Task 16.3

Possibilities of Nordic hydro power generation flexibility and transmission capacity expansion to support the integration of Northern European wind power production: 2020 and 2030 case studies

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	Name	Company
Author/s	Hossein Farahmand	SINTEF Energy Research
	Stefan Jaehnert	SINTEF Energy Research
	Tobias Aigner	SINTEF Energy Research
	Daniel Huertas-Hernando	SINTEF Energy Research
Task Leader	Daniel Huertas-Hernando	SINTEF Energy Research
WP Leader	Poul E. Sørensen	DTU Wind Energy

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Executive Summary

This report is written within subtask 16.3 of the TWENTIES project, and constitutes the analysis of grid implications regarding the use of flexible hydropower production in the Nordic power system to support the integration of wind power production (WPP) in the Northern European power system for the period between 2020 and 2030.

The potential of Nordic hydro power production flexibility has been assessed in Deliverable D16.2. This report analyses the necessary transmission capacity investments in order to reduce the challenges related to wind power production variability in Northern Europe. Expansion scenarios for wind power installations for 2020 and 2030 are defined in D16.1. The main focus of interest in this report is on long-term cost-benefits and annual strategies to reduce and balance WPP uncertainties from offshore WPP facilities in the North and Baltic Seas.

Nordic hydro power has ideal characteristics for providing balancing energy and increases the production flexibility in the power system. In order to effectively utilise this production flexibility, a sufficient amount of transmission capacity has to be available between the Nordic area and Northern Europe. This report determines the possibilities of flexible hydro power production in the Nordic area to support the European power system under the influence of large scale WPP for the years 2020 and 2030

The analysis includes three interrelated simulation steps. The first step focuses on the strategic use of hydro energy in the day-ahead market. The analysis considers the detailed modelling of water courses and hydro production in the Nordic region. In the second step, grid expansion scenarios are evaluated based on the day-ahead market results, considering both - offshore and onshore grid connections. Cost-benefit analyses for selected transmission expansion scenarios are carried out, taking operational cost savings and investment costs of newly built transmission capacity into account. Investments in transmission capacity result in a better utilisation of hydro power, wind and other renewables in the system. Finally, the results of the two previous simulation steps are verified, based upon detailed flow-based power market simulations using a detailed grid model for the whole European system. Based on a DC power flow approach the optimal generation dispatch is computed. The effect of the offshore grid structure proposed in the IEE-EU OffshoreGrid project is considered. The main goal of this report is the identification of critical transmission corridors and suggestion of new transmission capacity to enable the optimal use of hydro power to reduce the production uncertainty from wind power generation.

Table of Contents

1 Introduction

This document presents the deliverable D16.3, which is one of the deliverables contained in WP 16 as stated in the DoW:

Description of deliverable in DoW WP16

Deliverables:			
D16.3	SINTEF	Report on grid impact	M24

The use of hydro power for balancing WPP variations requires available grid capacity for power transmission. As is, the transmission grid presently constrains the access of hydro power facilities to the power markets and therefore limits the provision of balancing power. Stronger interconnections between the hydro based Nordic area and Continental Europe can be realised by an offshore grid, whereas the utilisation of hydro units in the Alps requires grid reinforcements in the Continental European transmission system.

The sub-task in this report addresses the following topics:

- Identification of critical transmission corridors and the suggestion of new transmission capacity to enable a better utilisation of hydro power for balancing WPP variations. The evaluation is based on power system simulations using the Power System Simulation Tool (PSST), calculating grid sensitivities.
- A preliminary cost-benefit analysis of selected transmission lines, taking operational cost reductions resulting from newly established transmission lines and associated investment cost into account. The operational cost reductions are determined by power system simulations using the PSST model. A more detailed cost-benefit analysis illustrating the influence of transmission expansion on the operational costs will be carried out in 16.2.4.

1.1. Expected outcomes of this analysis (SINTEF)

- Reference to the KPI's:

KPI.16.TF2.4 – D16.3	*Potential for increased hydro power generation capacity in the Nordic synchronous system by 2020 and 2030 [MW].* Reference: This deliverable has considered two Scenarios for increased hydropower potential generation capacity and pump storage flexibility in Norway, as described in D16.2. The increased hydropower potential generation capacity considered is 11.2GW in 2020 and 18.2 GW in 2030
KPI.16.TF2.6 – D16.3	*Possible reduction in onshore transmission capacity in Northern Europe and the Nordic area, assuming an offshore grid combining wind farm grid connections and inter-area connections, under the precondition of an optimal use of Nordic hydro [km×MW]* Reference: Onshore grid constraints strongly influence the flows across a meshed offshore grid, therefore affecting the optimal use of wind and hydro. Long term strategies for the development of offshore grids and onshore grid expansion must be done in a coordinated way to ensure optimal developments. This is one of our main findings. It is shown that a fully meshed offshore grid will provide transmission flexibility to circumvent possible bottlenecks in the onshore grid which prevent optimal wind penetration. The analysis also demonstrates the correlation between the pumping strategies in the Norwegian system and the onshore and offshore wind variations around the North Sea. It is not easy to provide [km x MW] figures since the situation depends on which onshore grid expansion strategy is considered against a given offshore grid topology. We provide estimates for the most relevant case in this respect, the case without onshore grid expansion (denoted as Case -IC in the text). The net benefit from offshore grid expansion by additional 1GW offshore HVDC capacity (Case A-C), allowing increased wind penetration and use of flexible hydro power, is equal to 30800 (km × MW) onshore transmission "equivalent" investment for the Baseline wind scenario and 131128 (km × MW) onshore transmission "equivalent" investment for the High wind scenario. The difference in installed capacity at offshore wind farms around the North Sea between the Baseline and High wind scenario is 3185 MW. These (km × MW) onshore transmission "equivalent" figures quantify the relative value of offshore grid expansion with respect to onshore transmission expansion.

- Additional outcomes of interest:

  In this work (D16.3) the offshore grid topology defined by the IEE-EU OffshoreGrid project is used as a baseline topology of a cost-efficient multi-terminal HVDC offshore grid in the North and Baltic Sea. WP15 has explored in detail the socio-economic and operational aspects of such large meshed grids offshore.

  In D16.3 we assume that meshed offshore grids are socio-economic beneficial as well as operational and reliable. The transmission capacity requirements and benefits from offshore grid flexibility investigated here focus, based on these previous assumptions, on optimal use of Nordic hydro power to balance the production variability from offshore wind power in the North Sea and the Baltic Sea.

  As such, the work on D16.3 can be understood as a detailed sensitivity analysis to assess the robustness of a possible costs-beneficial offshore grid topology (in this case the one proposed by the IEE-EU OffshoreGrid project) under a different set of assumptions and for a different set of scenarios than the ones considered in the IEE-EU OffshoreGrid project. Moreover, detailed analysis of the impact that onshore grid reinforcement strategies will have for the design of cost-beneficial offshore grid topologies is investigated in this work.

1.2. Relation to this work with demo 4 (ENERGINET.DK)

- <u>Demo #4 Wind Variability & Storm Control</u>

  Large offshore wind production variations in North Sea will correlate with variable power flows between Continental Europe and Nordic region. Ramp Following Control (RFC) strategies together with Load Frequency Control (LFC) in the Nordic region and West Denmark can contribute to power system balance restoration (in the event of large variations in offshore wind generation), as demonstrated in D6.2 of WP6 - Demo#4. RFC will have an impact on the Nordic frequency quality. In addition, the rate of change of pumped storage in hydropower stations will introduce an additional load, which also will affect the Nordic frequency. The relative rate of change in pumping stations with respect to the variations of wind power and flows between the Nordic and Continental Europe system / North Sea will also affect the frequency. These aspects are also being investigated in the joint ENK.DK, DTU, SINTEF deliverable D12.2.

  Offshore wind variability, pumped storage loads and power flow on the HVDC links connected to the Nordic power system as simulated in this D16.3 analysis, are likely to have significant influence on the Nordic frequency quality in the future. On-going further work by SINTEF within Demo#4 analyses frequency deviations, assuming realistic wind power and power flows variations and pumping rates from the results of D16.3. Focus is on whether frequency deviations are although significant, still within operational limits or not. A publication is expected out of this work.

