Future scenarios of the Baltic power system with large penetration of renewables

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***Abstract*—We model a hypothetical future scenario of the Baltic power system in 2050 with renewables-dominated generation, significantly increased electricity demand and synchronous operation with Continental Europe grid. A number of scenarios and sensitivities are assessed in terms of technical indicators such as renewable energy and demand curtailment, peaker power plant utilization as well as economic indicators like the electricity market price dynamics. We find that a future Baltic power system with a major share of renewables is viable both from the technical and economic perspective. It is shown that the flexibility already inherent in the Baltic power system can be successfully utilized for integrating significant capacities of renewables with relatively minor needs for additional flexibility.**

***Index Terms*—electricity market, modelling, power system, price, renewables**

I. INTRODUCTION

Latvia, Lithuania and Estonia joined the Nordic electricity wholesale exchange Nord Pool in 2013. Since then, its day-ahead market has been the main marketplace for the physical electricity trade. However, the Baltic power system has been going through and will be even more impacted in near future by three major changes. First, all the three countries are going to significantly increase the share of renewable energy sources (RES) in their power generation mix. Second, there is ambition to electrify various sectors, e.g. transportation and heat. Third, by 2025 the interconnections to Russia and Belarus will be severed and the connection to Poland strengthened due to the ongoing desynchronization project [1].

Overall, there have not been many studies dealing specifically with the long-term future of the Baltic power system and electricity markets. One major initiative was analysis of the Baltic Energy Technology Scenarios in 2018 [2] to explore the decarbonization-driven changes in the Baltic energy system until 2030. The most recent notable contributions are [3], [4] where an open-source Baltic power system model for 2030 is developed in the Backbone framework (in GAMS). It is found that “hourly operation of the system, with a high share of wind and solar, is based on active use of storages and interconnectors”. Moreover, modelling results raised “concerns about the amount of Estonian dispatchable capacity, the commercial feasibility of Latvian natural gas CHPs, and the high ramping rates of Lithuanian interconnectors” [4]. The model was used also to study the impact of building sector on the Baltic energy system decarbonization [5].

Studies [6]–[9], on the other hand, considered further future scenarios (for 2050) looking into topics like the impact of major transport electrification [6], future reserve requirements [7] and increasing penetration of RES [8], [9]. However, in these studies, the operation of each market actor was optimized individually based on exogenous or forecasted price signals. This implies that efficient utilization of flexibility sources system-wise might be hindered and its value not fully exposed.

In this study, we assess the potential evolution of the Baltic power system and electricity price in 2050 in light of the expected changes and considering a number of influencing parameters with uncertain forecasts while taking into account operational constraints. We analyze two main issues: first, generation capacity adequacy and peak power plant usage, which is imperative for the security of supply; second, electricity market price dynamics, which are ultimately passed down to the end-consumers thus impacting energy affordability. Future electricity prices in the Baltic states are estimated endogenously by the model.

II. METHODOLOGY

A. Model

For the purpose of the study, a simplified model of the Baltic power system was created in the SpineOpt modelling framework [10] which allows developing models using basic building blocks like nodes, units, connections and relationships between these entities. A graphical representation of the model is provided in Fig. 1. Each of the Baltic states is treated as a single node (i.e., internal transmission networks are not modelled), and the connections between Latvia and Estonia and between Latvia and Lithuania are modelled with a single bidirectional connection each, whereby the available transfer capacity in either direction can be varied for every time step of the model horizon.

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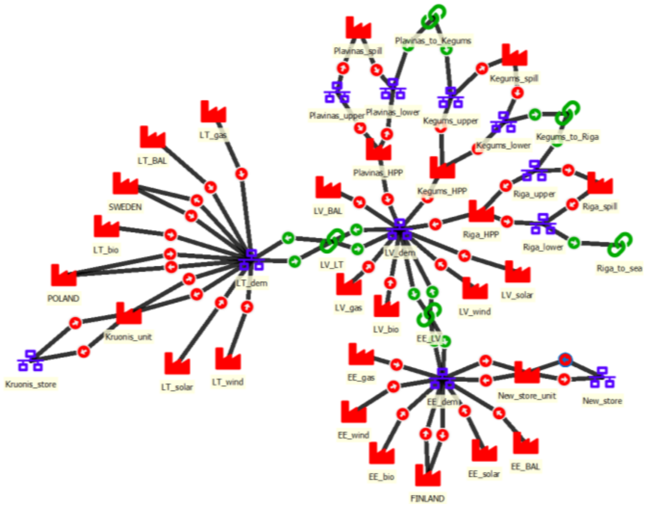

