Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

Marta Ulvensøen

# Changes in the European energy system, resulting from increase in Norwegain transmission capacity and hydropower development

Master's thesis in Energy and Environmental Engineering
Supervisor: Steve Völler
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NTNU
Kunnskap for en bedre verden

# Abstract

This master thesis has analysed the European energy system, with focus on more development of hydropower and reservoir capacity in Norway, more wind power development in both Norway and Great Britain and an increased exchange capacity from Norway to continental Europe and Great Britain. The European energy system is also assumed changing, mostly due to the increased implementation of renewable energy sources like wind and solar energy. In addition, old technologies with high $CO_2$-emissions and/or decreased profitability are assumed phased out gradually.

These analyses are realized using EMPS/Samkjøringsmodellen, using an existing model and an extended model. 16 different simulations for three focus years 2020, 2030 and 2040 were performed. The simulations are done for base scenarios and scenarios with adjustments for hydropower, wind power and/or transmission capacity. For all simulations it is used two different scenarios for fuel-prices and $CO_2$-taxes, the Current Policies Scenario and the 450 Scenario. The CP scenario represents the current policies scenario. The 450 Scenario represent an assumed more restricted scenario with higher level for prices and taxes, especially for coal. The scenarios are collected from World Energy Outlook 2016 (WEO) issued by International Energy Agency (IEA).

The results show that $CO_2$-emissions, are closely related to production mixes and import/export of power in the modelled energy system. Especially will the emissions be reduced, if more renewable energy sources and a stricter policy for fuel-prices and $CO_2$-taxes where applied. In this project modelled with more hydropower in Norway and more wind power in Norway and Great Britain. The reduction for $CO_2$-coefficient where 1,9 $gCO_2$/kWh (6,5 Mt-$CO_2$) given inclusion of more hydropower compared to the base scenario in year 2040. The reduction increased to 3,2 $gCO_2$/kWh (11,7 Mt-$CO_2$) if the investment algorithm for cables where applied for the same scenario. Scenario that made most impact where the scenario investment algorithm with development of cable and wind. The reduction was 35,8 $gCO_2$/kWh (125,6 Mt-$CO_2$). The effect of used policies given fuel-prices and $CO_2$-taxes are also important, in year 2020 the difference between 450 Scenario and CP Scenario was -1,0 $gCO_2$/kWh (3,4 Mt-$CO_2$) in favour for 450 Scenario. In year 2040 the difference is -70,7 $gCO_2$/kWh (255,5 Mt-$CO_2$) in favour of the same scenario.

# Sammendrag

Denne masteroppgaven har analysert det Europeiske energisystemet. Analysen har hatt hovedfokus på utvikling av mer vannkraft i Norge, utvikling av mer vindkraft i Norge og Storbritannia og økt overføringskapasitet fra Norge til Storbritannia og kontinental Europa. Over tid er det også antatt generelle endringer i det Europeiske energisystemet gitt økt implementering av fornybare energikilder som vindenergi og solenergi. I tillegg antas det at gamle teknologier med høye $CO_2$-utslipp og/eller redusert lønnsomhet gradvis vil fases ut.

Analysene er gjennomført i EMPS/Samkjøringsmodellen, gitt en eksisterende modell og en utvidet modell. Det er gjennomført 16 ulike simuleringer for tre fokusår 2020, 2030 and 2040. Simuleringene er gjort for referanse scenarier, og scenarier med endringer for vannkraft, vindkraft og/eller overføringskapasitet. For alle simuleringer er det brukt to ulike brenselspriser og $CO_2$ -avgift scenarier, enten CP Scenarioet eller 450 Scenarioet. CP Scenarioet representer nåværende scenario. 450 Scenarioet representerer et antatt fremtidig scenarium med høyere prise og avgifter for spesielt kull. Scenarioene er hentet fra World Energy Outlook 2016 (WEO) gitt ut av International Energy Agency (IEA).

Resultatene viser at en reduksjon av utslippene for $CO_2$ er nært knyttet til både produksjonsblandingen i modellert energisystem og import/eksport av strøm. Spesielt vil reduksjonen for utslippene bli lavere dersom flere fornybare energikilder og en strengere politikk for drivstoffpriser og $CO_2$-avgifter antas. I dette prosjektet modellert for mer vannkraft i Norge og mer vindkraft i Norge og Storbritannia. Reduksjonen gitt $CO_2$-koeffisienten er 1,92 $gCO_2$/kWh (6 549 Mt-$CO_2$) for scenarioet med mer vannkraft sammenlignet med basisscenarioet i år 2040. For scenarioet med økt vannkraft produksjon ble det også implementert en investeringsalgoritme for utvikling av sjøkabler fra Norge. Det økte reduksjonen til 3,21 $gCO_2$/kWh (11 677 Mt-$CO_2$. I scenarioet med investerings algoritme for både kabler og vindkraft var reduksjonen enda høyere 35,8 $gCO_2$/kWh (125,6 Mt-$CO_2$). Betydningen av framtidig politikk for brenselspriser og $CO_2$-avgifter er også viktig. I år 2020 var forskjellen mellom 450 Scenarioet og CP Scenarioet 1,02 $gCO_2$/kWh (3 379 Mt-$CO_2$) til fordel for 450 Scenarioet. I år 2040 økte dette til 70,66 $gCO_2$/kWh (255 504 Mt-$CO_2$) til fordel for samme scenario.

# Acknowledgment

This project is written as a part of the course, TET4900 Electrical Energy Engineering Master Thesis, at Norwegian University of Science and Technology (NTNU) during the spring of 2019. The work presented in this project was carried out at the Department of Electric Power Engineering. Researcher Steve Völler and Professor Magnus Korpås, have respectively been my supervisor and co-supervisor.

I would like to thank my supervisor and co-supervisor for their guidance and feedback!
Lastly, thank you to my family and friends!

Trondheim, 16th of June
Marta Ulvensøen

# Table of contents

# Appendix A

# Appendix B

# Appendix C

# Appendix D

# List of figures

# List of tables

# Abbreviations

| | |
|---|---|
| **450** | 450 Scenario (fuel-prices and $CO_2$-taxes) |
| **ACER** | Agency for the Cooperation of Energy Regulators |
| **CBA** | Cost Benefit Analysis |
| **CCGT** | Combined Cycle Gas Turbine |
| **CCS** | Carbon Capture and Storage |
| **CHP** | Combined Heat and Power |
| **CORDIS** | The Community Research and Development Information |
| **CP** | Current Policies Scenario (fuel-prices and $CO_2$-taxes) |
| **EEA** | European Economic Area |
| **EMPS** | EFI's Multi-area Power-market Simulator |
| **ENTSO-E** | European Network of Transmission System Operators, Electricity |
| **EOPS** | EFI's One-area Power-market Simulator |
| **ETYS** | Electricity Ten Year Statement |
| **EU** | European Union |
| **GHG** | Greenhouse gases |
| **HVDC** | High Voltage Direct Current |
| **IEA** | International Energy Agency |
| **MAMSL** | Meters above mean sea level |
| **NOAA** | National Oceanic and Atmospheric Administration, U.S. Department of Commerce |
| **NVE** | Norwegian Water Resources and Energy Directorate |
| **OCGT** | Open Cycle Gas Turbine |
| **REF2016** | EU Reference Scenario 2016 |
| **RES** | Renewable Energy Sources |
| **SYS** | Seven Year Statement |
| **TSO** | Transmission System Operator |
| **TYNDP** | Ten Years Network Development Plan |
| **VI V2 V3 V4** | Visions 1, 2, 3 and 4 (from TYNDP 2016) |
| **WEO** | World Energy Outlook |

# 1 Motivation and background

A well-known concept is “The Green shift”(1). The global climate and environmental challenges require changes within nature’s tolerance limits. The European energy system has to reduce the negative consequences for climate and environment, given GHG emissions. The European energy system is already changing, mostly due to the increased implementation of renewable energy sources like wind and solar energy. In addition, old technologies with high $CO_2$-emissions and/or decreased profitability (high fuel prices, high $CO_2$-taxes, low efficiency) will be phased out. A result is the need for reliable and flexible energy source. Hydropower plants with reservoirs can provide parts of the backup energy to sustain other renewables with intermittent service and ensures electricity supply in times when there is for example no wind or sun.

Hydropower is by far the main source of electric power production in Norway today. Depending on annual inflow, around 95 %of all electric power production in Norway comes from hydropower(2). Norway’s hydropower capacity is well developed, although the potential is still higher. Both installed capacity and reservoir capacity are possible to develop further. A high percentage of Norway’s hydropower plants are old(3). The high age affects the efficiency and not suitable capacity factor compared to today’s production scheme.

A beneficial inclusion of Norway’s hydropower is of interest to Europe giving a contribution to a higher share of flexible renewable energy source(4). Norway has a total of eight interconnections(5) with neighbouring countries (Sweden, Denmark, Finland, Netherland, Germany and Russian federation). The Norwegian exchange capacity with connecting areas is currently 6200 MW. This corresponds to about 20 % of the installed production capacity in Norway. A higher exchange capacity from Norway to both continental Europe and Great Britain will be helpful for their inclusion of more renewables in the energy mix.

In this master thesis, the aim is to analyse the changes to the European and Norwegian energy system, if transmission capacities are further increased, and hydropower and wind power capacities are enlarged. These analyses will mainly be realized using EMPS/Samkjøringsmodellen(6), using an existing model and extended model.

# 2 Literature review

## 2.1 The Norwegian energy system

On 1 January 2018, the power supply in Norway had an installed production capacity of 33,8 GW. In 2017, total power production in Norway was 149,4 TWh(7). Table 2.1 shows the Norwegian power production in 2017.

**Table 2.1 Distribution of power production in Norway**

| Energy production (in 2017) | [GWh] | Share % | Change in share 2016- 2017 |
|---|---|---|---|
| Production in total | 149 402 | 100 | 0,3 |
| Hydropower production | 143 112 | 95,8 | -0,2 |
| Thermal power production | 3 436 | 2,3 | -0,6 |
| Wind power production | 2 854 | 1,9 | 34,9 |

The Norwegian energy system consists of hydropower, wind power and thermal power. Hydropower accounts for most of the Norwegian power supply, and the resource depends on the annual rainfall(8). This is different than other power systems in Europe, where thermal power generation still dominates, and fuels (e.g. gas, coal and biomass) are available in the markets. The Norwegian hydropower can store energy. Norway has half of Europe's magazine capacity, and more than 75 % of the Norwegian production capacity can be regulated(8). The magazine power plants have high flexibility and production can be adjusted up and down quickly as needed, at a low cost. In the power system, there must be a balance between consumption and production at all time. An increasing amount of unregulated power generation, such as wind power and solar power, places greater demands on the availability of flexibility in the remaining power system.

Norway is now in a period where more renewable energy is being built than in several decades. Despite that wind power today has a relatively modest share of the production capacity, the technology is dominant in today's investment picture for onshore wind power(9).

### 2.1.1 The Norwegian hydropower system

Hydropower is by far the main source of electricity production in Norway today. The Norwegian hydropower are also important in a European perspective, Norway is Europe's renewable battery. Norway has around 50% of the reservoir capacity in Europe. Reservoirs provides the required backup energy to sustain other renewables with intermittent service and ensures electricity supply in times when there is for example no wind or sun.

Norway has good natural conditions for development of hydropower(10). The average height of the land area is 400 MAMSL. Since hydropower energy is based on potential energy, many areas are suited for hydropower in Norway. Annual precipitation of 1,000-3,000 mm in coastal areas is common. In Western Norway, the terrain is steep, which means that the fall height is great also over short stretches and this makes it easier to utilize the waterfall.

NVE has the administrative responsibility in Norway to have an overview over existing hydropower plants and potential for new plants. Table 2.2 shows an overview over the Norwegian hydropower system as of 01.01.2019(2)

**Table 2.2 Hydropower system in Norway 01.01.2019**

| **Category** | **Number** | **Installed capacity [MW]** | **Annual production [TWh]** |
|---|---|---|---|
| **Under 1 MW** | 571 | 184 | 0,79 |
| **1-10 MW** | 715 | 2 518 | 9,91 |
| **10-100 MW** | 257 | 9 545 | 42,25 |
| **Over 100 MW** | 83 | 20 010 | 82,12 |
| **Pumped storage** | 30 | --- | -0,16 |
| **Total** | Plants: 1626<br>Pumped storage: 30 | 32 257 | 134,91 |

In Norway are the most profitable projects, not located in protected areas, already built. In the future it is believed it will be relatively little new hydropower development. Based on NVE numbers, 3 TWh hydropower will be built until year 2020 and between year 2020 and 2030 it will be built 1 TWh more new hydropower.(11) A new prerequisite from NVE is the increase of inflow to existing hydropower plants(12). For the period between year 2010 and 2017 the percentage increase for production are higher than the percentage increase for installed capacity compared to period 1990-2009. This indicates that inflow to the Norwegian hydropower system is increasing. Based on NVEs assumption, the inflow is assumed to increase by 4 TWh between year 2020 and 2030. Norway’s hydropower plants are also aging.(3) A general increase for the efficiencies should also be expected. This in total gives a higher increase given energy production compared to installed capacity.

### 2.1.2 The Norwegian wind power system

The Norwegian wind power production was 1,9 % of the total energy production in 2017. NVE has the administrative task to have an overview over existing wind power plants and potential for new plants. In 2018 NVE launched the wind power database(13). The wind power database contains all operative wind power plants in Norway. Table 2.3 gives an overview over wind power in Norway today.

**Table 2.3 Wind power production in Norway**

| Wind power | 2018 | 2019 (expected increase) |
|---|---|---|
| **Installed capacity [MW]** | 1 695 | 3 032 (+1 337) |
| **Production (annual) [TWh]** | 3,9 (5,3) | 8,4 (+4,5) |

The Power Market Analysis 2018 from NVE(11) assumes an increase of 21 TWh until year 2030. This gives a percentage increase of 396 % from annual production in 2018.

NVE have also published a report about the proposal for a national framework for wind power onshore in Norway(9). The report was prepared on behalf of the Ministry of Petroleum and Energy in Norway. The report discus where the most suitable areas in Norway for onshore wind power, given environment and social impacts. Installed capacity, of 2018, are expected to have annual production of 5,3 TWh. Table 2.3 shows a lower production in 2018, since wind power are dependent on the weather and climate. The national framework for wind power on land in Norway indicates an annual production of 12,2 TWh when all ongoing wind power projects are completed. A total of 37 projects have also a finalized license but are not yet started. Production from those projects are estimated to a total of 10,7 TWh. If all projects are finalized, the total annual production are 22,9 TWh.

The same report mentions the high potential for offshore wind power in Norway. Today it is considered possible to build bottom-fixed wind turbines down to 50-60 m water depths. Technology development will increase the potential for even lower depths. The Norwegian continental shelf is often deeper than 50-60 meters and are dependent on a technology development. Floating installations are technology are in development. They are mainly built as demonstration projects. Today Norway has one demonstration turbine called Hywind outside Karmøy, installed in 2009. The technology concept from Hywind makes it possible for depths down to 800 meters. In Scotland it is installed five turbines with the same concept.

Kjeller Vindteknikk has mapped the offshore wind power potential for NVE in shallow areas, less than 20 meters(14). The potential is estimated to be between 6 000- 30 000 MW. The numbers depended on whether the minimum distance from land requirement are set from 1-10 km. The potential for wind power farther out than ten kilometres is also huge, illustrated in the wind power map from Kjeller Vindteknikk in Appendix A. In United Kingdom is the average size for installed capacity 1 GW for ongoing projects for offshore wind power(15).

SINTEF and NTNTU have done studies about development of offshore grid combined with offshore wind power in Northern Europe(16, 17). In the case study for one of the projects it is assumed a total installed capacity of 3,5 GW (four projects) for floating offshore projects in Norway(16). The study also discusses how the transmission grid should be developed given different constraints as the high investment cost for HVDC connections. This case study illustrates the potential for floating wind power projects combined with offshore grid connecting countries and offshore installations.

## 2.2 Wind power in United Kingdom

United Kingdom works towards a more renewable energy system to fit for the future, and generation from both onshore wind and offshore wind is a central part for that shift. Today renewable energies provide almost a third of United Kingdom’s power production. Wind power generates half of that amount again. For offshore wind, United Kingdom is a world leader with more installed capacity than any other country. The offshore wind sector in United Kingdom has ambitious for plans for further development(18). Table 2.4 gives an overview of installed onshore and offshore wind power in UK collected 05.06.2019(15).

**Table 2.4 UK wind power (collected 05.06.2019)**

| | **Onshore wind** | **Offshore wind** | **Total** |
|---|---|---|---|
| **Installed capacity [MW]** | 13 038 | 8 483 | 21 522 |
| **Production [TWh]** | - | - | 26,8 |

The table is collected from RenewableUK, data are updated as soon new information are received. The data is only from projects larger than 100 kW. RenewableUK have also an overview over consented projects and projects under construction. Consented projects for onshore wind power are 4 660 MW. Projects under construction for onshore and offshore wind power are, respectively 645 MW and 2 882 MW. If both consented projects and projects under construction are finalized, the total installed capacity will increase with 8 187 MW, an increase of 38 %.

Siemens UK predicts in a short note from 2014(19) that by year 2020 a total of 14 GW will be installed offshore. Projects under development and projects with development license are just above 40 GW. The estimate for year 2020 from Siemens UK was 2,6 GW higher than currently available number from RenewableUK.

The study mentioned in Chapter 2.1.2 includes also assumed estimates for installed capacity in Great Britain as well(16). The assumed value for installed capacity in the same case study is in total 44,6 GW.

## 2.3 Norway's interconnections to Europe

Norway has today eight interconnections with neighbouring countries (Sweden, Denmark, Finland, Netherland, Germany and Russian Federation). The Norwegian exchange capacity with connecting areas is currently around 6200 MW(20). Two new international connections to Germany(21) and Great Britain(22) are planned to be completed in 2019 and 2021, respectively, and are 1400 MW each. This will increase the total Norwegian exchange capacity to about 9,000 MW. Norway will thus have a very high proportion of exchange capacity compared to many of the European countries. In the future it is believed that the exchange capacity will be further developed. Table 2.5 gives an overview of existing cross-border capacities as of 2019(23).

**Table 2.5 Overview of existing Norwegian cross-border capacities**

| Interconnection | Information | Max Export capacity [MW] |
|---|---|---|
| **Norway - Finland** | One line | 50 |
| **Norway - Sweden** | Several lines | 3695 |
| **Norway - Denmark** | Skagerrak 1- 4 | 1 700 |
| **Norway - Netherlands** | NorNed | 700 |

Figure 2.1 gives an overview over interconnections between Nordic countries(5). In near future Norway's interconnections with Europe and Great Britain will be stronger, given ongoing projects.

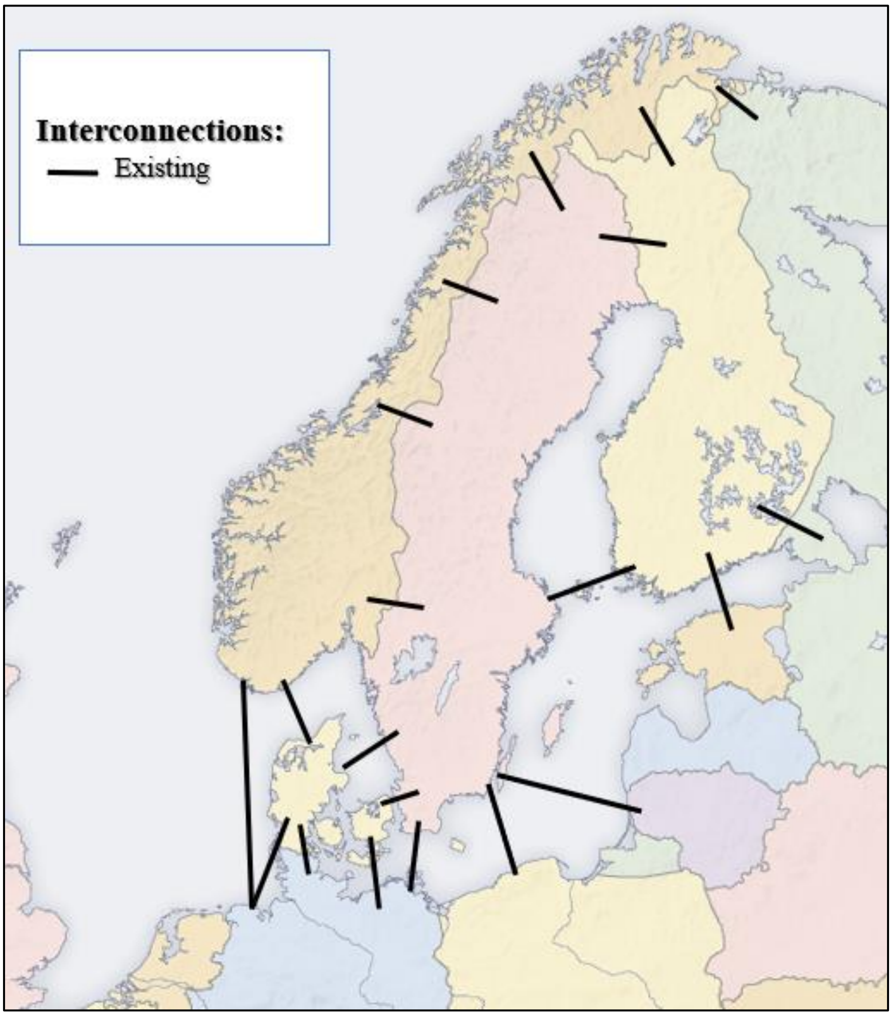


**Figure 2.1 Interconnections between Nordic countries**

ENTSO-E, the organization for TSOs in Europe, regularly publish reports about future network development in Europe in the report framework TYNDP. The TYNDP framework discuss network projects and identifies bottlenecks in the European energy system and describes expected exchange capacities between different countries based on known plans.

In NVEs Power Market analysis 2018(11), they identify which projects in TYNDP2018(24) affects the Norwegian energy system. The net capacity in Europe are expected to increase strongly over the next ten years. This is due to large changes in the power market and the increased grid demand, for example due to a high increase of none flexible RES. In coming years Norway will be connected to Great Britain. Great Britain have ongoing projects about strengthen existing connections to neighbouring countries. Mentioned connections in the report are further development of existing cable from Great Britain to France and Great Britain to Germany. This will reduce the price difference between Great Britain and the rest of continental Europe. ENTSO-E have also included the project NorthConnect(25) between Norway and Great Britain at 1400 MW. This connection is not included in NVEs dataset since the project is currently under concession procedures.

In March 2018 the Norwegian Parliament, Stortinget, adopted Norwegian membership in ACER(26). In Norway NVE has the control authority and will participate via the EEA agreement. ACER tasks are contributing to the harmonization of technical regulations (network codes and guidelines), supervise energy markets and facilitating the development of new electricity and gas networks, including interconnectors (international cables). Before adopting the membership in the winter 2017/2018 there was discussions about whether Norway should join ACER(27). The discussion was how much power is delegated from national level to European level in energy politics. An argument was that Norwegian co-operation with EU and ACER involves a loss of control over own natural resources in Norway. Another argument was that Norwegian co-operation with the EU affects the development of interconnectors to neighbouring countries.

## 2.4 Area prices and power markets in Europe

Nord Pool runs the power market in Europe, originally for the Nordic countries. They deliver both day-ahead and intraday markets to their customers. The day-ahead market(28) is the main arena for trading of power, and are done for the Nordic, Baltic and UK. The intraday market is a supplement to the day-ahead market and helps secure the balance between supply and demand. Nord Pool offers these services for 13 countries. In total Nord Pool trades power in 13 markets and other specific related services such as compliance, data or courses

The Nordic and Baltics are divided into bidding areas by the local TSO in order to handle congestion in the grid. Each bidding area can have a balance, deficit or surplus of electricity. The electricity will flow from areas where the offered price is lower towards areas where demand is higher and offered prices are higher. In some cases, the transmission capacity between bidding areas are not enough to reach price convergence across all areas. The limited capacity, bottlenecks, leads to bidding areas having different price, e.g. area prices(29). If the system has none bottlenecks the system gets identical area prices for all areas.

Figure 2.2 shows a special situation were Denmark and Germany have an overproduction of wind power(28). Denmark export power to all connecting countries except from Germany since the price is even lower there. This situation shows that the existing transmission network able to compensate for the lateral distribution between production and consumption/export(30).

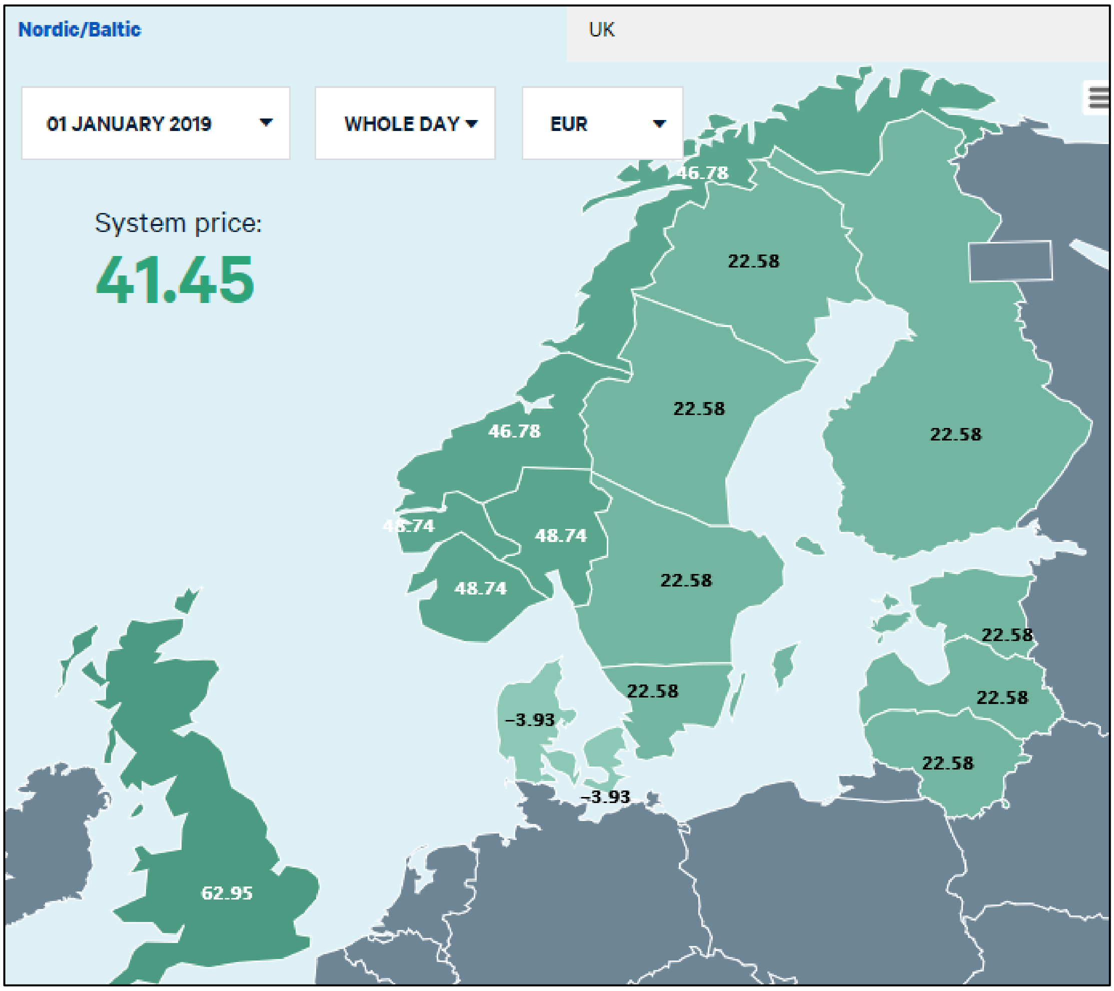


**Figure 2.2 System prices and area prices from Nord Pool 01.01.2019**

The system price [EUR/MWh] is a price set where all congestion restrictions capacities are set to infinity, e.g. a system price is an unconstrained market clearing reference price for the whole system. Nord Pool calculates the system price after all area price are calculated for all bidding areas. Flows (import/sales, export/purchase) between the Nordics, Netherland, Germany, Poland and the Baltics considered the system price. Area configuration used in system price calculation differs from configuration used in area price calculation, since the Nordics (Norway, Denmark, Sweden and Finland) are set as one common bidding areas (capacities within these areas are set to infinity).

In NVE's Power Market Analysis 2018, they have analyzed the power prices for Norway toward year 2030.(11) The power prices are calculated based on a normal year with starting point in year 2020. The calculations assume an increase from 32 EUR/MWh in 2020 to 36 EUR/MWh in 2030 with a minimum and maximum of respectively 22 EUR/MWh and 54 EUR/MWh in 2030 depending on precondition for fuel-prices and $CO_2$-taxes. The increased prices are due to preconditions about higher $CO_2$-taxes and new offshore cables to Great Britain and Denmark.

After the report NVE published in 2018, a short note where published in the autumn(31). The note discussed the Norwegian electricity prices without connections abroad (for both cables and lines) due to the dry summer in 2018 and high fuel prices. In an imaginary situation with none interconnections abroad, power producers must save the water throughout the winter until the snow melts. Thus, power prices are pushed upwards, and can be very high in dry years. In wet years the power price can be very low when Norway does not have the opportunity to export the surplus. The analysis from NVE shows that the power price without interconnections is 2-3 times higher in winter compared to a situation with connections where Norway can both import and export power. Power exchange with abroad helps to reduce the risk of running out of water for power production and contributes to increased security of supply in the Norwegian power system. The note has an opposite results in contrast to the Power Market Analysis 2018 which assumed an increase around 2-3 EUR/MWh for the power prices in year 2030 due to two new interconnectors to Europe.(11)

## 2.5 EMPS in general

EMPS (multi-area Power-market Simulator) is the software used in this master thesis. EMPS (known in Norway as "Samkjøringsmodellen") was developed in the 1970s by Elektrisitetsforsyningens Forskningsinstitutt (EFI), now SINTEF Energy Research(6). A corresponding software for single hydro power plants EOPS (one-area Power-market Simulator) was also developed around the same time.

The software was developed because of a need for optimal operation scheduling of the Norwegian hydropower. Since EMPS was developed the energy system/market has grown more complex.  Today the model is capable to simulate the whole energy system in Europe and is used by around 200 users for strategic analyses. Example of users are Power Producers, TSO, Regulators, Consulting Companies and Academic & Research.

### 2.5.1 The model concepts

The main objective of EMPS is:

*Minimize the expected cost (or maximize the socio-economic benefit) in the whole system, considering all constraints.*

In principle, this solution will coincide with the outcome in a well-functioning (=ideal) electricity market. The simulated system can e.g. be the Nordic system or Northern Europe.

The model optimizes the utilization of hydropower resources within the available degrees of freedom(32). The model has degrees of freedom both on the supply side and the demand side. On the supply side, the degree of freedom is linked to the management of a strongly time-variant hydropower inflow, thermal production and potential import from other areas. On the demand side, the degree of freedom is linked to the purchase of power for flexible consumption, potential export to other interconnected power networks and possible reductions in contract supplies during periods with critically low power supply.

The size of the simulated system only depends on the complexity of the system. A bigger and more detailed system gives longer simulation time. The basic time step in the EMPS model is one week, with a horizon of up to ten years. Within each week, the time-resolution is 1 hour or longer. Figure 2.3 gives an overview over the EMPS and EOPS model in a flowchart.

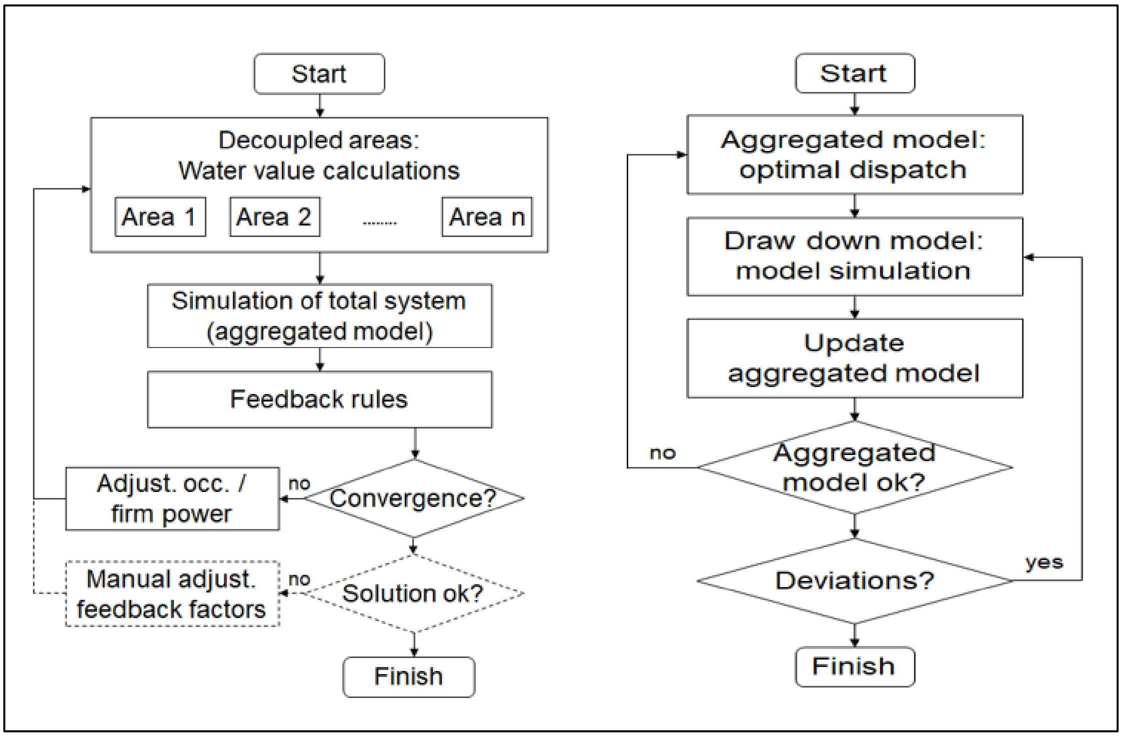


**Figure 2.3 Flowchart of EMPS (left) and EOPS (right) model(33)**

EMPS(34, 35) uses a two-step solutions procedure, consisting of:

- Strategy phase: The incremental water values (marginal costs for hydropower) are computed for each area using stochastic dynamic programming (SDP). A heuristic approach is used to treat the interaction between areas.
- Simulation phase: The total system costs are minimized week by week for each climate scenario in a linear problem formulation.