- Demo #3HVDC Offshore Grid

  The safe and reliable operation of a multi-terminal HVDC grid offshore is investigated in Demo#3. This work (D16.3) assumes that a fully meshed multi-terminal HVDC grid offshore is both socio-economically feasible and operational in a safe and reliable way, so it implicitly incorporates the lessons learnt in Demo#3. The results and analysis from the project (WP15 - WP16) will identify the benefits and challenges regarding configurations incorporating offshore trans-border connection between different control zones offshore, making up a large scale meshed offshore grids.

- Demo #5 NetFlex & Demo # 6 FlexGrid

  One of the main conclusions of this work (D16.3) is that onshore grid constraints strongly influence the flows across a meshed offshore grid, therefore affecting the optimal use of wind and hydro power. Long term strategies for the development of offshore grids and onshore grid expansion must be done in a coordinated way to ensure optimal developments. In Demo#5, optimal use of Power Flow Control devices and Wide Area Measurement Technologies is investigated. The lessons learnt in this demonstration will help the system operators to extend grid transport capabilities and grid flexibility as well as advance monitoring of the real time power flows. Moreover, in Demo#5 - Demo#6, added flexibility of the onshore grid by means of dynamic line rating is investigated such that wind power production & penetration and allocation of transmission capacity are correlated in an optimal way. These aspect have not been considered explicitly in D16.3 but our conclusions indicate that flexible onshore transmission capacity by means of optimal use of power flow control devices and dynamic line rating could be very beneficial from a socio-economic point of view in future systems with large wind power penetration.

Part I- Power Market Simulations of Scenarios for Northern Europe (2010, 2020 and 2030)

2 Introduction

Nordic hydro power has got ideal characteristics for providing balancing power and to increase production flexibility in the power system. In order to effectively utilize this production flexibility, a sufficient amount of transmission capacity has to be available between the Nordic region and Northern Europe.
The first step in our analysis focuses on the strategic use of hydro energy in the day-ahead market. The analysis considers detailed modelling of water courses and hydro production in the Nordic region. The analysis of the future Nordic power system requires a detailed simulation of the Northern European power system (Germany, the Netherlands) due to possible interactions between both areas, resulting from an expected increase of transmission capacity between the Nordic area and Continental Europe. Therefore, data model sets for these countries are developed and implemented in SINTEF's Multi-area Power-market Simulator (EMPS). The model focuses on the different power system characteristics, considering the distinguishing features of the thermal dominated system in Continental Europe and the hydro-thermal system in the Nordic area.

Part – I is divided into three main parts:

Description of developed scenarios for Northern Europe including the years 2010, 2020 and 2030. The scenarios include assumptions for generation, transmission and consumption and their prospective development.

A discussion of the evaluated simulation results based on the developed scenarios for Northern Europe. The discussion includes a result comparison based on two different approaches - simulating the system load in aggregated and sequential time steps.

- A discussion of the gird expansion results including an investment analysis for the 2030 scenario. Furthermore, a sensitivity analysis is added, investigating the effect of increased fuel costs vs. the costs for transmission capacity expansion and their respective influence on area prices in the Nordic area.

3 Power system scenario development

3.1 Model overview

The Northern European power market model implemented in EMPS includes a detailed system description for Norway, Sweden, Finland, Denmark, Germany, the Netherlands, Belgium and Great Britain. Furthermore, the exchange to neighbouring countries is considered in the simulations. Within the model, Norway, Sweden, Denmark, Germany and Great Britain are split into several areas, accounting for water courses and bottlenecks in the transmission system.

Area model:

The transmission system description available from the Norwegian Water Resources and Energy Directorate (fully detailed for Norway, aggregated for Sweden) [1] was used to map generation facilities and the consumption to individual busses in the Nordic transmission grid. The according data used in the grid study is described in Part-II. During the mapping of the EMPS data set, the system data and the hydropower system in particular, was updated to match the transmission grid. The rearrangement of hydro power facilities focuses on the Norwegian areas[1]. The resulting model areas are shown in Figure 1 while the according area names are given in Table 1.

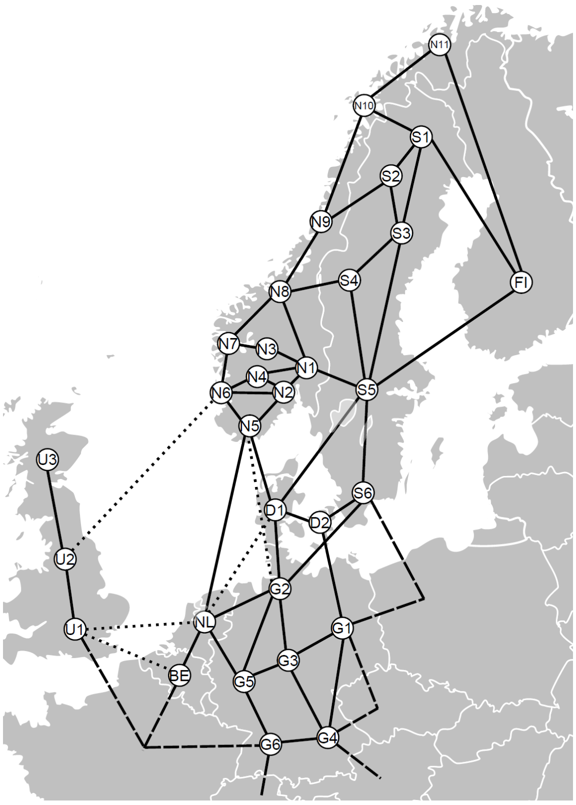


Figure 1. Geographic overview of the EMPS dataset

[1] The rearrangement includes the abolishment of the area GLOMMA and the shifting of water course between areas in Southern Norway.

Table 1. Day-ahead spot areas in EMPS

Norway:					
N1	OSTLAND	N2	SOROST	N3	HALLINGDAL
N4	TELEMARK	N5	SORLAND	N6	VESTSYD
N7	VESTMIDT	N8	NORGEMIDT	N9	HELGELAND
N10	TROMS	N11	FINNMARK		
Sweden:					
S1	SVER-ON1	S2	SVER-ON2	S3	SVER-NN1
S4	SVER-NN2	S5	SVER-MID	S6	SVER-SYD
Finland:					
FI	FINLAND				
Denmark:					
D1	DANM-VEST	D2	DANM-OST		
Germany:					
G1	TYSK-OST	G2	TYSK-NORD	G3	TYSK-MID
G4	TYSK-SYD	G5	TYSK-VEST	G6	TYSK-SVEST
Netherlands:					
NL	NEDERLAND				
Belgium:					
BE	BELGIA				
Great Britain:					
U1	GB-SOUTH	U2	GB-MID	U3	GB-NORTH

In addition to the upper areas some additional areas are defined, mainly representing offshore wind farms. An overview on these areas along with their utilisation is given in Table 2. Each of these areas is connected to one of the previously mentioned areas assuming an infinite transmission capacity.

Table 2. Additional areas in EMPS

Area name	Connected to	Remark
TYSK-IVEST	TYSK-VEST	Includes all lignite power plants of TYSK-VEST
NORGEM-OWP	NORGEMIDT	Areas include offshore Wind Power Plants (WPP)
VESTMI-OWP	VESTMIDT	
VESTSY-OWP	VESTSYD	
SORLAN-OWP	SORLAND	
AEGIR-OWP	SORLAND	
SVER-S-OWP	SVER-SYD	
DANM-O-OWP	DANM-OST	
DANM-V-OWP	DANM-VEST	
TYSK-O-OWP	TYSK-OST	
TYSK-V-OWP	TYSK-NORD	
NEDERL-OWP	NEDERLAND	
BELGIA-OWP	BELGIA	
DOGGERBANK	GB-MID	
GB-N-OWP	GB-NORTH	
GB-M-OWP	GB-MID	
GB-S-OWP	GB-SOUTH	

Finally, there is a set of areas used to model the neighbouring countries of the simulate area in Continental Europe. These areas are presented in Table 3. The exchange from and to the respective countries is modelled by an hourly exchange pattern based on the recorded data provided by ENTSO-E [2]. The areas in Table 3 are included in the simulations to account for a certain energy import as well as export and to consider potential loop flows through the respective countries[2].

