Energy and reserve markets: interdependency in high-renewables electricity systems

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Abstract

Markets for electric energy and reserves are linked as the same physical assets operate in both markets. Two different designs are commonly used for clearing energy and reserve markets; joint clearing or sequential clearing. It's generally accepted that joint clearing results in higher (or at least the same) social welfare than a pure sequential clearing. However, the impact of an increasing share of intermittent renewables on the interdependency between energy and reserves has been underexposed in literature. This paper studies the coupling between day-ahead energy markets and reserve markets for allocation and activation, and this for different shares of intermittent renewables (i.e. wind and solar PV). Towards this end, a large scale unit commitment model is deployed to a case study inspired by the Central Western European system. Different scenarios, developed within the EU-SysFlex project, are considered. The study indicates that the interdependency between energy and reserve markets increases with increasing share of intermittent renewables. As such, the cost difference, evaluated in real-time, between joint and sequential clearing increase as well with increasing share of intermittent renewables. The analysis shows that this impact can be partially compensated by an increasing role of renewables and flexible load in reserve provision.

Keywords: Power system analysis, unit commitment, reserves, market clearing, Central Western European system, EU-SysFlex

1. Introduction

Short-term operational reserves are necessary to deal with uncertainty inherent to electricity systems, such as forced outages and forecast errors. They are used to maintain the supply-demand balance at all times. This type of reserves can be provided by power plants, renewable generation units, storage units or flexible load. System operators procure reserves (well) before the moment of delivery and activate them in real-time when needed to deal with imbalances.

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This paper addresses the interdependency between day-ahead markets for energy and markets for reserves allocation and activation. Energy and reserve markets are linked through the technical constraints of reserve providers, e.g. generation limits of power plants (Morales-España et al., 2013; Ruiz et al., 2009). The use of capacity for reserves (generation, load or storage capacity) constrains the use of that same capacity in the energy market, and vice versa (Chen et al., 2006; Liu and Tomsovic, 2014). As such, the outcome of the energy market constrains the outcome of the reserve market, in terms of costs and scheduling, and vice versa.

Two different market designs are commonly used to organize energy and reserve markets: joint clearing and sequential clearing (González et al., 2014). In joint markets, day-ahead energy and reserves clear simultaneously. Interdependencies between both are implicitly accounted for. Joint markets are based on a Unit Commitment style optimization that dispatches energy and reserves on unit level. Examples of joint markets are the US competitive markets such as PJM, CAISO, ERCOT, MISO and NYISO (González et al., 2014; Al-Abdullah and Sahraei-Ardakani, 2016). In sequential markets, energy and reserves clear sequentially without implicitly accounting for interdependencies. Sequential markets are based on a quantity-price optimization that dispatches energy and reserves at portfolio level. Market operators then schedule their units based on the resulting market prices, accounting for interdependencies between energy and reserves. The European Integrated Energy Market is based on sequential market clearing (González et al., 2014; European Commission, 2017; Gebrekiros et al., 2015). Note that also in sequential markets, there is likely an impact of the reserve market on the energy market (and vice versa). It can be expected that market players anticipate the reserve market while bidding into the energy market.

It is generally accepted that joint markets result in higher (or at least the same) social welfare than pure sequential markets, as joint markets better account for the various couplings between energy and reserve markets (Soleymani et al., 2007). Galiana et al. (2005) illustrate, based on unit commitment modeling, the strong coupling between energy and various reserve products. They show for a stylized 3-bus system that joint market clearing results in lower system costs. Domínguez et al. (2019) show for a stylized 24-bus system that a co-optimized scheduling of energy and reserves results in a more efficient market design, compared to scheduling reserves before or after scheduling energy. Though, they also illustrate that scheduling reserves after the energy market can be as efficient as a joint clearing, if system operators of different zones coordinate the cross-border procurement of reserves.

This work contributes to the existing literature in two ways. First, the interdependency between energy and reserve markets is studied in detail for different levels of intermittent renewables such

as wind and solar PV. The amount of reserves required is expected to increase with increasing renewable penetration. Moreover, renewables with zero marginal generation costs impact the merit order and hence the interdependencies between energy and reserve markets. Second, a realistic and large-scale case study of the Central Western European is considered. The operations of this power system is modeled with a detailed unit commitment model, both for a joint and a sequential market design and for different levels of renewables. Note that this analysis focuses on the technical interdependencies between energy and reserves, assuming perfect markets (i.e. perfect competition and perfect information). From this analysis, implications for the design of future energy and reserve markets in Europe are derived.

