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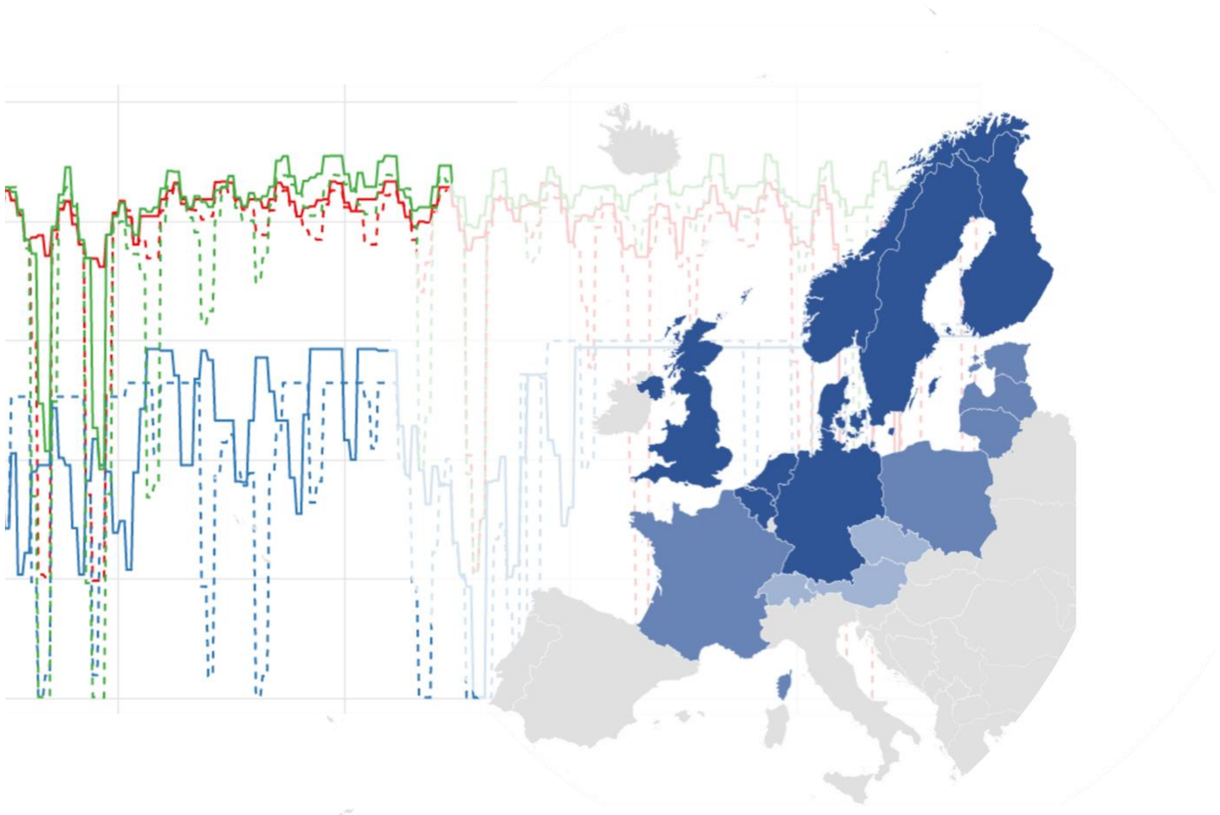
HydroCen Report nr.5

Power Price Scenarios

Results from the Reference scenario and the Low Emission scenario

Linn Emelie Schäffer
Ingeborg Graabak



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Abstract

Schäffer, L.E., Graabak, I. 2019. Power Price Scenarios. HydroCen Report 5. Norwegian Research Centre for Hydropower Technology

This report is written as a part of HydroCen WP3.1. The aim of the research described in this report is to show and quantify variation in power prices in Northern Europe in 2030. The background for this study is the need for reduction of green-house-gases (GHG) emissions and EUs policy for transforming the energy system and in particular the power system to low carbon systems. The assessment of power prices in Northern Europe in 2030 uses scenario methodology. A Reference scenario and Low emission scenario are defined for 2030. The Reference scenario is based on a renewable target of 27% in 2030 in the energy mix. The Low emission scenario aims to reflect the most recent targets and ambitions for the power system in Northern Europe in 2030. In this scenario, a larger share of the power production is based on wind and solar resources. The report compose and discusses results from the Reference and Low emission scenarios with focus on production mix and impact on power prices. The aim is to achieve an improved understanding of price characteristics and the price drivers in 2030.

The results show that the price variation increase in the Low emissions scenario as more renewables are added to the system. In Norway the maximum price difference within a 24-hour period, a week and a month approximately doubles in the Low emission scenario compared to the Reference scenario. Further quantitative measures of this increase are shown in the report. Furthermore, it is shown that the short-term price variation is much higher in Germany and Great Britain than in Norway. The income for a hydropower producer in Southern Norway is shown to hardly increase in the Low emission scenario compared to the Reference scenario as the average power price decrease. However, it is also show that hydropower producers achieve a higher value per unit of energy produced than wind and solar power plants and that the value of flexibility increases in the Low emission scenario compared to the Reference scenario.

In the Low emission scenario, there are periods with zero prices in the South of Norway. A main part of the nearly zero prices are observed during the summer but there are also occurrences in the winter. More detailed economic results are given for some hydropower plants, some of which include pumping. The realized value of hydropower plants with pumping might be underestimated.

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Content

Foreword

The main purpose of this report is to document some of the results from the scenario analysis conducted in WP 3.1 of HydroCen. The main aim of the study is to improve the understanding of the characteristics of the European and Nordic power market in 2030. The HydroCen research centre is financed by the Norwegian Research Council, the Norwegian hydropower industry, NVE and the Norwegian environment agency.

We want to thank the user partners in HydroCen WP 3 – Agder Energi, TrønderEnergi, Glitre Energi, Statkraft, Lyse, BKK, NVE, Hydro, NTE, Tafjord Kraft, E-CO, SKL, Sunnfjord Energi and NTNU - for useful discussions and comments in this work.

Trondheim February 2019, Linn Emelie Schäffer

1 Introduction

This report is written as a part of HydroCen WP3.1. The aim of the research described in this report is to show and quantify variation in power prices in Northern Europe in 2030. The work addresses some of the questions and topics discussed at the HydroCen workshops in 2017 [1] and 2018 on future market structures and prices. The content of the report is discussed with the Reference group for HydroCen WP3.

The background for this study is the need for reduction of green-house-gases (GHG) emissions and EUs policy for transforming the energy- and power system to low carbon systems. In October 2014, the European Council agreed on a new 2030 Framework for climate and energy, including EU-wide targets and policy objectives for the period between 2020 and 2030. Two of the targets for 2030 where [2]:

- 40% cut in greenhouse gas emission compared to 1990 level
- At least 27% share of renewable energy consumption

In 2018, the EU Energy ministers agreed a binding renewable energy target of 32% by 2030, up from the previous goal of 27% [3]. Variable non-dispatchable wind and solar power production is expected to constitute a large share of the power production in a future Europe with low GHG emissions [4]. In the current power system, dispatchable power plants are used to balance the net load. Increasing shares of wind and solar power production cause long periods with low power prices, and in some cases even negative prices as a result of different subsidies. Low prices in combination with tighter emission constraints will push present fossil production out of the market. New measures will become necessary to balance the variability in the power production, e.g. grids, storages or flexible demand. Pumped storage can be one of the technologies balancing variable wind and solar power production. The hydropower reservoirs in Norway represent approximately half of the total hydro storage capacity in Europe with about 85 TWh of storage [5]. Currently, Norway has little pumped-storage capacity, almost solely designed for seasonal pumping of inflow. Pervious research has shown that if pumped-storage capacity is increased in Norway, Norwegian hydropower may be able to balance significant shares of the power production from RES in neighbouring countries, drive cost down, and increase reliability [6].

Investigation of power prices in Norther Europe in 2030 uses scenario methodology. A Reference scenario is defined in discussions with the Reference group in work package three of HydroCen. The Reference scenario and the underlaying assumption are described in detail in [7]. The scenario is partly based on EUCO30 from 2016 [8]. The scenario is based on a renewable target of 27% in 2030 in the energy mix.

An alternative scenario to the Reference scenario – the Low emission scenario – aims to reflect the most recent targets and ambitions for the power system in Northern Europe in 2030. In the scenario, a larger share of the power production is based on wind and solar resources. For Germany, renewable production constitutes nearly 65 % of the annual production. This is in accordance with the most recent political ambitions in Germany [9]. Furthermore, the scenario assumes that all power production from lignite, about 12 GW, is phased out. In the Reference scenario, the coal-based capacity makes out about 14% of the power generation capacity in Germany. In the Low emission scenario, coal-based capacity is reduced to 7% of the capacity mix. In addition, the transmission capacity from Norway to Germany and Great Britain has been doubled from the Reference scenario.

In this report we discuss results from the Reference and Low emission scenarios with focus on production mix and implication on power prices. The aim is to achieve an improved understanding of price characteristics and the price drivers in 2030. A complete overview of the areas included in the model is given in Appendix 1 –

2 Power Production

The reference scenario is based on a renewable target of 27% for the energy system in 2030 in Europe. The Low emission scenario is a scenario with higher shares of variable renewable power production than the Reference scenario. The modelled area[1] has 47% renewable power production in the Reference scenario, and 23% from variable renewable power production. The Low emission scenario reflects the most recent climate targets for the power system in Northern Europe in 2030. More capacity of wind and solar power production is added in several countries, increasing the share of power production from renewables in the system to 53%. The share of power production from variable renewables in the Low emission scenario is increased to 30%. Power production from coal is reduced with about 54% in Germany and 29% for the total system in the Low emission scenario compared to the Reference scenario. The power production mix and share of renewables is given in Table 2-1 and Table 2-2. Figure 2-1 to Figure 2-8 illustrate the production mix for Germany, Great Britain and South of Norway[2] for a selected historical weather year in both scenarios.

Table 2-1 Average annual power production Reference scenario, all simulation years

Reference scenario										
Country	Thermal (including nuclear) [TWh]	Bio [TWh]	Hydro [TWh]	Solar [TWh]	Wind [TWh]	Rationing of demand [TWh]	Demand [TWh]	Sum production [TWh]	Sum renewable production [TWh]	Share RES/Dem and [%]
Norge_S	0	0	90	1	6	0	97	97	97	100
Norge_M	0	0	29	0	7	0	28	36	36	129
Norge_N	0	0	9	0	2	0	11	11	11	100
Sverige_N	51	19	58	0	23	0	115	151	100	87
Sverige_S	4	9	5	0	14	0	27	32	28	104
Finland	38	31	13	0	8	0	92	90	52	57
Danmark	6	10	0	1	27	0	43	44	38	88
Tyskland	251	59	28	75	132	0.07	576	545	294	51
Nederland	54	14	0	5	23	0	120	96	42	35
Belgia	37	7	0	6	17	0	88	67	30	34
Storbritanni	257	30	5	9	73	0	351	374	117	33
Frankrike	372	29	73	30	40	0	503	544	172	34
Polen	140	20	4	1	25	0	185	190	50	27
Baltic	11	2	4	0	4	0	30	21	10	33
TOTAL	1221	230	318	128	401	0.07	2266	2298	1077	

[1] Includes detailed modelling of demand and supply of electricity in Norway, Sweden, Denmark, Finland, the Baltic region, Germany, Poland, the Netherlands, Belgium, Great Britain and France.
[2] The areas included in South of Norway are given in Appendix 1.

Table 2-2: Average annual power production Low emission scenario, all simulation years

Low emission scenario										
Country	Thermal (including nuclear) [TWh]	Bio [TWh]	Hydro [TWh]	Solar [TWh]	Wind [TWh]	Rationing of demand [TWh]	Demand [TWh]	Sum production [TWh]	renewable production [TWh]	Share RES/Demand [%]
Norge_S	0	0	90	2	14	0.00	97	105	105	108
Norge_M	0	0	29	0	7	0.00	28	36	36	131
Norge_N	0	0	9	0	2	0.00	11	12	12	104
Sverige_N	50	19	58	1	23	0.00	115	151	101	87
Sverige_S	3	9	5	1	14	0.00	27	33	30	110
Finland	37	30	13	1	9	0.00	92	90	53	57
Danmark	5	10	0	2	39	0.00	43	56	50	117
Tyskland	166	56	28	109	177	0.36	576	537	370	64
Nederland	47	14	0	13	25	0.00	120	99	52	43
Belgia	33	7	0	9	18	0.00	88	67	34	38
Storbritannia	226	29	5	30	82	0.00	351	371	145	41
Frankrike	365	27	73	36	48	0.00	503	549	183	37
Polen	132	20	4	1	30	0.00	185	187	55	30
Baltic	10	2	4	0	5	0.00	30	21	11	37
TOTAL	1075	222	317	204	495	0.36	2267	2313	1237	

The power production from wind and solar is higher in the Low emission scenario for all the regions. For Germany, as shown in Figure 2-1 and Figure 2-2, the number of hours where wind and solar are the only (or close to the only) power producing technologies producing increases notably in the Low emission scenario compared to the Reference scenario.

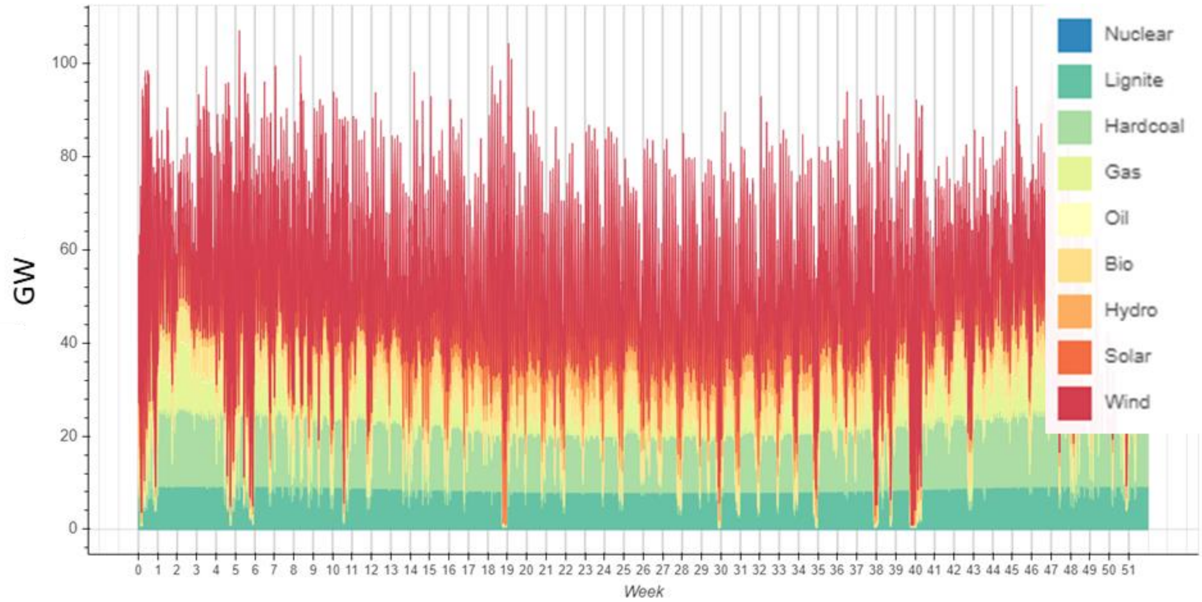

Figure 2-1: Reference scenario. Power production Germany hour-by-hour for weather year 1988.

