formulation strategy. The simulated period in the Prometheus/Atlas modelling framework is one week long, corresponding to a mid-March period, though results will be shown for a single day.

The day-ahead market is run for a period of 24 hours at 12am the previous day, using the load and VRE forecasts available at that time. The intraday market session is run for a period of 24 hours at 12pm, using, again, the latest forecasts available.

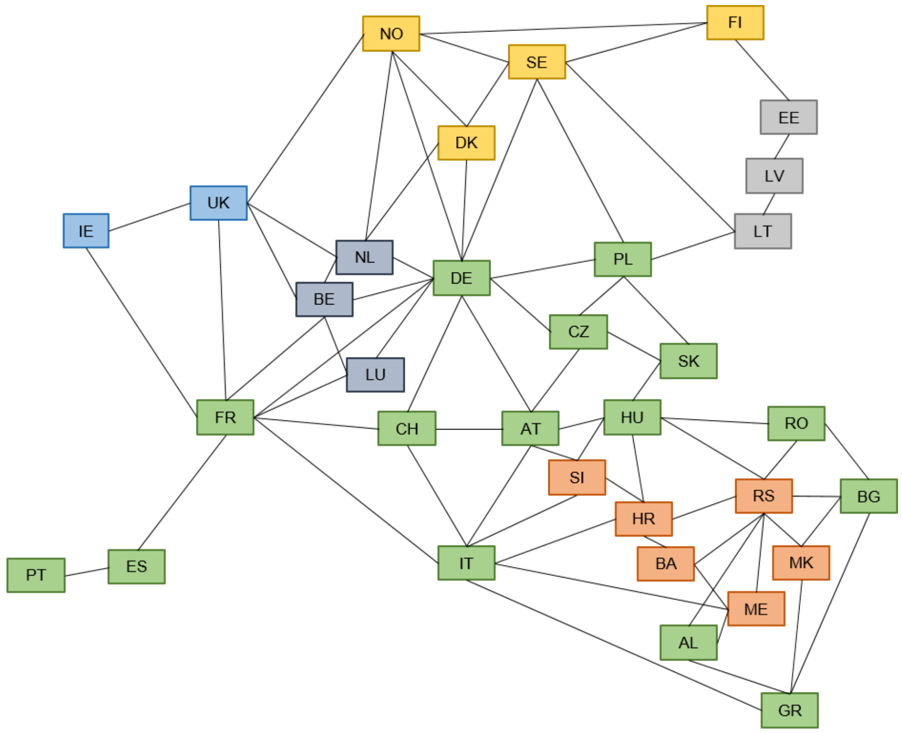

Figure 2: Zonal study system map

2.2.2 Nodal market case study

2.2.2.1 Scenario assumptions

The nodal case study is based on a scenario inspired from RTE's "Bilan Prévisionnel" of 2021[2] for the target year 2030. This scenario is consistent with the objectives of France's "National Low-Carbon Strategy" for 2050 and with the trajectory presented in the French "Multiannual energy plan" for 2030.

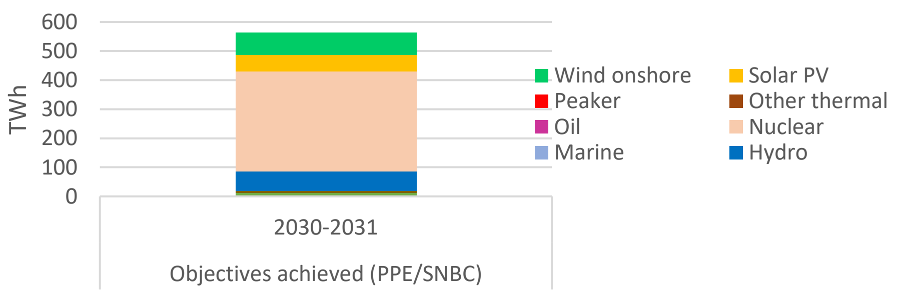

Figure 3: French electricity mix in the "Bilan Prévisionnel" scenario for target year 2030

The case study focuses on a single week, ranging from the 28th of October to the 6th of November, based on historical data. Detailed analysis is made on the first day of the week, and on the Friday. This choice was made to capture relevant snapshots for the electric system with the following characteristics: (i) high wind availability at the end of the week, (ii) national public holiday on the 1st of November (Friday), leading to a larger load forecast error, (iii) one

[2] Les bilans prévisionnels | RTE (rte-france.com)

full week beginning with 4 working days, 1 bank holiday and 2 week-end days, (iv) mid-season period. Even if the nodal simulations for this case study are not made on an exhaustive annual representation of the climatic and disruptive events for the electric system, the selected week offers an interesting time period which can show a variety of different situations.

Nationally installed capacities and demands are disaggregated between each market zone (node). The generation forecasts fed to market agents at the different stages of the market sequence are based on historical data from the "Daily Network Situations" calculated daily at RTE. The obtained situation for this case study at nodal scale is depicted in Figure 4 with the electricity demand over the whole week for each market zone, aggregated at the national level.

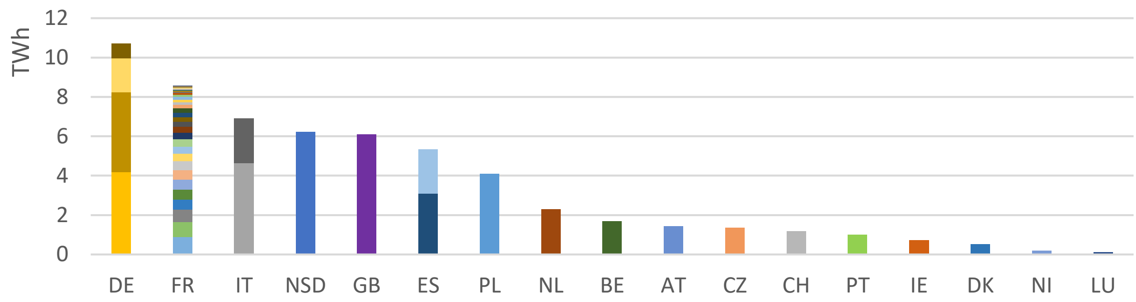

Figure 4: Total electricity demand over the simulated week for each market zone (TWh) - Colours within a bar correspond to the different nodes that make up a region

The nodal hourly load forecast data is based on historical data from the Pan-European Market Modelling Data base (PEMMDB), rescaled to match the scenario demand volumes. Similarly, hourly VRE capacity factors are based on PEMMDB historical data, which are multiplied by the scenario's nodal installed capacities to obtain hourly generation forecasts.

2.2.2.2 Network representation

The specificity of the nodal study is the detailed representation of the transmission grid topology alongside network electrical constraints. The equivalent network used in the case study was computed based on a combination of the explicit network data from ENTSO-E's Ten-Year Network Development Plan (TYNDP), which accounts for both existing and expected interconnection capacity, and RTE's own database for the French high-voltage network (225/400 kV).

France is divided into 26 market zones, which we will call macro-nodes, designed to be electrically consistent and thus expressing major network constraints. 2 of these 26 macro-nodes (numbered 14 and 8 in Figure 5) are also subdivided into a total of 34 micro-nodes, locally providing a more detailed representation of the existing high-voltage network. The macro-nodes to subdivide were chosen due to their central location (to avoid boundary effects on computation results), and because fossil, nuclear and renewable power plants are present. Other countries are modelled using 1 to 4 nodes, as shown in the following figures.

While in the Antares simulations, the nodal network was modelled using equivalent impedance, in Prometheus/Atlas, it was modelled using PTDFs. More details on the modelling is available in deliverable D2.3.

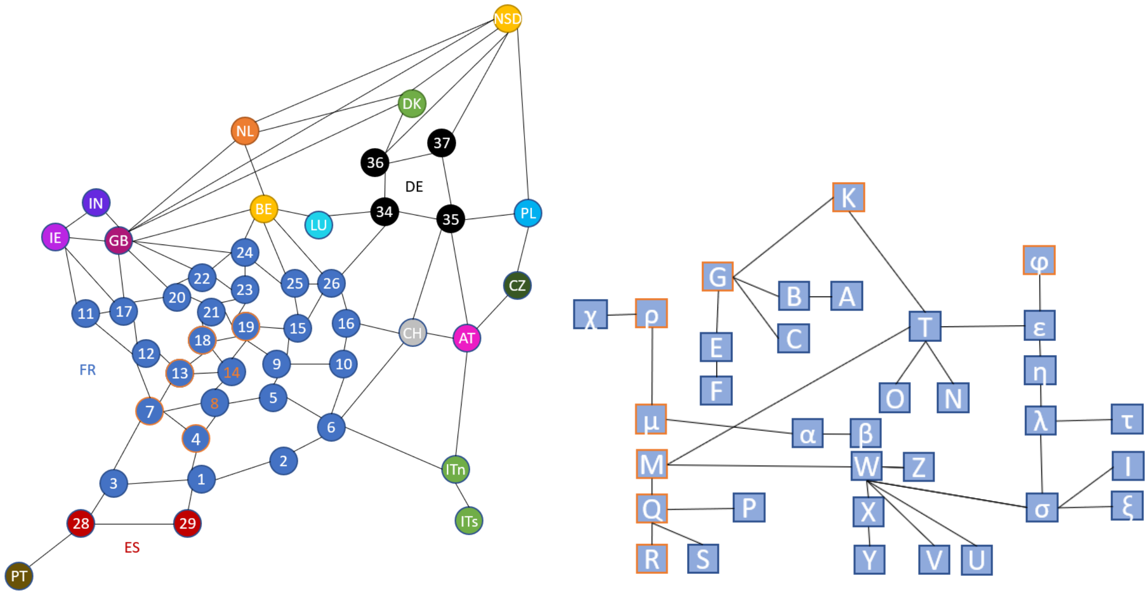

Figure 5: Nodal study network representation

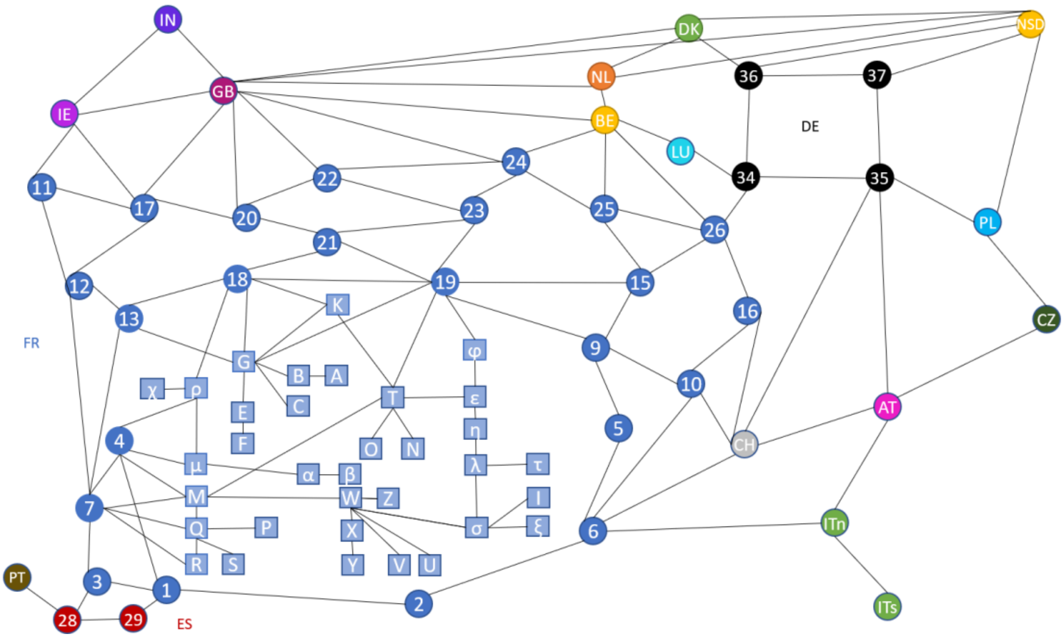

Figure 6: Full representation of the nodal study network model

2.2.2.3 Evolution of forecasts over market horizons

The day-ahead marked is run for a period of 24hours at 11am on the previous day, using the load and VRE forecasts available at that time. The first (so-called) intraday market session is run for a period of 24 hours at 7pm on the previous day using the latest forecasts available. Similarly, a second intraday market session is run at 6am on the day of delivery, on the remaining hours of the day.

Note that for the intraday market sessions, the load and VRE forecasts are updated for French nodes only (i.e. for other countries, day-ahead forecasts are considered for intraday as well), hence the fairly limited evolution in net load forecasts represented in Figure 7.

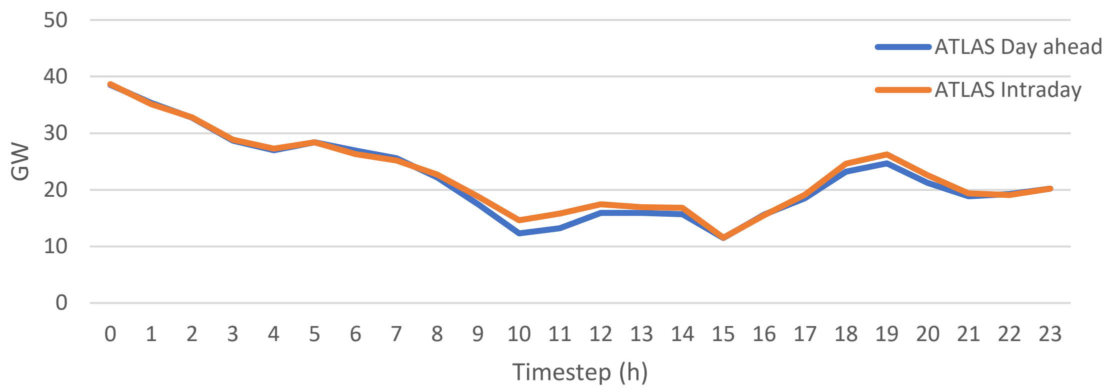

Figure 7: Net load forecast differences between day-ahead and intraday – Europe level – Day 5

2.3 Market-agent decision making throughout the market sequence

As described in deliverable D.2.3, the Atlas modelling process consists of a series of steps, modelling the different decisions market agents make during a market sequence (see Figure 8). Note that the modelling considers one generator agent and one consumer agent per zone. Using zonal market modelling results, we will now illustrate the impact of each step on market agent decision making. For the sake of simplicity, this analysis focusses on CCGT plants on the Spanish zone.

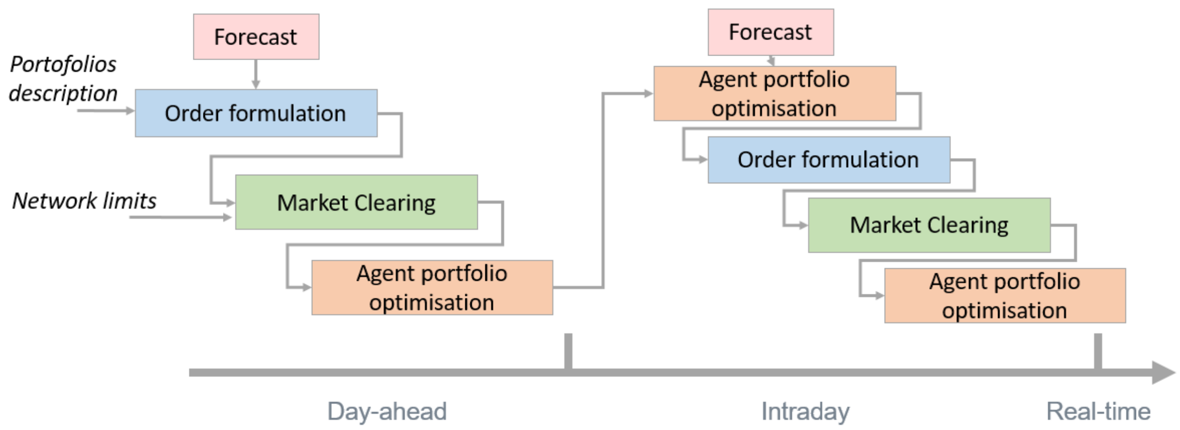

Figure 8: Atlas market sequence modelling

Starting with the “order formulation” module, based on day-ahead price forecasts formulated by Antares, market agents (one generator and one consumer per zone) formulate buy- and sell-orders that maximise their per-unit profit. The “market clearing” module then gathers all these orders, determines which of these are to be accepted or rejected, and defines the power exchanges between zones along with zonal prices. Figure 9 provides an example of the sell-orders formulated for the aggregated Spanish CCGT plants (both minimum and maximum quantities), and the quantity matched with buy-orders by the clearing process.

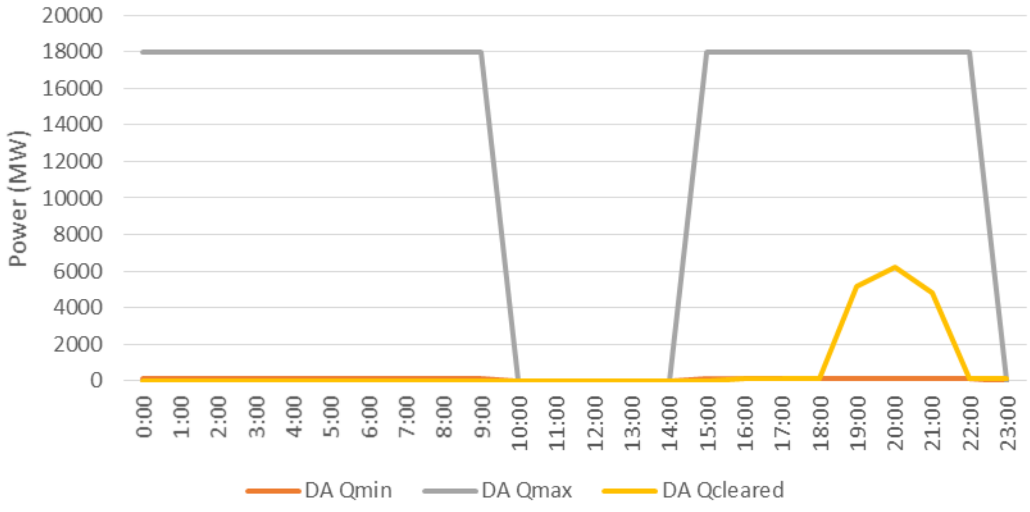

Figure 9: One day's worth of formulated and cleared sell orders on the day-ahead market for CCGT plants in Spain

In the following step ("portfolio optimisation"), each agent is told which of its orders was accepted in the market clearing process. Each agent then solves a new optimisation problem, accounting for market profit, operational costs, imbalance costs and unprovided reserve costs. This is the last stage of the day-ahead horizon, the result of which is shown in Figure 10. We can see that the Spanish generator agent has found a cheaper way of fulfilling its market engagement by making use of other assets.

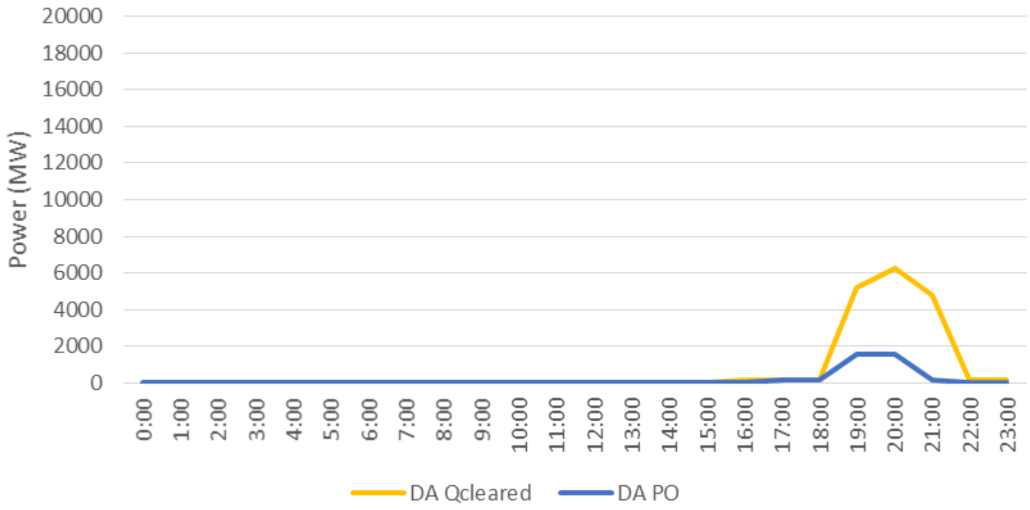

Figure 10: Quantity cleared on the day-ahead market and result of the day-ahead portfolio optimisation for CCGT plants in Spain

As we move into the intraday, new load, wind and solar generation forecasts are made available. As seen in Figure 1, the intraday forecast of Spanish net load is quite different to the one made on the day-ahead, most notably in the morning hours. As a result, performing a new portfolio optimisation with this updated information leads to significant changes where CCGT plants are concerned, as illustrated in Figure 11.

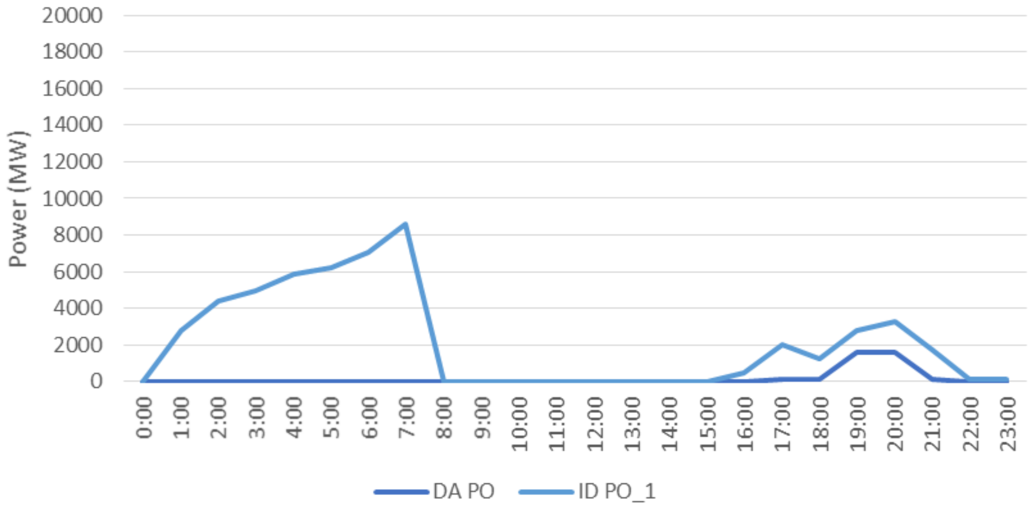

Figure 11: Portfolio optimisation results for the day-ahead and for the first instance of the first session of the intraday market (see Figure 8)

Based on these new results, market agents can formulate new sets of both buy- and sell-orders to adjust their market positions determined by the day-ahead market clearing. These orders are then cleared by the intraday market (yellow line in Figure 12 below), and a new instance of portfolio optimisation can again be run (lighter blue line in Figure 12 below). This marks the end of the first intraday market session; note that an additional session can then be run, as is the case in the nodal market study.

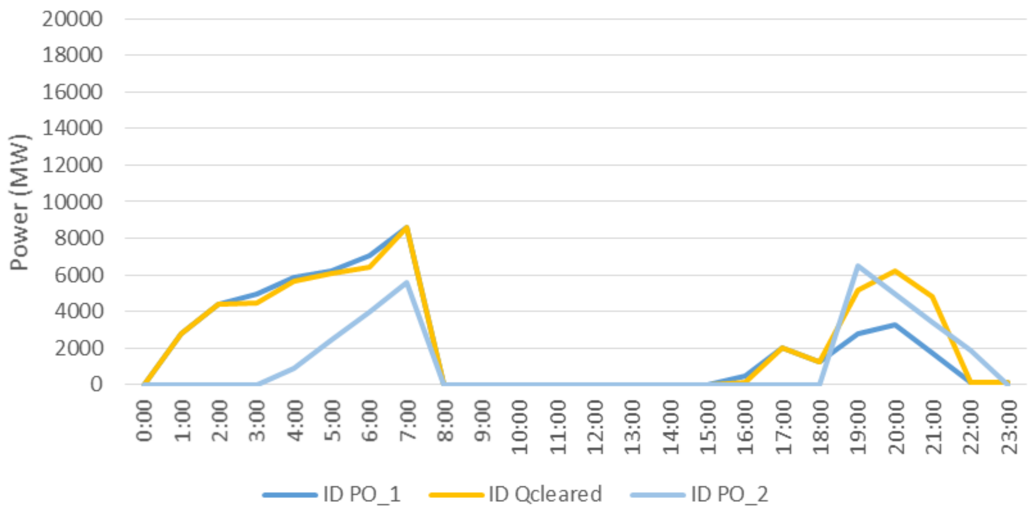

Figure 12: Portfolio optimisation results and quantity cleared by the intraday market

2.4 Detailed analyses

Having illustrated the effect of the different steps of the market sequence on a single technology for a single node of the zonal study, we will now carry out more in-depth analyses. Still based on the zonal market case study, by comparing day-ahead and intraday market outcomes, we will show how accounting for the agents' decision making as uncertainty is gradually reduced impacts the system both on a physical (unit dispatch, power flows, storage in/out-flows….) and economic level (market prices, asset revenue). We will then illustrate how some of our observations are affected if we move to a nodal market organisation.

Considering the very limited period on which the results are shown, they should be interpreted with care. While they can be used to illustrate certain phenomena, they should not be considered to be representative of the situations that a power system may experience, with all the limitations this may imply.

2.4.1 Main observations made on the zonal market case study

The key point to make is that due to the combined effects of all the decisions agents must make over the market sequence (see Section 2.3), the outcomes of the day-ahead and intraday markets are significantly different.

2.4.1.1 Comparison of DA and ID market dispatch and flexibility activation

First, let us look at differences in terms of flexibility solution dispatch, as shown in Figure 13. Between the day-ahead and the intraday forecasts, the net load summed over the whole day and the whole of Europe has only changed by 13 GWh (0.02%). However, some flexibility solutions in specific countries have adjusted their behaviour by 39 GWh (thermal_base and thermal_intermediate in Spain), and some countries' net positions have changed by as much as 93 GWh (United Kingdom).

In our results, the adjustment of interconnector power flows represents a very significant part of the differences between the DA and ID markets. One should however keep in mind that, as discussed in Section 2.1, our forecast error methodology does not express geographical and temporal correlations. Therefore, the tendency of forecast errors to cancel out over neighbouring countries is potentially overestimated, meaning the convenience of interconnection as a means of dealing with net load uncertainty may also be overestimated.

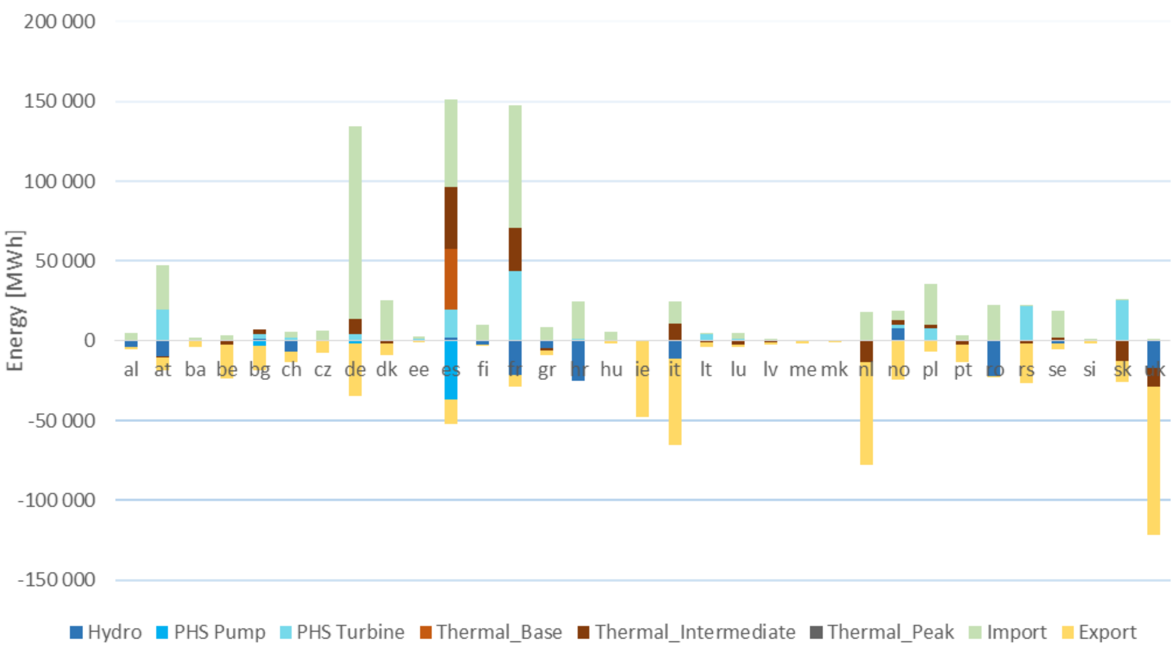

Figure 13: Difference in flexibility solution dispatch between the day-ahead and the intraday market, aggregated over the 24 hours of the simulated day, shown for all 33 countries.

Instead of aggregating the differences over a whole day, Figure 14 and Figure 15 concentrate on single hours of the dispatch, 2pm and 7pm respectively. At 2pm, European net load forecasts are lower in ID than in DA. Hydro generation therefore drops to compensate, along with CCGT generation, to a lesser extent. This results in a change in different countries' net positions; the interconnector flows are hence adjusted.

At 7pm, ID French and German peak load are higher than was expected in DA. This is partially compensated by net load forecast errors in other countries, and partly by CCGT and hydro plants.