Figure 1. Entity graph of the Baltic power system model in SpineOpt

For each country, the power production capabilities are grouped by type, except for the three Latvian hydropower plants (Plavinas, Kegums and Riga HPP) which are treated separately, first, to account for their water storage capabilities and, second, to consider the time-delayed hydraulic linkage between these cascade power plants (they are situated in series on the Daugava river [11]). There are also two closed-loop storage power plants modelled: the existing Kruonis pumped storage HPP (PSHPP) and a prospective new PSHPP in Estonia. For the respective storage nodes as well as for the upper reservoirs of the three Latvian HPPs a cyclic condition constraint is imposed. This means that the amount of stored energy at the end of each optimization window must be equal to or greater than the initial amount.

The other types of production units considered are wind, solar and biomass power plants (which generically includes also other renewable fuels and waste) as well as expensive peaker power plants which can be assumed to be fueled by natural gas, but in principle they could be also implemented as other technologies or even price-driven demand response. In the simplified model, the only parameters needed to model the operation of the (technology-agnostic) peaker units is their capacity and generation cost (sum of fuel, variable operation and maintenance (O&M), and emission costs). As limited interconnector capacities between the Baltic states can cause the need for localized peakers, we assume in the model to have 500 MW of peaker capacity in each country, which roughly corresponds to one CCGT unit per country.

Additionally, to ensure that the model can be feasibly solved, we add a balancing unit in each country with unlimited capacity (in practice, a very high capacity, significantly higher than the peak demand) and a price equal to the day-ahead market ceiling. These artificial units ensure that the demand and supply is balanced in the model, and the modelled energy production in these units is to be interpreted as, in fact, pro-rata demand curtailment due to inadequate generation capacities. The high price ensures that mandatory demand reduction is done only as a last resort, not unlike how it is done in reality in current European day-ahead markets.

The power systems of neighboring countries (Finland, Sweden and Poland) are out-of-scope of the model and instead are considered in a simplified form by two parameters: the bidirectional transfer capacities and the exogenous electricity market price at each time step which enables consideration of the import and export flows, including also any transit flows.

The model is solved as a linear programming problem using Clp solver [12]. The optimization variables are the flows to/from units and connections. The objective of optimization is to minimize the total operational costs of the various modelled power plants and the electricity import costs. As we also allow for electricity export, the export prices are negative in the model, meaning that larger exports aid in minimizing the total cost, and they only occur if the income from export supersedes the O&M/fuel costs incurred from additional generation (or the import cost from a different area, in the case of transit trade). In the current model implementation, we assume perfect foresight within the optimization horizon.

B. *Validation and Selection of Optimization Horizon*

To test and validate the created Baltic power system model and its components, we perform a model run for a full year in hourly resolution using 2020 as the reference for input parameters and timeseries such as generation capacities, wind, solar and other RES production, demand, electricity market prices in Sweden, Poland and Finland and the available hourly transfer capacities in each considered interconnection based on public data [13], [14]. A particular point of interest is the accuracy and trustworthiness of the hydraulically linked HPP component of the model. These HPPs are a very significant electrical energy source in the Baltics with some limited but valuable inherent flexibility in the short-term timeframe [11].

Detailed data regarding the water inflow in the upstream reservoir (Plavinas) is not publicly available, however, total hourly production in the three HPPs is known, in addition to the reported average efficiency of power production in these plants (18 100 m^3/MWh) [15]. Using 15 publicly available water inflow measurements from the city of Daugavpils (further upstream from the Plavinas HPP) from 2020 [16], we interpolate an hourly inflow profile and resize it to match the total amount of water that should have passed through the cascaded HPPs in 2020 to match the reported electricity production and efficiency. The obtained inflow profile is shown in Fig. 2.