Table 3. Bordering-country areas in EMPS

Area name	Connected to	Remark
FRANKRIKE	TYSK-VEST TYSK-SVEST BELGIA GB-SOUTH	
SVEITS	TYSK-SVEST	
OSTERRIKE	TYSK-SYD	
TSJEKKIA	TYSK-OST TYSK-SYD	
POLEN	SVER-SYD TYSK-OST	

The development of the scenarios included the years 2010, 2020 and 2030. The scenario 2010 represents the actual system state and is used to calibration purposes. The 2020 scenario incorporates expected future generation and transmission capacity expansions. Beside further changes in the generation capacity, the 2030 scenario also incorporates the development of an "Offshore grid" in the North Sea. A general growth in demand of electricity is considered in both future scenarios.

The following sections include a detailed description of developed scenarios and the assumptions made, with respect to power production, transmission and consumption.

3.2 Power production

3.2.1 Hydro power production

The hydro power production is modelled with its water courses, including single reservoirs and hydro power plants. The Norwegian areas were rearranged based on the available NVE – transmission data set [1]. The data set now includes the connection between single hydro power plants and specific busses in the transmission system. Furthermore, the data modification included the moving of water courses between different areas. This mostly concerns Southern Norway. This means in particular that the GLOMMA area is removed and its water courses are moved to the OSTLAND area. Furthermore, the areas SOROST, TELEMARK and HALLINGDAL, which previously only included thermal production facilities, now include water courses as well. In addition, some shifting of water courses was done throughout the areas

[2] Important loop flows are through Poland and the Czech Republic.

SORLAND, VESTSYD, VESTMIDT and HALLINGDAL. The final geographic distribution of the Southern Norwegian areas is shown in Figure 2[3]. A detailed overview of the areas and the location of the according water courses can be found in the database available for Google Earth.

The developed future scenarios are based on the D16.2 deliverable and the CEDREN report [3]. The CEDREN report comprises several case studies for the expansion of hydro power production capacity as well as pumping capacity in Southern Norway. Three different scenarios are defined, ranging from a capacity increase of about 11GW (scenario 1) up to an increase of 18GW (scenario 3). For the development of the future system scenarios, scenario number one with an increase of 11GW is chosen.
To incorporate the increase of the production capacity in the EMPS dataset, existing hydro modules are expanded rather than defining new hydro modules. The model distinguishes between new power generation and pumping capacity. In case of pump storage facilities, the respective installed generation capacity is increased equal to the installed pump capacity. If the expansion in a water course comprises several cascading hydro power stations, the capacities of all the power stations are increased so that the overall sum equals the total expansion in the water course.

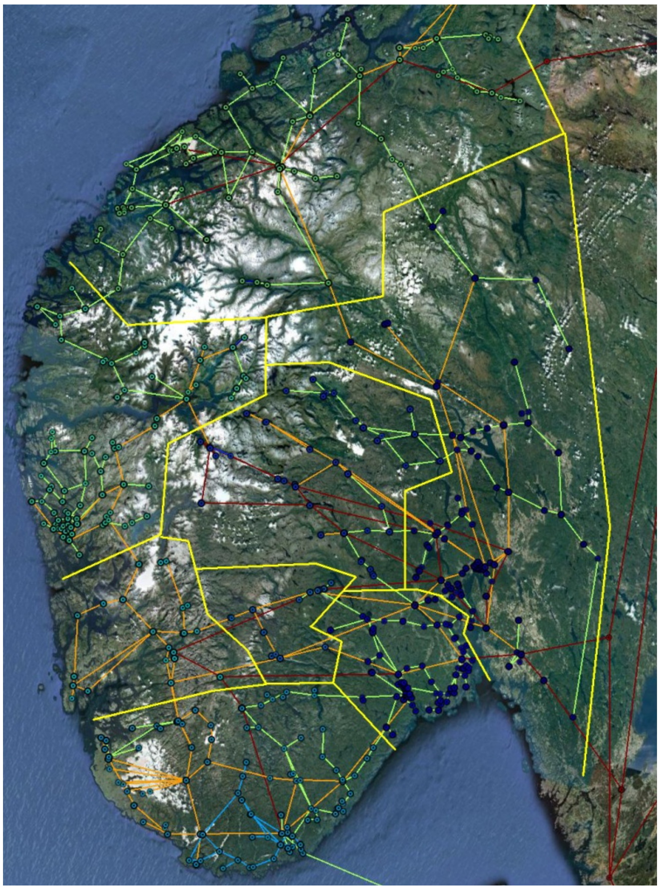


Figure 2. Area division in Southern Norway

[3] The yellow lines represent the different area borders.

The expansion in the Norwegian hydro power production is solely an expansion of generation and pumping capacity, with no additional inflow. In contrast, there is some additional hydro power production in the future power system scenario in the Swedish power system, mainly due to the installation of small-scale hydro power facilities. The hydro generation capacity in Sweden is expected to increase by 1GW.

In Finland and in Great Britain hydro power production is modelled by aggregated reservoirs and hydro power plants using an aggregated area inflow. For future system scenarios, no expansion of hydro power production is included.

In the remaining countries (especially Germany) hydro power production is defined by the annual produced energy and the annual production profile. Like for Great Britain and Finland, no hydropower expansion is included in the future scenarios for Germany.

3.2.2 Thermal power production

The scenario development for thermal power production is based on the ENTSO-E figures for the 2010 generation capacity and the generation mix, the report "EU energy trends to 2030" [4] and the scenarios implemented in the IEE-EU OffshoreGrid project [5]. In the model thermal power production is modelled by 350 individual power plants. For the implementation of thermal power plants in Sweden, Finland, Denmark, Germany, the Netherlands and Belgium the ADAPT-sheet [6] is used as a data basis. In accordance with the assumptions made in the EU energy trends [4], old power plants are decommissioned and new power plants are commissioned in order to comply with the according net generation capacities. The installed capacities per country can be found in Table 48 through Table 50. For Germany [7], the Netherlands [8] and Great Britain [9] projected and planned power plants are considered in the regarded for the commissioning of new power plants. (Don't understand this sentence)

Thermal production is generally divided into dispatchable and non-dispatchable power plants. Non-dispatchable power plants comprise base-load power plants, e.g., nuclear plants and small-scale Combined Heat and Power (CHP) plants. The remaining power plants are considered to be dispatchable.

These dispatchable thermal power plants are defined by their available generation capacity per week and their marginal production costs[4]. These input parameters are taken from the Adapt-Excel-sheet [6]. The input parameters included in the ADAPT sheet determine the power plants by the different fuel types, the respective fuel costs, the CO_2 prices, the year of construction and further power plant details. In the future scenarios for 2020 and 2030, fuel costs are assumed to be constant, while the CO_2 price is expected to increase from 13 EUR/t (2010) up to 44 EUR/t (2020 and 2030) according to the assumptions made in the IEE-EU OffshoreGrid project [5].

In order to achieve representative simulation results, the 2010 scenario is fitted to the reported generation mix [10]. The model is adjusted by adapting the availability factors (percentage of time in which the power

[4] Estimations for start-up cost are available, but normally not used in the simulations yet. See section 4.2 for a further discussion on the topic of start-up costs.

plant is able to produce) of thermal power plants. The resulting availability factors are given in Table 4, showing that, e.g., the capacity of hard coal power plants has to be reduced significantly in order to achieve representative outcomes in the day-ahead market dispatch.

Table 4. Availability for power plants of different fuel types

	Bio mass	Lignite	Hard coal	Gas	Oil
Availability (%)	75	90	80	95	100

In addition to the annual availability, a weekly availability profile has been defined for the thermal power production. Figure 3 shows the availability curves of the different thermal power plant types, as reported by EEX [11]. The figure shows, that the availability of thermal power plants is significantly reduced during the summer period. These curves are used to estimate a general availability curve, which is implemented in the model, shown in Figure 3. The generic curve is used for bio mass, lignite, hard coal and gas power plants.

