

Impacts of wind power forecast error in the Finnish electricity market in 2030

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Abstract—This study investigates the impacts of day-ahead wind power forecast errors on the Nordic electricity market in 2030, with a focus on Finland's bidding zone. The increasing share of variable renewable energy generation in the Nordic power system is expected to increase the errors between the forecasted and realized power generation which increases the demand for electricity balancing markets. Using a two-stage model in PLEXOS, the study simulates the day-ahead and balancing power markets of the entire Nordic and Baltic area, analyzing the volume of balancing power required and the technologies providing it. The results show that the largest balancing power will be provided with hydropower and cross-border interconnections, while nuclear, combined heat and power, and demand-side response will play supplementary roles.

Index terms—Balancing power market, Energy system modeling, System flexibility

I. INTRODUCTION

The transmission system operators (TSOs) of Finland and Sweden in the Nordics are anticipating considerable growth in balancing power market (BPM) volumes in the coming years [1], [2]. This development is caused by the increased share of variable renewable energy (VRE) power in the electricity market causing more significant discrepancies between the forecasted day-ahead (DA) and realized electricity generation due to the stochasticity of VRE power generation [1]. The Finnish TSO Fingrid forecasts that by 2030 in Finland, wind power will account for 46 % and PV power 8 % of total electricity production [3]. Therefore, stochastic power generation is expected to grow considerably from 2024 shares where wind accounted for 25.1 % and PV for 1.5 % based on the ENTSO-E data [4].

The Nordic electricity market is a competitive electricity market consisting of three main markets, day-ahead market (DAM) intraday market (IDM), and BPM which aim to ensure the competitive electricity price and balance between the electricity supply and demand [5]. The DAM is an electricity marketplace where electricity spot prices for the hours of the next day are determined [5]. For each period, electricity producers bid on the market with the available electricity at their corresponding short-run marginal price, constructing demand and supply curves for each hour. The curves are

defined based on the merit order, leading to curves where the lower marginal cost generators are more competitive [5].

The VRE power producers bid to the DAM with forecasted power generation. However, the forecasts are associated with forecast errors due to weather stochasticity. Moreover, the errors are found to increase linearly with VRE power production in the respective bidding zone [6]. Therefore, the growing VRE power production causes higher forecast errors which must be managed in the IDM or BPM.

After the announcement of DAM prices, an IDM is opened which closes one hour before the delivery hour [5]. In the Nordics, the market participants may buy balancing production in the IDM on a pay-as-bid basis [7]. The IDM is typically used to balance stochastic forecast errors and replace unavailable supply due to unexpected outages [7]. After the intraday market closure one hour before the delivery time, the local TSO is still responsible for keeping the electricity grid supply and demand stable at the delivery moment [5]. To assess this requirement, the Nordic TSOs have different reserve market products in the BPM for maintaining the grid frequency at every point in time [5].

In this study perspective, the most relevant BPM products are the manual frequency restoration reserve (mFRR) and automatic frequency restoration reserve (aFRR) which are utilized for normal stochastic imbalances [1]. The energy activation in these markets is decided based on a pay-as-cleared basis which leads to merit order bid activation that aims for a cost-effective selection of balancing resources [1]. In these markets, hydropower is a dominating technology in Nordics which can also provide balancing power from one bidding zone to another whenever interconnection capacity is available. In addition, wind power and demand response have increased their share in providing capacity to these markets [1].

Currently, the Nordic mFRR market is separate from the other European markets. However, the Nordic countries are planning to join the common European mFRR energy activation market (MARI) in 2027/2028 [1]. Similarly, the Nordic countries plan to join the European aFRR market PICASSO in 2026 where some Nordic TSOs are already connected [1], [8]. These developments are expected to enable

more efficient balancing resource allocation between countries which could reduce the balancing costs [1], [8].

This study models the 2030 Nordic electricity market BPM due to wind power forecast error. The study focuses on the bidding zone of Finland in 2030. In addition, the results of balancing power procurement from other zones to the Finnish zone are analyzed in this study. The questions this study aims to answer are:

1. How much balancing power in Finland is required in 2030 due to wind forecast error?
2. What technologies provide the balancing power and how much is transmitted from the neighboring bidding zones?