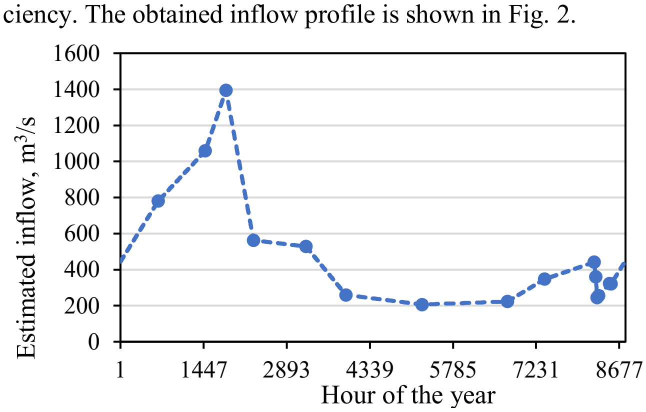

Figure 2. Estimated hourly inflow of Plavinas HPP reservoir in 2020

Apart from validating the model performance, we also strive to identify an appropriate rolling optimization horizon to be used when modelling the full calendar year. It is assumed that for each optimization window the forecasts of load, RES production and prices in neighboring bidding areas are perfect. We hypothesize that a 2-week window is sufficient as it allows capturing the flexibility offered by the HPP reservoirs and Kruonis PSHPP while reducing the timespan of the perfect forecast assumption. Furthermore, it significantly decreases the computational burden.

The modelled 168-hour moving average of the total power production on the Daugava River HPPs depending on the rolling optimization horizon is shown in Fig. 3. The figure also displays the moving average of the actual recorded power production in these HPPs in 2020. A small optimization horizon (single day) provides for a fairly stable production schedule which closely matches the assumed inflow pattern (Fig. 2). An optimization horizon from 1 to 2 weeks causes more medium-term fluctuations in the schedule since, on the one hand, the flexibility offered by the reservoirs can be better exploited while, on the other hand, the requirement to return to the initial storage levels at the end of each horizon (due to implied inability to forecast further in the future) causes a more varied schedule.

As this second consideration has less weight with 3-month and 1-year optimization horizons, the production then is less varied on average, especially under low-inflow conditions in the second half of the modelled year. Evidently, longer optimization horizons do not result in seasonal exploitation of storage capacities (due to the limited size, the storage is more suitable for short to medium term flexibility), and, overall, the average generation schedule still follows the annual inflow pattern even with 3-month and 1-year horizons. In general, the statistical properties of the modelled HPPs' operation are similar regardless of the selected optimization horizon (CV ranges from 1.38 to 1.52, correlation to inflow timeseries – from 0.41 to 0.45).

The above considerations allow us to conclude that a 2-week optimization horizon is sufficient for modelling the Baltic power system as it allows fully exploiting the reservoir flexibility without needlessly increasing the computational burden (on a standard desktop computer, modelling of a year with a 2-week rolling optimization horizon took approximately 30 min to solve whereas optimizing the whole year at once required about 9.5 hours).

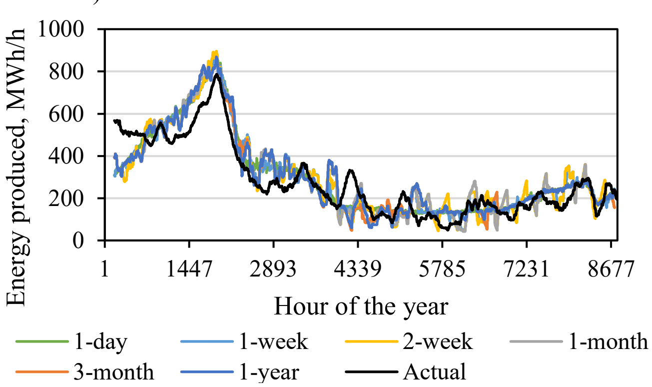

Figure 3. 168-hour moving average energy production in Daugava HPPs depending on the rolling optimization horizon

When comparing the modelled cascaded HPPs' power production with the historical data (black line in Fig. 3), it can be seen that the actual schedule exhibits seasonal variability which is similar to the modelled cases, i.e. it generally aligns with the seasonal characteristics of the inflow (Fig. 2), but, compared to model results, has less variation (CV is 1.07).

Some systemic issues can be observed when comparing the actual production to the modelling results. Namely, the production at the beginning of the year is underestimated whereas during the spring flood season it is overestimated, most likely pointing to issues in the inflow estimation, where a lot of uncertainty was involved, or as a consequence of the linearized model used. Nevertheless, in total, the modelled case leads to 4.4% to 6.4% overestimation of the electricity production in Daugava HPPs compared to the recorded values (depending on the source used for the actual total production [13], [14]). This margin of error is deemed to be satisfactory and can be assumed as, to some extent, inclusive of indirect assumptions on the increase of HPP equipment efficiency in the future.