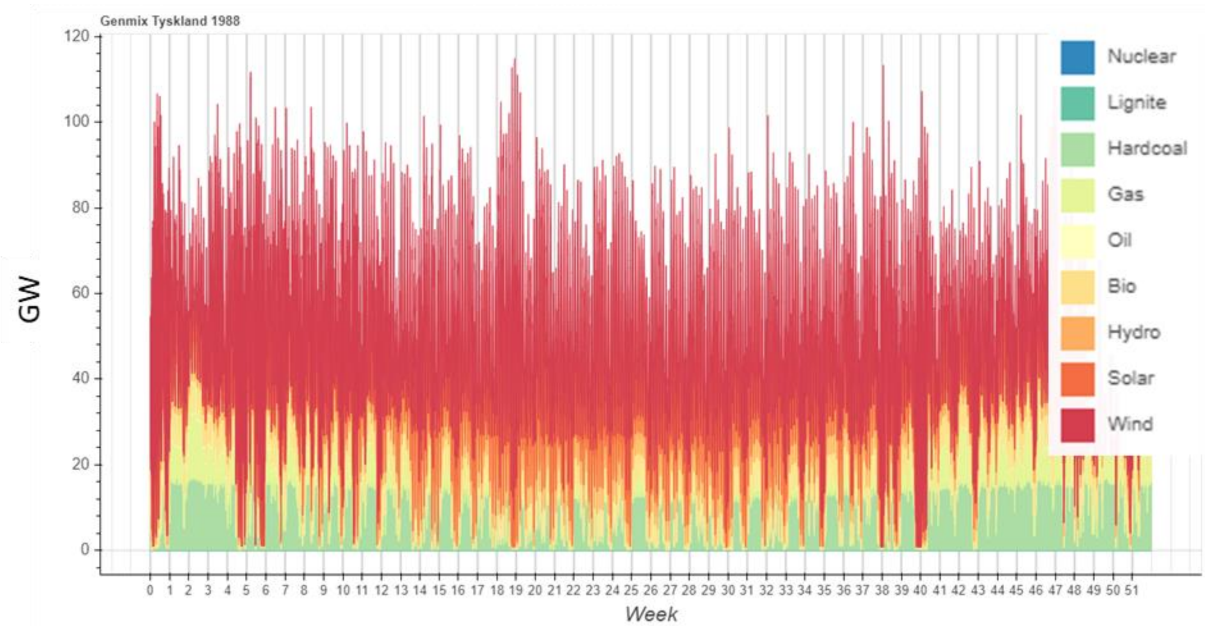

Figure 2-2: Low emission scenario. Power production Germany hour-by-hour for weather year 1988.

The same tendencies can be seen in the other European countries. In Great Britain, the increased production from variable renewables is reducing the production time of base-load units as seen when comparing Figure 2-3 and Figure 2-4. In the Low emission scenario, even nuclear units are operating more flexible (ramping down within the allowed limits of 25-30%) in some hours. In other hours, wind and solar power plants have low production and flexible units have to ramp up the production.

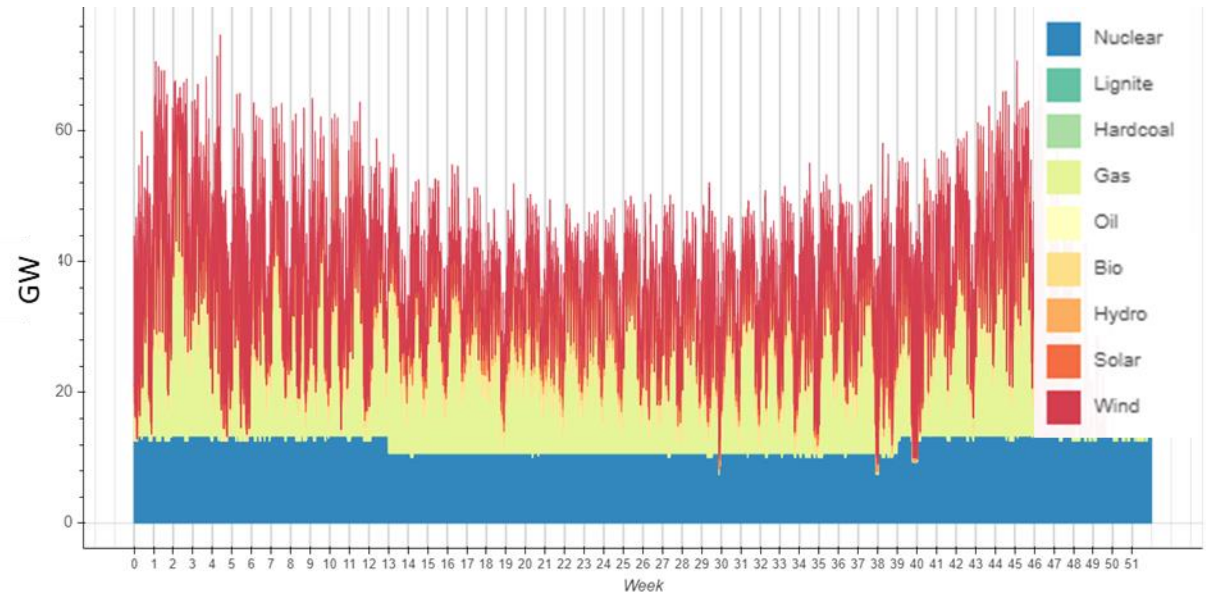

Figure 2-3: Reference scenario. Power production Great Britain hour-by-hour for weather year 1988.

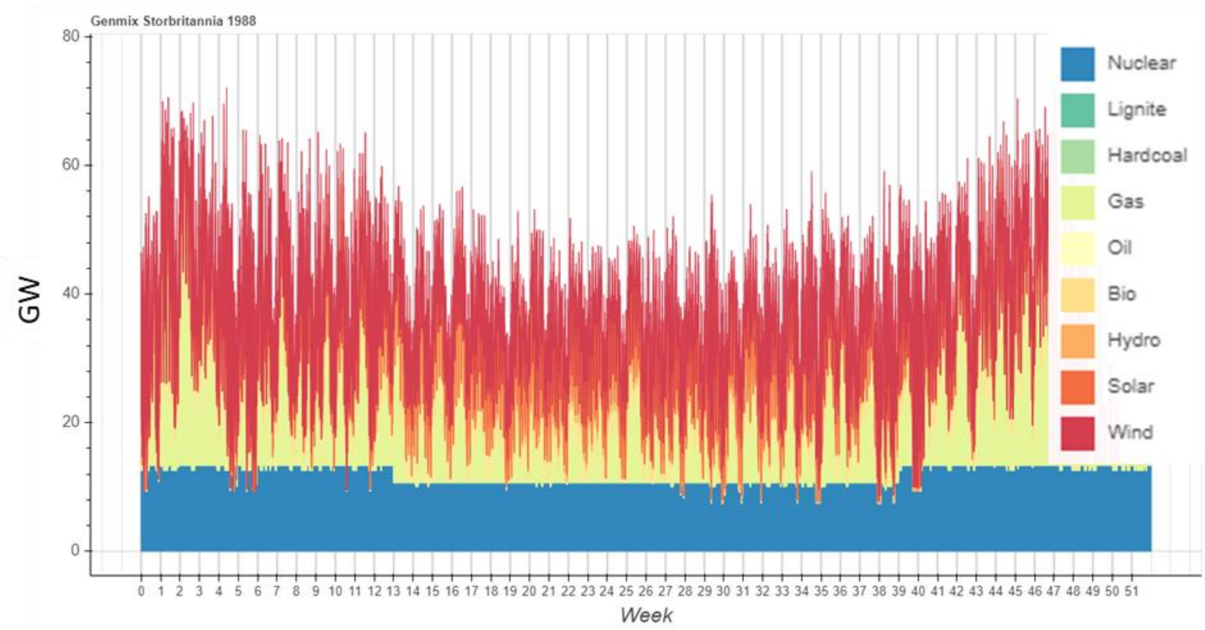

Figure 2-4: Low emission scenario. Power production Great Britain hour-by-hour for weather year 1988.

Figure 2-5 and Figure 2-6 shows the power production in Southern Norway. In both scenarios, hydropower production capacity is ramping up and down frequently to adjust for variable renewable power production and variations in demand. The pattern is similar between the scenarios, but the variation in production from wind and solar is more profound in the Low emission scenario. In some periods during winter, only a small share of the production is from hydropower and the rest is covered by wind power production and import. This is better illustrated in Figure 2-7 and Figure 2-8 where we have look closer on the first and last weeks of the year in the Low emission scenario.

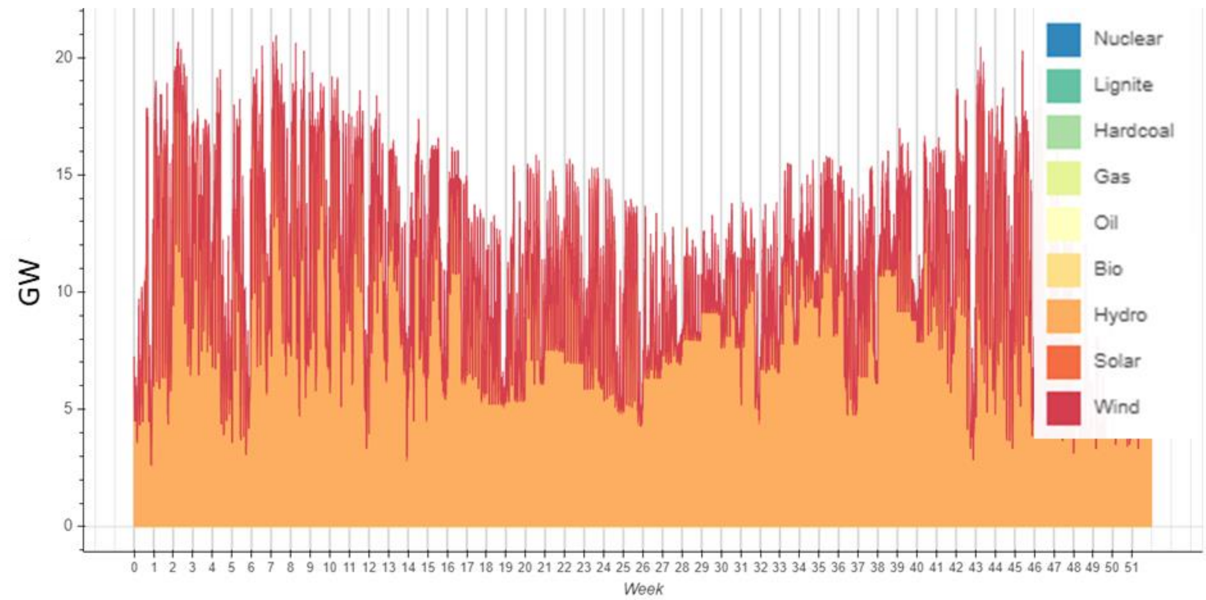

Figure 2-5: Reference scenario. Power production Southern Norway hour-by-hour for weather year 1988.

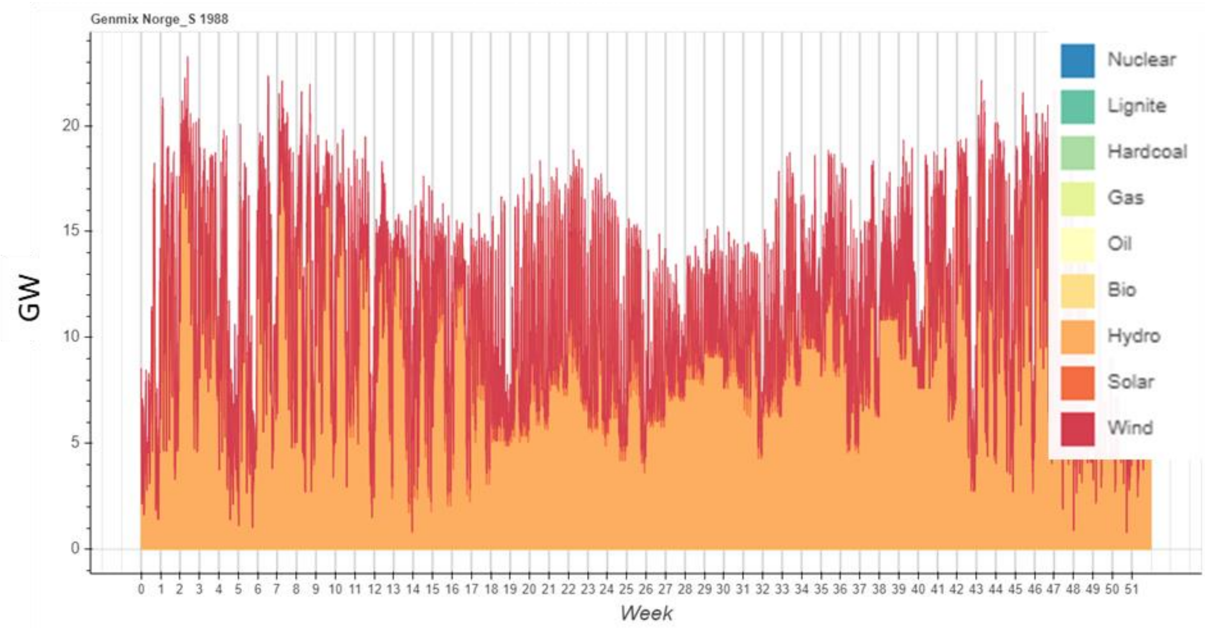

Figure 2-6: Low emission scenario. Power production Southern Norway hour-by-hour for weather year 1988.The whole year.

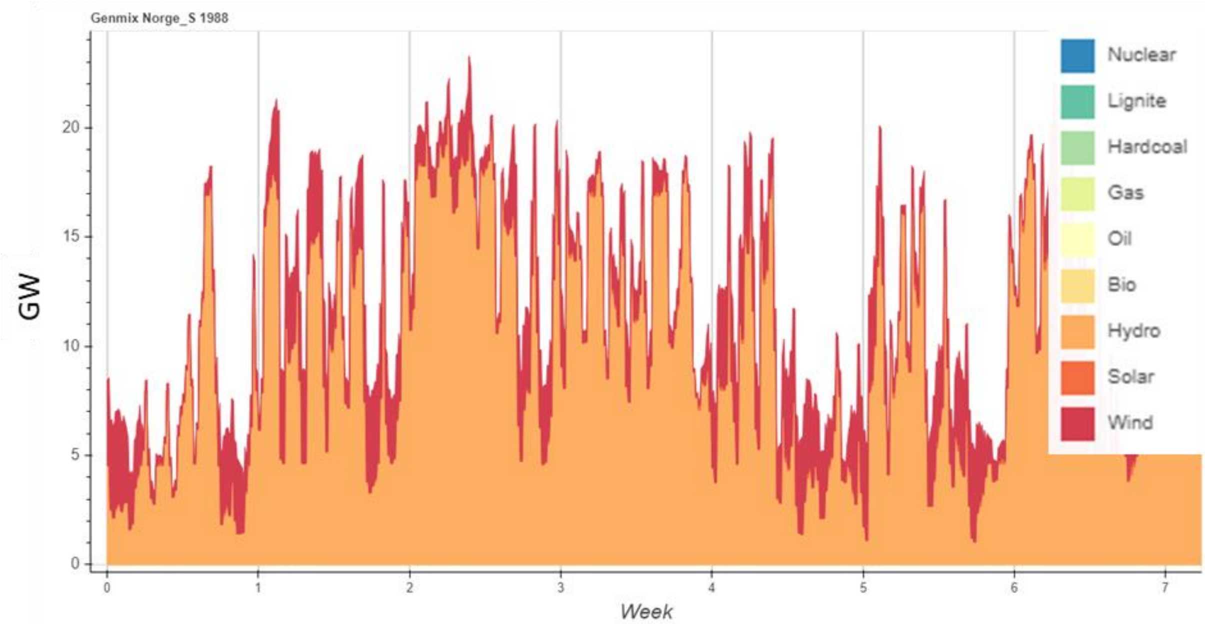

Figure 2-7: Low emission scenario. Power production Southern Norway hour-by-hour for weather year 1988. The first weeks of the year.

