Author Accepted Manuscript version of the paper by Birger Mo, Arild Helseth and Stefan Rex.
in 2023 19th International Conference on the European Energy Market - EEM (2023) DOI: http://dx.doi.org/10.1109/EEM58374.2023.10161839.

Modelling uncertainty in gas and CO2 prices – consequences for electricity price

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***Abstract*—A hydro-thermal market model is applied to a description of the north-European electricity system. The paper describes how modelling uncertain gas and CO_2 prices affects uncertainty in calculated electricity prices. Gas and CO_2 price uncertainty are modelled using historic price variations. With this new uncertainty modelling, the resulting electricity price uncertainty increases significantly compared to the deterministic modelling of thermal marginal costs that is standard in these types of models. Changes in electricity price uncertainty are shown using visual and quantitative measures for some representative price areas in the modelled system. Price forecasts from hydro-thermal models are among others used for hydro investment analysis. An underestimation of the future price uncertainty leads to less investment in flexibility which is much needed in the future electricity system with large shares of new renewables.**

***Index Terms*—Hydro-thermal market models, uncertainty measures, investment, flexibility.**

I. INTRODUCTION

Hydro-thermal models have many different applications. In liberalized markets like the NordPool market, an important application is price forecasting, either operational forecasts some years ahead or price forecasts for some future stage, the last type typically used for investment analysis.

The hydro-thermal models are often formulated as large scale stochastic dynamic optimization problems. The stochastic part has in the Nordics traditionally been given by weather uncertainty modelled using historical variation in inflows, wind speed, solar radiation, and temperature. This leads to weather-related uncertainty in renewable electricity production as well as load uncertainty caused by temperature.

In this work we focus on the EMPS model [1] which is a hydro-thermal market model used extensively in the Nordic countries for price forecasting, transmission expansion planning, and analysis of security of supply. The model calculates optimal hydro operation strategies for a given system and simulates the balance between supply and demand of electricity for a detailed description of the physical system.

More than 90 % of Norway's electricity production comes from hydropower. The main hydro expansion ended in the mid-eighties, such that most of the plants are old and built for a system with different properties. Today’s system includes a much larger share of new renewables and has much stronger connections to the rest of Europe through subsea cables. The European system is also changing very fast, and the importance of flexibility and long-term storages is assumed to increase in the future. Norwegian hydropower already provides flexibility and storage capacity but can provide much more if the capacities of existing plants are increased and pumped storage possibilities are utilized.

The typical individual producer's investment decision process includes simulations of optimal operation for different investment alternatives [2]. A required input for such simulations is the price forecast for future stages, e.g., ten years ahead. The price forecasts are typically calculated using a hydro-thermal market model like the EMPS model. We have noticed that the uncertainty in terms of price variation produced by the EMPS model is smaller than the observed price variation in the market. Investments in flexibility have no value in the absence of price variation or uncertainty. An underestimation of this uncertainty therefore gives less than optimal investments in flexibility if no compensating measures are taken. There are several possible causes for the model's underestimation of uncertainty:

- Exogenous prices that are uncertain are modelled as deterministic.
- It is impossible in such a large-scale model to include all physical constraints that affect real operation.
- The model assumes a perfect market, while imperfections exist in reality.
- Forced outages of power system components are not considered.

It is not possible to include all these causes in a detailed hydro-thermal market model because of model complexity and calculation times, mainly caused by the hydro part of the model.

This work was funded by The Research Council of Norway through project no. 257588.

This paper describes the consequences for the uncertainty and variation in Norwegian electricity prices of including uncertainty modelling of European gas and CO_2 prices in a hydro-thermal market model. Reference [3] deals with a related subject but modelled European electricity prices as exogenously given stochastic prices and calculated the socioeconomic consequences of transmission investment between Norway and Europe. In this paper, we model the whole northern European electricity market in one integrated hydro-thermal model and report on consequences of this new modelling for different qualitative and quantitative measures of uncertainty and variation.

II. Modelling the System

A. Dataset

The dataset used in this project is based on a further development of a dataset described in [4] and [5]. Figure 1 shows a map of the modelled system. The darker blue countries are modelled more detailed than the lighter blue countries. The dataset includes modelling of about 1500 individual hydro reservoirs and plants, mainly in Norway and Sweden. In total, the dataset includes 156 individual gas fired power plants, mainly Germany, UK, Netherlands, and Denmark. The dataset describes a possible electricity system by 2030, but the forecasted system description has not been updated based on the last 2-3 years development of the energy market. The simulations have a time resolution of 3 hours and use the weather years 1958-2015.