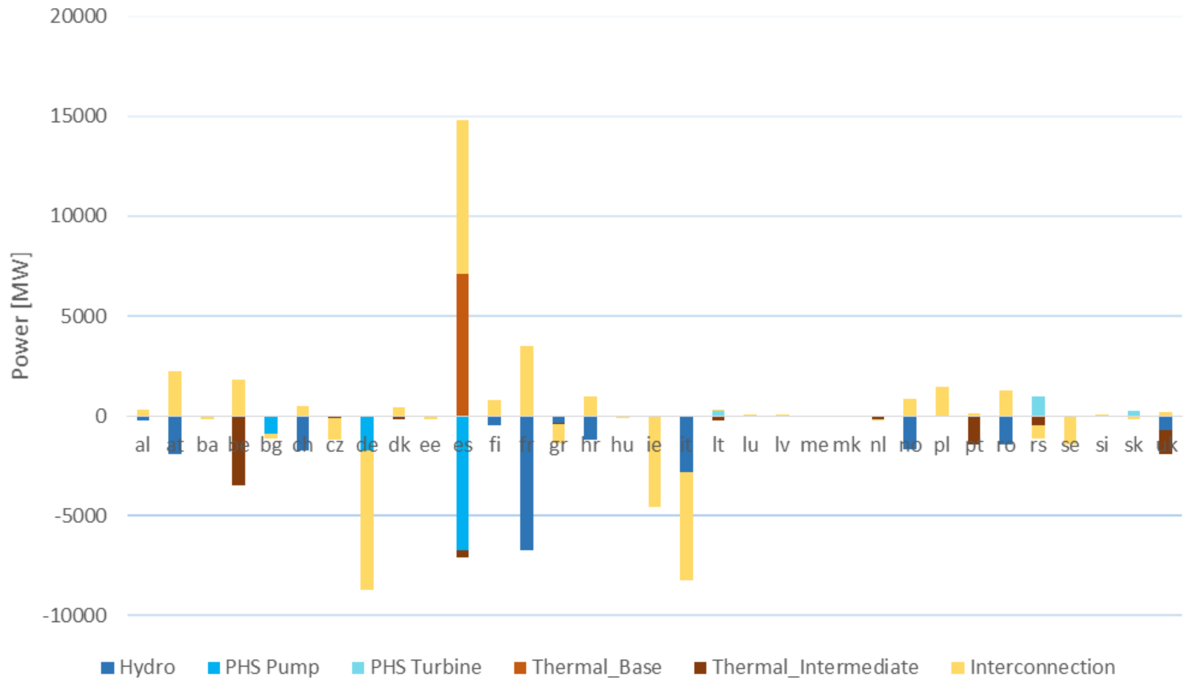

Figure 14: At 2pm, difference in flexibility solution dispatch between the day-ahead and the first intraday market session, for all 33 considered countries

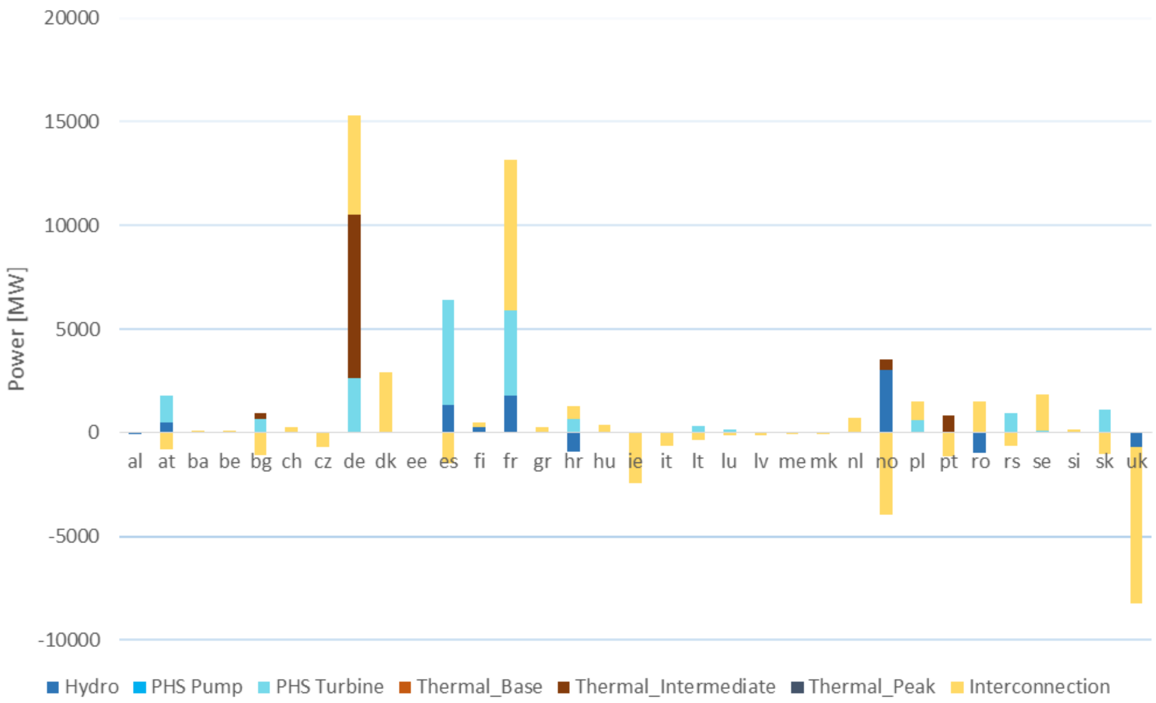

Figure 15: At 7pm, difference in flexibility solution dispatch between the day-ahead and the first intraday market session, for all 33 considered countries

2.4.1.2 Comparison of DA and ID power flows

As suggested by the changes in net positions shown in the previous three figures, updates in load and VRE forecasts and the subsequent dispatch decisions can lead to significant changes in interconnector flows between the DA and ID markets. Looking specifically at congestions (see Figure 16), it is interesting to note that out of congestions anticipated in the DA market, 35% of them disappear altogether when we move to the ID market. New congestions amounting to 12% of the initial number appear, while 10% of congestions occur in the opposite direction of what was originally expected.

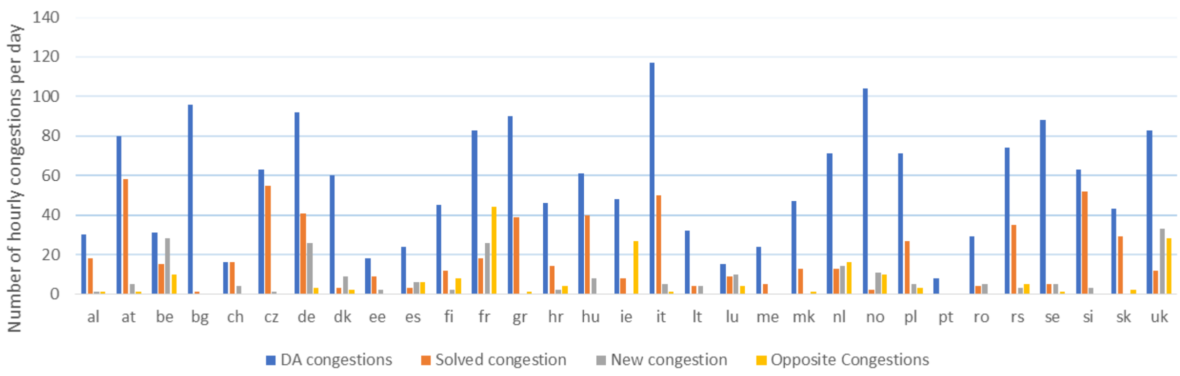

Figure 16: Evolution of cross-border congestions between the DA and ID markets, aggregated by country.

This inability to anticipate congestions in the DA market raises numerous questions, not least whether the day-ahead is an appropriate lead-time to make so many dispatch decisions in a high VRE-share power system. It also points to the need for improved coordination between TSOs, be it for the cross-border capacity calculation process, to share information and allocate capacity in the ID, or to implement a coordinated re-dispatch. The consideration of uncertainty in the day-ahead capacity calculation and allocation process is a promising solution to this problem, which RTE is currently investigating (see work by Emily Little, whose PhD subject is “The future of cross-border capacity management in Europe”).

Lastly, these results suggest that where long-term planning is concerned, there is a need for a thorough assessment of our modelling methodologies used to determine cross-border capacity. Here, we used a single modelling approach; testing out others and evaluating their impact on model outcomes seems to be an important prerequisite before defining future cross-border capacity management rules..

2.4.1.3 Comparison of DA and ID market prices and asset revenues

Another important aspect of our simulation results is that of market prices and asset revenues, which can have valuable implications for market design. We will start by having a look at the spread of both DA and ID market prices, shown in Figure 17. Note that only some of the 33 countries considered in the simulation are shown in this graph: the ones that aren’t shown experienced loss-of-load, leading to very high prices and impeding graph readability. The reasons behind this loss-of-load were not thoroughly explored due to lack of time.

DA market prices are noticeably higher than ID ones, despite net load forecasts being higher in the intraday. The reasons behind this were not thoroughly examined either, and one should keep in mind that these results were obtained based on a simulation of power system operation over a single day. This graph can hence hardly be considered as more than a simple illustration of the fact that DA and ID prices may differ greatly.

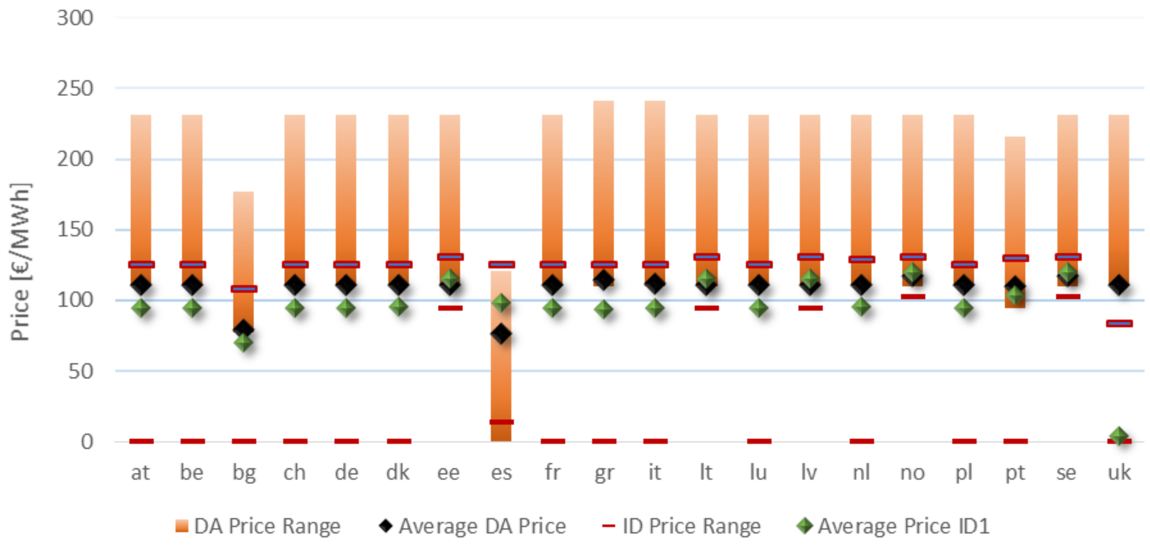

Figure 17: Price range on a 24 hour period on DA and ID markets

Zooming in on a specific hour for a specific zone, Figure 18 provides a more detailed understanding of the phenomena at play using merit order curves. Note that for the ID market, the orders that are shown are adjustments made to the DA market positions. Load can therefore appear on the “traditional” supply curve, while wind and hydro appear on the “traditional” demand curve. As well as illustrating the reduction in volume proposed on the ID market (e.g. nuclear behaviour is already set), these graphs show how flexible units, namely PSH, can potentially formulate orders only on the ID, the DA market spread not being wide enough to ensure profitability. These graphs also highlight the importance of different modelling assumptions, such as the prices at which load and VRE are to bid to readjust their position on the ID market.

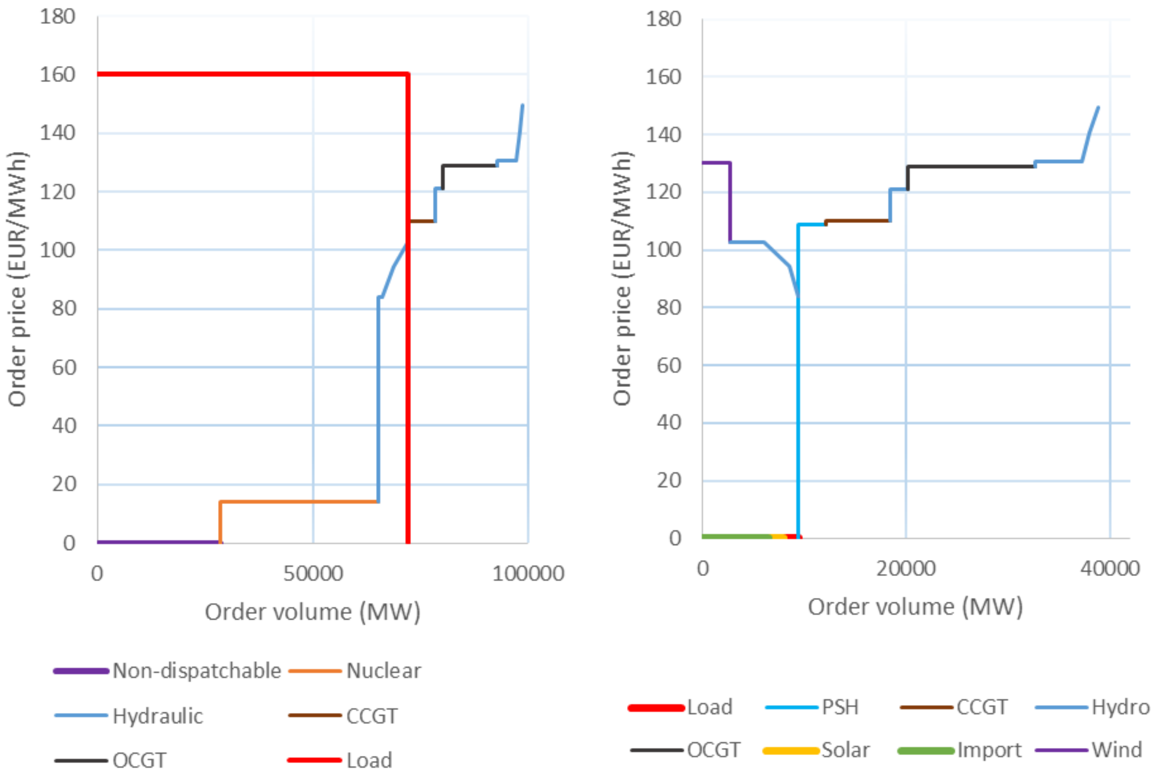

Figure 18: Merit-order curves for the DA (left) and ID (right) markets, for a single hour on the French system

While these results do not allow any form of generalisation, note that in theory, ID prices are likely to be more volatile and hence show wider spreads than DA prices: there are fewer technologies and units able to adjust their position, meaning the merit-order will have fewer intermediate steps. This leads to reduced market liquidity.

By subtracting each asset’s marginal cost from the market clearing price, and summing the result over the entire day, we obtain asset market profits represented in the following two graphs. First concentrating on flexible assets, besides the fact that, with our marginal cost assumptions, hydro seems to be the most profitable asset, it is worth noting that different technologies obtain different proportions of their profit on the DA and ID markets, and that these profits vary considerably between countries. Despite the limited time that has been invested in analysing the simulated market prices and exploring the way they are affected by different modelling assumptions,, this is a fairly robust observation.

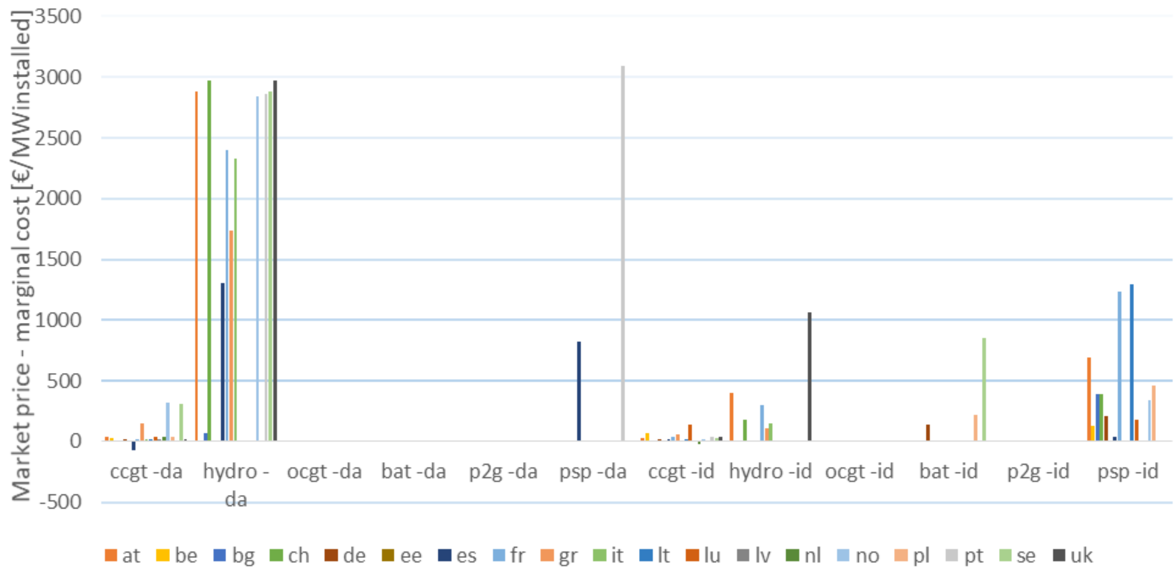

Figure 19: Flexible asset market profit on the DA and ID markets

Now looking at less flexible assets (see Figure 20), for all technologies, profits are far greater on the DA than on the ID market. Wind and solar power profits on the ID market are essentially linked to changes in generation forecasts, and can therefore take negative values.

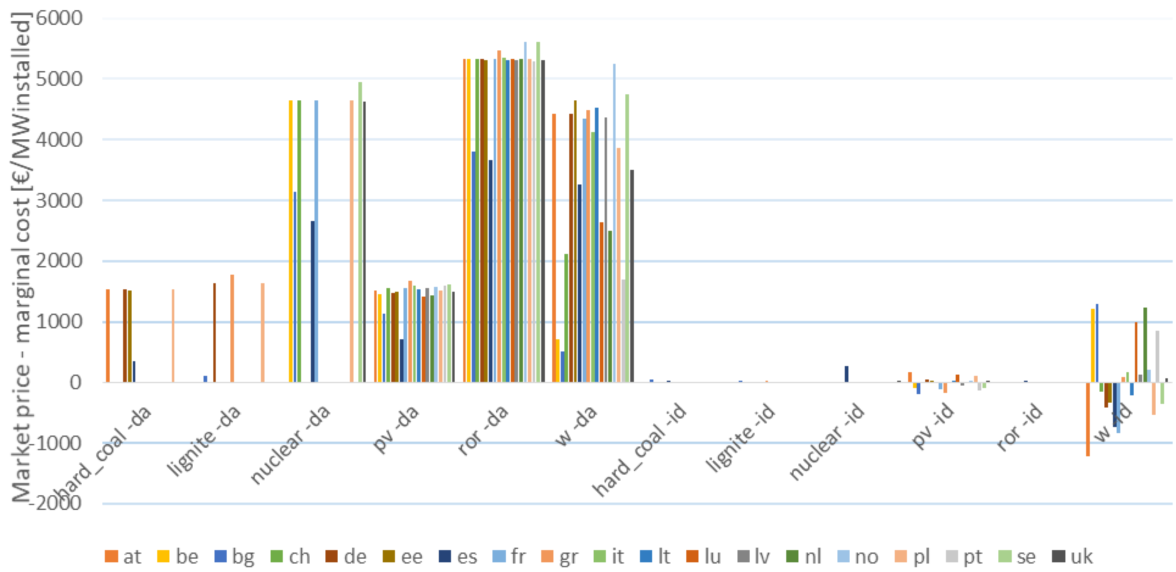

Figure 20: Less flexible asset market profit on the DA and ID markets

Figure 21 provides a more detailed view of the situation on the French zone. ID market revenue for VRE is nearly systematically below or equal to zero, as its generation output was over-evaluated in DA.

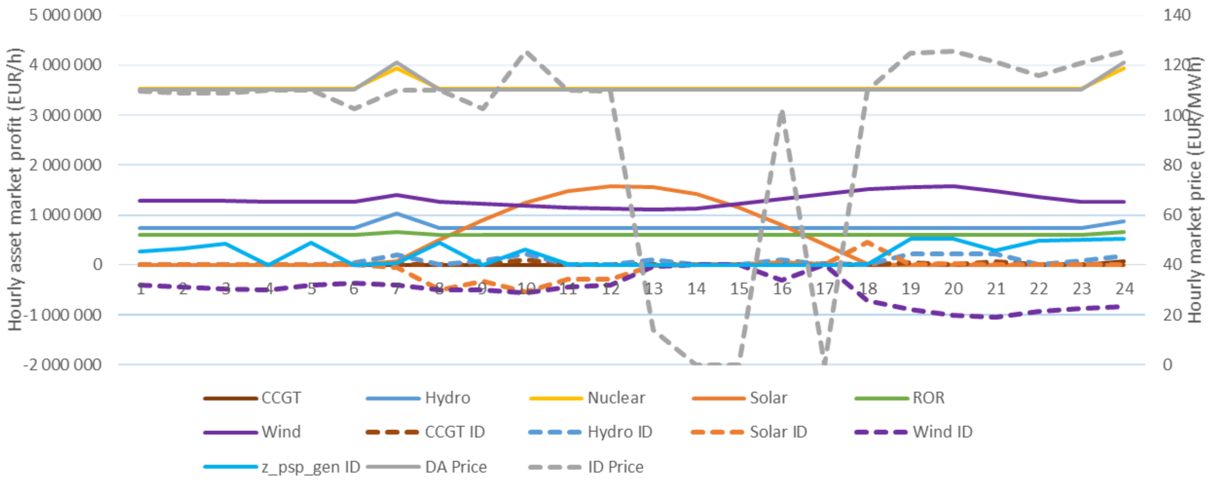

Figure 21: Hourly asset market profit and market price, for France (where ID is not specified, DA is implied)

Despite the previously mentioned limitations regarding market prices which directly translate to market profits, these results do suggest that considering both day-ahead and intra-day markets is necessary to ensure effective long-term power system planning. An optimal investment plan obtained by a methodology assuming perfect foresight will miss effects associated with the need to manage lead-time dependent uncertainty, leading to sub-optimal solutions or even solutions that are unable to ensure security-of-supply. Further work is required to quantify the extent of this bias, and to see how it is affected by the inclusion of additional flexibility solutions.

Beyond theoretical centralised optimal power system planning, studies assessing the value of a specific technology should also account for these effects and not focus solely on the spot (day-ahead) market. Indeed, many flexibility solutions will make most of their profit on the ID market, i.e. the value they will bring to the system will primarily be linked to their ability to adjust their behaviour close to real-time to cope with system-wide uncertainty.

On a similar note, the design of capacity mechanisms should account for all revenue streams: not only the spot market or ancillary services, but the intraday market also.

2.4.2 Confirmation of these observations with the nodal market case study

The selection of results shown in this section aim to provide backing or contradiction to the observations made on the zonal study results. For further details, see Appendix 7.1.

First of all, it is worth discussing how the evolution of net-load forecasts changes with the considered geographical level. Figure 22 shows this evolution at macro- and micro-nodal level for a selection of 6 nodes. We remind you that forecasts are updated for French nodes only. We can see that as we move to smaller nodes, forecasts are less precise, and net load is more volatile. This raises the question of whether the nodal level is an appropriate one to make day-ahead unit-commitment decisions.

Figure 22: Evolution in net load forecasts at macro- (top) and micro- nodal (bottom) levels. Blue lines correspond to DA forecasts at 12am, orange lines to DA forecasts at 7pm, and grey lines to ID forecasts at 12am. Note that for the ID, only wind and solar forecasts are updated, not load. The two last micro-nodes have neither wind nor solar capacity, their orange and grey lines are hence superimposed.

Looking at flexibility solution dispatch differences between the DA and the two ID market sessions, we can see that the observations made in the zonal case study are confirmed: the network provides a significant proportion of flexibility, along with, for certain nodes, nuclear (thermal_base) and power-to-gas (P2G) (note that there are slight differences in the technologies considered in the two case studies). Another important element to notice is that most of the adjustment is made between the two intraday market sessions, suggesting that at 12pm in day-ahead, poor net-load forecasts lead to a need for flexible capacity that can adjust its behaviour on short notice. This highlights the need to push this analysis further and add real-time balancing to the simulation, currently ongoing work at RTE (see work by Florent Cogen, whose PhD focusses on the architecture of European balancing mechanisms).

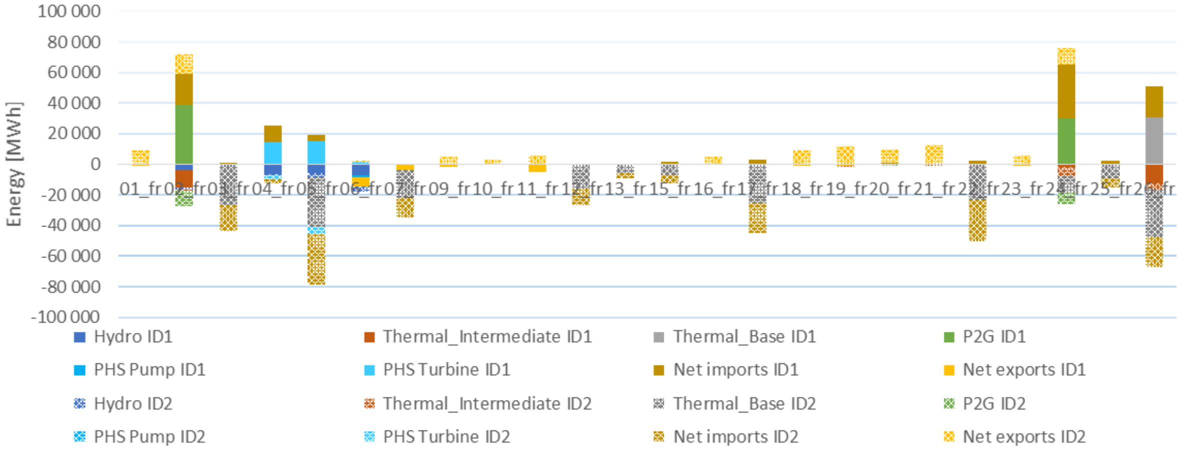

Figure 23: Difference in flexibility solution dispatch between (i) the day-ahead and the first intraday market session, and between (ii) the first and second intraday market sessions. Results are aggregated over the 24 hours of the simulated day, shown for all French macro-nodes.

Focussing on macro-node 2 (one of the two experiencing P2G modulation), investigating the hourly behaviour of CCGT and P2G leads to puzzling observations: we can have simultaneous burning of gas to generate electricity in CCGT plants and electricity consumption to produce H2 by electrolysers, i.e. destruction of energy. This behaviour is to be expected considering the modelling chosen for electrolysers which is based on current market design: electrolysers produce “green” hydrogen based on guarantee of origin certificates which do not specify the time of generation, and are paid according to the amount of H2 produced in MWh.

To avoid this absurd behaviour caused by poor market design, one option could be to specify the time of generation on guarantee of origin certificates. Another could be to incentivise investment in electrolysers based on per capacity payments rather than per energy payments. This solution would likely be preferable under a tender system, to avoid having to pour public funding into privately owned stranded assets.

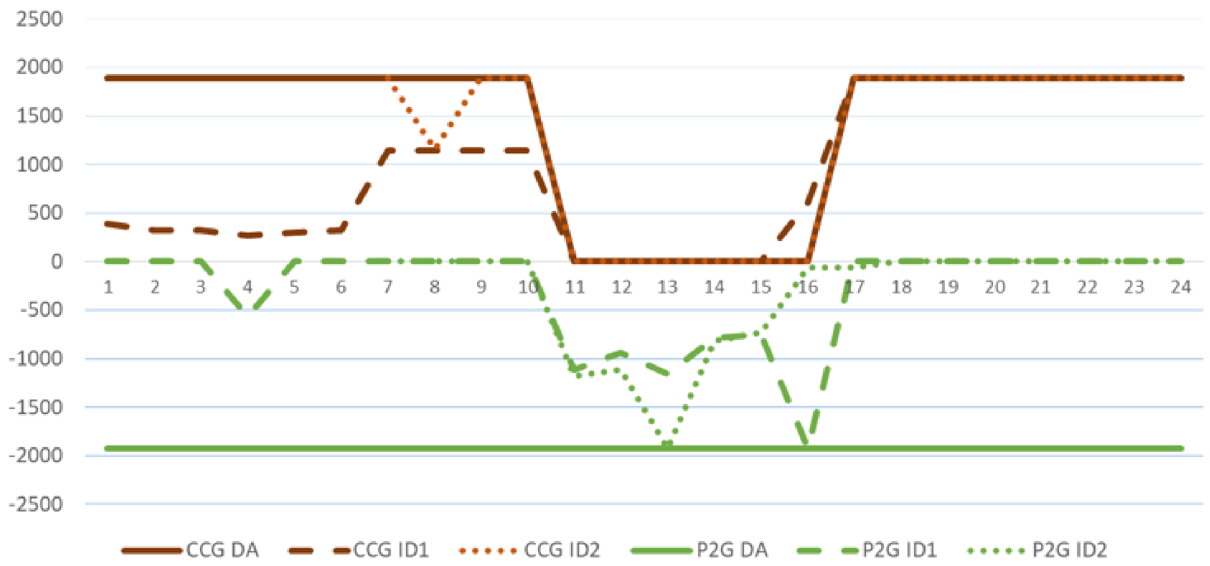

Figure 24: CCGT and power-to-gas hourly dispatch in DA and ID for macro-node 02_FR

It is also interesting to point out dispatch adjustments made in other European countries. Despite their net-load forecasts not having been updated, significant dispatch differences can be observed, with thermal generation this time playing a greater role (see Figure 25).

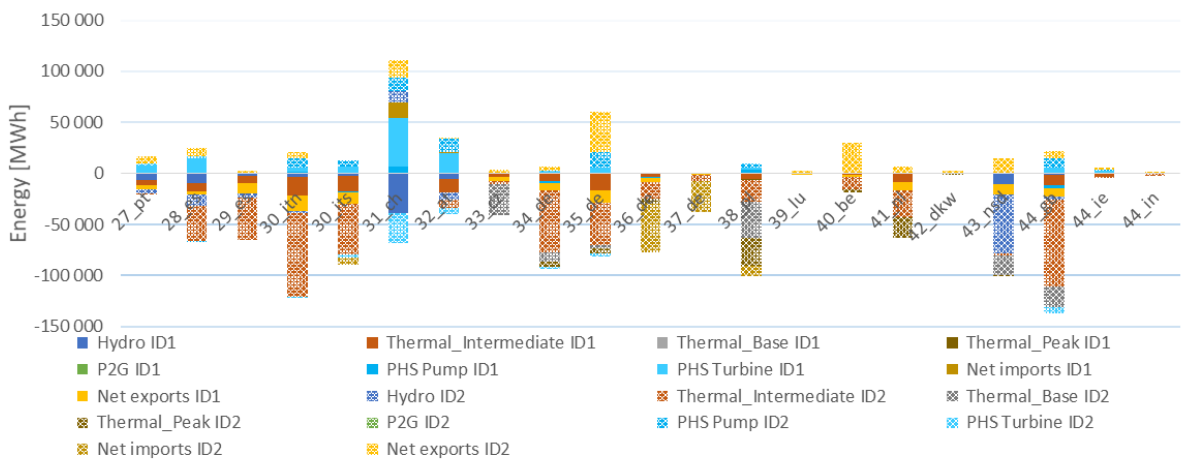

Figure 25: Difference in flexibility solution dispatch between (i) the day-ahead and the first intraday market session, and between (ii) the first and second intraday market sessions. Results are aggregated over the 24 hours of the simulated day, shown for various European macro-nodes.