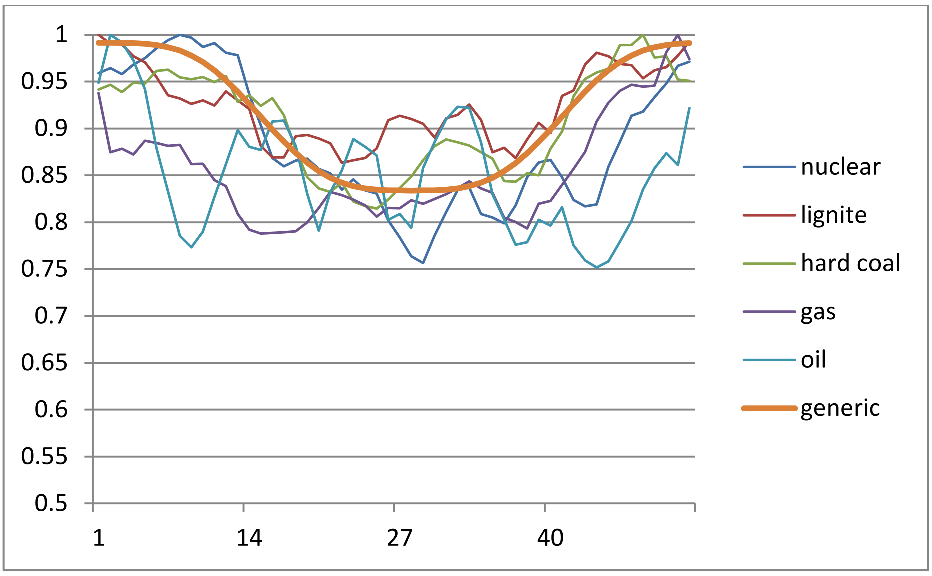


Figure 3. Availability of different power plant types (Source: EEX [11]) and implemented generic availability for all dispatchable thermal power plants

To account for the significant share of district heating (DH), the generation of thermal power plants delivering district heat are divided in a heat-driven electricity production with low marginal production costs (10EUR/MWh) and a remaining part (pure electricity production) using the original marginal production costs. The ratio between these shares shifts between summer and winter, as shown in Figure 4. During winter time, about two-thirds of the power production of the DH - thermal power plants is heat-driven, while during summer time it is only 5%. These are rough estimates and need to be validated in the future.

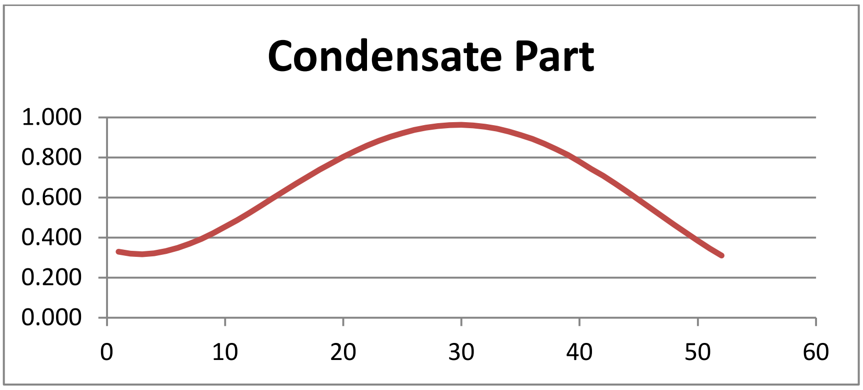


Figure 4. Share of electricity-driven-production of District Heating power plants for each week of the year (53 weeks)

3.2.3 Nuclear power production

Similar to dispatchable thermal production, nuclear power production is defined by a reference production profile and the annual produced energy (see Table 51 through Table 53). For future scenarios the current policies are regarded, leading to an approximate halving of the nuclear power production in Northern Europe. This includes a complete decommissioning of all nuclear plants in Germany and Belgium, whereas a small increase in the installed capacity is expected for Finland and Great Britain up to 2030.

3.2.4 Wind power production

WPP is modelled based on wind speed time series data for each area. Based on a wind speed to power conversion the respective wind power area production is simulated. For the simulations with EMPS, "Reanalysis wind speed data" is utilised, which is available from 1948 through 2005, available from the Susplan project [12]. The reason for choosing this wind speed data with relatively low geographical as well as temporal resolution is the availability of several years of wind speed as well as solar radiation data. The focus of the market study Part I is the determination of the long-term strategy for optimal hydropower production in future scenarios of large scale deployment of offshore wind. An important part of this strategy is determined by the water value calculation of the market model used. For this calculation, it is essential to consider the variations of both wind and solar (variable) power production throughout several climatic years, in order to determine the optimal long-term utilisation of the hydro-reservoirs. On the other hand, in Part 2 where detailed grid studies are performed, high resolution wind data from Deliverable D16.1 [14] is used instead. The use of D16.1 wind data is essential to properly capture the correct features regarding wind variability and its impact on the grid.

Installed onshore wind power generation capacities are taken from the EWEA scenarios [13]. The onshore wind power capacity is aggregated for each area. For offshore wind capacities, separate areas are implemented in the model while the installed capacities are taken from Deliverable D16.1 [14]. The installed capacities can be found in Table 48 through Table 50. Further details are also provided in Table 55 and Table 56 in Part-II.

3.2.5 Solar power production

Solar power production is modelled in the same way as wind power production. The simulated production time series is based on solar radiation data along with the installed solar production capacities. The solar data is likewise taken from the Susplan project [12]. Solar data is available for the years 1984 through 2005. Solar power production is only modelled for Germany and the Netherlands having a significant amount of PV installations while it is neglected in all other countries. The installed solar power generation capacity can be found in Table 48 though Table 50.

3.2.6 Reserve Capacity

To account the requirements for operational reserves, a certain reserve capacity is subtracted from of the total installed thermal production capacity. This is done by setting the availability of all dispatchable thermal power plants to 95%[5]. As a simplification in the Nordic system, hydro power plants are assumed to be able to provide sufficient reserve capacity throughout the year.

3.3 Consumption

For the 2010 scenario the consumption per country is based on the previously described EMPS-data set. The future development for 2020 and 2030 is based on the EU Energy trends [4]. Therefore, the respective consumption per country is increased by the relative increase reported in [4]. Norway is assumed to have the same development as Sweden. The assumed consumption is given in Table 5.

Table 5. Consumption development per country [GWh]

	2010:	2020:	2030:	2010-2020	2010-2030
Norway	114753	120726	123886	6%	9%
Sweden	143038	151620	155911	6%	9%
Finland	87162	93263	93263	7%	7%
Denmark	35900	37336	41644	4%	16%
Germany	616800	647640	678480	5%	10%
Netherlands	108000	119880	125280	11%	16%
Belgium	88265	100622	114744	14%	30%
Great Britain	350000	378000	399000	8%	14%

3.4 Transmission system

In general, EMPS is divided into areas, which are connected by transmission corridors, representing aggregated transmission lines. These corridors are defined by their direction-depending net transfer capacities (NTC) and linear transmission losses. The NTCs for corridors in the 2010 scenarios are taken

[5] The scaling is done in the ADAPT-Excel sheet

from the previous EMPS model along with the revised changes according to the NVE grid description. Current NTCs for cross-border capacities are based on the data provided by ENTSO-E [2].

The future scenarios are updated including internal and cross-border connections. For the future development of the NTCs, upcoming projects included in ENTSO-E's "Ten-years-network-development plan" [15] are taken into account. All expansions and the commissioning of individual cross-border connections, as well as internal transmission expansions, are implemented in the 2020 scenario. For the 2030 scenario the additional transmission system development in the North Sea is considered according to the numbers from the Offshore grid project [5].

3.4.1 HVDC connections

The 2020 scenario includes the commissioning of the Skagerrak IV, the NorNed II, the Nordlink, the Cobra and the BritNed HVDC cables. Table 6 shows the development of the HVDC connections between the Nordic area, Continental Europe as well as the UK. The numbers are based on the data provided in [15].