The software also considers transmissions constraints between areas and climatic differences (rainfall, wind, solar radiation) for major geographical areas or regional subsystems.

### 2.5.2 Model elements

**Areas:** The model assumes that the complete electrical system is divided into areas or sub-systems, each area are one EOPS module. The system is divided into areas based on hydrological or other characteristics related to the hydropower system or limitations in the transmission system. Each area can contain local hydropower, thermal power, firm contracts (load) and interruptible contracts (price-dependent market). An area will in addition have electric connections to other areas with defined capacity, loss and transmission fees. Figure 2.4 gives a schematic description over an example area.

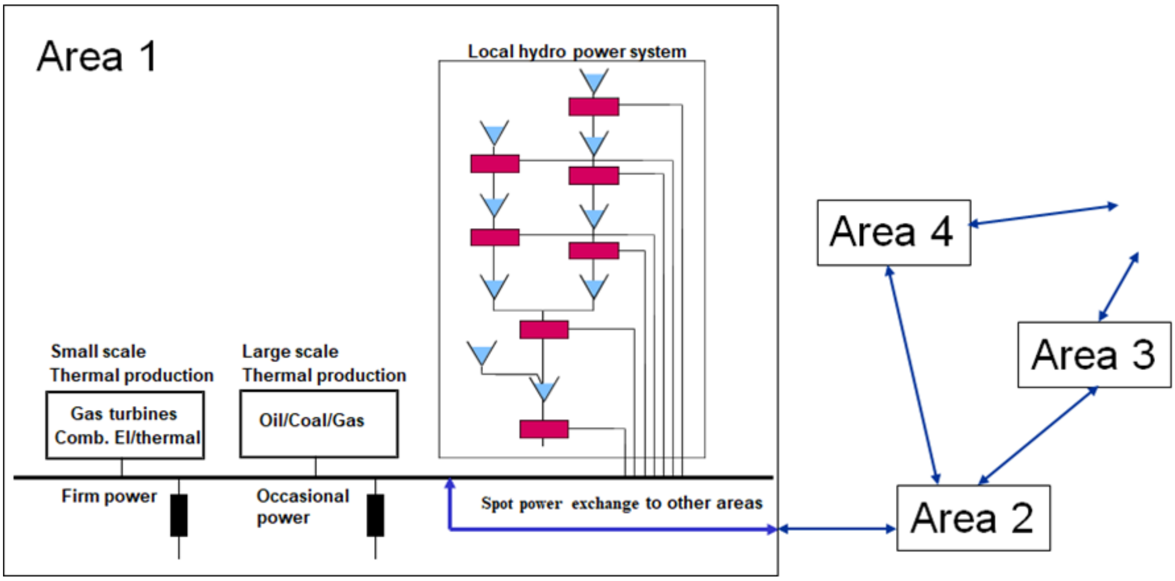


**Figure 2.4 Schematic description of an EMPS area(33)**

**Hydropower:** The hydropower system is modelled in detail. Complicated watercourses are modelled by joining standard hydropower modules. Different areas with similar characteristics within an area gives possibility to include a detailed representation of a hydropower system. The hydropower reservoir is described by the volume in the reservoir. The relation between filling and elevation (reservoir curve) is given as a piecewise linear curve.

**Wind power and solar power:** The energy sources are modelled by historical data for the multi-year simulation. Produced energy are given by installed capacity in area for chosen historical data for weather and climate years.

**Other generation:** Modelled for thermal power plants**.** The modelling of thermal generation is quite simplified in the EMPS and EOPS models. Most of the complications with scheduling of thermal power have a short time perspective, typically within one or two weeks and mostly days. The basic model of a thermal plant in the EMPS and EOPS models are mainly based on the maximum production capacity.

**Transmission:** Exchange capacity between areas, transmission loss and availability are specified for each line between areas.

**Consumption:** Each area has a specified demand and are specified by annual levels, including both yearly weekly profile and hourly profile within week.

In this project the setup used for the EMPS model is the following:

- Area description
- Power plant capacities
- Generated energy by fuel-type
- Inflow scenarios
- Wind & solar time series
- Demand curves
- Transmission system
- Fuel prices

# 3 Scenario data

## 3.1 Input data

Building a functional EMPS model requires different input data. The EMPS model requires data about thermal power plants, demand, prices and more. In this project, simulations are done with a long horizon (2040). This requires scenarios for the European system with long enough time span and with certain level of detail.

A basis from the project “EU Reference Scenario 2016” (REF2016)(36) was chosen as the main source for the scenario building. None member countries in EU[1] is not part of that project. The none member countries in the model have instead data from “Ten Year Network Development Plant 2016” (TYNDP2016)(37). When better aggregation was needed for specific power plant types datasets from SUSPLAN and Eurostat were used.

### 3.1.1 EU Reference Scenario 2016

The REF2016(36, 38) gives a consistent approach for projecting long term energy, transport and climate trends across the EU. Within EU it is used as a key support for policy making. The report is a forecast, so there are several unknowns. The range of unknowns are from technological costs, fossil fuel prices to implementation of new policies across EU.

REF2016 provides following data of interest:

- Includes EU28-countries
- Time horizon from 2000-2050, 5-year time step
- Each time step has a detailed description of the power system; i.e. installed capacity per fuel type (e.g. coal, gas, wind, solar biomass, hydro), produced energy per fuel type, electricity demand, efficiencies etc.
- Share of CCS, Combined Heat & Power

The REF2016 is from 2016, therefore all new measurements are not included. Since REF2016 does not include the politically agreed but not yet legally adopted 2030 climate and energy targets, some data is out of date already in 2019. An example is that Great Britain will phase out their thermal power based on coal by 2023(39). This is not considered in the used scenario building.

[1] Albania, Bosnia and Herzegivina, Montenegro, Macedonia, Northern Ireland, Norway, Serbia and Switzerland,

### 3.1.2 Ten Year Network Development Plan 2016

ENTSO-E, the European Network of Transmission System Operators for Electricity, issues the TYNDP. ENTSO-E represents 43 electricity transmission system operators (TSOs) from 36 countries across Europe. The TSO in Norway is Statnett. ENTSO-E have the objective of setting up the internal energy market and ensuring its optimal functioning, and of supporting the ambitious European energy and climate agenda together with it is members. Important issues today are the integration of a high degree of Renewables in Europe's energy system, the development of consecutive flexibility, and a much more customer centric approach than in the past.

The Ten-year network development plan (TYNDP)(37) is issued by ENTSO-E, the last in 2018. The different editions offer a view on what grid is needed where, to achieve Europe's climate objectives by 2030. TYNDP2016 reports provides an overview of European significance, which includes several scenarios, based on a common data set with a CBA methodology. The scenarios consist of four long-term scenarios ("Visions") for 2030 and one mid-term scenario for 2020. The four scenarios are Vision 1 Slowest Progress, Vision 2 Constrained Progress, Vision 3 National Green Transition and Vision 4 European Green Revolution. The closest one to the EU data was Vision 2 ("Constrained Progress"), from which the data was taken. The scenario report from TYNDP2016 explains the differences between the four visions given economy and market, demand, generation. Figure 3.1 gives the relation between the four visions regarding a European framework and the Energy roadmap 2050(37).

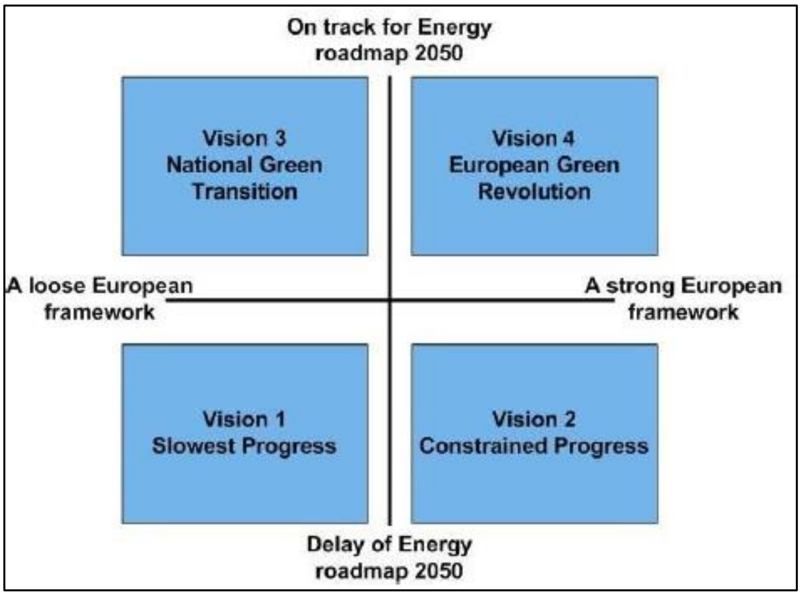


**Figure 3.1 Two-axis overview of the four visions (general) from TYNDP2016**

The TYNDP includes all European countries. The non-member countries of EU have therefore datasets from TYNDP. REF2016 is not updated since 2016, it is decided to use datasets from the same year for the TYNDP in the model and scenarios.

### 3.1.3 SUSPLAN

SUSPLAN(40) is a project within CORDIS in EU. CORDIS mission is to create innovative products and services and simulate growth across Europe.

SUSPLAN wish to contribute to development of regional and Pan-European guidelines for more efficient integrations of renewable energy into future infrastructure. The main objective is to develop guidelines for an efficient integration of RES into different sectors in today’s system in a future perspective. The guidelines consist of strategies for decision makers and power distributors with time perspective 2030- 2050. Establishing of the guidelines are based on:

- Scenario analysis in selected representative regions and trans-national regions based on real data, and by using quantitative models. The scenario studies cover technical, market, socio-economic, legal, policy as well as environmental aspects.
- Comparing regional and trans-national possibilities, challenges and barriers.
- Systematic evaluation and comparison of the future possibilities for development.
- Generalization of the results.

Based on the guidelines SUSPLAN are part of making information available for interested actors regarding scenarios for a sustainable development of the European energy system.

### 3.1.4 Eurostat

Eurostat is the statistical office of the EU. The mission for Eurostat is to provide high quality statistics for Europe.

Eurostat's process and publish comparable statistical information at European level. Member States collects data by their statistical authorities. The statistical authorities verify and analyse national data and send them to Eurostat. Eurostat's consolidate the data and ensure they are comparable, using harmonized methodology.

In this project Eurostat’s dataset for CHP data, 2005- 2014(41) are used, since the REF2016 only gives the total share of installed capacity for CHP power plants. Given Eurostat’s data it is possible to get a better classification and split the total installed capacity for CHP power plants into different CHP plant types.

## 3.2 Scenario building

Datasets from REF2016, TYNDP2016, SUSPLAN and Eurostat regarding energy sources, grid and demand are used to build scenarios with time-step 5 year from 2000 to 2060.

The datasets have different level of detail. REF2016 are more extensive than TYNDP2016. Where it is needed, missing data are interpolated and extrapolated. This had no big influence on Norway and Switzerland, since these countries depend mostly on hydropower and nuclear energy. This is due no big changes in available capacity over the years. For the Balkan countries, modelled areas have none direct interconnections to the focus areas (Norway and Great Britain).

The focus years in this project are respectively 2020, 2030 and 2040. Year 2020 are used as the reference year to illustrate today's energy system. Year 2030 and 2040 are used for future scenarios. In year 2040 are the biggest adjustments compared to base scenario done.

The Scenario building are done in an excel-file. Data from each respective focus year and scenario is used as input data to xml-files used in the EMPS program. Performed simulations are shown in Table 5.1 in the Chapter 5.

# 4 Model

## 4.1 EMPS model

In this peoject the basis for analyzed EMPS model is a model further called EMPS 1 developed by supervisor Steve Völler(33). The EMPS 1 models the European energy system.

The model description defines the contents of an area, e.g. how the watercourses of the hydro power plants are defined, what type of thermal power it contains, the shape of the demand curve and so on. These data are gathered from different projects within this field, used reports and studies are explained in Chapter 3.

### 4.1.1 Model schematic and overview

The EMPS 1 model consists of areas and connections. Within an area the power system for that region is specified, and the connections reflect the transmission lines with their limits. All areas and connections together build the energy system that is used in EMPS 1. For this project, the schematic in Figure 4.1 displays the used model. The data for areas in red are taken from the REF2016 while the orange areas based mainly on data from TYNDP2016. Transmission lines in red are onshore connections and blue are offshore connections. Not all connections are in operation before year 2030. The HVDC offshore connection to Great Britain (UK) from Norway (NO5) is an example.

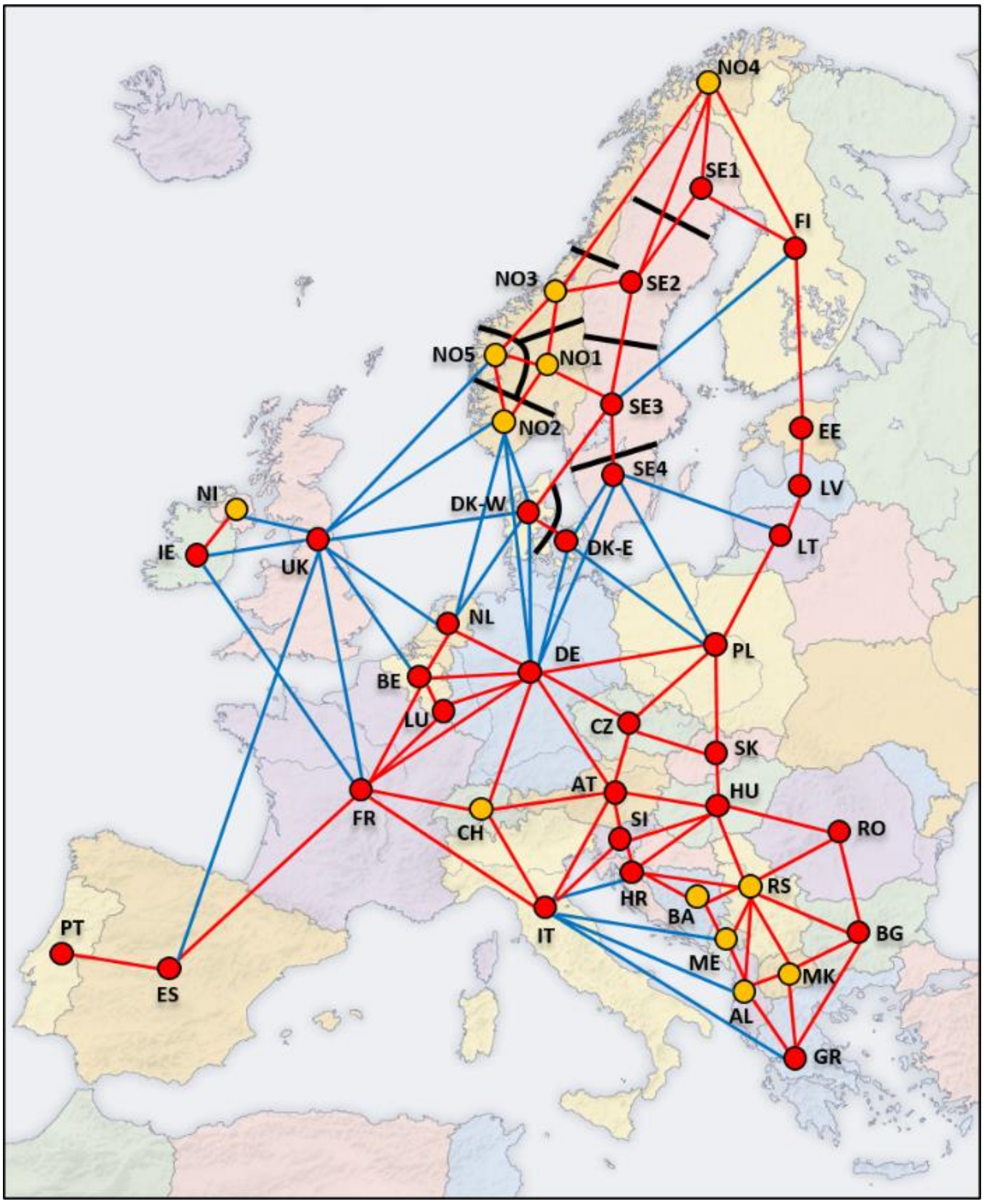


**Figure 4.1 Schematic description of the EMPS 1 model(33)**

The model of the European energy system (EMPS 1) includes the following:

- 34 countries with 42 areas
- total of 96 transmission lines
- 787 thermal power plants of 17 different types
- 42 areas with hydro power, split into reservoirs and run-of-river
- 37 areas with solar generation
- 41 areas with wind generation, whereof 25 also has offshore wind in addition

In further subchapters 4.1.2 to 4.1.10are the different elements in the EMPS 1 model developed by Steve Völler(33) explained.

### 4.1.2 Areas

The EMPS 1 consists of several areas. Usually one for each country, except Norway, Sweden and Denmark. These countries have constraints in the transmission system, given different locations for production and consumption. Norway has five areas given bidding areas from Nord Pool(28). Sweden has four areas due to strong connection to Norway. Denmark has two areas. DK-East belongs to the Nordic synchronous zone and DK-West to the continental zone. All areas are listed in Table 4.1.

**Table 4.1 Area numbers, abbreviations and names in EMPS 1(33)**

| # | EMPS | Name | # | EMPS | Name |
|---|---|---|---|---|---|
| **1** | AL | Albania | **22** | LV | Latvia |
| **2** | AT | Austria | **23** | ME | Montenegro |
| **3** | BA | Bosnia and Herzegovina | **24** | MK | Macedonia |
| **4** | BE | Belgium | **25** | NI | Northern Ireland |
| **5** | BG | Bulgaria | **26** | NL | Netherland |
| **6** | CH | Switzerland | **27** | NO1 | Norway 1 |
| **7** | CZ | Czech Republic | **28** | NO2 | Norway 2 |
| **8** | DE | Germany | **29** | NO3 | Norway 3 |
| **9** | DK-E | Denmark East | **30** | NO4 | Norway 4 |
| **10** | DK-W | Denmark West | **31** | NO5 | Norway 5 |
| **11** | EE | Estonia | **32** | PL | Poland |
| **12** | ES | Spain | **33** | PT | Portugal |
| **13** | FI | Finland | **34** | RO | Romania |
| **14** | FR | France | **35** | RS | Serbia |
| **15** | GR | Greece | **36** | SE1 | Sweden 1 |
| **16** | HR | Croatia | **37** | SE2 | Sweden 2 |
| **17** | HU | Hungary | **38** | SE3 | Sweden 3 |
| **18** | IE | Ireland | **39** | SE4 | Sweden 4 |
| **19** | IT | Italy | **40** | SI | Slovenia |
| **20** | LT | Lithuania | **41** | SK | Slovakia |
| **21** | LU | Luxembourg | **42** | UK | United Kingdom |

### 4.1.3 Demand curves

The total demand is given as a yearly sum for each area. The value depends on the chosen year and scenario year. This value is then divided into 52 weeks, based on the associated weekly demand curve of the area. The weekly value is then further split into hourly values for the specific week. Each week has a slightly different shape, depending on the time of the year. Figure 4.2 gives an overview over demand curves in the EMPS 1 model. The time values give an hourly demand.

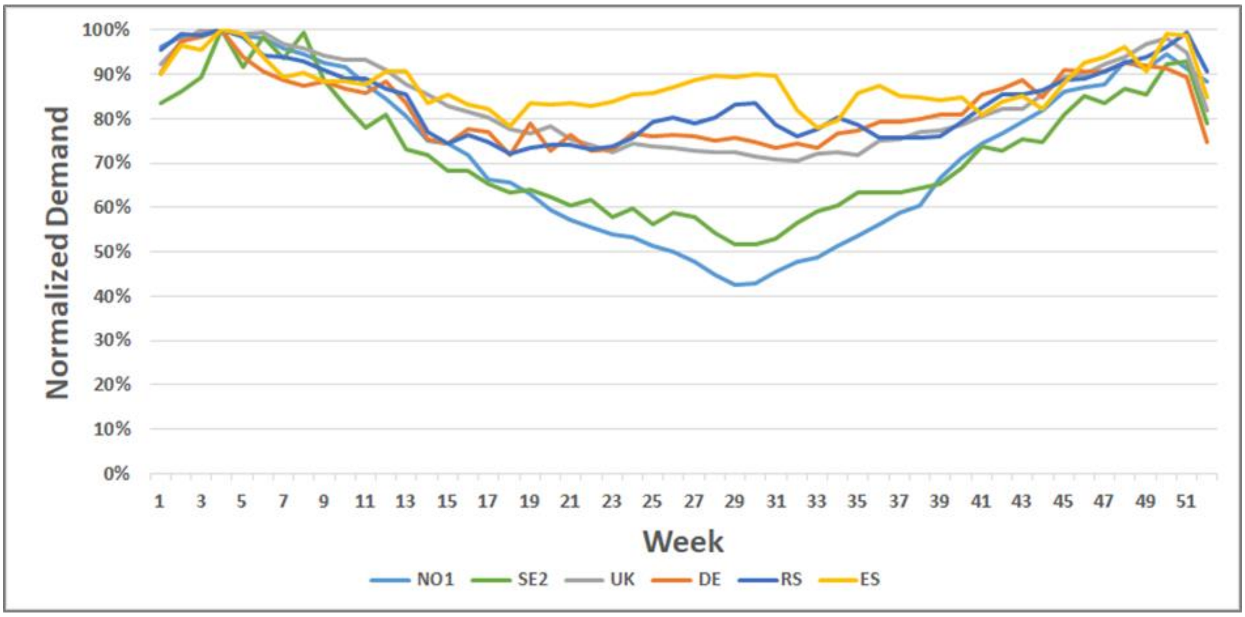


**Figure 4.2 Demand curves for weekly values given different areas(33)**

The EMPS 1 operates with different load profiles given geographical location and climate. This is adjusted manually for each country. Table 4.2 and Figure 4.3 shows the notable differences for the six load profiles in the EMPS 1 model

**Table 4.2 Loadprofiles in EMPS model**

| Weekprofile | Distribution |
|---|---|
| **PL_Flat** | Flat over whole year |
| **PL_01** | 10% lower in summer |
| **PL_02** | 20% lower in summer |
| **PL_03** | 30% lower in summer |
| **PL_04** | 40% lower in summer |
| **PL_05** | 50% lower in summer |

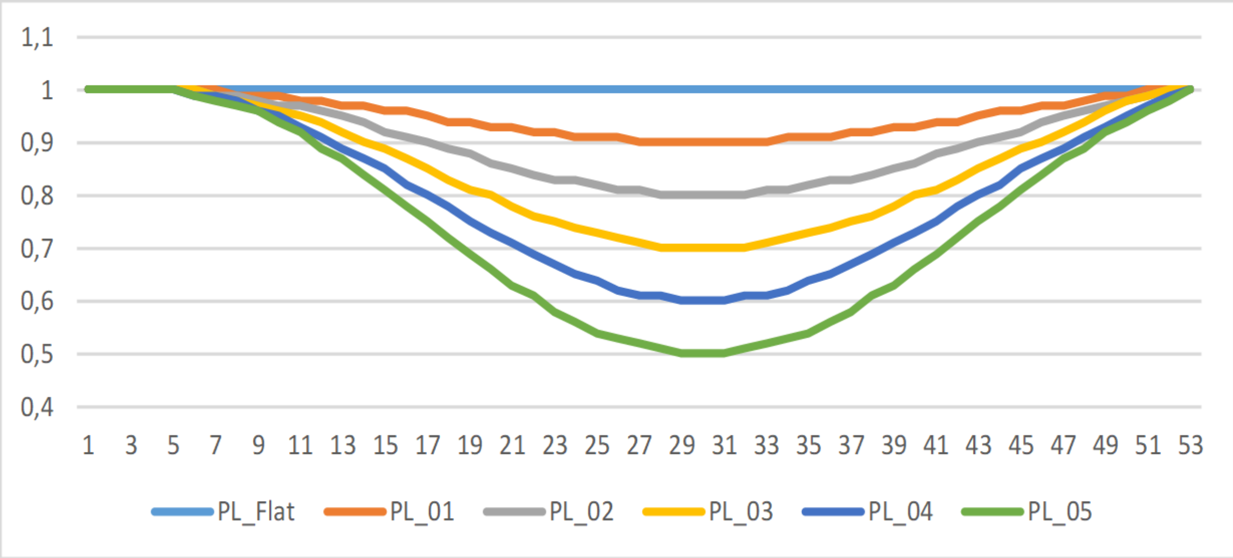


**Figure 4.3 Weekly distribution for loadprofiles in EMPS model(33)**

### 4.1.4 Hydropower

#### *4.1.4.1 Hydropower production*

The annual hydropower production in Norway is 134,9 TWh(2) and the storable share is around 85 TWh(33). The average net-export is 11,3 TWh(33). Due to climate variations, the heights of the level in reservoirs vary. This influences the production and import/export, since Norway depends heavily on hydropower. Figure 4.4 shows reservoir levels between year 1990-2018. The variations for the reservoir levels are almost 40 % between different years.

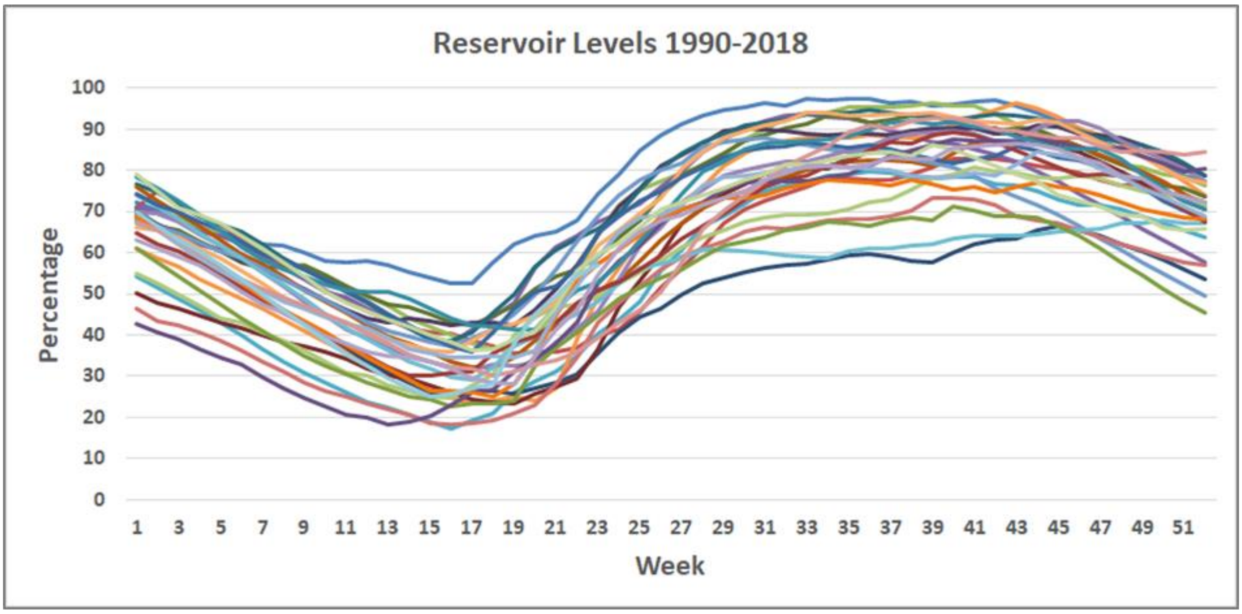


**Figure 4.4 Historically reservoir levels in Norway(33)**

Changes on the reservoir levels affects the Norwegian power balance, supply of electric energy sorted by energy type. Lower hydropower production also leads to a higher share of other energy sources.

#### *4.1.4.2 Hydropower aggregation*

In the EMPS 1 model, the hydropower courses of each area are aggregated to one equivalent plant. This is due to lack of information about detailed hydropower courses. Public available information could be used, but a detailed course would not lead to significantly better results for this project. More information would also increase the data gathering, simulation and post-processing time unnecessarily. Figure 4.5 shows a model of a hydropower plant in the EMPS model.

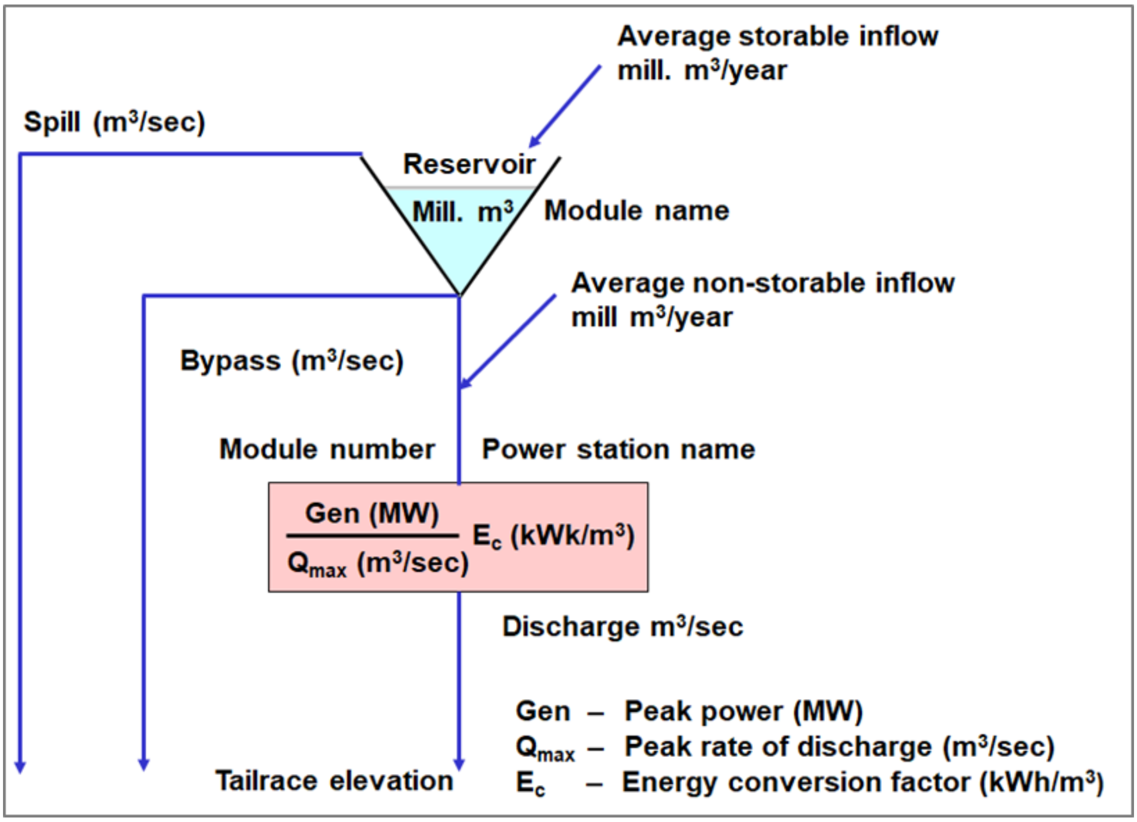


**Figure 4.5 Model of a hydropower plant in EMPS(33)**

Figure 4.6 shows aggregation of a water course with different hydropower plants to one equivalent plant.

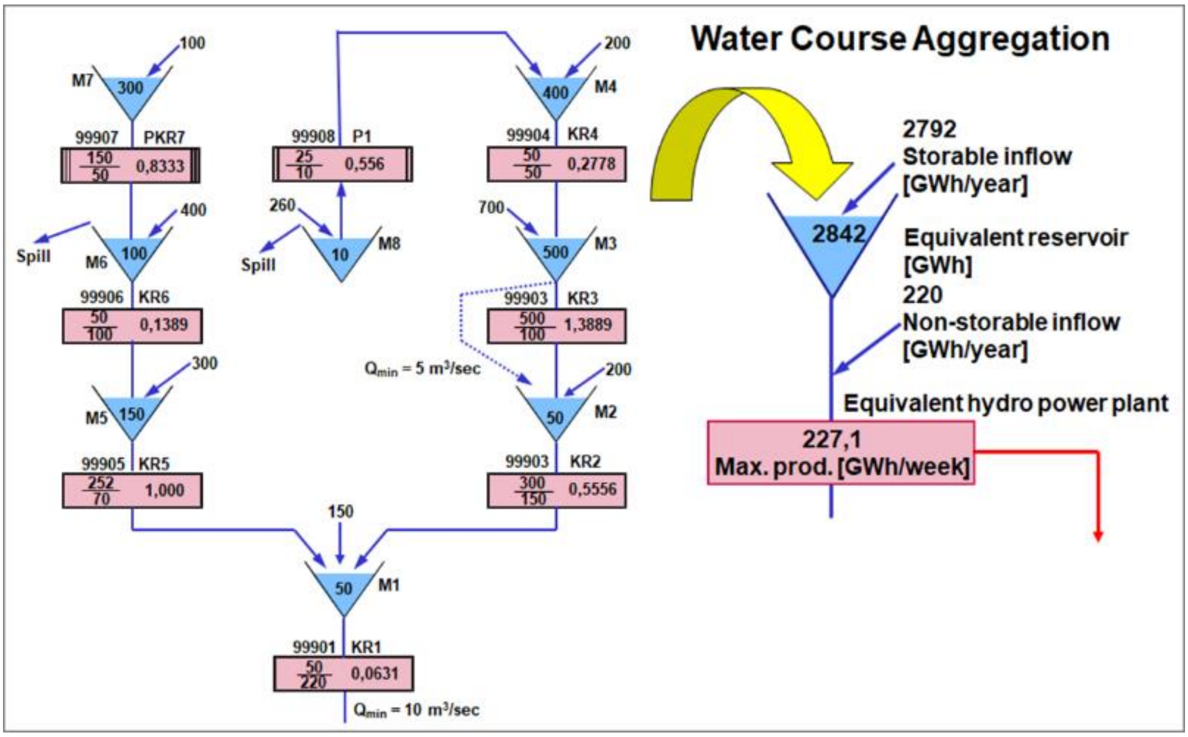


**Figure 4.6 Aggregation of hydropower plants(33)**

### *4.1.4.3 Reservoir, run-of-river and inflow*

A hydropower system consists of hydropower plants with a reservoir or run-of-river plants. The run-of-river power plants cannot be optimised, since they have an unregulated production due to the rainfall. The power plants with a reservoir can be optimised. The optimisation can be done within the limits set by operation and/or environmental issues. Environmental issues are full reservoirs, minimal reservoir height and minimal water flow. Full reservoirs leads also too spillage, and all inflow is not used for energy production. The ratio for reservoirs and run-of-river plants are taken from models used in SUSPLAN. A sample for the EMPS 1 model can be seen in Table 4.3.