Looking at cross-border congestions between European macro-nodes, the instability which was observed in the zonal study is also very present in the nodal study. This is despite net load forecasts not having been updated for countries outside of France.

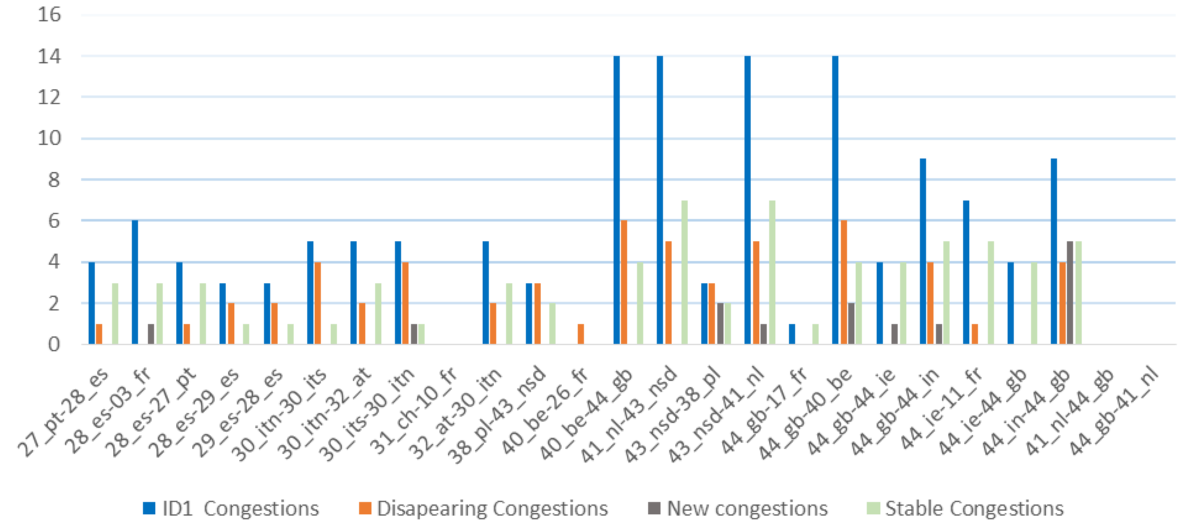

Figure 26: Evolution of cross-border congestions between the two ID market sessions, aggregated by country.

Lastly concerning market prices, behaviours are similar to those obtained for the zonal market: DA and ID prices can take very different ranges of values. However, as mentioned previously, we did not invest enough time to investigate the reasons behind this.

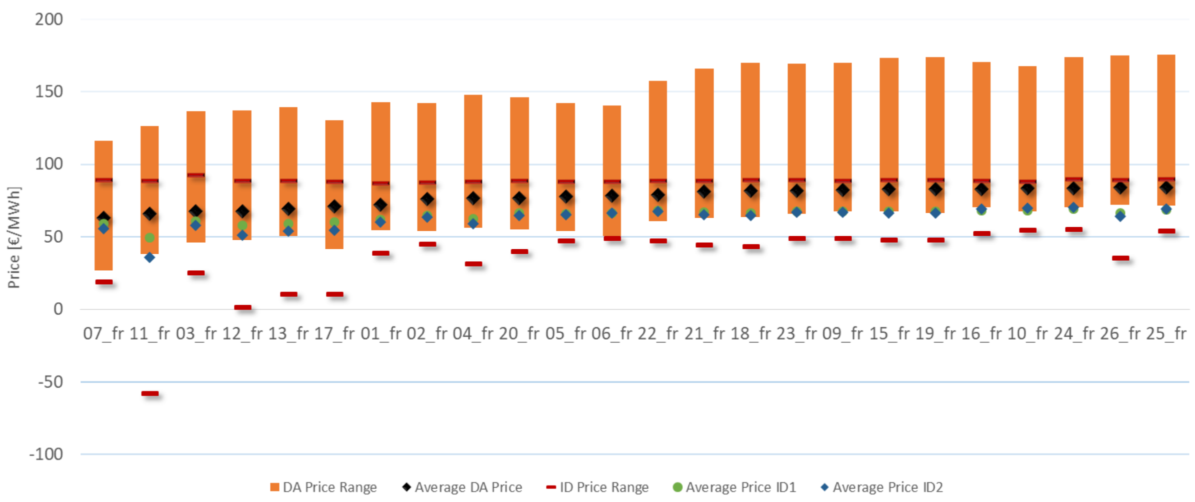

Figure 27: DA and ID market price range for French macro-nodes

3 JMM and CEGrid model results

3.1 Case study settings

The detailed description of our methodology and the Joint market model (JMM) can be found in D 2.3. In brief, the JMM is specifically designed to model the outcomes of the current and future interconnected electricity markets, including also related markets like the reserve and district heating markets and reflecting the interplay with the European electricity grid.

Subsequently, we present the results of our zonal and nodal case studies. We investigate the operation of the European electricity markets over the entire year 2030 with a focus on the interplay between renewables, grid, and flexibility use. The zonal study is based on a representation of the entire EU (except Cyprus and Malta) plus neighbouring countries including the United Kingdom, Norway, Switzerland, and the Balkans. The focus of the zonal calculations – supported by the rolling planning approach of our model[3], which allows the investigation of the impact of new or updated information – is particularly on the impacts of forecast errors on production adjustments and market outcomes.

The fuel prices as key inputs for the simulations are summarised in Table 1. The CO_2 price is set to 100 €/t for the case study. Grid data are based on the dataset provided by ENTSO-E in the context of the Ten Year Network Development Plan (TYNDP 2020). Generation capacities, infeed time series and demand data are aligned on the outcomes of OSMOSE WP1[4].

Table 1: Fuel prices for the JMM case studies in EUR/MWh

Fuel	Biomass	Coal	Fueloil	Heat	Lightoil	Lignite	Nat. Gas	Nuclear	PEAT
Price [€/MWh]	9.03	2.22	12.51	7.92	20.53	1.53	6.64	0.95	1.53

Table 2: Electricity Demand for selected countries in the JMM case studies in GWh

			Austria	Belgium	France	Germany	Netherlands	Switzerland
Electric Demand		[GWh]	70,081	84,665	440,532	529,828	125,593	52,343
Photovoltaics		[GWh]	6,507	6,422	46,736	88,329	13,144	8,288
Wind	Onshore	[GWh]	9,237	6,884	87,002	166,713	20,258	300
	Offshore	[GWh]	-	4,957	19,726	35,001	17,429	-

3.2 Zonal market results

Subsequently we first present some general results of our zonal model calculations with a particular focus on prices and generation volumes in the countries studied.

As indicated in Figure 28, the average day-ahead electricity prices vary over the year and across the countries studied, in some cases considerably. The highest average day-ahead prices are observed in Poland, the Czech Republic and Germany, at over and around 80 €/MWh. This relatively high price level also continues in the Benelux and the Scandinavian countries with over 70 €/MWh. Considerably lower prices are observed in southern Europe notably in Spain and Portugal, but also in France, Italy and Switzerland.

The price level is driven in particular by the Europe-wide CO2 price of 100 €/t. This induces higher price levels countries with a high share of fossil fuels in electricity generation, such as Poland. In countries such as France with a high share of low carbon electricity generation from renewables or nuclear energy in electricity generation, lower price levels are observed. Yet it must be kept in mind that these prices only reflect variable generation costs as the JMM focus on operational dispatch decisions neglecting investments and related fixed costs. Also the

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[3] See deliverable 2.3 for further information.

[4] D1.1 – European Long-Term Scenarios Description

prices reflect the cost level of the marginal generation technologies in each hour including possibilities for imports and exports and not the average variable cost of the generation mix.

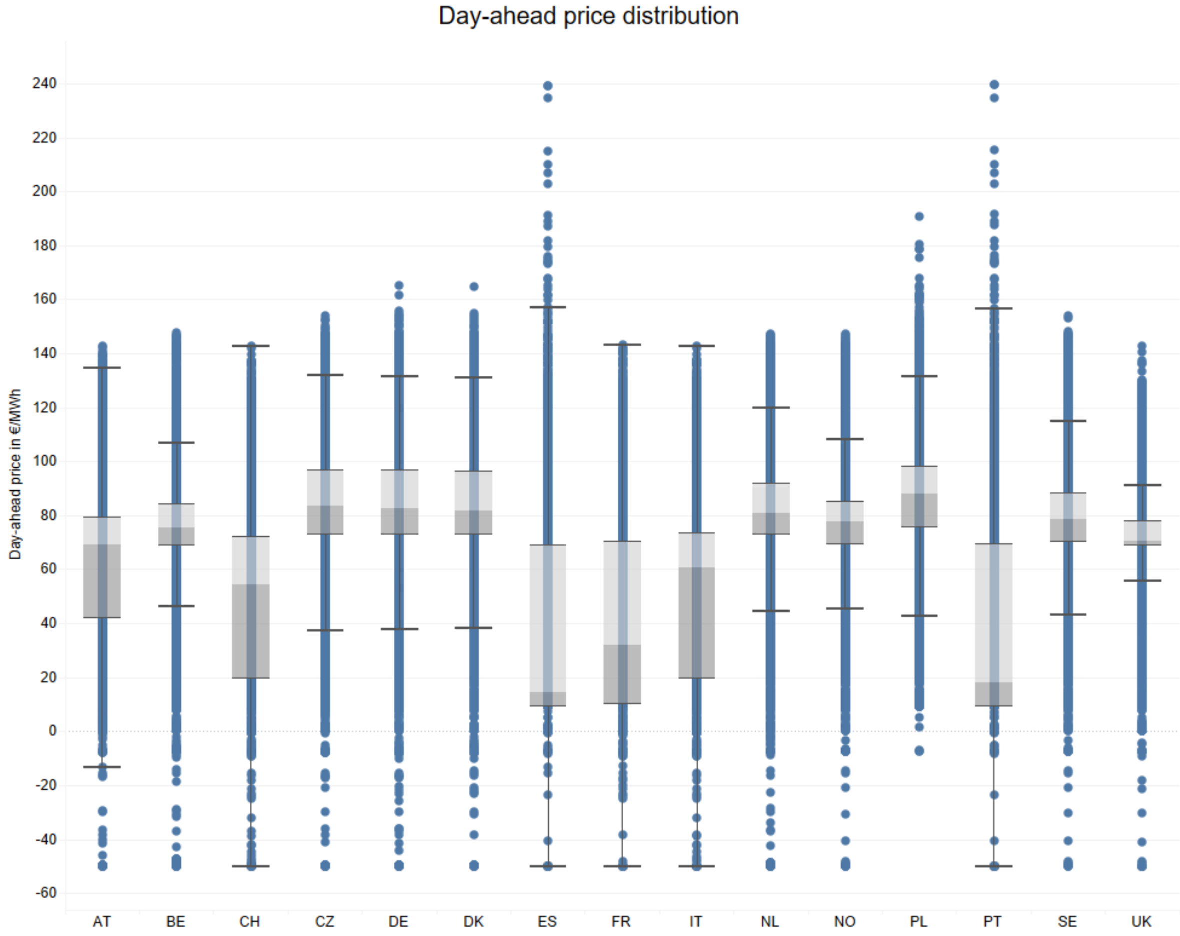

Figure 28: Averages of day-ahead prices in selected countries

The price duration curve shows the distribution of the observed day-ahead prices over the 8760 hours of the year and thus show in how many hours certain price limits are exceeded or undershot. In addition, the curve, more than just the average day-ahead prices, enables further insights regarding marginal costs and price-setting technologies in the different countries. For the sake of clarity, we focus on a comparison of the prices in Germany and France over the course of the year. With average prices of 79.66 €/MWh in Germany and 42.41 €/MWh in France, considerable differences are already evident. The PDCs in Figure 29 mirror the overall higher price level in Germany. However, not only the levels but also the curves differ. In France, the plateau at around 10 €/MWh is striking, which is not observable in Germany. This plateau reflects the large number of hours in which nuclear power plants are price setting. The fact that the prices differ substantially underlines furthermore that the grid infrastructure, despite cross-border transmission development, still constrains the electricity exchange between countries.

Figure 29: Comparison of price duration curves in Germany and France

Figure 30 provides an overview of the 2030 generation mix across Europe, which is characterised in particular by non-fossil energy sources. Where available, hydropower dominates renewable energy sources as in the Scandinavian countries and the countries of the Alpine region. In Norway, 89% of the electricity generated comes from hydropower, followed by Switzerland with 74% and Austria with 70%. Where hydropower is less available, wind dominates renewable electricity generation, followed by solar. Bioenergy only plays a significant role in a few countries such as Germany or Italy, with a share of around 7%.

Regarding nuclear energy, the share in France is highest with around 66%. Nuclear energy yet also plays an important role in electricity generation in Poland, Belgium, the Czech Republic and Sweden.

Among fossil fuels, natural gas dominates in all countries. Coal only plays a limited role in a few countries such as Germany and Poland. In most countries, coal and lignite are no longer part of the energy mix. This development is due to their CO2 intensity in combination with the high CO2 price of 100€/t.

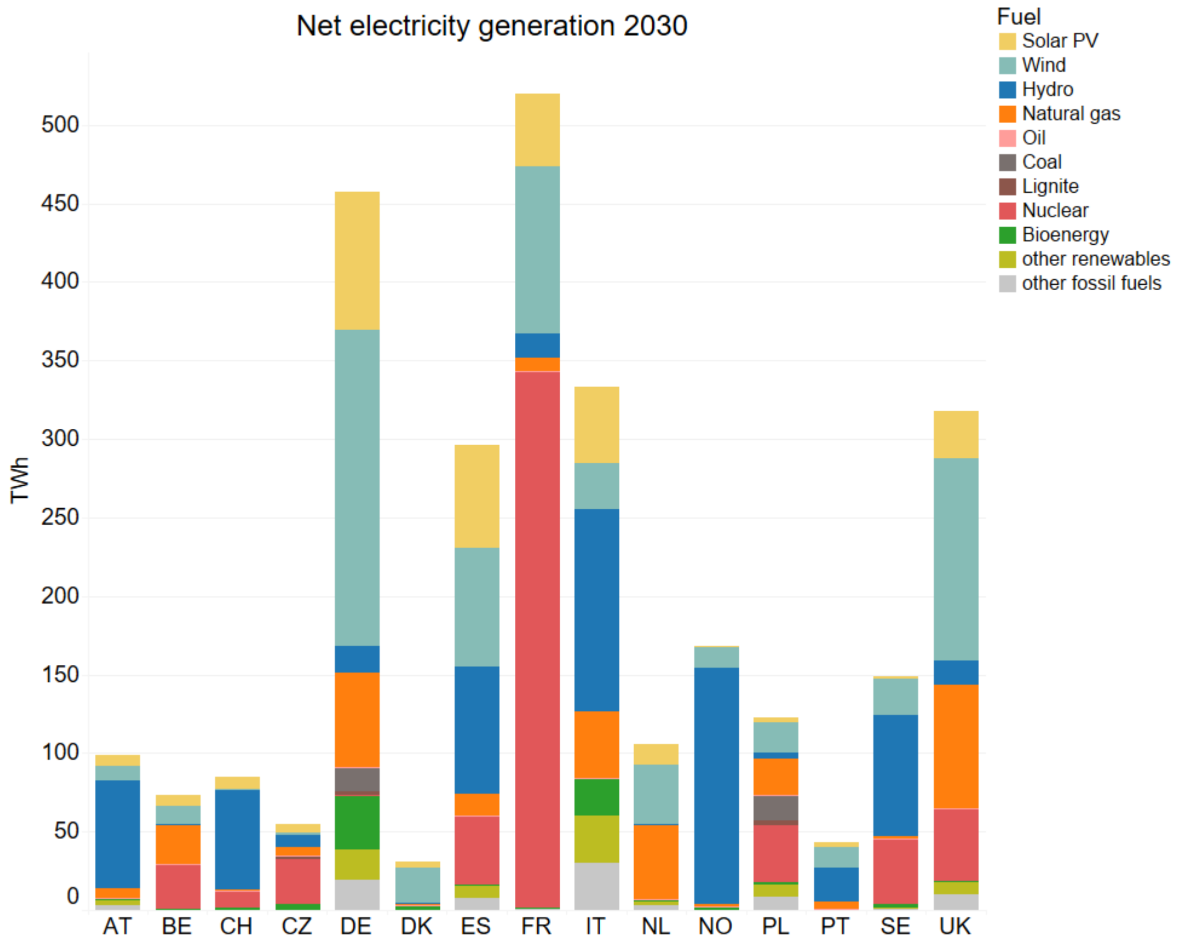

Figure 30: Electricity mix in selected countries

In order to investigate the interaction of electricity prices and generation in more detail, the focus is subsequently laid on a high-price week and a low-price week in France and Germany respectively. The weeks considered are in November, with average prices of over 97 €/MWh in Germany and 67 €/MWh in France, and in June, with average prices of 70 €/MWh in Germany and 8 €/MWh in France.

Figure 31 shows the low-price week with a high share of renewable electricity generation in both countries. Thereby strong solar generation induces the characteristic diurnal wave pattern. Germany and France differ particularly regarding the dominant share of continuous nuclear generation in France, which is not present in Germany. The price pattern in Germany shows a price increase during the afternoon with the decrease in solar generation and simultaneous increase in load. The lowest prices of the day are typically in the midday hours with the highest solar generation. In France, this price volatility depending on the renewable generation is not visible and the price curve is almost completely flat. June 17 is also worth mentioning, as we can observe negative prices in both countries. Here, during the weekend, the high feed-in of renewable energy meets a lower load compared to the weekdays and thus ensures a supply surplus in the hours of strong solar generation. Given that a market premium is modelled as support mechanism for renewable generation, negative electricity prices arise in some hours when curtailment of renewables sets the price.

When looking at the last week of November as an example of a week with high prices, some differences immediately stand out compared to the week with low prices just considered. In both France and Germany, the renewable share of electricity generation is significantly lower. Due to the time of year, we see significantly less solar generation in the electricity mix and a clearly visible use of coal alongside gas as a fossil source in Germany. In France, the generation of the dominant nuclear power is now even more pronounced. Price levels are substantially higher in both countries, so that the average price this week is around 97 €/MWh in Germany and 67 €/MWh in France. As can be seen in Figure 31, the curves in both countries are now much more similar than during the low-price week, which is related to the now visible intraday price variations in France. The price curves here show two daily peaks, one in the morning and one in the afternoon.

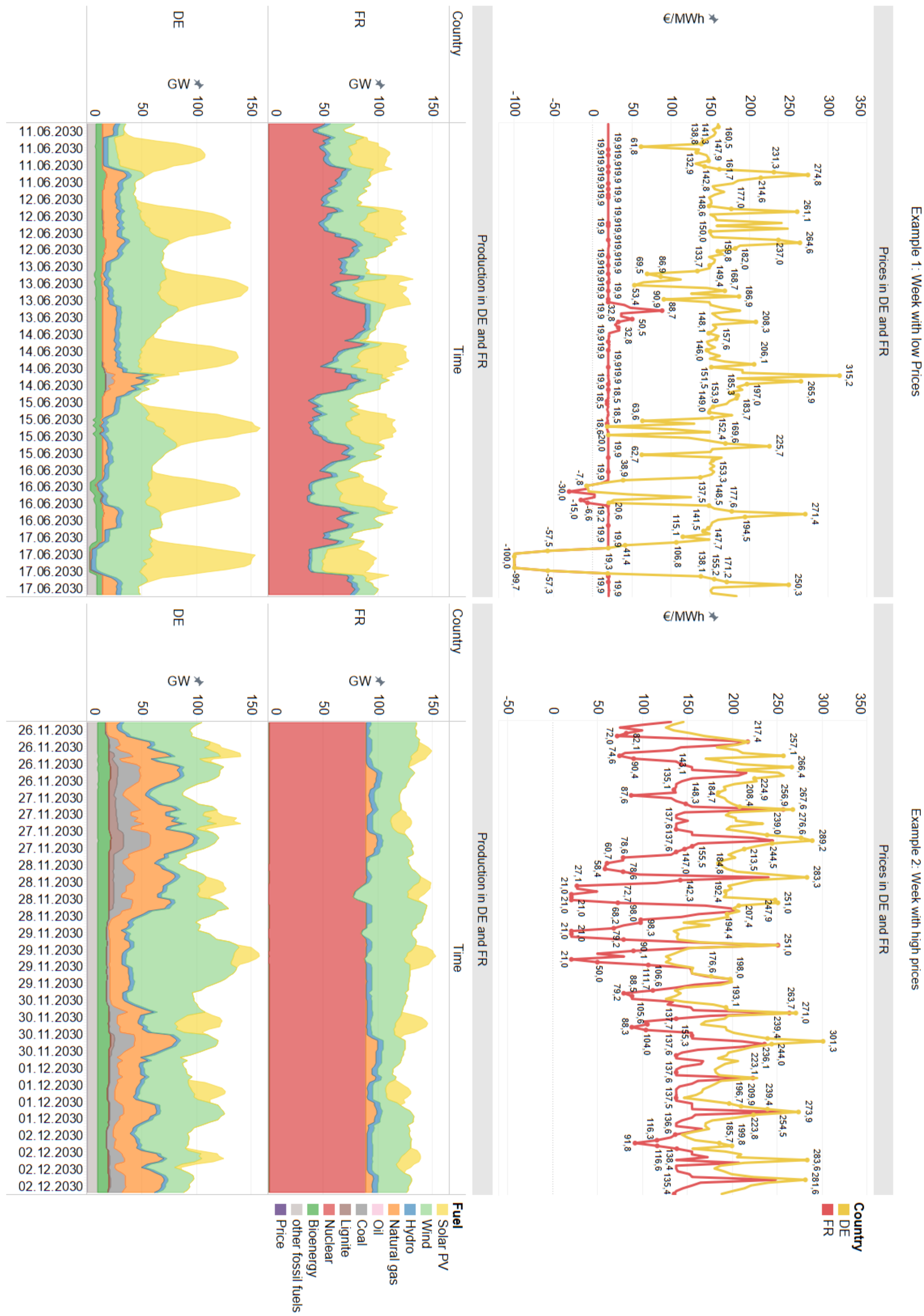

Figure 31: Prices and corresponding production in two exemplary weeks

As our market model takes advantage of a rolling planning approach, it allows us to study not only the outcome of a day-ahead market, but also lets us study the impact new incoming information has on unit commitment and finding a market equilibrium. With information updates we here refer to the methodology of temporally and spatially correlated forecast updates presented in detail in deliverable 2.3. Starting 36 h ahead of realization, we present every three hours gradually updated wind forecasts to the model and assess how generation units – given their technical restrictions such as minimum load or minimum down times – adapt their production schedules (unit commitment and dispatch) to the new information. Subsequently, we focus on the total impact by comparing changes between the day-ahead schedules and the final schedules based on the last available update. Thereby, we exclude schedules for time periods which have been obtained using different planning horizons since the change in the planning horizon may induce also schedule updates.

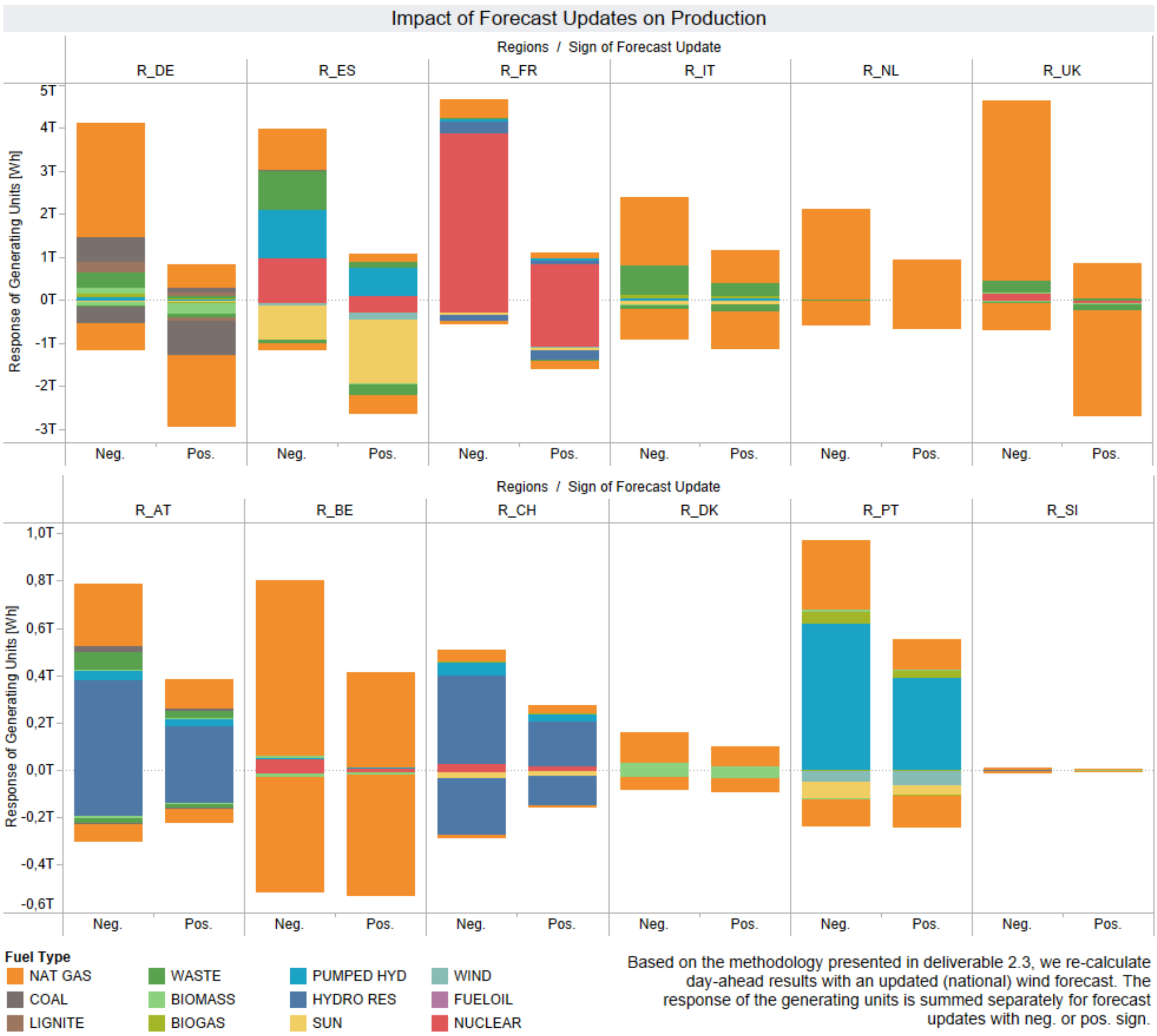

Figure 32: Impact of Forecast Updates on Production per Country and Sign of Forecast Updates

Figure 32 shows how technology classes respond to forecast updates in every single hour of the year. Results are summed per market area, technology, and sign of the (national) forecast update.[5]The results show that the intuition that negative wind forecast updates induce a production increase of conventional generating units in the same market zone and vice versa is not always confirmed. Yet there is consistent market-related explanation: flexibilities are also activated cross-border and forecast updates may be of opposite sign in different countries. This explanation is supported by the additional observation that the "intuitive pattern" is only present in large market areas. Specifically, systems with large flexibilities arising from (hydro) storage, namely Austria and Switzerland, show little correlation between their national forecast updates and the response of their generation units. This is supported by the scatter plots presented in Figure 34 which summarize the hourly responses to the corresponding forecast updates. In future systems with large shares of new (battery) storage, such effects may also be observable in other countries. In large countries like Germany and Spain, the dots group around a (not depicted) downward sloping line which indicates negative correlations between forecast updates and corresponding changes in national power plant schedules. For comparably smaller systems like those in Austria and Switzerland, there is no systematic pattern, hence a cross-border activation of flexibilities is the dominating driver. Moreover, the operational behaviour of storage technologies, especially pumped hydro units, does almost not correlate with forecast updates, independently from their location. This may be attributed to cross-temporal substitution patterns: e.g., if hydropower is used to compensate a negative wind forecast update in one hour, the usage of hydro resources may be reduced in subsequent hours to avoid excessive decreases in storage filling levels. In these hours then thermal generation may in turn increase its production. This complex substitution pattern is economically efficient if it allows avoiding the use of high-cost thermal flexibilities in the hour with the original negative wind forecast update.

Besides the correlation of flexibility provision and national forecast updates, Figure 33 compares technology shares of the total production with shares for up- and downward flexibility provision. Figure 32 already indicates that mainly controllable, non-supply-driven, i.e. mostly conventional technologies provide flexibilities - with few exceptions mostly on the Iberian Peninsula. Therefore, Figure 33 is limited to conventional technologies[6]. The figure shows that flexibility provision mostly is driven by the overall portfolio mix per market area and therefore, shows a diverse picture. A notable deviation from this is that storage units, if available, contribute to a greater extent to flexibility provision than to production. In detail, pumped hydro units solely provide upward flexibility and seem to be, where available, one of the most popular options to respond to a shortfall in wind energy production. Hydro reservoirs, on the contrary, not only provide upward flexibility more hesitantly than pumped storages, but they also seem to rather take advantage of a surplus of wind energy – as also stated in the paragraph above – to spare their stored energy, which is, once withdrawn, irreversibly lost for production in subsequent periods. Besides storage assets, flexibility is mostly provided by technologies found on the right side of the merit order of each market zone. Thus, flexible gas-fired units

[5] As introduced in deliverable 2.3, we provide our model with correlated wind forecast updates for each market area. Therefore, we determine the sign of each national forecast update and group production adaptions per positive and negative (national) forecast updates. A positive forecast update refers to a surplus of expected wind energy, a negative forecast update to the opposite.