There are few studies covering exactly this topic. However, similar studies related to DAM and BPM pricing and bidding strategies in the Nordics are available. References [9], [10] explored different bidding strategies for wind producers which consider both DAM and BPM. Ref. [11] also studied the same topic but for the Nordic hydropower producers. Moreover, a study [12] analyzed the impact of wind power forecast imbalance on the BPM prices. Thus, this paper, compared to already published literature, explores the BPM in future scenarios and on a larger scale with a model containing the entire Nordic and Baltic electricity market. This allows this study to find more comprehensive trends in the Nordic BPM compared to the previous studies only analyzing specific operating strategies.

II. MATERIALS AND METHODS

The modeling uses a power system model that includes the Nordic and Baltic areas. The model is implemented with PLEXOS 11.0, a commercial energy market simulation software [13]. PLEXOS is based on optimizing the dispatch of different resources by minimizing the system costs. The modeling of this study uses the Projected Assessment of System Adequacy (PASA), medium-term (MT), and short-term (ST) schedules.

PASA is utilized in the model to create maintenance phases for the generators. The MT schedule is used to optimize MT objectives, in this study, the hydro reservoirs, which would be computationally too expensive to optimize at a smaller resolution. The MT optimization is achieved by combining the horizon intervals into blocks that are computationally less expensive to solve. The results from the MT schedule are then decomposed and passed to the ST schedule to solve.

The ST schedule is the last modeling phase where the mixed integer optimization (MIP) problem is solved in chronological order and specified interval resolution, the lowest possible being 5 minutes. This study has an hourly resolution, resulting in 8760 intervals.

The Nordic and Baltic model utilized in this study is based on the work from a study analyzing potential electricity scarcity situations in the Finnish power system in 2030 [14]. The model contains the existing bidding zones of each country as nodes that are connected to the other zones by the interconnections that are already or expected to be operational in 2030. In

addition, the model has simplified the electricity price profile representation of the neighboring bidding zones, Great Britain, the Netherlands, Germany, and Poland.

The power grid in the model is simplified, where only the transmission lines between the bidding zones are considered. The transmission networks inside the zones are not considered, hence, possible bottlenecks that may occur inside the zones are not considered. No losses are modelled in the power grid model, which is assumed to be contained in the future demand profiles.

This study uses a two-stage model for modeling separately the DAM outcome in the first stage, which is then utilized in the second stage to represent the BPM. The DAM model utilizes the forecasted and the BPM the realized wind power profiles. Moreover, the second model constructs the balancing market bids based on the available capacity, which depends on the uncommitted capacity after the DAM outcome. The bid quantity may also be negative if the generator can reduce the generation from the committed DA quantity. For the balancing market bids, the prices are defined as the short-term marginal costs retrieved from the DAM solution, making the BPM marginally priced.

However, the daily bidding strategies in the DAM and BPM are simplified from the DA commitment and multiple BPM auctions for many periods in a day, into only the DAM outcome and a simplified BPM outcome with a single bidding problem. Study [9] made a similar assumption in the model. In this study, this simplification was seen as justified because otherwise additional assumptions, complicating the model significantly, should be made regarding how many hours before the delivery time actions to balance the wind forecasting error should happen.

TABLE I. Assumed capacities of different technologies in the entire model and Finland. Values are acquired from TYNDP [15].

Technology	Nordics & Baltics	Finland
	GW	GW
Coal	0.8	0.0
Nuclear	11.4	4.4
Gas	3.5	0.0
Oil	2.0	0.0
Oil Shale	1.8	0.0
Solar	46.0	10.7
Wind Onshore	52.3	15.0
Wind Offshore	4.3	0.0
Hydro	46.7	3.2
CHP	9.6	5.3

Moreover, the IDM is not considered in this study. Instead, all the balancing power procurement is modeled in a single market model based on marginal pricing. Thus, the balancing market model models both IDM and BPM operations. This assumption was made because the IDM modeling is difficult due to the IDM procurement being on a pay-as-bid basis [7]

instead of marginal pricing. In reality, traded volumes after the DAM outcome in the IDM have accounted for more than half of the total volumes [16]. Nevertheless, the study results find the total volumes of balancing power and technologies procured for balancing.