**Table 4.3 Selection of some hydro courses in EMPS with their values, 2040**

| Area | Reservoir volume [GWh] | Installed capacity [MW] | Annual production [TWh] | Regulation factor | Regulated production [TWh] | Unregulated production [TWh] |
|---|---|---|---|---|---|---|
| **NO1** | 11 098 | 6 872 | 27,4 | 0,626 | 17,1 | 10,2 |
| **NO2** | 33 379 | 14 026 | 47,3 | 0,818 | 38,9 | 8,7 |
| **NO3** | 8 272 | 4 330 | 15,4 | 0,694 | 10,8 | 4,8 |
| **NO4** | 19 621 | 5 927 | 21,7 | 0,879 | 19,1 | 2,6 |
| **NO5** | 13 755 | 7 892 | 24,9 | 0,844 | 21,1 | 3,9 |

The normalized inflow has differences between geographical areas, not necessarily countries. Especially the difference is visible between inflows where the main driver is snow melting, rain and snow melting/rain.

### 4.1.5 Wind and solar data

In the EMPS model is it important to use dataset for wind and solar generation with the same time solutions or measuring settings. Since the EMPS tool needs historical data for the multi-year simulation. This requires datasets for a wind and solar that both covers the area of interest and includes enough years.

For this project it is utilized Reanalysis data provided by NOAA(42). The Reanalysis data measures/calculates climate data around the globe based on a grid with a 2.5◦ - resolution. The EMPS 1 model consist off aggregated nodes. The measurements-points for wind and solar are set with coordinates and are interpolated based on the four-corner-values from Reanalysis to get specific values for any given area in the EMPS 1 model.

The data have a time resolution of 6 h-mean values. The EMPS 1 model contains of 75 year for the simulation data. The wind data consist of 61 consecutive years and solar has 22. Therefore, the dataset is reused to fill up the years until 75 years is reached. The data gives a good enough difference for the climate years containing different values for inflow, wind and solar. The time-series are rated to 1 GW, which means 1 GW wind capacity produces the amount given in the time-series. A 0.5 GW solar capacity gives the time-series multiplied with 0.5.

### 4.1.6 Energy system description

Building a functional model for EMPS 1 requires information about thermal power plants, demand, prices etc. Based on datasets from REF2016 and TYNDP2016, a model was built for each year from 2000 until 2060. Since the REF2016 scenario ends in 2050, the two last year's where extrapolated, based on the previous years. The TYNDP2016 scenario ended in 2040, the future where all extrapolated. The extrapolated values may lead to a flattering of the values. In this project focus years are 2020 to 2040 with 10-year time step, so it is not affected greatly by the extrapolated values. The EMPS 1 model consists of different power plant types, described in Table 4.4.

**Table 4.4 Power plant types in the EMPS model(33)**

| Category | Fuel type | Power plant | Remarks |
|---|---|---|---|
| Thermal | Coal | Hard coal | |
| | | Lignite | Share of lignite based on TYNDP2016 from ENTSO-E |
| | Gas | Gas-Conventional | Steam plants |
| | | Gas-OCGT | Open-cycle gas turbine |
| | | Gas-CCGT | Comined-cycle gas turbine |
| | | Gas-CCS | Gas power plants with carbon capture and storage |
| | Oil | Oil | |
| | Nuclear | Nuclear | |
| Renewable | Wind | Wind | |
| | Solar | Solar | |
| | Hydro | Hydro | Split into reservoir and run-of-river |
| | Biomass | Biomass | |
| | Other RES | Other RES | |
| Others | Others | Others | e.g. hydrogen, methanol |
| CHP | Coal | CHP_Coal | CHP based on coal |
| | Gas | CHP_Gas | CHP based on gas |
| | Oil | CHP_Oil | CHP based on oil |
| | Biomass | CHP_RES | CHP based on biomass |
| | Others | CHP_Divers | CHP based on other fuel types |

#### 4.1.6.1 Coal and gas

Fuels for thermal plants can come from coal and gas. Coal comes either from hard coal or lignite. Some countries in Europe have lignite coal plants, since it is cheap and can be harvested locally. The share of lignite is based on values from the TYNDP2016 project, given total installed coal capacity from REF2016. Lignite have higher emissions compared to hard coal.

The installed capacity for gas power plants are split into four types of gas power plants, to include different technologies and out-phasing. The share of CCS is set to gas power plants, since these technologies will be present in all simulated years, while coal will be phased out. The amount of CCS is subtracted from CCGT-plants to stay in line with the total gas capacity.

#### 4.1.6.2 Installed capacity versus genrated energy

Some of the power plants in an energy system run all the time. Either due to low marginal costs (base load power plants like nuclear) or because they are dependent on climatic phenomena (wind & solar, run-of-river). Within the EMPS 1 model, some of the power plants have these characteristics.

Wind and solar generation produce strictly based on their time series if prices are higher than zero. Thermal power plants can also run all the time, either due to constraints (CHP-plants) and/or low fuel costs (nuclear). For these plants, the total annual energy generated was given as an input to the model (from REF2016). The input corresponds to the maximal energy that this power plant type can produce. Table 4.5 gives an overview of the different power plants and how they are modelled in EMPS 1 model.

**Table 4.5 Input values and operation of the different power plant types(33)**

| **Input value** | **Power plant type** | **Operation based on…** |
|---|---|---|
| Installed capacity | Hard coal, lignite, gas, oil, hydro (reservoir) | fuel price, CO2 price |
| Generated energy | Nuclear, biomass, other RES, others, CHP | fuel price (very low), CO2 price |
| Time series | Wind, solar, hydro (run-of-river) | directly based on input |

#### *4.1.6.3 Combined heat and power (CHP)*

CHP plants produces heat as main output, e.g. for district heating. The electricity output from the CHP plant are included in the EMPS 1 model. The share of CHP-plants of the total installed capacity is given in REF2016. Given Eurostat dataset a better classification based on fuel types is used. The energy amount is split into different plant types given plant types in Table 4.4. The Eurostat dataset ended in 2014, data after 2014 is extrapolated based on the CHP share from REF2016.

### 4.1.7 Aggregation and disaggregation of power plants

Each country in Europe has several types of power plant technologies and individual power plants. Open source datasets for including all power plants in Europe does not exist. In this project it is not necessary to include every single power plant(33). Data combined from SUSPLAN and the REF2016 are used to construct a set of power plants.

Given each country, all power plants are aggregated to one power plant per type. The one power plant type has data for total installed capacity and efficiency. That plant is split into three different power plants of the same type with different efficiencies. Values are collected from TYNDP2016. The three different power plants represent the average of an old, moderately old and modern power plant. Figure 4.7 illustrates how this aggregation and disaggregation are performed for an example area.

| Country | Name | Type | Capacity (MW) | Efficiency (%) |
|---|---|---|---|---|
| Example | Thermal plant 1 | Hard Coal | 200 | 41,0 % |
| Example | Thermal plant 2 | Hard Coal | 400 | 40,0 % |
| Example | Thermal plant 3 | Hard Coal | 600 | 48,0 % |
| Example | Thermal plant 4 | Hard Coal | 800 | 39,0 % |
| Example | Thermal plant 5 | Hard Coal | 1000 | 43,0 % |
| Example | Thermal plant 6 | Hard Coal | 100 | 40,0 % |
| Example | Thermal plant 7 | Gas | 120 | 32,0 % |
| Example | Thermal plant 8 | Gas | 180 | 37,0 % |
| Example | Thermal plant 9 | Gas | 500 | 44,0 % |
| Example | Thermal plant 10 | Gas | 400 | 41,0 % |
| Example | Thermal plant 11 | Gas | 360 | 45,0 % |
| Example | Thermal plant 12 | Gas | 1100 | 48,0 % |
| Example | Thermal plant 13 | Gas | 310 | 39,0 % |
| Example | Thermal plant 14 | Gas | 560 | 43,0 % |
| Example | Thermal plant 15 | Gas | 600 | 40,0 % |
| Example | Thermal plant 16 | Gas | 720 | 51,0 % |
| Example | Thermal plant 17 | Oil | 410 | 38,0 % |
| Example | Thermal plant 18 | Oil | 300 | 42,0 % |
| Example | Thermal plant 19 | Oil | 190 | 46,0 % |
| Example | Thermal plant 20 | Nuclear | 860 | 33,0 % |

Aggregate all power plants of the same type to one

| Type | Capacity (MW) | Efficiency (%) |
|---|---|---|
| Hard Coal | 3100 | 41,8 % |
| Gas | 4730 | 42,0 % |
| Oil | 900 | 42,0 % |
| Nuclear | 860 | 33,0 % |

Disaggregate the power plant to three plants with varied efficiency, also split into different technologies

| Type | Capacity (MW) | Efficiency (% |
|---|---|---|
| Hard Coal | 1033 | 30,0 % |
| Hard Coal | 1033 | 38,0 % |
| Hard Coal | 1033 | 46,0 % |
| Gas CCGT | 526 | 33,0 % |
| Gas CCGT | 526 | 46,0 % |
| Gas CCGT | 526 | 60,0 % |
| Gas Conv | 526 | 25,0 % |
| Gas Conv | 526 | 34,0 % |
| Gas Conv | 526 | 42,0 % |
| Gas OCGT | 526 | 35,0 % |
| Gas OCGT | 526 | 40,0 % |
| Gas OCGT | 526 | 44,0 % |
| Oil | 300 | 32,0 % |
| Oil | 300 | 35,0 % |
| Oil | 300 | 38,0 % |
| Nuclear | 860 | 33,0 % |

**Figure 4.7 Aggregation and disaggregation for an example area**

### 4.1.8 Out-phasing of old technologies and increase of efficiency

An energy system is in a constant transformation. New power plants and new technologies are built while others will be decommissioned. All this leads to change of power plant types in the system, an improvement in efficiency and a change of technologies. This project intends to give a representation a changing European power plant fleet in the simulated time span.

The first step is to include the out-phasing of old technologies. The gradually out-phasing will include lignite coal, conventional gas power plants and open-cycle gas power plants. Table 4.6 shows the distribution among the technologies for gas.

**Table 4.6 Share for gas power technologies over the years(33)**

| Type | 2020 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| Gas–Conv. | 10 % | 10 % | 10 % | 5 % | 5 % |
| Gas–OCGT | 30 % | 25 % | 25 % | 25 % | 25 % |
| Gas CCGT | 60 % | 65 % | 65 % | 65 % | 70 % |

The next step is to include the phase-out of old power plants with poor efficiency. Decommissioning happens naturally in an energy system. Better technologies are developed, power plants with bad efficiencies earn less money, and power plants eventually reaches end-of lifetime. Table 4.7 shows the share of the power plants within the before mentioned three efficiency categories.

**Table 4.7 Share of fossil energy technologies over the years(33)**

| Type | 2020 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| Old | 20 % | 15 % | 10 % | 0 % | 0 % |
| Moderately old | 30 % | 30 % | 30 % | 25 % | 15 % |
| Modern | 50 % | 55 % | 60 % | 75 % | 85 % |
| EMPS average | 40,6 % | 41,5 % | 42,3 % | 44,4 % | 45,2 % |
| REF2016 | 40,4 % | 41,3 % | 42,2 % | 45,5 % | 48,2 % |

### 4.1.9 Transmission grid

All areas in the EMPS 1 model are connected to one or more areas via transmission lines. In EMPS, only the transmission grid between countries is modelled. The distribution grid within the country including national constrains is not modelled. Exceptions are the countries that include several areas (Norway, Sweden, Denmark). How the areas are connected via transmission lines, is taken from data provided by ENTSO-E. They publish connections between European areas and offshore connections for the years 2020 and 2030. Based on this and additional transmission expansion plans, the transmission system for the other years is modelled. Linear transmission losses are based on SUSPLAN (1% onshore, 2% onshore in Norway and Sweden, 4% offshore).

### 4.1.10 Fuel prices and $CO_2$-taxes

Fuel prices and the $CO_2$-taxes are from the WEO 2016 by IEA(43). The WEO is a report that considers and analyses the global context and development that influences commodity prices. The values presented are used in the overall scenario building methodology. Data for the following parameters are available from the WEO:

- Natural gas price
- Oil price
- Hard coal price
- CO2 price

Additional fuel prices necessary as input to the power system model is calculated in the following way(33):

- Lignite: was set to 25% of the hard coal price and changes accordingly over the years
- Nuclear: was set to 37.56 €/pound, is constant in all scenarios
- Biomass: was set to 6.49 €/MWh, is constant in all scenarios
- CHP: was set to 0.01 €/MWh for all technologies, since they have to run depending on the heat demand
- Others: was set to 1 €/MWh, is constant in all scenarios
- Other Renewables: was set to 1 €/MWh, is constant in all scenarios
- CCS: technologies using CCS have the same fuel prices and lower efficiency as technologies without CCS

Based on this, it was developed a Current Policies (CP) Scenario, New Policies (NP) Scenario and 450 (450) Scenario(33). In performed simulations the CP and 450 Scenarios are used. The 450 Scenario assumes more investment in the energy production sector compared to the CP Scenario. This implies new technologies and higher efficiencies for power plants.

This project has done simulations for years 2020, 2030 and 2040, an excerpt of fuel-prices and $CO_2$-taxes are included in Appendix C.

## 4.2 Extended EMPS model

The extension from the EMPS 1 model to a new model is done in this project.

### 4.2.1 Model schematic and overview for extended model

The extended model (further called EMPS 2) divides UK into three different areas, UK-N, UK-M and UK-S.

**Table 4.8 Area numbers, abbreviations and names in extended EMPS model**

| # | EMPS | Name |
|---|---|---|
| 42 | UK-N | United Kingdom, north |
| 43 | UK-M | United Kingdom, mid |
| 44 | UK-S | United Kingdom, south |

Figure 4.8 displays the section where the EMPS 2 model is extended. The figure is modelled as the EMPS  1 model in Figure 4.1

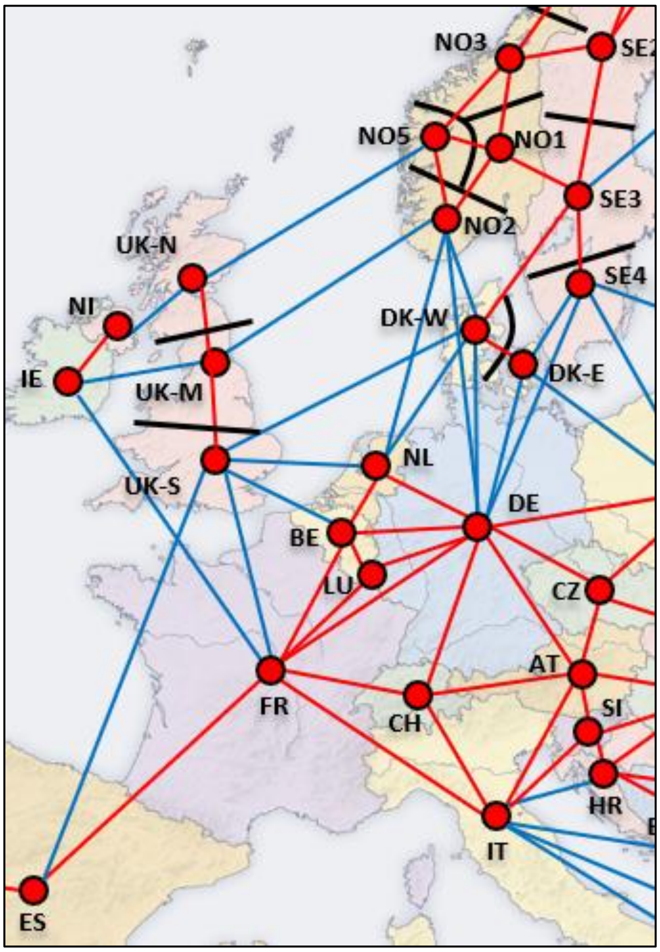


**Figure 4.8 Schematic description (section) of the EMPS 2 model**

The extended model of the European energy system (EMPS 2) includes the following:

- 34 countries with 44 areas
- total of 98 transmission lines
- 787 thermal power plants of 17 different types
- 43 areas with hydro power, split into reservoirs and run-of-river
- 39 areas with solar generation
- 43 areas with wind generation, whereof 27 also has offshore wind in addition

### 4.2.2 Distribution between UK areas

The motivation for extending the model is the lateral distribution between production and consumption. In 2010 a similar extension of the model for UK was done by supervisor Steve Völler for other projects. The extension where based on the Seven Year Statement (SYS)(44) from 2010. In 2012 the Electricity Ten Year Statement (ETYS)(45), replaced the former National Grid electricity publications SYS and the Offshore Development Information Statement (ODIS). The report is issued by National Grid who are the System Operator (SO) in Great Britain. The report is based on input from the Transmission Owners (TOs) in Scotland (SHE Transmission and SP Transmission), and in England and Wales (NGET).

From the report the system boundaries are set based on Appendix A – System Schematic and Geographic in ETYS 2018. System boundary B6 represent the boundary between UK-N and UK-M. System boundary B9 represent the boundary between UK-M and UK-S. These boundaries are selected since they distribute the ETYS zones respectively and the transmission grid between the areas are possible to detect. In 2014 the ETYS zones division changed, the ETYS zones after 2014 are be used in EMPS 2. Figure of the transmission system boundaries in Great Britain are shown in Appendix B.

Given input data for the EMPS 2 model, it is needed to distribute the installed capacity and demand for the different areas and the available transmission grid between the areas. Table 4.9 and Table 4.10 shows the ETYS zones, boundaries and transmission capacity between the UK areas. In both year 2020 and 2030 the rating from 2017/2018 are used, after 2030 it is assumed an increase in the exchange capacity.

**Table 4.9 ETYS zones for areas in UK**

| | UK-N | UK-M | UK-S |
|---|---|---|---|
| ETYS zones | S0, T0 | Q0, R0, P0, M0, N0, L0, K0 | A0, B0, C0, D0, E0, F0, G0, H0 |

**Table 4.10 Transmission capacity between areas in UK**

| Between | Boundary | Rating MW (winter) 2017/2018 |
|---|---|---|
| UK-N and UK-M | B6 | 9 386 |
| UK-M and UK-S | B9 | 20 125 |

The report and appendixes for SYS and ETYS changed in both year 2012 and year 2016. Due to the changes in the datasets from the appendixes from ETYS it is decided to use different datasets for installed capacity, transmission grid and demand.

Distribution in the UK areas for installed capacity is based on Appendix F- Generation Data 2015(46). In that dataset it is predicted future installed capacity until 2035. This project study scenarios until 2040. The distribution for demand only has minor changes over the year, so the 2035 distribution is used for 2040.The share of the different energy sources in the UK areas have only minor or none changes between 2030 and 2035. The distribution of installed capacity in UK areas are shown in Appendix B.

Transmission grid between the UK areas are based on Appendix B - System Network Data 2018(47). The rating (in MW) between nodes in different areas are based on winter rating (in MVA) and power factor (PF) 0,93 for all lines/cables. Since the numbers are from 2018, it is not assumed major changes on the rating until 2030. From 2040 it is predicted an increase in the capacity for UK-N- UK-M and for UK-M- UK-S, respectively 2000 MW and 400 MW. The rating for the transmission grid between areas are shown in Table 4.10.

The demand in the UK areas are based on numbers for demand from 2010 in the SYS report(44). The demand is predicted with time step 1 year from 2010 until 2016. The changes from 2010 until 2016 are small, so the distribution of demand in UK areas from 2016 are used for all years between 2020- 2040 (time step 5 years). Table 4.11 shows the demand in the UK areas for 2016.

**Table 4.11 Distribution of demand (2016) in UK areas**

| UK areas | Consumption [GWh] | Share of demand |
|---|---|---|
| UK- N | 5 864 | 10,1 % |
| UK-M | 22 933 | 39,6 % |
| UK-S | 29 147 | 50,3 % |

Dividing UK into three different areas may have an impact, if the grid is a limiting factor given lateral distribution between production and consumption in UK. In some occasions fossil energy sources have to produce energy, even though a RES is available in a neighbouring. This is due to the maximum exchange capacity between the areas. Th

e two planned offshore cables to UK from NO2 and NO5 are planned to be connected to respectively UK-M and UK-N. In order to utilize imported power from Norway, the transmission between UK areas requires a high enough exchange capacity.

## 4.3 Investment algorithm

The investment algorithm is a functionality for investment in the EMPS model(48). The functionality makes it possible to obtain model-determined capacity that is consistent with simulated power prices for a given stage. The investment algorithm has been implemented for the following capacities:

- Thermal power production (e.g. gas, bio etc.)
- Wind power production
- Transmission network in modelled system

The project desire to examine the optimal size for a selection of offshore interconnections from Norway and installed capacity for wind power in NO and UK. The investment algorithm is implemented for four simulations in focus year 2040. In the scenario building it is assumed a fixed size for all cables and installed capacity for wind power. By implementing the investment algorithm, a cost decides the development of cables, solar power and wind power in described areas.

Table 4.12 gives an overview for offshore cables between areas where the investment algorithm is implemented.

**Table 4.12 Investment cost for selected offshore cables**

| Cable between | | Cost [EUR/MW/year] | Initial size in 2040 [MW] |
|---|---|---|---|
| NO2 | DK-W | 40 000 | 1 640 |
| NO2 | DE | 40 000 | 3 500 |
| NO2 | NL | 40 000 | 700 |
| NO2 | UK-M | 40 000 | 1 400 |
| NO2 | UK-N | 40 000 | 2 000 |

Table 4.13 gives an overview for the cost for developing wind power and solar power for selected areas.

**Table 4.13 Investment cost for wind power for selected areas**

| Areas | Energy source | Cost [EUR] |
|---|---|---|
| NO1, NO2, NO3, NO4, NO5 | Wind power | 22 000 |
| UK-N, UK-M, UK-S | Wind power, solar power | 22 000, 80 000 |

The investment cost are adjusted based on the journal article «Mot et grønnere Europa: Virkninger av EUs klimapolitikk for 2030»(49). The prices are not validated in this project.

# 5 Simulations

In this project simulations are performed for both the EMPS 1 model and the EMPS 2 model. Chapter 3 explains the development of used base scenarios and references. Chapter 4 explains both models. Table 5.1 shows an overview over the 16 performed simulations of both models (EMPS 1 and EMPS 2).

**Table 5.1 Overview over performed simulations**

| Simulation | Year | Fuel-price and $CO_2$-taxes | Changes |
|---|---|---|---|
| **Base cases (EMPS 1)** | 2040 | CP | |
| | 2040 | 450 | |
| **Base cases (EMPS 2)** | 2020 | CP | UK divided to UK-N, UK-M and UK-S |
| | 2020 | 450 | |
| | 2030 | CP | |
| | 2030 | 450 | |
| | 2040 | CP | |
| | 2040 | 450 | |
| **Inclusion of hydropower (EMPS 2)** | 2030 | CP | Manually adjusted for Norwegian hydropower from 135,8 TWh to 142,0 TWh(11) |
| | 2030 | 450 | |
| | 2040 | CP | Manually adjusted for Norwegian hydropower from 137,3 TWh to 158,2 TWh(50, 51) |
| | 2040 | 450 | |
| **Investment algorithm (EMPS 2)** | 2040 | CP | Adjusted with investment algorithm for:<br>• offshore cables from Norway |
| | 2040 | 450 | |
| | 2040 | 450 | Adjusted with:<br>• hydropower from 137,3 TWh to 158,2 TWh<br>• offshore cables from Norway |
| | 2040 | 450 | Adjusted with investment algorithm for:<br>• offshore cables from Norway<br>• wind power development in NO and UK |

# 6 Results and analysis

The structure for the result chapter are given in Table 6.1.

**Table 6.1 Structure in results chapter**

| Chapter | Results | Note |
|---|---|---|
| **6.1** | Comparison between EMPS 1 (old model) and EMPS 2 (extended model) | |
| **6.2** | Base year 2020 (for production pattern, emissions and exchange) | |
| **6.3** | Focus year 2030 (for production pattern, emissions and exchange) | Complementary results in Appendix D |
| **6.4** | Focus year 2040 (for production pattern, emissions and exchange) | Complementary results in Appendix D |
| **6.5.1** | Area prices for base year 2020 | |
| **6.5.2** | Area prices for focus year 2030 | |
| **6.5.3** | Area prices for focus year 2030 | Complementary results in Appendix D |

## 6.1 EMPS 1 and EMPS 2

In Chapter 4 both models, EMPS 1 (old model) and EMPS 2 (new model), are explained. EMPS 2 is developed based on EMPS 1. EMPS 2 divides UK into three areas respectively UK-N, UK-M and UK-S. Both models are simulated for the CP and 450 scenarios for year 2040. The models are compared due to the extension from the old model (EMPS 1) to the new model (EMPS 2).

### 6.1.1 CP Scenario

Table 6.2 shows the small differences in $CO_2$-coefficient. The differences in $CO_2$-coefficient within the UK areas are notable, since UK-S are more dependent of fossil energy sources. UK-S also have none connection to Norwegian areas as UK-N and UK-M. The small difference for $CO_2$-coefficient indicates that the transmission capacity is not a limiting factor, which is illustrated in Figure 6.3.

**Table 6.2 $CO_2$- Coefficient for CP Scenario in year 2040**

| | **$CO_2$-Coefficient [$gCO_2$/kWh]** | |
|---|---|---|
| ***Areas*** | *EMPS 1* | *EMPS 2* |
| **All** | 169,37 | 169,32 |
| **Nordic (NO+SE+FI)** | 12,46 | 12,42 |
| **UK (UK-N, UK-M, UK-S)** | 65,99 | 65,80 (17,28, 60,12, 93,37) |

Figure 6.1 shows that the change in production mix are highest for UK. Since UK will produce less gas and coal, giving a lower $CO_2$-coefficent in the EMPS 2. The difference is though low, with the biggest difference a little above 300 GWh. A 300 GWh difference is small compared to total production in each area. In the EMPS 2 hydropower from NO areas and SE areas and nuclear power from SE3 replaces gas power production in UK. NO areas and DK areas are transit areas for the power transfer to UK.

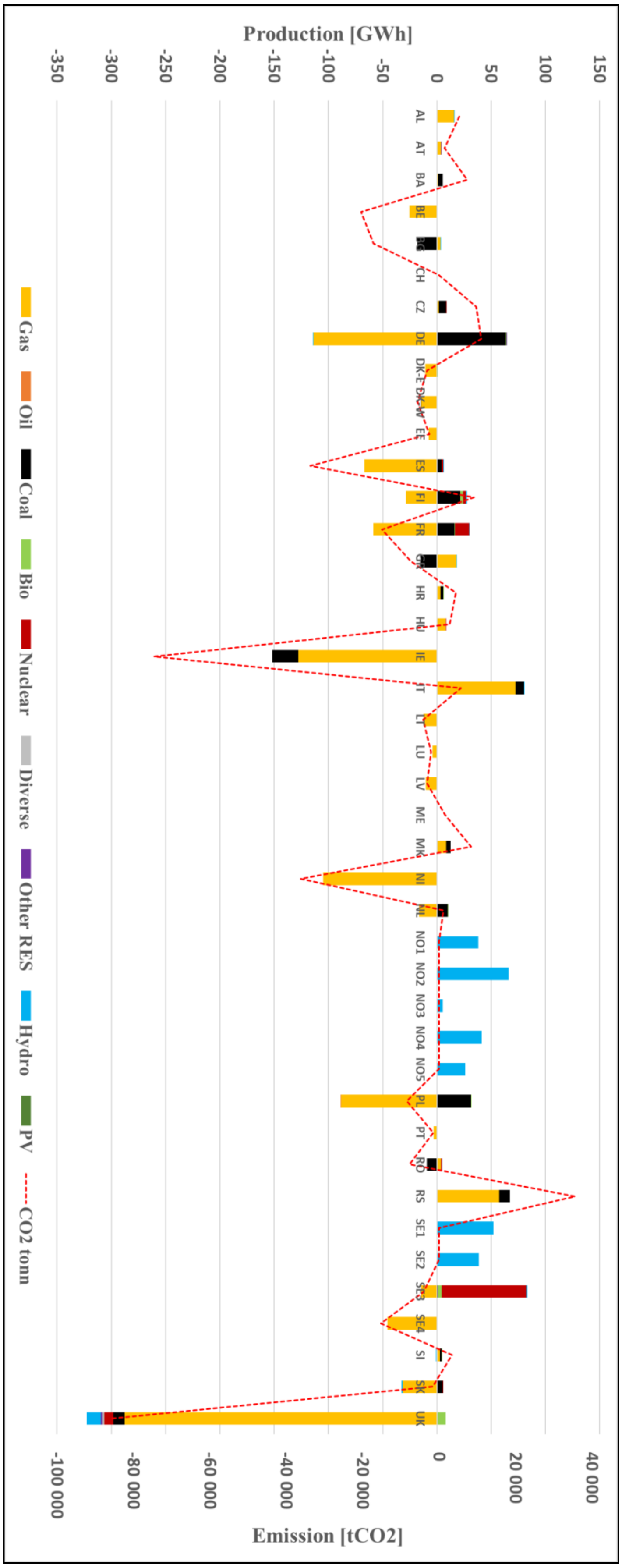


**Figure 6.1 EMPS 2 vrs. EMPS 1, Production mix (aggregated sum) CP Scenario year 2040**

### 6.1.2 450 Scenario

Table 6.3 shows the same small differences for $CO_2$-coeffisient. This indicates that the transmission capacity is also not a limiting factor for the 450 Scenario. Compared to $CO_2$-coefficents in Table 6.2 are the $CO_2$-coefficents for all areas lower in the entire energy system. The $CO_2$-coefficents for the Nordic, UK, UK-M and UK-S are higher since the production of gas power is higher in EMPS 2.

**Table 6.3 CO2- Coefficient for 450 Scenario (in 2040)**

| | **$CO_2$-Coefficient [$gCO_2$/kWh]** | |
|---|---|---|
| **Areas** | EMPS 1 | EMPS 2 |
| **All** | 98,94 | 98,66 |
| **Nordic (NO+SE+FI)** | 15,67 | 15,75 |
| **UK, (UK-N, UK-M, UK-S)** | 87,25 | 87,81 (8,04, 77,64, 129,30) |

Figure 6.2 shows that the energy system for the 450 Scenario is more dependent on gas than coal compared to CP Scenario in Figure 6.1. Which explains the lower $CO_2$-coefficient for all areas. This have led to an increase in gas production in UK, which again have given higher $CO_2$-coefficient for UK areas. Figure 6.1and Figure 6.2 illustrates the impact of the fuel-prices and $CO_2$-taxes. The 450 Scenario have high coal prices and low gas prices compared to the CP Scenario. The gas power plants in UK will run instead off hard coal power plants in neighbouring areas. The deficit of power in UK are also lower compared to the CP Scenario, and the need for imported power are not that important.

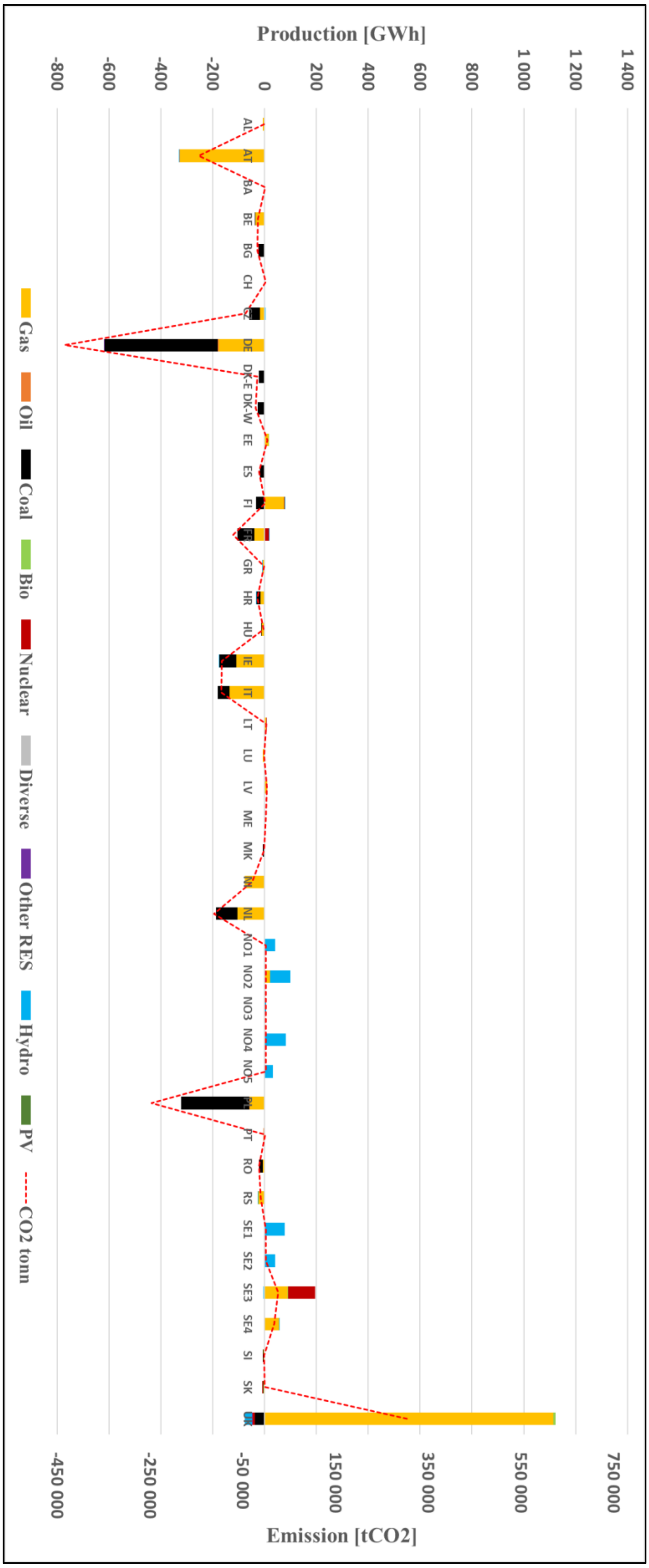


**Figure 6.2 EMPS 2 vrs. EMPS 1, Production mix (aggregated sum) 450 Scenario year 2040**

### 6.1.3 Exchange of power

In EMPS 2 the model is extended with two transmission lines for respectively UK-N to UK-M and UK-M to UK-S. The production pattern and $CO_2$-coefficient indicated for both scenarios that the exchange capacity between the UK areas is not a limiting factor. The transmission capacity for the two lines UK-N- UK-M and UK-M- UK-S are respectively 11 386 MW and 20 525 MW. For both transmission lines the utilization is low. Figure 6.3 shows also that transferred power goes mostly from north to south for both transmission lines.