[6] Please note that the limitation to technologies that can provide flexibility causes the filtered production shares shown in Figure 33 to misalign with the previously shown unfiltered results Figure 30.

with high marginal costs are most likely to provide downward flexibility first. These units dominate flexibility provision in Belgium, the Netherlands, the UK and partly also in Italy. Specific national characteristics in the portfolio mix as, for example, a very high share of nuclear power plants in France, and large shares of biomass in Denmark or coal-fired units in Germany yet lead to modifications in the technology shares. This also leads to the interesting observation that Austria and Switzerland use their hydro reservoirs, though contributing equally to production, differently for both up- and downward flexibility provision. The use of nuclear in Belgium and Spain provides a similar example.

Note that in the investigated setting, neither demand side technologies nor RES curtailment contributed substantially to flexibility provision (cf. also Figure 32) as they are rather expensive. Batteries and other storages are by contrast not that large in this scenario. The contribution of changed interzonal flows via interconnections are not explicitly shown here as the focus is on changes in production in each country.

Figure 33: Comparison of shares in production and in flexibility provision for controllable technologies

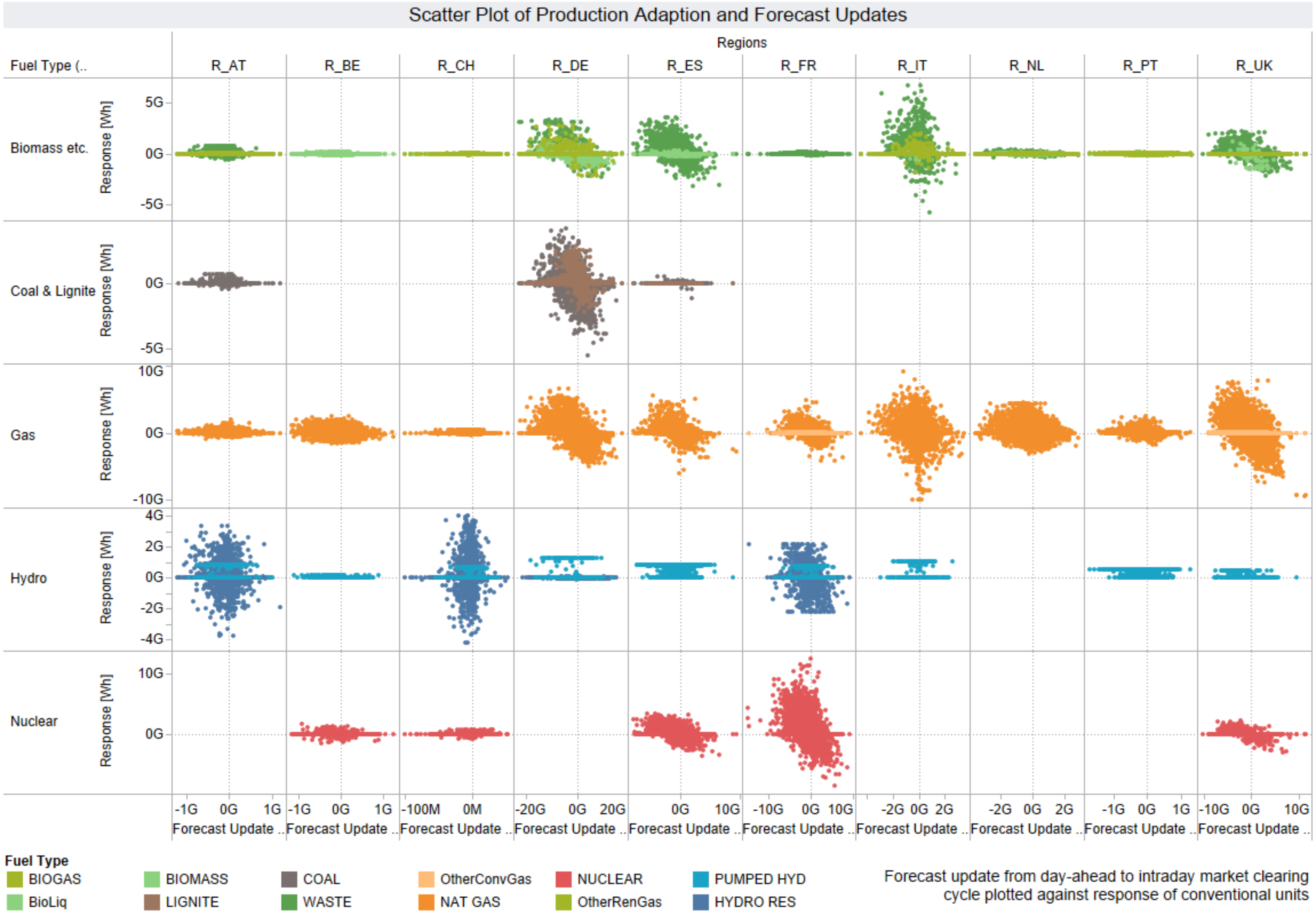
Scatter Plot of Production Adaption and Forecast Updates
Regions
Fuel Type (..
R_AT
R_BE
R_CH
R_DE
R_ES
R_FR
R_IT
R_NL
R_PT
R_UK
Biomass etc.
Coal & Lignite
Gas
Hydro
Nuclear
Response [Wh]
Forecast Update ..
Fuel Type
BIOGAS
BioLiq
BIOMASS
LIGNITE
COAL
WASTE
OtherConvGas
NAT GAS
NUCLEAR
OtherRenGas
PUMPED HYD
HYDRO RES
Forecast update from day-ahead to intraday market clearing cycle plotted against response of conventional units

Figure 34: Scatter plot of production adaption and forecast updates

3.3 Nodal market results

In the nodal study, the focus is on spatial patterns of market outcomes. Whereas the general setting of the nodal market study follows the setup of the zonal study, the setup obviously differs regarding market zones, which also implies that grid restrictions and time series data are disaggregated to a nodal scope. A detailed description of the approach can be found in Deliverable 2.3.

We consider a nodal market design for Austria, Belgium, France, Germany, and Switzerland while neighbouring countries are represented by a single node. Whereas the single-node representation collapses the country-wide demand and generation into one node, we base our nodal market representation on the high-voltage transmission grid nodes in the different

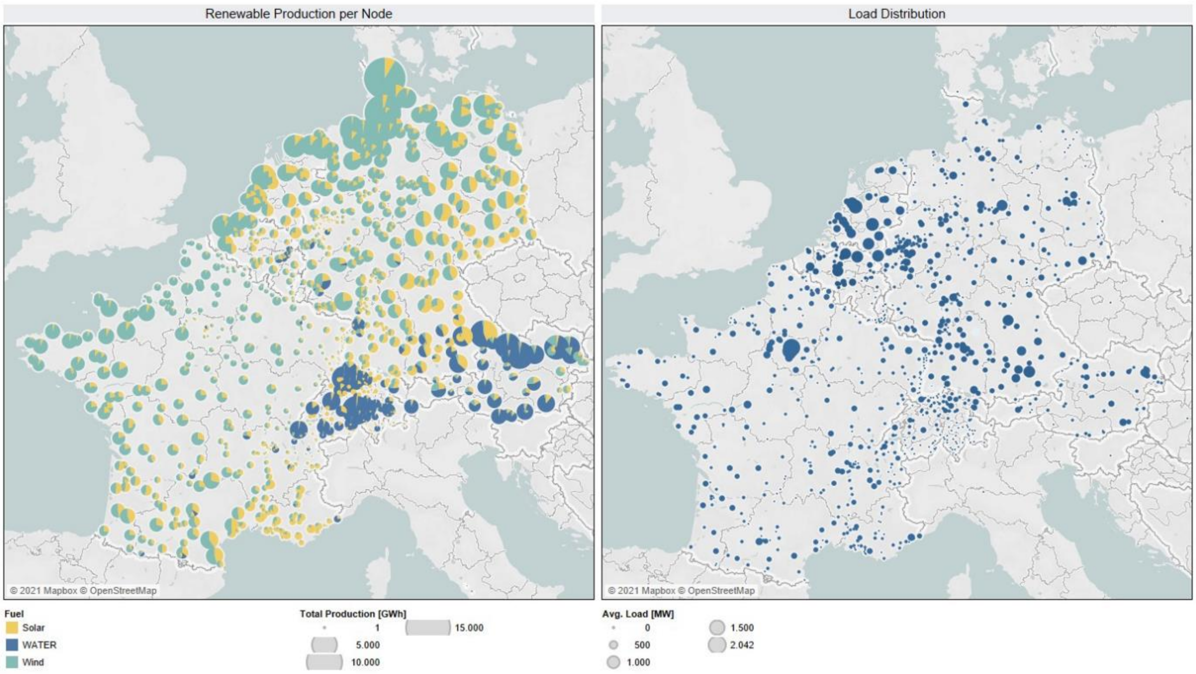

Figure 35: RES and Load Distribution in nodal setting

countries. As Figure 35 (right-hand side) shows, nodes are not evenly distributed within countries and/or regions. In large metropolitan areas and in selected countries, e.g., the Netherlands, grids with lower voltage levels play an important role that is not part of the data set. This, in conjunction with a lack of detailed timeseries on nodal load distribution may imply a mismatch between load allocation. Furthermore, the grid topology was modelled as static, thus there are no "load-following" line switching operations throughout the model horizon. These generalizations may lead to an unprecise grid representation that – where necessary – was adapted (rebalancing of load has been performed). These modifications may lead to price distortions in the market outcome.[7]

[7] On the other hand, the zonal market results presented earlier do not include the redispatch which has to be organized and paid for by the TSOs to avoid overloading of power lines and transformers.

The disaggregation of RES time series results in the distribution portrayed in Figure 35 above. The disaggregation of hydro production[8] is thereby based on data about existing capacities which imply that production is mostly limited to the Alpine area. For photovoltaic and wind production, a more sophisticated approach has been applied to match zonal data obtained from WP1. Thereby regional and nodal wind and solar radiation data are combined with data on installed capacities to obtain nodal time series with varying shapes and magnitude at each node. Correspondingly, wind production dominates in coastal areas and, when moving from northwest to southeast, shares of photovoltaic production increase. Actually, PV infeed dominates RES production, for example, in Bavaria or Provence-Alpes-Côte d'Azur. Furthermore, it is worth noting that nodes along the German, Dutch and Belgian North Sea shore show a significantly higher production from wind units than other nodes inland or along the French Atlantic shore.

Figure 36 shows the annual average day ahead price for each node. The colour of each node indicates the average price with prices above 50 € per MWh being light green, above 75 € per MWh yellow and above 125 € per MWh red.

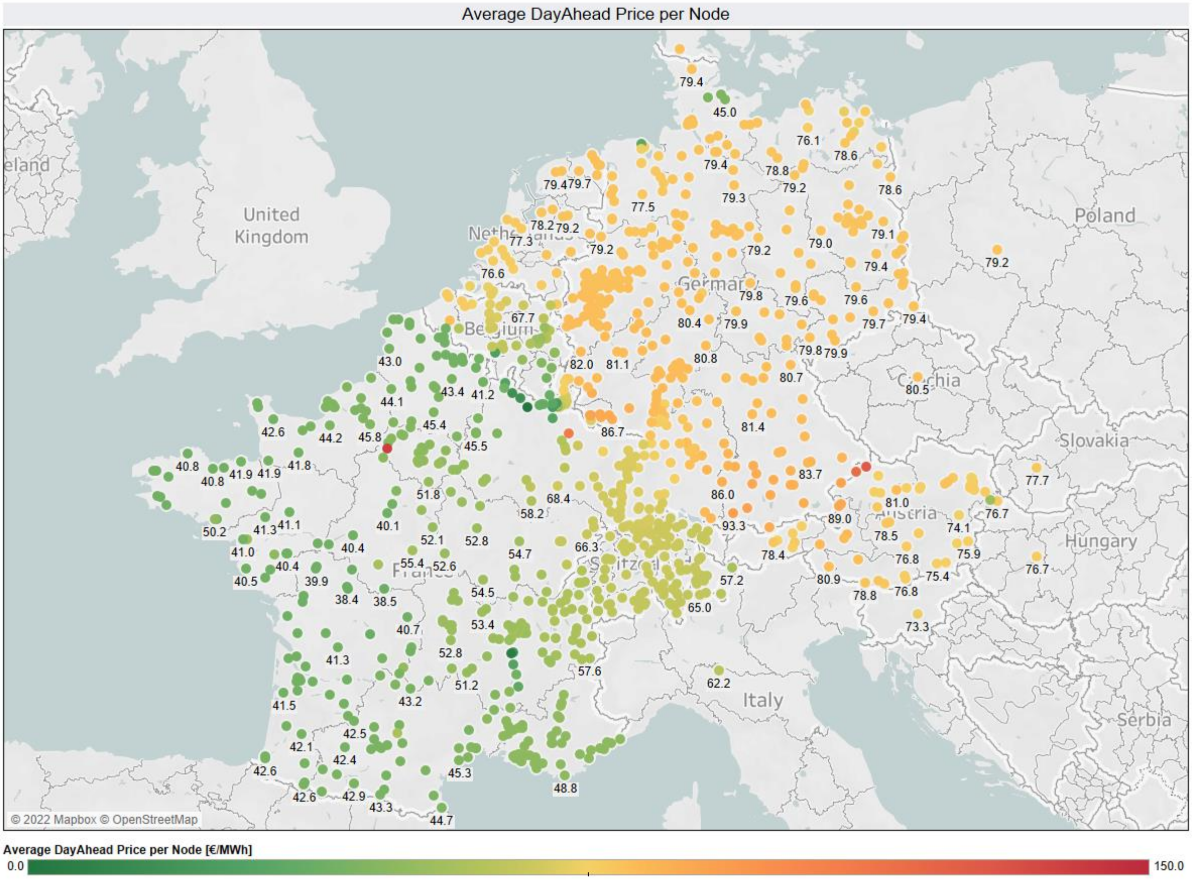

Figure 36: Average nodal Day-Ahead Prices per Year

[8] Water respectively hydro here exclusively refers to run-of-river production.

The price map reveals a clear, almost national, distinction of price clusters although the results of a nodal study are depicted. Austrian, German and Dutch nodes form a first cluster of nodes with average prices near 80 € per MWh – see also Figure 37. Whereas prices in the Netherlands and in the Northern half of Germany show no clear geographical pattern, prices in Southern Germany tend to be higher than in the remainder of the group. The cluster also contains some outliers: A few nodes in Northern Germany have considerably lower average prices as a result of high wind turbine concentrations in coastal counties with simultaneously low load– as also shown in Figure 35. A second group of outliers with an average price per year of 130 € emerges in the German-Austrian border area. France, except for its Eastern border area, forms the second cluster. In contrast to the first cluster, prices are here in the range of 40 to 50 € per MWh at most western nodes and thus much lower than in the first cluster. Upward outliers emerge near Paris and downward ones, for example, near the Luxembourgian border. When interpreting the prices, one yet must bear in mind that they are derived based on short-run marginal costs of generation units and thus do not reflect the capital expenditures related to the different generation assets.

The observed patterns intermingle, as both Figure 36 and Figure 37 indicate, in Belgium but also in South-Western Germany and Central-Eastern France. Switzerland also has an intermediate price level and the variation of average prices inside the country is rather low. By contrast, price dispersion is rather high in Belgium. This may be partly attributed to limited transmission capacities on cross-border and internal lines. Yet also the limited flexibilities available in Belgium compared to the important hydro storage capacities in Switzerland contribute to higher temporal and spatial price volatility.

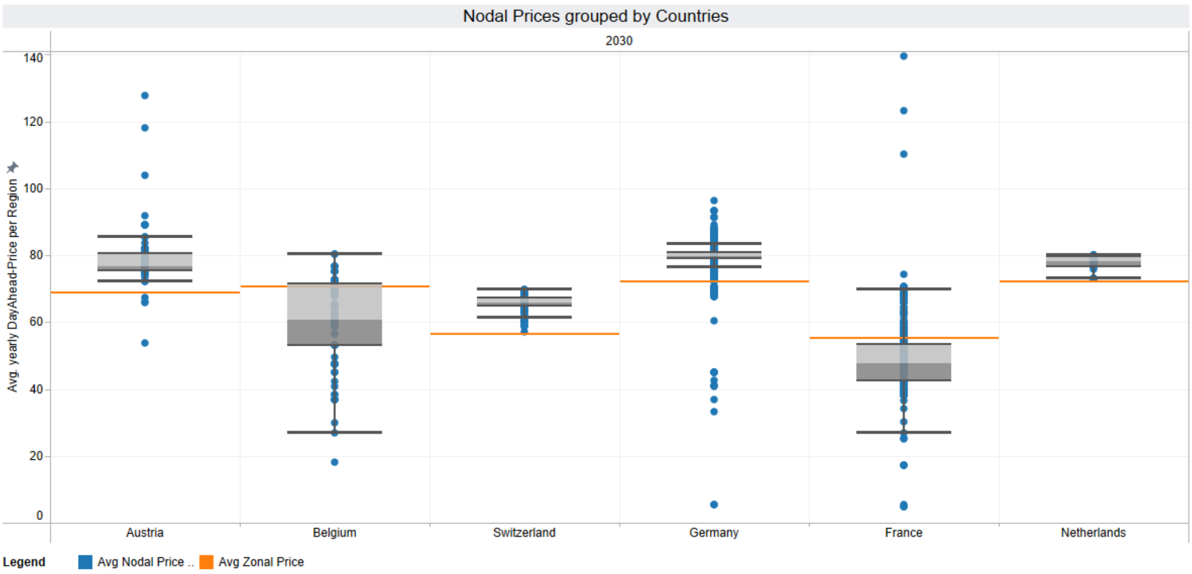

Figure 37: Box plot of annual average prices per node and corresponding zonal prices

Figure 37 also enables a comparison of annual average prices from both the nodal and the zonal study on a country basis. Nodal prices are presented in a box plot in which the grey-shaded areas correspond to 50 % of the nodes (prices between the first and the third quartile) while the remaining nodes are represented by individual blue dots. The national price averages from the zonal study are displayed by orange lines. Though the zonal and nodal study are based on the same general case settings, intra-zonal grid restrictions do not affect prices in the zonal study, yet they have an impact in the nodal study. The results should yet not be overinterpreted, as the nodal representation of the grid is exclusively based on the transmission grid. Besides real shortages of transmission capacities also a misrepresentation of the network may affect results. For example, whereas Germany’s largest metropolitan area, the Rhine-Ruhr area, is represented by several nodes with relatively low load – see Figure 35 – the Île-de-France area but also entire countries, for example, the Netherlands are represented by only few nodes with relatively high loads. This discrepancy which is related to the omission of the distribution networks but also to a static grid topology as mentioned above may induce faulty representations of the network and consequently of the price outcomes. This may also affect the aggregation of nodal prices even if load or production weighted prices are used. Therefore, we refrain from aggregating nodal prices other than in the box plot. When comparing these to the zonal prices, two patterns are observable in Figure 37 (not considering outliers): In the zonal study, prices for Austria, Switzerland, Germany and the Netherlands are below the lower whisker[9] of the range of nodal prices – arguably caused by technology shifts, as portrayed by Figure 38. The nodal price range coincidently is rather small which may be a consequence of marginal costs being set by similar technologies across the entire country. On the contrary, Belgium and France show a broader range of yearly average prices at their nodes, but the country-wise price from the zonal study is close to the third quartile of the nodal results. Hence, the zonal market setting does not only eliminate price variations within the zones but also reduces the price dispersion between zones – this is probably related to the fact that less grid constraints are included in the zonal market clearing and thus more energy may be transferred from one country to another, even between areas located far from the borders. The differences in price patterns may also affect the valuation of flexibilities located at different grid nodes as will be discussed below.

[9] Whiskers represent 1.5x Inter-Quartile Range.

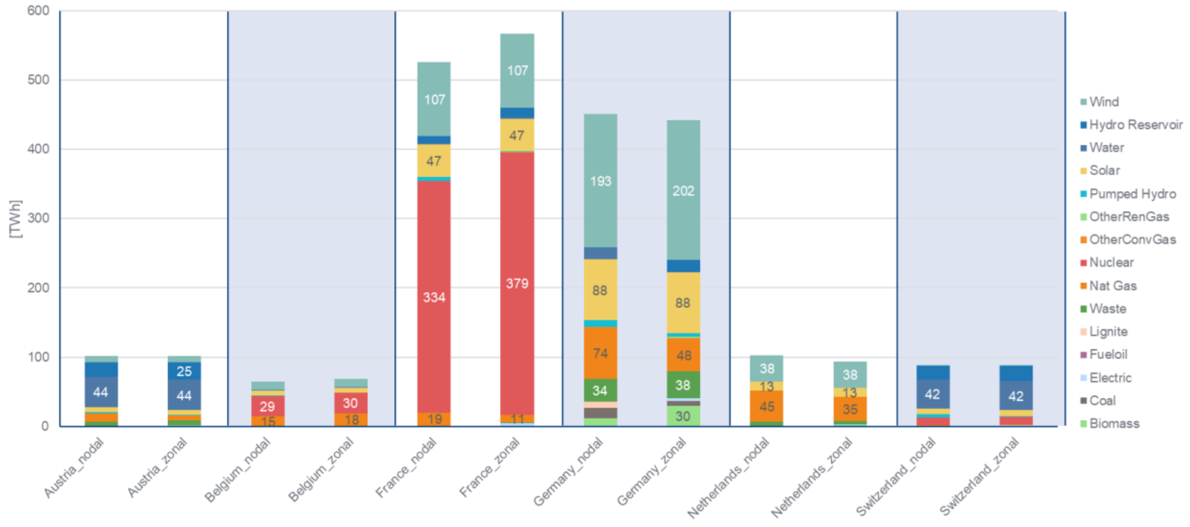

Figure 38: Aggregated production per year for the zonal and nodal simulations

As indicated in Figure 38, the generation mix in Austria, Belgium, and Switzerland is rather similar in the zonal and nodal settings. The same is true for most technology shares in Germany and the Netherlands, yet the electricity generation from wind, biomass and waste is lower in the nodal setting while simultaneously the output of gas fired units increases in both countries. The technology switch between cheap RES production and expensive gas units indicates redispatch and therefore (nodal) grid locks, predominantly within the German system. Further, about 40 TWh of French nuclear production from the zonal study is replaced by an increased production from gas-fired units mainly in Germany, the Netherlands and Belgium. This may be explained by the need to use flexible (hydro) storage in the nodal study to a larger extent for coping with grid bottlenecks whereas it may be dispatched as complement to nuclear base load generation when intrazonal grid restrictions are neglected.

As a complement to the aggregated data presented in the previous figures, Figure 39 provides insights on time series of prices and the corresponding production. Thereby an unweighted average of nodal prices within each country is depicted while production is summed over the corresponding nodes. Whereas the left-hand side of the figure portrays an exemplary week with low prices, the interplay of prices and production for a week with high prices is displayed on the right.

In both figures, the price patterns clearly reflect the marginal production technologies in each country: The absence of production from gas units in the low-price example week in France coincides with prices below 25 € per MWh, while prices in Germany fall to 40 € per MWh when gas units drop out from production and rise to approximately 90 € per MWh when they are present and most likely price setting. Whereas prices do not align in many situations, both markets are jointly driven by the German RES oversupply during the weekend of the low-price week. During the high-price week, gas-fired units are at the margin in both markets most of the time, which causes both price curves to align. However, during the weekend, French prices drop significantly lower than their German counterparts. This coincides with an almost vanishing production of gas-fired units in France.

In terms of production, the more heterogeneous and volatile German generation mix is clearly visible. In France, though nuclear power dominates production, two operation modes may yet be distinguished: The nuclear fleet is running at full capacity during the high price week – as indicated by the almost constant production and by prices that are far above the marginal cost of nuclear generation. By contrast it is clearly in load-following operation mode during the low-price week. However, an exception to the latter can be seen mid-day during the weekend of the low-price week: nuclear production drops to a plateau of approximately 15 GW, while simultaneously negative prices in Germany and France indicate an ongoing oversupply situation. This remaining plateau hence reflects the aggregated minimum output of operating nuclear units in France. As restarting nuclear units after a full shutdown is lengthy and costly, the figure illustrates the trade-off between significant minimum output levels from nuclear units in oversupply situations vs. their operational availability in the remaining hours. Production in Germany not only shows the high impact of seasonality on photovoltaic production, but also a dwindling market for fossil production technologies, notably for coal and lignite fired power stations. Given the high CO_2-price of 100 € per t in the study, the marginal cost of coal and lignite fired units exceed those of gas plants, correspondingly they are operating in less hours.

A commonality between both countries can be found in the operation of pumped hydro storages. Their almost identical production patterns indicate that they take advantage of low prices due to mid-day photovoltaic production for pumping and then produce electricity during the following hours characterised by fading solar radiation, high load and corresponding high price levels. However, both in France and Germany, this buy-low-sell-high strategy is more extensively applied in summer than in winter. This is at first sight surprising given the significant prices differences occurring also in winter. Yet the profitability of storage operation depends on the ratio of prices during pumping relative to prices during turbine operation and not on the absolute price difference. For profitable arbitrage operation, the price ratio must exceed the cycle efficiency of the storage – then the costs related to losses can be recovered from the operation margin earned.

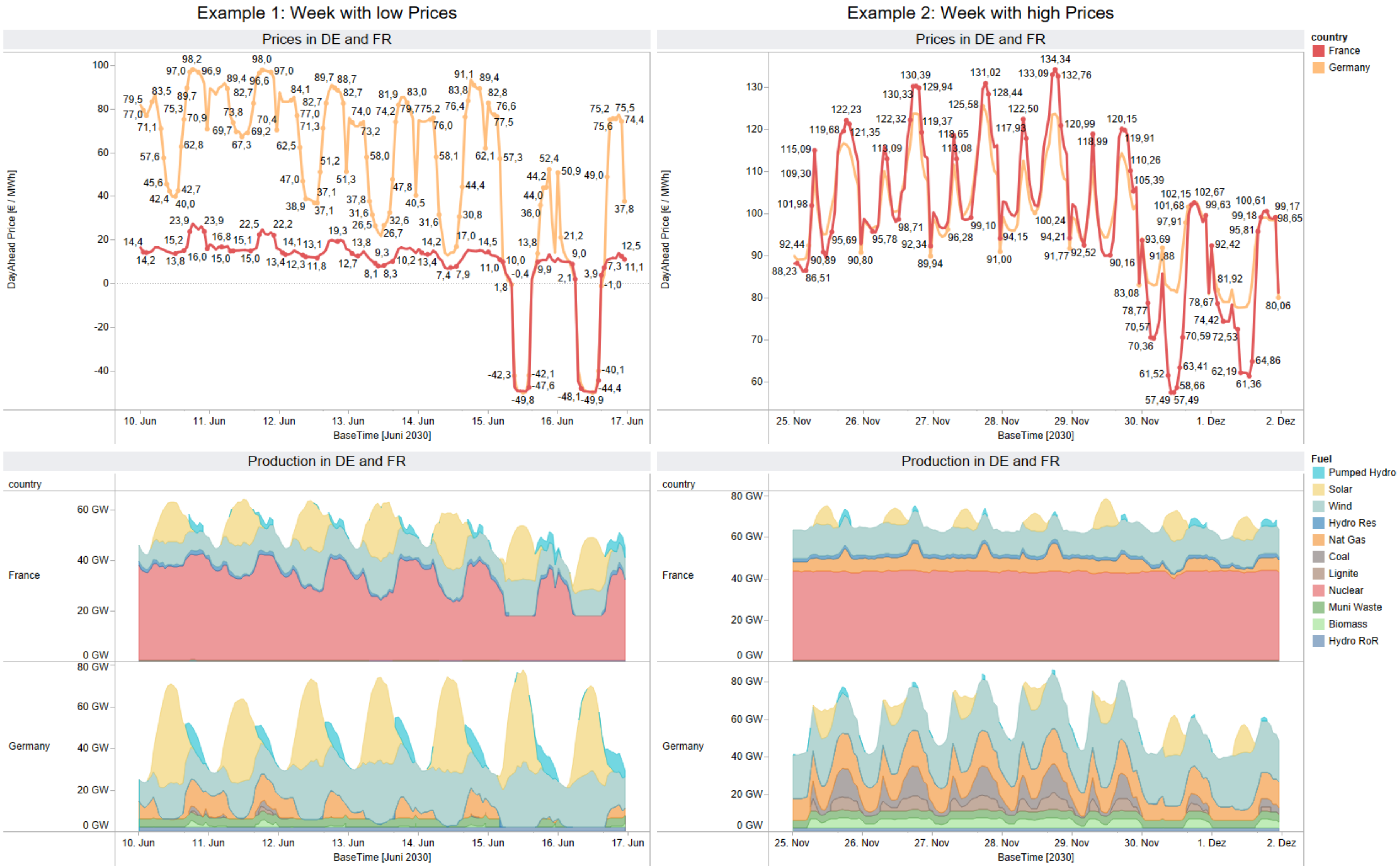
Example 1: Week with low Prices
Example 2: Week with high Prices
Prices in DE and FR
Prices in DE and FR
DayAhead Price [€ / MWh]
BaseTime [Juni 2030]
BaseTime [2030]
country
France
Germany
Production in DE and FR
Production in DE and FR
country
France
Germany
Fuel
Pumped Hydro
Solar
Wind
Hydro Res
Nat Gas
Coal
Lignite
Nuclear
Muni Waste
Biomass
Hydro RoR

Figure 39: Price and corresponding Production for two exemplary weeks with low Prices (left) and high Prices (right)

3.4 Spatial variations in the value of exemplary flexibilities

The results of the nodal study presented in the previous section provide a description of the optimal system operation and the corresponding marginal cost of service delivery in a future system with high shares of variable renewable generation. The nodal prices derived in this setting reflect the marginal value of an additional unit of supply respectively the cost of a marginal unit of demand at each node. Combining these marginal values with the operation constraints of a flexible system element such as battery storage allows the assessment of the value of this flexibility in a system perspective. In essence, such an approach corresponds to the assessment of profitability that a private investor would carry out when facing the nodal prices as market outcomes and while considering that his own (relatively small) investment would not impact the overall market result ("price taker" assumption).

Assuming investment costs are equal on all grid locations, the economic viability of such an investment is then driven by the different local price patterns. Taking the 2030 nodal market results of Section 3.4 as basis and applying an intertemporal optimization model for storage operation, the location-dependent annual contribution margins may be derived for an exemplary storage configuration.