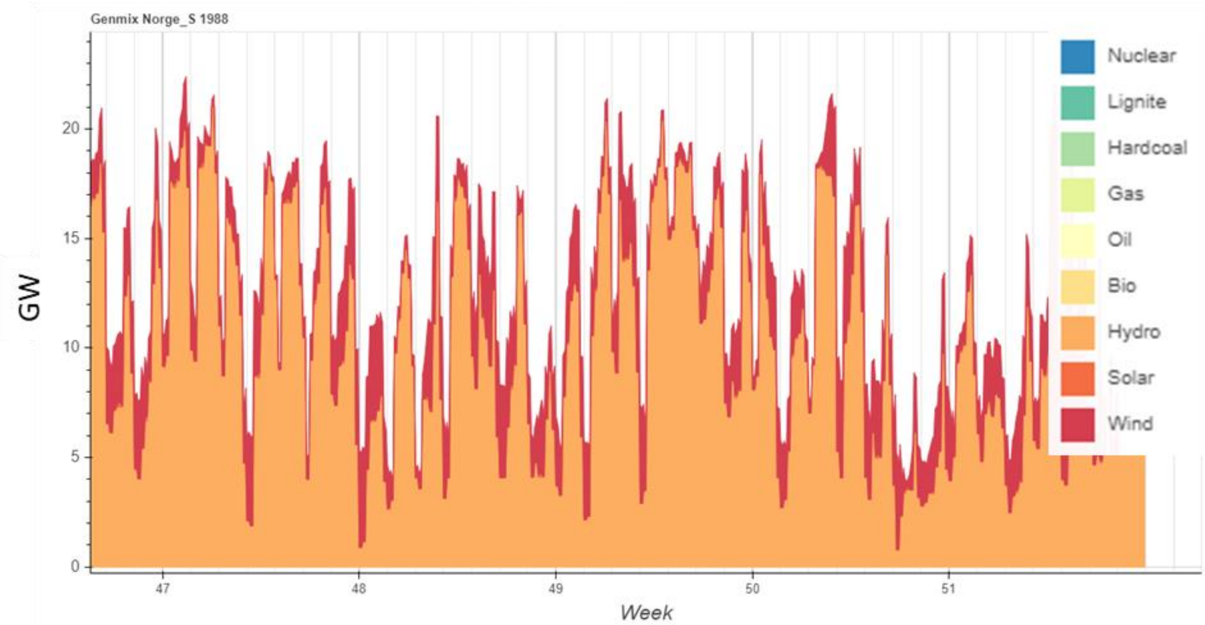

Figure 2-8: Low emission scenario. Power production Southern Norway hour-by-hour for weather year 1988.The last weeks of the year.

3 Power Prices

The different capacity mix and production patterns in the two scenarios have a considerable influence on the power prices. The increase of variable renewables in the Low emission scenario makes the system more unpredictable and give larger price variations, which influence the average power price. Table 3-1 shows the average price over the 58 simulated years in the two scenarios for a selection of areas. Figure 3-1 shows the weekly average power price over a year in different parts of Norway in the two scenarios. The largest price difference is observed during the summer period, where the power price in the Low emission scenario is lower than in the Reference scenario. Figure 3-2 shows the same for Germany, Great Britain and South of Norway. In summer, the power prices in all areas are lower in the Low emission scenario than in the Reference scenario. However, the largest price differences between the scenarios can be observed during the winter period, where the power price in the Low emission scenario is considerably higher than in the Reference scenario for both Germany and Great Britain.

Table 3-1: Average power price over the simulation period for selected areas in the two scenarios.

Area	Average Power Price [EUR/MWh]	
	Reference Scenario	Low Emission Scenario
OSTLAND	42.6	39.9
SORLAND	42.1	39.0
TYSK-NORD	62.2	84.1
TYSK-MIDT	62.5	87.8
GB-SOUTH	45.8	43.1
GB-MID	45.4	42.7
GB-NORTH	38.1	34.8

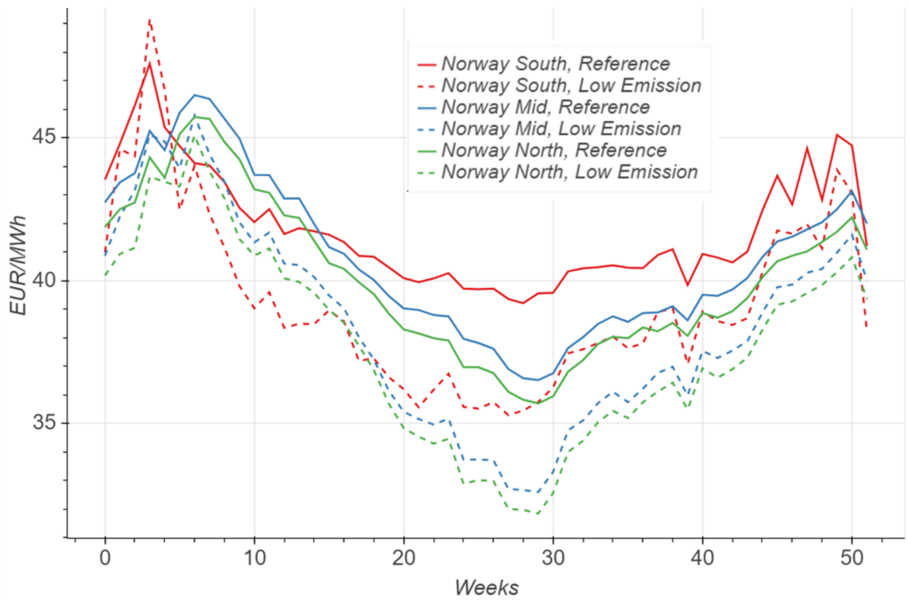

Figure 3-1: Plot of the weekly average price over a year in South of Norway (red), Middle of Norway (blue) and North of Norway (green). The Unbroken lines are the prices in the Reference scenario, while the broken lines are the Low emission scenario.

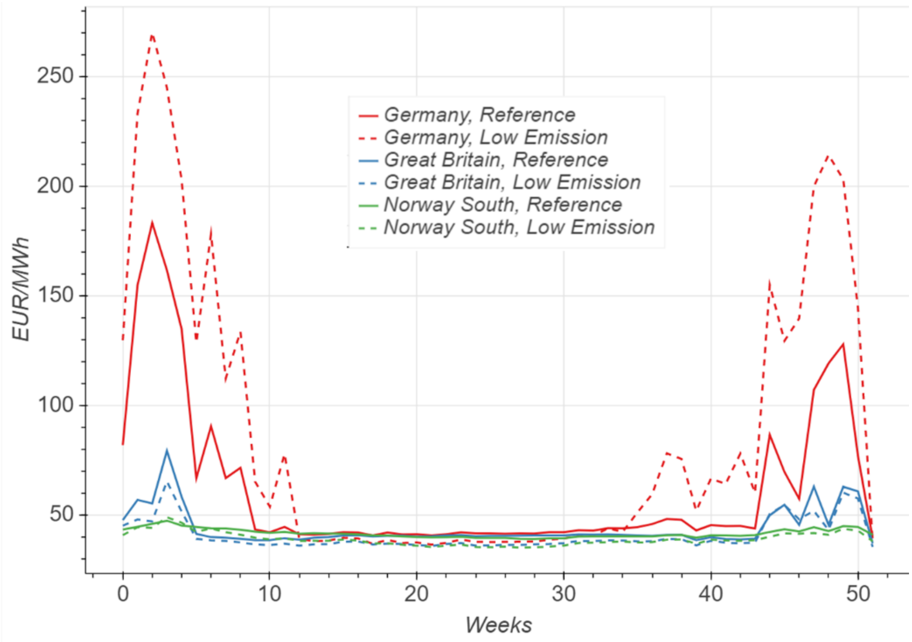

Figure 3-2: Plot of the weekly average price over a year in Germany (red), Great Britain(blue) and South of Norway (green). The Unbroken lines are the prices in the Reference scenario, while the broken lines are the Low emission scenario.

3.1 Price Level

Thermal power production remains an important part of the European power system in both scenarios. This implies that the power price is strongly impacted by the marginal costs of the thermal units, i.e. the fuel- and the CO_2-prices. We have simulated a low-fuel-price case to illustrate the influence of fuel prices on the power price. In this case, the fuel prices for coal and gas are reduced with 20% while the CO_2-price is reduced from 30 EUR/t to 10 EUR/t. Figure 3-3 illustrates the duration curve of the power price in all simulated years in North of Germany, Great Britain and South of Norway in the Reference scenario and the low-fuel-price case, called Reference_low in Figure 3-3 and Figure 3-4. The price level is about 10-15 EUR/MWh lower in the low-fuel-price case. Figure 3-4 illustrates the impact on the power price in a historical, normal inflow year in South of Norway in the Reference scenario and in the low-fuel-price case.

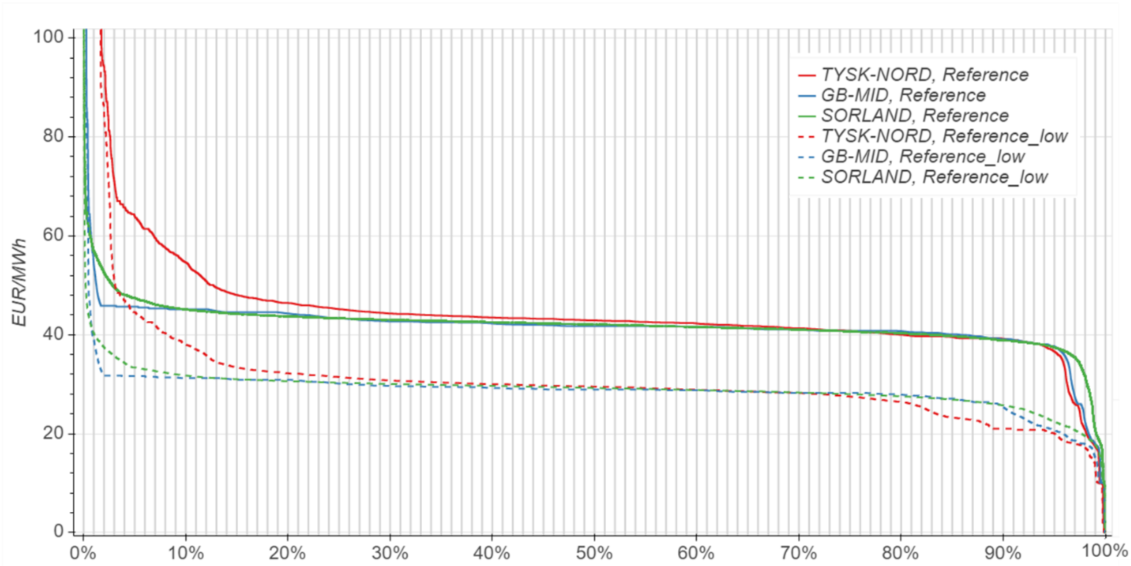

Figure 3-3: Plot of the duration curve of the power price for all simulated years in North of Germany (red), Middle of Great Britain (blue) and South of Norway (Sorland) (green). The Unbroken lines are the prices in the Reference scenario, while the broken lines are the low fuel- and CO2-price case.

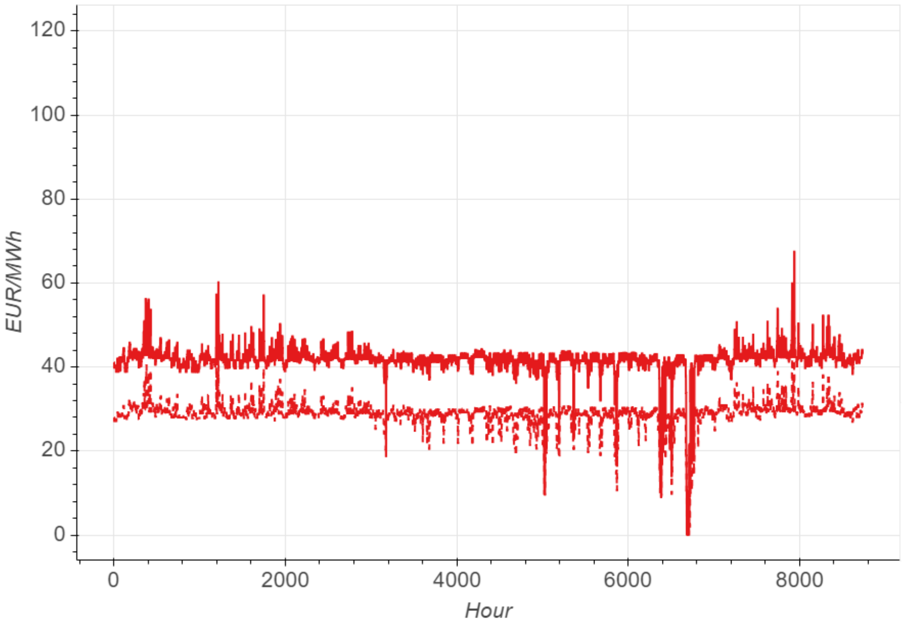

Figure 3-4: Plot of the power price in a "normal inflow" year (1988) in South of Norway (Sorland). The Unbroken line is the prices in the Reference scenario, while the broken line (the lower) is the low fuel- and CO2-price case.

Figure 3-3 and Figure 3-4 clearly illustrate how the fuel- and CO_2-prices impact the level of the power price by shifting the entire price curve up or down. In the Reference and Low emission scenarios, the fuel prices and the CO_2-price are assumed equal and constant through the year. Hence, for most hours, the power prices are at the same price level in the two scenarios. Instead, there is a larger difference in the most extreme hours. This is illustrated in Figure 3-5 where the duration curves of the power price in all simulated years are plotted for the Reference and Low emission scenarios. In about 70-80% of the hours the prices are at the same level. Still, there are large differences in the average prices, as given in Table 3-1.

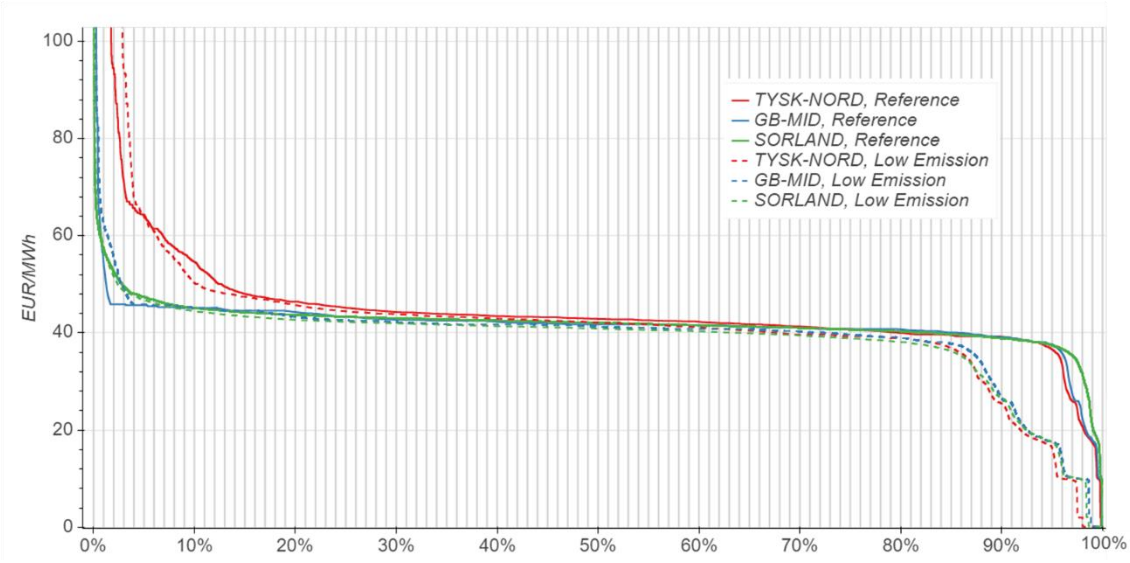

Figure 3-5: Plot of the duration curve of the power price for all simulated years in North of Germany (red), Middle of Great Britain (blue) and South of Norway (Sorland) (green). The Unbroken lines are the prices in the Reference scenario, while the broken lines are the prices in the Low emission scenario.