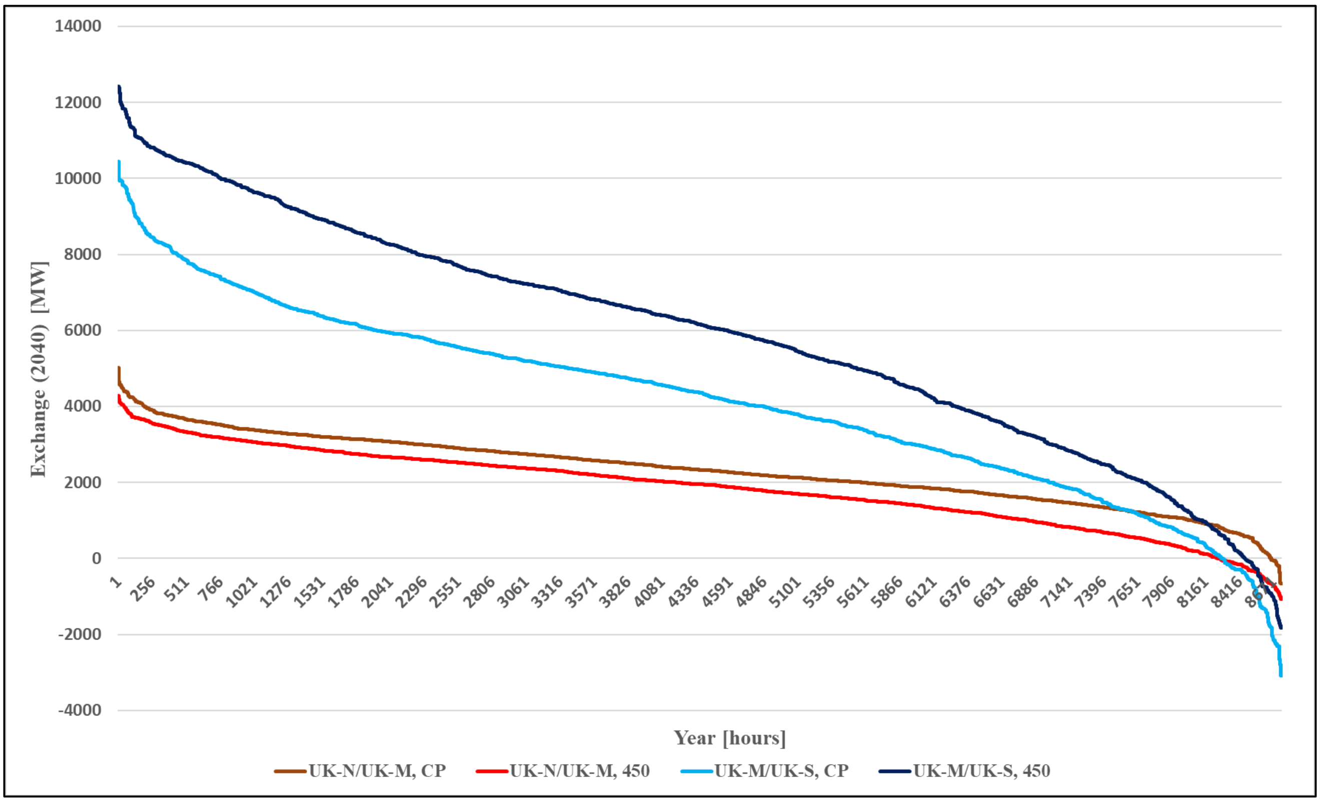


**Figure 6.3 Exchange EMPS 2 for CP- and 450 Scenario year 2040**

## 6.2 Base year 2020

The simulation and results are from EMPS 2 model. In this project two different scenarios for fuel-prices and $CO_2$-taxes are used. Since year 2020 are set as the base case, there are not expected major changes compared for today.

Figure 6.4 shows there are some minor changes within some areas. The difference is slightly less hard coal and some more gas for the 450 Scenario. The $CO_2$ emissions are also varying given each year, the emissions are especially higher in the CP Scenario compared to the 450 Scenario for DE. The reason are the different fuel-prices for the 450 Scenario and CP Scenario. In the 450 Scenario the gas price is significantly lower than the hard coal price compared to the CP Scenario.

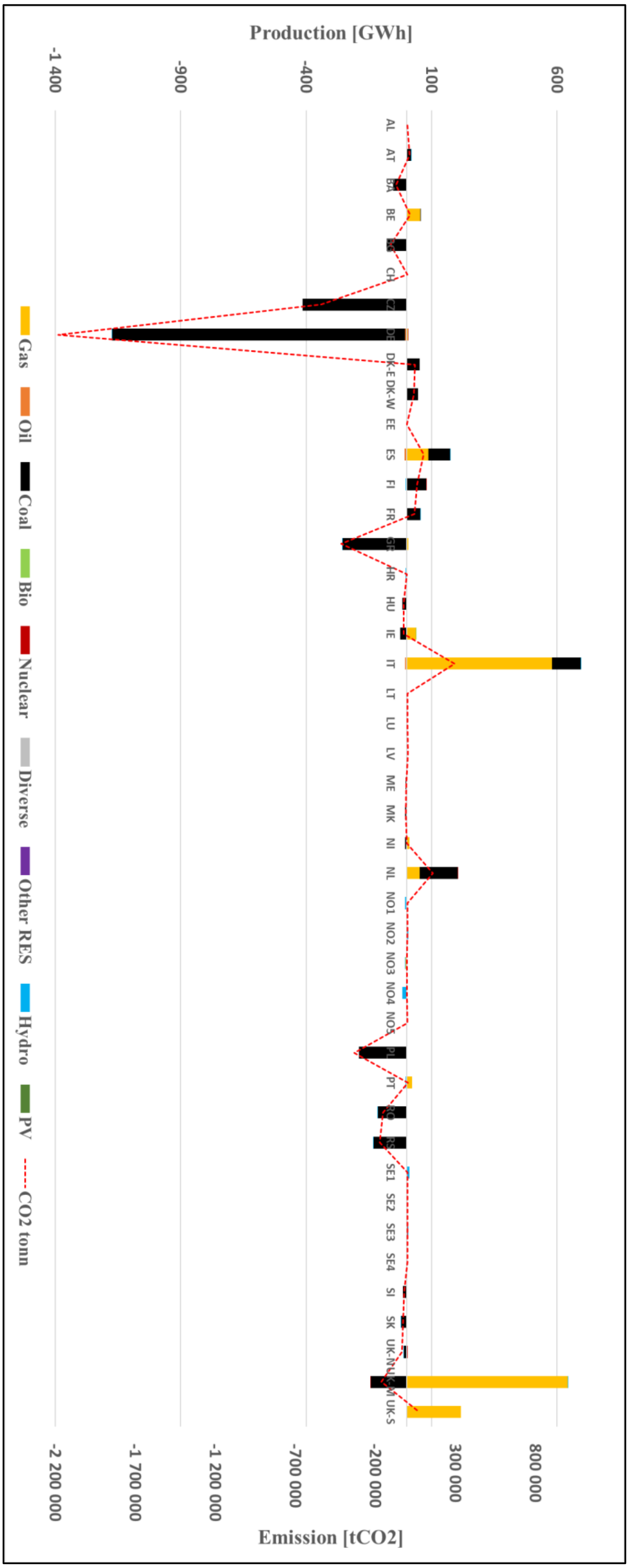


**Figure 6.4 450 vrs. CP, Production mix (aggregated sum) and emissions year 2020**

A normal guess with a harder price regime for the 450 Scenario for fuel-prices and $CO_2$-taxes is a lower share of fossil fuels. Figure 6.5shows the $CO_2$-coefficient for all areas in all years and base cases (2020, 2030, 2040). The $CO_2$-coefficient decrease for the total energy system. For the UK areas the $CO_2$-coefficient are lowest in year 2030, due to gas power replacing lignite coal. Lignite coal is the most emissions intensive energy source in this project. In year 2040 lignite coal is almost phased out.

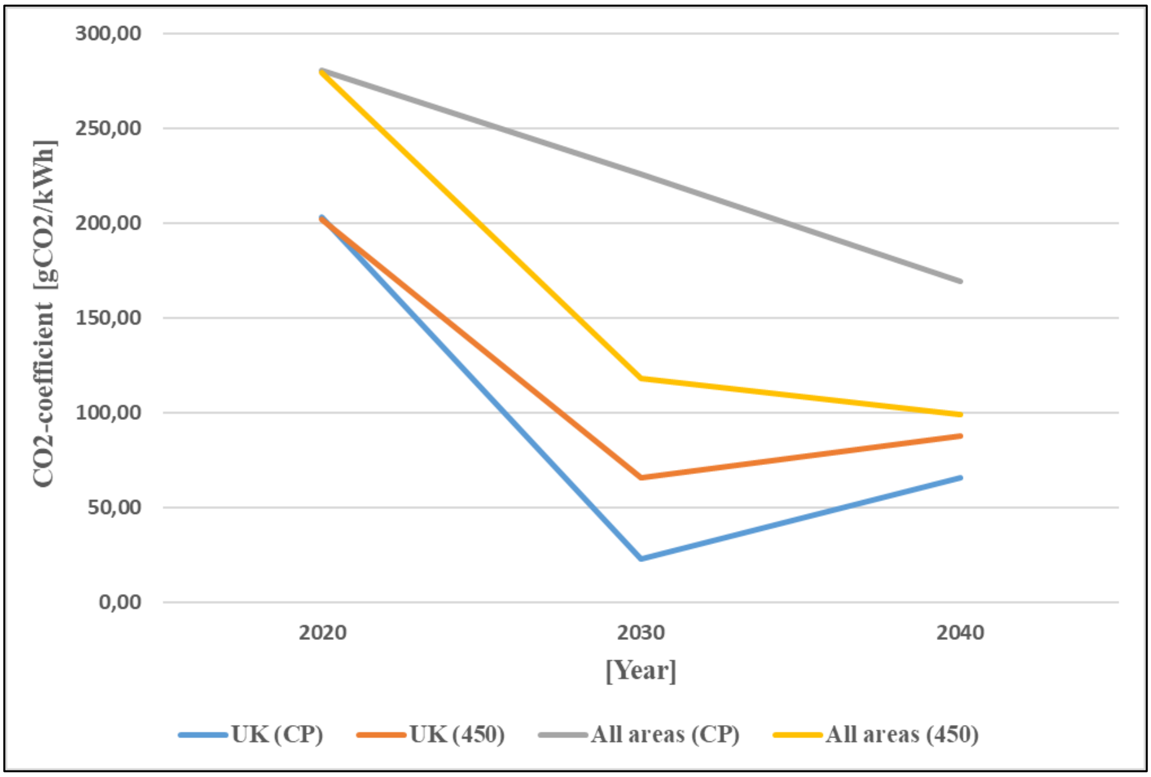


**Figure 6.5 $CO_2$-coeffisient for UK areas and whole system, year 2020, 2030 and 240**

### 6.2.1 Exchange of power

In year 2020 it is no clear distinction between CP Scenario and 450 Scenario. The differences for price for the scenario policies is not yet high. This is illustrated in Figure 6.6 for exchange of power between NO2 and NO5.

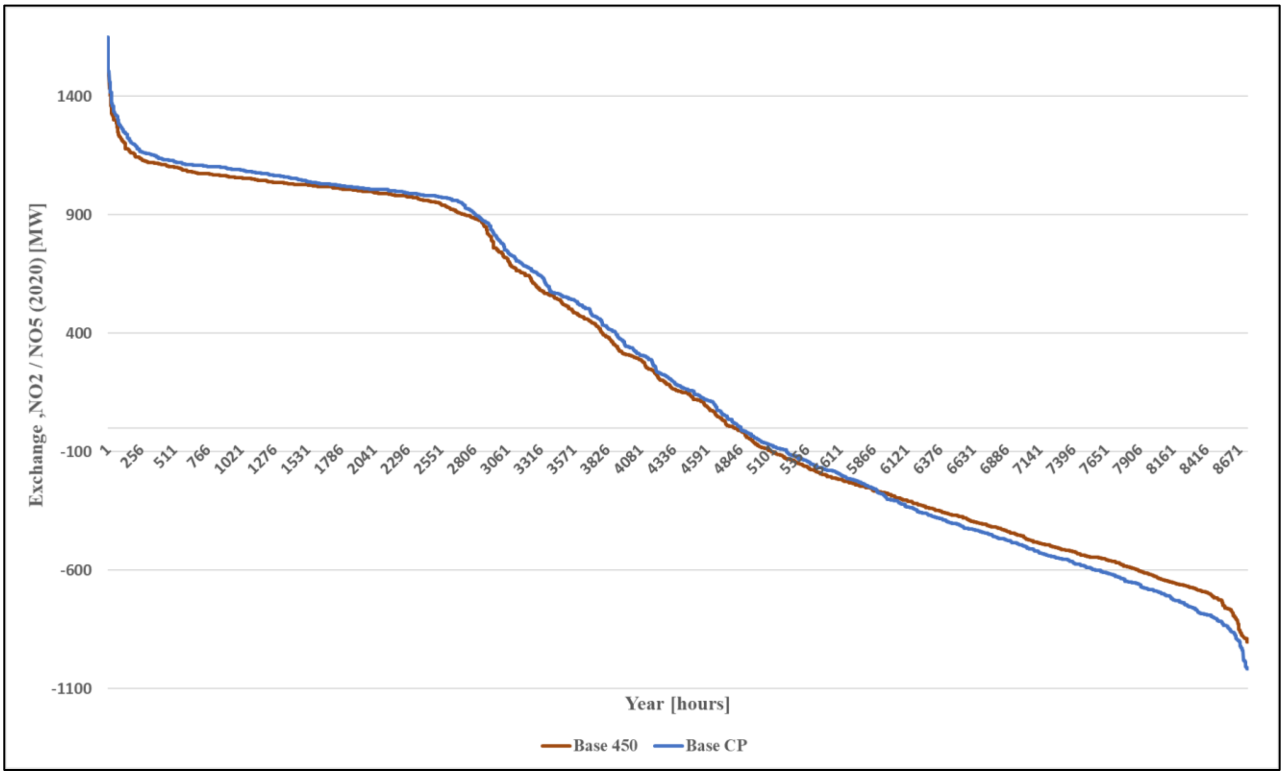


**Figure 6.6 Exchange year 2020 for CP and 450 Scenario between areas NO2 and NO5**

In this project it is of interest to see if the offshore cables from Norway are near maximum exchange capacity. Table 6.4 shows installed exchange capacities in year 2020 and maximum exchange of power for the CP Scenario and the 450 Scneario.

**Table 6.4 Exchange capacity for offshore cables from Norway, year 2020**

| **Areas** | | **Exchange capacity [MW]** | | | |
|---|---|---|---|---|---|
| **From** | **To** | **From** | **To** | **Max. from NO2 (CP)** | **Max. from NO2 (450)** |
| NO2 | DK-W | 1640 | 1640 | 1420 | 1430 |
| NO2 | DE | 1400 | 1400 | 1310 | 1325 |
| NO2 | NL | 700 | 700 | 672 | 674 |
| NO2 | UK-M | 1400 | 1400 | 1400 | 1400 |

Figure 6.7 shows that for all cables the transfer of electricity goes mainly from NO2 to DK-W, DE, NL and UK-M. Maximum transmission capacity occurs for a longer time periods for the cable to UK-M. The other cables are close to maximum capacity from NO2, but not at the limit. From DK-W, DE and NL to NO2 the exchange capacity is at maximum capacity in short periods.

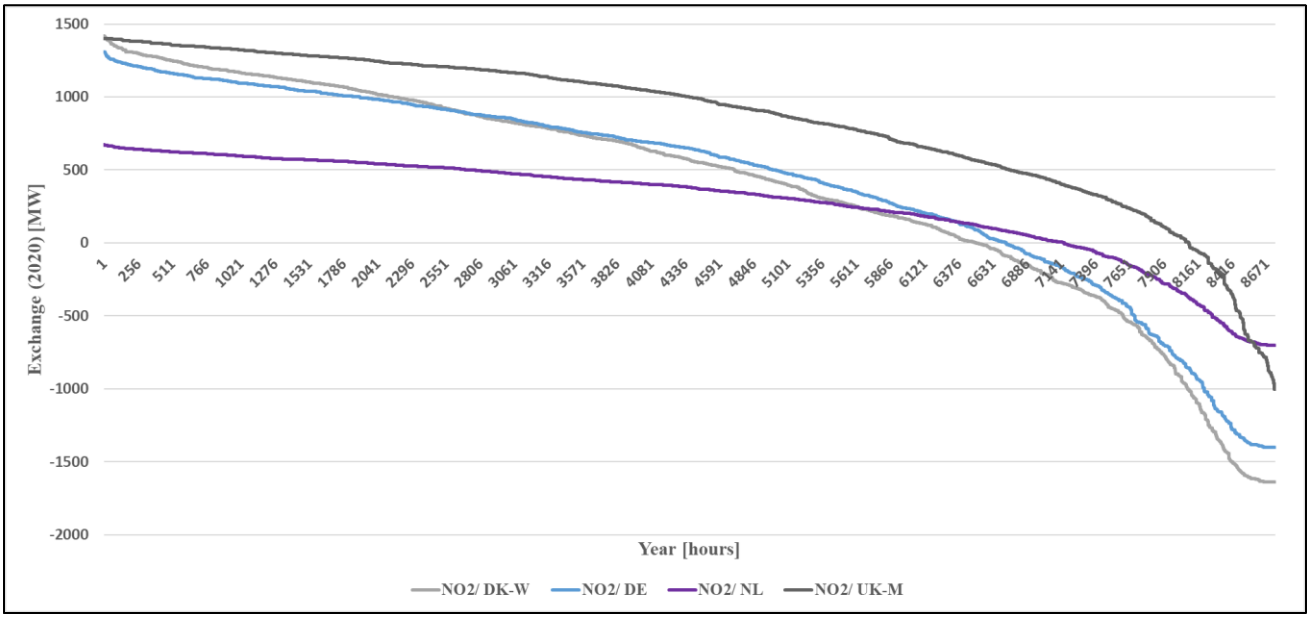


**Figure 6.7 Exchange year 2020 for 450 Scenario from NO2 to DK-W, DE, NL and UK-M**

Figure 6.8 shows exchange within UK areas and exchange between UK-S and NL. This figure indicates a deficit of energy in UK-S. All neighbouring areas are exporting to UK-S. Transmission lines for UK-N to UK-UK-M and UK-M to UK-S have only transfer of power from north to south. The offshore cable from UK-S to NL, also shows that the transmission of power mainly goes from NL to UK-S. The same trend applies for the cables FR to UK-S and DK-W to UK-S- Given Figure 6.8 and export of power from NO2 to UK-M, the deficit of power in UK-S clearly visible.

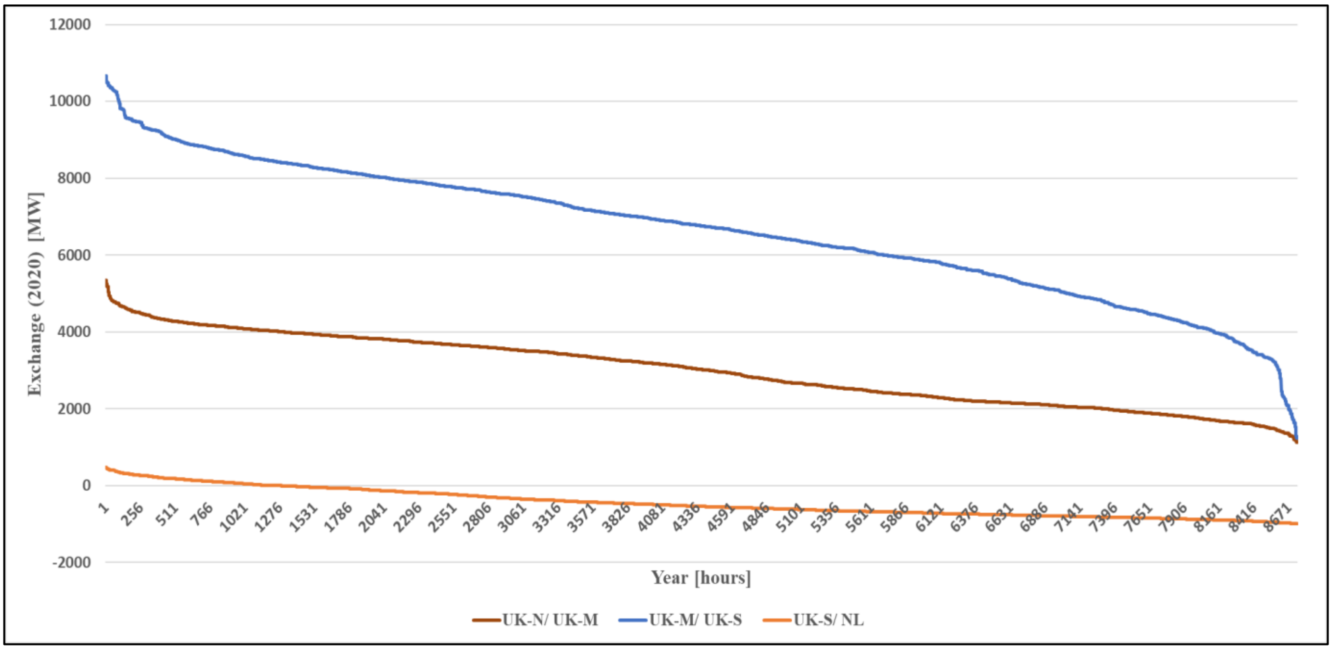


**Figure 6.8 Exchange year 2020 for 450 Scenario between UK areas and UK-S-NL**

## 6.3 Focus year 2030

The simulation and results are from EMPS 2 model. In this subchapter the two fuel-price and $CO_2$-tax scenarios are divided and then compared for the different scenarios for the Base case scenario and more hydropower development in NO areas in Norway.

### 6.3.1 CP Scenario

In the Hydro 2030 Scenario the total Norwegian hydro power production are set to increase from 135,8 TWh to 142,0 TWh, with similar distribution between the five NO areas as the Base Scenario for year 2030. The results are viewed for the entire energy system. Table 6.5 shows a higher energy production for Hydro 2030, and lower energy production for especially gas and coal. The total $CO_2$-coefficient for the modelled energy system are:

- Base 2030: $CO_2$-coefficient all areas 225,97 $gCO_2/kWh$
- Hydro 2030: $CO_2$-coefficient all areas 224,36 $gCO_2/kWh$

The total energy production for Hydro 2030 are also slightly higher than Base 2030. The reason is the export of hydropower from NO areas to neighbouring areas. This is shown in Figure 6.10 and Figure 6.11.

**Table 6.5 Energy production distribution (CP scenario) for base 2030 and hydro 2030**

| | **Energy [GWh]** | | |
|---|---|---|---|
| ***Name*** | *Base 2030* | *Hydro 2030* | *Difference* |
| **Gas Conv** | 0 | 0 | 0,0 |
| **Gas CCGT** | 30 775 | 30 762 | -13,0 |
| **Gas OCGT** | 0 | 0 | 0,0 |
| **Gas CCS** | 105 | 106 | 0,4 |
| **CHP Gas** | 131 101 | 131 090 | -11,0 |
| **Oil** | 0 | 0 | 0 |
| **CHP Oil** | 3 509 | 3 510 | -0,6 |
| **Lignite** | 280 842 | 281 793 | -950,9 |
| **Hard Coal** | 349 803 | 353 892 | -4 089,9 |
| **CHP Coal** | 30 529 | 30 534 | -5,3 |
| **Bio** | 204 493 | 204 500 | -6,5 |
| **Nuclear** | 785 227 | 785 278 | -51,5 |
| **Diverse** | 0 | 0 | 0,0 |
| **CHP Diverse** | 18 632 | 18 632 | 0,0 |
| **Other RES** | 16 654 | 16 654 | 0,0 |
| **CHP RES** | 83 373 | 83 373 | 0,0 |
| **Hydro** | 584 770 | 590 612 | 5 842,5 |
| **PV** | 232 828 | 232 828 | 0,0 |
| **Wind** | 618 324 | 618 324 | 0,0 |
| ***Sum*** | ***3 376 068*** | ***3 376 068*** | ***714,3*** |

### 6.3.2 450 Scenario

The same trends can be seen for the 450 Scenario as the CP scenario in Chapter 6.3.1. Since the same increase in hydropower production are assumed. The difference is even smaller compared to the CP scenario:

- Base 2030: $CO_2$-coefficient all areas 117,97 $gCO_2/kWh$
- Hydro 2030: $CO_2$-coefficient all areas 117,12 $gCO_2/kWh$

The $CO_2$-coefficient is also lower, since the distribution has a lower share of especially hard coal and lignite. The total energy production for Hydro 2030 are also slightly higher than Base 2030, as in CP scenario, the reason for that is the need for export of Norwegian hydro power to neighbouring areas. This is shown in Figure 6.10 and Figure 6.11

**Table 6.6 Energy production distribution (450 scenario) for base 2030 and hydro 2030**

| | **Energy [GWh]** | | |
|---|---|---|---|
| ***Name*** | *Base 2030* | *Hydro 2030* | *Difference* |
| **Gas Conv** | 0 | 0 | 0,0 |
| **Gas CCGT** | 492 396 | 489 562 | -2 834,4 |
| **Gas OCGT** | 2 | 2 | 0,0 |
| **Gas CCS** | 8 671 | 8 664 | -7,0 |
| **CHP Gas** | 127 964 | 127 941 | -23,1 |
| **Oil** | 0 | 0 | 0,0 |
| **CHP Oil** | 3 438 | 3 436 | -2,0 |
| **Lignite** | 7 651 | 7 536 | -114,5 |
| **Hard Coal** | 160 486 | 158 732 | -1 753,4 |
| **CHP Coal** | 27 189 | 27 110 | -79,5 |
| **Bio** | 204 498 | 204 489 | -9,5 |
| **Nuclear** | 785 276 | 785 200 | -76,4 |
| **Diverse** | 0 | 0 | 0,0 |
| **CHP Diverse** | 18 632 | 18 632 | 0,0 |
| **Other RES** | 16 654 | 16 654 | 0,0 |
| **CHP RES** | 83 373 | 83 373 | 0,0 |
| **Hydro** | 584 769 | 590 559 | 5 789,1 |
| **PV** | 232 828 | 232 828 | 0,0 |
| **Wind** | 618 324 | 618 324 | 0,0 |
| ***Sum*** | ***3 372 152*** | ***3 373 041*** | ***889,2*** |

### 6.3.3 Exchange of power

In year 2030 the distinction between CP Scenario and 450 Scenario are quite clear, illustrated in Figure 6.9. For year 2030 it is set a higher production of hydropower in NO areas, this gives a slightly higher transmission capacity from north to south in UK areas. This distinction is quite small though.

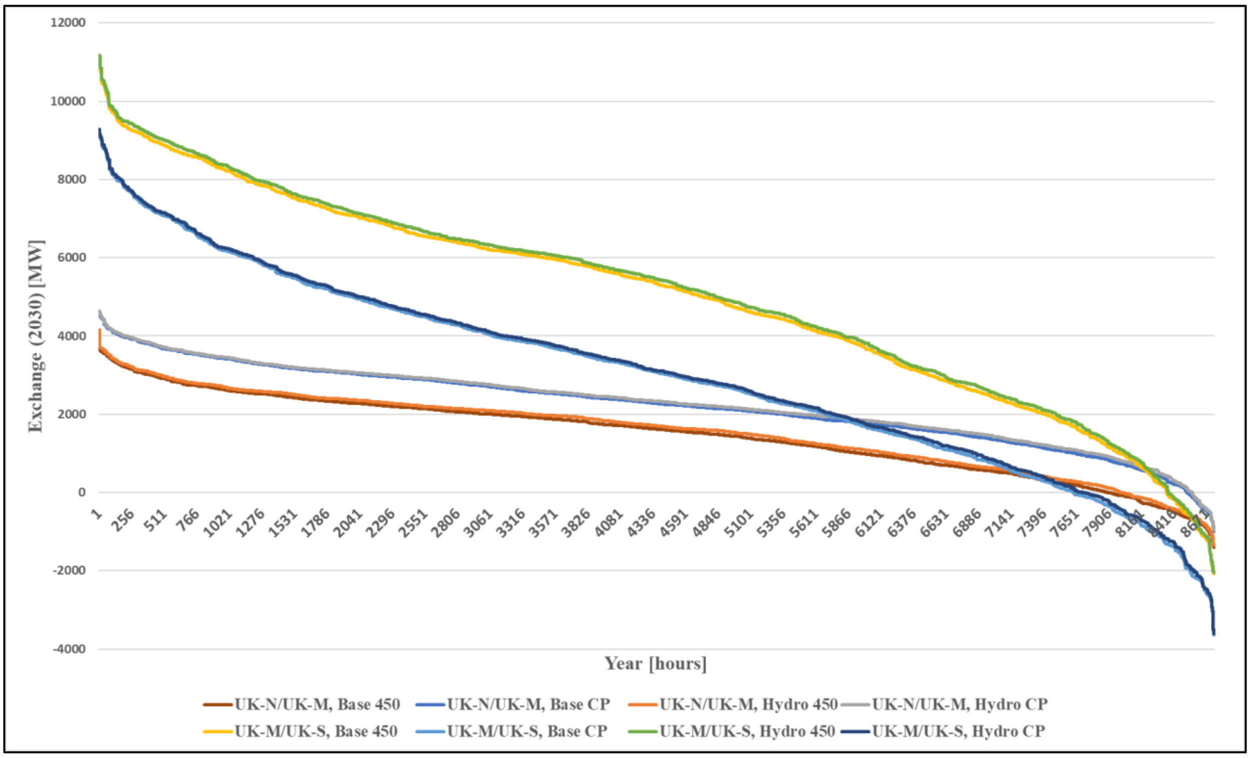


**Figure 6.9 Exchange year 2030 for CP- and 450 Scenario for UK-N to UK-M and UK-M to UK-S**

The inclusion of more hydropower affects exchange of power for offshore cables from NO areas. This is illustrated for the cables NO2- UK-M in Figure 6.10, NO5- UK-N in Figure 6.11 and UK-S- NL in Figure 6.12.

Inclusion of more hydropower production in NO areas increases the exchanged power from NO2 to UK-M for both scenarios, illustrated in Figure 6.10. The CP Scenario exports more power to UK-M from NO2 compared to the 450 Scenario. The gas prices are low also in year 2030 compared to hard coal prices and gas prices in the 450 Scenario. The need for imported power is therefore lower.

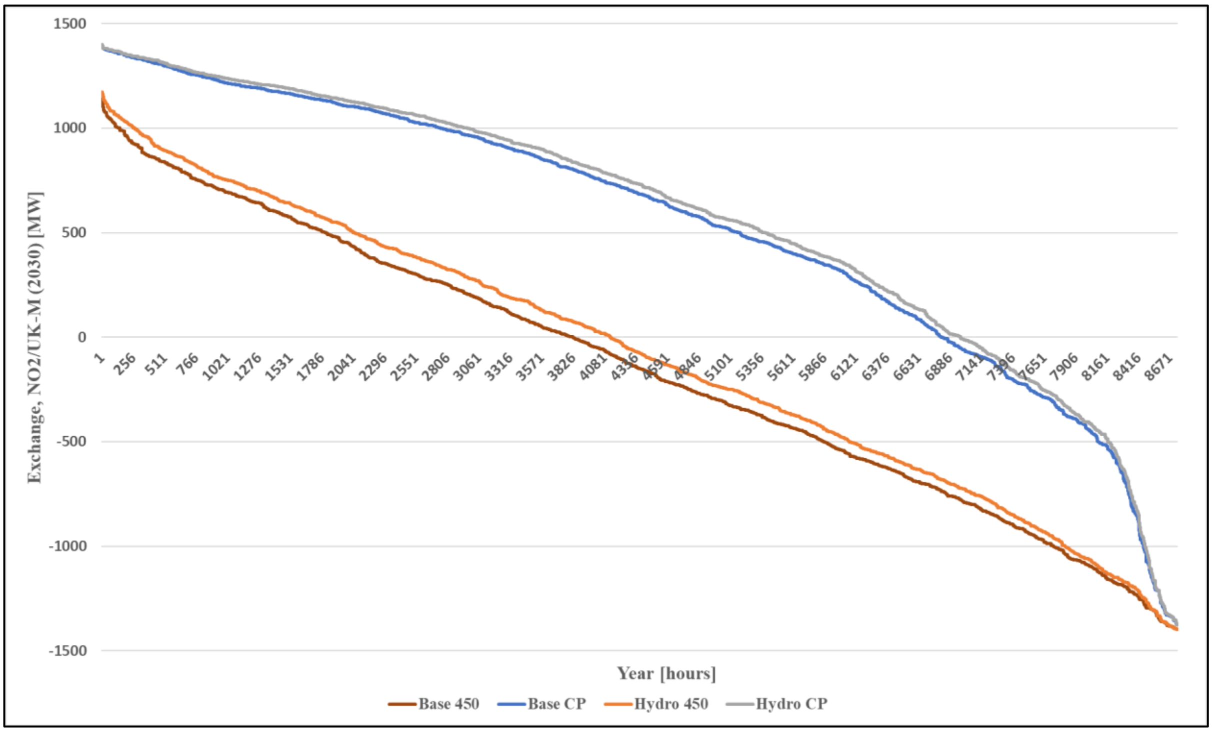


**Figure 6.10 Exchange year 2030 between areas NO2 and UK-M**

The same trend applies for the connection NO2 and UK-M, illustrated in Figure 6.11.