Table 6. Development of HVDC cable transmission capacities [MW]

Cable name	from	to	2010:		2020/30:	
NorNed I & II	SORLAND	NEDERLAND	700	700	1400	1400
Nordlink	SORLAND	TYSK-NORD	-	-	1400	1400
Cobra	DANM-VEST	NEDERLAND	-	-	700	700
BritNed	NEDERLAND	GB-SOUTH	-	-	1000	1000
Skagerrak	SORLAND	DANM-VEST	900	900	1600	1600
Storebælt	DANM-OST	DANM-VEST	500	500	500	500
Konti-Skan	SVER-MIDT	DANM-VEST	720	720	720	720
Kontek	DANM-OST	TYSK-OST	550	550	600	600
Baltic	SVER-SYD	TYSK-NORD	525	400	600	600
SwePol	SVER-SYD	POLEN	450	450	450	450
Fenno-Skan	SVER-MIDT	FINLAND	550	550	1100	1100
Nemo	BELGIA	GB-SOUTH	-	-	1000	1000
NorBrit	VESTSYD	GB-MID	-	-	1400	1400
Interconnector:	From	To	2010:		2020/30:	
	DANM-VEST	TYSK-NORD	1400	800	2400	2400
	TYSK-NORD	NEDERLAND	1350	1350	2250	2250

	TYSK-VEST	NEDERLAND	2700	2700	4050	4050
	TYSK-VEST	BELGIA	-	-	1600	1600
	NEDERLAND	BELGIA	1350	1350	2400	2400

3.4.2 Norwegian transmission system

The upgrades in the Norwegian grid mostly concern the strengthening of the transmission capacity in the North-South direction. In addition, the Sima-Samnanger line is incorporated, strengthening the grid on the west-coast of Norway. The prospective grid development is based on Statnett's network development plan [16]. The planned change from a lower to a higher voltage level is considered in the transmission expansion plans. The additional capacity resulting from a higher voltage level (220kV to 400kV) increases the transmission capacity by 500 MW, so from 500 MW to 1 GW. The resulting transmission capacities of the transmission corridors are shown in Table 7. The NTCs for the expansions are estimated per circuit as:

- 220kV: 200 MW
- 300kV: 500 MW
- 400kV: 1 GW

However, the resulting NTC might differ, since the 2010's NTCs are based on expert knowledge. Possible reductions of the NTCs compared to the actual transmission capacity in the 2010 scenario are kept in the future scenarios.

Table 7. Norwegian transmission capacities [MW]

			Number of circuits				Number of circuits		
from	to	2010:	>220kV	300kV	400kV	2020/30:	>220kV	300kV	400kV
Ostland	Sorost	1800		2	1	2300		1	2
Ostland	Hallingdal	3300		3	3	4800			6
Ostland	Telemark	2000		2	1	2000		2	1
Ostland	Norgemidt	600	1	1		1100	1		1
Sorost	Telemark	500		1		500		1	
Sorost	Sorland	600		1		1100			1
Sorost	Vestsyd	900			1	900			1
Hallingdal	Vesmidt	450		1		2000			2
Telemark	Vestsyd	900		1	1	900		1	1
Sorland	Vestsyd	2000		2	1	3500		2	2
Vestsyd	Vestmidt	450		1		2000			2

Vestmidt	Norgemidt	130	1			1095			1
Norgemidt	Helgeland	900		2		1900			2
Helgeland	Troms	600		1		1100			2
Troms	Finnmark	150	1			950			1

In addition to the internal upgrades in Norway, the connections to Sweden are strengthened. In particular, this includes the commissioning of the South-West-link (see [17]). The development of the Norwegian-Swedish connections is shown in Table 8.

Table 8. Norwegian-Swedish transmission capacities [MW]

from	to	2010:			2020/30:	
OSTLAND	SVER-MIDT	1800	1800		3200	3200
NORGEMIDT	SVER-NN2	900	900		900	900
HELGELAND	SVER-ON2	200	200		1000	1000
TROMS	SVER-ON1	700	700		1700	1700

3.4.3 Swedish transmission system

Likewise in Norway, a strengthening of the transmission grid from the North to the South is expected in Sweden (see [17]). The main expansion is expected in Southern Sweden, tackling the currently observed congestion issues and allowing a higher exchange to the Continental system across the HVDC-connections. The overview on the current and future transmission capacities in Sweden is given in Table 9.

Table 9. Inner-Swedish transmission capacities [MW]

from	to	2010:			2020/30:	
SVER-ON1	SVER-ON2	2400	2400		2700	2700
SVER-ON1	SVER-NN1	2400	2400		2400	2400
SVER-ON2	SVER-NN1	4800	4800		4800	4800
SVER-NN1	SVER-NN2	1200	1200		1200	1200
SVER-NN1	SVER-MIDT	7200	7200		7200	7200
SVER-NN2	SVER-MIDT	1200	1200		1200	1200
SVER-MIDT	SVER-SYD	3500	3500		5200	5200

3.4.4 Germany

The determination and expansion of the German transmission capacities is based on the estimation methodology used throughout the DENA grid study II [18]. The study only considers transmission lines with a voltage level of 220 kV and 380 kV, respectively. The resulting net transmission capacities are 725 MW for

220 kV and 1250 MW for 380 kV. These transmission capacities are in accordance with a maximum current of 2720 A (thermal limit of a duplex cable) and the determination of the NTCs according to:

$$NTC = 0.7 \times \sqrt{3} \times U \times I \tag{1}$$

The additional factor of 0.7 reduces the maximal thermal transmission capacity of the transmission line, considering stability issues and potential loop flows in the AC-transmission grid.

According to the DENA grid study II [18] this assumed expansion constitutes a higher bound for transmission expansion in our analysis and therefore corresponds to the "No constraint (NC)" case considered in the grid simulations in Part-II. Furthermore, detailed analysis on the effect of internal constrains and recent plans for expansion in Germany are considered in Part-II.

Table 10. German transmission capacities

from	to	Circuits 2010:		2010:	Add. cap. (Dena II):	2020/30:
		220kV:	380kV:			
		725 MW	1250 MW			
TYSK-OST	TYSK-NORD	0	0	0	3100	3100
TYSK-OST	TYSK-MIDT	0	4	5000	0	5000
TYSK-OST	TYSK-SYD	0	2	2500	7300	9800
TYSK-NORD	TYSK-MIDT	2	4	6450	9600	16050
TYSK-NORD	TYSK-VEST	0	2	2500	0	2500
TYSK-MIDT	TYSK-SYD	2	2	3950	0	3950
TYSK-MIDT	TYSK-VEST	3	7	10925	6200	17125
TYSK-SYD	TYSK-SVEST	0	6	7500	7000	14500
TYSK-VEST	TYSK-SVEST	9	3	10275	3400	13675

3.4.5 Great Britain

For Great Britain only the main island (excluding Northern Ireland / Ireland) is considered. It is divided into three areas, namely South, Mid and North, taking the respective inter-area transmission bottlenecks into account.

In the future scenarios an expansion of these transmission corridors is included. Especially the transmission expansion to Scotland is essential in order to enable the transport of WPP to the load centres in the mid and south of Great Britain. These transmission expansions include the planned HVDC cables along the coast from Scotland to England (Eastlink/ Westlink) [9]. The implemented net transmission capacities for Great Britain can be found in Table 11.

Table 11. Great Britain transmission capacities [MW]

		2010:			2020/30:	
GB-SOUTH	GB-MID	11000	11000		15000	15000
GB-MID	GB-NORTH	3000	3000		7000	7000

3.4.6 Offshore grid

Due to the significant increase of offshore wind power in the North Sea up to 2030, the offshore grid in the North Sea is modelled according to the assumptions made in [5]. Figure 5 shows the suggested offshore grid. The grid includes the Dogger Bank wind farm area as a hub including connections to offshore wind farms in Norway, Germany and the Netherlands. Furthermore, a connection of offshore wind areas along the Continental coast of the North Sea is expected.

Table 12 presents the respective transmission capacity.

Table 12. Offshore grid transmission capacities [MW]

			2010:			2030:	
1	SORLAN-OWP	DOGGERBANK	-			1000	1000
2	TYSK-V-OWP	DOGGERBANK	-			1000	1000
3	NEDERL-OWP	DOGGERBANK	-			1000	1000
4	BELGIA	NEDERL-OWP	-			1000	1000
5	NEDERL-OWP	GB-S-OWP	-			1000	1000