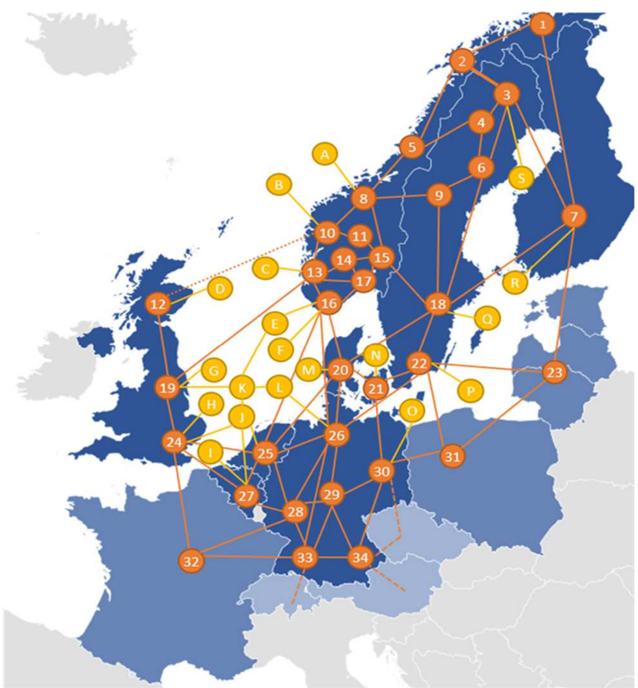

Figure 1. Map of modelled electricity system in the hydro-thermal market model

Individual thermal units are modelled by their capacity, fuel type, efficiency, and CO_2 emission coefficients. Fuel and CO_2 prices are traditionally assumed to be deterministic time-dependent input parameters. Together with the plant specific parameters these prices give the marginal production costs for each individual thermal unit. The fundamental model may be run separately for different fuel or CO_2 price assumptions but does not support integrated modelling of simultaneous uncertainty in weather and fuel prices.

B. Uncertainty modelling of gas and CO_2 prices

In this work, we include uncertainty in gas and CO_2 prices and study the effect on different measures for variation in the Norwegian electricity price. We compute the same measures with the traditional deterministic modelling of gas and CO_2 prices for comparison.

To utilize the stochastic optimization properties of the EMPS model, the uncertainty modelling of the thermal units must be adapted to the weather year description, i.e., one value per time period and weather year must be defined for the gas price and for the CO_2 price. We have chosen to represent the uncertainty in these prices using the historic price variation for the period January 1st, 2011, to December 31st, 2021. We also assume that the gas and CO_2 price variation are independent of the weather. This might not be true, e.g., because gas is used for heating, but the main point here is to show the effect of "realistic" uncertainty in these prices on Norwegian electricity price variation, not to model the best possible relations. This can be included at a later stage if shown to be important. The observations give 11 years of sequential gas and CO_2 price data. Assuming independent scenarios, the data can be reused to give prices for all the 58 weather years in the simulation. In consequence, each gas price value is used at least 5 times. Fig. 2 shows weekly average prices and percentiles for the gas price used in the simulation. The historic values are scaled proportionally to give an average gas price of 19 EUR/MWh. Fig. 3 shows the same type of values for CO_2 price which are scaled to give an average price of 30 EUR/ton.

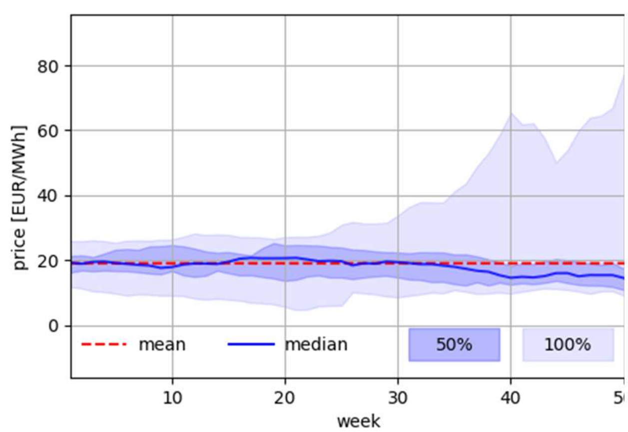

Figure 2. Average and percentiles of input gas prices.

