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Modeling the power market impacts of different scenarios for the long term development of the heat sector

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Abstract

Increased domestic and international electric transmission capacity, increased production of variable renewable energy (VRE), and structural changes in electricity demand imply changes in the Norwegian energy system. An increasing power export surplus as a consequence of increasing VRE investments are expected to cause lower average electricity prices, higher power price variations, and more use of electricity in thermal systems. In this study we analyse the effects of changes in the level of flexibility offered by the Norwegian heat sector under different meteorological conditions. The analysis is carried out using the Balmorel partial equilibrium model, extended to simulate the Norwegian heat and power market in great detail. Results show that in years with high power supply and low consumption, the value of VRE is greatly dependent on the load shedding capabilities in the heat market. Likewise, in a year with low power supply and high consumption, large impacts on VRE values are seen when removing the possibility of reducing electricity consumption in the heat sector. For the long term development of the Nordic energy system, ensuring high levels of flexibility in the heat sector are important in order to efficiently adapt more VRE, and hence fulfil renewable energy targets.

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Keywords: Power system flexibility; Variable renewable generation; District heating; Nordic power market ;

1. Introduction

The Norwegian energy system is currently undergoing major changes, caused by increased political and physical integration with the European market. The National Renewable Energy Action Plan for Norway under Directive

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2009/28/EC stated in 2012 that the Norwegian target is a renewable percentage of 67.5 in 2020. To meet this target, a common Norwegian-Swedish market for electricity certificates was established in January 2012, to ensure 26.4 TWh new electricity production based on renewable energy (RE) in 2020. The Norwegian Parliament has also adopted a resolution asking the Government to introduce a ban on heating based on fossil fuels in households and for base loads in other buildings by 2020 [1].

Thermal heating systems may provide both short- and long term flexibility to the energy system. Expected lower electricity prices combined with ambitions to reduce the use of fossil fuels imply that more electricity is likely to be used for heating in Norway. Expectations of more variability in power prices rise as a consequence of more variable renewable energy (VRE) and more transmission lines to the continent. This implies new opportunities for producers of thermal energy to periodically increase their electricity consumption and hence provide increased short run flexibility to the systems. The majority of district heating systems in Norway has been developed over the last decade and provides currently about 3% of the domestic stationary energy consumption [2]. Limited availability of hydronic heat distribution, relatively low electricity prices, and low building density are among the explanations for the low share of district heating in Norway compared to the most Europe countries. Trømborg et al [3] estimated that the production of heat based on biomass in central heating and expansion of existing district heating plants was likely to increase by approximately 3 TWh from the 2010 level towards 2020, under a likely development in the biomass and energy markets. In addition, about 4 TWh of oil is currently used in central heating systems in Norway. In total, central and district heating systems based on renewable energy may potentially expand by 6-8 TWh towards 2020. The objective of this study is to analyze how the electricity use in the heating sector affects the power market. More specifically we model power price levels, power price variations, and VRE revenues in a base case with the current power and heat system and compare those findings with two alternative scenarios where we assume i) removal of electricity boilers in district heating installations and ii) large scale substitution of current oil fired boilers for electricity boilers in central heating systems.

2. Methodology

2.1. Balmorel energy system model

The electricity market impacts of the different heat market scenarios are analyzed applying a combined power and heat market model with a detailed time and spatial resolution, calibrated for the electricity system in 2012. This model is based on the Balmorel model structure which is a convex and linear partial equilibrium model simulating generation, transmission, and consumption of electricity under the assumption of competitive markets (see e.g. [4]). Our model version covers the Nordic countries, Germany, the Netherlands, and the UK and is calibrated with updated 2012 power system data for all model countries and provides a specifically detailed representation of the Nordic countries. Norway is represented with 15 regions, while the other Nordic countries are subdivided according to Nordpool price areas; Germany, Netherlands and the UK are each modeled as one region. Within each region, individual power plants are aggregated into groups based on main fuel, technology, and conversion efficiency. For example, coal fired condensing power plants in Germany are aggregated in to four different groups where each group acts as one power plant. Storage capacities for reservoir hydro are also aggregated on region level. Furthermore, bottlenecks in transmission between regions are modeled by entering capacities for the central grid.