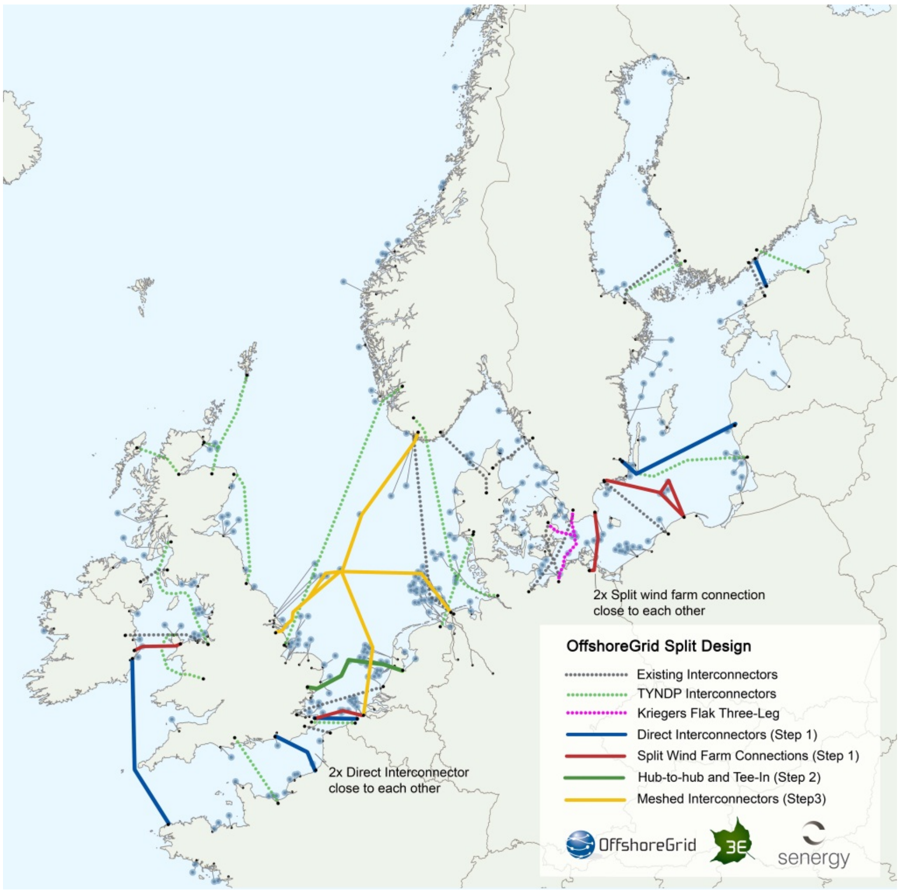


Figure 5. Offshore grid for the North Sea in 2030 [5]

4 Model simulation methodology / runs

The previously described scenarios are simulated with EMPS. Within the simulation, special attention is given to the increasing share of variable WPP in the future scenarios.

The simulation process of EMPS consists of two main phases, the strategy phase and the simulation phase. The objective in the strategy phase is to determine the "water-value maps" for the different hydro areas, defining the long-term handling of the hydro reservoirs. The following simulations phase validates the long-term strategy and determines a detailed system dispatch by simulating the power system throughout several years.

To take the variability of WPP into account, sequential (chronological) periods shall be used throughout the simulation. In general, EMPS is based on weekly simulation steps but includes the possibility to divide a full week into several periods. For this division there are two types of periods[6]:

- aggregated load periods - aggregating all hours of a load period during a week

[6] The normal representation in EMPS is aggregated periods, defining several load levels during a week. However, in this case an average wind production throughout the week is utilised, neglecting the significant variability of WPP. Thus, sequential periods, which define a chronological division of the week should be used, considering the variability of WPP.

- sequential load periods - aggregating chronological hours of a load period during a week

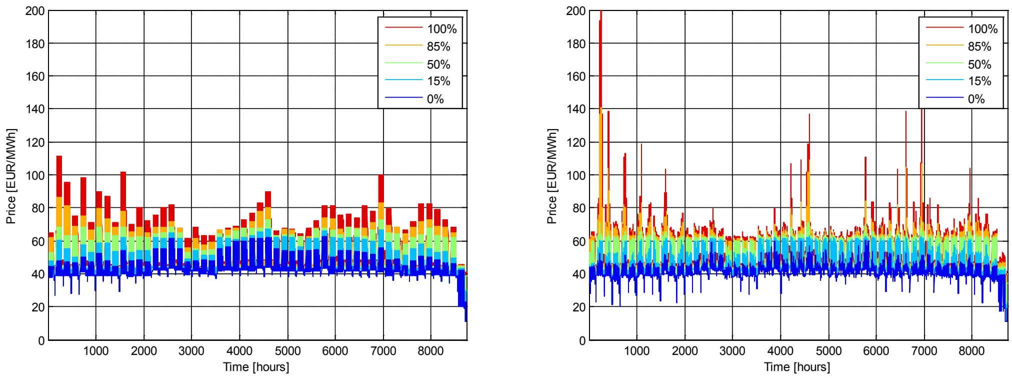
In the following sections the utilisation of different methodologies in EMPS is discussed. These included the utilisation of aggregated and sequential periods in the strategy and the simulation phase, as well as the utilisation of start-up costs in the EMPS model.

4.1 Aggregated vs. sequential periods in the simulation

In the simulation phase the whole system is simulated, including a detailed representation of the hydropower system. During this phase, the calculated water values are used as the marginal production costs for the hydro power plants.

The chosen type of periods has a significant impact on the representation of electricity production from variable renewable energy sources, such as WPP and Solar Power Production (SPP). With aggregated periods an average production is assumed throughout a week, whereas with sequential periods, only the production of some sequential hours is aggregated. Thus, sequential periods still incorporate a significant share of the variability of production from RES. This variability has a significant impact on the system dispatch and hence prices, resulting in a higher volatility. Figure 6 shows a comparison of the prices in Northern Germany for aggregated and sequential periods, illustrating the increased price volatility.

However, the utilisation of sequential periods drastically increases the calculation time by a factor 5 to 10. The increase of the solution time thereby strongly depends on the share of variable power production. The higher the share of variable power production is, the more the calculation time increases[7].



a) aggregated b) sequential

Figure 6. Area price in Northern Germany aggregated / sequential periods during system simulation

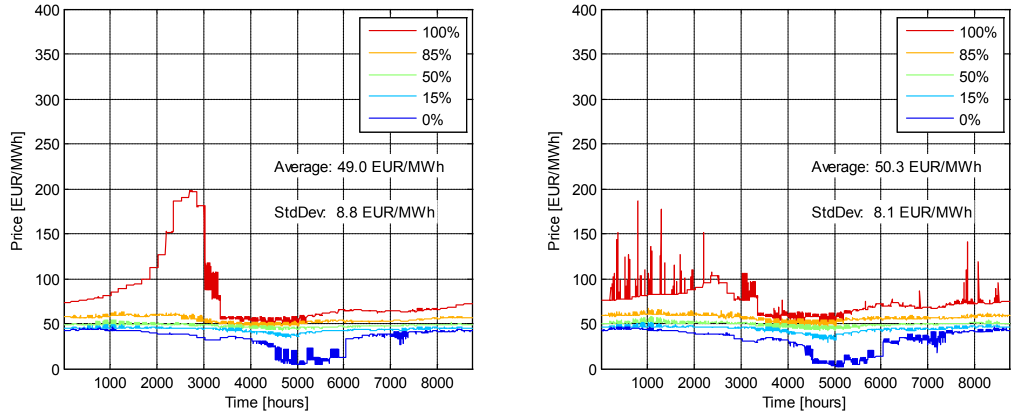
[7] An explanation for the increase of calculation time with the increase of variable WPP is the solver, which is used to solve the underlying linear problem. Used is COIN, which has a warm-start methodology, using the solution in the previous step as the initial state of the problem for the next step. The higher the WPP becomes, the more the solution of the single steps differs from each other. Hence, the result is an increase in solution time.

4.2 Simulation without vs. with start-up costs

A further challenge is an appropriate representation of the thermal power production. As mentioned in the previous chapter, the starting up and stopping of thermal is normally neglected in EMPS. However, considering these two issues as well as the start-up state of thermal power plants has a significant impact on the system dispatch as well as resulting are prices.

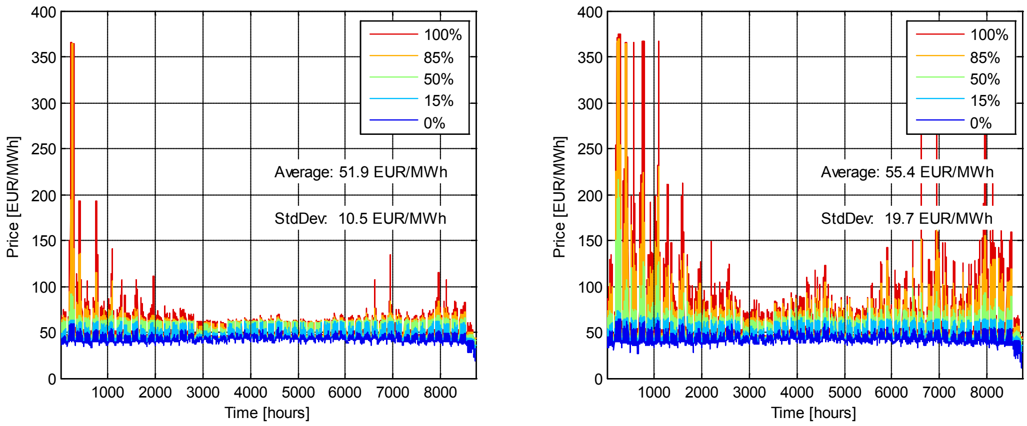
Due to a necessary change in the problem description[8] the solution time increases drastically. To stay within acceptable limits of calculation time, only 10 climatic years have been used, when using start-up costs in EMPS.