C. *Metrics of Interest*

When assessing and comparing the outputs of model runs for various scenarios, the following metrics are considered:

- Curtailed wind and solar generation. It is calculated as the difference between the theoretical maximum of wind turbine and PV plant energy production under given weather conditions (accounting for seasonal/daily variations and capacity factors) and the production that can be either supplied to the grid to meet the demand or stored, or exported.

- Peaker power plant production. It is calculated as the sum energy produced by the assumed peak load plants throughout the modelled year. Additionally, the number of hours during the year when the activation of such units is necessary is also tracked and reported.

- Curtailed demand is calculated based on the total unsatisfied demand in the Baltics due to generation inadequacy.

- As an economic indicator, we look at the average and median electricity price in each scenario. The hourly price is derived from the costs of the marginal supply unit, i.e. it is taken from the dual of the load balance constraint from the optimization results. The simplified operational cost assumptions are as follows: wind 0 €/MWh, solar 1 €/MWh, hydro 4 €/MWh, biomass 10 €/MWh, peaker units 500 €/MWh, demand curtailment 3000 €/MWh and imported electricity – according to exogenous timeseries.

D. *Scenarios*

The *Base* scenario envisions the Baltic power system dominated by wind and solar energy in 2050. We assume a total of 6 GW installed wind capacity and 2 GW of solar. The wind capacity is divided equally between onshore and offshore with capacity factors of 30.88% and 45% respectively. In addition to 1.5 GW of peak power plant capacity there are also biomass cogeneration power plants, but their available capacity is assumed to be time-variable based on historical profiles. Annual demand projections, summarized in Table I, are linearly extrapolated from the TSO plans for 2030.

TABLE I. ELECTRICITY DEMAND ASSUMPTIONS FOR 2050

	Lithuania	Latvia	Estonia
Annual consumption, TWh	11.246	9.598	21.315
Peak demand, GW	3.483	1.575	1.992

Interconnections with neighboring countries and Baltic internal connections have the following maximum transfer capacities: Poland–Lithuania 1700 MW (after the construction of the Harmony Link), Lithuania–Sweden 700 MW, Latvia–Lithuania 1500 MW, Latvia–Estonia 1500 MW (after reconstruction of the lines), Estonia–Finland 1016 MW. Moreover, we model occasional reductions in transfer capacities and outages based on historical profiles. For all input timeseries, the hourly trajectories are based on data from 2020, adjusting the values to match the assumptions for 2050.

Another future development included in the *Base* scenario is the construction of a new pumped storage plant in Estonia [17] with a 480/500 MW discharge/charge capacity, 6 GWh storage capacity and round-trip efficiency of 0.8, and the installation of a fifth 225 MW unit in the Kruonis PSHPP in Lithuania [18].

Using the *Base* scenario as a starting point, we derive additional scenarios for analysis by modifying one key assumption compared to the *Base* case. Namely, in the *Perfect interconnections* scenario, we assume that the interconnections are always fully available at their maximum capacity. This is to quantify the significance of transfer capacities in the modelling results. In the *DR* scenario, we assume that demand response measures have allowed to reduce demand fluctuations and peak demand resulting in a 50% decrease of the demand timeseries standard deviation. In the *Extra storage* scenario, the power and storage capacity of the new storage plant are doubled, whereas in the *No new storage* (*No stor.*) scenario the plan for the new storage plant is discarded instead. Finally, there are two scenarios varying the inflow of Daugava HPPs: *Dry year* and *Wet year*, with a 50% reduction and increase of the available water resources respectively.

Additionally, sensitivity analysis is performed for the *Base* scenario by varying assumptions on the annual demand, installed wind capacity and solar capacity.

III. RESULTS

A. Main Scenarios

In the *Base* scenario, there are only 4.146 GWh of wind and solar energy curtailed in the modelled year, which constitutes 0.02% of the theoretically expected production (Table II). In essence, this means that the assumed RES capacities are not oversized and fit well with the demand projections. Peaker power plants had to be activated in 642 hours to produce 0.643 TWh of energy in total. The selected peaker capacity was insufficient in only 24 hours of the year when demand curtailment was simulated for a total of 0.15 TWh. However, the hourly maximum curtailment reached significant 1.1 GW. Overall, this shows good capabilities of the considered flexibility measures to balance the increased intermittent RES penetration and risen electricity demand.