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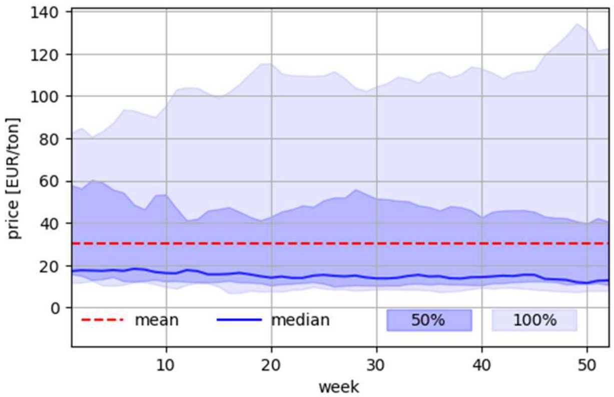

Figure 3. Average and percentiles for input CO_2 prices.

III. SIMULATION RESULTS

A. Simulation process

The purpose of this work is to test how modelling of uncertainty in gas and CO_2 prices affect the uncertainty and variations of simulated electricity prices. The dataset also includes other thermal units that are not affected by the stochastic modelling in this test. Coal-fired plants, for instance, have a deterministic CO_2 price of 30 EUR/ton also for the stochastic cases.

We simulate with the EMPS model using a deterministic description of gas and CO_2 prices and compare with simulations using a stochastic modelling of gas and CO_2 as described in the previous chapter. For the deterministic case the gas and CO_2 prices are assumed to be constant at 19 EUR/MWh and 30 EUR/ton, respectively. The stochastic case has the exact same average price for each time period of the year, but the uncertainty is described by the historical variation as shown if Fig. 2 and Fig 3.

B. Qualitative measures

We compare different qualitative and quantitative measures that represent uncertainty and variation for the two simulated cases. Fig. 4 and Fig. 5 show percentiles and average simulated electricity prices in northern Germany (area 26) in Fig. 1. This price area includes many gas-fired plants and is therefore directly affected by the uncertainty modelling. We see from the figures, if we look closely, that the distance between the percentiles is larger for the stochastic description of gas and CO_2 price. Note that the prices shown in the figures are based on weekly average prices. The price variation within the week in Germany is very high depending on the load and weather-related variation in wind and solar production. The observed short-term variation in gas and CO_2 prices are relatively small and we have therefore used weekly resolution in these figures to increase readability. Fig. 6 and Fig. 7 show the price statistics for a price area in the southeast of Norway. We see that although Norway is 100 % based on renewable production, the uncertainty modeling of thermal production costs has increased the distance between the percentiles for the Norwegian price area.

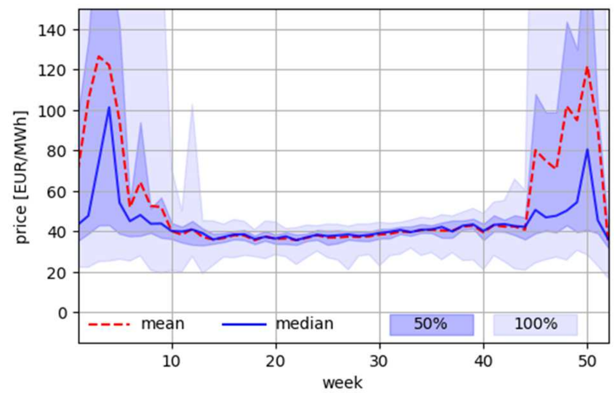

Figure 4. Simulated prices (average and percentiles) for area number 26 (northern Germany, see Figure 2) for the case with deterministic description of gas and CO_2 prices.

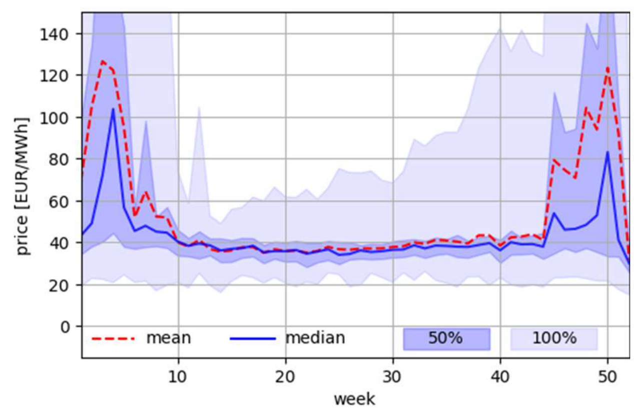

Figure 5. Simulated prices (average and percentiles) for area number 26 (northern Germany, see Figure 2) for the case with stochastic description of gas and CO_2 prices.