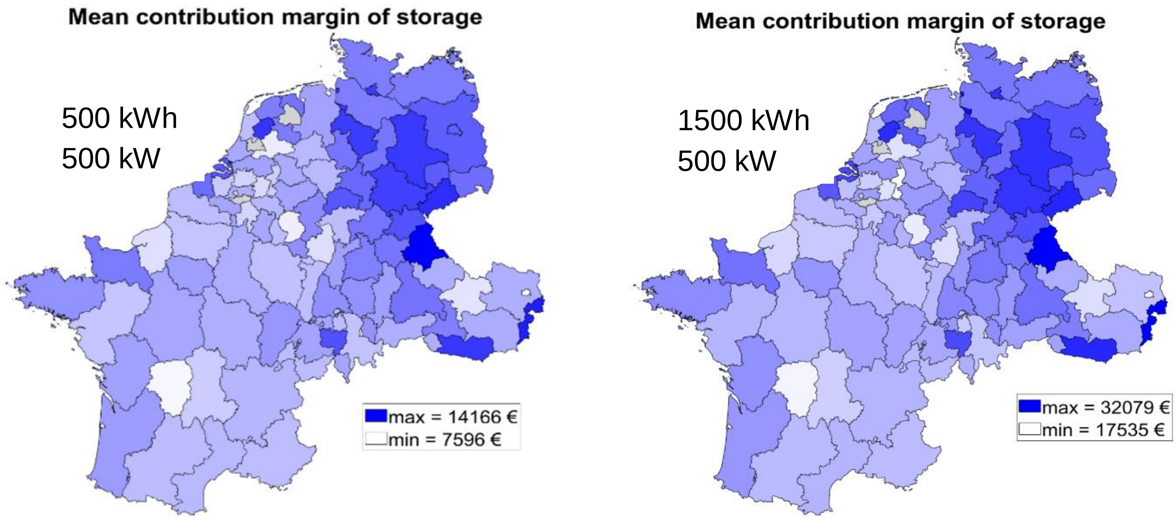

Figure 40: Profitability of two storage configurations at different locations based on the prices of the nodal study

The corresponding results are shown in Figure 40 for two storage configurations. On the left side a fast storage with an energy-to-power ratio (E/P ratio) of 1 is considered, i.e., this storage may be fully charged or discharged within one hour of operation. On the right side, the E/P ratio is set to 3, i.e., this storage has a higher energy content yet is slower to charge and discharge. Results are presented at a NUTS2 aggregation level, i.e., averaged over geographical entities corresponding to (former) French regions or German Regierungsbezirke instead of considering individual grid nodes. From the figures it is obvious that the contribution margins considerably differ between locations, with margins being typically higher in Germany than in France. This is in line with the larger price variations observed in Germany over the two exemplary weeks depicted in Figure 39. Yet even inside Germany, there are substantial differences in profitability – and in contrast to naïve expectations, the highest margins are not observed in the coastal locations with high renewable infeeds.

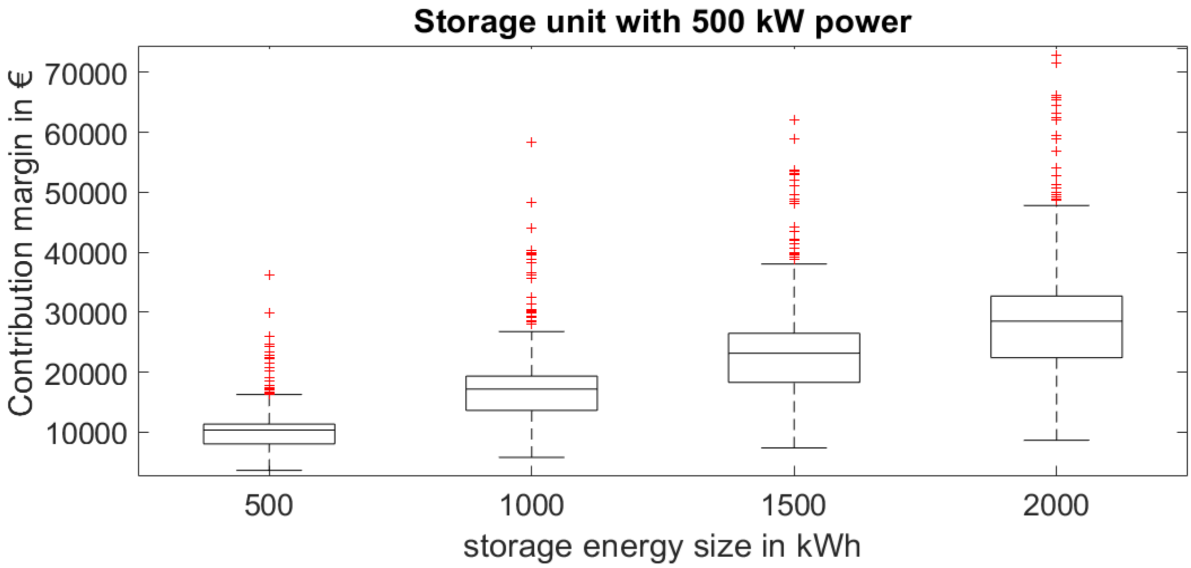

Figure 41: Profitability of the storage configurations with increasing energy capacity

When comparing the small (fast) and the large (slow) storage, the spatial patterns of "sweet spots" for storage investment turn out to be rather similar for both configurations. With respect to the absolute profitability, the earnings of the larger storage increase with a decreasing rate. Figure 41 illustrates the decreasing marginal contribution margin at all locations for different energy capacities for the same storage power rating. Contribution margins of storage units with high power ratings contribute similar margins to configurations where the storage unit could be fully filled or emptied within one market timestep. Units with power ratings above that threshold would need to participate in other markets to monetize their short-term flexibility, as their flexibility potential would not be rewarded in the energy market but comes at increased investment cost that is not depicted here.

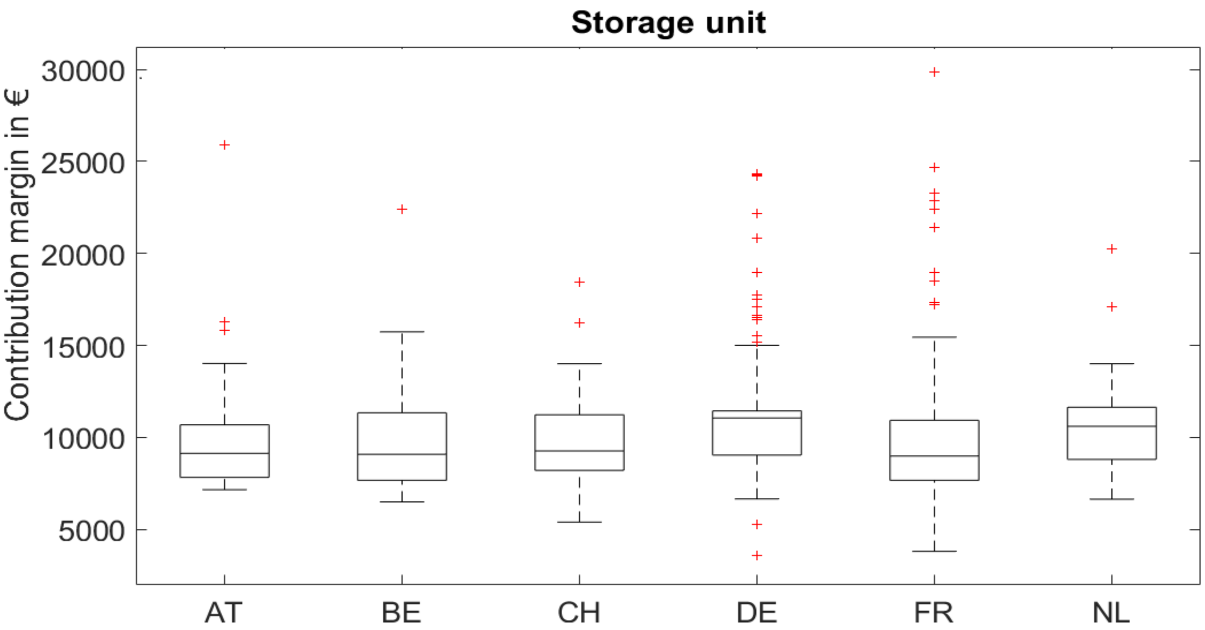

Figure 42: Box plot of annual operation margins for an exemplary storage configuration based on the prices of the nodal study

Figure 42 shows the range of spatial variation of contribution margins within and across countries for the small storage configuration. While the overall range looks rather different for the various countries, a closer inspection of the median contribution margins reveals that the median location (the horizontal line within the box) leads to more than 10.000 EUR annual operation margin in Germany against less than 9.000 EUR in France. For the more extreme locations the variation is even higher. Assuming specific investment cost of 200€/kWh[10] for storage, the median (static) payback time would be approximately 10 years. The graph yet highlights that important variations in the system value of such a flexibility exist within a country which are related to the uneven distribution of variable generation resources and loads across the countries (cf. Figure 35). Together with limitations in transmission line capacities these result in differences in nodal prices as depicted in Figure 36. These locational differences in storage values are not visible to investors if only zonal market prices are applied. Obviously, investment decisions will also take into account other revenue streams for storages, e.g. revenues on the reserve markets. These are not included in this system simulation, yet in zonal markets also reserve market prices are generally not differentiated by location Hence these results suggest that specific incentives for the locational choice of flexibility investments are advisable. Ex-post local redispatch markets would be an option. Yet, its consecutive clearing mechanism is prone to market power issues, in particularly increase-decreasing gaming. Another possibility for an efficient single market-clearing process would be through a move towards nodal pricing. Further options include location-dependent grid charges or through locationally differentiated supports or locally differentiated tenders for investments.

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[10] See National Renewable Energy Laboratory, Technical report: Identifying and Overcoming Critical Barriers to Widespread Second Use of PEV Batteries, 2015, p. 22f

Figure 43 provides an additional analysis of the variations in contribution margins across locations. By plotting the annual contribution margin on the vertical axis against the standard deviation of hourly prices on the horizontal axis it becomes obvious that the standard deviation is not a very good predictor of the profitability of this storage configuration in a certain location. In contrast, Figure 44 depicts the local contribution margins by the average daily price spread. The latter indicator leads to a higher correlation and corresponding steeper slopes of the regression lines, which implies that battery storage units are rather operated in daily cycles, and it is not the overall variability of prices during the entire year that drives the profitability. Put differently: the important difference in price levels between the two exemplary weeks shown in Figure 39 cannot be exploited by short-term storage units like batteries. Rather it is the price variations within the day (or week) that drive the profitability.

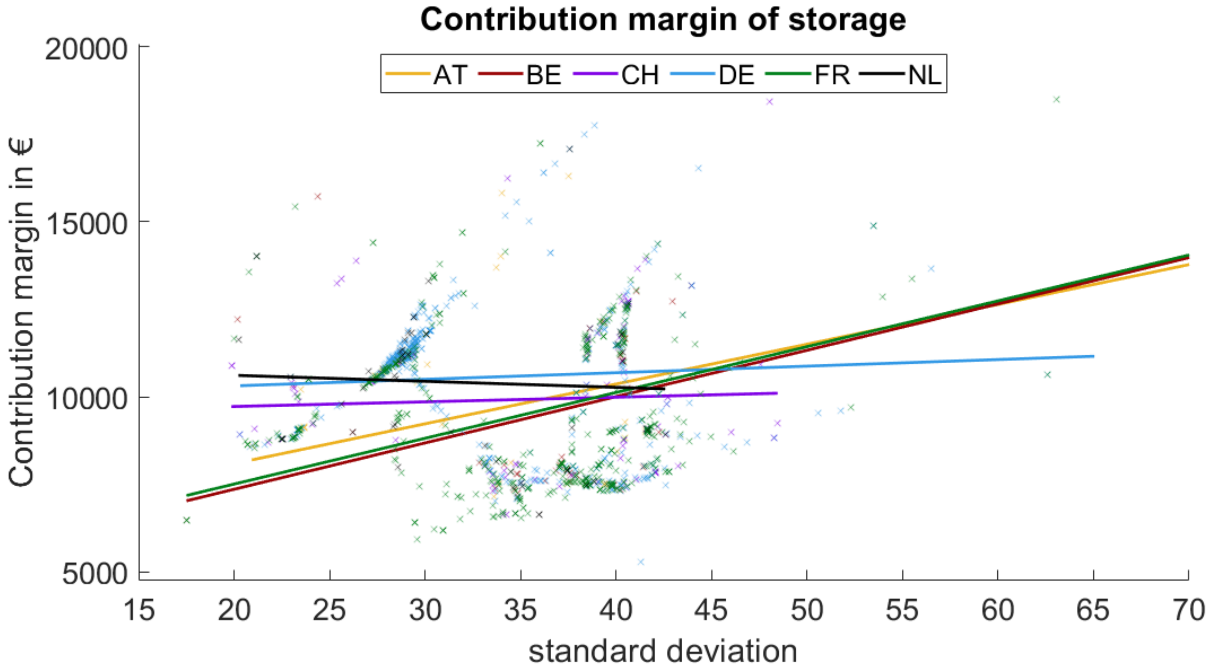

Figure 43: Scatter plot of annual contribution margins for a storage configuration based on the standard deviation of the prices of the nodal study

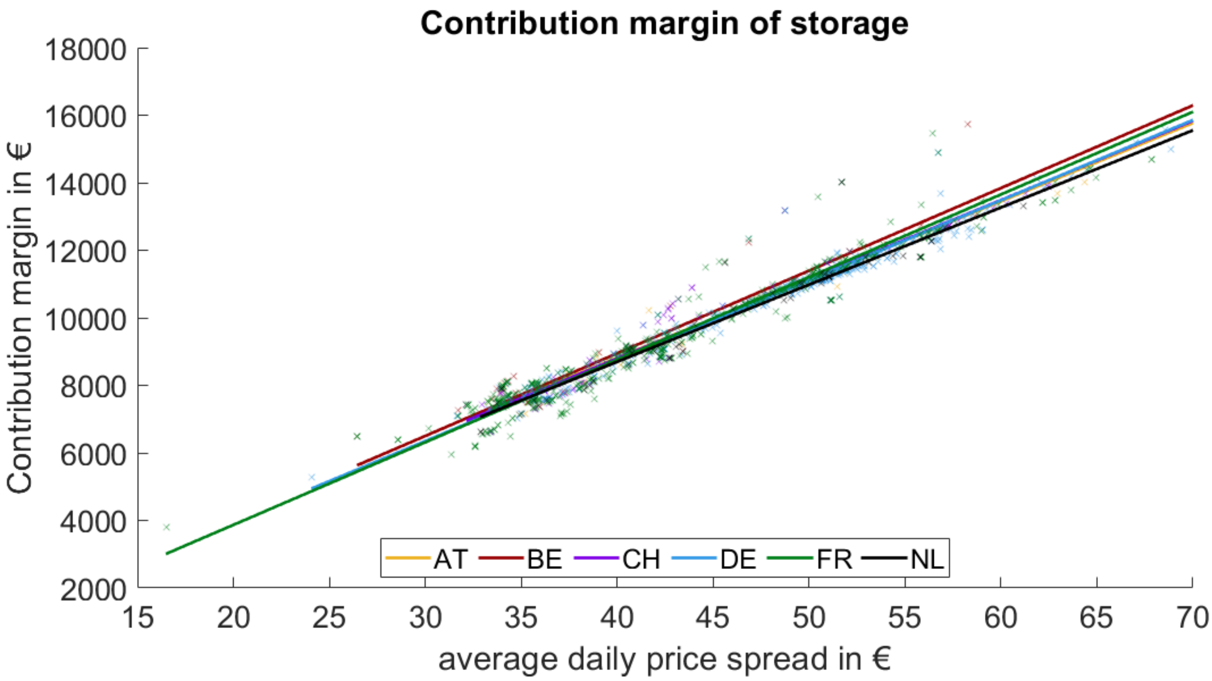

Figure 44: Scatter plot of annual contribution margins for an exemplary storage configuration based on the daily average prices spread

4 TSO/DSO interface modelling results

This case study aims to validate the TSO/DSO interface modelling methodology described in deliverable 2.3, by applying it to a representation of the power system of central France. This methodology aims to (i) simulate power system behaviour at the TSO/DSO interface and (ii) evaluate whether flexibility products can be activated on the distribution side while respecting network constraints.

First of all, a group of 263 Distributed Networks (DN) was selected, spread over seven regions (i.e., Auvergne, Bourgogne, Centre, Basse-Normandie, Île-de-France, Pays de la Loire, Rhône-Alpes) and fourteen departments (i.e., Allier, Cher, Essonne, Eure-et-Loir, Indre, Loir-et-Cher, Loire, Loiret, Nièvre, Orne, Puy-de-Dôme, Sarthe, Yonne, Yvelines). These DNs are supplied by the HV nodes of the French sub-transmission grid (namely, 63 kV, 90 kV, and 150 kV), and in several cases there is a node of HHV in the same location (225 kV or 400 kV). The MV side of the TSO/DSO interface supplies the DNs with nominal voltage ranging from 6 kV up to 20 kV depending on the DSO (the most common voltage level is 20 kV). Figure 45 shows the selected group of DNs.

Figure 45: Selected TSO/DSO interfaces in central France

The first contribution of the proposed approach is the model of each considered DN, developed based on open data only. They were represented using so-called synthetic networks. This task is helpful for TSOs and for stakeholders that do not have a detailed knowledge of the distribution grid. These synthetic networks are constituted using a combination of elementary portions of networks, representative of given ambits (i.e., urban, rural and industrial feeder). A synthetic network is obtained by combining different territorial characteristics with estimated demand and production.

At this point of the procedure, the power profile exchanged at the TSO/DSO interface and the network downstream of any studied TSO/DSO interface are completely known. The network is represented in terms of conductors, topology, connected load and generation, and it can be used for any study focusing on the distribution system.

Besides the negotiations and trades within the energy market, the results of the ancillary service (AS) market play an important role in the definition of the final electricity bill of end-users. Ancillary services are necessary to operate the power system securely and adequately. They have traditionally been provided by transmission system users and producers, except renewable-based ones. Nowadays, energy production from renewable energy sources influences system operation and makes it more complex to balance generation and demand at every single point in time with enough security margins. The flexibility of demand and local generation, mainly connected to the distribution grid, is the key to avoiding massive infrastructure investments for network reinforcement and not jeopardizing the high levels of system stability and security obtained so far. Thus, the general result of the proposed approach is the quantification of the availability of flexibility products and the relevant costs to be offered to the existing global AS market by the DERs connected to the selected DNs. Such quantification considers the grid limitations by using the synthetic model of the networks for checking the compliance with the technical constraints of the possible provision of flexibility products.

In addition, to integrate the studies within OSMOSE WP2, the synthetic models of the distribution networks are also used for detecting possible technical constraint violations arising by the forecasted offers to the day head and in the intraday energy market in some days of 2035, as resulted by the nodal studies performed by RTE (see 2.2.2 of this report).

4.1 Assumptions and results

Some assumptions have been made for modelling the distribution networks, assessing the flexibility services potentially offered to the existing global AS and new local markets, and, finally, for integrating the ENSIEL studies with the RTE ones, as detailed as follows.

4.1.1 Modelling the distribution networks

Once defined, the list of TSO/DSO interfaces that cover a given territory, public data on electric demand and production of the most suitable territorial portions (i.e., the EPCI- *établissement public de coopération intercommunale*), provided by the transmission (i.e., RTE) and/or the main distribution system operator (i.e., Enedis) websites, were used for building the power profile exchange at the TSO/DSO interfaces. The most recent data found at the beginning of this study referred to 2018, and thus this year was considered as a reference. According to the DSO website data, this annual energy was distributed between the demand sectors (i.e., agricultural, industrial, tertiary-commercial, and residential) and then attributed to the TSO/DSO interfaces by resorting to GIS tools following the procedure described in deliverable

2.3. Typical load profiles relevant to each customer category and differentiated by seasons and day of the week (i.e., working days, Saturdays, Sundays and holidays) have been used to assess the hourly load profiles at the TSO/DSO interfaces.

Regarding the production profiles, starting from data on the installed capacity of RES-based generation, the same approach used for the demand allowed estimating the production profiles at the TSO/DSO interfaces. Since the vast majority of DG connected to the MV distribution networks is based on RES, in many cases, the position and size of generators has been made publicly available by network operators. Thus, the production by the local generation has been mapped to each territorial portion according to this information by considering the rated power capacity of the generators and the production potential of the site. Only wind and solar plants are considered connected to the MV distribution networks. The total installed capacity has been shared between the transmission and the distribution grids (i.e., 35% of PV and 80% of wind are supposed to be connected to the distribution system). We assumed radiation data from the PVGIS database for the PV production and average historical records for the wind plants for building typical seasonal profiles. In Figure 46, some residual power profiles at the TSO/DSO interfaces, obtained by subtracting the estimated production to the estimated load demand, are shown as an example. The first remark is that many DNs experience a reverse flow towards the transmission grid starting from the assumed DG data.

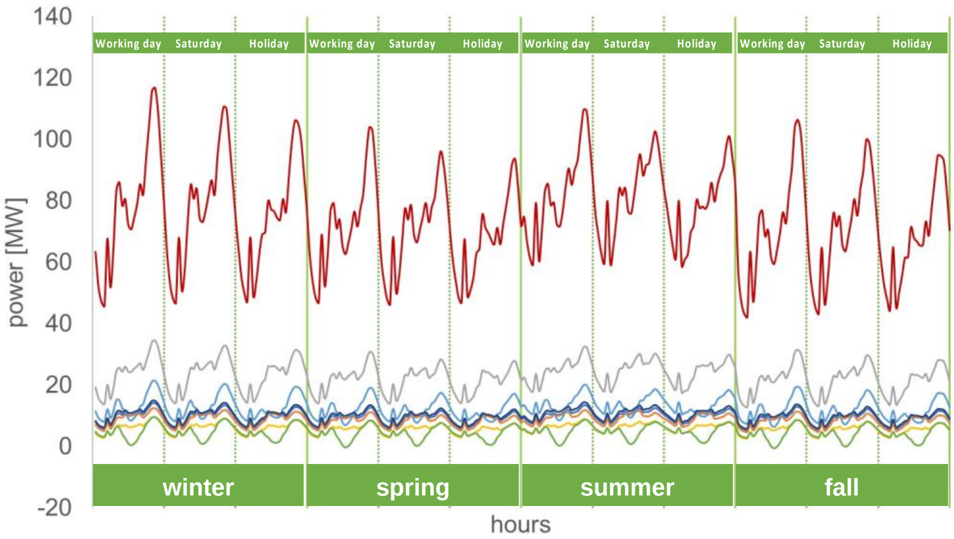

Figure 46: Power profile exchange at some TSO/DSO interfaces

A fixed annual growth rate of 4.84% has been assumed for forecasting the power profiles in the future year 2035. In particular, by starting to the French electricity demand in 2018, equal to 475 TWh/year, we assume a final yearly demand of entire France equal to 498 TWh/year[9] in 2035.

. In addition, it is assumed that, in 2035, 25 TWh/year[11] will be consumed by electric vehicles and, thus, such demand (about 5% of the total) has been added to the yearly calculated demand of each DN. The RTE nodal studies provided the forecasted installed capacity of RES-based generation.

Information related to the demography, the land cover and usage, as, for instance, the number of buildings, the number of employees, etc., derived by resorting GIS tools were used to characterize the area served by a given DN and to assess the proper combination of the elementary portions (i.e., the typical *feeders,* shown in Figure 47) of distribution networks representative of given ambits considered for building the synthetic network of each real DN. Table 3 and Table 4 report the main data of the typical feeders used for modelling the DNs.

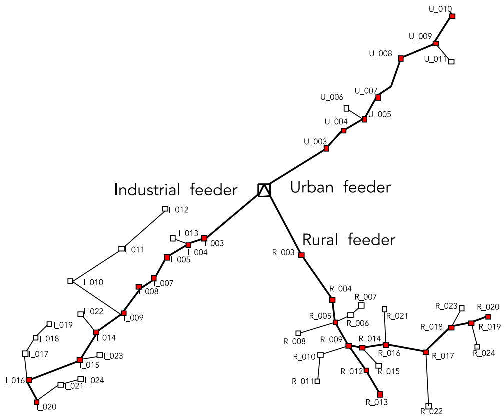

Figure 47: Elementary portions of network used for building the model of real DNs

Table 3: Data relevant to the typical feeders 1/2

Feeder	MV Nodes	Total Length [km]	Max distance from TSO/DSO interface [km]	Load [MVA]	LV installed power [%]
Rural	22	40.11	20.85	3.51	99.6
Urban	9	1.23	1.21	3.62	97.6
Industrial	22	18.09	11.21	4.04	32.1

Table 4: Data relevant to the typical feeders 2/2

Feeder	Agricultural cons. [GWh/y] ([%])	Industrial cons. [GWh/y] ([%])	Tertiary cons. [GWh/y] ([%])	Domestic cons. [GWh/y] ([%])	Total energy cons. [GWh/y]
Rural	5.89 (37.10%)	0.061 (0.38%)	0.0 (0%)	9.9 (62.51%)	15.87
Urban	0.0 (0%)	0.31 (2.48%)	6.95 (55.76%)	5.20 (41.76%)	12.46
Industrial	0.0 (0%)	13.98 (65.92%)	2.22 (10.47%)	5.01 (23.61%)	21.21

For instance, the distribution network downstream of the TSO/DSO interface highlighted in Figure 48 a) can be represented by the combination of 1 rural feeder, 7 urban feeders and 1 industrial feeder, as in Figure 48 e).

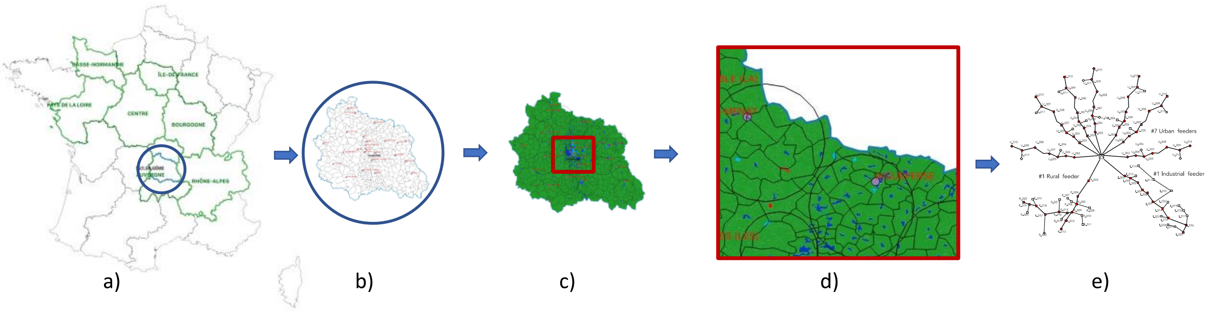

Figure 48: Example of synthetic network representation

Once the passive networks have been modelled, one or more distributed generation (DG) scenarios have been applied to the model. The scenario chosen for the studies described in this report aimed to reproduce the realistic scenario of DG by positioning generators in the representative feeders that compose the passive model of the DN until it achieves the supposed real or forecasted DG installed capacity. In the proposed approach, the DG units are chosen among discrete sizes, previously fixed, typical for each technology (e.g., PV aggregated sizes can be from 250 kW, while the wind turbines considered range starts from smaller sizes, such as 20 kW or 60 kW). Since the position of the generators impacts network behaviour, especially when the feasibility of the flexibility products offered is assessed, two scenarios are implemented:

- The first one, named *fit & forget,* is designed for creating the slightest negative impact on the network operation: generators even small in size spread along all the feeders that compose the network model.
- The second, named *critical scenario,* consists of big power plants (i.e., 1000 kW and 1500 kW for both PV and wind) concentrated in few positions, even not convenient for the network operation (e.g., at the end of a long rural feeder).

In both scenarios, any distributed generation representing a volume below 30% of connected load is connected to existing MV feeders. Any distributed generation in excess of 30% is connected to a dedicated feeder (on the MV side of the TSO/DSO interface), allowing DG to provide flexibility services without impacting MV operation.

The synthetic load and generation data may differ from those estimated for the real DN. In the resulting representation, only 9 DNs are built with an absolute error in the annual energy greater than 20% (234 <10%), as reported in Figure 49. Such error has been covered by considering a further feeder (named *jolly feeder*) in the model, deemed non-flexible for the further calculations. The *jolly feeder* behaves as a generator or load depending on the error sign.

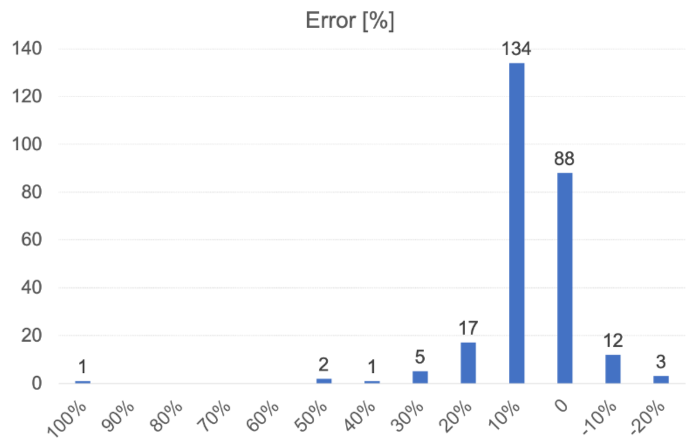

Figure 49: Resulting errors [%] in annual energy of the DN model, covered by the jolly feeder

Table 5 reports the resulting synthetic networks composition of the selected 263 real DNs.