To illustrate the impact of utilising start-up costs a simulation is run for 2010, defining the start-up costs for about 350 thermal power plants. Figure 7 and Figure 8 show the resulting area prices for the simulations with and without start-up costs. In Germany (thermal dominated power system) significantly higher price volatility is observed, when running the simulations with start-up costs. The consideration of start-up costs not only has a direct impact in the thermal areas, but also on the hydro area.



a) without start-up costs　　b) with start-up costs

Figure 7. Area prices in Norway without / with start-up costs during simulation



a) Without start-up costs　　b) with start-up costs

Figure 8. Area prices in Germany without / with start-up costs during simulation

[8] The underlying problem description has to be changed from a network problem to a general linear problem.

Although the start-up costs have a significant impact on the market simulations, they are not implemented in the set of analyses presented in the following section. This is because:

i) A statistically representative set of differences between the climatic years is desired for the focus of the work here. Typically this requires the utilisation of 75 different years, especially when determining the water values for the reservoirs.

ii) The focus of the market simulations here is not the solution of a detailed unit-commitment problem but rather on long term strategic usage of hydro energy as *flexible* energy sources to compensate for the variability of wind power and other renewables in the system.

5 Simulation results

The previously defined scenarios are simulated with EMPS using a chronological description (sequential periods), but neglecting the start-up costs of thermal power plants. As discussed in the previous section, these assumptions certainly underestimate price volatility, due to neglecting start-up costs. However, the simulation results give a rather good indication of future changes and challenges in the Northern European power system.

This chapter presents and discusses the simulation results. It is finalised with a transmission investment analysis, which is intended to identify further required expansions. Furthermore, a short sensitivity analysis is included addressing the impact of increased interconnection capacity on price levels in the different areas.

A detailed overview of the resulting generation mixes for the scenarios of 2010, 2020 as well as 2030 per country can be found in the appendix in Table 51 through Table 53. The generation mix resulting from EMPS for 2010 is put in comparison with the generation mix reported by ENTSO-E [10] and to the generation mix stated in the EU energy trends [4] for each of the scenarios (2010, 2020 and 2030).

With the initial fitting of the model, the generation mix of 2010 is reproduced rather well. The main difference is the ratio between the productions from hard coal versus gas power plants. There is more production from hard coal power plants observed in EMPS, than it is reported by ENTSO-E. This is probably due to neglecting the start-up costs in EMPS so far. However, the implemented availability parameters especially for hard coal are rather low anyway.

A more detailed analysis on the impact of the increased WPP and the expansion of transmission capacity on the system dispatch in Northern Europe is given in the following. The overview includes prices of Norway (high installed hydro capacity and connections to Continental Europe) and Germany (high installed WPP capacity). Additionally, the reservoir handling and hydro power production in Norway is shown.

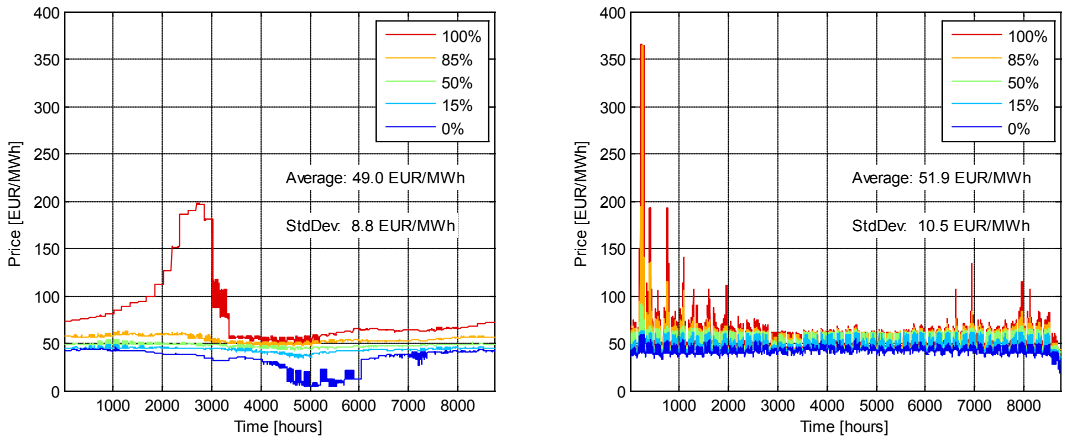
The following diagrams show the percentiles of the according plotted value based on 75 climatic years[9] (1931-2005). As the main influence of a climatic year is the hydro inflow in the Nordic area and the WPP in

[9] A climatic year refers to the inflow to the Nordic hydro system, the temperature and the wind speeds as well as solar radiation.

Continental Europe, single percentiles do not refer to the same climatic year (in the Nordic area and Continental Europe).

5.1 Area prices – Nordic / Continental areas

In 2010 the main characteristics of a hydro and a thermal system can be observed in the plotted area prices (see Figure 9). In the hydro system (Norway) big price differences occur between the different climatic years, with high prices during dry and low prices during wet years. However, the hour to hour price difference is relatively small. In contrast the thermal system (Germany) the hour to hour price difference is much larger, while there is no significant difference between the different climatic years. Highest prices can be observed during winter time, when the demand is higher, while prices tend to be lower in the summer time. This seasonal behaviour is much more observable in the Nordic system, as the difference in the demand level is much higher than in the Continental European system[10].

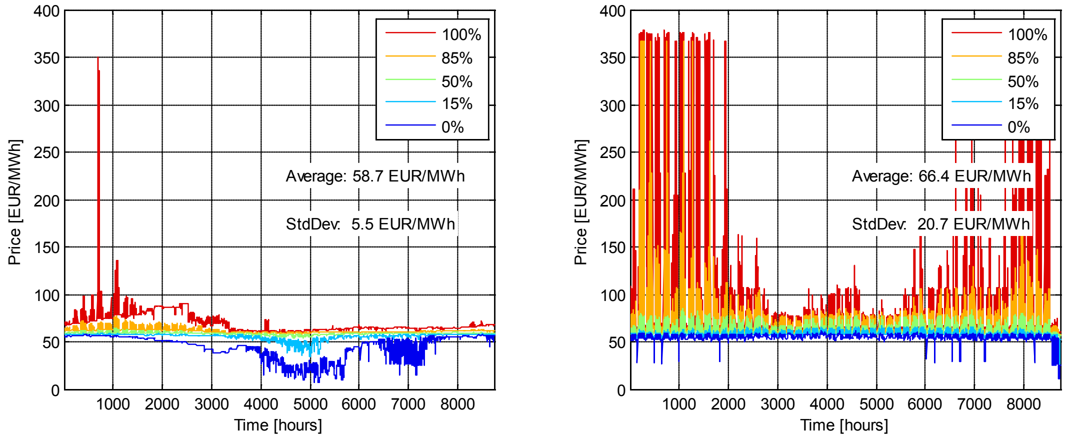


a) Norway b) Germany

Figure 9. Area prices 2010

In 2020 the price figures change (Figure 10). In Norway, the difference between the climatic years becomes less, due to the transmission expansion and hence higher interconnection capacity to Continental Europe. Thus, more energy can be exported during wet years, resulting in less spillage (less zero prices). On the other side more energy can be imported during dry years, reducing the risk of rationing (reduction of high prices). While there is less difference between the climatic years, the short-term price volatility increases. The increasing short-term volatility of prices can also be observed in the Continental European area, where additionally more price dips occur. These price dips are due to the higher share of WPP and occur, when there is high WPP production, which replaces a significant share of the base load power production. Especially in Germany the price volatility becomes much higher due to the large increase of WPP. At the same time the overall price level increases due to the increasing marginal production costs of thermal power plants (increased CO_2 costs).