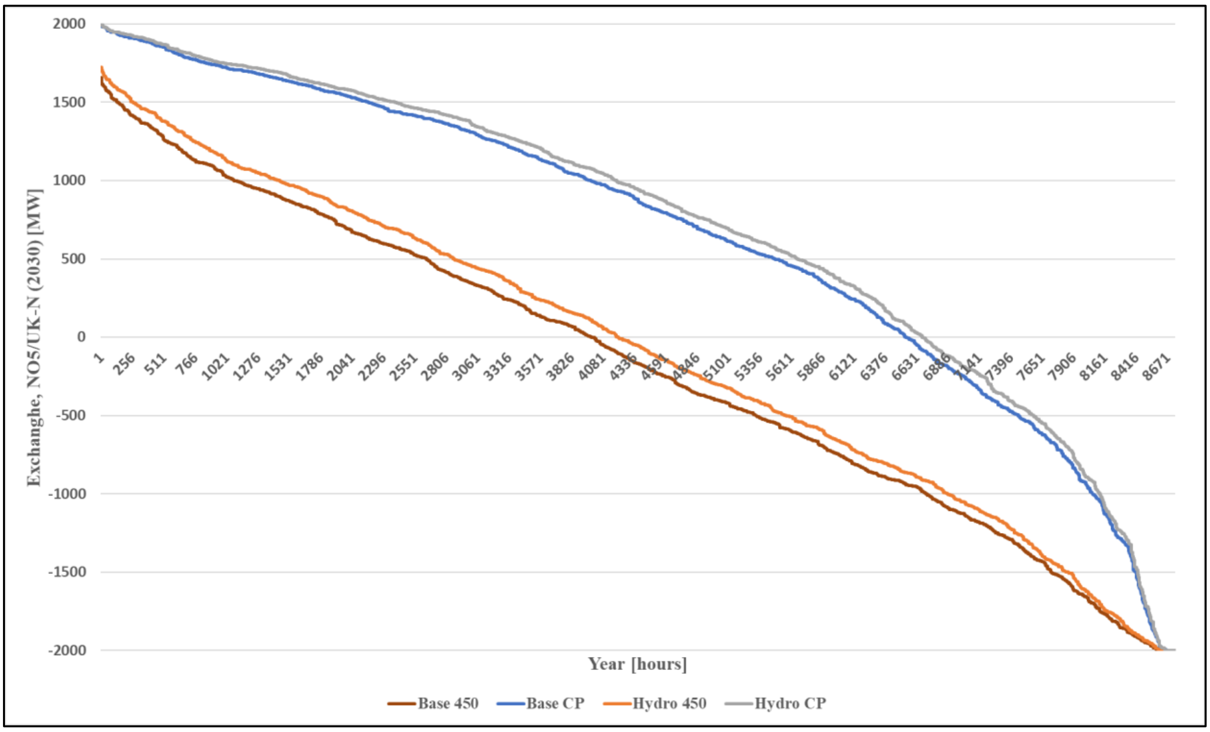


**Figure 6.11 Exchange year 2030 between areas NO5 and UK-N**

Figures for NO2 to DK-W, DE and NL can be found in Appendix C. All figures have the same trends as Figure 6.10 and Figure 6.11.

The increased import of power from NO areas to UK areas for the CP Scenario affects exchange of power from NL to UK-S and BE to UK-S, illustrated in Figure 6.12 for UK-S to NL. Compared to exchanged power between UK-S and NL in year 2020 in Figure 6.8, most of the exchanged power flows from UK-S to NL instead of from NL to UK-S. The transfer of power is also close to maximum capacity in short periods.

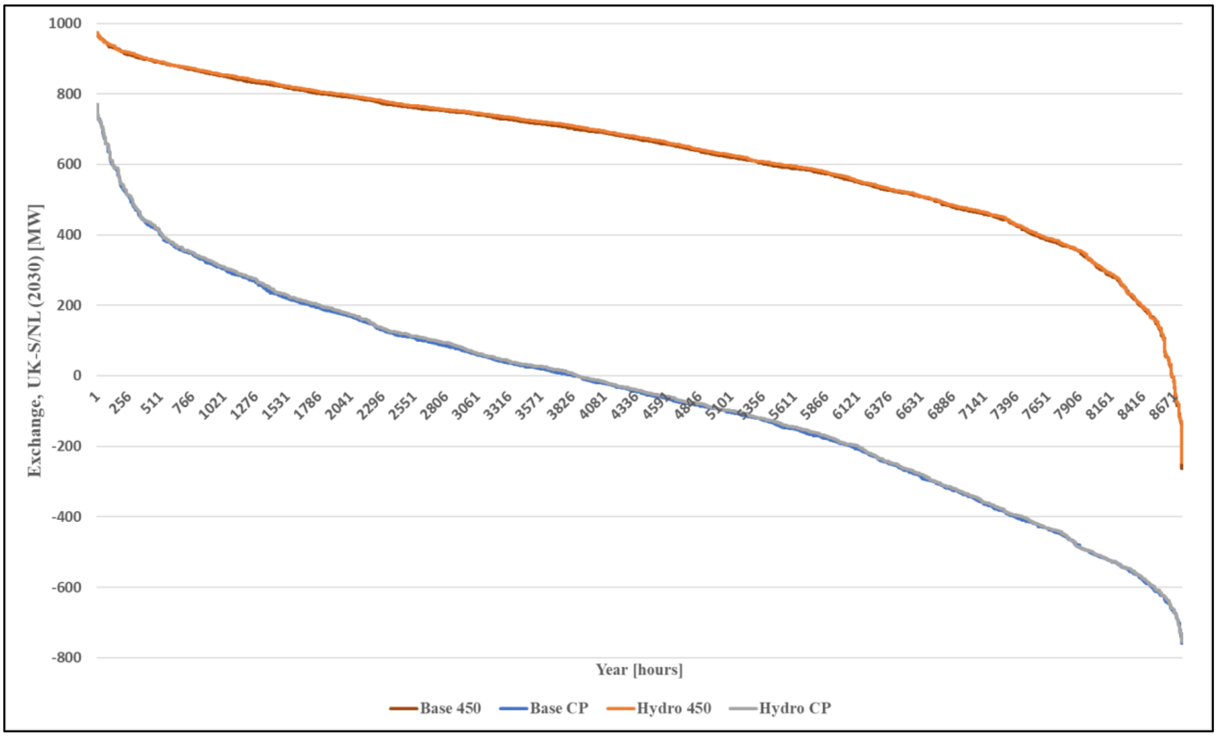


**Figure 6.12 Exchange year 2030 between areas UK-S and NL**

The deficit of power in UK-S still need import of power from FR, as well with the other connections (UK-M and DK-W). The difference for import/export from BE, FR and NL are the deficit/surplus in the area. FR has a surplus of power and BE and NL has a deficit of power.

## 6.4 Focus year 2040

In this subchapter the two fuel-price and $CO_2$-taxes scenarios are divided and then compared for the different scenarios for base case, more hydropower development, investment algorithm for cables between NO and UK and wind power development in both UK and NO.

### 6.4.1 CP Scenario

For the CP Scenario in year 2040 three different simulations is performed:

- Base 2040
- Hydro 2040
  Inclusion of more hydropower production in NO areas from 137,3 TWh to 158,2 TWh
- Base&investment cable 2040
  An investment algorithm sets the transmission capacity on offshore cables from NO areas.

Figure 6.13 shows that the increased hydropower production makes a positive impact on the production pattern and $CO_2$-emissions. The increased hydropower production replaces coal- and gas power. This is due to increased hydropower production in NO areas. In year 2040 the interconnections from NO areas are also strong and surplus of power from NO areas are exported.

Figure 6.14 shows a negative impact on the production pattern, with an increased hard coal production in both DE and PL. That leads to increased $CO_2$-coefficient for the energy system. This is due to the CP Scenario favouring hard coal based on fuel-prices. The investment algorithm invests in higher exchange on offshore cables from Norway. Norway will then act as transit country for coal power from DE and PL in areas with deficit of power as UK-S.

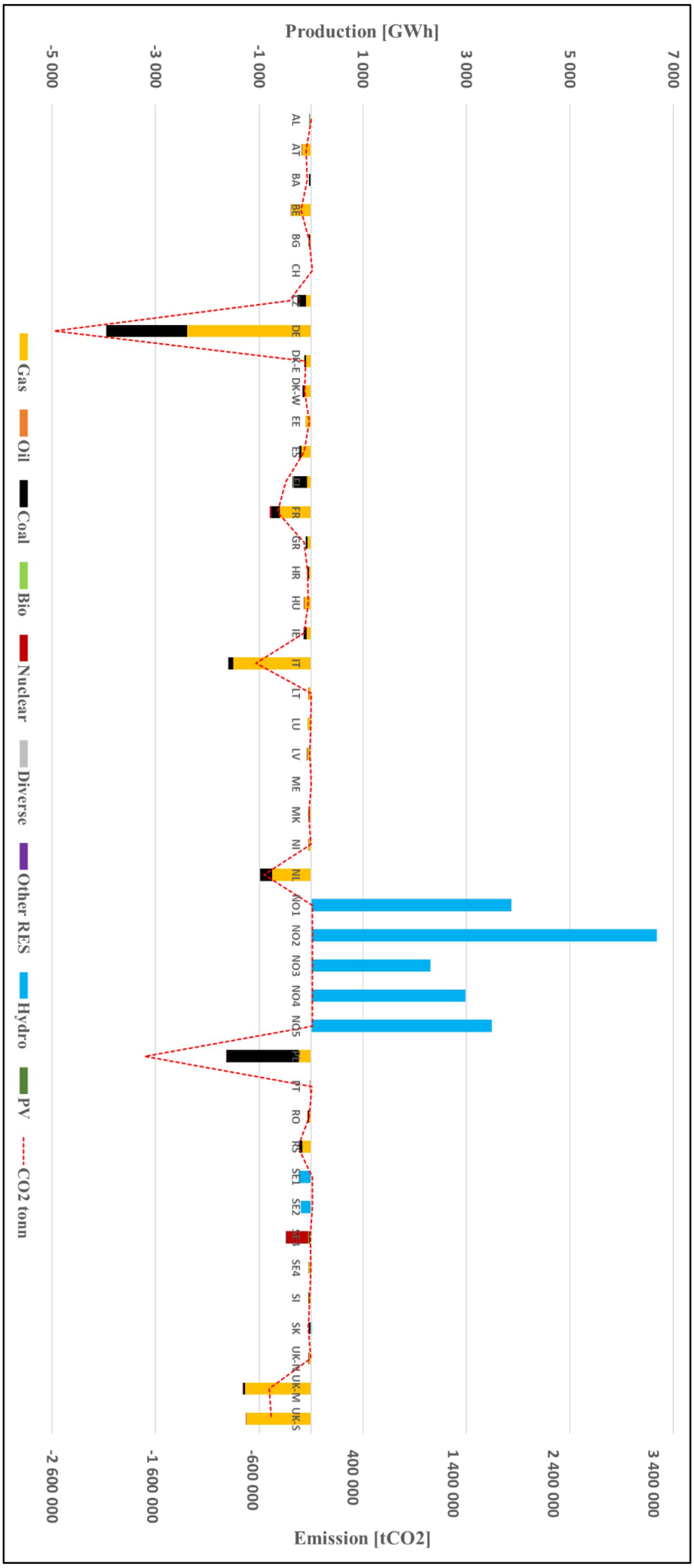


**Figure 6.13 Difference for Production mix (aggregated sum) CP Scenario, Hydro 2040- Base 2040**

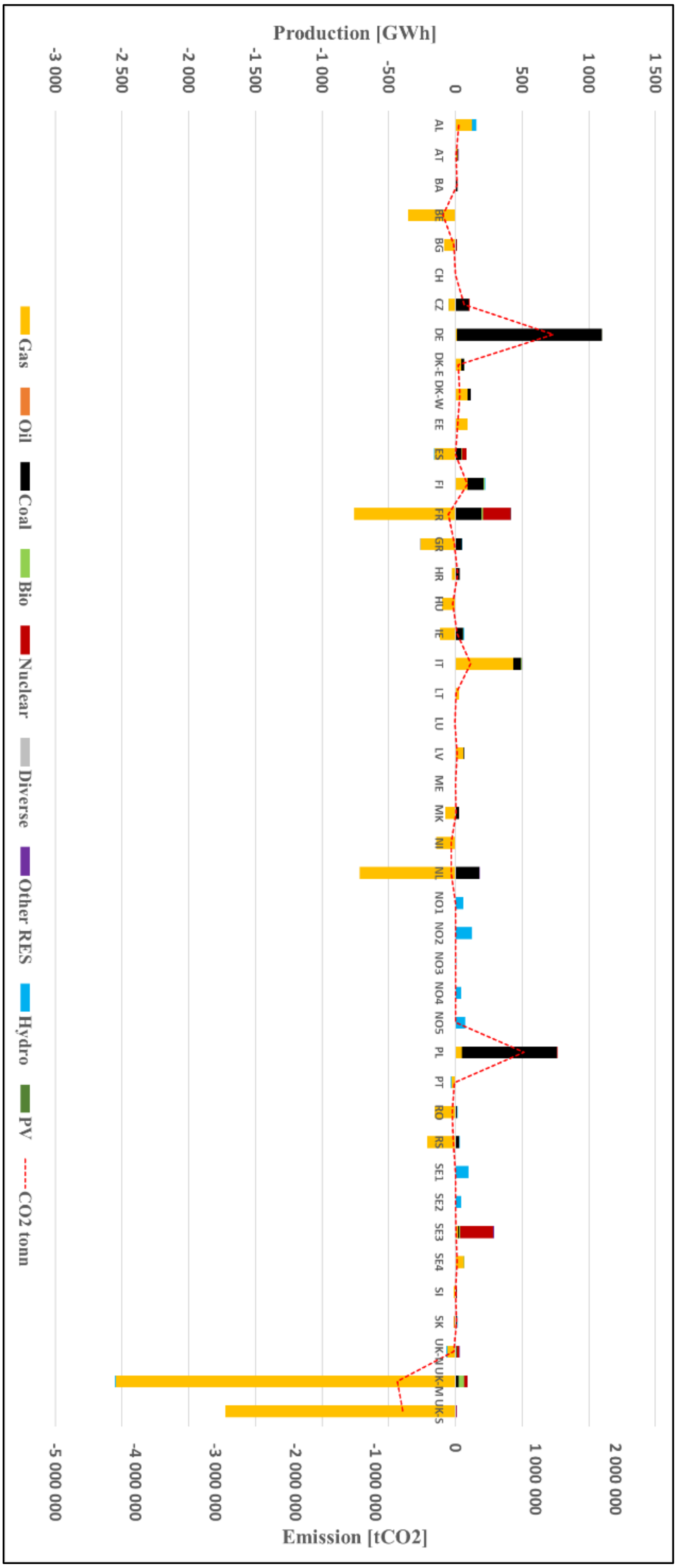


**Figure 6.14 Difference for Production mix (aggregated sum) CP Scenario, -Inv. Cables 2040- Base 2040**

Table 6.7 gives an overview over the $CO_2$-coefficient for all CP Scenarios in year 2040. Inclusion of more hydropower production in NO areas makes the most positive impact for emissions given $CO_2$. The UK $CO_2$-coefficient decreases in the Base&investment cable scenario unlike the Base scenario. This is due to the reduction of gas power production, where hard coal power from DE and PL replace the deficit for the total of UK areas

**Table 6.7 CO2-coefficients (CP Scenario) for Base 2040, Hydro 2040 and Inv. cable 2040**

| **Area** | **Base 2040 [g$CO_2$/kWh]** | **Hydro 2040 [g$CO_2$/kWh]** | **Investment cables 2040 [g$CO_2$/kWh]** |
|---|---|---|---|
| **NO+SE+FI** | 12,42 | 11,20 | 12,84 |
| **NO+SE+DK+DE+NL+UK** | 194,63 | 190,20 | 194,93 |
| **UK** | 65,80 | 63,79 | 62,52 |
| **All** | 169,37 | 166,86 | 169,72 |

### 6.4.2 450 Scenario

For the 450 Scenario in year 2040 five different simulations are performed:

- Base 2040
- Hydro 2040
  Inclusion of more hydropower production in NO areas from 137,3 TWh to 158,2 TWh
- Base&investment cable 2040
  Investment algorithm for offshore cables from NO areas.
- Hydro&investment cable 2040
  Inclusion of more hydropower production in NO areas from 137,3 TWh to 158,2 TWh and investment algorithm for offshore cables from NO areas.
- Investment cable&wind 2040
  Investment algorithm for offshore cables from NO areas and development of wind power in NO areas and UK areas

Figure 6.15 shows an increased installed capacity for wind power for scenario Investment cable&wind. The increase is quite extensive compared to previous installed capacity. The increase is 38 % higher than the Base 2040 scenario. Other installed capacities are the same for all scenarios, since the installed capacity are not manually adjusted for other scenarios. Hydropower and wind power production are increased in their respective scenarios and reduced respectively for emission intensive energy sources compared to Base 240 scenario.

The increase from hydropower production is due to the inclusion of more hydropower in NO areas. The increase from wind power production is due to the development of wind power (given the investment algorithm) in NO areas and UK areas

Both Figure 6.15 and Table 6.8 shows that the production pattern has changed to a higher share of RES, given a significantly reduction of emissions from $CO_2$. The RES technologies are not included in the figure since they have none $CO_2$ -emissions.


**Figure 6.15 Percent change from Base 2040, Emissions (450 Scenario) for Hydro 2040, Inv. cable 2040, Hydro and inv. cable 2040 and Inv. cable and wind 2040**

Table 6.8 gives an overview over $CO_2$-coefficients for performed simulations given different areas and the whole energy system. The changes for the $CO_2$-coefficient is small for all scenarios, except Investment cable&wind. The Investment cable&wind scenario is the scenario with the highest change due to wind power replacing more fossil energy sources.

**Table 6.8 CO2-coefficients for 450 Scenarios, year 2040**

| Area | NO+SE+FI [gCO$_2$/kWh] | NO+SE+ DK+DE+NL+UK [gCO$_2$/kWh] | UK [gCO$_2$/kWh] | All [gCO$_2$/kWh] |
|---|---|---|---|---|
| **Base** | 15,75 | 111,93 | 87,81 | 98,66 |
| **Hydro** | 13,09 | 108,55 | 86,32 | 96,74 |
| **Base and Inv. cable** | 16,75 | 111,01 | 87,24 | 98,25 |
| **Hydro and Inv. cable** | 14,85 | 106,20 | 85,63 | 95,45 |
| **Inv. cable and wind** | 3,83 | 54,14 | 30,32 | 62,87 |

The increase in both installed capacity and production for wind power is quite extensive for the scenario with Investment cable&wind. Table 6.9 shows the increase for wind power in NO areas, UK areas and the total energy system. The total installed capacity and energy production increases respectively 38 % and 51 % if the increase is allocated to the entire modelled energy system.

**Table 6.9 Wind power production with investment algorithm, year 2040**

| **2040** | **Installed capacity [MW]** | | | **Production [GWh]** | | |
|---|---|---|---|---|---|---|
| **Areas** | **Base** | **Wind inv.** | **Increase** | **Base** | **Wind inv.** | **Increase** |
| **NO1** | 0 | 0 | - | 0 | 0 | - |
| **NO2** | 860 | 20 860 | 2326 % | 2 277 | 57 446 | 2423 % |
| **NO3** | 655 | 11 855 | 1710 % | 1 398 | 32 050 | 2193 % |
| **NO4** | 331 | 13 331 | 3927 % | 729 | 29 564 | 3955 % |
| **NO5** | 312 | 20 312 | 6410 % | 804 | 54 227 | 6645 % |
| **NO all** | 2 158 | 66 358 | 2975 % | 5 208 | 173 287 | 3227 % |
| **UK-N** | 12 721 | 32 721 | 157 % | 38 057 | 100 412 | 164 % |
| **UK-M** | 11 410 | 31 410 | 175 % | 34 137 | 96 490 | 183 % |
| **UK-S** | 9 158 | 29 158 | 218 % | 27 400 | 89 752 | 228 % |
| **UK all** | 33 289 | 93 289 | 180 % | 99 594 | 286 654 | 188 % |
| **All areas** | *328 604* | *452 804* | *38 %* | *702 113* | *1 057 252* | *51 %* |

### 6.4.3 Exchange of power

In year 2040 it is applied an investment algorithm for offshore cables from NO areas (NO2 and NO5). The exchange capacity between UK-N to UK-M and UK-M to UK-S for year 2020 and year 2030 are assumed an increase. Which gives a total exchange capacity for UK-N to UK-M and UK-M to UK-S on respectively 11 386 MW and 20 525 MW.

Table 6.10 gives an overview over exchange capacities for cables where the investment algorithm was applied. The scenario Investment cable&wind have a huge exchange capacity compared to the other scenarios.

**Table 6.10 Exchange capacities for offshore cables with investment algorithm, year 2040**

| **Areas** | | **Exchange capacity [MW] (From, To)** | | | | |
|---|---|---|---|---|---|---|
| **From** | **To** | **Original** | **Base Inv. (450)** | **Hydro Inv (450)** | **Inv Wind (450)** | **Base Inv. (CP)** |
| NO2 | DK-W | 1640, 1640 | 1640, 1640 | 1640, 1640 | 1640, 1640 | 1640, 1640 |
| NO2 | DE | 1400, 1400 | 5500, 5500 | 6500, 6500 | 21300, 21300 | 5700, 5700 |
| NO2 | NL | 700, 700 | 1800, 1800 | 2500, 2500 | 7400, 7400 | 2200, 2200 |
| NO2 | UK-M | 1400. 1400 | 3100, 3100 | 3500, 3500 | 21100, 21100 | 3300, 3300 |
| NO5 | UK-N | 2000, 2000 | 4600, 4600 | 5300, 5300 | 8900, 8900 | 4900, 4900 |

In earlier simulation years 2020 and 2030, the exchange capacity was not a limiting factor between UK areas. With the huge increase for exchange capacity for the scenario Investment cable&wind, the transmission line between UK-N and UK-M are close to maximum limit. This is illustrated in Figure 6.16.

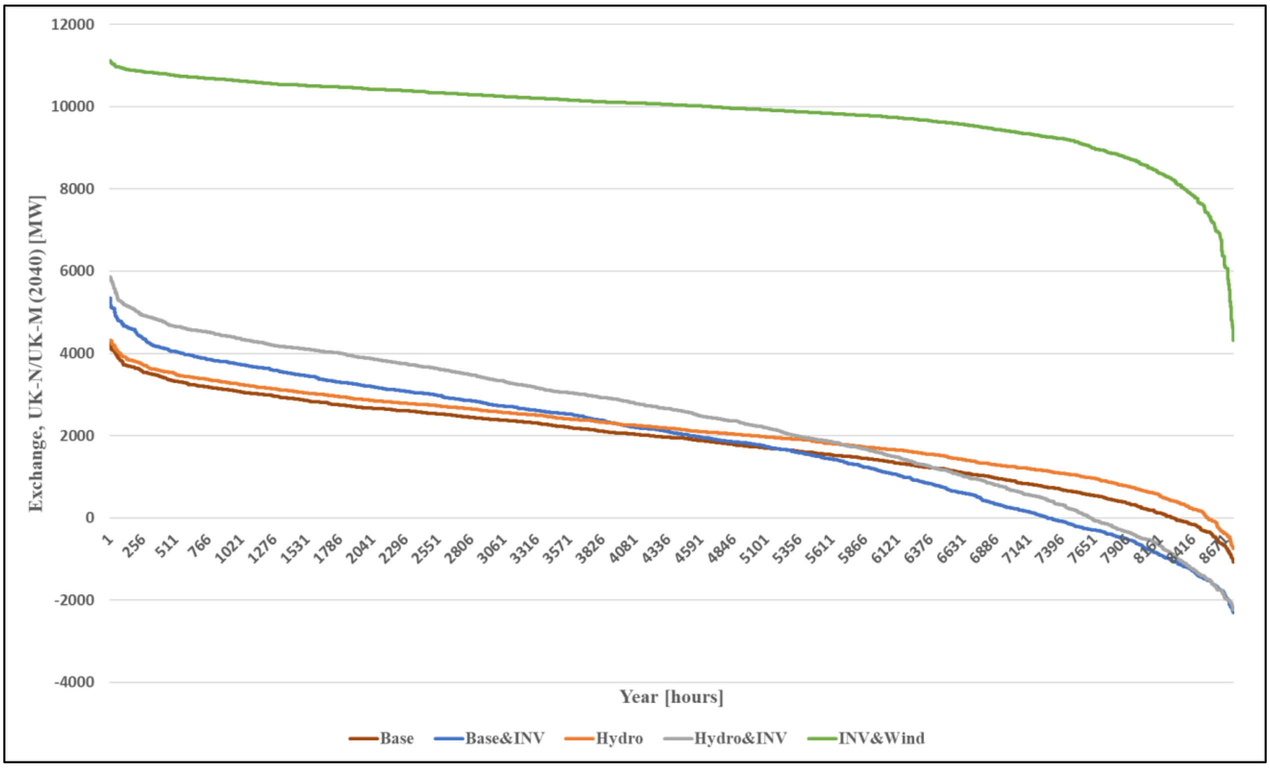


**Figure 6.16 Exchange year 2040 for 450 Scenarios between areas UK-N and UK-M**

The scenario Investment cable&wind reaches not the maximum exchange capacity for the transmission limit for UK-M to UK-S, illustrated in Figure 6.17. This indicates that the exchange capacity between UK-M and UK-S never are a limiting factor.

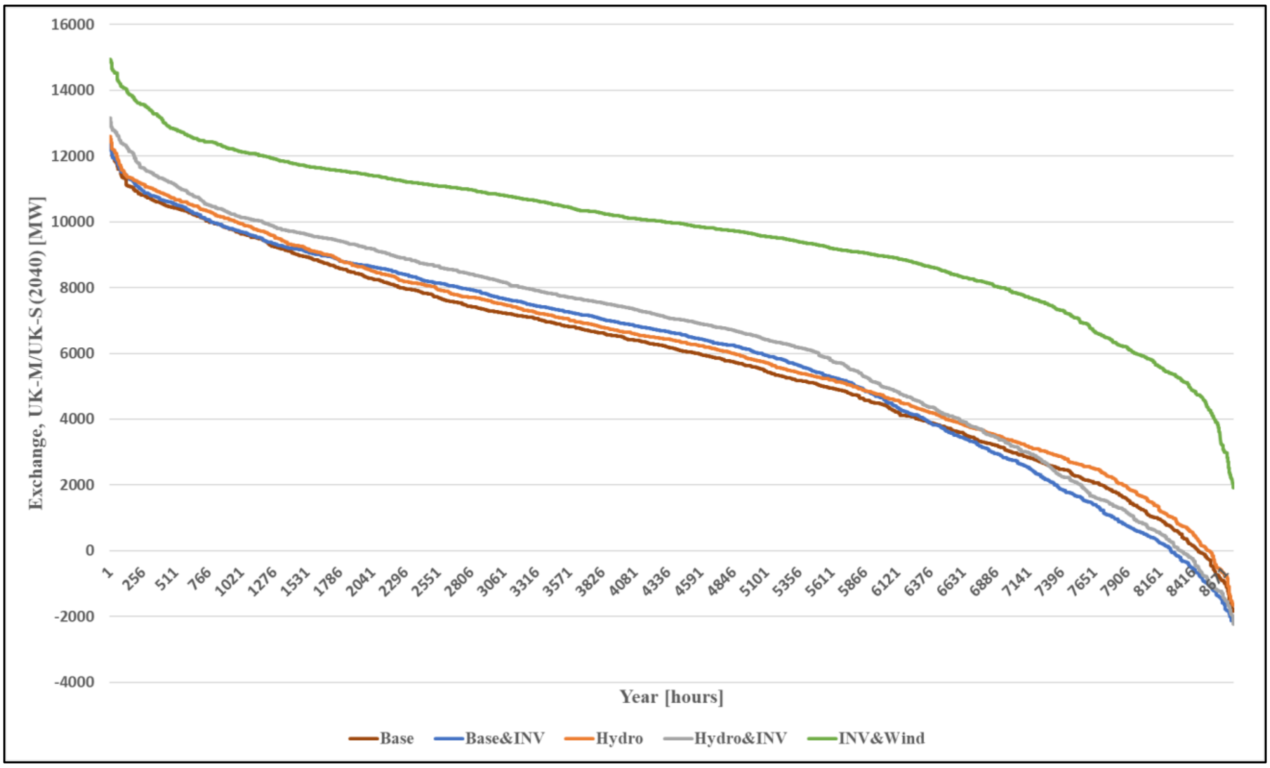


**Figure 6.17 Exchange year 2040 for 450 Scenarios between areas UK-M and UK-S**

In Table 6.10 offshore cables from NO areas listed with new exchange capacities. A selection of these connections are viewed in Figure 6.18 for NO2 to DK-W, Figure 6.19 for NO2 to DE and Figure 6.20 for NO2 to UK-M. Figures for NO2 to NL and NO5 to UK-N are given in Appendix D, since they have the same trends as NO2 to DE.

Figure 6.18 shows that the transfer of power almost only goes from NO2 to DK-W for the scenario with investment cables and wind power. Compared to the other scenarios it doesn't utilize the exchange capacity as good as the other scenarios.

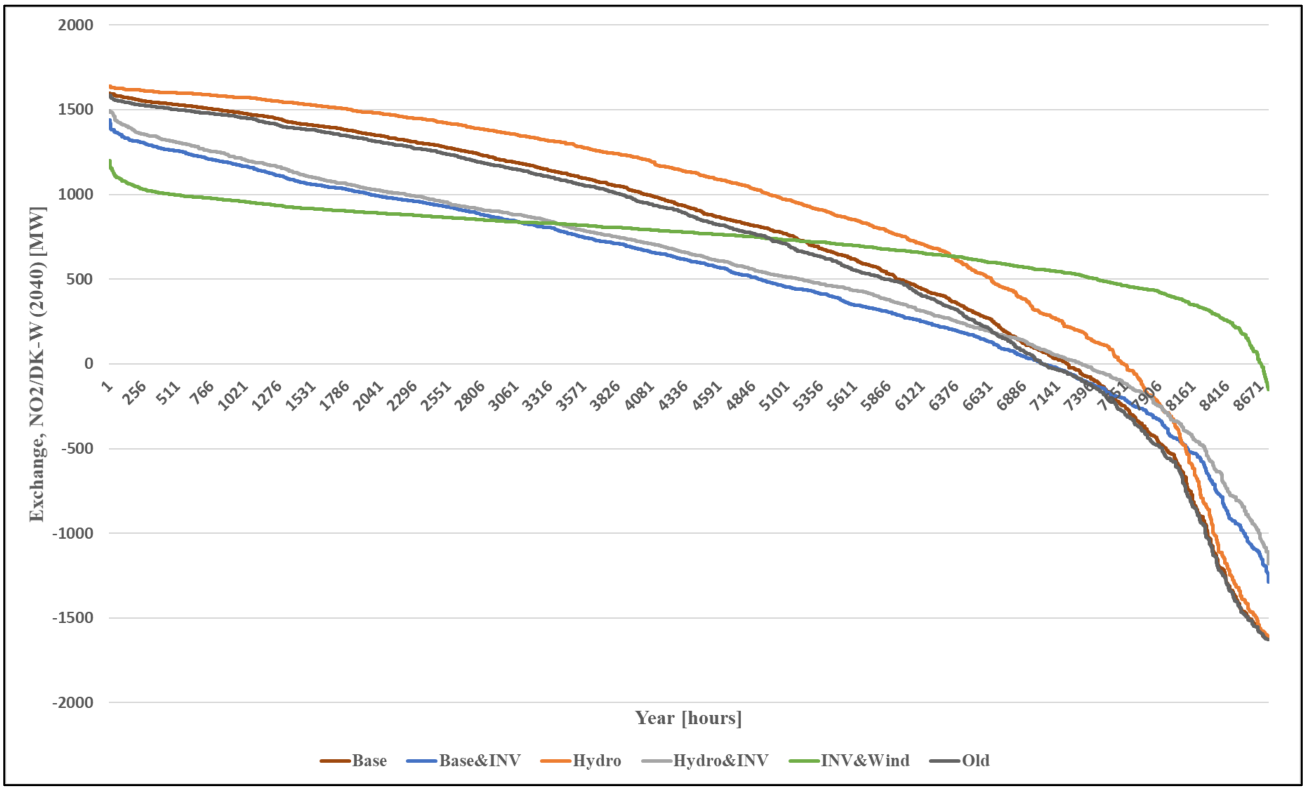


**Figure 6.18 Exchange capacity year 2040 for 450 Scenarios between areas NO2 and DK-W**

Figure 6.19 shows that the scenario Investment cable&wind always transfer more power than the other scenarios. The transfer of power also goes only in the direction NO2 to DE. The same trends apply for NO2 to NL, and almost for NO5 to UK-N. For the cable NO5 to UK-N, in a short time periods the transfer of power goes from UK-N to NO5.

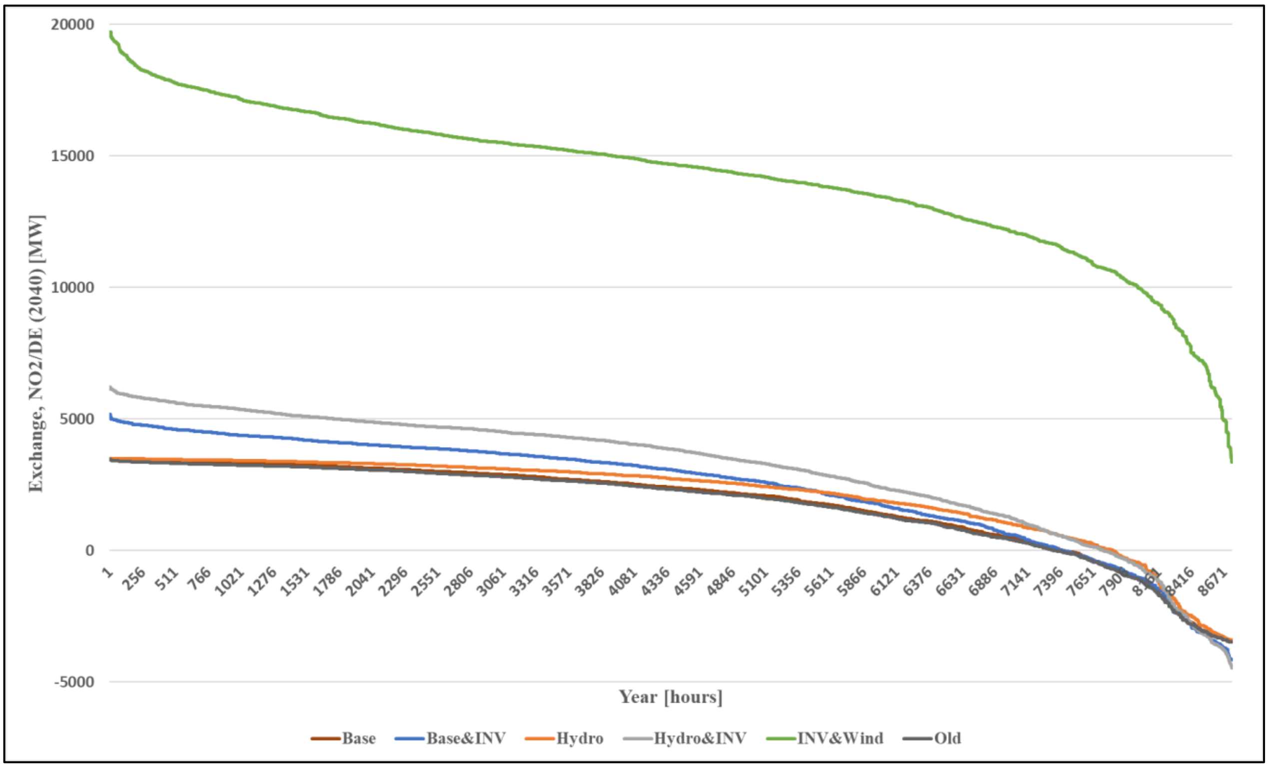


**Figure 6.19 Exchange year 2040 for 450 Scenarios between areas NO2 and DE**

Figure 6.20 shows that the scenario with Investment cable&wind differs from the other scenarios. The other scenarios have mostly transfer of power from NO2 to UK-M. Instead has the investment cable&wind scenario exclusively transfer of power from UK-M to NO2. Since both UK areas and NO areas have an enormous increase of wind power. The need from transport of power to areas in continental Europe is huge for the variable energy source wind power. Since the scenario also has the opportunity to develop higher exchange capacity on all offshore cables from NO areas. The wind power from UK takes a detour through NO areas further to areas in continental Europe.