3.2 Price Variation

The impact on the power price of power production from variable renewables increases with the share of variable renewables in the system. The share of variable renewables that can be integrated in the system before it has a considerable impact on the power price depends on the flexibility of the other units in the system. As the penetration of unregulated, variable power production increase, other power producing technologies (with higher marginal costs) have to ramp down production to avoid a surplus of energy in the system. If the production from cheap, unregulated power is high enough, the power price falls towards zero. In the Low emission scenario this happens more often, as can be seen in Figure 3-6, and when comparing Figure 3-7 and Figure 3-8. Similarly, if there is not enough flexible power production to cover the peak demand in hours with low production of wind and solar, load shedding can become necessary and the power price will become very high. This leads to high price variations, which again impacts the average price.

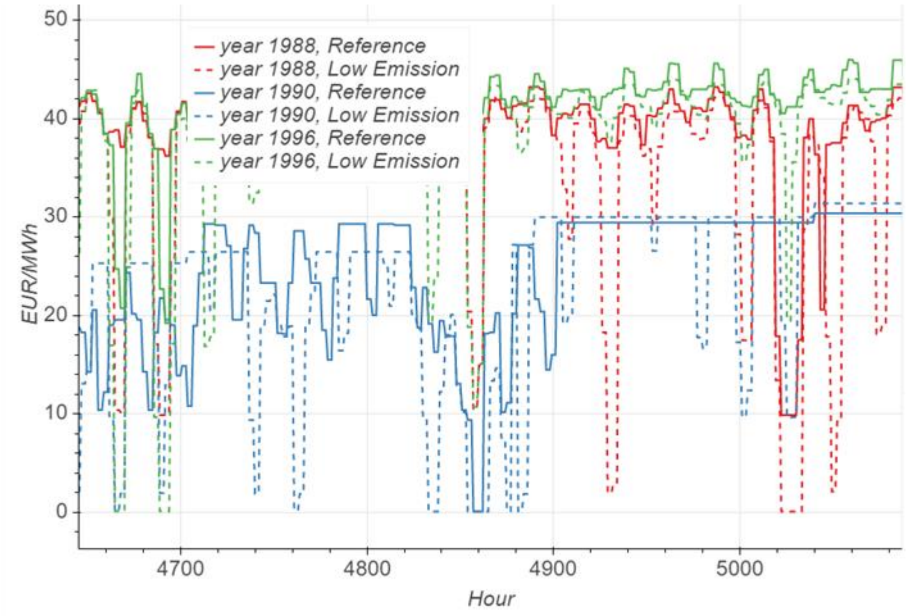

Figure 3-6: Reference scenario (unbroken lines) versus Low emission scenario (broken lines). Power prices in South of Norway (Sorland) for some hours in summer; 1988 year with normal inflow (red) – 1990 wet year (blue) – 1996 dry year (green).

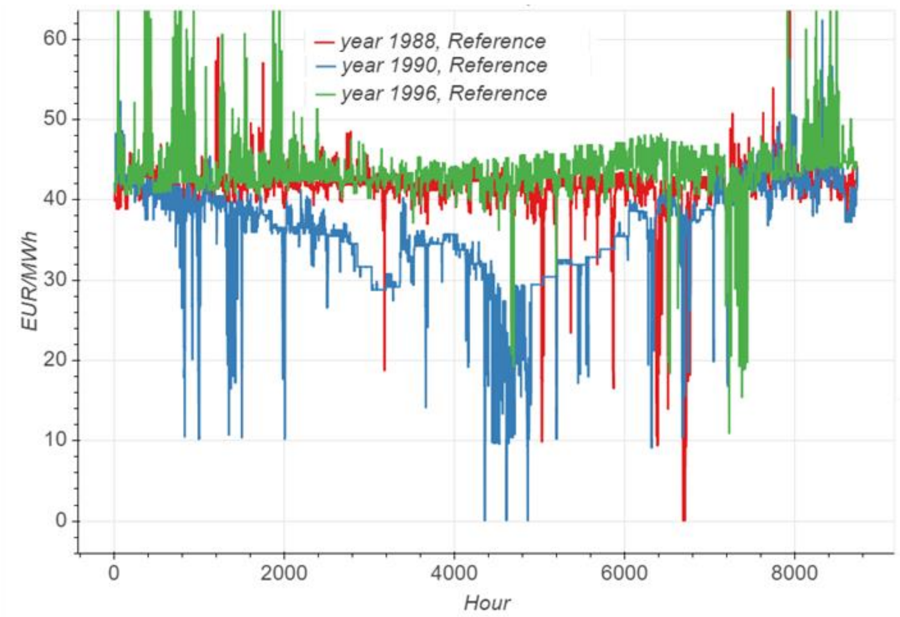

Figure 3-7: Reference scenario. Power prices in South of Norway (Sorland); 1988 year with normal inflow (red) – 1990 wet year (blue) – 1996 dry year (green).

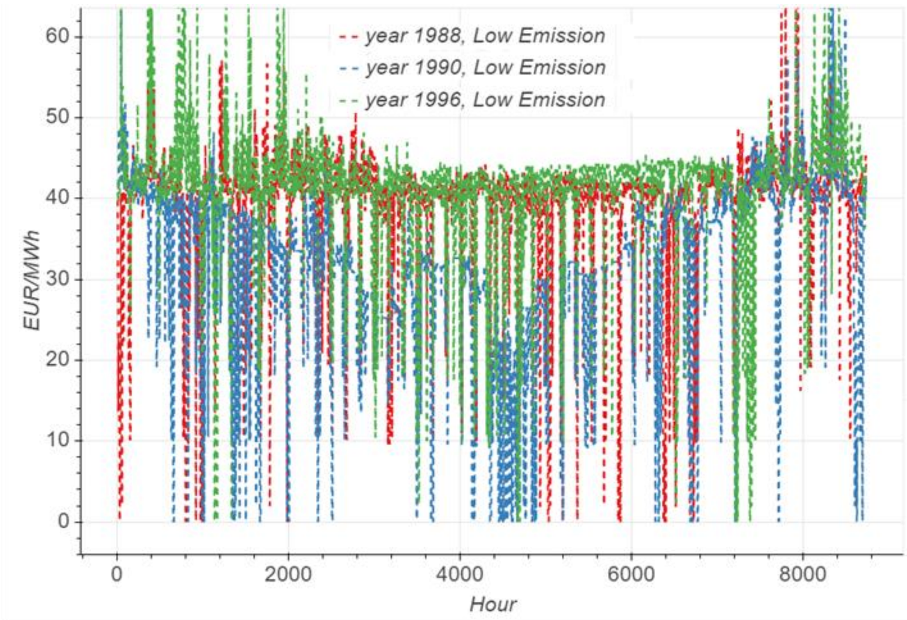

Figure 3-8: Low emission scenario. Power prices in South of Norway (Sorland); 1988 year with normal inflow (red) – 1990 wet year (blue) – 1996 dry year (green).

The maximum price difference, the difference between the maximum and minimum price within a period, can be used as a measure of the price variation in the system. We have calculated time series for the maximum price difference within consecutive time periods of different lengths; 24 hours, a week and a month, all over 58 years. A price cap, limiting the maximum price to 300 EUR/MWh, is used in the calculations. The mean and standard deviation of the series are given in Table 3-2 and Table 3-3. The lowest price differences are in Norway, while Germany has the highest price differences. In all areas, the price differences are higher in the Low emission scenario than in the Reference scenario. An exception is North in Great Britain, within a monthly time resolution the mean maximum price difference in this region is lower in the Low emission scenario than in the Reference scenario. Furthermore, the standard deviations of the maximum price difference series for Great Britain are lower in the Low emission scenario.

Table 3-2: Reference scenario and Low emission scenario, simulation for 58 weather years. Mean of the maximum price variance within 24 hours, a week and a month for different areas.

	Mean of Maximum Price Difference					
	Reference Scenario			Low Emission Scenario		
Area	Daily	Weekly	Monthly	Daily	Weekly	Monthly
OSTLAND	4.3	11.7	25.3	8.5	24.8	46.0
SORLAND	5.0	13.8	28.0	12.8	36.6	61.0
TYSK-NORD	26.0	78.5	137.8	39.9	116.6	182.6
TYSK-MIDT	26.3	79.0	138.3	42.2	119.6	183.3
GB-SOUTH	11.2	35.8	77.7	18.7	55.9	102.7
GB-MID	11.0	35.5	77.3	18.3	55.0	101.7
GB-NORTH	19.1	53.5	92.3	24.3	62.6	102.4

Table 3-3: Reference scenario and Low emission scenario, simulation for 58 weather years. Standard deviation of the maximum price variance within 24 hours, a week and a month for different areas.

	Standard Deviation of Maximum Price Difference					
	Reference Scenario			Low Emission Scenario		
Area	Daily	Weekly	Monthly	Daily	Weekly	Monthly
OSTLAND	8.4	15.8	26.0	13.8	24.1	38.3
SORLAND	8.4	16.0	25.1	15.3	25.4	41.9
TYSK-NORD	45.6	77.7	96.6	61.4	94.8	107.6
TYSK-MIDT	45.6	77.6	96.4	62.5	95.2	107.1
GB-SOUTH	28.1	57.7	90.1	27.3	51.9	82.4
GB-MID	28.1	57.7	90.2	27.3	52.1	82.7
GB-NORTH	29.9	59.8	90.0	26.9	52.3	82.5

Figure 3-9 and Figure 3-10 shows the mean and the 10- and 90-percentile, based on 58 inflow years, of the max price differences in South of Norway (Sorland) within a 24-hour period in the Reference scenario and Low emission scenario respectively. In both scenarios, the highest price differences are in the winter, but there are also periods with lower price differences in the winter and larger price differences in the summer. In each week there are some days with high price difference and some with low, as a result of variations in demand. The plots of the price difference reveal a systematic pattern with a peak in price difference within each week. This can be seen in coherence with the load profiles used in the model. The load is modelled using a weekly and a yearly profile, and this clearly impacts the pattern of the variation in power price.

Comparing the two scenarios, the price differences are higher in the Low emission scenario. Notice the increase of number days with a price difference over 20 EUR/MWh in the summer period in the Low emission scenario.

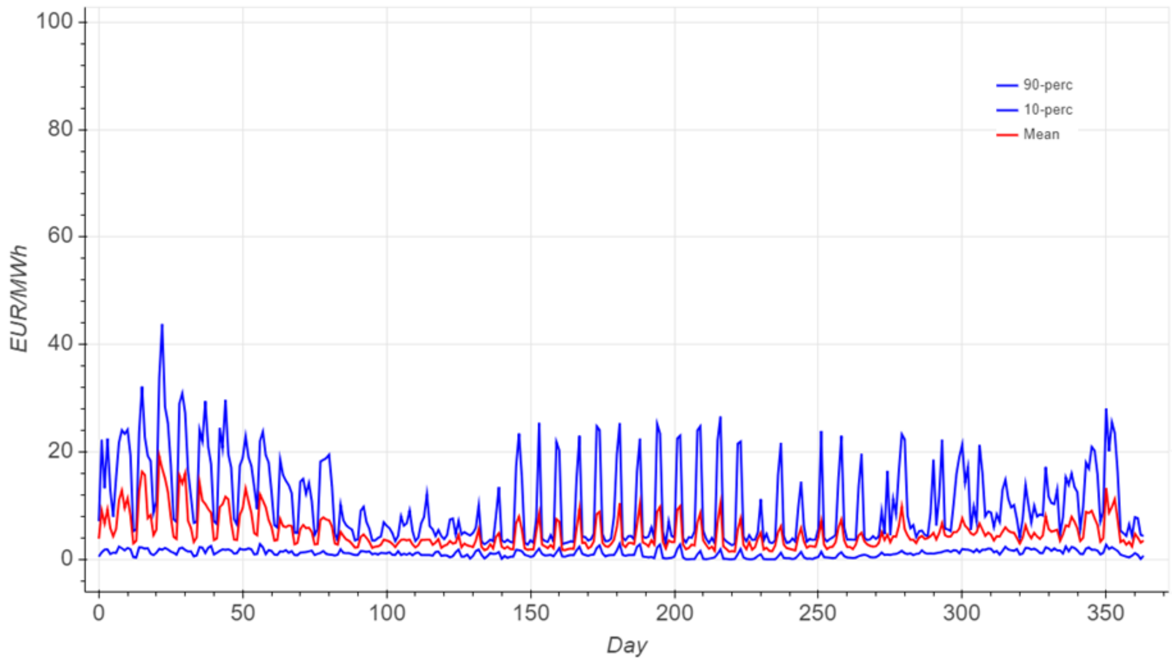

Figure 3-9: Maximum price difference over a 24-hour time period in the Reference scenario for 58 simulated weather years. The blue lines are the 10- and 90- percentiles, while the red line is the mean. South of Norway

(Sorland).

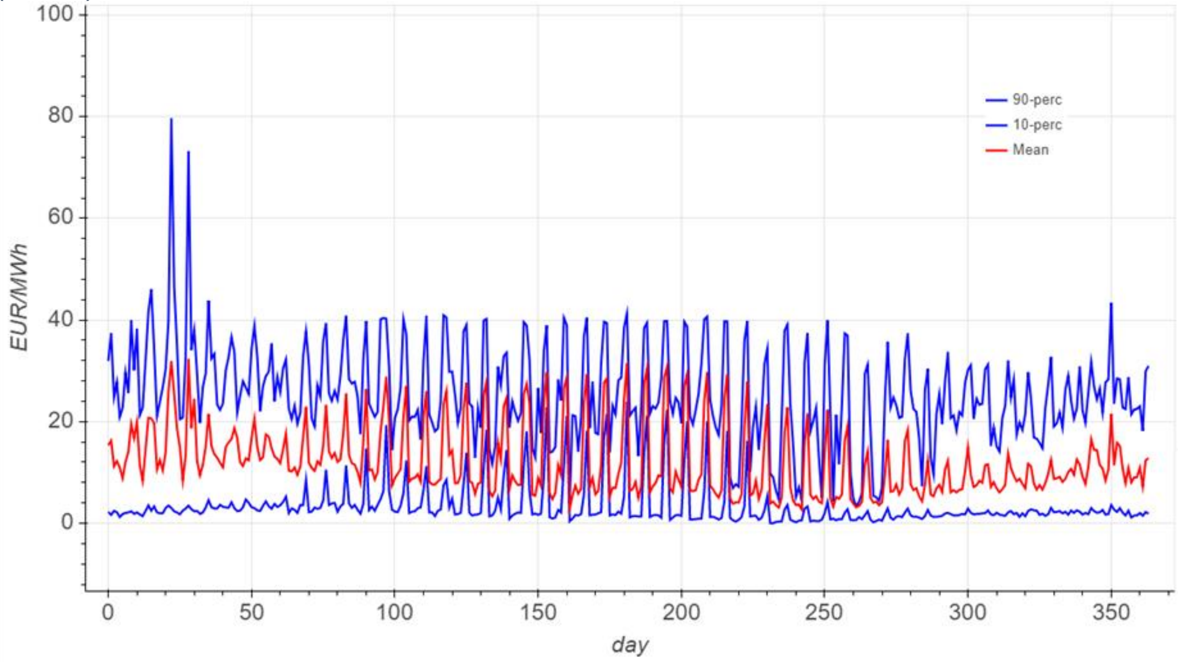

Figure 3-10: Maximum price difference over a 24-hour time period in the Low emission scenario for 58 simulated weather years. The blue lines are the 10- and 90- percentiles, while the red line is the mean. South of Norway (Sorland).