This paper focuses on generation forecast errors for wind and solar PV as source of uncertainty in the power system. Wind and solar PV forecasts are characterized by three aspects. First, forecasts improve with shorter forecast horizons, though only considerably below a 4 to 6 hours forecast horizon, both for wind and solar PV ([Ahlstrom et al., 2013](#); [Tuohy et al., 2015](#); [Orwig et al., 2014](#)). In other words, day-ahead forecasts only become more accurate several hours before real-time. This implies that system operators need to contract enough fast reserves to deal with last-minute changes in generation ([Håberg and Doorman, 2016](#); [Petitet et al., 2019](#)). Second, forecasts improve with aggregation effects—in relative terms expressing forecast errors as percentage of forecasted generation or installed capacity. Aggregating multiple wind and solar PV plants reduces aggregated forecast errors, as opposing forecast errors balance out. As such, larger market zones have lower relative forecast errors and lower need for reserves—again, in relative terms ([Van den Bergh et al., 2017](#)). Third, low-probability high-impact forecast errors are important, given that the need for reserves is sized based on these events (when high levels of reliability are required). Forecast errors are often mathematically described by a Gaussian or beta-distribution. However, these distributions tend to underestimate large forecast error with low probability, in particular for wind ([Bruninx and Delarue, 2014](#)).

This paper focuses on the allocation of reserves which can be activated in the time range of minutes to quarter-hours. In European terminology, Automated and Manual Frequency Restoration Reserves (aFRR and mFRR) are considered in this paper, as well as Restoration Reserves (RR). Frequency Containment Reserves (FCR)—which react in a time frame of seconds—are not considered ([ENTSO-E, 2013](#)). Besides, this paper addresses all three phases of reserve markets. First, the required level of reserves is determined in the dimensioning or sizing phase. Second, reserves are procured and allocation in the procurement or allocation phase. Third, reserves can be activated in real-time to deal with imbalances ([Van den Bergh et al., 2018](#); [De Vos et al., 2011](#); [Gazafroudi](#)

et al., 2017). Though all phases are considered, the main focus is on the allocation phase as the difference between joint and sequential market clearing becomes apparent in this phase.

Section 2 outlines the methodology, covering the framework, case studies and model description. Section 3 presents and discusses the results. Section 4 concludes.

2. Methodology

This study aims to quantify the cost difference between sequential and joint energy-reserve market clearing for different levels of renewables. This section discusses the framework used to quantify this cost difference, presents the simulation model and outlines the case study of Central Western Europe.

2.1. Framework

Reserve and energy markets consist of several sequential phases in Europe. The exact order of those phases might depend on the reserve type and can differ between countries, but generally speaking reserve and energy markets are organized as follows: reserve sizing occurs well before real-time (e.g. year ahead), energy is traded on forward markets, reserves are procured at portfolio level, energy is traded in the day-ahead market, reserves are allocated to units, energy is traded intra-day, and reserves are activated in real-time. This full procedure is simplified in this study, for the sake of clarity, to three phases: (1) the day-ahead energy market, (2) the day-ahead allocation of reserves, and (3) the real-time activation of reserves. The sizing of reserves happens ex-ante and exogenously to the framework. The remainder of this subsection describes how joint and sequential energy-reserve markets are represented and modeled in this study.

In a sequential market design, the 3 considered phases occur sequentially. In other words, the model describing a sequential market consists of 3 consecutive model runs. In a joint market design, the day-ahead energy market is cleared simultaneously with the allocation of reserves, followed by real-time reserve activation. In other words, the model describing a joint market consists of 2 consecutive model runs.

Figure 1 gives an overview of the different markets and model runs. The different model runs are linked as follows. In a sequential design, it is assumed that the day-ahead energy and reserve markets are linked by (see model runs S1-S2 and link A in Figure 1):

- Base and medium load power plants can not start up or shut down between the energy and reserve market (i.e. nuclear power plants, coal and lignite fired power plants, and combined

cycle gas turbines), but peak load power plants can (i.e. open cycle gas turbines and internal combustion engines);

- Import/export schedules resulting from the day-ahead energy market must be respected in the reserve market. In other words, national reserve markets are considered, without the possibility to allocate reserves cross-border;
- In the reserve allocation phase, reserve requirements are imposed to the model.