Table 5: Synthetic networks composition of the selected 263 real DNs

N	Name	N. feeders	Estimated demand [GWh/year]	Error [%]
1	ALENCON	7 R; 1 I; 15 U;	338.8	-1.1
2	ANCIZES (LES)	3 R; 0 I; 1 U;	67.8	5.3
3	ARPAJON	0 R; 0 I; 11 U;	149.6	0.7
4	AUXERRE	0 R; 0 I; 11 U;	151.7	2.1
5	BOURBON-L ARCHAMBAUL	7 R; 0 I; 1 U;	130.5	-1.1
6	BAYET	3 R; 0 I; 3 U;	82.2	-11
7	BELLENAVES	3 R; 0 I; 1 U;	71	9.5
8	BIZETTE	0 R; 0 I; 9 U;	128.6	5.5
9	BONNETABLE	4 R; 0 I; 3 U;	101.9	-6.2
10	BEAUGENCY	1 R; 0 I; 5 U;	86.8	2.7
11	CHATEAUNEUF-SUR-LOIRE	2 R; 0 I; 3 U;	78	4.7
12	CROIX-DE-NEYRAT	1 R; 0 I; 16 U;	241.4	3.5
13	CHAINGY	1 R; 0 I; 8 U;	136.1	8.2
14	CHARLIEU	2 R; 0 I; 3 U;	63.7	-16.8
15	CHARTREUX	1 R; 1 I; 55 U;	767.6	-1.7
16	CHENET	0 R; 0 I; 13 U;	178.2	1.5
17	CLAMECY	4 R; 0 I; 3 U;	104.6	-3.4
18	COMMENTRY	4 R; 0 I; 3 U;	113.7	4.9
19	CONNERRE	5 R; 0 I; 5 U;	149.2	-1.9
20	COSNE	2 R; 0 I; 5 U;	105.2	3.7
21	CRUCHET (LE)	4 R; 0 I; 8 U;	181.7	3.3
22	CHATEAUDUN	2 R; 0 I; 8 U;	148.7	4.6
23	COURPIERE	4 R; 0 I; 0 U;	65.1	-4
24	DREUX	0 R; 0 I; 1 U;	14.7	8.4
25	EPERNON	1 R; 0 I; 6 U;	106.5	8
26	EPINAY-SOUS-SENART	2 R; 2 I; 84 U;	1219.5	0.7
27	FLECHE (LA)	6 R; 0 I; 6 U;	186.5	2.1
28	FRESNAY	4 R; 0 I; 3 U;	102.9	-5.1
29	ITTEVILLE	3 R; 0 I; 14 U;	238.3	-0.6
30	JEU-LES-BOIS	12 R; 0 I; 3 U;	239.7	-1.6
31	JACQUARD	0 R; 0 I; 6 U;	91.4	11.4
32	JARGEAU	1 R; 0 I; 8 U;	133.6	6.5
33	LENTIGNY	4 R; 0 I; 5 U;	130.4	-3.6
34	LEVROUX	2 R; 0 I; 1 U;	56.6	16.4
35	LORRIS	3 R; 0 I; 2 U;	81.3	4.4
36	LOUVECIENNES	4 R; 1 I; 123 U;	1741.4	-0.5
37	MAGNANVILLE	1 R; 0 I; 15 U;	221.2	0.8
38	MAMERS	2 R; 0 I; 8 U;	133.4	-6.3
39	MAZIERES	1 R; 0 I; 8 U;	126.9	1.5
40	MIGENNES	0 R; 0 I; 13 U;	188.1	6.7
41	MOISY	7 R; 0 I; 7 U;	203.2	-4.8
42	MONTLUCON	3 R; 0 I; 9 U;	180	4.3
43	MONTROND	3 R; 0 I; 5 U;	117.6	-0.6
44	ORGERES	1 R; 0 I; 4 U;	71.2	0.4
45	RIORGES	0 R; 0 I; 1 U;	24.9	45.7
46	RUBLOTS (LES)	6 R; 0 I; 4 U;	155.5	0
47	SUPER-BESSE	4 R; 0 I; 1 U;	76.8	-5.7
48	SARDON	2 R; 0 I; 8 U;	140	-1.3
49	SAINT-AMAND-MONTRON	4 R; 0 I; 3 U;	118.9	9
50	ST-CALAIS	2 R; 0 I; 3 U;	79.8	6.8

N	Name	N. feeders	Estimated demand [GWh/year]	Error [%]
51	ST-PIERRE-ROCHE	5 R; 0 I; 1 U;	100.7	2.6
52	VAILLY	2 R; 0 I; 0 U;	43.8	22.7
53	VENESMES	8 R; 0 I; 3 U;	175.8	0
54	ARNAGE	4 R; 0 I; 9 U;	190.4	0.6
55	AUVILLIERS	2 R; 0 I; 7 U;	128.8	0.3
56	AYDES (LES)	1 R; 1 I; 12 U;	189.3	-5.9
57	BONNEVAL	1 R; 0 I; 8 U;	125.4	0.4
58	BUSSIERES	3 R; 0 I; 2 U;	71.1	-9.3
59	CHAMP-DU-GEAI	8 R; 1 I; 22 U;	450.4	-0.8
60	CHATEAU-DU-LOIR	2 R; 0 I; 3 U;	80	7.1
61	CELLES	4 R; 0 I; 3 U;	96.3	-12.3
62	CONTRES	6 R; 0 I; 3 U;	152.5	6.9
63	COULLONS	2 R; 0 I; 4 U;	90.6	3.1
64	DEOLS	1 R; 1 I; 0 U;	35.9	-7
65	ECOMMOY	5 R; 0 I; 5 U;	145.2	-4.8
66	ENVAL	14 R; 0 I; 10 U;	372.9	0.3
67	FORTAIE (LA)	2 R; 0 I; 3 U;	71.9	-3.4
68	GRIGNY	1 R; 1 I; 60 U;	860.1	1.4
69	JUINE	2 R; 0 I; 9 U;	156.6	0.8
70	LIERS	0 R; 2 I; 22 U;	346.7	1.9
71	LIEVE	1 R; 0 I; 23 U;	330.3	0.9
72	LUISANT	0 R; 0 I; 5 U;	70.3	4
73	MARTRES DE VEYRE	2 R; 0 I; 12 U;	192.2	-1.9
74	MEZEL	3 R; 0 I; 12 U;	222.3	4.3
75	MONDOUBLEAU	4 R; 0 I; 3 U;	102.2	-5.9
76	NEVERS	3 R; 0 I; 4 U;	117.5	10.8
77	OLLIERGUES	4 R; 0 I; 1 U;	74.9	-8.3
78	PAYOLLES (LES)	4 R; 0 I; 4 U;	117.2	-3.8
79	PERROY	3 R; 0 I; 1 U;	66.9	4
80	PHELIBON	2 R; 0 I; 1 U;	59.1	19.9
81	POISSY	5 R; 1 I; 34 U;	568.4	0.6
82	POLE 45	1 R; 1 I; 9 U;	136.1	-17.5
83	POURPRISES(LES)	0 R; 0 I; 6 U;	83.2	2.7
84	ROUSSON	0 R; 1 I; 16 U;	234.2	-1.4
85	SABLE	7 R; 0 I; 10 U;	257.6	1.6
86	SEIGY	3 R; 0 I; 2 U;	71.7	-8.4
87	ST-DOULCHARD	0 R; 0 I; 6 U;	83.8	3.3
88	ST-PIERRE-LE-MOUTIER	2 R; 0 I; 0 U;	35.3	4.3
89	ST-SAUVES	2 R; 0 I; 1 U;	40.3	-17.4
90	TERTRE	2 R; 0 I; 3 U;	76.2	2.4
91	THIERS	3 R; 0 I; 3 U;	83.4	-9.4
92	THIOT	1 R; 0 I; 3 U;	59.9	4.2
93	TOURY	0 R; 0 I; 1 U;	21.8	38
94	VALENCAY	2 R; 0 I; 1 U;	53.7	11.9
95	VALLON	2 R; 0 I; 1 U;	45.9	-3.1
96	VERDIN	0 R; 0 I; 2 U;	34.4	21.5
97	VERNELLE (LA)	4 R; 0 I; 5 U;	136.1	0.7
98	VIMOUTIERS	7 R; 0 I; 2 U;	141.9	-2.5
99	VILLEFRANCHE	3 R; 0 I; 1 U;	58.2	-10.3
100	YZEURE	1 R; 0 I; 7 U;	114.5	2.7

N	Name	N. feeders	Estimated demand [GWh/year]	Error [%]
101	CHARTRES-SUD	1 R; 0 I; 4 U;	68.1	-4.1
102	FOUCAUDIERE (LA)	0 R; 1 I; 9 U;	144.6	1.1
103	AIGURANDE	4 R; 0 I; 2 U;	95.5	0.9
104	ANNAY	0 R; 0 I; 5 U;	75.7	10.8
105	BIRON	4 R; 0 I; 13 U;	249.1	2.4
106	BLOIS-NORD	4 R; 0 I; 11 U;	224.8	3.8
107	BOURG (LE)	6 R; 0 I; 2 U;	132.3	2.8
108	BRIARE	2 R; 0 I; 2 U;	64.6	5.8
109	BUZANCAIS	2 R; 0 I; 2 U;	53.2	-14.3
110	CLAIRE-FONTAINE	1 R; 0 I; 5 U;	89.4	5.6
111	CHAFAUDS	1 R; 0 I; 6 U;	100.7	2.7
112	CHANGY	13 R; 0 I; 6 U;	296.4	-1.5
113	CHECY	6 R; 0 I; 13 U;	282.4	1.9
114	COULEUVRE	5 R; 0 I; 1 U;	106.9	8.3
115	DOMPIERRE	7 R; 0 I; 5 U;	194.9	4.6
116	DOUDOYE	8 R; 0 I; 1 U;	137.4	-8.3
117	ELANCOURT	1 R; 1 I; 18 U;	275.5	-2.1
118	FERRANDE (LA)	5 R; 0 I; 1 U;	93.2	-5.2
119	FOURAUDERIE	2 R; 0 I; 2 U;	63.8	4.6
120	GANNAT	1 R; 0 I; 3 U;	58.1	1.2
121	GERMIGNY	0 R; 0 I; 7 U;	104.2	9.3
122	GRIBOUZY (LES)	3 R; 0 I; 6 U;	133.1	1
123	LAMOTTE-BEUVRON	3 R; 0 I; 2 U;	87.4	11
124	LIMAY	2 R; 1 I; 17 U;	278.4	-2.3
125	MONTAIGUT LE BLANC	8 R; 0 I; 3 U;	174.7	-0.7
126	MADRON (LE)	1 R; 0 I; 6 U;	110.6	11.5
127	MAILLY	1 R; 0 I; 10 U;	151.5	-0.3
128	MALAGUAY	0 R; 0 I; 1 U;	17.2	21.4
129	MARCHAIS	0 R; 0 I; 11 U;	153.6	3.3
130	MATEL	1 R; 0 I; 1 U;	25.3	-20.3
131	MEHUN (-SUR-YEVRE)	6 R; 0 I; 6 U;	181.7	-0.4
132	MOLINONS	0 R; 0 I; 4 U;	62	12.9
133	NOGENT-LE-ROTROU	4 R; 0 I; 5 U;	134.4	-0.6
134	POISARD	0 R; 0 I; 7 U;	95.3	0.8
135	RIVE-DE-GIER	1 R; 0 I; 7 U;	112.4	0.8
136	RAMBOUILLET	4 R; 0 I; 10 U;	199.2	-1.8
137	RIVIERE (LA)	2 R; 0 I; 3 U;	82.6	10
138	SELLES-SUR-CHER	3 R; 0 I; 3 U;	90	-1.4
139	SURY-LE-COMTAL	1 R; 0 I; 3 U;	50.6	-13.5
140	SANCERRE	2 R; 0 I; 2 U;	56.8	-7.1
141	SENONCHES	8 R; 0 I; 10 U;	273.3	1.1
142	SOLEIL (LE)	1 R; 1 I; 9 U;	148.9	-7.4
143	SOURCE	3 R; 1 I; 18 U;	310.5	-1.5
144	ST-JUST (-SUR-LOIRE)	3 R; 0 I; 9 U;	176	2.1
145	ST-GERMAIN-DU-PUY	3 R; 1 I; 5 U;	126.8	-10.2
146	THEIL (LE)	3 R; 0 I; 2 U;	85.1	8.6
147	THIMERT	2 R; 0 I; 6 U;	118.2	2.8
148	THIONVILLE (CLIENT)	2 R; 0 I; 10 U;	161	-4.8
149	TIVERNON	0 R; 0 I; 0 U;	7.1	100
150	VARENNES-SUR-ALLIER	4 R; 0 I; 4 U;	123.2	1.2

N	Name	N. feeders	Estimated demand [GWh/year]	Error [%]
151	VENDOME	3 R; 0 I; 14 U;	245.3	2.3
152	VERINNERIE (LA)	1 R; 0 I; 20 U;	286.4	-0.2
153	VIERZON	1 R; 0 I; 1 U;	33	7.7
154	VOLVIC	2 R; 0 I; 4 U;	87.6	-0.3
155	VOVES	1 R; 0 I; 5 U;	85.7	1.5
156	AMBERT	7 R; 0 I; 2 U;	152.5	4.7
157	AMILLY	2 R; 0 I; 5 U;	114	11.1
158	ARGENTAN	0 R; 0 I; 4 U;	59.2	8.7
159	BELNEUF	2 R; 1 I; 34 U;	494.7	-4
160	BESSEY	4 R; 0 I; 4 U;	126	3.4
161	BOUBLE (LA)	3 R; 0 I; 0 U;	57	11
162	BREAU	0 R; 0 I; 16 U;	226	4.4
163	CHAMBON-FEUGEROLLES	0 R; 0 I; 4 U;	56.3	4.1
164	CEBAZAT	1 R; 1 I; 7 U;	124.4	-6.9
165	CHAINEAU (LA)	2 R; 0 I; 1 U;	37.9	-24.8
166	CHAILLOTS (LES)	0 R; 1 I; 16 U;	232.2	-2.3
167	CHATILLON (-SUR INDRE)	1 R; 0 I; 1 U;	40.5	24.9
168	CORBIGNY	4 R; 0 I; 1 U;	85.2	4.7
169	COURTENAY	2 R; 0 I; 8 U;	141.8	0
170	DONJON (LE)	3 R; 0 I; 0 U;	53.9	5.8
171	DURRE (LA)	2 R; 0 I; 3 U;	71.2	-4.4
172	ESSONNES	0 R; 0 I; 10 U;	135.3	0.2
173	FERTE-BERNARD (LA)	3 R; 0 I; 4 U;	99	-5.8
174	FEURS	3 R; 0 I; 4 U;	116.3	9.9
175	FLERS	7 R; 0 I; 8 U;	221.6	-2.2
176	FONTAINES (LES) (REGIE DE	0 R; 1 I; 0 U;	17.3	-23.9
177	GELLAINVILLE	0 R; 0 I; 2 U;	27.5	2
178	HENRICHEMONT	5 R; 0 I; 1 U;	99.3	1.3
179	HORME (L)	4 R; 1 I; 12 U;	242.1	-3.8
180	LIMOUZAT (LE)	5 R; 0 I; 1 U;	96.6	-1.6
181	LOUPE (LA)	3 R; 0 I; 1 U;	74.3	13.5
182	MAINTENON	1 R; 0 I; 6 U;	96.5	-1.4
183	MAINVILLIERS	0 R; 0 I; 2 U;	31.9	15.3
184	MALESHERBES	1 R; 0 I; 3 U;	49.3	-16.5
185	MASSY	1 R; 2 I; 54 U;	793	0.5
186	MERANTAIS	3 R; 0 I; 13 U;	217	-4.3
187	MORVENT	6 R; 0 I; 28 U;	491.6	2.5
188	MOUSSEAUX	0 R; 0 I; 3 U;	47.7	15.1
189	MONTFORT (-L AMAURY)	5 R; 0 I; 22 U;	388.1	1.7
190	MONTJAY	3 R; 1 I; 29 U;	463.9	0
191	MONTRICHARD	2 R; 0 I; 4 U;	91.3	3.8
192	NERONDES	5 R; 0 I; 1 U;	108.4	9.5
193	NOUROTTES	3 R; 2 I; 53 U;	799.1	-1.3
194	ORCHIDEES (LES)	2 R; 1 I; 7 U;	151.5	1.1
195	POIRIER	1 R; 0 I; 8 U;	127.4	1.9
196	SARRE	1 R; 4 I; 15 U;	309.6	1.4
197	SAUILLY	0 R; 0 I; 12 U;	160.6	-0.9
198	SAULES	1 R; 1 I; 34 U;	503.2	1.1
199	SEMINAIRE	4 R; 1 I; 2 U;	113.5	-2.3
200	ST-BONNET (-LE-CHATEAU)	11 R; 0 I; 3 U;	233.3	2.9

N	Name	N. feeders	Estimated demand [GWh/year]	Error [%]
201	STE-JAMME (-SUR-SARTHE)	5 R; 0 I; 12 U;	254.4	3.1
202	ST-PRIX	3 R; 0 I; 1 U;	67.1	4.2
203	ST-YORRE	4 R; 0 I; 3 U;	115.2	6.1
204	TONNERRE	0 R; 0 I; 10 U;	146.4	7.8
205	VEAUCHE	5 R; 0 I; 10 U;	220.9	0.6
206	VERSAILLES	3 R; 2 I; 88 U;	1282	0
207	VIBRAYE	5 R; 0 I; 1 U;	97.6	-0.5
208	VICHY	1 R; 0 I; 5 U;	88.4	4.5
209	VILLEMANDEUR	1 R; 0 I; 12 U;	180.9	1.1
210	VILLEMENT	2 R; 0 I; 10 U;	172.1	1.9
211	AIGUEPERSE	1 R; 0 I; 6 U;	93	-5.3
212	ANGELIQUE	3 R; 0 I; 4 U;	96.9	-8.1
213	ARPENTS (LES)	1 R; 0 I; 7 U;	113.3	1.6
214	AUBIGNY	2 R; 0 I; 2 U;	51	-19.3
215	AUNEAU	1 R; 0 I; 13 U;	202.3	4.9
216	AVALLON	0 R; 0 I; 6 U;	89.5	9.4
217	BROU	2 R; 0 I; 4 U;	88	0.2
218	BEAUNE-	2 R; 0 I; 3 U;	78.2	5
219	CHATEAU-CHINON	2 R; 0 I; 0 U;	44.4	23.8
220	CHARITE-SUR-LOIRE (LA)	4 R; 0 I; 2 U;	86.9	-8.9
221	CHARNY	0 R; 0 I; 5 U;	64	-5.5
222	CHAZELLES	3 R; 0 I; 5 U;	120.2	1.6
223	CHEVAIN	2 R; 0 I; 7 U;	135.6	5.4
224	COLUMEAUX (LES)	3 R; 0 I; 9 U;	166.2	-3.7
225	COQUIBUS	0 R; 1 I; 9 U;	142.4	-0.4
226	COURS	3 R; 0 I; 2 U;	80.7	3.6
227	CHAMPVERT	5 R; 0 I; 3 U;	129.1	3.1
228	CRESSANGES	3 R; 0 I; 1 U;	66	2.6
229	DOMFRONT	7 R; 0 I; 3 U;	157.6	-0.9
230	EGUZON	3 R; 0 I; 1 U;	58.2	-10.4
231	FIRMINY-VERT	0 R; 0 I; 3 U;	44	8
232	FERRIERE	7 R; 0 I; 4 U;	180.8	4.6
233	GRAND LUCE	7 R; 0 I; 4 U;	160.3	-7.6
234	GARCHIZY	5 R; 0 I; 8 U;	197.8	2.6
235	ISSOIRE	4 R; 0 I; 5 U;	146.1	7.5
236	LOGES (LES)	0 R; 1 I; 6 U;	105.6	3
237	LOISIVIERE	10 R; 0 I; 4 U;	227.1	1.7
238	MOINGT	2 R; 0 I; 2 U;	60.4	-0.8
239	MORIGNY	1 R; 0 I; 5 U;	86	1.9
240	MONTVERDUN	5 R; 0 I; 4 U;	143.8	3.6
241	MUREAUX (LES)	4 R; 2 I; 59 U;	902.2	-0.6
242	NEULISE	3 R; 0 I; 1 U;	62.7	-2.5
243	ONZAIN	8 R; 0 I; 9 U;	256.3	-0.2
244	PONT-DE-MENAT	3 R; 0 I; 0 U;	56.3	9.8
245	PARIZE	3 R; 0 I; 2 U;	87.4	11
246	PAROY	0 R; 0 I; 7 U;	91.8	-2.9
247	PITHIVIERS	0 R; 0 I; 2 U;	33	18.2
248	PLUMASSERIE (LA)	0 R; 0 I; 9 U;	124.9	2.7
249	PRAULIAT	2 R; 0 I; 18 U;	278.9	0.7
250	REBOURSIN	3 R; 0 I; 3 U;	94.2	3.1

N	Name	N. feeders	Estimated demand [GWh/year]	Error [%]
251	REINIERE	9 R; 0 I; 4 U;	194.1	-6.3
252	RICHEBOURG	1 R; 0 I; 7 U;	115.2	3.3
253	ROANNE	0 R; 0 I; 1 U;	27	50
254	ROMORANTIN	2 R; 0 I; 3 U;	80.4	7.5
255	ROUSSINES	2 R; 0 I; 0 U;	31.3	-8.2
256	SILLE-LE-GUILLAUME	4 R; 0 I; 4 U;	114.9	-5.9
257	SULLY-SUR-LOIRE	3 R; 0 I; 3 U;	86.2	-5.8
258	ST-AUBIN	3 R; 2 I; 70 U;	1046.1	0.7
259	ST-HONORE	2 R; 0 I; 0 U;	40.5	16.4
260	ST-MARCEL	3 R; 0 I; 2 U;	77.1	-0.8
261	TOURNOISIS	2 R; 1 I; 8 U;	158.9	-2.8
262	VINEUIL	1 R; 0 I; 4 U;	75.1	5.6
263	VOINGT	3 R; 0 I; 0 U;	52.3	2.9

4.1.2 Assessing the market potential

Many different flexibility products can be offered by DERs, both global (e.g. balancing, frequency control, voltage control, demand response, black-start capability, etc.) and local applications (voltage control, congestion management, demand response, islanding...). In the work presented here, these products are not simulated per se. Instead, the procedure described in Figure 50 checks whether changes in distributed active and reactive power are technically feasible.

In the studies described in this report, it is assumed that the new market players behave rationally in the market and that services proposed to the DSO and TSO are proposed at the same price. These offers are subdivided into upward and downward (i.e., upward - UP means that local production increases and demand decreases; downward - DW means the opposite: production decreases and demand increases).

The methodology is described in the deliverable D2.3 and summarized in the flow chart of Figure 50. The methodology starts by evaluating the *theoretical market potential*, i.e., the volume of DER bids that can be offered in either direction, UP or DW. The final goal is to estimate the *feasible market potential* of a given DN, i.e., the share of the *theoretical market potential* that can be offered to the TSO in the ancillary service market (no other markets were considered) without any harmful impact on distribution network operation. It is obtained by performing OPF calculations, subject to technical constraints on voltages and currents, for each considered hourly time interval (i.e., from t=t_0 to t=T, with t_0=0 and T=23 for each of the twelve typical days in the year, so the total number of simulated intervals is 288).

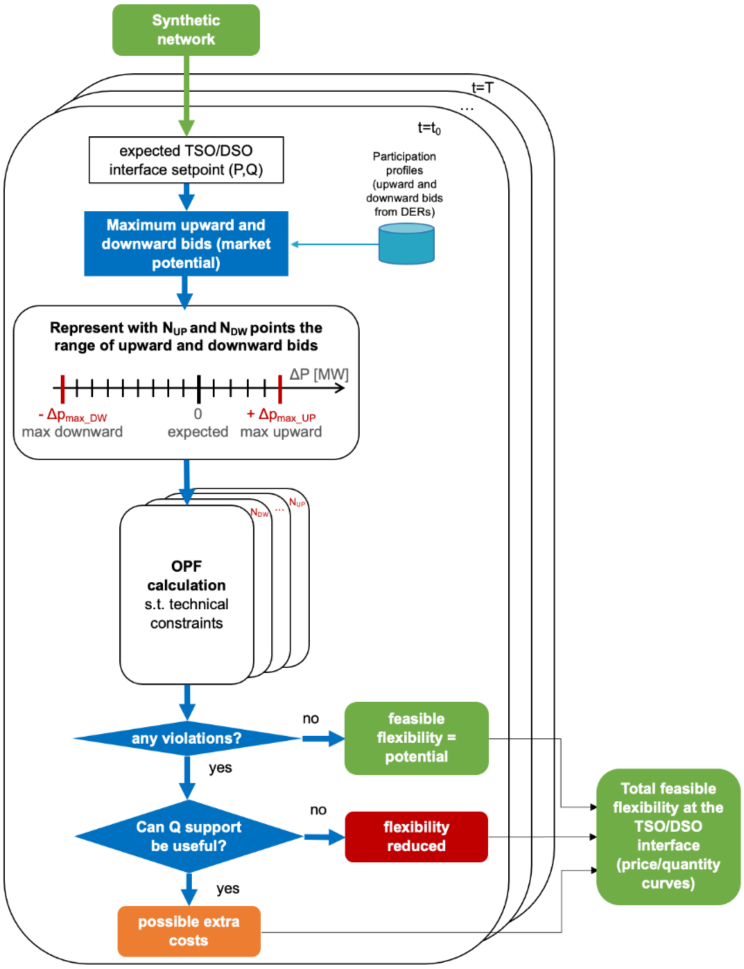

Figure 50: Flow chart of the procedure of quantitative assessment of market potential

Since the discretization impacts the accuracy of the results, but at the same time influences the computational time, in these studies, the maximum number of subdivisions (i.e., N_{UP} in upward and N_{DW} in downward) of the range of the potential flexibility, between $-\Delta p_{max\_DW}$ and Δp_{max_UP}, is set to 20. The maximum power variations at the TSO/DSO interface are calculated according to the participation profiles of the involved DERs. In particular, it is supposed that the DG owners offer the full capacity in DW (i.e., they offer to switch off their plants). Furthermore, since only RES-based DG is considered, it is supposed that the DG owners may offer in UP only a small volume because this implies derating their production. The active customers may bid both in DW by increasing their demand and in UP by reducing it. Generally, the offers of the active demand (AD) are not complete in both directions, and the maximum bids in UP and DW depend on the customer sector that participates in the AS market. Table 6 summarizes, in terms of quantity and price pairs, the participation level of the DERs that can be selected in the studies (in the table, CP is the day ahead energy market Clearing Price). In the proposed studies that produced the following results, it is supposed that only DG may offer both in UP (full capacity) and in DW (only 10% of their effective production). Regarding both RES owners and AD customers, their bidding strategy is profitable only if the ancillary service market participation allows a revenue increase with respect to the day-ahead energy market participation. This means that the final bid prices of the RES owners, expressed in €/MWh, have been assumed greater than the energy clearing price for upward reserve and at maximum zero for downward reserve. At the same time, the upward/downward economic offers of the AD customers must take into account the energy management system utilization to anticipate or postpone shiftable loads (i.e., the final bids should be higher than the market energy price for the upward bids and lower for downward bids). However, in the studies reported in this report, the prices are used only by way of comparison, and the absolute values are negligible for the discussed results.

Table 6: DER participation level

DER Participation	Downward reserve		Upward reserve	
	quantity [%]	*price [€/MWh]*	*quantity [%]*	*price [€/MWh]*
RES	even full capacity i.e., -100%	≤ 0	small i.e., +10%	> CP e.g., 2○ CP
AD customers (EVs included)	small/limited/full i.e., +5%, +20%, +100%	< CP e.g. 0.9○CP	small/limited/full i.e., -5%, -20%, -100%	> CP e.g. 1.1○CP

The OPF calculations are performed by using each point considered in the range of the potential flexibility of the given synthetic network, checking compliance with technical constraints. If no violations are found, the feasible flexibility is the same as the potential (green light); otherwise, two conditions may arise if violations of the technical constraints occur. Suppose the violation can be solved by resorting to reactive power support. In that case, an extra cost of flexibility can be added to the bids (orange light). In certain cases, if the violation cannot be solved with reactive power, the feasible flexibility region is reduced compared to the potential (red light). For example, Figure 51 shows the flexibility profile during one typical day of three DNs in the *critical scenario*. Figure 52 shows the same flexibility profile aggregated for the entire region. It is worth noticing that the spatial downscaling reveals local criticalities.

Table 7 reports the results of the entire region. In the *critical scenario*, the reduction of the theoretical market potential is, as expected, more significant than in the *fit and forget* scenario. This result demonstrates that the grid limitations of the distribution networks cannot be disregarded, and tools able to estimate the impact of the provision of some flexibility products from DERs, if awarded in the day ahead AS market sessions, may be very useful for avoiding extra costs.

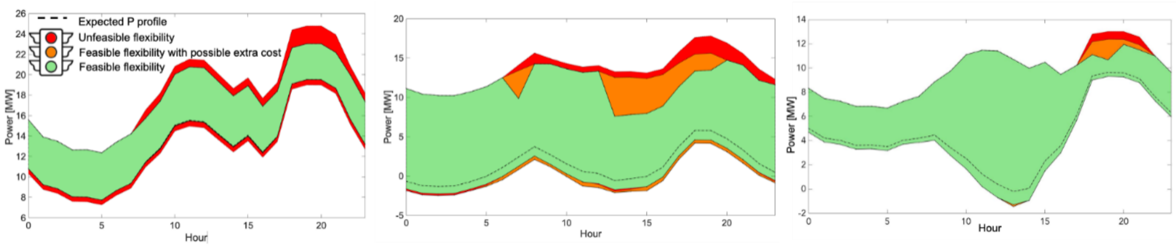

Figure 51: Flexibility profiles of three selected DNs (winter working day)

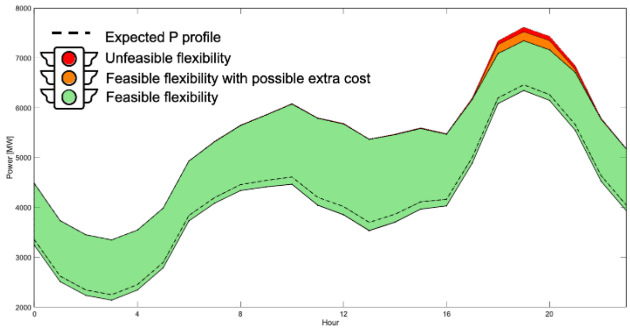

Figure 52: Flexibility profiles of the entire studied region (winter working day) in the critical scenario

Table 7: Results of the entire region

	UPWARD bids	DOWNWARD bids
Theoretical market potential [GWh/year]	1229.448	12294.482
Reduction in the F&F scenario (Feasible market potential) [%]	-1.43%	-0.91%
Reduction in the critical scenario (Feasible market potential) [%]	-14.6%	-10.8%

4.1.3 Integration of the studies

To integrate the studies described above and the nodal study performed by RTE, it was first necessary to match the two study scopes. In particular, within the area modelled as in the previous paragraphs, 34 substations of the HHV transmission grid of central France studied by RTE were identified. These substations have voltage levels equal to 225 kV or 400 kV and are shown in Figure 53. For each HHV substation, using the bids to the day-ahead energy market forecasted by the nodal studies described in 2.2.2 of this deliverable, the annual energy delivered to and produced by the networks behind these nodes and relevant demand and production profiles were estimated (Table 8).

Since the goal of the ENSIEL studies was to model the TSO/DSO interface and the DNs downstream of this interface (voltage level up to 20 kV), the first challenge was to associate DNs with the selected HHV substations. Since the transmission grid is meshed, such an association is not straightforward. The assumption made, according to RTE, was to match each HHV node to the electrically closest DNs. By doing so, 19 HHV were identified, supplying 112 DNs.