The same plot for Norther Germany is shown in Figure 3-11 and Figure 3-12. There are considerably higher price differences in this region than in Norway. Comparing the two scenarios, the patterns are the same as in Norway but more profound. Especially, there are more periods with extreme high price differences during winter in the Low emission scenario compared to the Reference scenario.

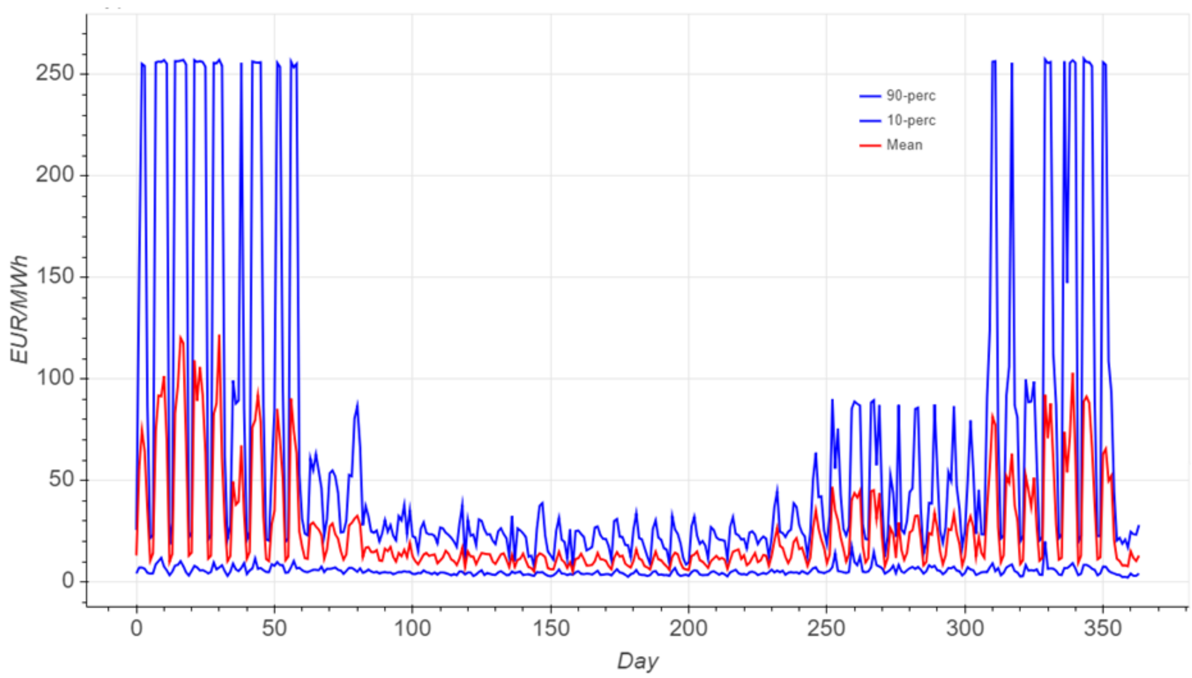

Figure 3-11: Maximum price difference over a 24-hour time period in the Reference scenario for 58 simulated weather years. The blue lines are the 10- and 90- percentiles, while the red line is the mean. Northern Germany.

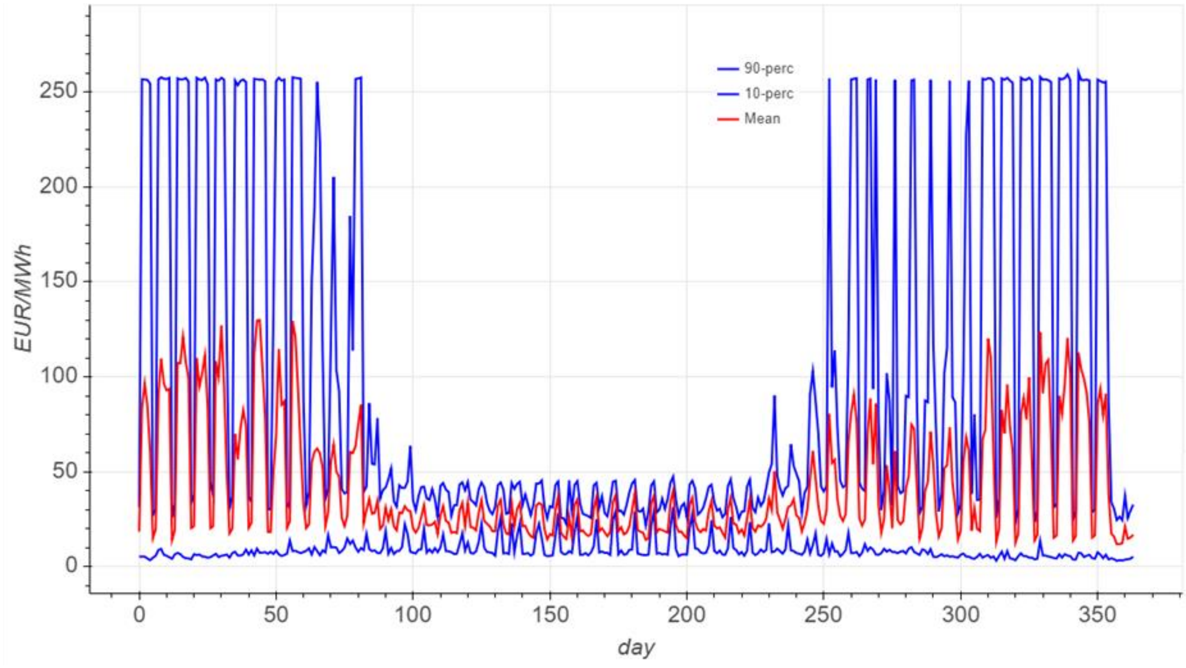

Figure 3-12: Maximum price difference over a 24-hour time period in the Low emission scenario for 58 simulated weather years. The blue lines are the 10- and 90- percentiles, while the red line is the mean. Northern Germany.

3.3 Price Variation and Average Power Price

There are considerable differences in the average power prices between the scenarios. This is a result of the occurrence of extreme prices, and the frequency of these occurrences. Comparing the average prices in the two scenarios, given in Table 3-1, we see that the average prices in Norway and Great Britain are lower in the Low emission scenario than in the Reference scenario. This is caused by an increase in number of hours with low prices, illustrated in Figure 3-13.

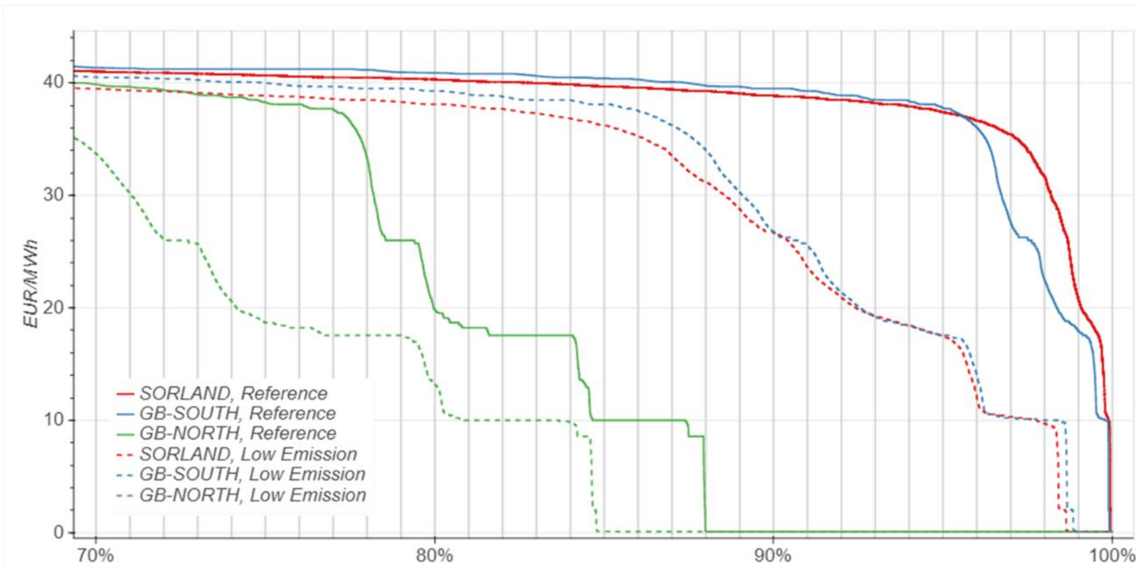

Figure 3-13: Illustrates the 30% hours with the lowest prices over the 58 simulated years in South of Norway, South of Great Britain and North of Great Britain. The unbroken lines are the prices from the Reference scenario and the broken lines are from the Low emission scenario.

In Germany, the average power price increases. This is because lignite is assumed phased out, reducing the capacity of regulatable power production. As a result, there are several periods with too little flexible production available to cover the peak demand when there is little production from wind and solar. The rationing cost, set to 3000 EUR/MWh in our dataset, is the highest cost alternative to balance demand and supply. Even if this only occurs in a limited number of hours, the impact on the average power price can be significant since the price difference from "normal operation" is large. Often the maximum cost alternative in the model is more extremely priced than the minimum price, which has a natural boundary at zero. Extreme high prices occur in Germany in both scenarios, but more often in the Low emission scenario, as illustrated in Figure 3-14. The extreme high price can spread from the area where it occurred to other regions if there are no congestions in the transmission system. The hours with extreme high price in Germany make out about 0.5% of the hours in the Reference scenario (the price is above 100 EUR/MWh in about 1.5-2% of the hours) and about 1.5% of the hours in the Low emission scenario (the price is above 100 EUR/MWh in about 3% of the hours). In some periods the price spreads to several other European countries.

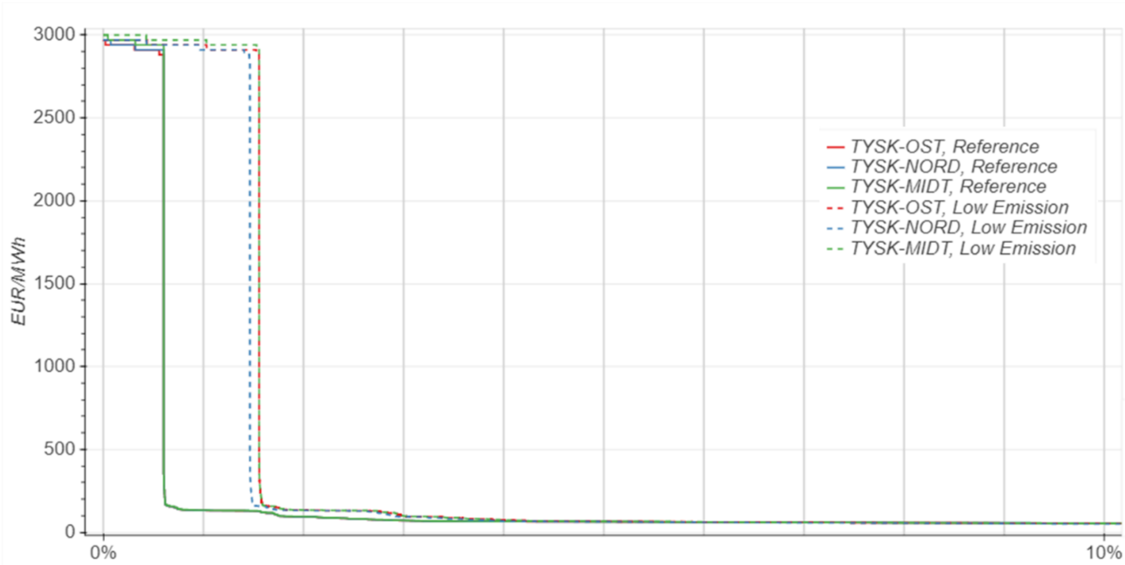

Figure 3-14: Illustrates the10% hours with the highest prices over the 58 simulated years in some of the German areas. The unbroken lines (left) show the power prices in the Reference scenario and the broken lines (right) the prices in the Low emission scenario.

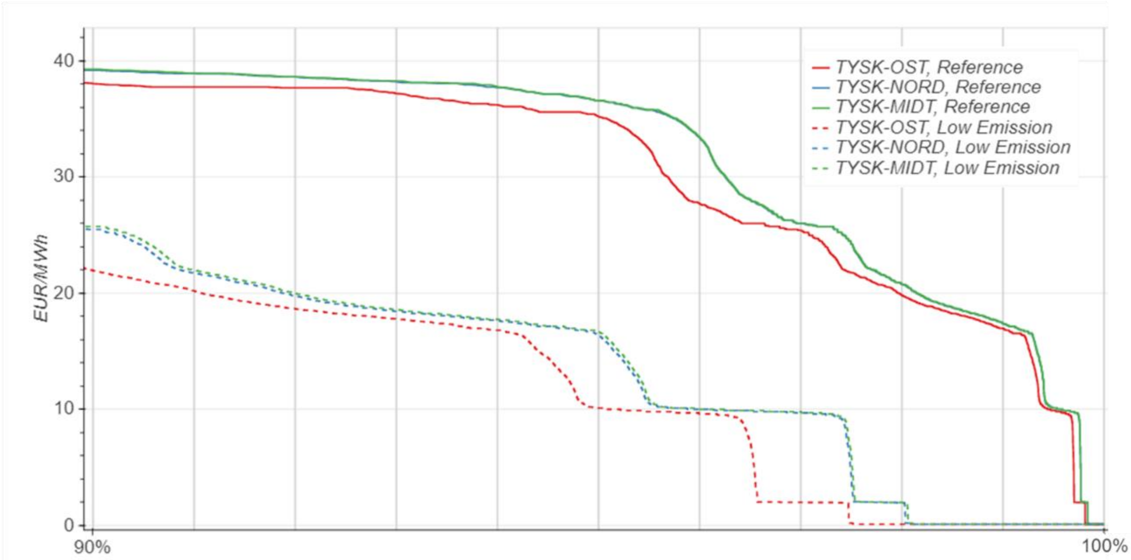

Figure 3-15: Illustrates the10% hours with the lowest prices over the 58 simulated years in some of the German areas. The unbroken lines are the results from the Reference scenario and the broken lines from the Low emission scenario.

Figure 3-15 shows the share of hours with extreme low prices in some German areas in the two scenarios. Prices at 10 EUR/MWh or lower occur about 0.5% of the hours in the Reference scenario and 2-5% of the hours in the Low emission scenario. In 2016 and 2017, the German power price was lower than 10 EUR/MWh 4-5% of the hours and zero or lower in 1-2 % of the hours. Considering the increase in renewables, larger amounts of prices around zero in Germany could be expected compared to the statistics. The low amount of zero prices in the simulations can be a result of several factors:

- Model simulations are always more optimal than the real world
- Three-hour time resolution is used in the simulations, while the real market has one-hour resolution
- Inflexible nuclear generation that does not stop production in short periods with low prices is phased out in Germany in 2030
- Increased transmission capacity is assumed in 2030 and existing transmission capacity internally and out of Germany is fully utilised

Negative power prices have been observed in Germany the last years as a result of subsidy schemes for renewables. Over time, when subsidies are phased out, negative power prices are not expected. In the EMPS model, the power price has a natural boundary at zero. Therefore, the average power price increase as the price of load shedding is much more extreme (3000 EUR/MWh) than of curtailment (0 EUR/MWh), even though there are more hours with low prices. Only a very limited amount of demand side flexibility is included in the scenarios[3], and shedding of load at a high cost is therefore the only possible way of balancing the system when all the available power production capacity is in use. Table 3-4 shows the impact on the average power price of using a price filter to set a price cap on the maximum price in the Reference scenario. This is done after the optimal solution for the system is found, limiting the maximum price in each hour. The highest impact of the cap is in the areas where the shortage occurs, or close to the areas with shortage. In Germany, the average power price is reduced with more than 25%, while the reduction in price in Great Britain is up to 8% and in Norway only is up to 0.3%. The same

[3] price sensitive industry in Norway and Sweden

numbers for the Low emission scenario are given in Table 3-5. In the Low emission scenario, the average price in Germany is reduced with up to 50% when a price cap is used. In Great Britain and Norway, the average price is reduced with up to 7% and 0.9% respectively.