The model, which is deterministic in a one year time frame (weekly in short term mode), calculates the electricity and production per technology, time unit, and region, minimizing total system costs for a given electricity demand, under certain capacity constraints regarding production and transmission. The associated dual variables, or shadow prices, show the marginal production costs, which reflect the electricity price when assuming competitive markets. For each scenario, market clearing conditions are analyzed by applying two different modes of the model: i) a long-term (one year) optimization horizon, including all 52 weeks divided into 34 time segments per week, and ii) a short-term (weekly) optimization horizon with an hourly time resolution. In this study the long term mode is run to allocate the hydro power generation and heat production through the year. This allocation is then used as input to the short term mode where the weekly production levels are allocated to the 168 hours.

A cost of thermal power plant ramping has been added to the original version of Balmorel. The cost is piecewise linear and the €/MW ramping cost is increasing with higher levels of ramping from one hour to the other. The code has also been modified to include pumped storage hydro power in the simulation.

2.2. Scenarios analyzed

Since CHP technology to a little extent is present in Norway, the main link between the power and the heat market is the use of electricity for heating. In hydronic heating systems this will be electric boilers and heat pumps. The level of capacity in these specific technologies defines the degree of connection between the two markets. When heat producers have the possibility to switch to alternative fuels, the connection between the power and the heat market is also flexible. In this study we analyze the following scenarios regarding the capacity of electric heat producing units:

1. *Baseline scenario*: Here, installed capacities in the heat market are set to 2012 levels for both the central- and the district heating market.
2. *No el:* In the "*No el"* scenario the electric boilers in both the district heat and central heat market are removed from the heating system. Here, the opportunity for electric boilers to shed load in low price periods is removed and hence flexibility is reduced.
3. *Conversion 50-50 hp el:* From 2020 oil fired boilers are prohibited as base load by [1]. As a consequence, many oil based heating systems will be converted to, among other alternatives, electric based systems. The two conversion scenarios make it possible to analyze the consequences of a conversion where electricity plays the leading role in replacing oil fired boilers. In the "Conversion 50-50 hp el" scenario oil fired boilers in the central heating system is replaced by heat pumps and electric boilers with each being able to serve 50 % of peak heat load. Removing the opportunity to switch from electric boilers to oil fired boilers will reduce the flexibility offered by the heating market.
4. *Conversion 100% el*: In the "conversion 100% el" scenario all oil fired boilers in central heating systems are converted into electric boilers. We expect greater impact when converting to only electric boilers because efficiency is lower and hence electricity use will be higher.

3. Model input data

3.1. Power market data

The power market dataset for the model is collected by the authors from different sources. It contains regionalized data on production capacities, transmission capacities, exchange to third countries, fuel prices, and consumption profiles, all based on observed levels from 2012. Most data are open source data collected from TSOs, national statistics offices, and power exchanges. The Norwegian dataset on hydro power and transmission data is provided by Statnett. Data on other power plant capacities are available from Nord Pool. The Swedish run of river hydro production profile is derived from the aggregated Norwegian run of river production time series provided by Statnett.

3.2. Heat market data

The current study includes a detailed modelling of the Norwegian heat market and includes the whole district heat sector, while the central heat sector only covers households and services. Capacity and yearly heat consumption data for district heating has been provided by Statistics Norway [5] and has been cross checked with questionnaire data from the largest district heating suppliers. This data includes 75 locations with a total capacity of 3 GW and yearly heat consumption of 4.7 TWh. Each location is modeled as a separate area. For the central heating market several sources are used, including heating oil consumption data from Statistics Norway [2], grid company data on electric boilers on flexible tariffs from NVE, and oil boiler capacity estimation done by Thema Consult [6]. The estimated total energy delivered by the central heating sector is 4.1 TWh. The heat producing units are aggregated to 17 county based areas, having a total capacity of 13 GW (1.2 GW in electric boilers and 11.8 GW for oil fired boilers). The electric boiler capacity is a conservative estimate, as only boilers on flexible tariffs are included. Electric boilers marked as “industry boilers” are also excluded.