Besides, for both joint and sequential designs, it is assumed that the day-ahead and real-time phases are linked by (see model runs S2-S3, J1-J2 and link B in Figure 1):

- The day-ahead generation schedules of power plants that can not deliver reserves, neither spinning nor non-spinning reserves, are set fixed (i.e. nuclear power plants¹, coal fired power plants and lignite fired power plants in this study);
- The day-ahead unit commitment schedules of power plants that can only deliver spinning reserves are set fixed (i.e. combined cycle gas turbines and nuclear power plants in France in this study);
- Import/export schedules resulting from the day-ahead energy market must be respected in the real-time reserve activation. In other words, national reserve markets are considered, without the possibility to activate reserves cross-border;
- In the real-time reserve activation phase, no reserve requirements are considered and the actual renewable generation is imposed to the model (instead of the day-ahead forecasted generation).

Figure 1. Overview of the framework, consisting of 3 market phases (energy market, reserve allocation and reserve activation) and 2 market designs (sequential and joint design), with 5 different model runs (S1-S3 and J1-J2) which are linked in 2 different ways (A and B).

¹Nuclear power plants in France are assumed to be able to deliver spinning reserves.

2.2. Model description

The Leuven University System Model (LUSYM) is used to simulate the different phases in the energy and reserve market: day-ahead energy market, day-ahead reserve allocation and real-time activation. LUSYM is a deterministic unit commitment model, formulated as a mixed-integer linear program in GAMS. The optimization problem is solved using the CPLEX 12.6 solver, with an optimality gap of 0.5%. The model is run on the Genius High Performance Computing cluster of the KU Leuven.

This subsection gives a concise overview of the objective function and main constraints of the unit commitment problem. The reader is referred to [Appendix A](#) for the nomenclature and to [Van den Bergh et al. \(2015\)](#) for an elaborate description of LUSYM.

The objective function of the unit commitment model is to minimize total operational system cost (Eq. 1), consisting of generation costs², start-up costs, load curtailment costs, renewables curtailment costs and reserve allocation costs for load and renewables curtailment³:

$$\min \sum_{i,t} (NC_i z_{i,t} + MC_i g_{i,t} + SUC_i v_{i,t}) + \sum_{n,t} (LC lc_{n,t} + RC rc_{n,t} + RAC^{lol} r_{n,t}^{lol} + RAC^{cur} r_{n,t}^{cur}) \quad (1)$$

The objective function is subject to the market clearing condition (Eq. 2), power plant generation limits (Eq. 3), minimum up and down times (Eqs. 4-5), the binary relationship between power plant states (Eq. 6), trade-based network constraints (Eqs. 7-8), curtailment constraints for load and renewables (Eqs. 9-10), and non-negative and binary constraints (Eqs. 11-13).

$$\sum_i A_{n,i}^{plant} (z_{i,t} \underline{P}_i + g_{i,t}) + RES_{n,t} - rc_{n,t} = D_{n,t} - lc_{n,t} + p_{n,t} \quad \forall n, \forall t \quad (2)$$

$$0 \leq g_{i,t} - r_{i,t}^- \leq g_{i,t} + r_{i,t}^+ \leq (\bar{P}_i - \underline{P}_i) z_{i,t} \quad \forall i, \forall t \quad (3)$$

$$1 - z_{i,t} \geq \sum_{t'=t+1-MDT_i}^t w_{i,t'} \quad \forall i, \forall t \quad (4)$$

$$z_{i,t} \geq \sum_{t'=t+1-MUT_i}^t v_{i,t'} \quad \forall i, \forall t \quad (5)$$

$$z_{i,t-1} - z_{i,t} + v_{i,t} - w_{i,t} = 0 \quad \forall i, \forall t \quad (6)$$

²A linear generation cost curve is being used—instead of a non-linear cost curve—in order to mimic current markets and to limit the computational cost. However, the loss in accuracy due to this linearization is very limited.

³Reserve allocation costs, i.e. the cost of not using a MW capacity in the energy market by reserving it for possible delivery of reserves in real-time, is explicitly modeled for load shedding (upward reserves) and renewables curtailment (downward reserves). Reserve allocation costs for power plants are implicitly accounted for in the model.