Table 3-4: Reference scenario, simulation for 58 weather years. Average power price for a selection of areas in the original scenario simulation and with a price cap of 300 EUR/MWh and 150 EUR/MWh.

Area	**Average Power Price Reference Scenario**		
	max price of 3000 €/MWh	max price of 300 €/MWh	max price of 150 €/MWh
OSTLAND	42.58	42.49	42.46
SORLAND	42.08	42.03	42.02
TYSK-NORD	62.18	46.31	45.39
TYSK-MIDT	62.51	46.47	45.54
GB-SOUTH	45.82	42.40	42.20
GB-MID	45.40	42.01	41.81
GB-NORTH	38.12	34.96	34.76

Table 3-5: Low emission scenario, simulation for 58 weather years. Average power price for a selection of areas in the original scenario simulation and with a price cap of 300 EUR/MWh and 150 EUR/MWh.

Area	**Average Power Price Low Emission Scenario**		
	max price of 3000 €/MWh	max price of 300 €/MWh	max price of 150 €/MWh
OSTLAND	39.9	39.6	39.6
SORLAND	39.0	38.7	38.7
TYSK-NORD	84.1	45.4	43.2
TYSK-MIDT	87.8	46.2	43.9
GB-SOUTH	43.1	40.1	39.9
GB-MID	42.7	39.7	39.5
GB-NORTH	34.8	32.3	32.1

3.4 Comparison to Similar Studies

NVE [10] and Statnett [11] regularly conduct scenario studies for the Nordic and European power market. The HydroCen analyses are based on the same major trends; decarbonisation of the power system and an increasing share of variable renewables. Still, there are several differences in the underlaying assumptions and how the system is modelled. A strength of this study is that only one model, the EMPS, is used for the entire region, integrating a high detail description of the Nordic hydropower system and a holistic description of the thermal power units in other European countries. The transmission system connecting areas is represented by limiting flows through maximum flow capacities.

Considering the price results, the average power price in South of Norway is at the same level in the three analyses. In 2017, NVE reported an expected average power price of 30 øre/kWh (~31 EUR/MWh) in Norway in 2030. In NVE's updated analysis in 2018, the expected average power price for Norway in 2030 was increased to 36 øre/kWh (~37 EUR/MWh) and 38 øre/kWh (~ 39 EUR/MWh) for South of Norway. Statnett reports an expected average power price of 40 EUR/MWh in South of Norway in 2030 in their most recent market analysis (2018), which is 4

EUR/MWh lower than the expected price they reported in 2016. In the HydroCen Reference scenario, the average power price in South of Norway is 42 EUR/MWh and in the HydroCen Low emission scenario it is 39 EUR/MWh.

The price difference between the North and South of Norway is higher in NVE's and Statnett's studies than in this study. While NVE and Statnett have a difference in the average power price of up to 9 EUR/MWh between North and South of Norway in 2030, we only get a difference in the average price of 2 EUR/MWh in the Reference scenario and 4 EUR/MWh in the Low emission scenario. The price difference between North and South of Norway is a result of the modelling of transmission capacity and the assumed wind power capacity in North of Norway and Sweden in the studies. Statnett and NVE use the Samnett model in their analyses. Samnett has an improved grid model for the transmission system, resembling the flow-based market clearing principle for the Nordic region. Such a model is better at modelling congestions and is likely to give larger price differences between areas than a simpler grid model.

A comparison of the average power prices for a selection of European countries are given in Table 3-6. For Germany and Denmark, the average prices in the HydroCen scenarios are considerable higher than in the two other studies. As discussed previously in this report, this is result of a limited number of hours with a very high price in Germany. When a price cap is used, the average price is reduced significantly in these areas and the results become closer to the other studies. In Great Britain, high shares of variable renewables combined with nuclear power and gas power plants result in periods with surplus of power production and low power prices in parts of Britain in our scenarios. This is pushing down the average power price in Great Britain, giving a lower expected power price for this region than in the other studies. In both the Reference and Low emission scenario there are quite large differences in power prices between the areas in Great Britain.

Table 3-6: The average power prices in the Reference and Low Emission scenarios compared to reported prices for 2030 by Statnett and NVE.

	Average Power price					
	NVE 2018 [øre/kWh]	Statnett 2018 [€/MWh]	Reference Scenario [€/MWh]	Low Emission Scenario [€/MWh]	Reference Scenario (max price= 300€/MWh)	Low Emission Scenario (max price= 300 €/MWh)
South of Norway	38	40	42	39	42	39
Middle of Norway	35	35	41	39	41	38
North of Norway	31	31	40	38	40	37
Sweden	36	37	40	38	40	38
Finland	36	37	41	38	40	38
Denmark	40	44	57	60	45	42
Germany	40	45	62	87	46	46
Great Britain	39	47	43	40	40	37

4 Realized Power Price

The realized power price[4] is the average price achieved by a plant or technology per unit of energy produced. This is a good measure of how flexible a plant or technology is to adjust production to variations in price. In general, the more flexible a unit is, the higher the realized power price will be. The realized power prices of different technologies are closely related to the penetration of variable renewables. When variable power production becomes large enough to cover demand in several hours, the power price is being pushed towards zero as there is no need for other power production technologies (with higher marginal costs) to produce. As a result, the realized power price of wind and solar power plants (and other inflexible production) will eventually decrease as larger amounts of variable renewables is integrated into the power system. Similarly, if there is not enough flexible power production to cover the peak in hours with low production from wind and solar, load shedding can become necessary and the power price will peak. Such hours give flexible units the opportunity to increase their income by ramping up production, while inflexible units are unable to take advantage of the same opportunity.

The realized power price for each technology and the average power price for a selection of areas are given in Table 4-1 and Table 4-2. The realized power price per technology differ between the two scenarios, but the tendencies are the same. In Norway, the high amount of flexible hydropower production makes the region capable of integrating large amounts of inflexible production. Hydropower achieves a realized price equal the average power price or higher, the realized power price of wind is a little lower and solar achieves a little less than wind again. This trend is consistent between the scenarios and a bit stronger in the scenario with higher share of variable renewables. In Germany, there is a larger difference in realized power price between flexible and inflexible production technologies. This is a result of the high price variation in this region. The extreme high prices will also here have an impact on the results, mostly on the realized power price of the flexible units. If a price cap is used, as discussed in the previous section, the average power price and the realized power price of the flexible units will be reduced. The differences in realized power price between the technologies are higher in the Low emission scenario. A similar trend can be seen in the areas in Great Britain, where both the flexible generators and base load production, such as nuclear, achieve a higher power price than wind and solar power plants. Worst off are wind power producers in North of Great Britain, where a high penetration of wind power gives the lowest realized power price of all the technologies in both the scenarios. This indicates several periods with surplus of power production from unregulated power plants in this region and a need for increased transmission capacity. This is an example of how the power price can collapse when the power production from variable renewables becomes higher than what the flexible power plants in the region can integrate.

Table 4-1 Reference scenario. Realized average power prices per technology for selected regions. All simulation years. If there is not given a price, there is no production in that region.

	Reference Scenario [EUR/MWh]									
Area	Nuclear	Lignite	Hardcoal	Gas	Oil	Bio	Hydro	Solar	Wind	Average
OSTLAND	-	-	-	-	-	-	42	41	-	43
SORLAND	-	-	-	-	-	-	43	41	41	42
TYSK-NORD	-	-	70	264	1 268	64	58	41	45	62
TYSK-MIDT	-	66	73	129	-	65	58	42	46	63
GB-SOUTH	46	-	-	54	105	46	53	41	40	46
GB-MID	46	-	-	52	2 448	46	53	41	45	45
GB-NORTH	40	-	-	57	1 737	45	48	36	23	38

[4] The realized power price is here defined as total income divided on total amount produced energy over a given period.

Table 4-2 Low emission scenario. Realized average power prices per technology for selected regions. All simulation years. If there is not given a price, there is no production in that region.

Area	Low Emission Scenario [EUR/MWh]									
	Nuclear	Lignite	Hardcoal	Gas	Oil	Bio	Hydro	Solar	Wind	Average
OSTLAND	-	-	-	-	-	-	40	36	-	40
SORLAND	-	-	-	-	-	-	42	34	37	39
TYSK-NORD	-	-	110	574	1 740	92	77	36	47	84
TYSK-MIDT	-	-	124	267	-	97	80	37	51	88
GB-SOUTH	44	-	-	55	101	45	51	35	36	43
GB-MID	43	-	-	53	2 477	45	51	34	42	43
GB-NORTH	37	-	-	56	1 715	44	44	29	20	35

Taking a closer look at Norway, the differences in realized power price on a technology level are not that large, but at a more detailed level the differences becomes more evident. We have studied the performance of four different hydropower stations to illustrate how flexible units perform better than inflexible units economically. The results are given in Table 4-3. To adjust for different capacity, the realized power price is used.

In the Reference scenario, the selected hydropower stations perform 3-8% better than average[5]. The wind and solar power plants performs 3-2% worse than average. Worst off is solar power with 3% lower income than the average price would give. In the Low emission scenario, the differences become larger. Svartevann (Duge) has the highest realized power price, 17% higher than the average price in this scenario. Wind power has an income which is 4% lower than average and PV ends up with 12% lower income than what the average price would give. These results clearly illustrate the value of being able to adjust operations to variations in price. Furthermore, it shows how increasing share of variable renewables reduce the income potential of inflexible power plants. The realized power prices are slightly higher for most of the hydropower plants in the Low emission scenario, but the difference is small compared to the Reference scenario. Furthermore, most of the hydropower units produce less with the same installed capacity in the Low emission scenario. In total this reduce the overall income of the hydropower plants in the Low emissions scenario compared to the Reference scenario. Still, the performance of the plants compared to the average power price implies that the value of flexibility is higher in the Low emission scenario even though the average price in the power system is reduced.

Table 4-3: Reference scenario and Low emission scenario. Comparison of power production and realized power price for four Norwegian hydro-power units and wind and PV capacity in South of Norway. The average power price is used as a bench mark.

Plant	Total production [GWh/year]		Realized power price [€/MWh]		Average power price [€/MWh]		Performance compared to average [%]	
	Reference	Low Emission	Reference	Low Emission	Reference	Low Emission	Reference	Low Emission
Blåsjø (Saurdal)	1 531	1 492	44.4	44.4	42.0	39.7	106 %	112 %
Aurland 3	326	313	44.2	44.5	41.5	38.8	107 %	115 %
Tonstad (Tonstad)	4 144	4 145	43.3	42.8	42.1	39.0	103 %	110 %
Svartevann (Duge)	393	372	45.3	45.8	42.1	39.0	108 %	117 %
Wind power Sorland	1 108	2 608	41.4	37.6	42.1	39.0	98 %	96 %
Solar power Sorland	120	390	40.8	34.4	42.1	39.0	97 %	88 %

[5] With average we mean the income achieved if assuming all production was sold at an average price. This is the same as assuming constant production throughout the year.

Table 4-4 gives the same results, but here a price filter is used to set a price cap of 300 EUR/MWh. The tendencies are the same between the power plants, but there is a small reduction in the difference between the best and worst unit. In the Low emission scenario, the best unit performs 15% better than average, while the worst perform 11% worse than average. With the price cap, none of the plants achieve a higher realized power price in the Low emission scenario than in the Reference scenario.

Table 4-4: Reference scenario and Low emission scenario. Comparison of power production and realized power price for four Norwegian hydro-power units and wind and PV capacity in South of Norway. The average power price is used as a bench mark. A price filter of 300 EUR/MWh is used to set a price cap on the maximum price.

Plant	Realized power price [€/MWh]		Average power price [€/MWh]		Performance compared to average [%]	
	Reference	Low Emission	Reference	Low Emission	Reference	Low Emission
Blåsjø (Saurdal)	44.2	43.5	41.9	39.5	105 %	110 %
Aurland 3	44.0	43.0	41.4	38.5	106 %	111 %
Tonstad (Tonstad)	43.2	42.2	42.0	38.7	103 %	109 %
Svartevann (Duge)	45.0	44.5	42.0	38.7	107 %	115 %
Wind power Sorland	41.3	37.5	42.0	38.7	98 %	97 %
Solar power Sorland	40.8	34.4	42.0	38.7	97 %	89 %

5 Example of period with very low power price in Norway in the winter

This example focuses on the Sorland area, a small area in the South of Norway which is tightly interconnected to continental Europe, as well as other areas in Norway. In the Low emission scenario, there are periods with zero (or near zero) prices in the South of Norway in the winter. Figure 5-1 shows an example of such a situation in Sorland from around hour 795 to hour 800. Figure 5-3 and Figure 5-4 show the same tendencies for the power price in Northern Germany and the Netherlands in the same period. There is maximum import from both of these areas to Norway for most of this period in the Reference scenario, as shown in Figure 5-5. In the Low emission scenario, the transmission capacity is increased and there is maximum import from Germany for parts of the period and partly import from the Netherlands, as shown Figure 5-6. Figure 5-2 shows that the hydropower production in Sorland is ramped down in this period for both scenarios. In the Reference scenario, the available flexibility in the Norwegian region maintain a stable power price while importing at a maximum. In the Low emission scenario on the other hand, the price drops in Norway as well and the maximum available import capacity is not utilised. The difference in the price response in the scenarios is a result of the total amount of available flexibility in the Sorland area and neighbouring areas compared to the amount of unregulated power. In the Low emission scenario, the share of unregulated power generation increases as there is higher production from variable renewables, as seen for Sorland in Figure 5-7. The unregulated power production is, as far as possible, balanced by the regulatable hydropower production. Figure 5-8 illustrate the demand in Sorland for the period. In the middle of the example period there is low demand due to the weekend. To see the full picture, all the areas connected to Sorland

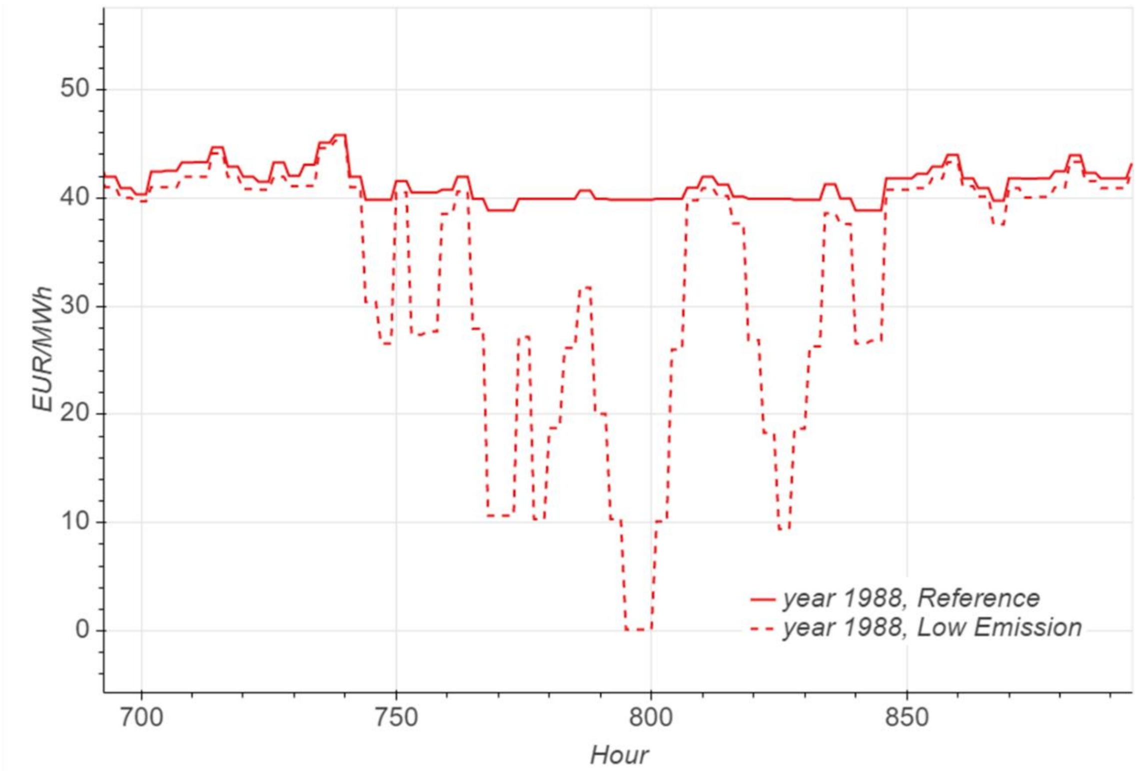

Figure 5-1 Reference scenario (unbroken line) and Low emission scenario (broken line) power price SORLAND winter period year with "normal" inflow (1988)