For fuel prices in the heating market, NVE data are used [7]. Grid rent for electricity use is set to 0.33 NOK/kWh for district heating and 0.39 NOK/kWh for central heating. Effect tariffs in grid rent are not included in this study.

3.3. Hydrological conditions and temperatures

The Norwegian power market is dominated by hydro power and the precipitation levels influence the power supply and hence prices to a large degree. At the same time, a significant share of electricity in Norway is used for heating purposes and consumption is closely linked to temperatures. To capture the different market impacts under different weather conditions, we have simulated the different scenarios described above given two different weather scenarios – i.e. inflow and temperatures according to observed values in i) 2010 and ii) 2012.

Table 1 shows the different parameters used in our simulation of the two weather scenarios. 2010 is a cold and dry year, while 2012 is a normal year in terms of temperature, but has a relatively high inflow. In 2010 the average temperature in Norway is 1.6 degrees Celsius below the 1981-2010 normal when measured in heating degree days, while 2012 is only 0.1 degrees Celsius below the same normal. For the whole Nordic region this results in a power consumption that is 7.4 TWh higher in 2010 than 2012, or 27.5 TWh for the whole system covered by the model. For the Norwegian heat market in the current study, the difference is 0.7 TWh. The inflow to Nordic reservoirs in 2010 and 2012 is respectively 174.7 and 227.2 TWh. The normal inflow is approximately 208 TWh. As inflow in our model is defined as the amount of water that is used in one year, we use production numbers instead of inflow numbers which gives a difference between the two years of 41.4 TWh. This results in a total change in market balance from these parameters of 69.6 TWh.

Table 1. Differences in scenario parameters for 2010 and 2012 (TWh).

Scenario parameter	2010	2012	Difference
Total Nordic power consumption	368.9	361.5	7.4
Total power consumption for all model countries	1359.7	1332.1	27.5
Norwegian heat consumption covered in the model	9.6	8.9	0.7
Nordic hydro power production	197.0	238.4	- 41.4

4. Results and discussion

4.1. Impacts on annual average power prices

Table 2 shows the model output in terms of key power price statistics for Norway (consumption weighted average). As expected, prices are much higher in the 2010 scenarios than in the 2012 scenarios. When we compare impacts of capacity changes for the two weather scenarios we observe two important effects. First, for the “No el” scenario we see a strong decline in average price in 2012, while for 2010 there is almost no price change. Second, for the “conversion scenarios” we observe, on the other hand, a strong rise in prices in the 2010 simulation while almost no change in 2012.

The first effect can be explained by the high price level in 2010 which inactivates electric boilers, making the removing of the capacity negligible. However, with the low 2012 prices electric boilers are much used and a big drop in prices are seen when the electric boilers are removed. This confirms that electric boilers in flexible heat systems help to keep electricity prices at higher levels in the wet/mild years.

The results for the conversion scenarios show that increased use of electricity in heating systems without substitution opportunities influence the power system substantially in years with low inflow and high consumption. The large price change may indicate reduced security of supply. In wet years, like 2012, there is hardly any power market impacts of the conversion assumed.

Table 2. Summary of key power price statistics for Norway according to the model simulations. Prices are consumption weighted average.