$$p_{n,t} = \sum_l A_{l,n} f_{l,t} \quad \forall n, \forall t \quad (7)$$

$$\underline{E}_l \leq f_{l,t} \leq \overline{F}_l \quad \forall l, \forall t \quad (8)$$

$$0 \leq lc_{n,t} + r_{n,t}^{lol} \leq D_{n,t} \quad \forall n, \forall t \quad (9)$$

$$0 \leq rc_{n,t} + r_{n,t}^{cur} \leq RES_{n,t} \quad \forall n, \forall t \quad (10)$$

$$g_{i,t}, r_{i,t}^+, r_{i,t}^- \geq 0 \quad \forall i, \forall t \quad (11)$$

$$rc_{n,t}, r_{n,t}^{cur}, lc_{n,t}, r_{n,t}^{lol} \geq 0 \quad \forall n, \forall t \quad (12)$$

$$z_{i,t}, w_{i,t}, v_{i,t} \in \{0, 1\} \quad \forall i, \forall t \quad (13)$$

In the day-ahead reserve allocation phase, additional spinning reserve requirements are imposed to the unit commitment model (Eqs. 14-15). Spinning reserve scheduling is constrained by the power output limits (Eq. 3) or the available renewables and flexible load (Eqs. 9-10). Non-spinning reserve requirements are not imposed to the unit commitment model. It is ex-post verified whether enough non-spinning reserves are available.⁴

$$\sum_i A_{n,i}^{plant} r_{i,t}^+ + r_{n,t}^{lol} + rc_{n,t} \geq SR_{n,t}^+ \quad \forall n, \forall t \quad (14)$$

$$\sum_i A_{n,i}^{plant} r_{i,t}^- + r_{n,t}^{cur} \geq SR_{n,t}^- \quad \forall n, \forall t \quad (15)$$

The unit commitment model allows import/export of energy only in the day-ahead energy market. Therefore the following constraint (Eq. 16) is added to the real-time reserve activation (and to the reserve allocation in a sequential market design) to ensure that the day-ahead import/export schedule is respected. The superscript DAEM refers to day-ahead energy market, the superscript DARA refers to the day-ahead reserve allocation and the superscript RTRA refers to the real-time reserve activation.

$$f_{l,t}^{DAEM} = f_{l,t}^{DARA} = f_{l,t}^{RTRA} \quad \forall l, \forall t \quad (16)$$

⁴A shortage of non-spinning reserves indicate a lack of installed flexible capacity. Hence, scheduling of non-spinning reserve is rather an investment-related issue than an operational issue and therefore beyond the scope of a unit commitment model.

To properly link the different market phases, the unit commitment and economic dispatch decisions of power plants can be linked between the different market phases. The unit commitment schedule of base and medium load power plants is set fixed between the day-ahead energy market (DAEM) and the day-ahead reserve allocation (DARA) in a sequential market design (Eq. 17).

$$z_{i,t}^{DAEM} = z_{i,t}^{DARA} \quad \forall i \in I^{base,medium}, \forall t \quad (17)$$

Between day-ahead reserve allocation (DARA) and real-time reserve activation (RTRA), the generation schedule is set fixed for generation units which can not deliver reserves, neither spinning nor non-spinning (Eq. 18). For generation units which can only deliver spinning reserves, the unit commitment schedule is set fixed (Eq. 19).

$$g_{i,t}^{DARA} = g_{i,t}^{RTRA} \quad \forall i \notin I^{sr} \& i \notin I^{nsr}, \forall t \quad (18)$$

$$z_{i,t}^{DARA} = z_{i,t}^{RTRA} \quad \forall i \in I^{sr}, \forall t \quad (19)$$

The model simulates a full year with a quarter-hourly time resolution, based on a series of 365 consecutive optimizations covering one day each. Consecutive days are linked to each other via sequential boundary conditions.⁵

A simplified trade-based network representation is implemented with a fixed transmission capacity between market zones and no transmission constraints within market zones (in line, roughly speaking, with the European Available Transfer Capacity system of market coupling). In a trade-based network representation, Kirchhoff's current law is taken into account and Kirchhoff's voltage law is neglected. The import/export position of each node is linked to the flows in the network by means of the network incidence matrix A which indicates for every line the starting node ($A_{l,n} = 1$) and ending node ($A_{l,n} = -1$). The reader is referred to [Van den Bergh et al. \(2014\)](#) or [Hobbs and Rijkers \(2004\)](#) for a detailed description of a trade-based network representation.

2.3. Case study

The Central Western European (CWE) power system is considered as case study, covering Belgium, France, Germany, Luxemburg and the Netherlands. The temporal scope is a full year with quarter-hourly time resolution (i.e. 35 040 time steps).

⁵An overlap of 12 hours between two days is implemented, based on the largest minimum up/down time in the generation portfolio (i.e., a 12 hour minimum up/down time for nuclear units and lignite fired units). As such, the model considers the full length of the nuclear minimum up/down time when taking a decision to start-up/shut-down a nuclear unit at the end of the considered day.