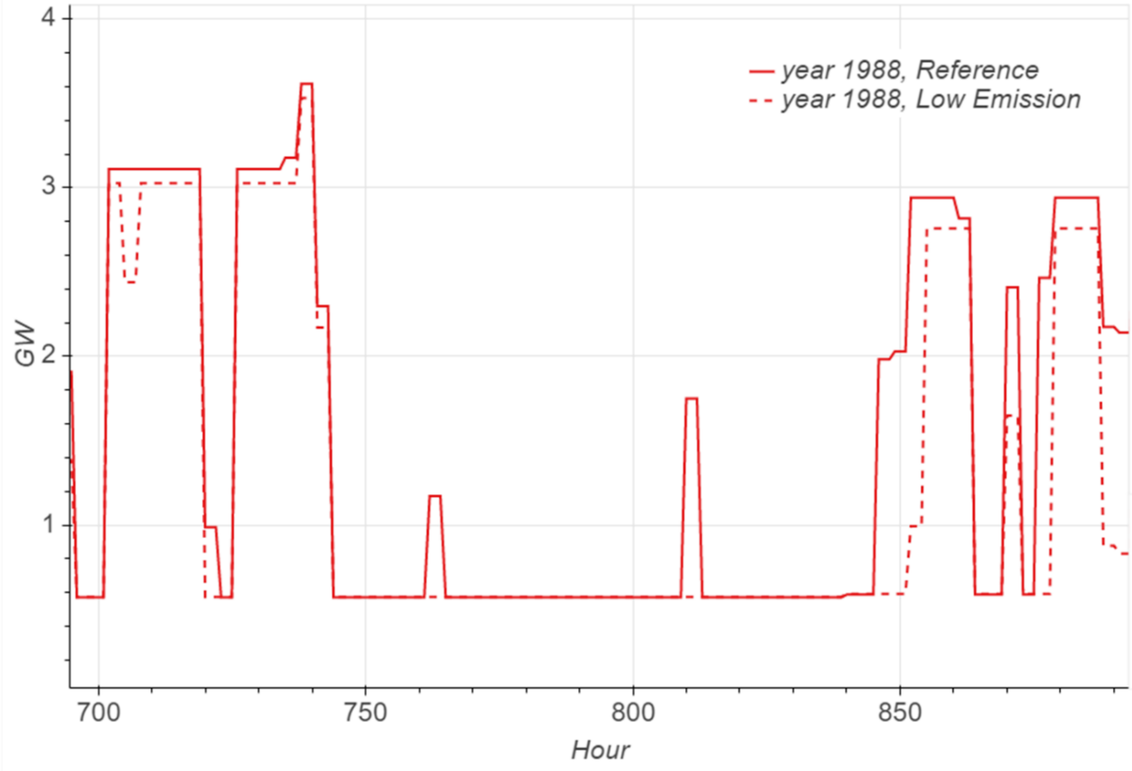

Figure 5-2 Hydropower production SORLAND winter period with low power price in 1988.

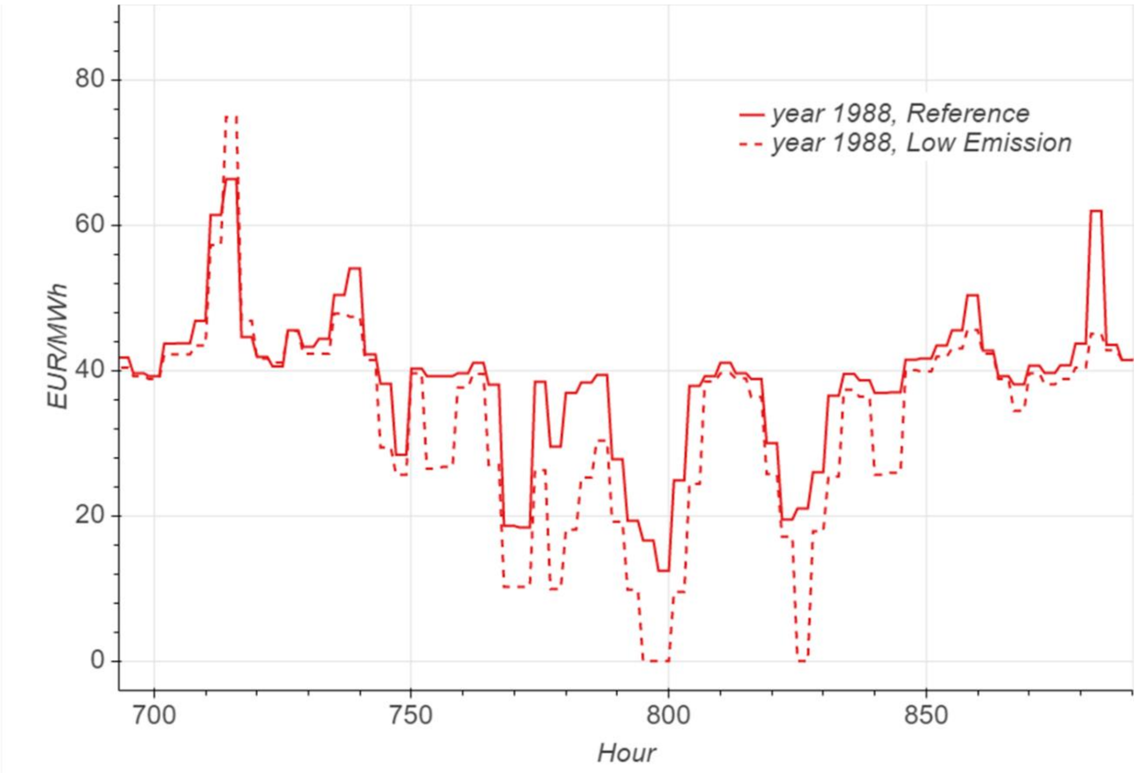

Figure 5-3 Reference scenario (unbroken line) and Low emission scenario (broken line) power price Northern Germany winter period 1988

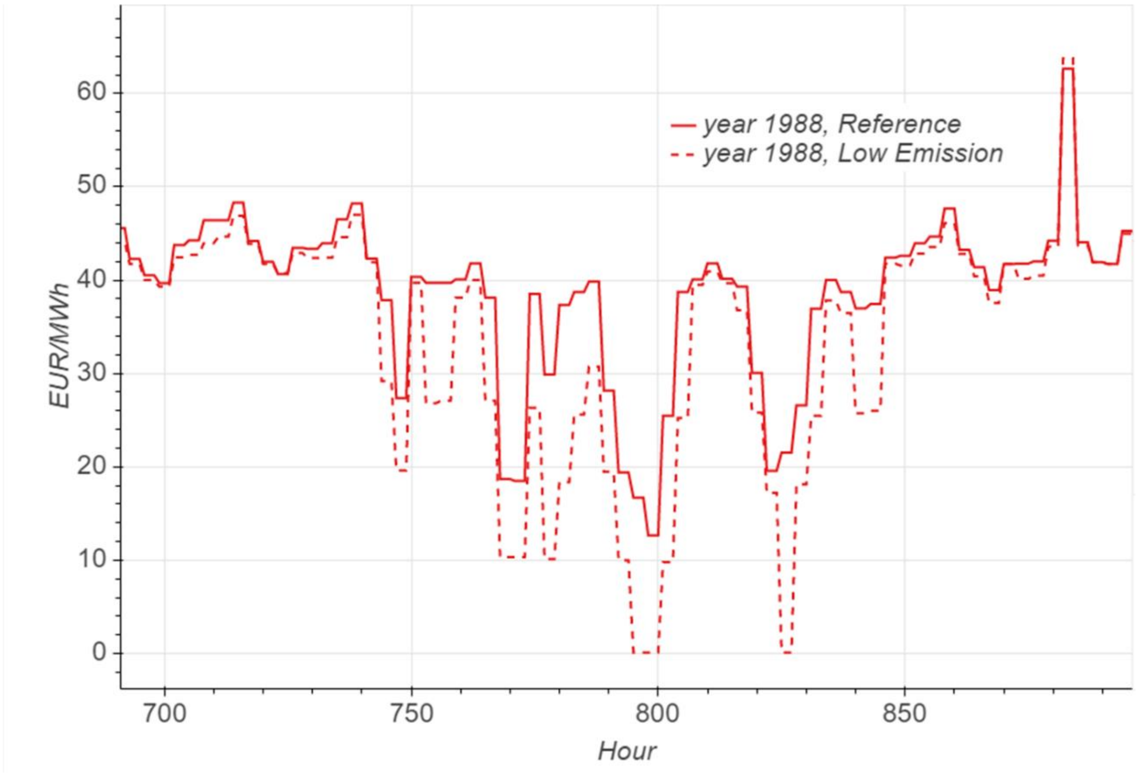

Figure 5-4 Reference scenario (unbroken line) and Low emission scenario (broken line) power price The Netherlands winter period 1988

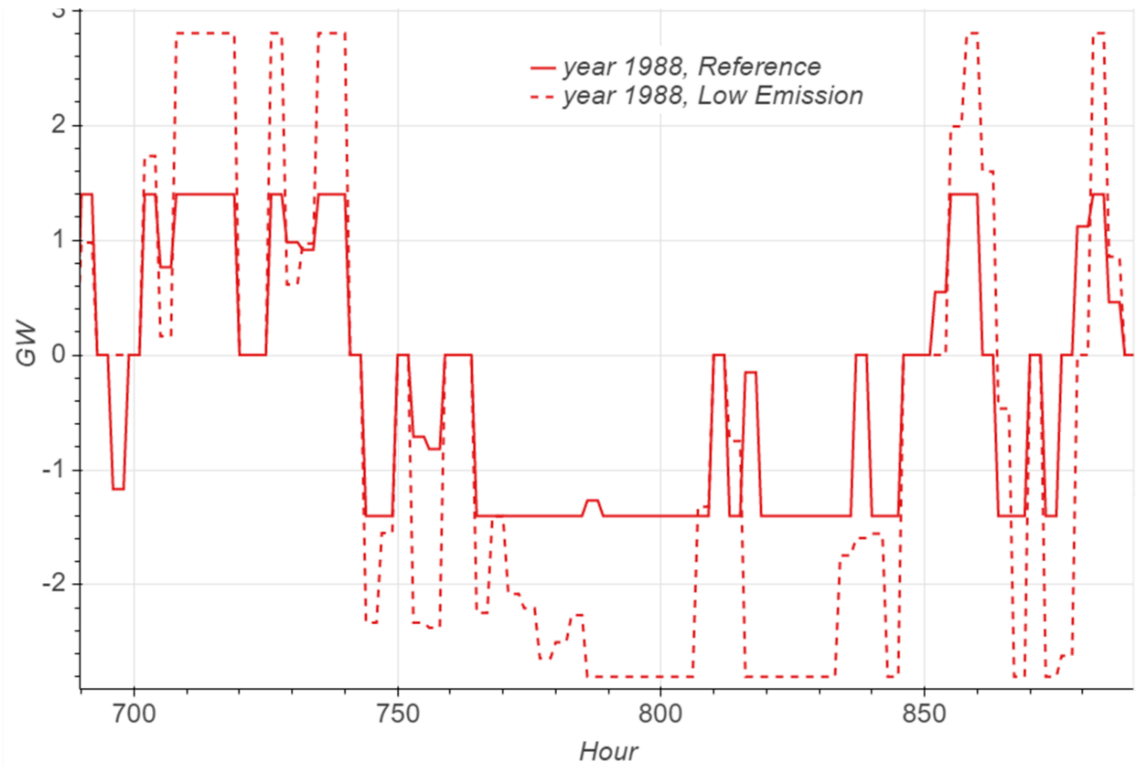

Figure 5-5 Exchange between SORLAND and Northern Germany winter period with low power price in 1988. Reference case (unbroken line) (max capacity 1400 MW) and Low emission scenario (broken line) (max capacity 2800 MW)

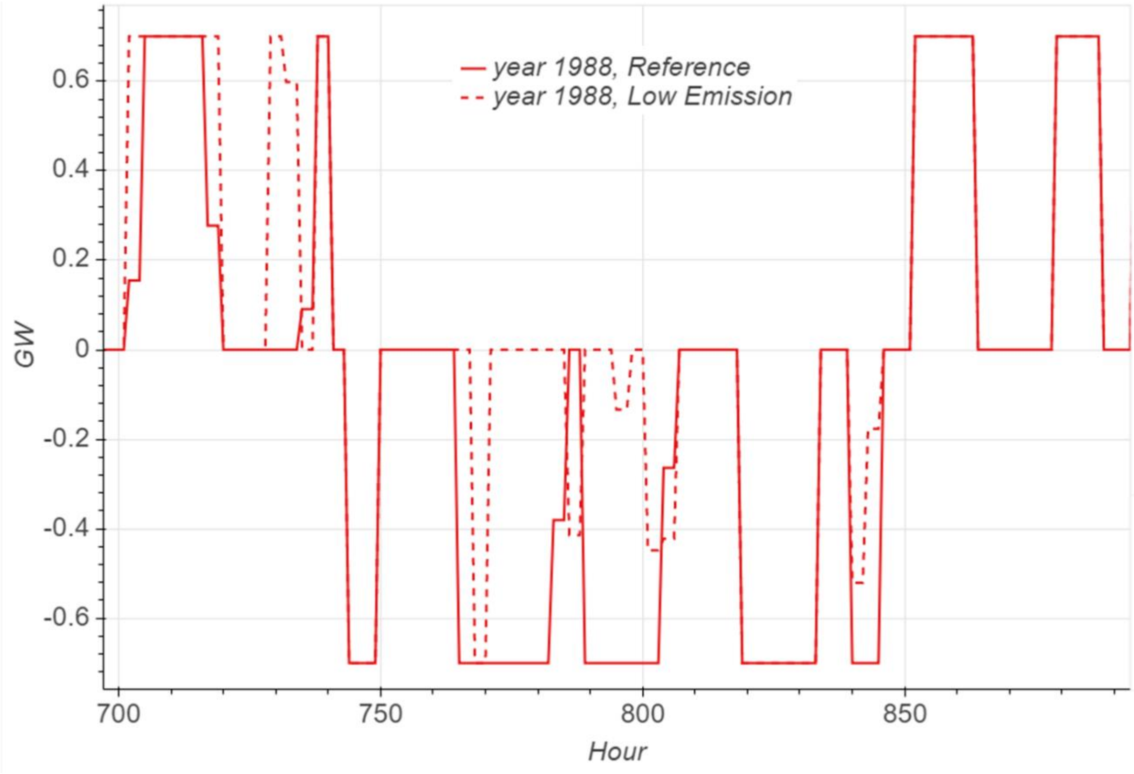

Figure 5-6 Exchange between SORLAND and The Netherlands winter period with low power price in 1988. Reference scenario (unbroken line) and Low emission scenario (broken line)