TABLE II. SCENARIO MODELLING RESULTS

	Base	***Perf. int.***	***DR***	***Extra stor.***	***No stor.***	***Dry year***	***Wet year***
Curtailed RES, GWh	4.1	2.6	3.4	2.1	9.8	4.1	4.1
Curtailed RES, %	0.02	0.01	0.02	0.01	0.05	0.02	0.02
Peaker energy, GWh	643.2	71.2	583.0	584.0	715.0	788.1	537.9
Peaker energy, %	1.53	0.17	1.39	1.39	1.71	1.88	1.28
Peaker use, hours	642	100	605	576	761	783	522
Curtailed demand, GWh	15.2	0.0	11.6	9.1	34.5	54.5	10.4
Curtailed demand, %	0.04	0.00	0.03	0.02	0.08	0.13	0.02
Curtail. dem., max, GW	1.104	0	0.928	1.104	1.907	1.739	1.104
Curtail. dem., hours	24	0	24	16	49	70	1
Average price, €/MWh	145.1	80.0	138.8	141.3	180.2	187.2	124.5
Median price, €/MWh	65.02	64.52	66.37	65.59	64.29	66.54	63.72
Physical balance, TWh	-15.0	-15.5	-14.9	-15.1	-14.8	-16.1	-13.7
Trade balance, bn.€	-2.54	-1.53	-2.36	-2.44	-3.09	-3.30	-2.04

The average and median electricity market price in the Baltic states in 2050 *Base* scenario is 145.12 €/MWh and 65.02 €/MWh respectively. The power system is nevertheless import-dependent, with the physical balance with Finland, Sweden and Poland netting to negative 15 TWh a year and the trade balance – negative 2.54 bn.€.

The results for all the scenarios are summarized in Table II. The scenario with perfect interconnector availability (*Perf. int.*) shows the large importance of interconnections for the Baltic power system. When excluding the capacity reductions and the occasional outages from the model, RES curtailment, peaker use and demand curtailment are significantly decreased. In fact, there is no demand curtailment at any hour within the modelled year. The price reduction is also most notable in the *Perf. int.* scenario (–44.9%) resulting in the average price of 80 €/MWh.

In the *DR* scenario, the smoother demand profile leads to modest improvements in the considered metrics. Notable, albeit expectable, is the reduction of the average electricity market price by 4.3% at the cost of increasing the median by 2.1%.

Similar effect is observable in the *Extra storage* scenario whereby doubling the size of the prospective new PSHPP (additional 500 MW power and 6 GWh capacity) had relatively minor positive impacts compared to the *Base* scenario results. It did not aid in reducing the maximum hourly curtailment. The minor effects can be largely explained by the *Base* scenario already having a reasonably balanced power system. However, if we remove the new storage altogether (minus 500 MW power and 6 GWh capacity), then the negative effects are evident. Particularly pronounced in the *No new storage* scenario is the rise of electricity prices, increasing by 24.2% to 180.2 €/MWh.

The last two scenarios allow considering the impact of annual weather variations, particularly, the hydrological conditions which are important in the Baltics due to the large role of the Daugava HPP cascade. While inflow variations did not affect wind and solar energy curtailment, they did have notable impact on the peaker power plant use and demand curtailment, e.g., in the *Wet year* scenario demand had to be curtailed only during a single hour. Notable impact on the electricity price can also be observed resulting in 187.2 €/MWh with the low inflow assumption and 124.5 €/MWh considering high inflow.

B. Sensitivities

To better expose the impact of certain input data assumptions, we performed sensitivity analysis on three parameters: demand, installed wind capacity and installed solar capacity. The figures referenced in this section can be found in the Appendix at the end of the paper.

In Fig. 4, it can be seen that, most of all, demand increases the use of the peaker plants, although there is a notable increase in demand curtailment as well. If we reduce the demand assumption, there is no demand curtailment, whereas with 150% of *Base* scenario demand, the curtailment constitutes already 2.8% of the annual consumption. In the latter scenario, there are 1921 hours with curtailment and a total of 5978 hours during which peaker plants are activated (supplying 12.46% of demand).

Increasing demand has a very strong impact on the electricity prices (Fig. 5). The more active usage of peaker plants and demand curtailment measures cause major price peaks with growing frequency.