Three different scenarios are considered for the CWE power system:

1. Current System: based on the 2018 actual CWE power system (18% wind and solar PV share);
2. Energy Transition: possible future CWE power system, characterized by an increased load and switch to wind and solar PV (30% wind and solar PV share);
3. Renewable Ambition: possible future CWE power system, characterized by a strong increase in load, driven by electrification in the heating and transport sector, and a drastic switch to renewables, amongst others driven by a high CO₂ price (45% wind and solar PV share).

The Energy Transition scenario and Renewable Ambition scenario are developed within the scope of the EU-SysFlex project ([EU-SysFlex, 2018](#)).⁶ Data for the Current System scenario is taken from the ENTSO-E Transparency Platform ([ENTSO-E, 2018](#)). Quarter-hourly load and renewable time series are taken for the year 2018 and scaled up to achieve annual renewable generation foreseen in the Energy Transition and Renewable Ambition scenario ([ENTSO-E, 2018](#); [TransnetBW, 2018](#); [Amprion, 2018](#); [50hertz, 2018](#); [Réseau de Transport d'Électricité \(RTE\), 2018](#); [Elia, 2018](#)). Both actuals and day-ahead forecast data is used for wind and solar PV time series. The generation portfolio on unit level is composed starting from the 2015 PLATTS database ([Platts, 2015](#)). Power plants are added or removed to match installed capacity per generation type. Net transfer capacities are taken from the 2030 scenario in ENTSO-E's Ten Year Network Development Plan ([ENTSO-E, 2016](#)).

Reserves are sized in order to cover at least 95% of the forecast errors, based on the combined probability density function of wind and solar PV forecast errors ([Doherty and O'Malley, 2005](#)). The reserve sizing is done country by country, and separately for daytimes (with solar forecast errors) and nights (without solar forecast errors). It is assumed that at least 50% of the overall reserve sizing has to be delivered by spinning reserves, which can be delivered by combined cycle gas turbines, open cycle gas turbines, internal combustion engines, nuclear in France, renewables curtailment (only downward reserves), curtailed renewables (only upward reserves) or load shedding (only upward reserves). Non-spinning reserves can only be delivered by open cycle gas turbines and internal combustion engines.⁷

⁶The EU-SysFlex project considers scenarios for almost the full European power system, i.e. 23 countries. A detailed unit commitment simulations is performed with LUSYM for 15 of these 23 countries, in order to obtain quarter-hourly import/export schedules between the countries in CWE and its neighboring countries. These import/export schedules are assumed to be fixed for different levels of renewables.

⁷The case study considers pumped-hydro storage only in the energy market. Given the deterministic nature of the model and the assumption of perfect information, the use of storage for reserves would be overestimated by the model. Therefore, storage is not considered in the allocation or activation of reserves.

Loss of load and renewables curtailment are only possible at a very high costs (10 000 €/MWh). This implies that they will only occur to avoid infeasibilities.

Table 1 and Table 2 summarize the key parameters of the Central Western European power system in the different scenarios.

	Current System	Energy Transition	Renewable Ambition
Load			
Annual (TWh)	1 177	1 241	1 381
Peak (GW)	200	238	264
Installed capacity (GW)			
Nuclear	79	60	32
Lignite	21	12	-
Coal	34	33	30
CCGT	62	53	99
OCGT	7	6	11
ICE	11	3	1
Hydro & Bio	44	44	48
Wind	68	115	167
Solar PV	52	99	142
Fuel prices			
Coal (€/MWh)	9	16	12
Gas (€/MWh)	17	25	15
Oil (€/MWh)	55	74	61
CO2 (€/tCO2)	18	27	90

Table 1. Overview of the different considered scenarios for the Central Western European power system. CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle Gas Turbine, ICE = Internal Combustion Engine.

	Efficiency (%)	$\underline{P}$ (% $\bar{P}$)	MUT/MDT (h)
Nuclear	33	50	12
Lignite	35/40/45	43	12
Coal	35/40/45	43	6
CCGT	40/48/58	35	3
OCGT	35/42	30	1
ICE	35/40	35	1

Table 2. Overview of technical characteristics of the power plant portfolio (Schröder et al., 2013). Different efficiencies are used based on the commissioning year of power plants. MUT = Minimum Up Time, MDT = Minimum Down Time, CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle Gas Turbine, ICE = Internal Combustion Engine.