The data utilized in the model is based primarily on the ENTSO-E Ten-Year Network Development Plan (TYNDP) data [15] for the expected demand, generation, and hydro inflows. Table I shows the assumed installed capacities of different generation technologies in the 2030 model for the entire model and the Finnish bidding zone alone.

In addition, the study makes the same assumption as in [14] for the demand side flexibility. In Finland, a 1240 MW demand side response (DSR) is available, where the price of activation is assumed to increase in steps of 0, 100, 200, 500, and 800 €/MWh when the demand response quantity increases. Moreover, Table II shows the import and export capacities of the Finnish zone to the neighboring zones in the model. The model also includes interconnections between the other bidding zones based on the TYNDP [15] data, including current and future operational lines (until 2030).

TABLE II. Assumed interconnections between the Finnish bidding zone (FI) and neighboring bidding zones SE1, SE3, and EE. Values are acquired from TYNDP [15].

Line	Export	Import
	MW	MW
FI-SE1	2000	2300
FI-SE3	1200	1200
FI-EE	1016	1016

TABLE III. 2030 total electrical load in the model for each country using 2006 meteorological data. Hourly demand profiles, where the annual values are calculated, are acquired from ENTSO-E ERAA [17]. The loads are distributed to each bidding zone based on the ERAA data, but presented here for each country for simplicity.

Country	Load
	TWh
Denmark	54.3
Estonia	6.9
Finland	114.6
Lithuania	20.8
Latvia	10.4
Norway	167.6
Sweden	161.7

The demand profiles for the model are acquired from ENTSO-E European Resource Adequacy Assessment (ERAA) datasets for each country in the model [17]. The model includes demand profiles for meteorological years between 1982-2016, which are scaled to demand conditions in 2030. The simulation draws samples from the data to allow analysis of 2030 scenarios

with different weather conditions. Table III shows the annual total electrical load for each country used in this study, utilizing the meteorological year of 2006. In 2024, the electricity demand in Finland was 82 TWh [4]. Thus, this study assumes the demand to grow by 33 TWh until 2030 in Finland. The main drivers for the demand growth are energy efficiency, electrification of different sectors such as district heating and transportation, and growing data center electricity demand [17].

To estimate the hourly production profiles of wind and PV generators, the climate data from ERAA is utilized to create multiple-year profiles from different meteorological years [17]. In addition, production, DA forecasts, and installed capacities for wind power in different bidding zones from the ENTSO-E transparency platform [4], are utilized to calculate forecast error profiles for wind power.

Eq. (1) is the calculation method with the ENTSO-E data for the forecast error relative to the installed capacity e_t^w for specific hours (t). In the eq. (1), the $P_{ENTSO-E,t}^w$, $\widehat{P_{ENTSO-E,t}^w}$, and $P_{ENTSO-E,nominal,t}^w$ are the realized wind power, forecasted wind power, and nominal wind power capacity, respectively, for each hour t from the ENTSO-E data [4].

$$e_t^w = \frac{(P_{ENTSO-E,t}^w - \widehat{P_{ENTSO-E,t}^w})}{P_{ENTSO-E,nominal,t}^w} \quad (1)$$