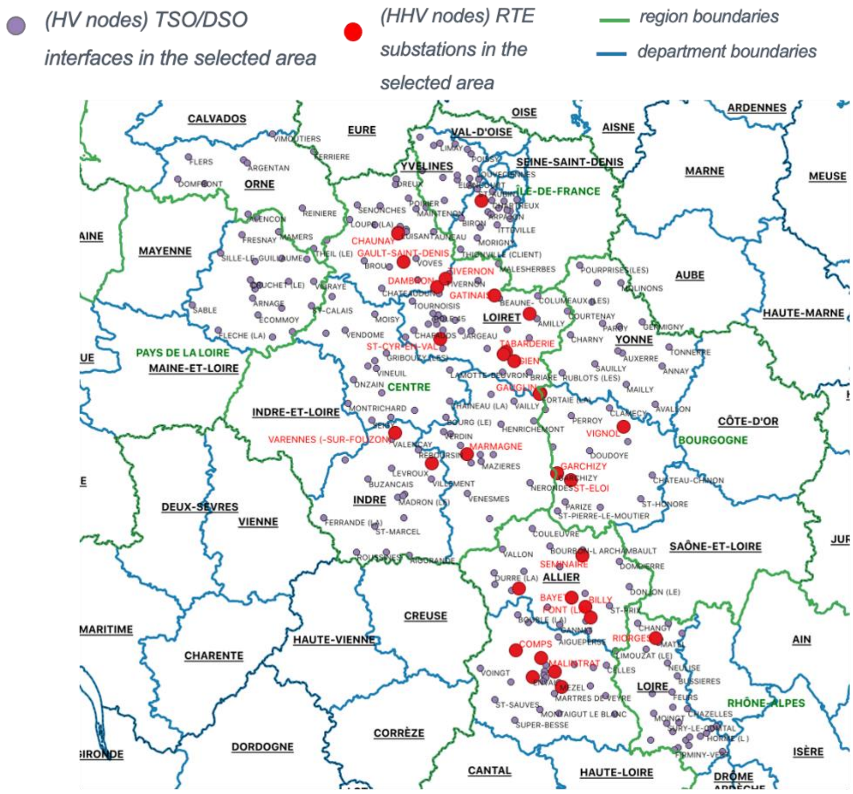

Figure 53: HHV nodes in the selected area

Table 8: Estimated annual energy of the selected HHV nodes

HHV node	*Estimated annual Energy [GWh/y]*
BAYETP6	827.149
CXNAYP6	1793.610
DAMBRP6	713.812
ENVALP6	938.289
FONT_P6	425.952
GARCHP6	595.814
GATI5P7	508.301
GAUGLP7	687.634
GIEN_P6	1186.645
LIGNAP6	538.966
MARMAP7	2268.482
MTVICP6	442.571
RIORGP6	105.363
SEMINP6	609.486
SSELOP6	878.852
VARE5P6	1386.419
VLEMAP6	992.874
VNOL_P6	310.340
VOLVIP6	442.408

Once the association was made, the HHV node estimated energies were downscaled among the MV DNs, by using the annual energy estimations of the DNs, resulting from the ENSIEL study (previous paragraphs), and calculating the share between the group of the DNs as a percentage of the total sum of the energies of the DNs associated to the same HHV node. For instance, Table 9 reports the results of such sharing for the HHV node BAYET P6.

Table 9: Downscaling of annual energies (from HHV node to the associated DNs)

HHV node	*Associated DN*	*Code*	*Share of the total HHV node energy*	*Reshared Energy [GWh/y]*
BAYET P6	BAYET	BAYETP3	12%	101.22
	BELLENAVES	BELL4P3	11%	87.42
	DOMPIERRE	DOMPIP3	29%	240.03
	GANNAT	GANNAP3	8%	66.36
	VARENNES-SUR-ALLIER	V.ALLP3	9%	71.53
	DONJON (LE)	DONJOP3	18%	151.69
	VICHY	VICHYP3	13%	108.90
		Total	**100%**	**827.14**

Then, one goal was to evaluate whether the buy- and sell-orders made to the DA and ID markets in RTE's nodal market study impact the distribution network operation modelled by ENSIEL. This goal is achieved by running hourly power flow (PF) calculations and by checking the technical constraints on voltages and currents of the synthetic distribution networks.

The flexibility provided by DERs to the TSO is assessed for all the hours without distribution bottlenecks. In contrast, the services that the DSO should use to solve bottlenecks in voltage regulation and power flow are evaluated in the other hours. Possibly, the residual DER flexibility for the TSO is also calculated. The quantitative assessment of market potential is assessed according to the procedure depicted in Figure 50. The simulated scenarios of the DG location are the same as the ones above described (*fit & forget* and *critical*). In these studies, the DG owners of PV and wind power plants and EVs participate in the AS market, the former by reducing generation output, the latter by reducing demand. Figure 54 shows the residual flexibility profiles of the aggregated DNs associated with the BAYET P6 HHV node, resulting from the simulation of the F&F scenario in an autumn working day of 2035. The dashed line is the expected power profile at the TSO/DSO interface. In green, the feasible flexibility that can be offered to the TSO without any harmful impact on the distribution system operation (i.e., in light green the downward feasible bids, in deep green the upward feasible bids), and in red the unfeasible quantity due to bottlenecks in distribution networks. On this day, no local services are needed because no violations of technical constraints occur.

Figure 54: BAYET P6: residual flexibility profiles (F&F scenario, 2035 autumn working day)

Another example is reported in the following figures Figure 53 - Figure 55. Figure 53 shows the expected profiles at the TSO/DSO interface of the aggregated DNs associated with the DAMBR P6 HHV node in the simulated day (i.e., 2035 autumn working day). For this group of DNs, the estimated expected annual demand is about 714 GWh/y (Table 8), and the installed power is about 151 MW of PV and 567 MW of wind. The expected production of such a high generation exceeds 30% of the demand, and 86 MW of PV and 449 of WIND are installed in dedicated feeders; the remaining part is installed along the networks. The production often exceeds the demand, and reverse flows to the transmission network regularly happen. The F&F case, in which the DG plants are spread along the network lines, causes only slight violations of the technical constraints. In the critical scenario however, severe overvoltage conditions may occur. In both cases, the DSO purchases local services by exploiting the flexibility offered by DERs for solving the network operation issues, and the expected profile at the TSO/DSO interface is slightly modified in the F&F scenario, more significantly in the critical one, due to the needed generation curtailment (i.e., 0.25 % of flexibility reduction is expected in the F&F and -5.51 % in the critical scenario, Figure 53).

Figure 54 and Figure 55, like Figure 52, show the residual flexibility profiles of the aggregated DNs in the F&F and in the critical scenario, respectively. It is evident that in the critical scenario, the upward flexibility volumes that the DSO may block are greater than the F&F scenario. This is due to the position of the DG that negatively impacts network operation. The final flexibility reductions in the proposed day are reported in Table 10, where the percentages include the volumes exploited by the DSO for solving network operation issues.

Table 10: Results of the DNs associated with the DAMBRP6 HHV node (2035 autumn working day)

	UPWARD bids	DOWNWARD bids
Theoretical market potential [GWh/year]	1031.84	1507.475
Reduction in the F&F scenario (Feasible market potential) [%]	-17.2%	-3.3%
Reduction in the critical scenario (Feasible market potential) [%]	-21.5%	-18.4%

Figure 53: DAMBR P6: expected power profiles at the TSO/DSO interface (estimated, F&F and critical scenarios)

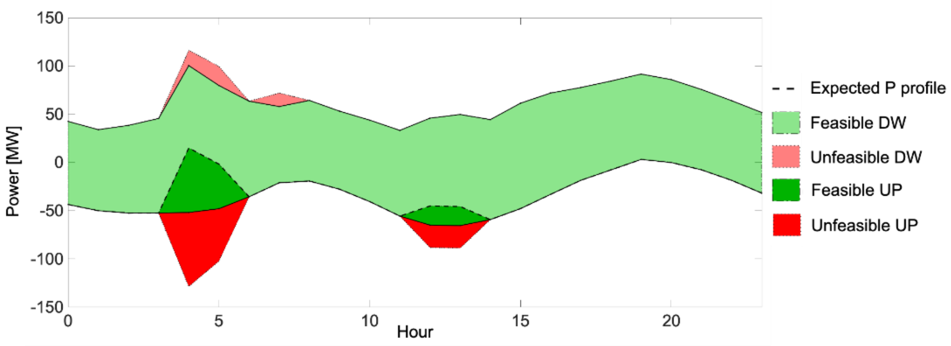

Figure 54: DAMBR P6: residual flexibility profiles (F&F scenario, 2035 autumn working day)

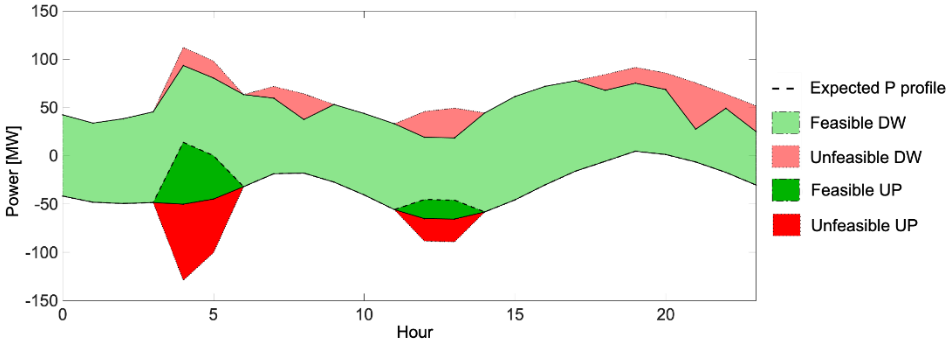

Figure 55: DAMBR P6: residual flexibility profiles (critical scenario, 2035 autumn working day)

5 Impact of topological actions

There is growing value in the optimization of the transmission grid when the share of variable RES increases. This is shown by (Little et al. 2021) for an academic dataset: RTS-96 network, with California-like wind and solar conditions. Figure 55 compares the total cost in three different situations: copper plate (as a baseline situation overlooking grid congestions), base network with congestion management limited to redispatch (No OTC), and base network with optimal topology control (OTC) integrated into congestion management practice. Production cost decreases as the amount of renewables increases. However, the plot shows the benefit of using grid flexibility (in blue) over alleviating congestions by only changing the generation pattern (in red). The difference in annual production cost between these two variations moves from \$40 thousand to \$66 million, over 18%, as more lower-cost energy sources are included in the system.

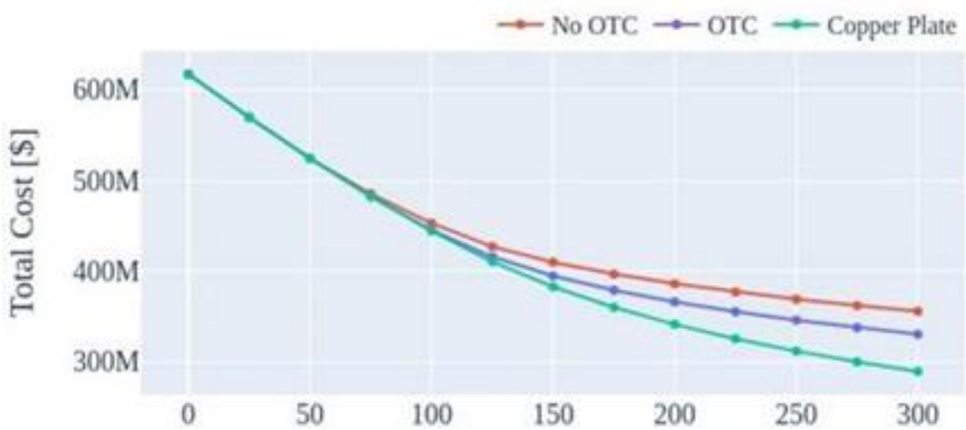

Figure 55: Total Cost Gained due to topological control actions – OTC = Optimal Topology Control (Source: Little et al. 2021)

Figure 56 focusses on hours where thermal generation is compulsory to supply the demand without optimal topology control (OTC), either due to insufficient total RES generation or insufficient grid capacity to transmit it to the consumers, and shows the wind curtailment reduction of OTC. Under these circumstances, the copper plate case is shown to have zero wind curtailment for all scenarios (as the optimal solution is to use all RES generation available), while any curbing of wind generation in the other two cases is due solely to network constraints. The grid flexibility actions allow for a reduction in curtailment of up to 20%. The difference in the curves continues to increase as more wind is introduced into the system.

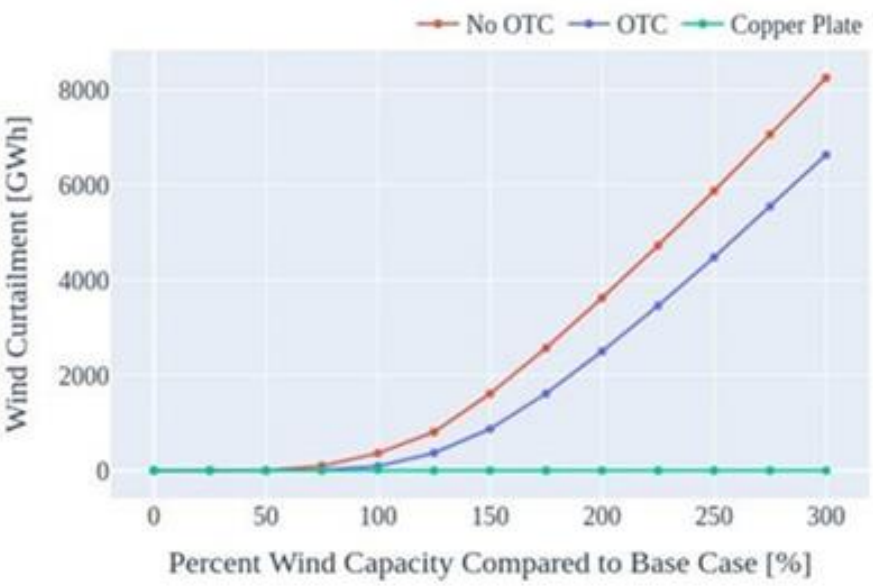

Figure 56: Sum of wind curtailment across all hours with thermal generation (Source: Little et al. 2021)

6 Conclusion

This document presented the results of the different simulations performed in work package 2. These results are compared and discussed in more detail in deliverable 2.5, which also makes various contributions regarding modelling good practice, issues requiring further work and regulatory recommendations.

7 Appendix

7.1 Detailed RTE nodal market simulation results

7.1.1.1 Comparison of DA and ID market dispatch and flexibility activation

Due to the evolution of net load forecasts (both forecasts on the consumption and renewable generation), generation dispatch varies between market horizons. The purpose of this section is to analyse the different evolutions of market dispatches between market horizons.

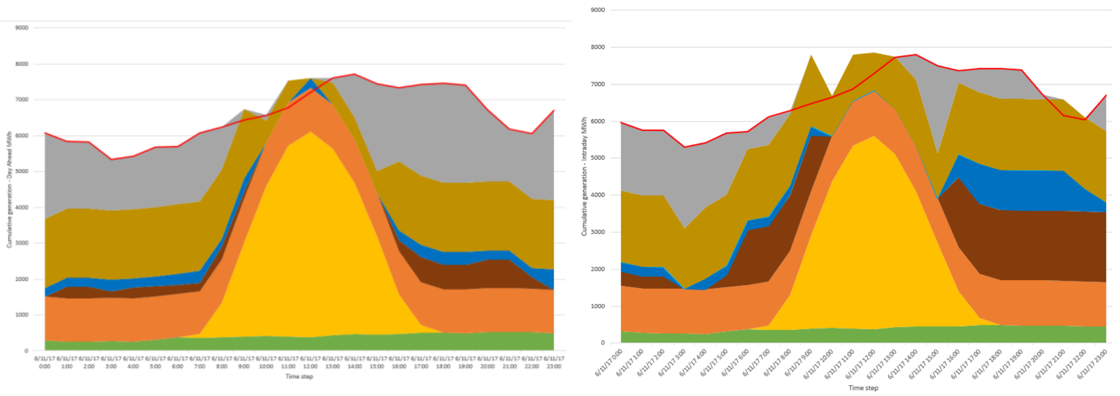

Figure 57: Generation stacks for the day-ahead (left) and intraday (right) markets – Focus on 02_fr – Day 1[12]

Figure 57 compares the generation dispatch of the day-ahead and intraday markets for a single French node on the first day (where electricity supply is piled up for each hour of the day and the load is represented in the red line. Generation above the red line is either exported or pumped in hydro pumped storage facilities). The differences between day ahead and intraday is due to a slightly lower solar PV generation in intraday, which forces flexibility solutions to be activated to compensate: thermal power plants, P2G and hydro.

[12] For colour coding, see Figure 75.

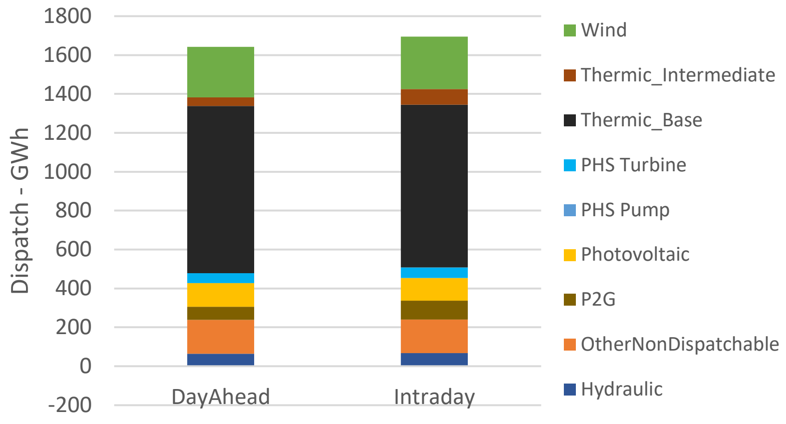

Figure 58: Dispatch evolution between market horizons – France – Day 1

The comparison of Figure 59 and Figure 60 shows the difference between Monday and Friday for six zones in France. It is interesting to note that most of the difference is due to changes in imports. Increased wind generation could explain why imports are favoured compared to thermal generation or hydro power which are more expensive. Looking more specifically at 02_fr, the average use rate of the interconnection with 01_fr which has a high potential for wind power, is increased from 4% to 14% in day ahead market and 10% to 18% in intraday between Monday and Friday, therefore supporting our observation. In the same way, there is an increased use of the interconnection between 04_fr and 07_fr.

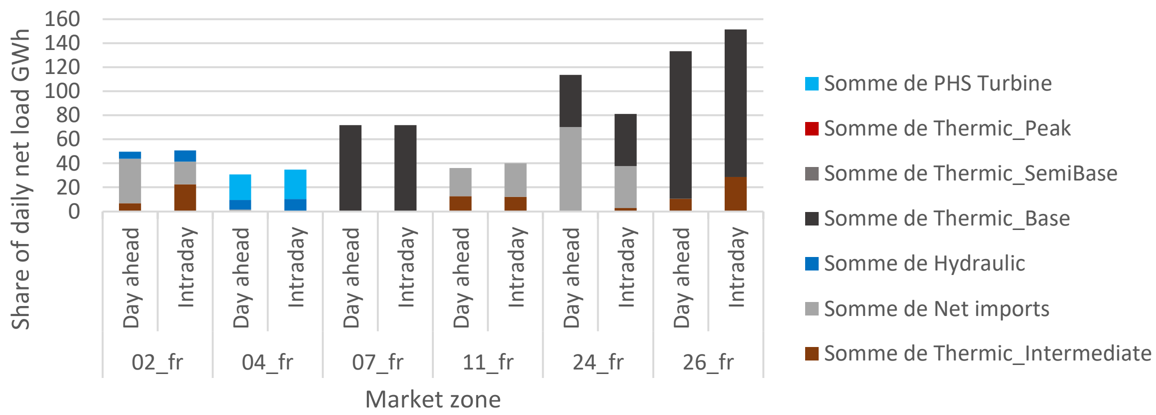

Figure 59: Daily contribution to net load for a few example nodes – Day 1

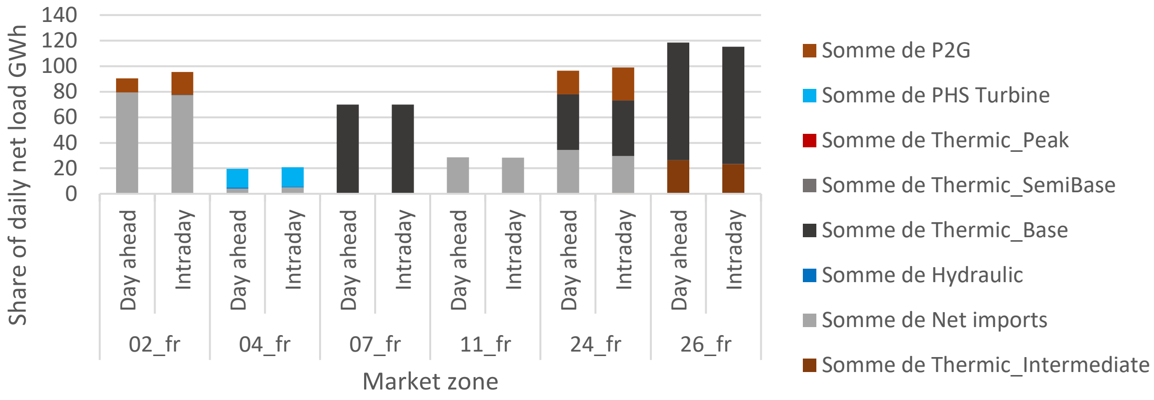

Figure 60: Daily contribution to net load for a few example nodes – Day 5

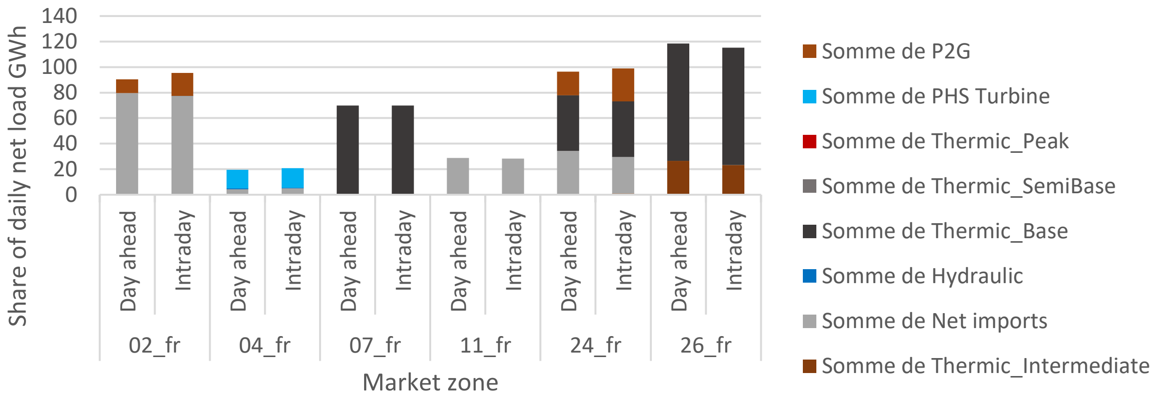

Figure 61 - Contribution to net load over the day for example nodes – Day 5

Dispatch costs are higher in the intraday market, due to the adjustments made after the day ahead with better forecasts. When flexibility (either for load balancing or congestion management) is not supplied by imports or hydro power but by thermal units, dispatch costs increase. The adjustments using thermal power plants can be made either to adapt to the updated net load forecast (example 26_Figure 61 - Contribution to net load over the day for example nodes – Day 5), or to reduce imports (02_fr). Net imports play an important role as for most nodes with no flexibility (either no dispatchable generation, or no generation at all), which is typically the case for many nodes of the "FR nodal" group, they are the only possible adjustment.

The dispatch of 29_es is one of those that has varied the most between the two market horizons for Friday. Figure 62 shows a clear evolution for pump storage and thermal units that has a direct impact on dispatch cost as shown in Figure 63. Using thermal units proves to be more expensive, inducing a higher dispatch cost in the day-ahead market. Another input of this last figure is the comparison with the price given by ANTARES simulations, which has the same scope but is based on perfect foresight and benevolent monopoly assumptions.

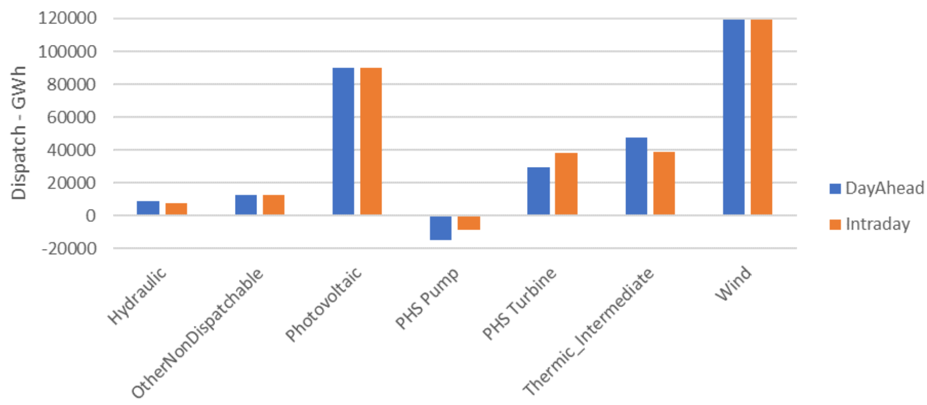

Figure 62: Evolution of dispatch between day-ahead and intraday market for 29_es – Day 5

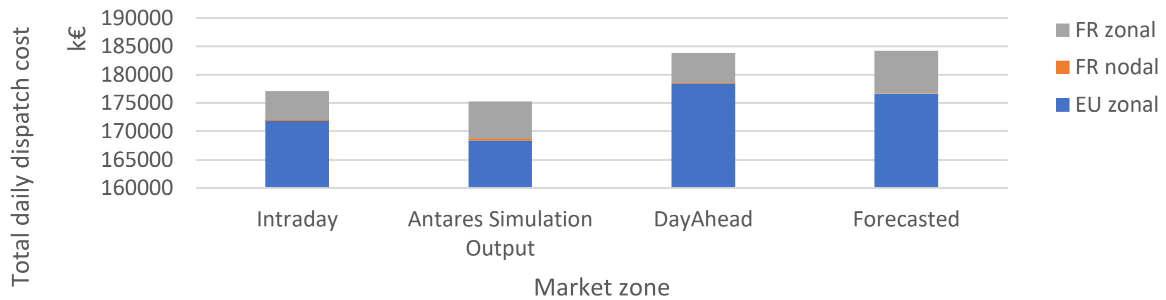

Figure 63: Dispatch cost variations between market horizons and modelling – Day 5

7.1.1.2 Comparison of power flows over the market sequence

Unless specified otherwise, the results shown for the intraday market corresponds to the first (so-called) intraday session, run at 7pm in D-1.

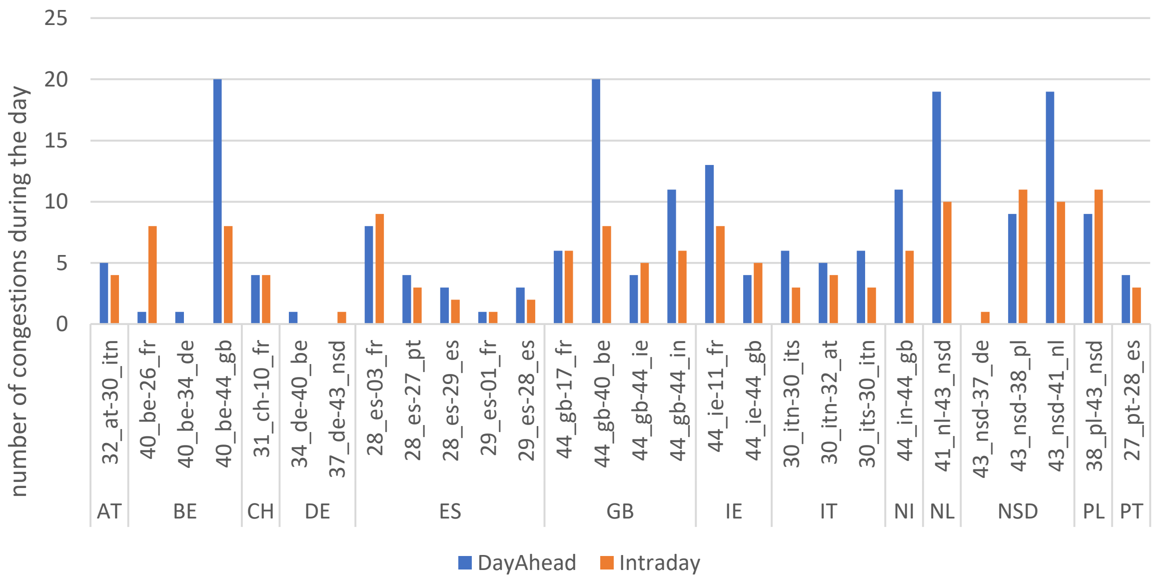

Figure 64: Congestion on European critical branches – Day 1

Congestions are detected on the network when the absolute use rate of a critical branch is higher than 99.9%. Absolute use rate is computed as the total flow in absolute value over the capacity in MW of the line (which can depend on the direction of the flow at the given timestep). Congestions are noticeable in the market prices values with higher marginal costs. On the first day of simulation (Monday), the total number of congestions is lower in intraday rather than day ahead market, as shown in Figure 66.

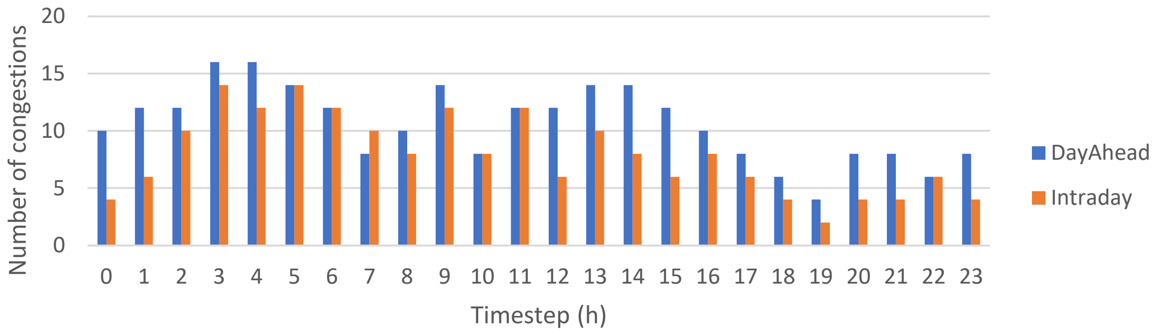

Figure 65: Number of congestions per hour over the entire perimeter – Day 1

The most congested period occurs between 3am and 4am for both market horizons. On closer inspection (see Figure 66), we can see that the lines on which congestions occur are very similar in the DA and ID market. At 3am, we can note that the congestion on line 44_ie – 11_fr which is solved by the intraday market, while a few new congestions appear.