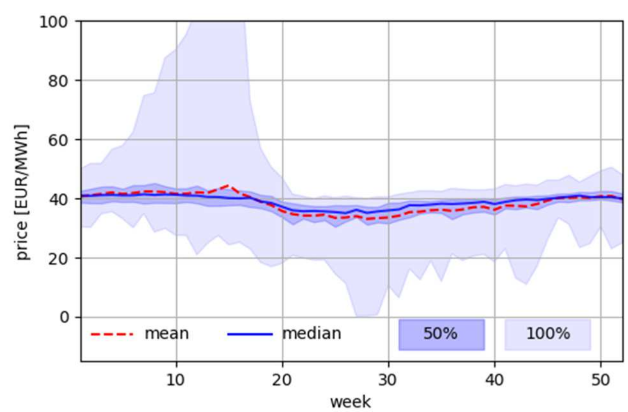

Figure 6 Simulated prices (average and percentiles) for area number 15 (central eastern Norway, see Figure 2) for the case with deterministic description of gas and CO_2 prices.

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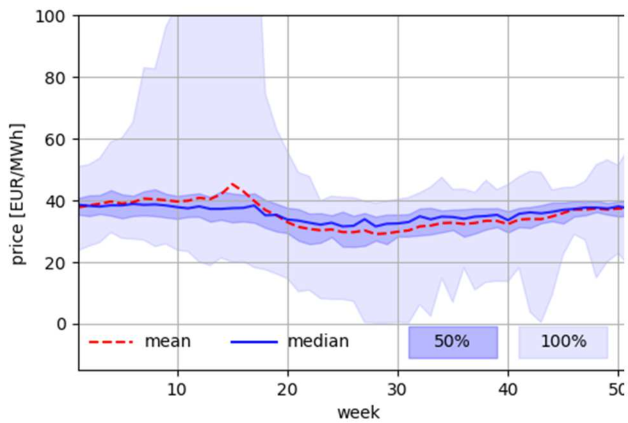

Figure 7. Simulated prices (average and percentiles) for area number 15 (central eastern Norway, see Figure 2) for the case with stochastic description of gas and CO_2 prices.

Fig. 8 and Fig 9 show duration curves for simulated prices in northern Germany and the south-east of Norway, respectively, with and without uncertainty modelling of gas and CO_2 prices. These curves are based on 56 time periods per week, corresponding to 3 hours time resolution, for 52 weeks per year and 58 weather years. In total, this amounts to 168 896 simulated prices in each area. These results show that the uncertainty modelling increases price variation both in northern Germany and south-eastern Norway. With deterministic gas and CO_2 prices, the duration curve exhibits an extended plateau at roughly 40 EUR/MWh, signaling little variation in the predicted electricity prices. In contrast, this plateau almost vanishes with stochastic input prices. The consequences in the other price areas in the south of Norway are similar to area 15, cf. Fig. 9.

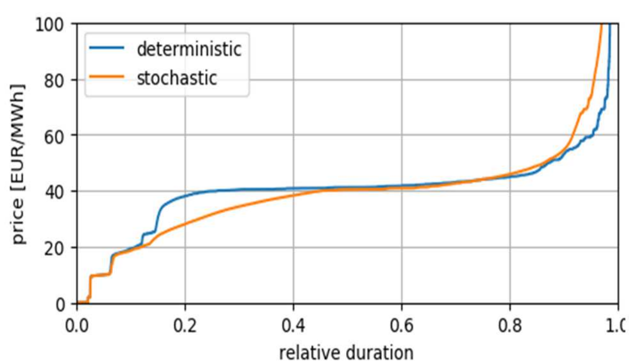

Figure 8. Duration curve of simulated prices in northern Germany, price area 26 in Fig 1.

C. *Quantitative measures*

While Figures 4-9 show visually how the variation in simulated electricity prices changes with stochastic modelling of gas and CO_2 prices, we now consider specific metrics based on differenced electricity price series.

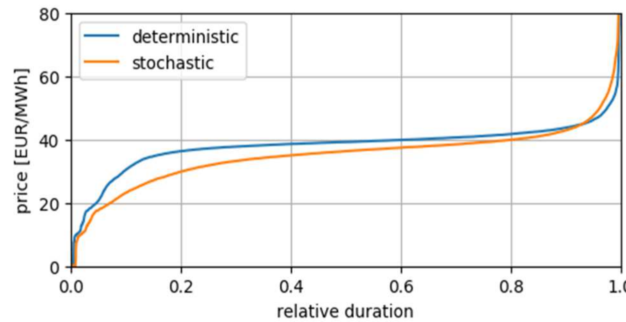

Figure 9. Duration of simulated prices in southeast of Norway, price area 15 in Fig. 1.