2.4. Limitations

The applied methodology is, for the sake of clarity, based on certain simplifications of the actual power system and market design. First, the intra-day market is not explicitly modeled. Day-ahead forecast errors need to be fully dealt with in real-time. However, in the actual market design, market players adjust intra-day their generation and consumption schedules based on continuously updated forecasts. The remaining real-time imbalance is then dealt with by the system operator. By considering two steps (day-ahead and real-time), the analysis takes a system-wide perspective

on reserves (rather than the perspective of a system operator), but likely underestimates the flexibility of the power system. Therefore the results from this analysis should be interpreted as an outer limit of the difference between sequential and joint market clearing.

Second, it is assumed in the sequential market design that market players do not take in any way reserves into account while scheduling energy day-ahead. However, it can be expected that in actual sequential markets, where market players know that energy scheduling will be followed by reserve scheduling, these players already (partly) anticipate reserve scheduling in the energy scheduling. As such, again, this analysis should be considered as an outer limit of the difference between sequential and joint market clearing.

Third, the analysis only considers wind and solar PV forecast errors as sources of uncertainties. Reserves needed to deal with forced outages or load forecast errors are not included.

3. Results and discussion

This section presents and discusses the simulation results. The impact of joint or sequential energy-reserve clearing on operational system costs and reserve allocation costs is presented, followed by a sensitivity analysis on the role of load and renewables in reserve provisioning. The insights from these results are then translated into implications for the design of future reserve markets in Europe.

3.1. Operational system costs

The analysis compares a sequential with a joint energy-reserve market design, based on total operational system costs. Operational system costs are evaluated for a full year and after the real-time reserve activation, to include both the cost of allocating and activating reserves.

Figure 2 shows the difference in total operational system cost between a sequential and joint market design. A positive cost difference indicates that a sequential market leads to higher operational costs than a joint market. The cost difference increases with increasing levels of wind and solar PV, up to 2.0-2.5% of total operational system cost at 30% wind and solar PV. The cost difference also increases in absolute terms. For example, for the Energy Transition scenario, the cost difference increase from €58M at 7% share wind and solar PV (on total operational system cost of €47.5B) to €535M at 33% share wind and solar PV (on a total operational system cost of €23.0B). Note that 2018 wind and solar PV share in CWE was 18%.

It is assumed that flexible load and renewables curtailment play a limited role in reserve provision. The cost of allocating and activating flexible load (as upward reserve) or renewables cur-

Figure 2. Difference in operational system costs between sequential and joint energy-reserve clearing, for different shares of wind and solar PV (cost evaluated for a full year after real-time phase).

tailment (as downward reserve) is set to 10 000 €/MW and 10 000 €/MWh respectively in the simulation, but evaluated ex-post at 100 €/MW and 100 €/MWh. This implies that flexible load and renewable curtailment will only occur when it is technically infeasible to deliver reserves with conventional generation units. Subsection 3.3 considers a sensitivity on this assumption.

The evolution of the cost difference, as a function of the wind and solar share, can be divided in 3 parts (see Figure 3 for the Energy Transition scenario). At low levels of wind and solar PV (up to 5-10% share), the cost difference is caused by the use of more expensive generation units to deliver reserves. In sequential reserve markets, reserves are allocated after the clearing of the day-ahead market and, as such, reserve allocation is constrained by the decisions taken in the day-ahead energy market. As a result, more flexible but also more expensive units are used to provide reserves (i.e. OCGT and ICE). At higher renewable shares (10-25%), flexible load is needed to deliver upward reserves in a sequential market design, further increasing the cost difference. At renewable shares above 25%, the cost difference due to different use of generation units as reserve providers start to decrease. At those levels of renewables, the residual load (load minus renewable generation) has become that small and variable that flexible generation units are needed in the energy market to deliver the residual load. As such, they don't need to be brought online just for delivering reserves. Therefore, the use of conventional generation units in joint and sequential reserve markets is becoming again more similar. At the same time, as reserve requirements continue to increase, more flexible load and renewables curtailment is needed to deliver these reserves. As

of that point, the cost difference is mainly caused by additional load shedding (upward reserves) and renewables curtailment (downward reserves).

Figure 3. Drivers of difference in operational systems costs between sequential and joint energy-reserve clearing in the Energy Transition scenario, for different shares of wind and solar PV (cost evaluated for a full year after real-time phase).

Note that wind and solar PV have a different impact on the simulation results. Forecast errors are different, with solar PV having a narrower probability distribution (i.e. lower forecast errors per installed capacity). This can be explained by the higher geographical spread, compared to (offshore) wind, and the fact that no reserves are needed during the night. As a result, fewer reserves are required for the same installed capacity of solar PV. As such, the difference between sequential and joint market clearing is smaller in a solar-PV system compared to a wind system (assuming same installed capacities)."