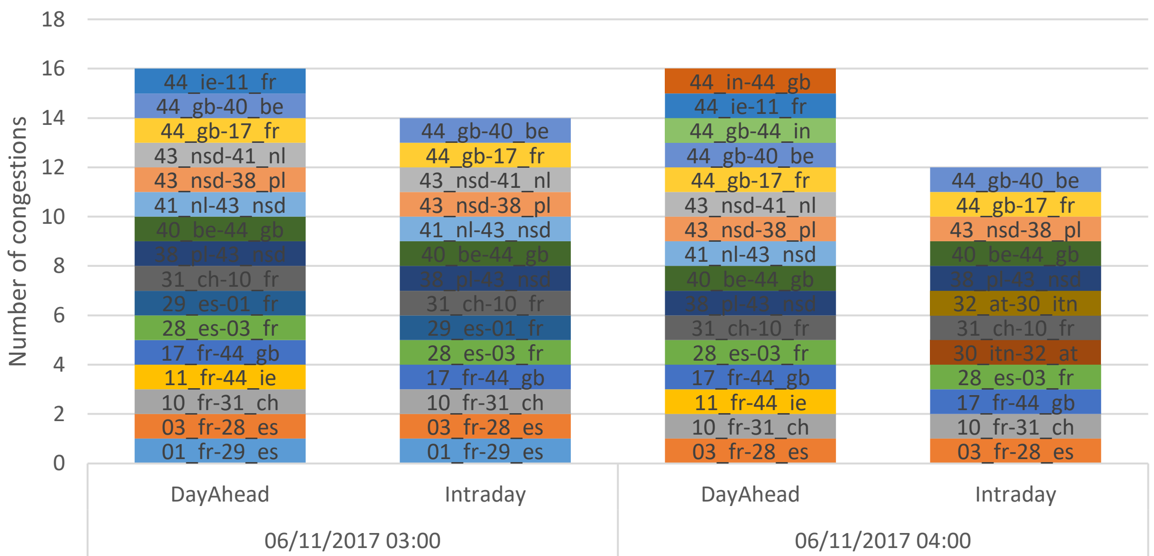

Figure 66: Evolution of congestion between two timesteps – Day 1

Price signals in nodal market model indicate the location of congestions: prices on both sides will diverge and can reach important values depending on the severity of the congestion.

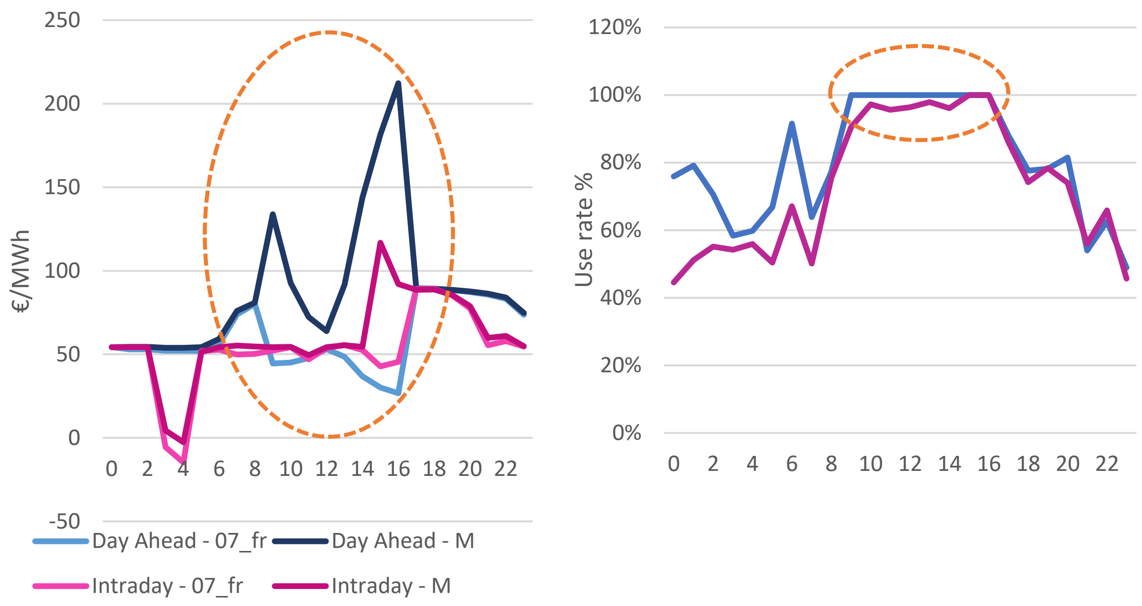

Figure 67: Marginal price evolution between market horizon (left) and evolution of the utilisation rate in % of the critical branch M - 07_fr (right) – Day 1

Figure 68 is a good example of prices divergence when a congestion occurs: in the day ahead market, the congestion lasts between 8am and 4pm, and in the intraday horizon the congestion only lasts for 2 hours between 2pm and 4pm. This example shows that congestions that exist in the day ahead can be solved in the intraday market: peak prices in the day ahead market are not as important on this example.

7.1.1.3 Comparison of market prices and asset revenues

Comparison with historical spot prices in France

Since the modelled scenario is based on historical weather conditions and similar load patterns (which are rescaled to match the projected 2035 demand volume), we can compare historical day ahead prices with simulated nodal prices on the day that was used for the nodal market simulation.

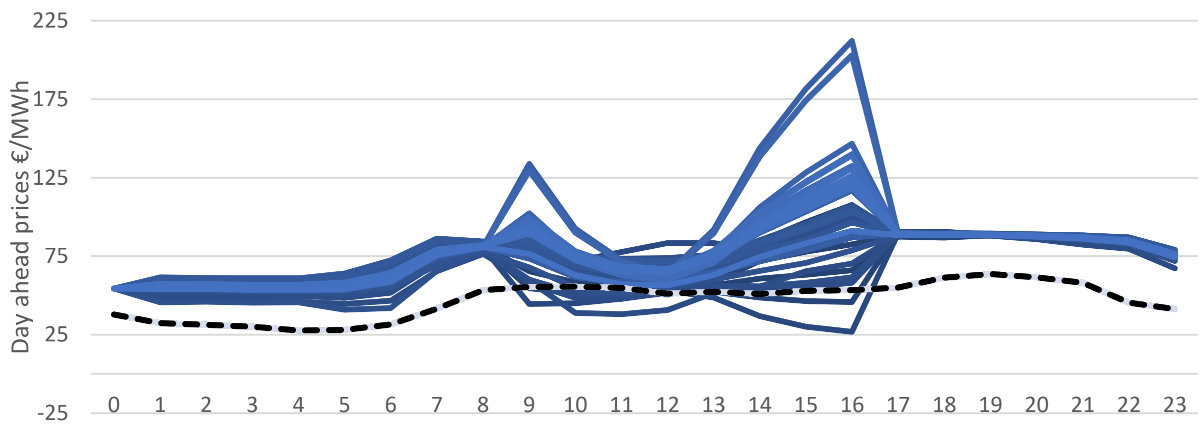

Figure 68: Comparison of nodal day ahead prices (blue) with historical spot prices (black dot) on French nodes – Day 1

Figure 68 compares the evolution of prices for each French market zone in the nodal model (blue lines) with the historical spot price for the French bidding zone. A first observation to be made is that modelled nodal prices on this typical Monday - which has no particular characteristics - are on average higher than the historical price. This can be explained because of the increased fuel prices considered in our modelling. It is interesting to notice that the "spatial" variability of nodal prices (differences between nodes) is more important during the day than the night. Hours between 8am and 4pm have more volatile nodal prices. This is due to the higher share of solar PV in the system. Solar PV production can cause additional constraints on some nodes which are reflected through the nodal prices. It would seem that as VRE shares increase, we observe an increase in nodal price divergence. We can also note that nodal prices tend to be higher during usual "peak" periods at the end of the day (6pm – 8pm), and in the morning (7am - 8am).

The fifth day of the simulation (Friday) allows us to study the impact of a higher penetration rate of renewables in the nodal study zone electricity mix on the prices, due to windy conditions.

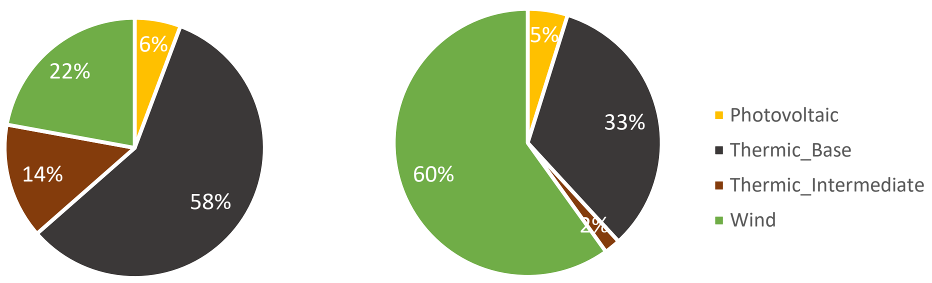

Figure 69: Electricity mix for French zones 14 and 9 (i.e. those represented at substation level) for day 1 (right) and day 5 (left)

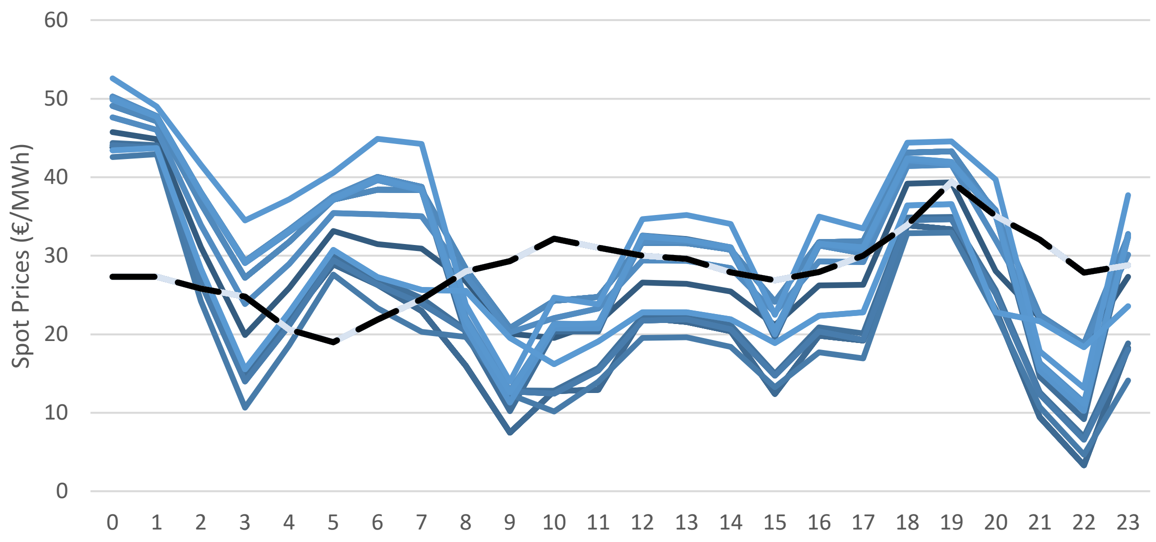

Figure 70: Comparison of French nodal spot prices (blue lines) with French historical spot prices (black dotted line) – Day 5

Thus, on this particular day, we can observe that nodal spot prices are not as high compared to the historical spot price, unlike what was observed for the first day of the simulation. Indeed, prices drop with increased wind generation, meaning that less thermal power plants need to stay on to meet the demand, thus reducing the impact of the rise in fuel prices on the nodal spot prices. Moreover, we can observe that the spatial variability of prices between different nodes stays approximately the same during the whole day, which was not the case in day 1 of the simulation (see Figure 70: Comparison of French nodal spot prices (blue lines) with French historical spot prices (black dotted line) – Day 5), where this phenomenon was mainly observed between 8am and 4pm, when there was a high penetration of solar PV in the system. Here, a high wind generation is observed during the whole day, along with a certain spatial variability between nodal prices. Thus, we may establish a causal link between a high penetration rate of renewables and an increase in the spatial variability in nodal prices.

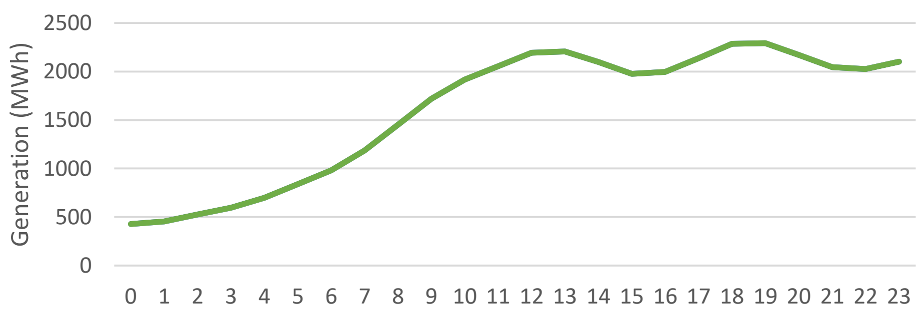

Figure 71: Wind generation day-ahead forecast for the nodal market study, aggregated for France – Day 5

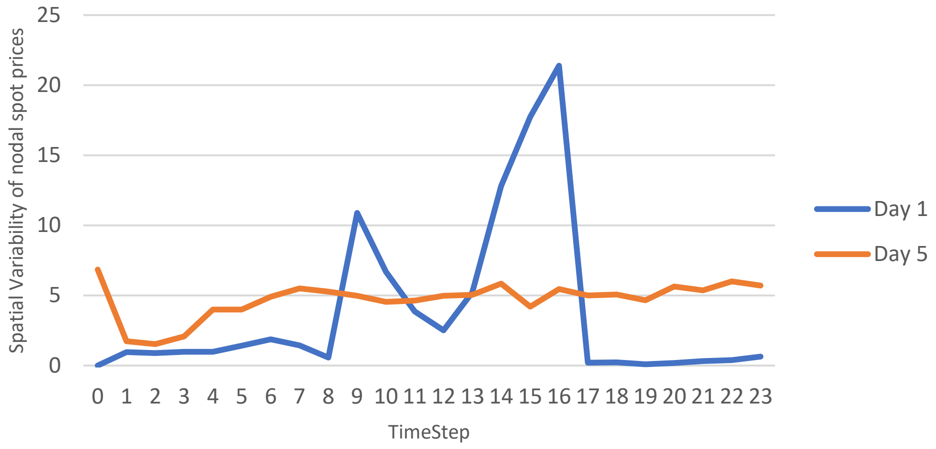

Figure 72: Comparison of spot prices standard deviations between nodes, for French zones 14 and 9 (i.e. those represented at substation level) – Days 1 and 5

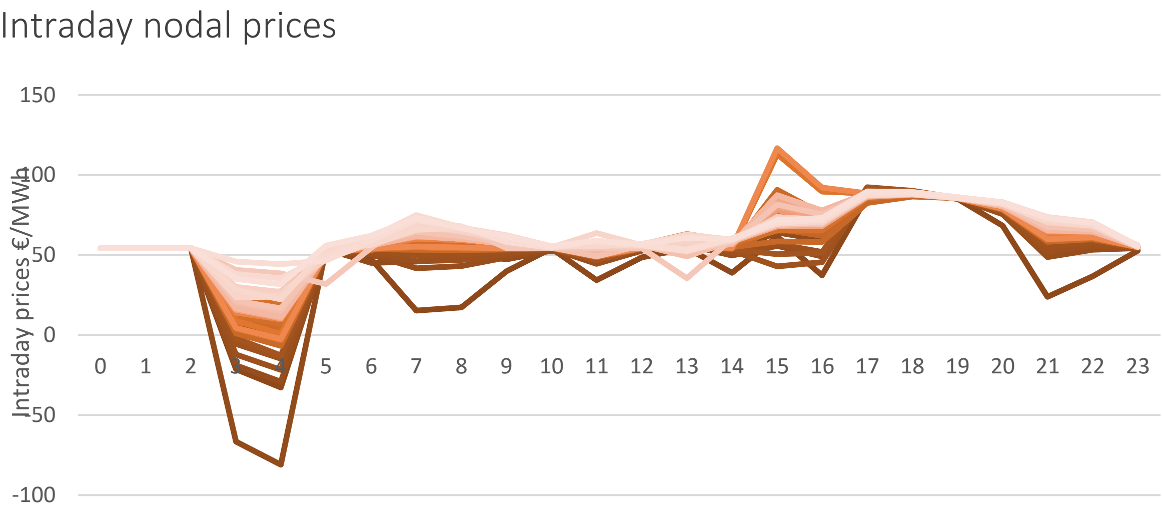

Figure 73: Intraday nodal prices on French nodes – Day 1

Intraday nodal prices as presented in Figure 73 present different variations compared to day ahead prices. Peak prices around 3pm are due to the congestion of the critical branch between 07_fr and M nodes (as explained in the caption of Figure 66). The congestion impact can be seen throughout the closest electrical nodes on their respective intraday prices. Nodes “below” the congestion (M, Q, P, S, R etc…) are subject to higher prices because of the congestion. Nodes “above” (07_fr, 03_fr, 12_fr etc.) have lower prices to help solve the congestion. The flows on surrounding critical branches are impacted and their utilisation rate are strongly correlated. These relations can be explained by the PTDF coefficients: the higher the PTDF coefficient on one critical branch for a given node is, the higher the impact on the node price connected to the critical branch will be. Nodal prices react as a “spectrum” around the congestion.

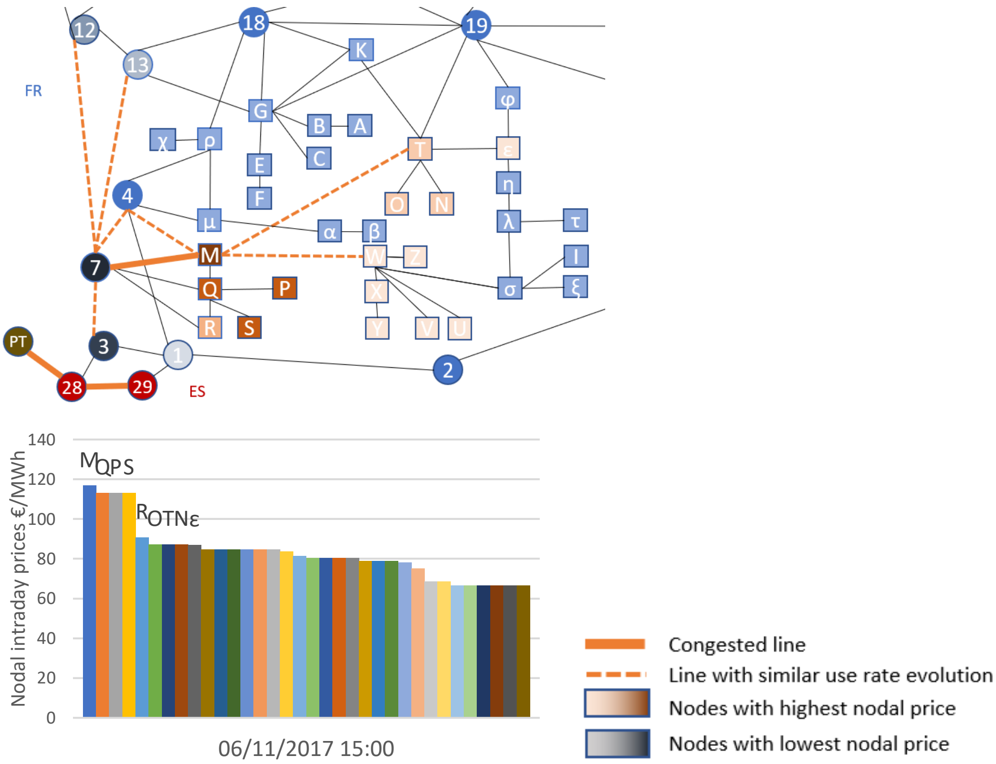

Figure 74: Example of a congestion impact on nodal prices around the congestion

Intraday nodal prices for French nodes around 3-4am present a noticeable specificity: they are lower than other prices when compared to European nodal prices. This can be explained after looking at France's overall net balance:

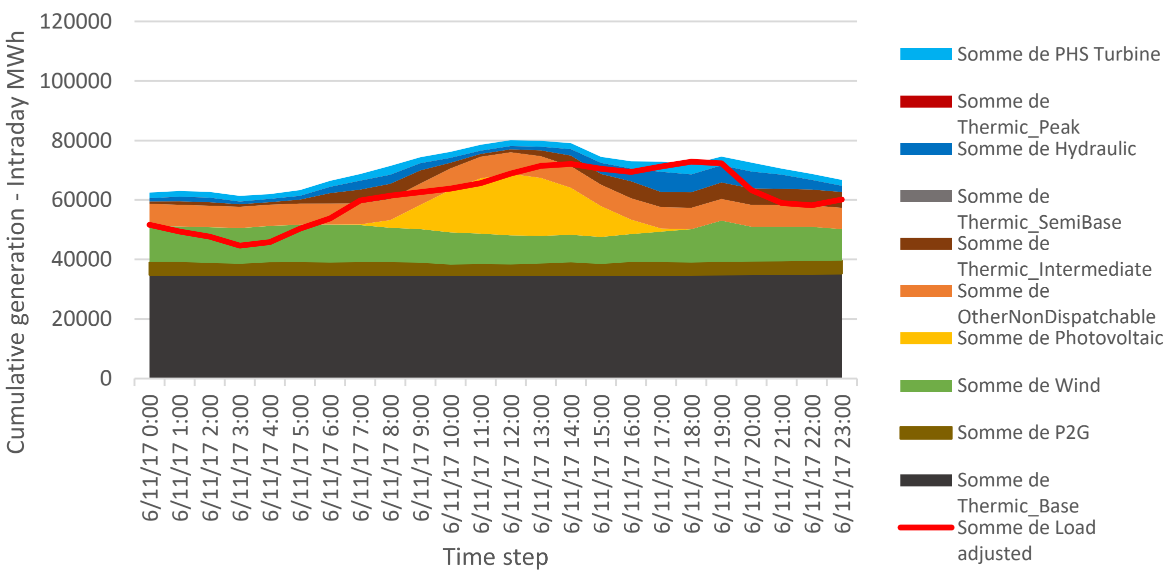

Figure 75: France generation stack – Intraday – Day 1

France exports a lot, as electricity demand in this period is low. This period is also the most congested, leading to low prices on the intraday market, which were not anticipated by the day ahead market. Overall, part of the generation must be curtailed because of the surplus of nondispatchable generation (such as wind) which cannot be exported nor consumed locally. Net load forecast between 3am and 4am did not anticipate this drop in intraday prices.

Nodal prices volatility

As observed in the previous sections, nodal prices can be quite volatile in periods with renewable production surplus, or uncertainties on the net load forecasts. Prices volatility can be studied either on a spatial level (standard deviation of nodal prices over all nodes for a given timestep), or on a time level (standard deviation of nodal prices over the day for a given node).

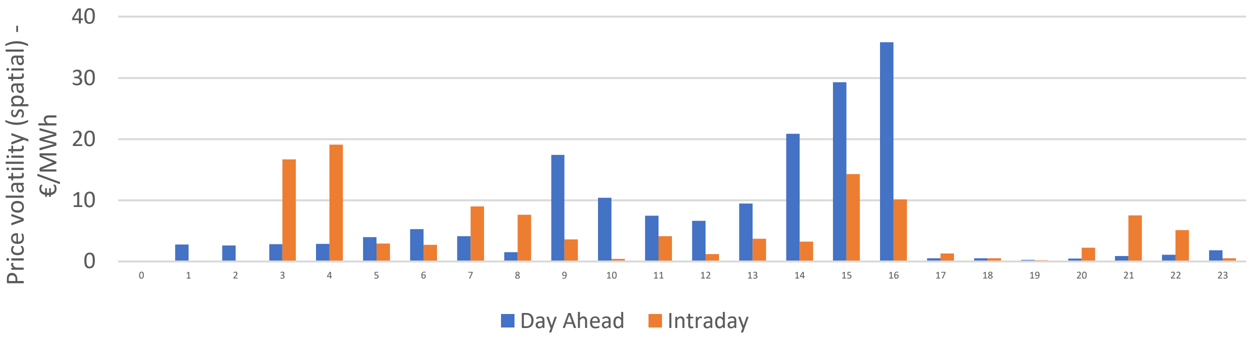

Figure 76: Nodal prices spatial volatility (France) – Day 1

Figure 76 shows the volatility induced by the variable solar PV production in day ahead with important differences between nodes in the same country (up to 35€/MWh difference at 4pm). The volatility due to generation curtailment between 3am and 4am is also visible for the intraday market. No clear trend can be deduced from the spatial volatility to understand if intraday or day ahead prices are more volatile on this example only.

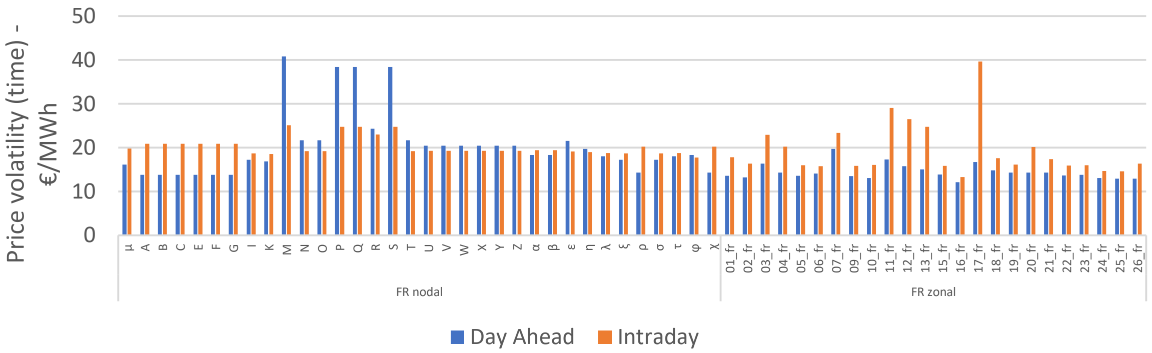

Figure 77: Nodal prices time volatility (France) – Day 1

Figure 77 focuses on time volatility for given nodes. Only French nodes were represented for the graph to be more readable. The congestion on the critical branch 07_fr – M which happens during a long period in day ahead has an impact on the volatility: nodes from the "Nodal FR" group, and particularly M, P, Q, R, S (which are the closest to the congestion with their PTDF), have a higher volatility than other nodes. On other French nodes, time volatility is more important in the intraday market than in day ahead. Some nodes are noticeable: 17_fr, 11_fr, 12_fr, 13_fr: as they are closer to the interconnection between FR, GB and IE (a zone with network constraints as shown in Figure 78) and 17_fr has an important generation due to the nuclear power plants in the region.

Moreover, nodal prices have the very special feature of including network constraints in the prices to which actors are confronted on the market. Such network constraints can cause nodal market prices to reach unprecedented values in the historical prices. For instance, on the fifth day of the simulation, higher wind generation induces a lot of congestions between zones with a high wind capacity and those without. As wind generation is cheaper, actors may prefer to import from zones with a surplus of wind generation. On day 5, it is the case in the north of Europe, which causes the congestions seen in Figure 78.

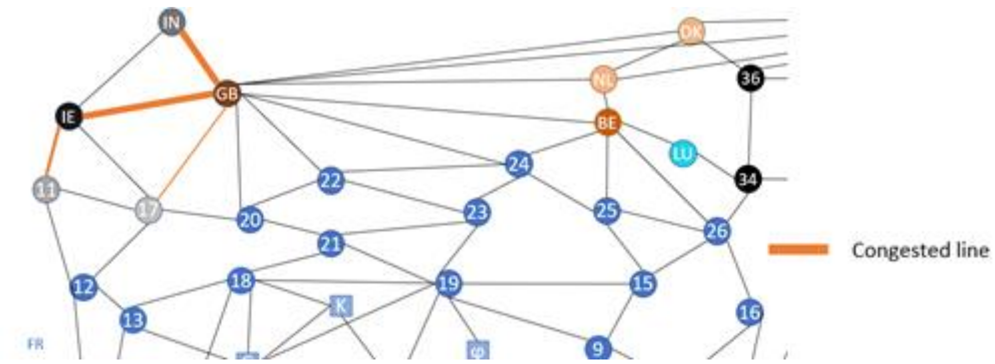

Figure 78: Congestions induced by a high wind generation in Northern Europe – Day 5. The width of a congested line is proportional to the number of congestion occurrences on the line

These congestions lead to negative prices – for instance nearly down to -500€/MWh for Ireland around 2am and 4am – when the marginal costs of generation in Great-Britain is much higher than the ones in Ireland. Those negative prices are not ones to which actors are accustomed nowadays.

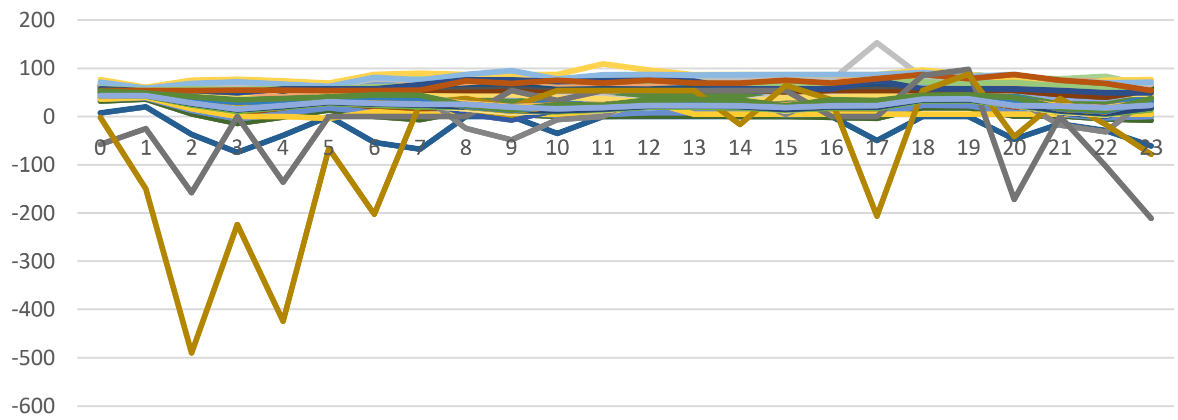

Figure 79: Intraday prices over all of the European market zones – Day 5