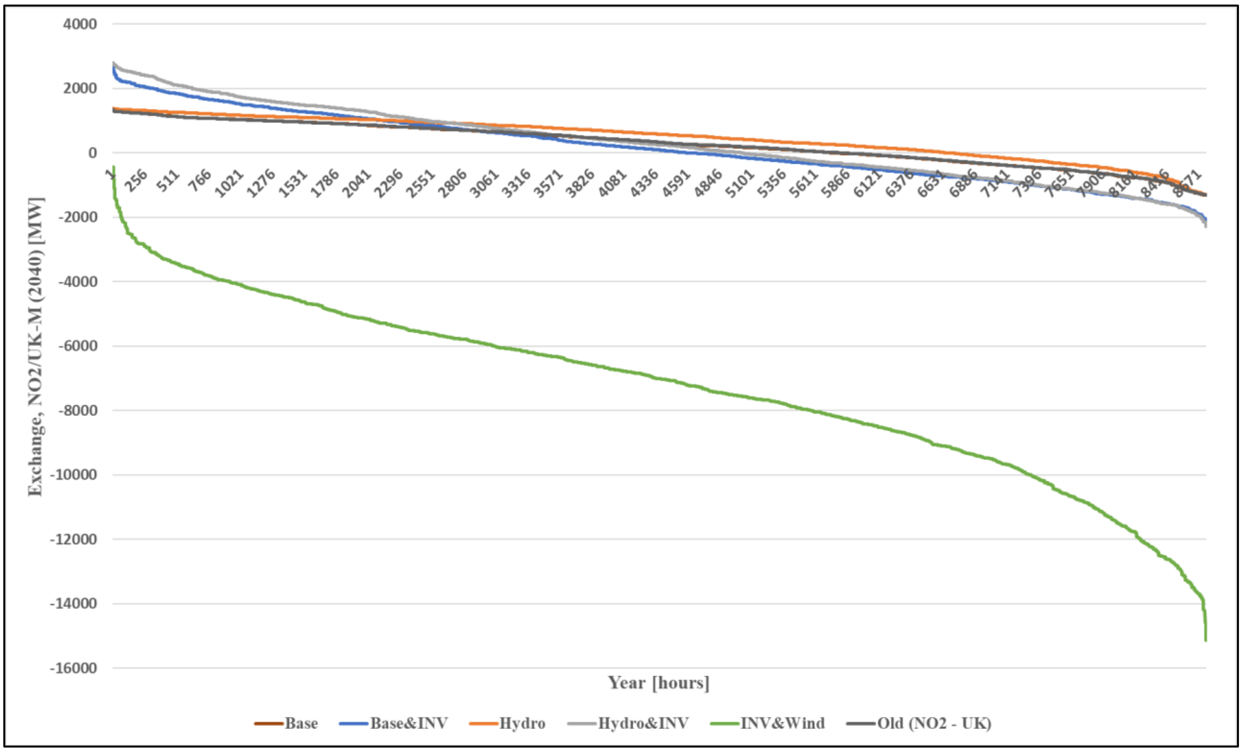


**Figure 6.20 Exchange year 2040 for 450 Scenarios between areas NO2 and UK-M**

Figure 6.21 indicates this detour for the scenario Investment cable&wind power. The transfer of power transfer between NO2 and NO5, goes exclusively from NO5 to NO2 and further to connecting areas in continental Europe.

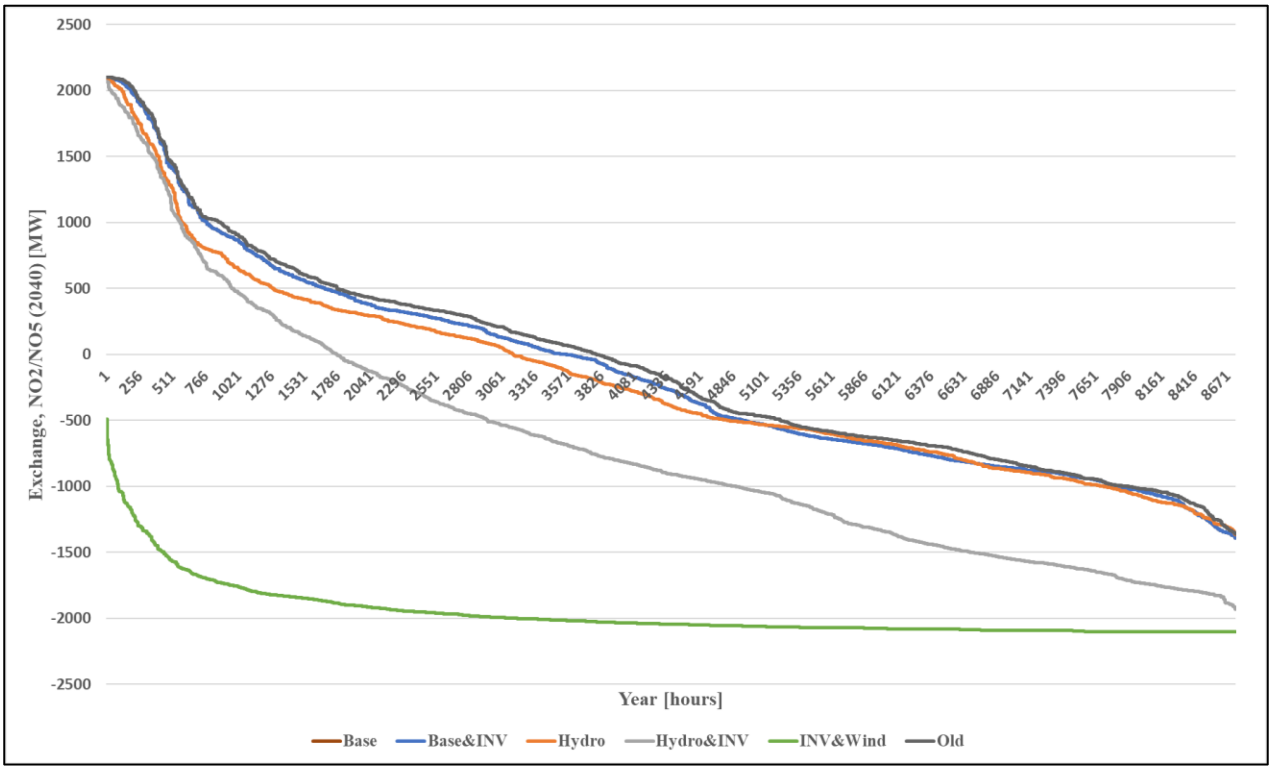


**Figure 6.21 Exchange year 2040 for 450 Scenarios between areas NO2 and NO5**

## 6.5 Area prices

The EMPS model calculates the area prices for each area in the model, the price is given in unit EUR/MWh. The focus areas are respectively UK-N, UK-M, UK-S, NO1, NO2, NO3, NO4 and NO5. It is also of interest to compare the area prices to continental Europe, FR and DE are chosen for that purpose.

### 6.5.1 2020 Area prices

In year 2020 two simulations is performed for the 450 Scenario and the CP Scenario. For the UK areas, UK-M represent the UK area prices since it is negligible differences between the areas. For NO areas, NO1 and NO2 are chosen. NO1 has negligible differences compared to NO3, NO4, NO5. NO2 has not the peak prices during the winter as the other NO areas. The area prices in Figure 6.22 and Figure 6.23 illustrates the monthly average area price over the year.

Table 6.11 gives an overview over estimated yearly average area price for Norway for performed simulations in year 2020. The price for all scenarios is higher than the estimate from Power Market analysis 2018 by NVE(11). That is due to different assumption regarding prices for fuels and taxes. In this project is not all considerations from NVEs estimate considered.

**Table 6.11 Average (year) area price for Norway year 2020**

| Source | Average year [EUR/MWh | Min, year [EUR/MWh | Max, year [EUR/MWh] |
|---|---|---|---|
| **NVE(11)** | 32 | 26 | 39 |
| **Base 2020 – CP** | 47 | 34 | 53 |
| **Base 2020 – 450** | 44 | 34 | 51 |

Figure 6.22 illustrates the high peak price for NO1 in March and April. The higher area prices compared to neighbouring areas happens due to bottlenecks in the transmission system. NO1 and NO3 has also a deficit of power.

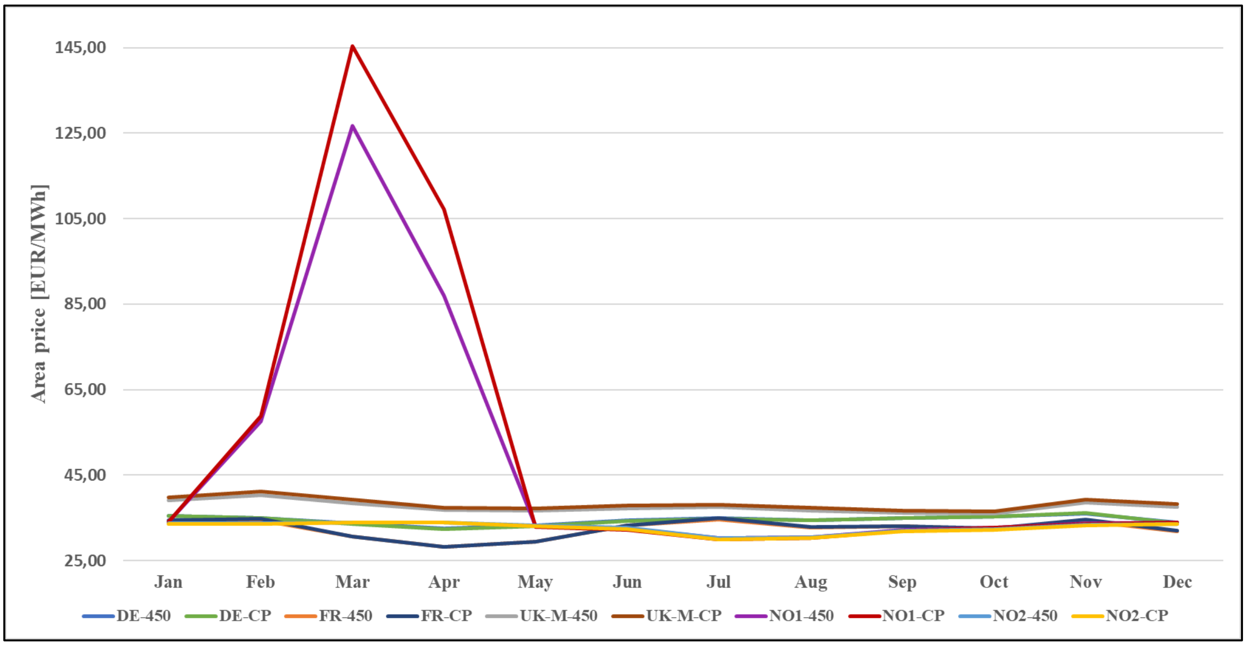


**Figure 6.22 Area prices (monthly average) year 2020 DE, FR, UK-M, NO1 and NO2 for CP and 450 Scenario**

Figure 6.23 is zoom in from Figure 6.22 for areas DE, FR, UK-M and NO2. The CP Scenario and 450 Scenario gives small differences, and the trends between CP and 450 scenarios are not clear in year 2020. For FR, UK and NO1 the CP Scenario gives slightly higher prices, but it is opposite for DE and NO2.

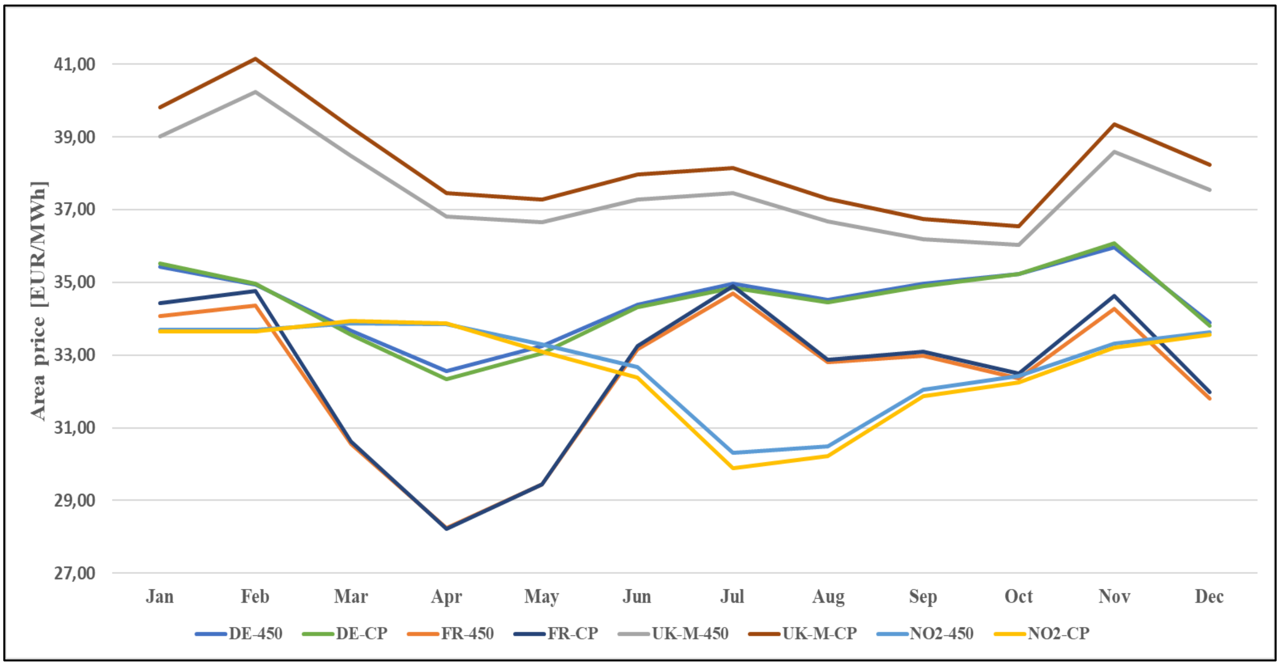


**Figure 6.23 Area prices (monthly average) year 2020 DE, FR, UK-M and NO2 for CP and 450 Scenario**

During a month, the area price changes every hour. Figure 6.24 illustrates the significant difference between average, minimum and maximum area price per month for NO1 given 450

Scenario. Usually the differences are not as high as in March and April month for NO1 in year 2020. The difference in April is 98 EUR/MWh. The maximum area prices occur in constrained time periods.

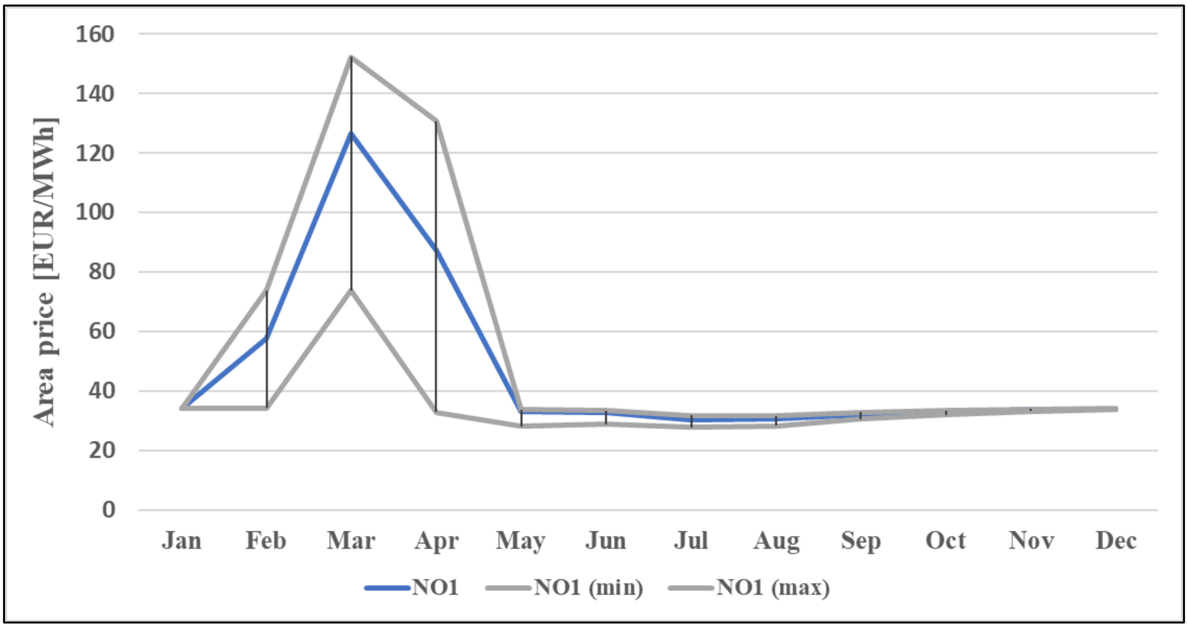


**Figure 6.24 Area prices (average, min and max) year 2020 NO1 for 450 Scenario**

Figure 6.25 illustrates the differences between average, minimum and maximum area price per month for NO2. The biggest difference between maximum and minimum area price (monthly) for UK-M is 6 EUR/MWh in May.

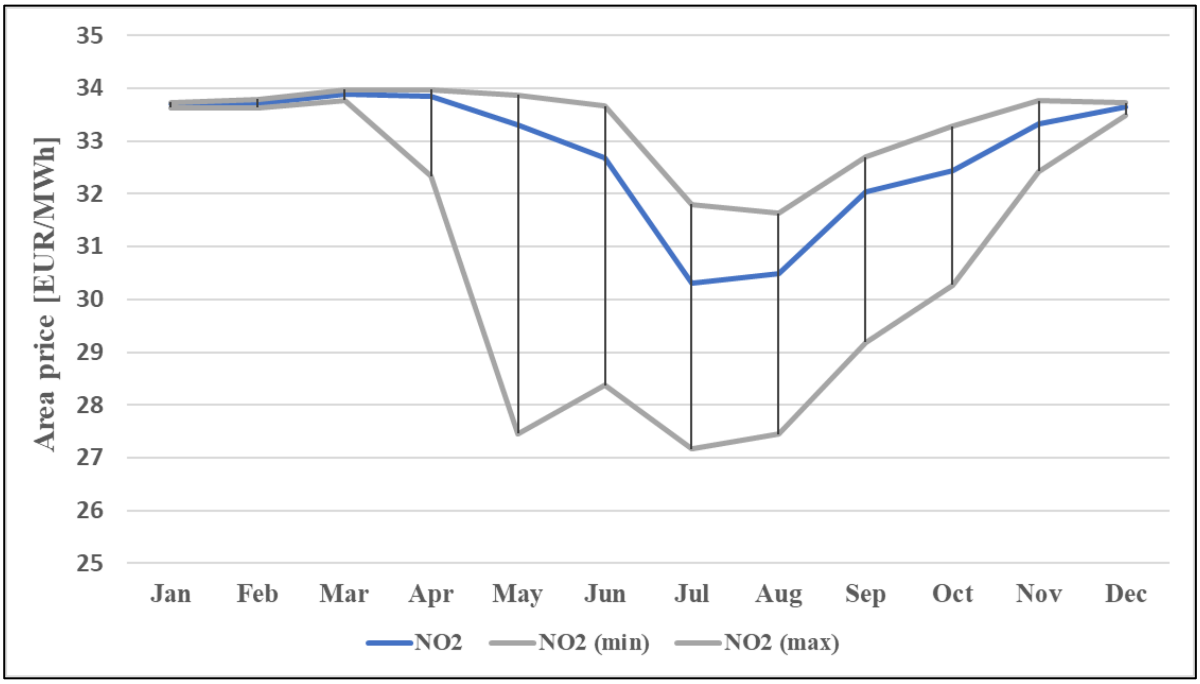


**Figure 6.25 Area prices (average, min and max) year 2020 NO2 for 450 Scenario**

Figure 6.26 illustrates the differences between average, minimum and maximum area price per month for UK-M. The biggest difference between maximum and minimum area price (monthly) for UK-M is 30 EUR/MWh in December.

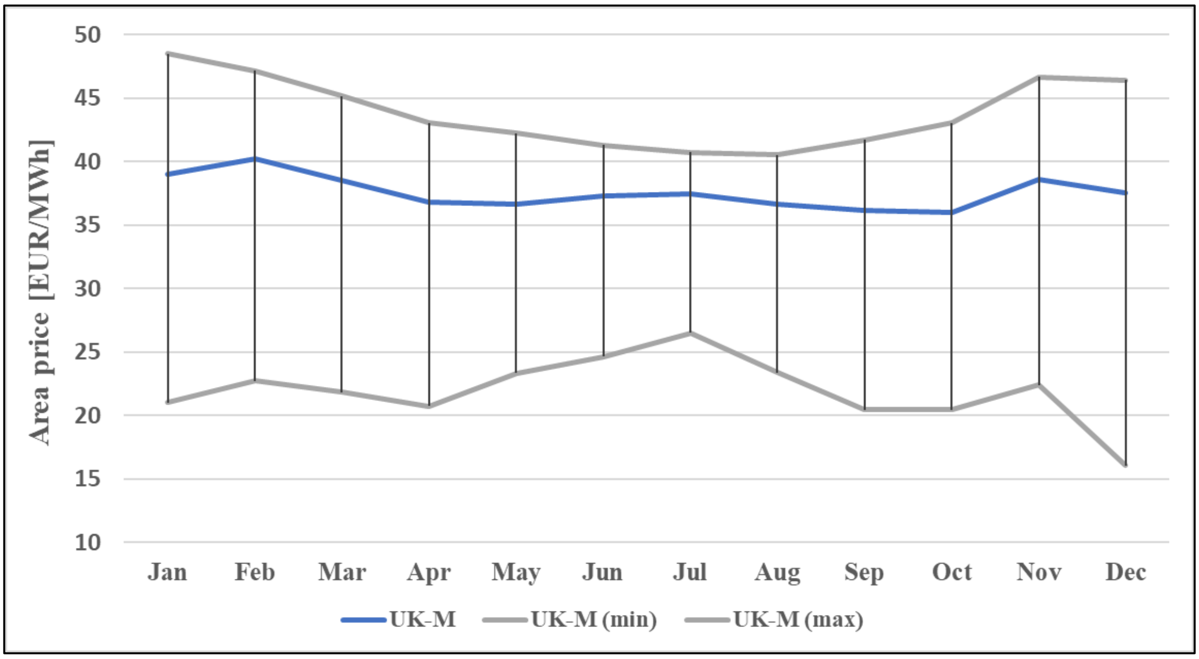


**Figure 6.26 Area prices (average, min and max) year 2020 UK-M for 450 Scenario**

### 6.5.2 2030 Area prices

In year 2030 four simulations is performed, Base and Hydro for both CP Scenario and 450 Scenario. UK areas is represented by UK-M, since differences still is negligible differences. For NO areas, NO2 and NO5 are chosen. NO2 and NO5 have interconnections to respectively UK-M and UK-N. DE and FR represent area prices for continental Europe.

Table 6.12 gives an overview over estimated yearly average area price for Norway for performed simulations in year 2030. The price for all scenarios is higher than the estimate by NVE(11), like year 2020. The increase between year 2020 to 2030 for the CP Scenario is 1 EUR/MWh compared to the increase of 4 EUR/MWh in the NVE estimate

**Table 6.12 Average (year) area price for Norway year 2030**

| Source | Average year [EUR/MWh | Min, year [EUR/MWh | Max, year [EUR/MWh] |
|---|---|---|---|
| **NVE(11)** | 36 | 22 | 54 |
| **Base 2030 – CP** | 49 | 39 | 51 |
| **Base 2030 – 450** | 89 | 73 | 92 |
| **Hydro 2030 – CP** | 48 | 38 | 50 |
| **Hydro 2030 – 450** | 87 | 71 | 80 |

Figure 6.27 illustrates the area price for base and hydro scenario given CP scenario. For all areas the hydro scenario gives a minor lower area price. This happens since hydropower replaces thermal power plants with cost for fuels. The high share of hydropower and lower demand in the NO areas gives lower area prices during summer compared to area prices in continental Europe (FR, DE and UK-M).

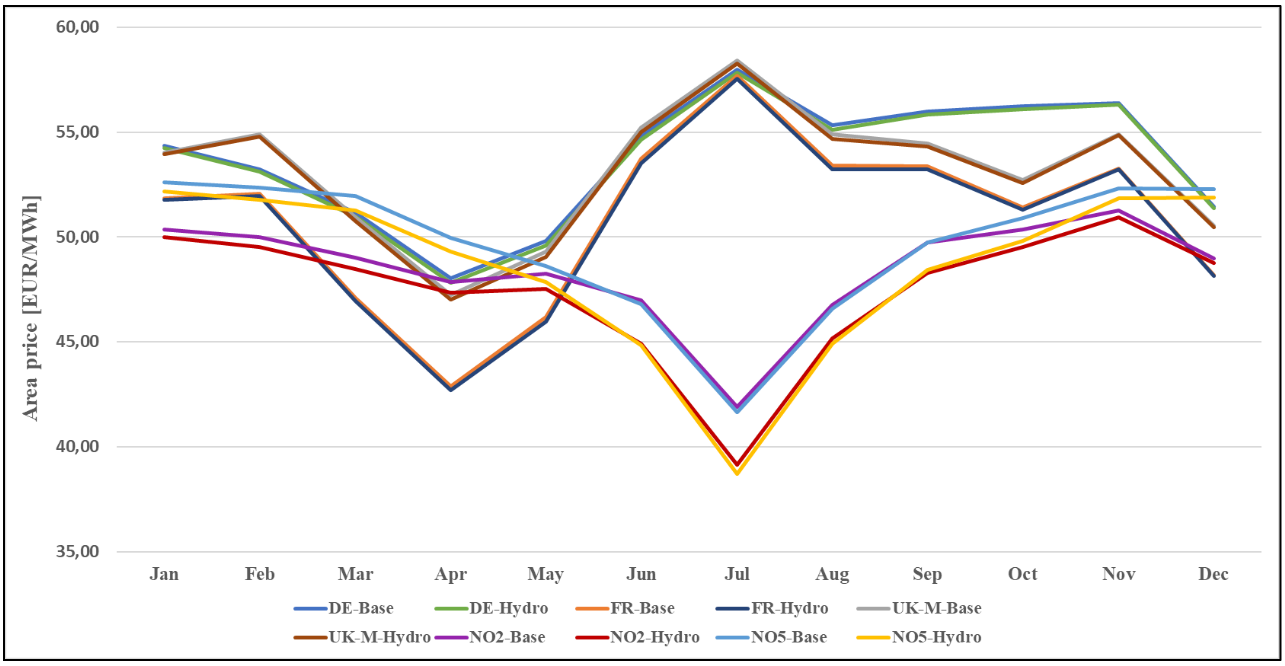


**Figure 6.27 Area prices (monthly average) year 2030 for CP Scenario DE, FR, UK-M, NO2 and NO5**

Figure 6.28 illustrates that also the 450 Scenario has a slightly lower area prices for the hydro scenario. The area prices for DE is level higher compared to FR and UK-M. The 450 Scenario has higher coal prices compared to CP Scenario. This affects the area prices in DE, since DE depends on coal power production in this project.

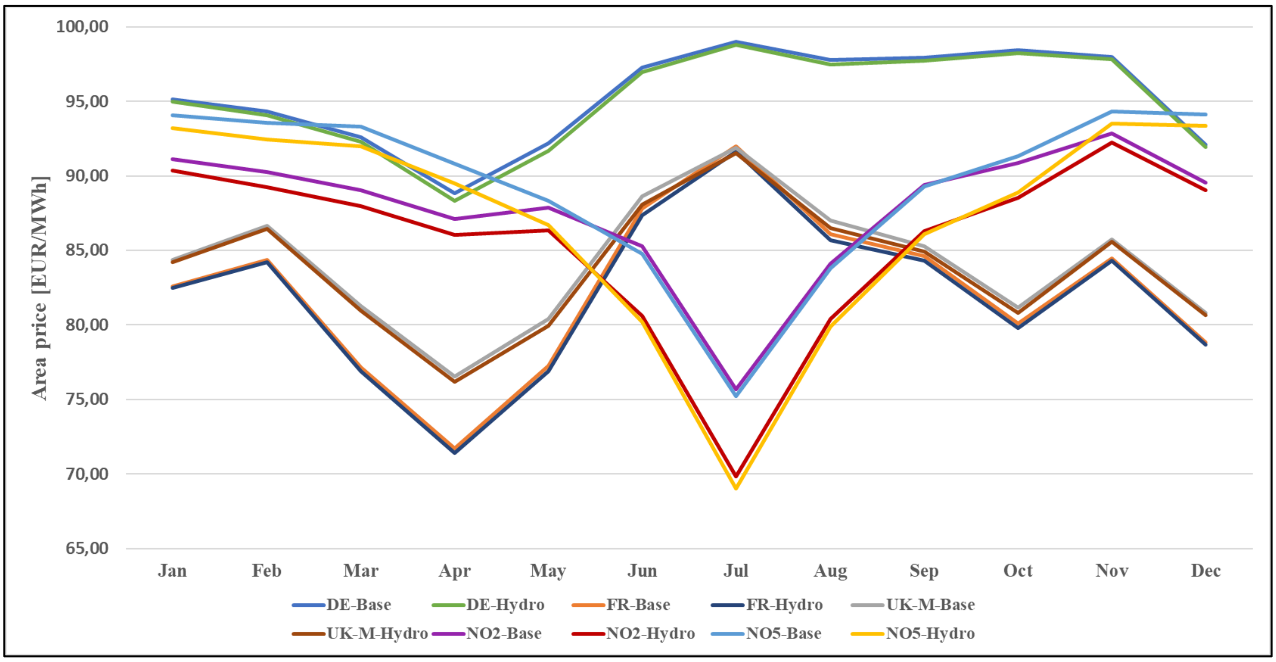


**Figure 6.28 Area prices (monthly average) year 2030 for 450 Scenario DE, FR, UK-M, NO2 and NO5**

In year 2030 the differences between for CP and 450 scenarios are visible. The trends are the same, but the 450 Scenario has area prices around 20-30 EUR/MWh higher.

### 6.5.3 2040 Area prices

In year 2040 the same trends for the difference between CP Scenario and 450 scenarios are applicable as in year 2030, with the same difference around 20-30 EUR/MWh. Given area prices in year 2040, the 450 Scenarios are given further explanations and figures in this subchapter. Figures for CP Scenarios can be found in Appendix C.

Figure 6.29 illustrates the monthly average area prices for DE, UK-M, NO2 and NO5 given scenarios for Old, Base and Hydro. The Hydro scenario gives the lowest area price for all areas. For the NO areas the area price is lower for the Old model compared to Base scenario. The difference between the Old model and base Scenario for DE and UK-M is almost negligible. Compared to the 450 Base Scenario in year 2030 from Figure 6.28, the area prices are 5-10 EUR/MWh higher.

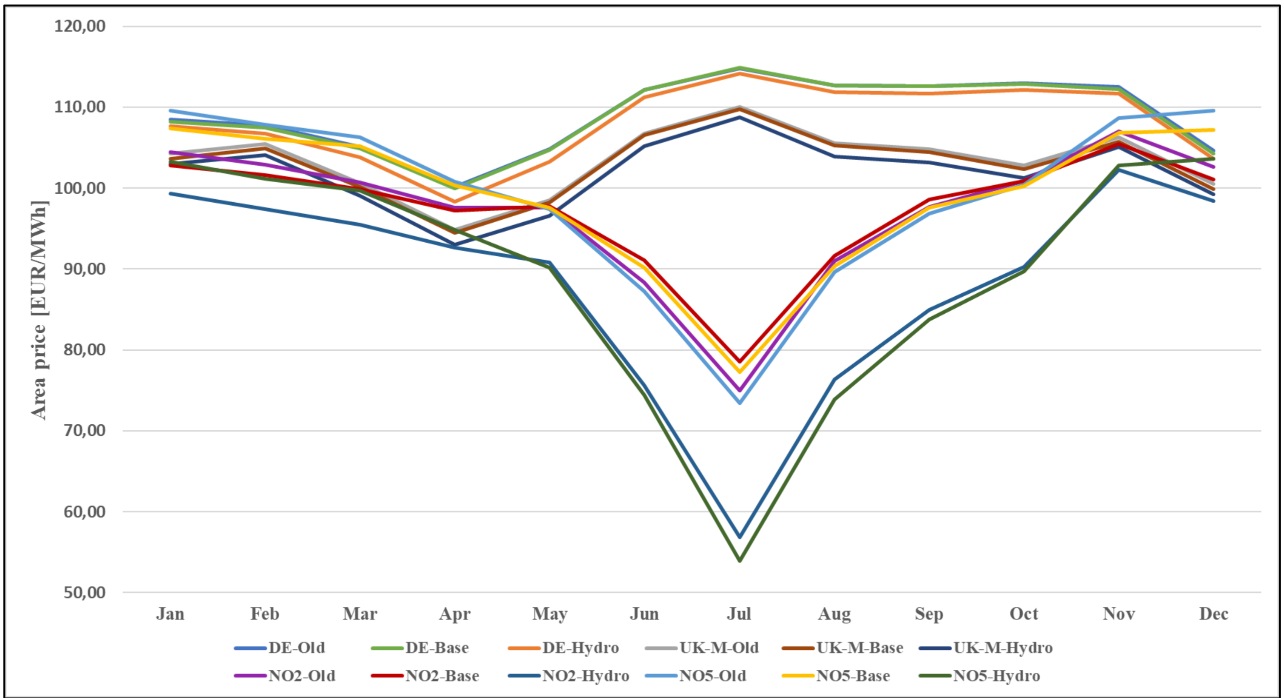


**Figure 6.29 Area prices (monthly average) year 2040 for 450 Scenario DE, UK-M, NO2 and NO5 given Old, Base and Hydro**

Figure 6.30 illustrates the monthly average area prices for DE, UK-M, NO2 and NO5 given scenarios for Base&Investment cable, Hydro & Investment cables and Investment cable&wind. The Investment cable&wind scenario show a strong connection for area prices between connecting areas. NO5 and UK-N have the lowest area prices with almost the same trend. The same is the case for NO2 and UK-M.The Base&Investment cable and Hydro&Investment cable scenarios have the same trends as in Figure 6.29.