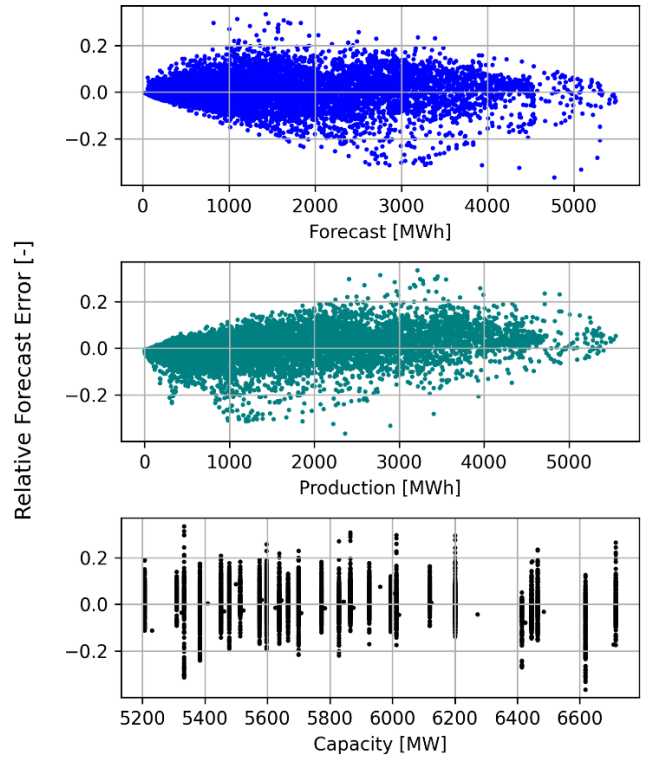


Figure 1. Scatter plot for the relative forecast error in Finland in 2023 as a function of the forecasted production, the realized production, and the installed capacity. The installed capacity data is from the Finnish TSO Fingrid open data service [18].

Hourly data of 2023 is used for the ENTSO-E parameters, which is assumed as the forecast error profile for each year in

the production data. The assumption of utilizing a historical forecast error profile is acceptable because the forecast error is only weakly correlated with the installed wind power capacity, wind production, and the forecast. This is shown in Figure 1, which indicates a weak correlation for the forecast error with these variables in a scatter plot.

However, the installed capacities are not provided in hourly granularity, but in annual granularity [4]. To overcome this lack of data, the installed capacity is assumed to grow linearly from the start-of-year capacity to the end-of-year capacity. Eq. (2) shows the calculation of the forecasted production in the PLEXOS model, where p_t^w is the capacity factor derived from ERAA data and $P_{nominal,t}^w$ is the nominal capacity of wind power from Table I.

$$\widehat{P}_t^w = (p_t^w + e_t^w)P_{nominal,t}^w \quad (2)$$

III. RESULTS AND DISCUSSION

Figure 2 shows an overall result from the BPM model in the Finnish bidding zone. The figure presents the hourly balancing power of different generating technologies. The figure shows that most of the balancing power due to wind power forecast errors is provided by the interconnections between the bidding zones and hydropower generators in Finland.

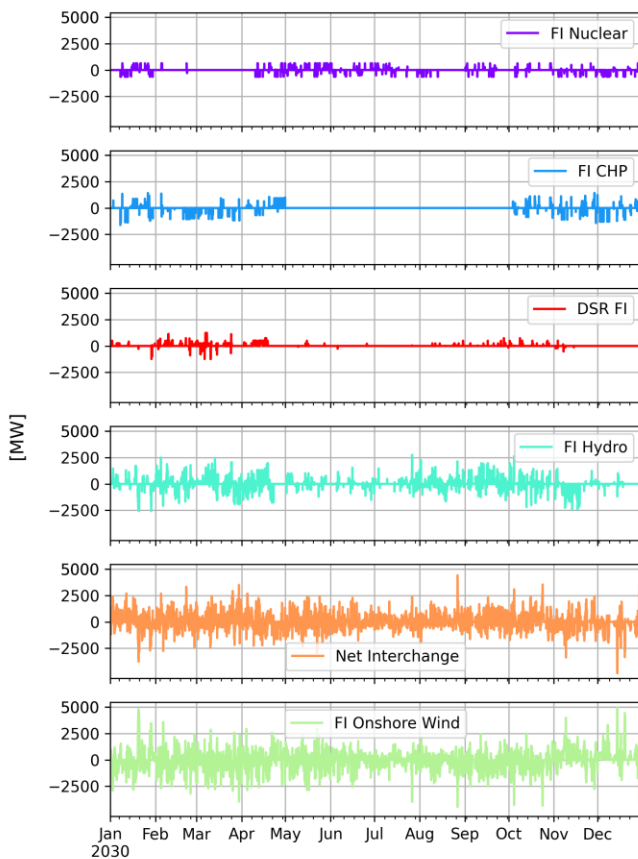


Figure 2. Hourly balancing power quantities in the Finnish bidding zone by different generation technologies.