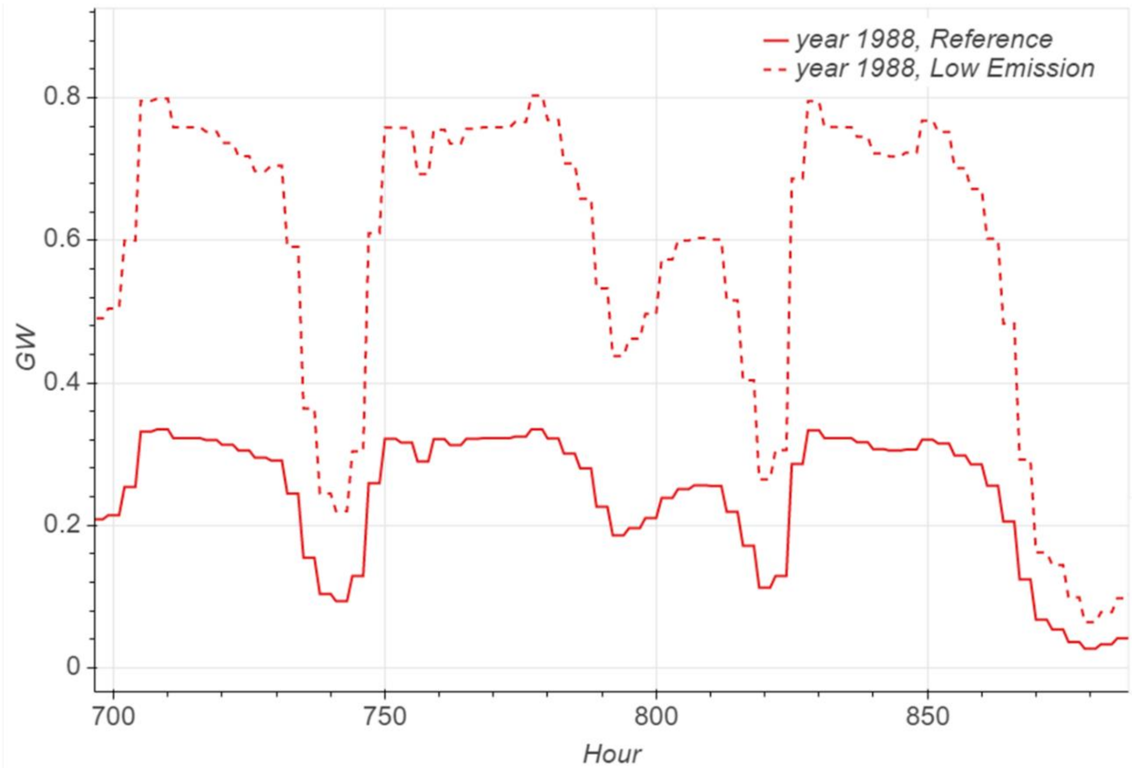

Figure 5-7 Wind and solar power production SORLAND weeks with low power price 1998. Reference scenario (broken line) and Low emission scenario (unbroken line).

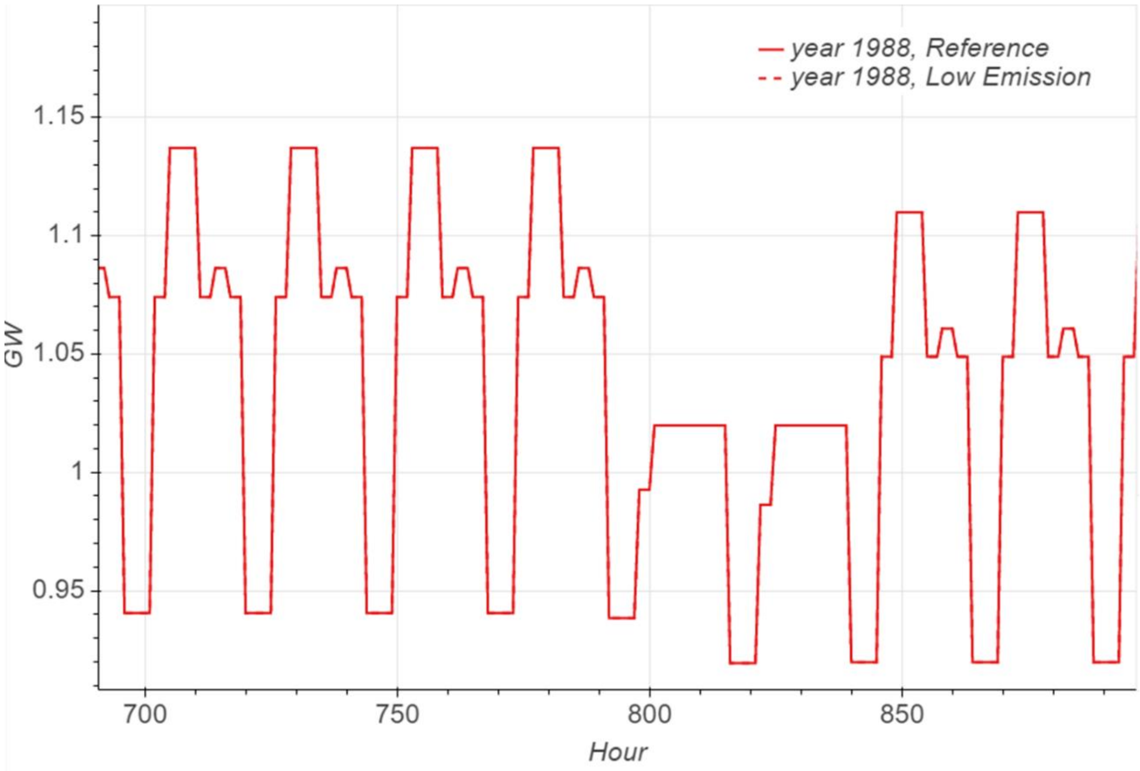

Figure 5-8: Demand SORLAND weeks with low power price 1998. The demand is equal in the two scenarios.

6 Conclusion and Final Remarks

This report presents the results from analyses of the power system in Northern Europe in 2030 with the power market model EMPS. The power system is analysed for two alternative scenarios: a Reference scenario partly based on the EUCO30 scenario and a Low emission alternative. The Low emission scenario has more wind and solar power production and less thermal production than the Reference scenario. The EUCO30 scenario was released in 2016. However, the aims for decarbonisation of the European power system are increasing. In 2018, the EU commission decided to increase the target for share of renewables in the energy system from 27% to 32%. Furthermore, Germany currently aims for 65% of renewables in their power system and recently decided to phase out coal by 2038. Finally, the deployment of solar power production has been higher than foreseen in the EUCO30. The Low emission scenario is a further development of the Reference scenario but reflects more of the recent results and increased targets. Still, thermal power production is still setting the price in most hours and fuel prices and the CO_2-price maintain an important influence on the price level.

The average power prices in Norway and Great Britain decrease from the Reference scenario to the Low emission scenario, see Table 3-1. This is because more capacity is added to the system. In Germany, the prices increase. More renewable capacity is added to the system in Germany, but there is also reduction of thermal capacity. In some periods there will be lack of capacity in Germany and the price will be at rationing level, i.e. 3000 Euro/MWh. Such prices highly impact the average prices. It is not realistic that Germany has much higher prices than other countries and further work should add some demand reduction in high price periods. Demand reduction/flexibility will remove the prices spikes and even out the prices between the countries.

As discussed, the short-term price variation increases in the Low emissions scenario as more renewables are added to the system. It was shown in Table 3-2 and Table 3-3 that the maximum price difference increases depending on the length of the period considered. Furthermore, higher short-term price variation can be expected in Germany and Great Britain than in Norway. In Norway the maximum price difference within a 24-hour period, a week and a month approximately doubles in the Low emission scenario compared to the Reference scenario.

As shown in Table 4-3 and Table 4-4, the income for a hydropower producer in Southern Norway hardly increases in the Low emission scenario compared to the Reference scenario, but keeps constant even with lower average prices. Prices in Southern Norway decreases in the Low emission scenario compared to the Reference scenario. There are hardly any periods with increased prices that could be utilized for increased hydropower production and possible increase in income. There are increased number of periods with very high prices in Germany, but due to limited transmission capacities, those prices are not visible in Southern Norway. However, the results also show that hydropower producers achieve a higher value per unit of energy produced than wind and solar power plants and that the value of flexibility increases in the Low emission scenario.

In the Low emission scenario, there are periods with zero prices in the South of Norway. A main part of the nearly zero prices are in the summer but there are also occurrences in the winter. Figure 5-1 to Figure 5-8 show an example of how such a situation can occur in a system with higher power production from variable renewables in Norway and increased transmission capacity to countries with high penetration of renewables.

7 Suggestions for Further Work

Analysis of the future European power system is based upon many assumptions about the development of the power system. Changes in assumptions about the European power system can result in both small or large changes in the operation of Norwegian hydropower and the power prices in Norway. Sensitivity analysis can be done for any of these assumptions. Some key assumptions are: the transmission capacity between Norway and Europe and within Norway, the capacity and prices of thermal power generation and the user flexibility.

Modelling of transmission capacity is important when considering price differences between different areas. A more detailed physical flow-based grid model will give more frequent and realistic occurrences of congestion and result in larger price differences between areas. An improved grid modelling of the transmission system, e.g. by using Samnett which include flow-based market clearing, could be used to assess and evaluate the impact of transmission capacity within countries. The main obstacle for such modelling is availability of detailed transmission data outside Norway.

In this study, a rather simple representation of demand was used, excluding price elasticity and load shifting. It was shown, as expected, that the used demand profiles have a clear impact on the power price variations. Modelling of end-user flexibility and load shifting capabilities would smooth some of these variations. Further studies should move away from using fixed demand profiles and focus more on modelling dynamic end-user flexibility. The EMPS model does not include functionality for such modelling, i.e. optimization of short-term storages such as batteries, CAES and heat storage. However, the FanSi prototype model [12] have this capability.

Furthermore, the Blåsjø, Aurland 3 and Svartevann hydropower plants, which were used in the example in Table 4-3 and Table 4-4, include pumping. The EMPS model mainly pumps due to seasonal variations or for moving inflow into the regulated watercourses and not because of short-term variations in the prices. A model like FanSi [12], which is solely based on formal optimization, will also utilize the low-price periods for pumping [6], if economical. Thus, the power producers will have more water available for production in the high price periods and their income would increase.

In addition, further work could look deeper into the detailed results for different hydropower stations and water courses. E.g. operation of individual plants in extreme dry or wet years. It would also be interesting to compare hydro operation and short-term price variations form the EMPS model with results from the FanSi model mentioned above.

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Appendix 1 – Areas in the Model

This study focuses on the power system in North-western Europe. The model includes detailed descriptions of demand and supply in: Norway, Sweden, Finland, Denmark, the Baltics, Poland, Germany, the Netherlands, Belgium, France, and Great Britain. The spatial resolution varies from 1-11 nodes per country. In addition, several offshore nodes are included. A full overview of the model areas is given in Figure A- 1. In addition, country-wise groups are sometimes used in the report. The mapping of onshore areas to the groups are given in Table A-1. Offshore nodes are included in the same group as the onshore node they are connected to. *South of Norway* is often referred to in the report and refers to Norway South. If *South of Norway (Sorland)* is referred to, results from area Sorland are used as representative results for Norway South.

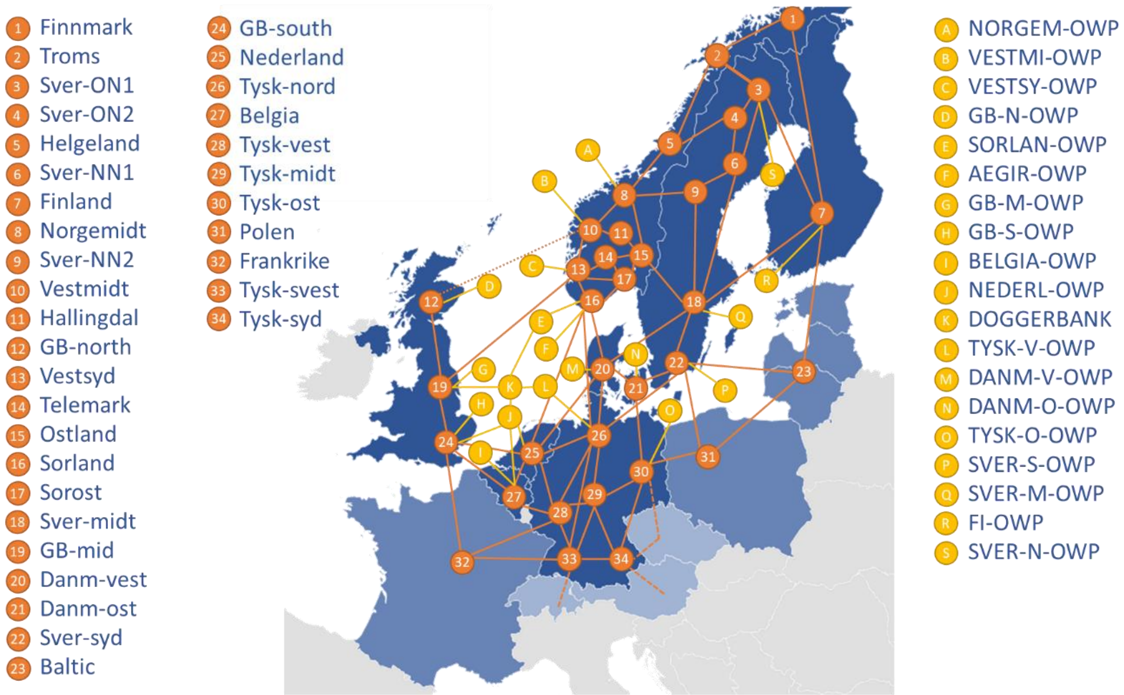

Figure A- 1: Complete overview of all areas included in the model and which areas that are connected.

Table A-1: Mapping of onshore areas to groups. In addition, offshore nodes connected to the onshore nodes are included in the same groups.

Group	**Areas included**
Norge_S/Norway South	Ostland, Sorost, Hallingdal, Telemark, Sorland, Vestsyd, Vestmidt
Norge_M/Norway Mid	Norgemidt, Helgeland
Norge_N/Norway North	Troms, Finnmark
Sverige_N/Sweden North	Sver-ON1, Sver-ON2, Sver-NN1, Sver-NN2, Sver-midt
Sverige_S/Sweden South	Sver-syd
Finland/Finland	Finland
Danmark/Denmark	Danm-ost, Danm-vest
Tyskland/Germany	Tysk-ost, Tysk-nord, Tysk-midt, Tysk-syd, Tysk-svest, Tysk-vest
Nederland/The Netherlands	Nederland
Belgia/Belgium	Belgia
Storbritannia/Great Britain	GB-south, GB-mid, GB-north
Frankrike/France	Frankrike
Polen/Poland	Polen
Baltic/The Baltic states	Baltic

Appendix 2 – Run Mode EMPS

In this study the EMPS model has been used with a dataset of Europe for year 2030. The dataset includes 53 areas that are modelled in detail and three exchange connections (56 areas in total), 56 three-hour time steps per week and 58 simulation years. The water value calculation is based on 58 historical weather years and a serial simulation has been conducted for the same historical years. The EMPS model include a broad variety of functionality. In this study we have used complete wind and solar power functionality (which make it possible to use wind and solar input data with hourly time resolution), start cost functionality and functionality for fine temporal resolution (allowing for three-hour time steps). For those familiar with the EMPS model the corresponding passwords are given below.

Passwords (protected functionality):

LTM_MPS_START

LTM_MPS_VIND

LTM_MPS_VINDEKSTRA

LTM_MPS_VINDPARKER

LTM_PRISAVSNITT_MAKS

Run modes:

LTM_ARCHIVE=TARC

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