Hydro&Investment cable scenario give lower area prices for NO areas compared to the Base&Investment.cable For the UK areas are same difference even smaller.

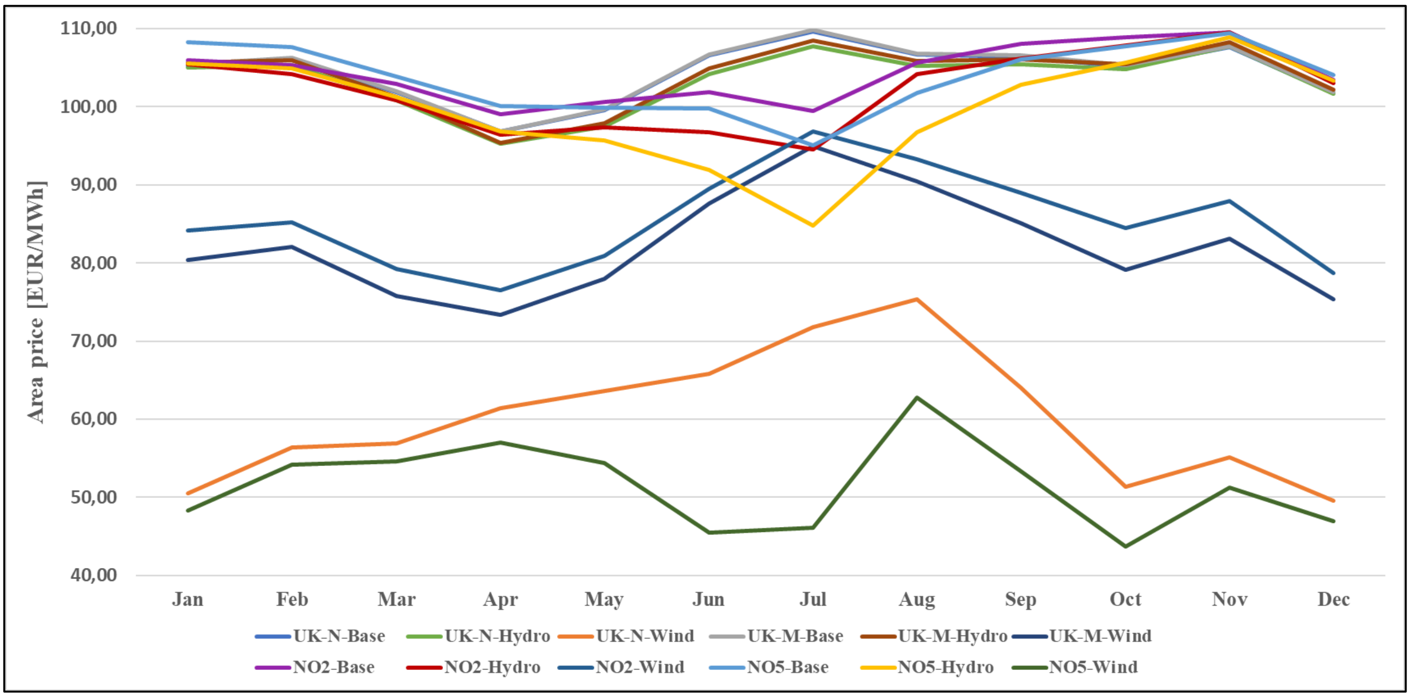


**Figure 6.30 Area prices (monthly average) year 2040 for 450 Scenario UK-N, UK-M, NO2 and NO5 given Base&inv, Hydro&inv and Inv&wind**

# 7 Discussion

Scenarios in this project are formulated to see if they make a positive impact on the European energy system. Especially inclusion of more hydropower from Norway and inclusion of more wind power in both Norway and Great Britain. An inclusion of more hydropower Norway is dependent of good enough exchange capacity to neighbouring countries (in this project modelled as areas) to be exploited in the rest of the system. Development of more wind power in both Norway and Great Britain have the same needs with good enough exchange capacities to neighbouring countries (i.e. areas). Wind power is not a flexible energy source, so it cannot be stored in reservoirs as a high share of the hydropower in Norway can.

## 7.1 Model changes

The extension of the model from one UK area to three UK areas where thought having an impact for the UK production pattern, given lateral distribution between production and consumption of energy in Great Britain. Given used datasets for powerlines in UK, the capacity between both UK-N- UK-M and UK-M- UK-S where not a limiting factor in 15 of 16 simulations. In scenario Investment cable&wind the exchange capacity where close to maximum capacity. The increased wind power production and exchange capacity on offshore cables are set by the investment algorithm. This is illustrated in Figure 6.16, Figure 6.20 and Figure 6.21, where surplus from wind power production takes a detour through Norway, before being transported to continental Europe. This detour is happening, because of an enormous increase in cross-border capacities for offshore cable from Norway.

## 7.2 The effect of different scenarios

### 7.2.1 Inclusion of more hydropower and wind power

In both year 2030 and 2040 it was assumed a higher energy production from hydropower, with the existing installed capacities. The assumed increased hydropower production in Norway are collected from NVE. For both years and the two different fuel-prices and $CO_2$-taxes scenarios it resulted in a higher production of hydropower and corresponding reduction of especially hard coal power and gas power in Germany and Poland. This is illustrated in Table 6.5, Table 6.6 and Figure 6.13.

The increase in wind power production in scenario Investment cable&wind are set by an investment algorithm. The investment algorithm is implemented in the EMPS 2 model. The investment cost where set equal for both onshore and offshore wind power Table 6.9 gives an overview over installed capacity and production for the scenario Investment cable&wind

compared to Base Scenario. The total increase with 38 % for installed capacity and 51 % for production are reasonable if it was attributed to all areas in the model. In this case it is only attributed to NO areas and UK areas, see Table 6.9.

The attribution for NO areas between Base 2040 and Investment cable&wind 2040 gives percentage increases of:

- 2975 % for installed capacity (from 2 158 MW to 66 358 MW))
- 3227 % for energy production (from 5,2 TWh to 173,3 TWh)

This is not very reasonable compared to estimates from NVE done by Kjeller Vindteknikk with development of offshore hydropower in Norway(14). The percentage increase from todays installed onshore wind power to inclusion of offshore wind power capacity are:

- 354 % for installed capacity (from 1 695 MW to 7 695 MW)
- 1770 % for installed capacity (from 1 695 MW to 31 695 MW)

Those estimates are based on whether the minimum distance from land requirement are set from 1-10km for offshore wind power. If development of floating wind power also is included, the increase can be even higher. Given the scenario Investment cable&wind development of floating wind power is also necessary to reach simulated installed capacity. This implies the same size as ongoing projects in UK today (around 1 GW) and total of 25-30 projects. This indicate that the developed wind power based on the investment algorithm might be reasonable, if Norway utilize the high offshore potential for wind power. However, is it dependent on a positive Norwegian Government and a plan to utilize the potential. Today is there still scepticism regarding big wind power projects in Norway(52).

The attribution for UK areas between Base 2040 and Investment cable& gives percentages increases of:

- 180 % for installed capacity (from 33 289 MW to 93 289 MW)
- 188 % for energy production (from 99,6 TWh to 286,7 TWh)

If all ongoing projects in ÙK today where finalized, the total installed capacity would be 29 709 MW. These projects are realized long before year 2040. This implicate that the Base 2040 have a too low assumption regarding installed capacity. In United Kingdom wind power is a central part for the shift to more renewable production pattern. They have also more ongoing projects regarding offshore wind. This makes it realistic to assume such an increase of wind power development in UK areas, since they have already had a quite extensive increase of wind power in their energy system.

### 7.2.2 Development of offshore cables from Norway

In year 2020 and 2030 exchange capacity was held at a fixed level. In year 2020 the utilization for offshore cables from Norway (NO2) to continental Europa (DK-W, DE and NL) were quite high. Even though most of the cables where not operating at maximum capacity over longer time periods. For the offshore cable from NO2 to UK-M the cable was operating at maximum capacity over longer time periods. The cable from Netherland (NL) to Great Britain (UK-S) was also in total transferring most of the power to Great Britain. This is illustrated in Figure 6.7 and Figure 6.8. In year 2030 two more scenarios were included, about more hydropower development in Norway. This gives a higher total share of total exchanged power from Norway to among others Great Britain. In year 2030 a new offshore cable from Norway (NO5) to Great Britain (UK-N) is included in the system. This led to less constrained exchange capacity on the other offshore cable to Great Britain. The utilization of the offshore cables is high, but not constrained over longer time periods as in year 2020. The offshore cable from Netherland (NL) to Great Britain (UK-S) is also not importing the same amount of power to Great Britain as in year 2020. Import of power from Norway with a higher share of renewable energy sources reduces the emissions and give a more renewable production pattern. This is illustrated in Figure 6.10, Figure 6.11 and Figure 6.12.

An investment algorithm is implemented for the 2040 scenario. The investment algorithm decides the maximum exchange capacity for the offshore cables from Norway to continental Europe and Great Britain. By implementing the investment algorithm, it is possible to see if it is reasonable to have a higher exchange capacity. Table 6.10 shows a higher exchange capacity for all scenarios with the investment algorithm except the connection NO2 to DK-W. In general, the CP Scenario resulted in a higher exchange capacity than the 450 Scenario. The differences for fuel-prices and $CO_2$-taxes are assumed high in year 2040 compared to previous years. Inclusion of more hydropower in Norway also sets a higher exchange capacity. All these new exchange capacities are an increase from 121 %-364 % compared to the Base Scenario. The increase for the scenario Investment cable&wind were between 345 %-1421 %. The increased exchange capacities made positive impacts on both production pattern and emissions.

This extensive development is dependent on positive decision makers (Governments in connecting countries) and the interest of investing in projects (from e.g. power- and grid-companies).

## 7.3 Changes in emissions

The emissions are in the EMPS model calculated as $CO_2$ ton per area. Given produced electricity in the areas, the $CO_2$-coefficient [$gCO_2$/kWh] are calculated. Figure 6.5 shows that the $CO_2$- coefficient are expected to decrease over the years for the base case scenarios, this is due to out-phasing of old power plants with higher emissions.

The reduction between 450 Scenario and CP Scenario for simulated years are interesting to investigate. The reduction for emissions for 450 Scenarios minus CP Scenarios is the following for $CO_2$-coefficients and million-tons $CO_2$:

- Year 2020: $CO_2$-coefficient 1,0 $gCO_2$/kWh (3,4 Mt-$CO_2$)
- Year 2030: $CO_2$-coefficient 108,0 $gCO_2$/kWh (365,1 Mt-$CO_2$)
- Year 2040: $CO_2$-coefficient 70,7 $gCO_2$/kWh (255,5 Mt-$CO_2$)

The distinction changes between the 450 Scenario and CP Scenario from year 2020 to 2040 is due to the changes for the fuel-prices. The 450 Scenario have higher hard coal prices compared to the CP Scenario. The 450 Scenario will therefore produce less energy from emission intensive technologies. In year 2040 the distinction is smaller compared to year 2030. In both cases gas power plants replaces coal power plants. In year 2030, gas replaces especially lignite coal, which is the fuel type with highest emissions. The share of lignite coal has decreased in year 2040, and the difference between hard coal power plants and gas power plants are not that huge.

In year 2030 and year 2040 more hydro power production was included in Norwegian areas. The distinction between base scenarios and hydro power scenarios are highest for the CP scenarios compared to the 450 Scenario. The reduction for emissions for Base 2030 minus Hydro 2030 is the following for $CO_2$-coefficients and million-tons $CO_2$:

- CP Scenarios

  Year 2030: $CO_2$-coefficient 1,6 $gCO_2$/kWh (5,3 Mt-$CO_2$)

  Year 2040: $CO_2$-coefficient 2,5 $gCO_2$/kWh (8,2 Mt-$CO_2$)
- 450 Scenarios

  Year 2030: $CO_2$-coefficient 0,9 $gCO_2$/kWh (2,8 Mt-$CO_2$)

  Year 2040: $CO_2$-coefficient 1,9 $gCO_2$/kWh (6,5 Mt-$CO_2$)

In year 2040 the inclusion of hydropower is higher. A higher decrease for the $CO_2$-coefficient is expected in year 2040. The same applies for the two scenarios CP and 450. The CP Scenario has higher fuel-prices and $CO_2$-taxes. The CP Scenario favours therefore more hydropower production with no fuel costs.

In year 2040, four scenarios had an investment algorithm implemented compared to respective base scenario, the increase and decrease for $CO_2$-coefficients and million-tons $CO_2$ is the following:

- CP Scenario 2040, increase:

  Investment cable: $CO_2$-coefficient 0,4 $gCO_2$/kWh (1,0 Mt-$CO_2$)
- 450 Scenarios, decrease

  Investment cable: $CO_2$-coefficient 0,4 $gCO_2$/kWh (1,7 Mt-$CO_2$)

  Hydro&investment cable: $CO_2$-coefficient 3,2 $gCO_2$/kWh (11,7 Mt-$CO_2$)

  Investment cable&wind: $CO_2$-coefficient 35,8 $gCO_2$/kWh (125,6 Mt-$CO_2$)

For the two base scenarios, CP and 450 with investment algorithm for cables, the distinction compared to base scenarios was low. The CP Scenario has an increase of emissions. Figure 6.14 shows an increase of coal power production and reduction of gas power production leading to the increased $CO_2$-coefficient. The difference for 450 Scenario is small, but a small share of hard coal power is replaced with gas power. The investment algorithm is also applied for the scenario with inclusion of more hydropower in Norway. The reduction is higher compared to year 2030, since more hydropower production are included. The last scenario with Investment cable&wind has a huge reduction in $CO_2$-coefficient compared to the other scenarios. This is due to the increased wind power production (51 % increase), which leads to a corresponding reduction of fossil energy sources.

## 7.4 Changing area prices

Area prices are affected both by fuel-prices and $CO_2$-taxes and limiting transmission capacities. In Chapter 6.5 area prices for selected areas are illustrated. Given the CP Scenario and 450 Scenario for fuel-prices and $CO_2$-taxes the differences are first visible for year 2030 and year 2040, this is illustrated in for example Figure 6.27 and Figure 6.28. The difference is around 20- 30 EUR/MWh higher for the 450 Scenario. This increase are reasonable given bigger differences between the scenarios in year 2030 and 2040 compared to year 2020.

For year 2020 the effect of deficit in an area are viewed in Figure 6.22. The Norwegian areas NO1, NO3, NO4 and NO5 had a high peak during winter. This were due to deficits in NO1 and NO3, and low amounts of power to be exported from NO4 and NO5. Most of the surplus in NO2 where exported. This led to a constrained transmission network from exchange neighbouring areas as SE1, SE2, SE3 and FI. The bottlenecks in the modelled system, give high area prices for areas importing power.

In year 2030 the difference between Base scenario and Hydro scenario are small, but the Hydro scenario gives slightly lower area price. The distinction between summer and winter are also notable for the NO areas. This is expected since Norway usually has lower area prices during summer due to increased hydropower production and lower demand in that period.

The investment algorithm simulated stronger interconnections between NO to UK and NO to continental Europe in year 2040. An energy system with no bottlenecks in the transmission network gives more equal area prices. The scenario Investment cable&wind shows this for area prices in areas NO2, NO5, UK-M and UK-N. Connecting areas have more equal price trends compared to scenario without the investment algorithm. This is illustrated in Figure 6.29 and Figure 6.30. The scenarios without investment algorithm have the same trends as previous years (2020 and 2030).

Given NVE's note about electricity prices, this project can see some of the same trends with lower prices during winter season for NO areas and area prices more affected by production pattern in continental Europe for simulated scenarios. The area prices in this project are higher compared to expectations from NVEs Power Market Analysis 2018(11), see Table 6.11 and Table 6.12. Since the price estimates are done based on different fuel-prices, $CO_2$-taxes and out-phasing strategies of old technologies.

## 7.5 Inaccuracies in modelling, simulations and scenario building

In this project there are three inaccuracies that may have affected the results. These three inaccuracies are:

- Old scenario building (mainly reports from 2016)
- Not calibrating the EMPS model between each simulation
- Not validating the investment cost in the implemented investment algorithm

**Old Scenario Building**

Most of the reports used for scenario building is based on reports from 2016. For instances has the TYNDP 2016 been updated with TYNDP 2018. Updating the scenario building would be too time-consuming in addition with the rest of the tasks in this project

Used reports in the scenario building are made on a more general approach, and all internal conditions in each area is not considered. For instance is it expected earlier out-phasing of coal in United Kingdom(39). New estimates from the British Government indicates that the British transmission system will have no coal power by 2023, two years before the original plan.

Another important assumption in this project is that the cable NortConnect (NO5 to UK-N) is set into operation by year 2030. A news article in "Teknisk Ukeblad" informs that the Government in Norway has asked NVE to postpone the decision regarding NorthConnect until the Power market analysis 2019 from NVE is ready(53). Brexit and the unresolved relationship between EU and United Kingdom are mentioned as an uncertainty in the case. Agder Energi, an owner in NortConnect and a Norwegian power company, warns that they fear Sweden and Denmark can make money from Norwegian power going through them on their way to other European countries. This can happen if Sweden and Denmark upgrade their connections to United Kingdom and other European countries before Norway. In the scenario with Investment cable&wind an example for what Agder Energi fears, is illustrated in Figure 6.20 and Figure 6.21. In that scenario the power is going through Norway, and Norway can make money on distributing power from United Kingdom to the rest of Europe.

**Calibration**

In this project it was not take into consideration the calibration of the EMPS model. The model was not calibrated for each simulation. Since it is performed 16 simulations in this project, calibration of the EMPS model would be too time consuming

In the User manual for EMPS(32) mentions the importance to check whether the water values make sense or not. This is often viewed for the reservoir level and time, illustrated using iso price curves. In this methodology, each iso prices curve is linked to a certain water value. In an EMPS model the strategy for each hydropower area is controlled by these water values. The iso price curves are regarded as reservoir control curves. The discharge strategy in the aggregate model is decided based on shape, level and the distance between iso price curves.

Since the EMPS model does not necessarily return an optimal solution without user assistance, the model should be calibrated. This can be done either automatically (taking up to 2-3 weeks) or manually (less time). This can be done by tuning the load (firm power) and occasional power market scaling correction factors, applying defined rules(35).

**Investment algorithm**

The investment algorithm where applied to 4 of 16 simulation, all in year 2040. In retrospect the investment cost was probably set a little too low. Given the low investment cost, the development of exchange capacity for offshore cables from Norway and wind power in Norway and Great Britain were high. Chapter 7.2 discussed if this development is realistic. The development of wind power has almost the potential in both countries but is not realistic that the entire potential is developed. For offshore connections, development is dependent on involved decision makers (Governments in connecting countries).

# 8 Conclusion

The Eurpean energy system was modelled in the EMPS model for 16 different scenarios. The scenarios differed regarding year, fuel-prices and $CO_2$-taxes, inclusion of more hydropower in Norway and implementation of an investment algorithm deciding development of offshore cables from Norway and development of wind power in Norway and Great Britain.

In year 2020, two simulations for two different fuel-prices and $CO_2$-taxes scenarios were performed. The difference between the two scenarios were small, with the 450 Scenario slightly better than the CP Scenario given $CO_2$-coefficient. A lower $CO_2$-coefficient indicates also a production mix with more renewable energy sources. Great Britain had a deficit in area UK-S and imported power both from Norway through UK-M and continental Europe.

In year 2030 two more scenarios where included with more hydropower production included in NO areas. This made a positive impact with decreased $CO_2$-coefficients and more renewable production pattern. The difference for the fuel-prices and $CO_2$-taxes scenarios increased. The 450 Scenario had more gas power instead of coal power. In year 2030 the modelled transmission network was not constrained as year 2020, since the offshore cable between NO5 and UK-N were set into operation.

In year 2040 the same positive effects occur for inclusion of even more hydropower. Implementation of the investment algorithm shows the positive effects of higher exchange capacities from areas with a surplus of renewable energy sources. The $CO_2$-coefficents for scenario with investment for both wind (in Norway and Great Britain) and offshore cables from Norway decreased the most compared to Base Scenario. If the change is attributed to all of Europe it is reasonable to have an increased installed capacity on 38 % and for energy production 51 %. Even allocated to just Norway and Great Britain the increase can be possible, if governments in both countries have an offensive strategy for wind power.

Results for the different focus-year shows that inclusion of more renewable energy sources and higher exchange capacity makes a positive impact for emissions in ton $CO_2$. This favours a well-developed transmission network that can meet the production/consumption and surplus/deficit of power in every hour regarding the lateral distribution of flexible and variable energy sources in Europe.

# 9 Further Work

Chapter 7.5 discuss possible sources of errors. Following inaccuracies can be further investigated:

- Updating the Scenario Building with more up to date data and make adjustment of inner peculiarities in focus areas.
- Validate the investment cost in the Investment Algorithm.
- Calibrate the EMPS model between each simulation and check whether the reservoir levels are reasonable for minimum and maximum reservoir level

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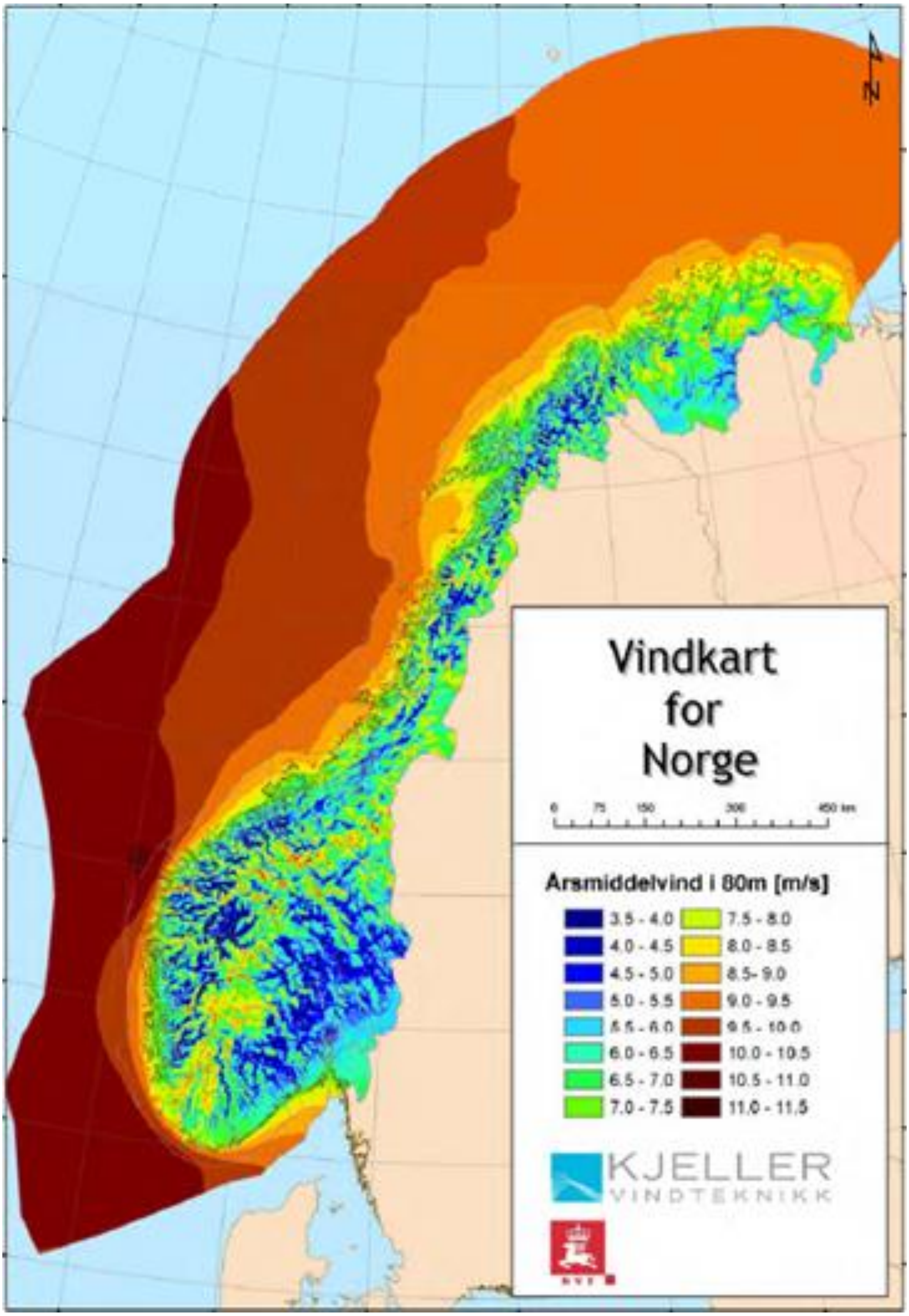
# Appendix A




**Appendix A - Figure 1 Wind power resources in Norway**

# Appendix B

Appendix B contains tables for distribution of installed capacity depending on energy source in the three UK areas and a figure showing transmission system boundaries in UK from ETYS 2018.

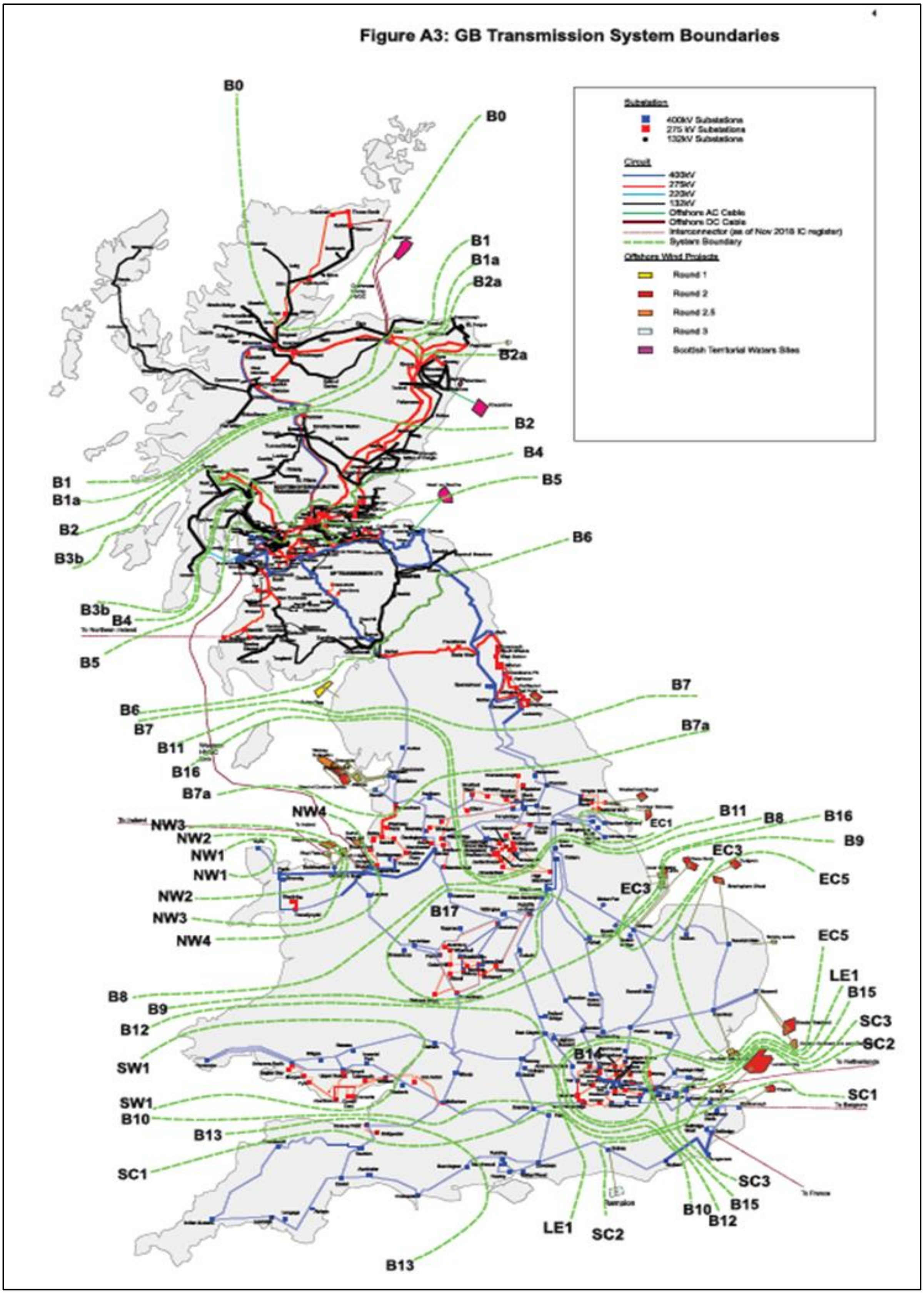
**Appendix B - Table 1 Distribution of installed capacity in UK areas**

| Energy source | UK areas | 2020 [%] | 2030 [%] | 2040 [%] |
|---|---|---|---|---|
| **Nuclear** | UK-N | 8,5 | 8,1 | 8,1 |
| | UK-M | 33,9 | 36,7 | 36,7 |
| | UK-S | 57,7 | 55,2 | 55,2 |
| **Bio** | UK-N | 5,2 | 5,2 | 5,2 |
| | UK-M | 94,8 | 94,8 | 94,8 |
| | UK-S | 0,0 | 0,0 | 0,0 |
| **Hard coal** | UK-N | 24,9 | 24,9 | 24,9 |
| | UK-M | 75,1 | 75,1 | 75,1 |
| | UK-S | 0,0 | 0,0 | 0,0 |
| **Gas** | UK-N | 1,0 | 1,0 | 1,0 |
| | UK-M | 46,2 | 46,2 | 46,2 |
| | UK-S | 52,8 | 52,8 | 52,8 |
| **Gas CCS** | UK-N | 0,0 | 0,0 | 0,0 |
| | UK-M | 100,0 | 100,0 | 100,0 |
| | UK-S | 0,0 | 0,0 | 0,0 |
| **Oil** | UK-N | 33,3 | 33,3 | 33,3 |
| | UK-M | 33,3 | 33,3 | 33,3 |
| | UK-S | 33,3 | 33,3 | 33,3 |
| **Diverse** | UK-N | 33,3 | 33,3 | 33,3 |
| | UK-M | 33,3 | 33,3 | 33,3 |
| | UK-S | 33,3 | 33,3 | 33,3 |
| **Other RES** | UK-N | 33,3 | 33,3 | 33,3 |
| | UK-M | 33,3 | 33,3 | 33,3 |
| | UK-S | 33,3 | 33,3 | 33,3 |
| **CHP coal** | UK-N | 6,5 | 6,5 | 7,0 |

| | | | | |
|---|---|---|---|---|
| | UK-M | 64,9 | 64,9 | 62,3 |
| | UK-S | 28,6 | 28,6 | 30,7 |
| **CHP gas** | UK-N | 6,5 | 6,5 | 7,0 |
| | UK-M | 64,9 | 64,9 | 62,3 |
| | UK-S | 28,6 | 28,6 | 30,7 |
| **CHP oil** | UK-N | 6,5 | 6,5 | 7,0 |
| | UK-M | 64,9 | 64,9 | 62,3 |
| | UK-S | 28,6 | 28,6 | 30,7 |
| **CHP res** | UK-N | 6,5 | 6,5 | 7,0 |
| | UK-M | 64,9 | 64,9 | 62,3 |
| | UK-S | 28,6 | 28,6 | 30,7 |
| **CHP divers** | UK-N | 6,5 | 6,5 | 7,0 |
| | UK-M | 64,9 | 64,9 | 62,3 |
| | UK-S | 28,6 | 28,6 | 30,7 |
| **Wind** | UK-N | 38,7 | 38,2 | 38,2 |
| | UK-M | 34,7 | 34,3 | 34,3 |
| | UK-S | 26,5 | 27,5 | 27,5 |
| **Solar** | UK-N | 0,3 | 0,3 | 0,3 |
| | UK-M | 15,8 | 15,8 | 15,8 |
| | UK-S | 83,9 | 83,9 | 83,9 |

**Appendix B - Table 2 Distribution of installed capacity and production for hydropower in UK areas**

| Hydropower | UK areas | 2020 [%] | 2030 [%] | 2040 [%] |
|---|---|---|---|---|
| **Installed capacity** | UK-N | 41,4 | 41,4 | 41,4 |
| | UK-M | 58,6 | 58,6 | 58,6 |
| | UK-S | 0,0 | 0,0 | 0,0 |
| **Production** | UK-N | 41,4 | 41,4 | 41,4 |
| | UK-M | 58,6 | 58,6 | 58,6 |
| | UK-S | 0,0 | 0,0 | 0,0 |




**Appendix B - Figure 1 Transmission system boundaries from ETYS 2018**

# Appendix C

Appendix C gives an overview over $CO_2$-tax and fuel prices for year 2020, 2030 and 2040.