	2012			2010			
	Baseline	No el	Conversion 50-50 hp el	Baseline	No el	Conversion 50-50 hp el	Conversion 100 % el
Average power price (€/MWh)	27.0	24.4	27.1	55.7	55.4	59.0	59.9
Standard deviation (€/MWh)	10.6	10.4	11.5	10.8	10.8	12.5	13.1
90th percentile (€/MWh)	35.0	32.7	34.7	66.3	66.2	71.5	73.4
10th percentile (€/MWh)	13.1	10.3	12.8	45.4	45.2	47.1	47.5
Hours with zero-prices	2	3	3	0	0	0	0

4.2. Impacts on the value of VRE resources

Figure 1 shows change in revenue for VRE compared to change in electricity prices when looking at selected scenarios in relation to baseline. When we remove electric boilers from the system, VRE generators experience a revenue reduction relatively larger than the average power price reduction in the same area. This effect is most pronounced for Norwegian and Swedish run of river hydro, and Danish wind power, i.e. when VRE penetration levels are high. In areas with low penetration, e.g. wind in Norway and Sweden, the effect is less clear. The conversion scenarios when using the 2010 weather data show opposite effects: With high VRE penetration the average power price increases more than the VRE revenue. Interestingly, revenues for wind power in Norway and Sweden increases more than the average price in the 2010 conversion scenario. Since both heat consumption and wind power production is high in the winter months, wind power producers will benefit greatly from the conversion to 100% electricity. This is likely because of the low penetration level of wind power in these areas.

The change in price vs. change in revenues shown in figure 1 can be explained by the value factor effect described by Hirth [8]. He showed that the higher the penetration of a VRE source, the lower the revenues will be compared to the average market price. These results, however, indicate that a flexible heating system reduce the impact of this effect.

The model study provide useful information on the power market impacts for different technological developments in the heat market, but like for all model studies, the results depends largely on the underlying data and model assumptions. Balmorel is a deterministic model type which applying only one time series for inflow, VRE and CHP power production and demand in the model optimization. Deterministic models tend to provide market equilibrium solutions that are more optimal – in terms of net socio economic surplus - than what is observed in the actual market where there are uncertainties related to weather, input prices, plant- and grid availability and power prices. Indeed, in hydro dominated power systems deterministic models will allocate hydro generation more optimal than the market actors through the year – if the model is not restricted in terms of hydro generation levels. Stochastic hydro scheduling models such as EMPS (e.g. [9]; [10]) will usually provide a more realistic allocation of the hydro reservoir resources. However, due to the computational complexity of stochastic dynamic programming models, they do not allow a very fine temporal resolution. For the present study, a deterministic model with hourly time resolution was regarded as the most appropriate modelling tool. Also, the Balmorel model has been calibrated to observed hydro generation levels historically, by imposing restriction on upper and lower reservoir levels, and overall the hydro power supply modelling is regarded as realistic in the present model version.