3.2. Reserve allocation costs

The subsection above focuses on operational system costs after the real-time phase. Similar trends are visible in the day-ahead market, after the scheduling of energy and reserves. Figure 4 shows the cost of reserve allocation for a sequential and joint design. The cost of reserve scheduling is determined as the difference in cost between a simulation with reserve constraints (i.e. simulations S2 and J1, see Figure 1) and without reserve constraints (i.e. simulation S1, see Figure 1). Figure 4 illustrates that reserve allocation costs increase with increasing levels of wind and solar PV, for both market designs. However, the cost increase is clearly stronger for a sequential market design.

Figure 4. Reserve allocation costs in the Energy Transition scenario, for different shares of wind and solar PV (cost evaluated for a full year after day-ahead market).

(a) Sequential design - upward.

(b) Joint design - upward.

(c) Sequential design - downward.

(d) Joint design - downward.

Figure 5. Contribution to allocation of spinning reserves in the Energy Transition scenario, by different reserve providers (for a full year).

Figure 5 shows the contribution of different reserve providers to the allocation of spinning reserves in the Energy Transition scenario, for joint and sequential market designs and for upward and downward reserves. Comparing sequential and joint market design, it becomes apparent that highly flexible but expensive reserve providers have a larger contribution in the sequential market design. OCGTs and ICs provide a larger share of upward reserves in a sequential design, while CCGTs are used more in a joint design. In a sequential design, even expensive reserves from load shedding are required. For downward reserves, curtailment of renewables is scheduled as reserves as of about 20% wind and solar PV share, while CCGTs can provide these downward reserves in a joint design.

Note that the reserve constraints are not always binding, in particular not at lower levels of wind and solar PV. For instance, at 7% share of wind and solar PV, the reserve constraints (upward and downward) are not binding for 71% of the time.⁸

3.3. Load and renewables

In the previous subsections, reserves were only provided by flexible load (upward) or renewables (downward) if it was technically infeasible to deliver reserves with conventional generation units. However, it can be expected that flexible load and renewables will play an increasingly important role in providing reserves, especially in a power system with high renewable shares.

Figure 6 shows the impact of reserve provision by flexible load and renewables in the Energy Transition scenario. Different simulations are run, with decreasing allocation costs for load and renewables.⁹ Reserve allocation cost for renewables can be understood as the opportunity cost of not generating (e.g. missed subsidies). The lower the allocation cost, the more reserves will be scheduled coming from load and renewables. As flexible load and renewables can provide reserves in a highly flexible way (e.g. no minimum on/off-times), the difference between a joint and sequential design decrease with decreasing reserve costs for flexible load and renewables.

3.4. Implications for reserve market design

The above results illustrate the cost increase of sequential energy-reserve market clearing, compared to a joint scheduling. Joint energy-reserve clearing is unlikely to become the target market

⁸Figure 5 is adjusted to account for this effect. The reserves scheduled above the required amount are not considered and deducted pro rate for the different reserve providers. This correction is executed for each time step and each country.

⁹Reserve activation costs for load and renewables are assumed to decrease in this paper in line with reserve allocation costs, from 100 €/MWh to 1 €/MWh.

Figure 6. Difference in operational system costs between sequential and joint energy-reserve clearing in the Energy Transition scenario, for different shares of wind and solar PV and different levels of allocation costs for load and renewables (cost evaluated for a full year after real-time phase).

design in a European context, at least in the short or near term. However, based on these quantitative results and taking the limitations of the modeling approach into account, the following three implications for the sequential energy and reserve markets in Europe can be derived.

First, the additional costs of sequential reserve scheduling is driven by the technical inflexibilities and limitations of conventional power plants (e.g. minimum up/down times). Load and renewables are more flexible in providing reserves, at least from a pure technical perspective. Therefore, reserve market design should be (further) opened up for reserve provision by renewables and flexible load. This could entail a broad set of actions, such as allowing load aggregators to bid in reserve markets or reducing contract durations to enable reserve provision by intermittent generation.

Second, as the required level of reserves increases with the share of wind and solar PV, the additional cost of a sequential market design increases as well. This effect can be partially offset by improving the dimensioning of reserves by, for instance, dynamic reserves and more short term reserve sizing. As such, the need for reserves can be determined more accurately and less reserves need to be scheduled.