**Appendix C - Table 1 Fuel-prices for CP Scenario and 450 Scenario**

| Scenario | Fuel | Unit | 2020 | 2030 | 2040 |
|---|---|---|---|---|---|
| **CP** | Nuclear | €/pound | 37,56 | 37,56 | 37,56 |
| | Bio | €/MWh | 6,49 | 6,49 | 6,49 |
| | Lignite | €/t | 14,65 | 18,03 | 19,83 |
| | HardCoal | €/t | 58,88 | 72,10 | 79,32 |
| | Gas | €/MWh | 22,45 | 34,14 | 39,98 |
| | Oil | €/barrel | 73,91 | 114,47 | 131,59 |
| | CHP | Depending on fuel-type | 0,01 | 0,01 | 0,01 |
| **450** | Nuclear | €/pound | 37,56 | 37,56 | 37,56 |
| | Bio | €/MWh | 6,49 | 6,49 | 6,49 |
| | Lignite | €/t | 13,07 | 12,84 | 11,49 |
| | HardCoal | €/t | 52,28 | 51,37 | 45,97 |
| | Gas | €/MWh | 21,22 | 28,91 | 30,45 |
| | Oil | €/barrel | 65,80 | 76,61 | 70,30 |
| | CHP | Depending on fuel-type | 0,01 | 0,01 | 0,01 |

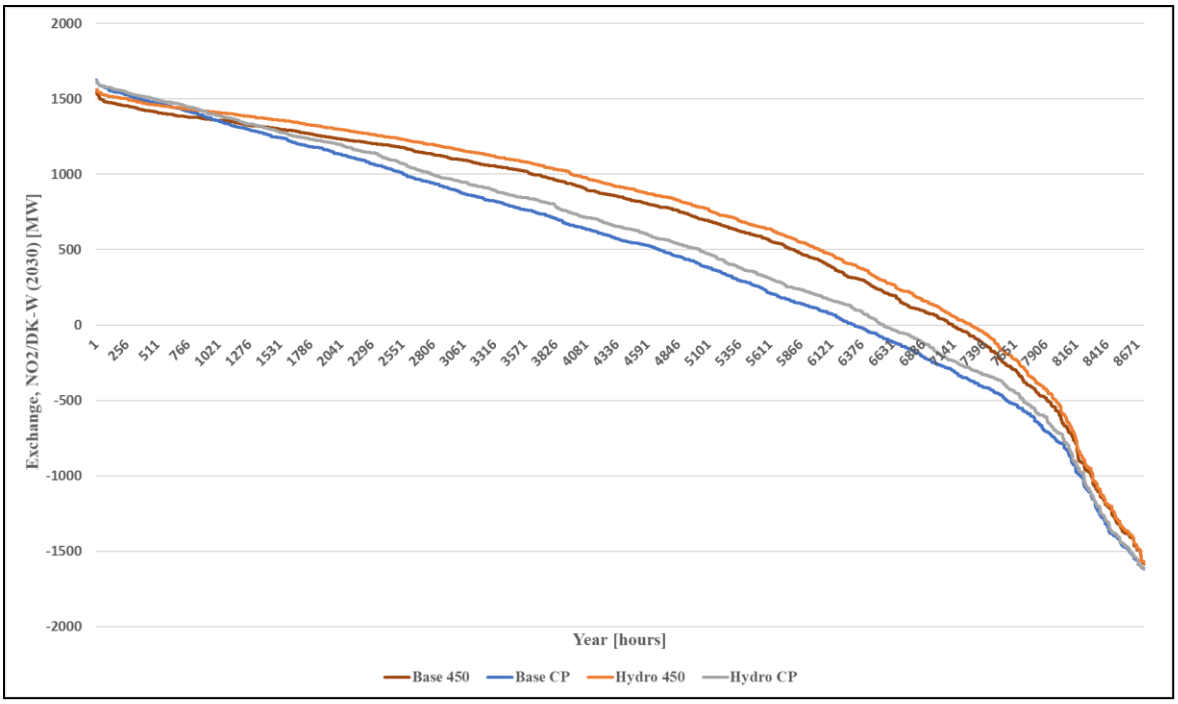
**Appendix C - Table 2 CO2-taxes**

| Scenario | Unit | 2020 | 2030 | 2040 |
|---|---|---|---|---|
| **$CO_2$ - CP** | €/tCO2 | 16,22 | 27,04 | 36,05 |
| **$CO_2$ - 450** | €/tCO2 | 18,03 | 90,13 | 126,18 |

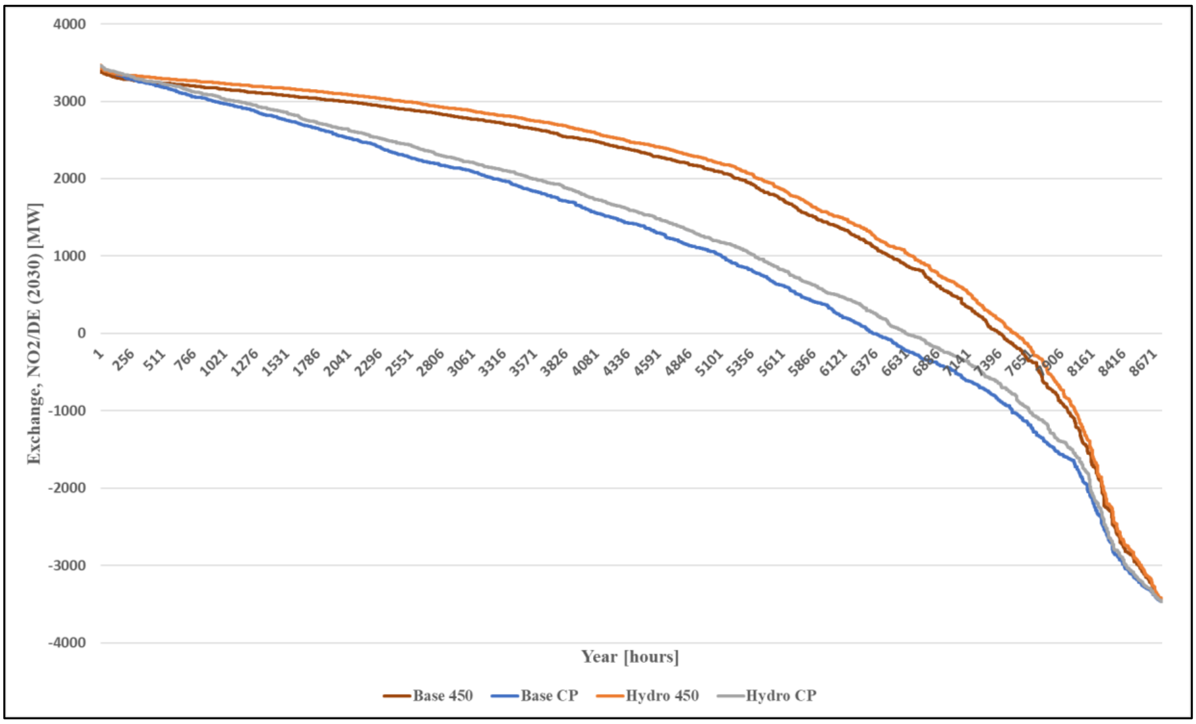
# Appendix D

**Focus year 2030, exchange capacity:**

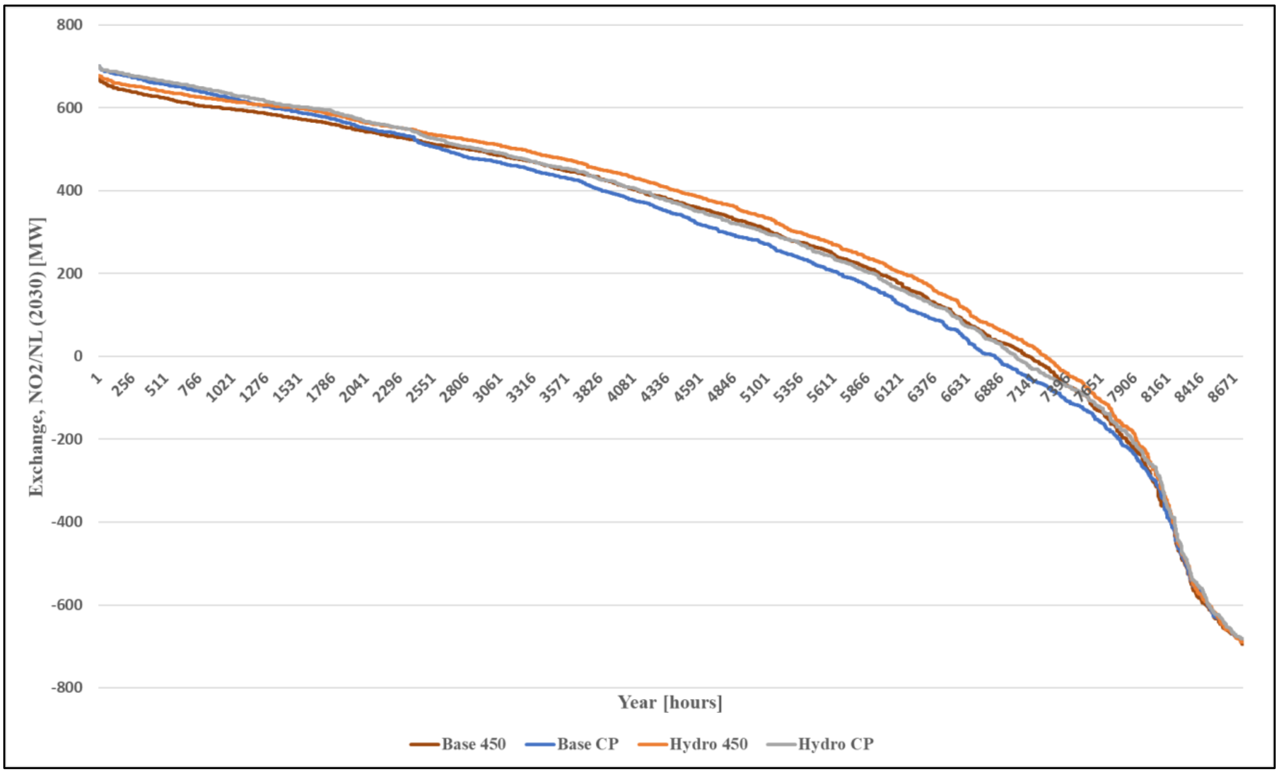
Figures shows exchange between NO2 and continental Europe (DK-W, DE and NL). Each figure contains the four performed simulations for focus year 2030.




**Appendix D - Figure 1 Exchange year 2030 between NO2 and DK-W**



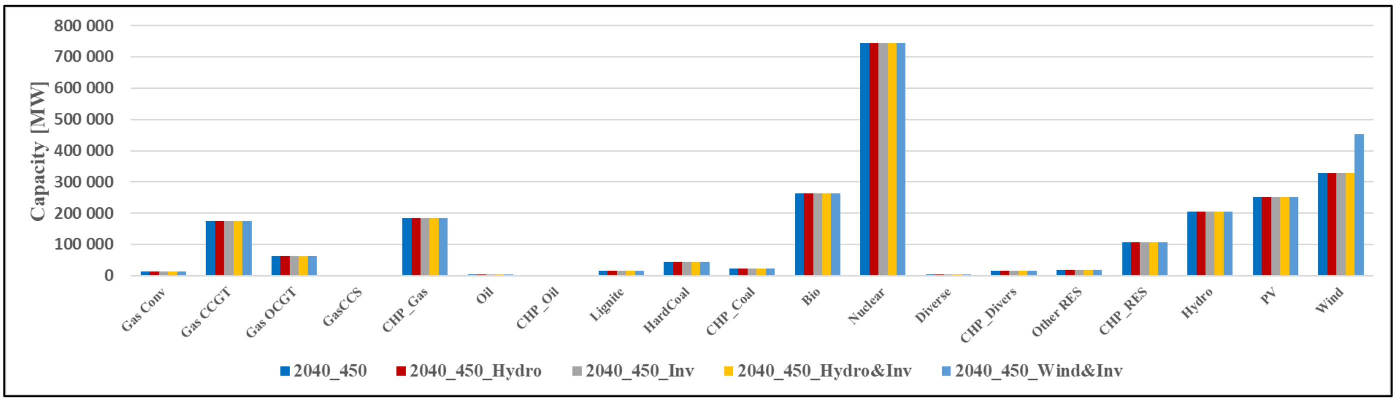

**Appendix D - Figure 2 Exchange year 2030 between NO2 and DE**



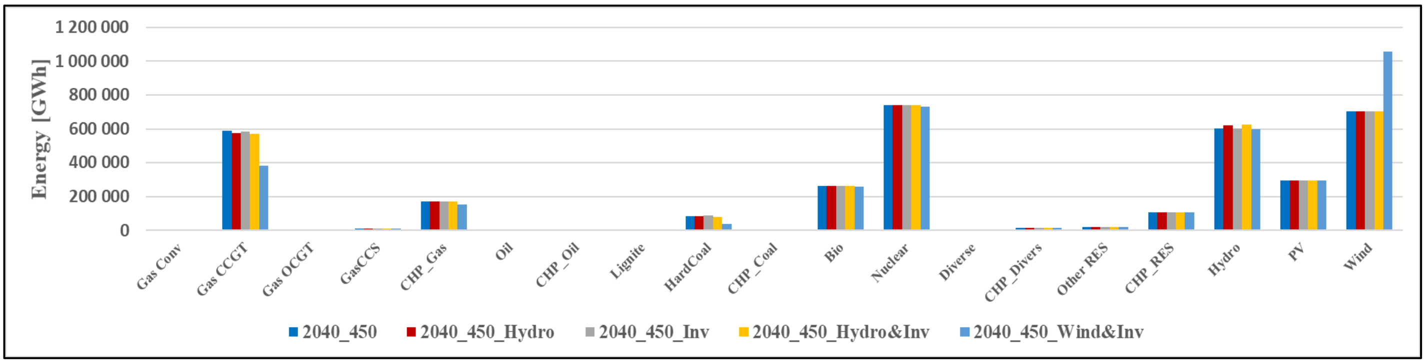

**Appendix D - Figure 3 Exchange year 2030 between NO2 and NL**

**Focus year 2040, production pattern and emissions:**

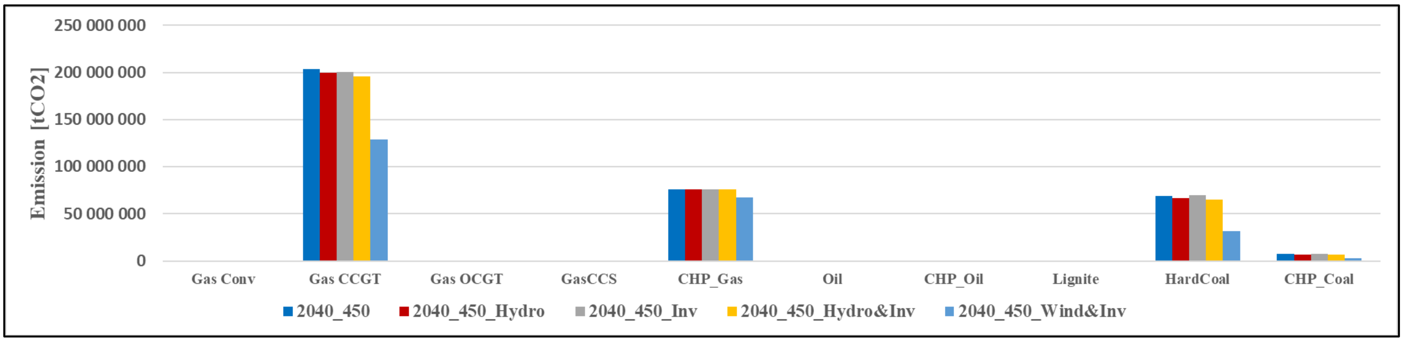
Figures shows installed capacity, energy production and emissions for 450 Scenarios.




**Appendix D - Figure 4 Installed capacity (450 scenario) for base 2040, hydro 2040, inv. cable 2040, hydro and inv. cable 2040 and inv. cable and wind 2040**



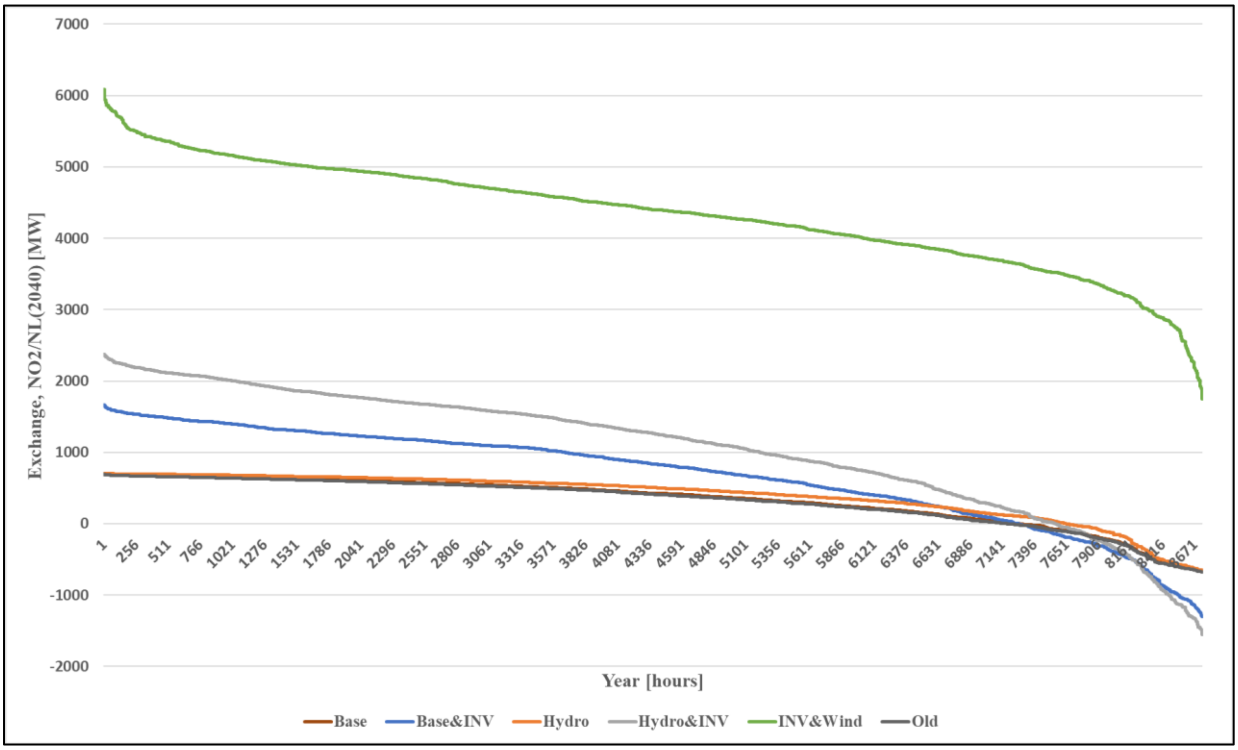

**Appendix D - Figure 5 Energy production (450 scenario) for base 2040, hydro 2040, inv. cable 2040, hydro and inv. cable 2040 and inv. cable and wind 2040**



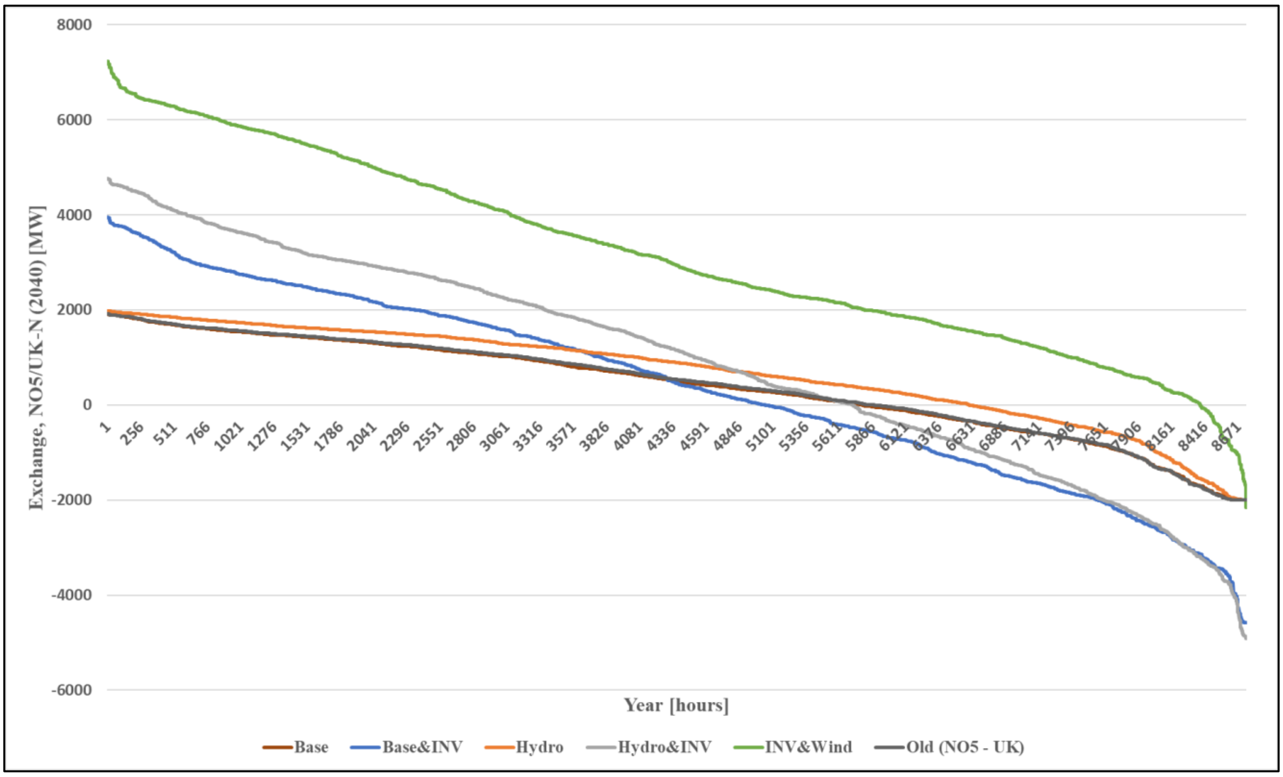

**Appendix D - Figure 6 Appendix C - Figure 6 Emissions (450 scenario) for base 2040, hydro 2040, inv. cable 2040, hydro and inv. cable 2040 and inv. cable and wind 2040**

**Focus year 2040, exchange capacity:**

Figures for exchange capacity between areas NO2 and NL and NO5 and UK-N for the 450 Scenario.



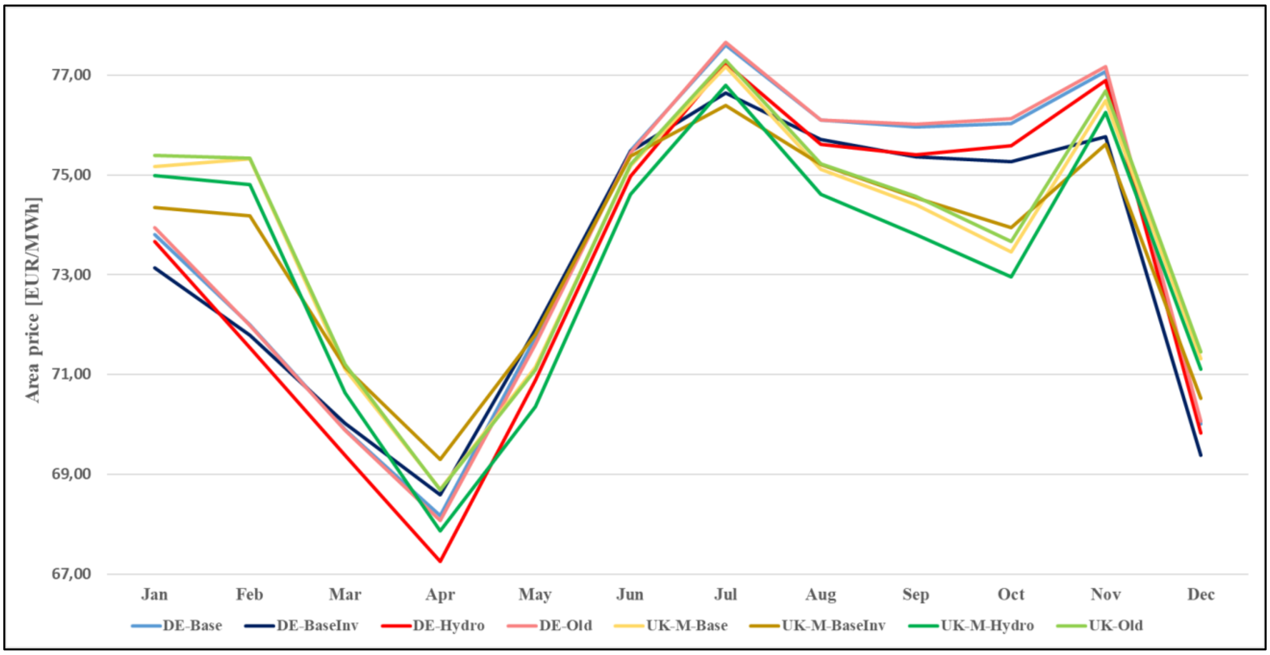

**Appendix D - Figure 7 Exchange year 2040 for 450 Scenarios between NO2 and NL**



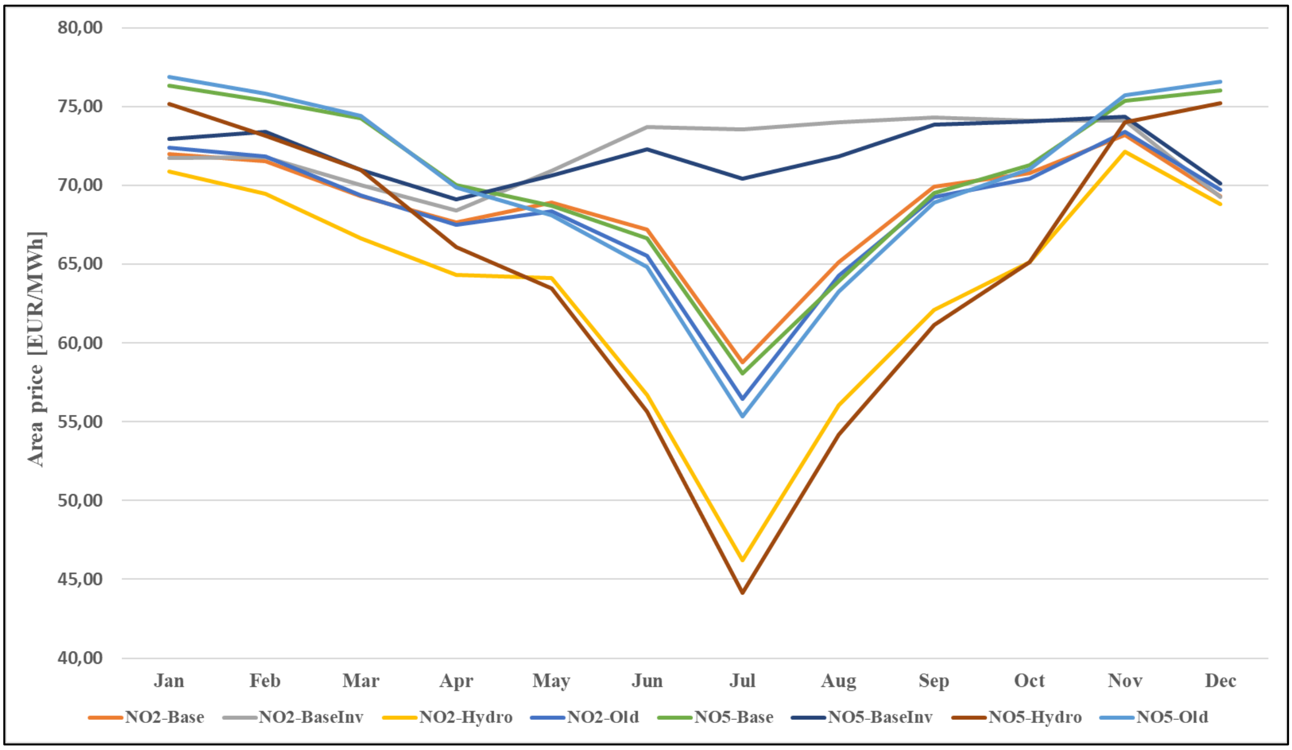

**Appendix D - Figure 8 Exchange year 2040 for 450 Scenarios between NO5 and UK-N**

**Focus year 2040, area prices:**

Figures for area prices (monthly average) for the CP Scenarios for areas DE, UK-M, NO2 and NO5.

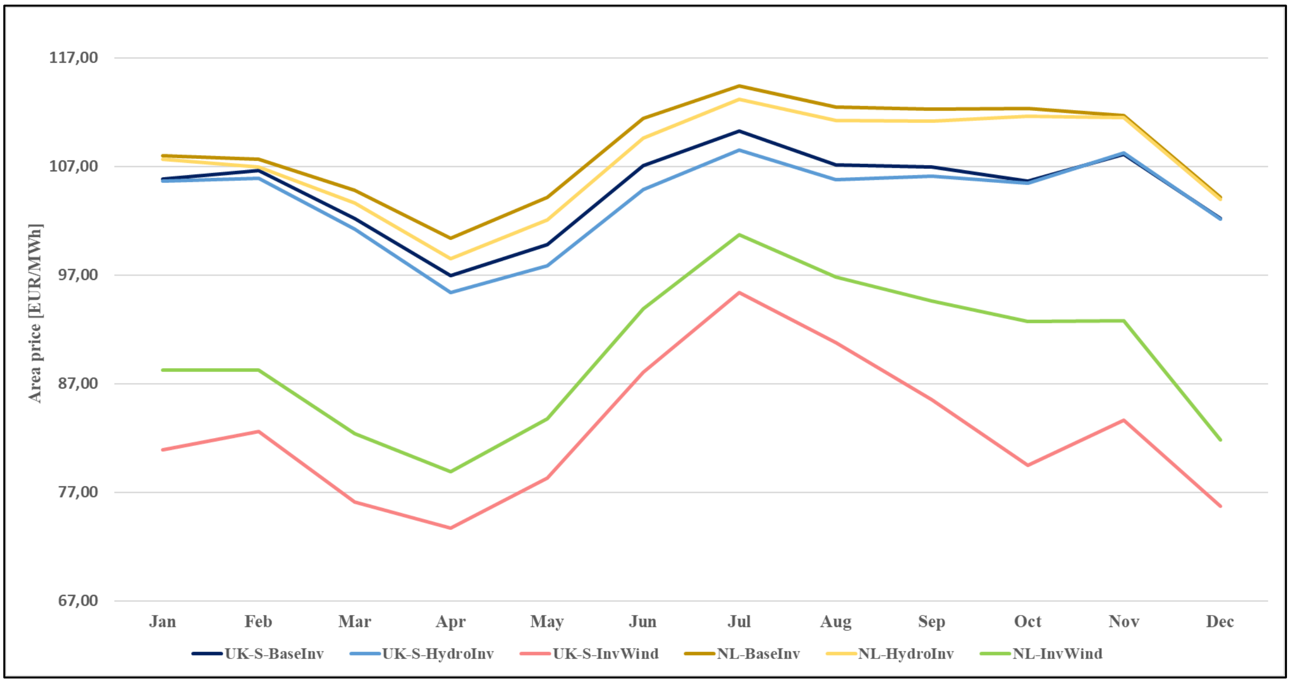



**Appendix D - Figure 9 Area prices (monthly average), year 2040 for CP Scenarios DE and UK-M**

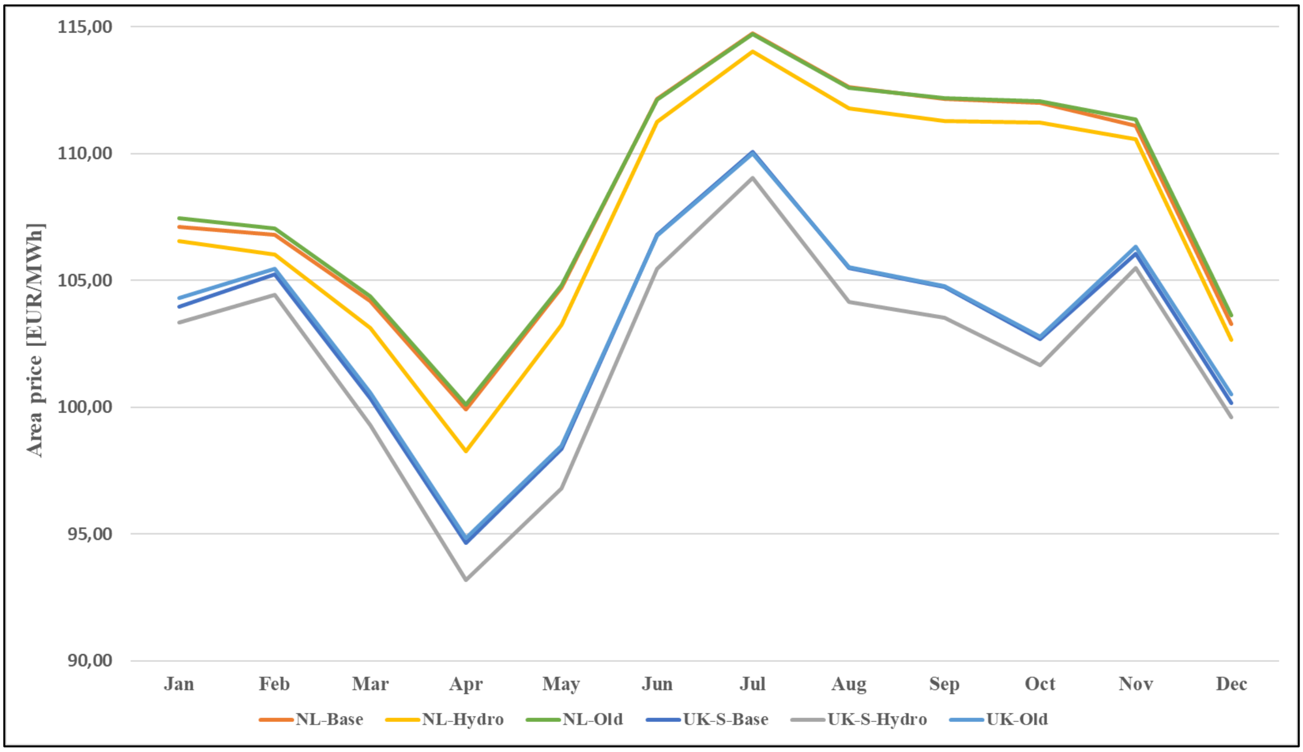



**Appendix D - Figure 10 Area prices (monthly average), year 2040 for CP Scenarios NO2 and NO5**

Figures for area prices (monthly average) for UK-S and NL for all 450 Scenarios.




**Appendix D - Figure 11 Area prices (monthly average), year 2040 for UK-S and NL given CP Scenario and investment algorithm**




**Appendix D - Figure 12 Area prices (monthly average), year 2040 for UK-S and NL given 450 Scenario without investment algorithm**

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