Comparing the sensitivity of the results with varied wind and solar capacities (Fig. 6–9), it is evident that assumptions on wind power have a more pronounced effect. This is largely driven by its significantly higher capacity factor. Interestingly, the wind capacity could be increased to 125% of the *Base* scenario assumption without incurring notable RES curtailment meanwhile allowing to reduce peaker use from 1.5% to 1.1% of demand (Fig. 6). In the solar sensitivities, however, only the peaker utilization metric experiences evident changes, albeit they are comparatively minor (Fig. 8). Similarly, wind variations have more impact on the hourly electricity prices than solar (Fig.7 and Fig. 8).

The impact of demand, wind capacity and solar capacity variations are summarized in Table III. Evidently, increasing the wind capacity indeed does have a very pronounced impact on the average price, whereas the median is affected to a lesser degree. Particularly notable, however, are the major impacts caused by relatively small changes in assumptions on the annual demand.

The overall results also show that the electricity price dynamics in the future high-RES Baltic power system will be very volatile. While for most of the time the electricity prices can be expected to be comparatively low, still due to extreme scarcity price events occurring in low-wind conditions the average price can reach a significantly higher level.

TABLE III. MODELLED PRICE IN SENSITIVITY ANALYSIS

	Demand scenarios (change from *Base* scenario)						
	70%	***80%***	***90%***	***100%***	***110%***	***120%***	***130%***
average	62.07	74.21	87.99	145.1	242.21	365.22	593.14
median	57.25	60.44	62.29	65.02	71.10	86.07	400.00
	Wind capacity scenarios (change from *Base* scenario)						
	50%	***75%***	***100%***	***125%***	***150%***	***175%***	***200%***
average	308.13	210.17	145.12	113.05	85.36	77.15	71.70
median	81.63	72.01	65.02	61.56	57.24	52.15	48.24
	Solar capacity scenarios (change from *Base* scenario)						
	50%	***75%***	***100%***	***125%***	***150%***	***175%***	***200%***
average	184.97	182.98	145.12	130.38	127.38	124.31	122.79
median	65.75	65.48	65.02	64.80	64.45	63.90	63.71

C. Limitations

The results presented in this study are not forecasts, but instead a series of what-if assessments. Consequently, they should only be utilized in conjunction with the modelling assumptions, inputs and the limitations inherent to the methodology. Some of the most important factors are acknowledged below.

First, the current implementation of the Baltic power system model is quite simplified as it is still a work in progress. For instance, it is formulated as a linear programming task for the time being not considering the ramping, minimum loading and up-time required from thermal plants.

Another drawback is its deterministic approach whereby we have assumed a perfect 2-week foresight of inflow, wind and solar production and demand. Moreover, storage plant operators participate in the system cost minimization task, even though in a small system like the Baltic power system it could be arguably expected that their profit-maximization task might lead to different schedules. These simplifications likely lead to lower market prices, less RES and demand curtailment as well as a lesser need for peaker power plants.

Third, the demand curtailment situations modelled could alternatively be solved by more effective demand response measures priced below the market price ceiling. Such an approach would likely act as a price-depressing measure leading to less pronounced and less frequent price peaks, in contrast to the previous points.

Finally, a major drawback is that currently no seasonal storage options are included in the simulations, i.e., the modelled power plants optimize their schedule only two weeks in advance. It could be argued that seasonal storage could aid in alleviating the identified scarcity events and lead to significantly lower electricity prices, however, this remains to be addressed in future iterations of the model.

IV. CONCLUSIONS

When modelling the Baltic power system in hypothetical future scenarios, it is evident that the existing energy storage solutions will prove to be paramount in accommodating the growing share of intermittent renewable energy sources. However, the construction of new conventional energy storage plants in the region seemingly adds little additional value to reducing the need for peaker power plants and decreasing the market prices. In other words, they aid in smoothening short-term residual load and RES fluctuations, but fail to rectify the seasonal nature of both wind and solar power production. The remaining flexibility needs could rather have to be addressed by long-duration energy storage solutions.

Initial results also confirm the major role of peaking power plants (e.g., natural gas fired or similar) as price setters in a RES-dominated future Baltic power system even if volume-wise they are used sparingly.

Overall, the modelled high-RES Baltic power system in the future can be deemed to be viable from both the adequacy and affordability point of view. Nevertheless, due to the comparatively small size, interconnections have proven to be a highly valuable and impactful source of flexibility.