In addition, the nuclear power assets provide some balancing power with the Olkiluoto 3 nuclear power plant (NPP), which is assumed to be capable of reducing the generation to 60 % of maximum capacity. Upward balancing is possible when the Olkiluoto 3 operates below the maximum capacity in the DA market outcome, which allows activating unused capacity in the BPM. NPPs are not typically utilized in BPM due to limited flexibility. However, Olkiluoto 3 is a modern NPP, and it has been observed from ENTSO-E generation data to provide flexibility down to 60 % of rated capacity in 2024 [4]. Moreover, the Finnish CHP assets are utilized in the balancing during the heating season when the plants are operational. Due to the low heat demand, high start-up costs, and the long time needed for cold start-up, operating the plants during summertime would not be a cost-effective solution compared to the other options.

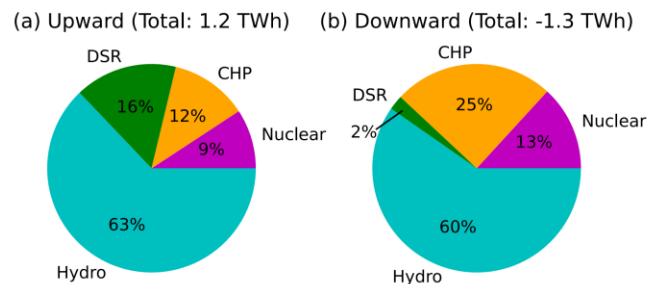


Figure 3. Domestic balancing power sources in 2030 for wind forecast and production imbalance in Finland for (a) upward and (b) downward balancing.

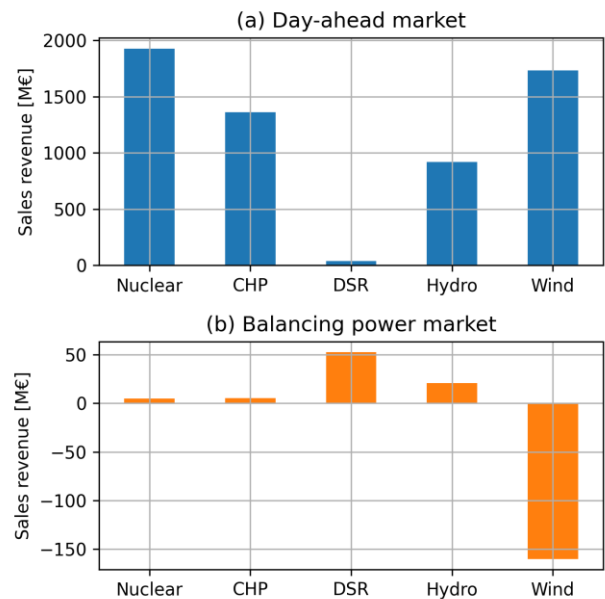


Figure 4. Annual sales revenues from (a) DAM and (b) BPM for Finnish generating assets. Note that for DAM, DSR represents the volume of activated DSR at DAM due to high prices.

Figure 3 shows the overall balancing volumes of the Finnish domestic generating assets. The figure shows that hydropower has a major role in balancing the imbalances caused by the wind

power forecasting error. Nuclear power and hydropower provide quite evenly upward and downward balancing. However, DSR is more utilized in providing upward power balancing, i.e., reducing power demand, and CHP generators are used more in downward balancing by reducing the generator power outputs.

Figure 4 shows the annual electricity sales revenues from the two modeled markets for different generating technologies in Finland. The results indicate that BPM costs reduce the overall sales revenues for the wind generators by 13.6 % compared to the DA market revenues. Revenues of nuclear, CHP, and hydro generators increase marginally. For the DSR, the DA market revenues indicate the value of avoided electricity costs due to reduced consumption. In the BPM, DSR sales revenues are bid activations creating revenue, which represent a share of 34 % from the BPM compared to the total value of actions in the BPM and DAM.