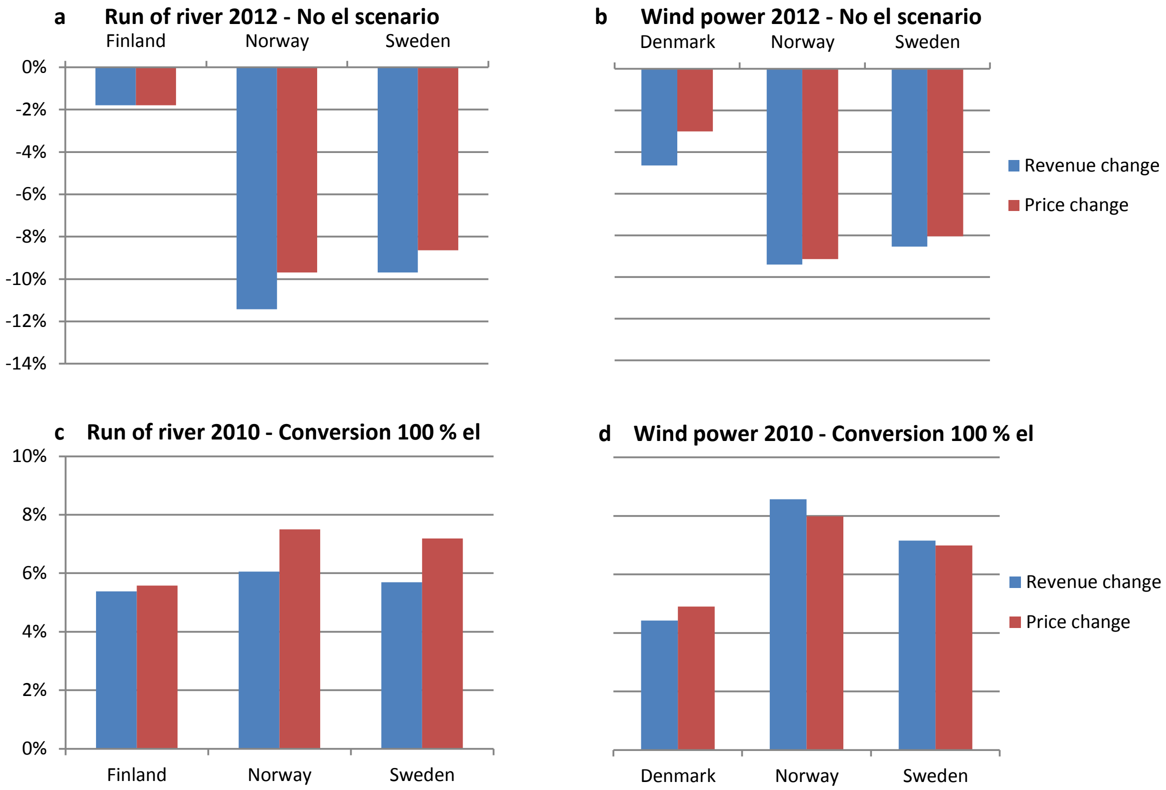

Fig. 1. (a) to (d): Revenue change and price change compared to baseline scenario for variable renewables in selected scenarios.

It should also be noted that this model study has not incorporated electric grid capacity tariffs when modelling electricity use in district heating. This implies that flexibility offered by electric boilers may be somewhat overestimated.

While the model applied in this study in many ways is dynamic, there are also some static factors. In modelling the difference between the two representative weather years, changing more parameters can be justified. For example, the price for heating oil would be higher in a cold year as the demand for heating oil will rise. Other relevant static parameters are import/export to third countries and output from CHP production.

This study assumes some rather extreme scenarios regarding changes in electricity use in the heat sector. The scenarios are chosen to show i) the overall impacts of electricity usage in the district heating sector and ii) the potential effects on the power market of a phase out of oil boilers. The future role of the heating system should be further analyzed to be fully understood. Further directions for research in this field include analysis of the impacts of increased capacity of electric boilers in district heating plants, and a more thorough quantification of the system services that may be obtained through a flexible interaction between the electricity and heat systems. Also, taking a Nordic perspective rather than a Norwegian one would be interesting, since the challenges related to power system regulation may be larger in other Nordic countries. Finally, in future studies more detail will be put in modelling the grid rent and especially the capacity tariff.

5. Conclusions

With the energy system model Balmorel, we have analyzed price effects when two types of flexibility in the heat market are removed. We conclude that the current installed capacity of electric boilers in district heating significantly increases power prices in wet years, and has little impact on prices and hence security of supply in dry years. We also conclude that if oil boilers in the central heating systems are replaced mainly by electric boilers and heat pumps, an increase in the electricity price in the drier than normal years should be expected. Installation of these technologies, without substitution opportunities cause, *ceteris paribus*, reduced security of electricity supply. It should be noted that Norway will likely have a rather firm electricity export surplus the coming two decades. By reducing flexibility in heat markets, we have shown that the revenues, and hence the value of variable renewables, are greatly dependent on that flexibility. Having in mind that large amounts of variable renewables are in the pipeline for the coming years, regulations should aim at releasing the flexibility potential in the heat market. Our results also show that meteorological conditions greatly impact the Nordic power system and also have important implications when analyzing flexibility issues.

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