From the simulated results, we have a sequence of simulated electricity prices corresponding to the input weather years. This a time series of 168896 values. The differenced price series is given by (1):

$$\Delta R(t) = P_R(t) - P_R(t-1) \qquad (1)$$

where

P_R - Simulated electricity prices with time resolution R (EUR/MWh)

t - Time period for given time resolution

As a quantitative measure of the price variation, we have chosen the standard deviation of the differenced price series $\Delta R(t)$. An advantage of this choice is that the resolution R can easily be adjusted to provide variation measures on different time scales. While R must be at least 3 hours, corresponding to the resolution of the simulation, the result series can be aggregated by taking averages over days, weeks, etc. to set a rougher R. Specifically, we have calculated the variation of prices with 5 different time resolutions: three-hourly, daily, weekly, four-weekly, and yearly.

Tables I and II show these measures for the input gas and CO_2 prices used in the stochastic case. We see that longer-term uncertainties are much larger than the short-term uncertainties. The observed gas and CO_2 prices that are available to us have daily time resolution, hence there is no measure for the 3 hours resolution.

Tables III and IV show the calculated measures based on simulated prices in the south-east of Norway (area 15). Table III shows the absolute values (EUR/MWh) and Table IV shows the values in percent of the average simulated prices. The stochastic modelling has increased the standard deviation to differenced price series significantly, especially for the longer time resolutions. The variation calculated with time resolution 4 weeks is almost doubled for the stochastic case. The average price level decreases with the stochastic modelling. We have chosen not to compare the uncertainty measures with observed price variation, e.g., for the period 2012-2022, because the dataset we have used describes a different system referred to 2030.

These variation measures provide information about the value of different types of storage flexibility. The seasonal type of hydro storages can benefit from short-term to seasonal price variations, whereas yearly storages can benefit from any price variation, including the long-term price variation between years.

TABLE I. AVERAGE PRICES AND STANDARD DEVIATION OF DIFFERENCED PRICE SERIES FOR GAS AND CO2

	Average	**3h**	**24h**	**168h**	**4 weeks**	**1 year**
Gas	19	-	1.2	2.7	5.4	9.9
CO_2	35.4	-	2.1	5.0	10.1	33.2

TABLE II. STANDARD DEVIATION OF DIFFERENCED PRICE SERIES RELATIVE TO AVERAGE PRICES (%) FOR GAS FOR DETERMINISTIC AND STOCHASTIC CASE

	3h	**24h**	**168h**	**4 weeks**	**1 year**
Gas	-	6.5	14.5	28.6	52.3
CO_2	-	7.0	16.6	33.7	110.6

TABLE III. AVERAGE PRICES AND STANDARD DEVIATION TO DIFFERENCED PRICE SERIES (EUR/MWH) FOR AREA 15 (CENTRAL EASTERN NORWAY) FOR DETERMINISTIC AND STOCHASTIC CASE

	Average	**3h**	**24h**	**168h**	**4 weeks**	**1 year**
Det.	38.2	3.6	3.9	4.9	6.8	5.0
Stoch.	35.4	4.1	4.5	7.1	12.2	7.5

TABLE IV. STANDARD DEVIATION OF DIFFERENCED PRICE SERIES RELATIVE TO AVERAGE PRICES (%) FOR AREA 15 (CENTRAL EASTERN NORWAY) FOR DETERMINISTIC AND STOCHASTIC CASE

	3h	**24h**	**168h**	**4 weeks**	**1 year**
Det.	9.4	10.2	12.9	17.8	13.2
Stoch.	11.6	12.8	20.0	34.5	21.9

IV. CONCLUSIONS AND FUTURE WORK

The purpose of this work was to evaluate how modelling of realistic uncertainty in thermal production costs increases the uncertainty of simulated electricity prices in a hydro-thermal market model. This uncertainty is especially important if the simulated prices are used to quantify either the value of flexibility or the price-related risk. We have shown that uncertainty modelling of gas and CO_2 prices increases the uncertainty of the simulated electricity prices significantly. The analysis could be improved in several ways:

Thermal units based on coal should also be included in the stochastic modelling. Future coal prices are also uncertain and coal-based units emit CO_2. If there is a positive correlation between coal and gas prices, the electricity price uncertainty would increase more with this modelling.

Possible correlations between fuel prices and weather should be identified and included in a method to generate cohesive scenarios for all uncertain input.

The EMPS model uses a somewhat simplified method to handle the interaction between different geographical areas when the hydro operation strategy is calculated. Reference [6] describes a model that calculates optimal hydro operation strategies for a detailed description using formal optimization. The next step is to study how representation of stochastic gas and CO_2 prices in that model will affect calculated prices and variation.

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