Third, it is illustrated that the additional cost of sequential clearing has a convex relation with the level of wind and solar PV. In other words, the cost difference becomes larger with increasing wind and solar PV, and at an increasing rate. This implies that the above implications are preferably taken into account sooner than later. The analysis shows clearly that there is a cost

of not acting or acting late.

4. Conclusion

This paper compares a joint and sequential energy-reserve market clearing, for different levels of wind and solar PV. The paper considers the Central Western European power system as case study. Three different scenarios for the Central Western European power systems are considered, based on scenarios developed within the EU-SysFlex project. A detailed unit commitment model simulates the day-ahead scheduling of energy and reserves, followed by a real-time activation of reserves to deal with forecast errors for wind and solar PV. The results from this analysis, in terms of difference between joint and sequential clearing, should be considered as outer limits, given that a pure sequential clearing is considered without explicitly accounting for the day-ahead market.

The analysis indicates higher operational system costs for sequential markets, up to 2-2.5% increase at 30% share of wind and solar PV. By allocation reserves after the day-ahead market, the reserve allocation on unit level is constrained by decisions taken in the day-ahead energy market. As a result, more flexible but also expensive units (i.e. OCGT and ICE) are used to provide reserves compared to a joint market clearing. The additional costs of sequential markets becomes smaller when flexible load and renewables can deliver reserves.

Based on the analysis, three implications for the current design of European reserve markets are derived. First, flexible load and renewables should play an increasingly important role in reserve provision. Second, the level of required reserves should be reduced by dynamic and shorter term reserve sizing. Third, the above implications are preferably taken into account sooner than later, as the additional cost of sequential energy-reserve clearing raises at increasing rate with higher shares of wind and solar PV.

Going forward, the authors aim to include cross-border reserve markets in the analysis. Cross-border reserve markets are likely to be implemented in Europe over the coming years. It can be expected that cross-border allocation and activation of reserves increases the availability of reserves and as such moves sequential energy-reserve clearing closer to joint energy-reserve clearing, in terms of system costs.

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Appendix A. Nomenclature

Sets

$i \in I$	set of power plants
$l \in L$	set of transmission lines
$n \in N$	set of zones
$t \in T$	set of time steps

Parameters

$A_{l,n}$	network incidence matrix
$A_{n,i}^{plant}$	matrix linking power plant i to zone n $\{0,1\}$
$D_{n,t}$	load at zone n and time step t (MW)
$\bar{F}_l$	maximum flow through line l (MW)
$\underline{F}_l$	minimum flow through line l (MW)
LC	load curtailment cost (0.25 €/MWh)
MC_i	marginal generation cost (0.25 €/MWh)
MDT_i	minimum down time of power plant i (qh)
MUT_i	minimum up time of power plant i (qh)
NC_i	generation cost at minimum output of power plant i (€/qh)
$\bar{P}_i$	maximum power output of power plant i (MW)
$\underline{P}_i$	minimum power output of power plant i (MW)
RAC^{cur}	reserve allocation cost for renewables curtailment (0.25 €/MW/h)
RAC^{lol}	reserve allocation cost for load shedding (0.25 €/MW/h)
RC	renewables curtailment cost (0.25 €/MWh)
$RES_{n,t}$	renewable generation at zone n and time step t (MW)
SR_n^+	required upward spinning reserve in zone n (MW)
SR_n^-	required downward spinning reserve in zone n (MW)
SUC_i	start-up cost of power plant i (€/start-up)

Variables

$f_{l,t}$	power flow through line l at time step t (MW)
$g_{i,t}$	power generation of power plant i above minimum output at time step t (MW)
$lc_{n,t}$	load curtailment at zone n and time step t (MW)
$p_{n,t}$	power injection in the grid at zone n and time step t (MW)
$r_{i,t}^+$	scheduled upward spinning reserve from power plant i at time step t (MW)
$r_{i,t}^-$	scheduled downward spinning reserve from power plant i at time step t (MW)
$r_{n,t}^{cur}$	scheduled spinning reserve from renewables curtailment at zone n and time step t (MW)
$r_{n,t}^{lol}$	scheduled spinning reserve from load shedding at zone n and time step t (MW)
$rc_{n,t}$	renewables curtailment at zone n and time step t (MW)
$v_{i,t}$	start-up status of power plant i at time step t $\{0,1\}$
$w_{i,t}$	shut-down status of power plant i at time step t $\{0,1\}$
$z_{i,t}$	on/off-status of power plant i at time step t $\{0,1\}$