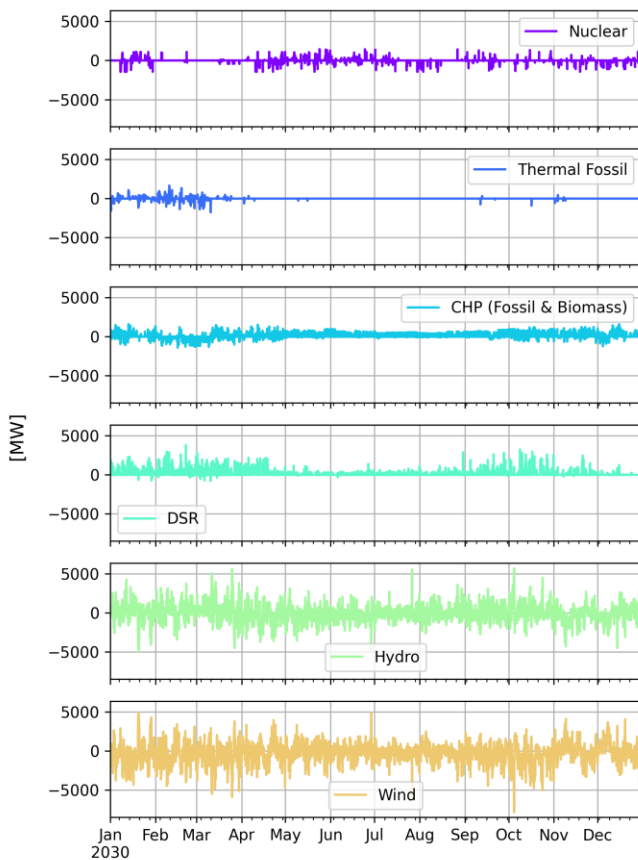


Figure 5. Hourly balancing power quantities in the whole Baltic and Nordic power systems by different generation technologies.

To expand the interconnection of the balancing power generation sources, Figure 5 shows the same power commitment difference between the DA market solution and BPM commitment, but for the entire system, including all Nordic and Baltic bidding zones. The figure shows that much of the balancing power is provided by the hydropower assets. Other technologies also provide flexibility. DSR is reducing the power demand most of the time, and the fossil thermal power generators are most of the time reducing the expensive

generation whenever possible due to the excess wind power generation. Moreover, nuclear power and CHP provide quite evenly additional power or reduce the production compared to the DA commitment. The CHP in the system-wide results contains the CHP plants in Finland and Denmark. Thus, the summer season balancing by the CHP plants is from the Danish bidding zones, as the Finnish CHP plants are not operating in the model during summer, as explained earlier.

IV. CONCLUSIONS

This study estimated the volumes and prices in the Nordic BPM in 2030, with a focus on the Finnish bidding zone. The increasing share of wind and solar power in the power system has been identified to increase the demand for balancing services in the electricity market due to the stochastic nature of wind and solar power. This study modelled the Nordic and Baltic power systems with a comprehensive electricity market model implemented with the commercial software PLEXOS. The software was utilized to develop a two-stage model representing DAM and BPM solutions solved in sequence.

The results indicate that hydropower and the interconnections between the bidding zones will play a dominant role in providing balancing power in Finland. Hydropower, with its abundance in the Nordics, can address the imbalances caused by wind power forecast errors. Moreover, interconnections with the neighboring bidding zones contribute significantly to the balancing power procurement, indicating the importance of cross-border electricity transmission providing balancing market services. In addition, nuclear power, CHP plants, and DSR in Finland provide some balancing services, though their roles are more limited compared to hydropower and interconnections.

Furthermore, the study indicates that the balancing power market reduces the overall revenues of wind power generators by 13.6 % while increasing the revenues by a slight margin for other technologies, such as nuclear, CHP, and hydropower. In addition, DSR achieves a notable share of its electricity sales revenues from the BPM. Further research should investigate the amount of DSR activated at various price levels.

However, the study has certain limitations. The exclusion of the IDM, which operates on a pay-as-bid basis, may change the balancing costs to some extent. Additionally, the assumption of a single bidding problem for the BPM simplifies the complex reality of multiple bidding auctions and real-time adjustments. Furthermore, future research should be developed to include other sources of power imbalance sourced from the solar power forecast and load forecasting errors. Including all relevant stochastic sources of imbalances could increase confidence in evaluating whether the balancing resources are adequate in the Nordic power system in 2030.

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