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APPENDIX

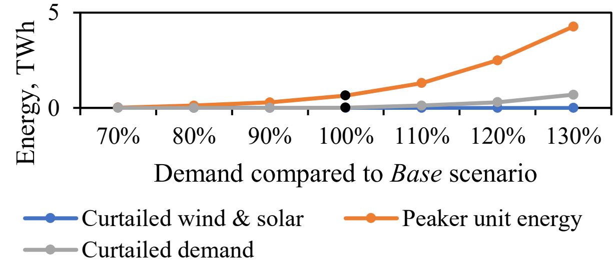

Figure 4. Results of demand sensitivity analysis

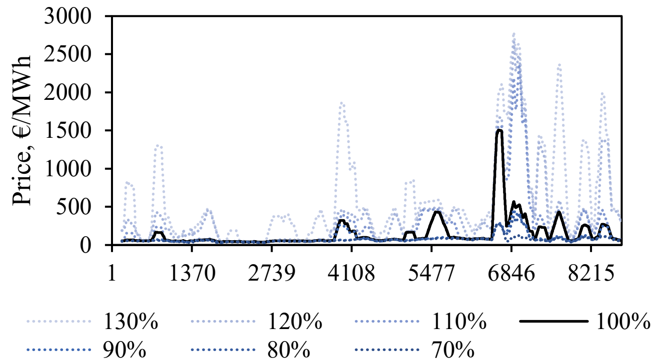

Figure 5. 168-hour moving average price in demand sensitivity analysis

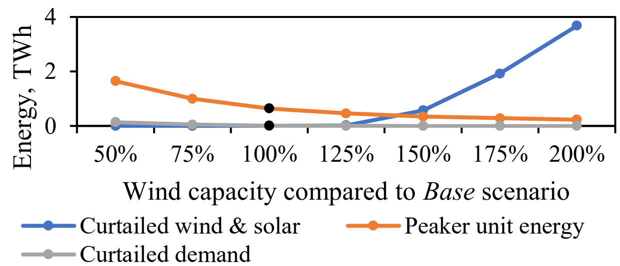

Figure 6. Results of wind capacity sensitivity analysis

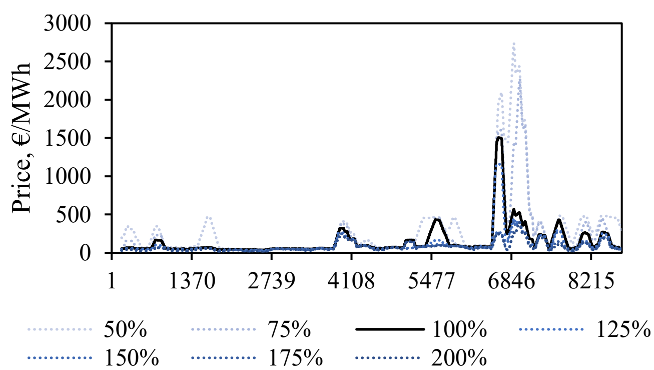

Figure 7. 168-hour moving avg. price in wind capacity sensitivity analysis

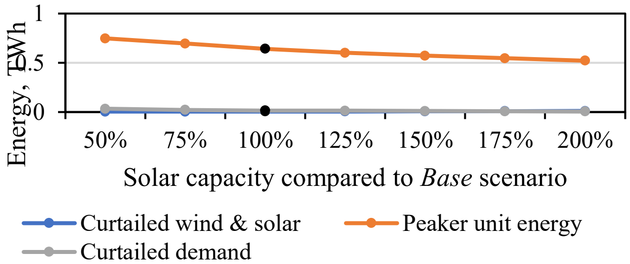

Figure 8. Results of solar capacity sensitivity analysis

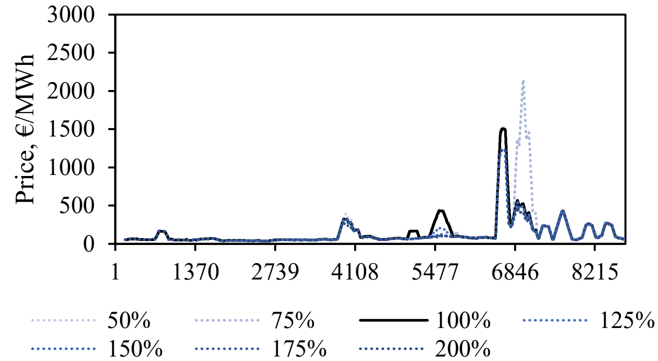

Figure 9. 168-hour moving avg. price in solar capacity sensitivity analysis

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