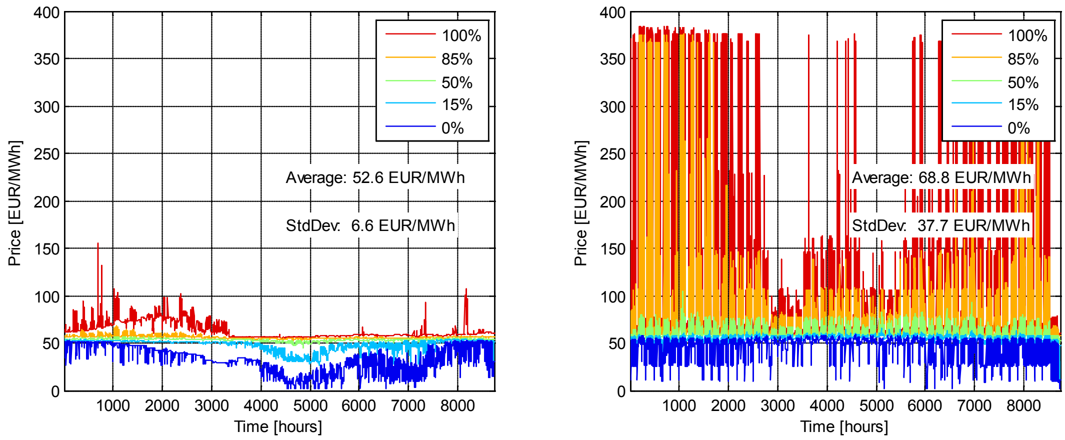
[10] There is a significant share of electrical heating in the Nordic area, causing a significant demand increase during winter time.



a) Norway b) Germany

Figure 10. Area prices 2020

In 2030, with further WPP penetration of the system the general trend up to 2020 continues. Even higher price spikes and dips occur, while the general price level tends to be lower. This mean price reduction results from the high WPP at zero marginal cost.



a) Southern Norway b) Northern Germany

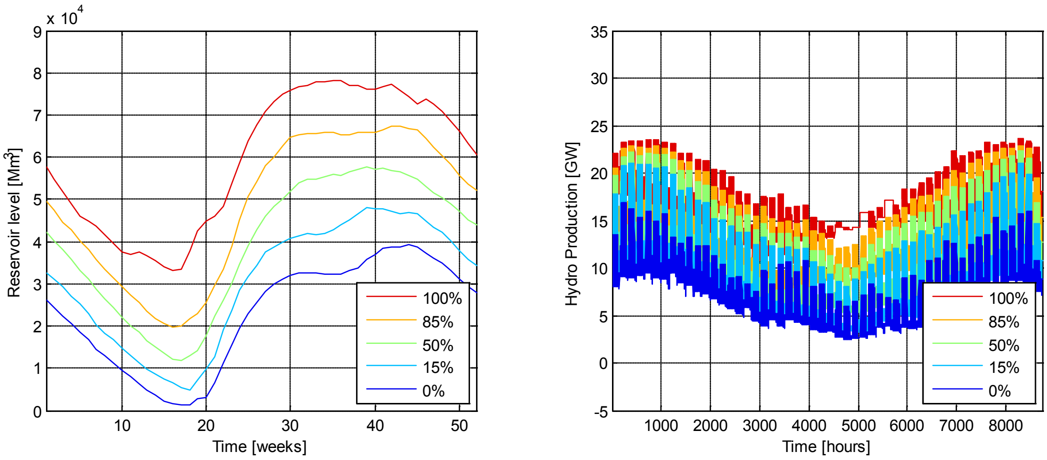
Figure 11. Area prices 2030

5.2 Hydro power production / reservoir handling

The large share of hydro power production is considered to provide an essential share of production flexibility to the Continental power system in order to be able to integrate large amounts of variable power production from RES into the power system. Thus, in the following the prospective development of the Nordic hydro power production is analysed.

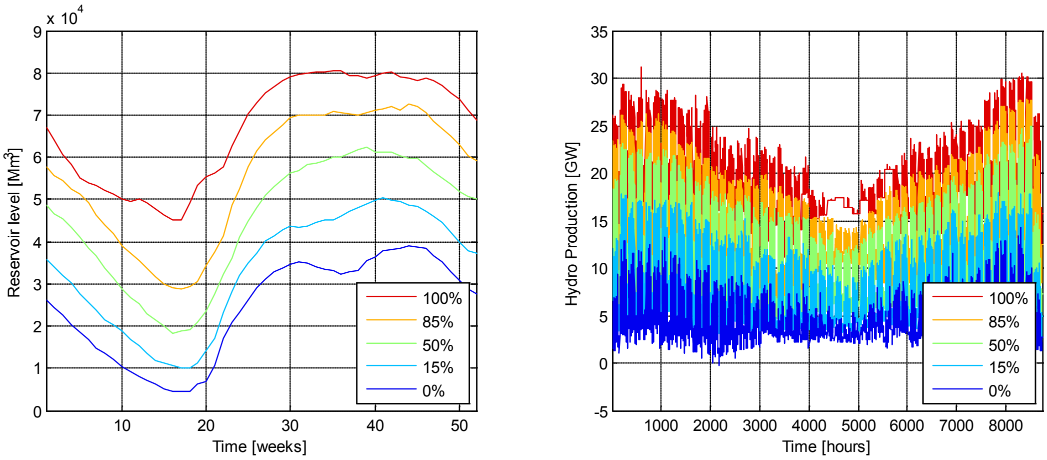
In 2010, the reservoir handling (Figure 12 a) is quite characteristic for the Nordic countries, with depletion during the winter and early spring as well as a filling during the other time of the year. Assessing the reservoir handling for the future (Figure 13 a and Figure 14 a) scenarios shows minor differences. It can be observed, that the reservoir levels become higher in general, while the long-term reservoir storage capability is utilised less. This means, percentiles of the reservoir handling become more spread and flatter. It also indicates a change of the reservoir utilisation from a long-term perspective to a more short-term.

The aggregated hydro production for Norway illustrates, that significant changes in the hydro production pattern can be expected. In 2010 (Figure 12 b) there is a rather stable seasonal production trend, with higher production during winter time and lower production during the summer, according to the changes in the demand. In addition there is a diurnal pattern, according to the differences in demand during day and night time as well as the weekend. This stable seasonal pattern vanishes and a more volatile hydro power production occurs in the future scenarios (Figure 13 b and Figure 14 b). These changes are due to the significant integration of WPP in the future power system.



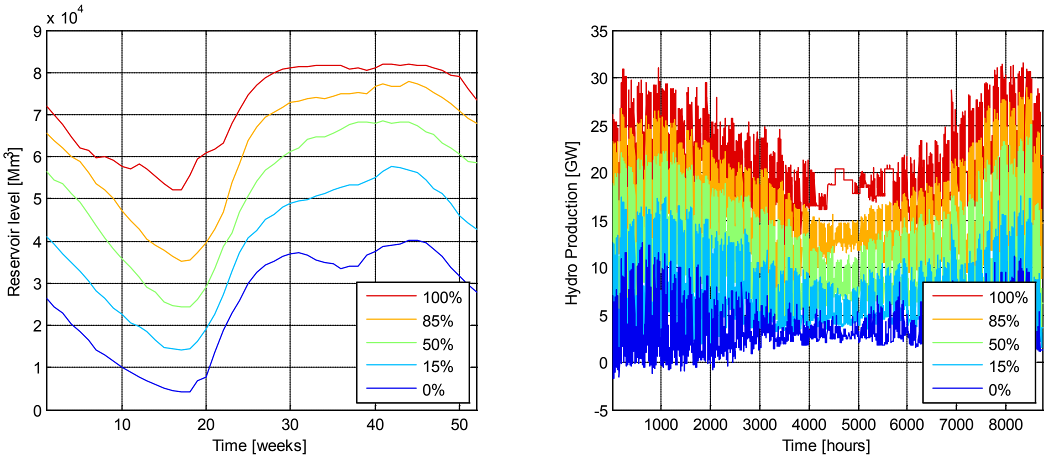
a) Reservoir handling b) Hydro production

Figure 12. Reservoir handling / Hydro production in Norway 2010



a) Reservoir handling b) Hydro production

Figure 13. Reservoir handling / Hydro production in Norway 2020



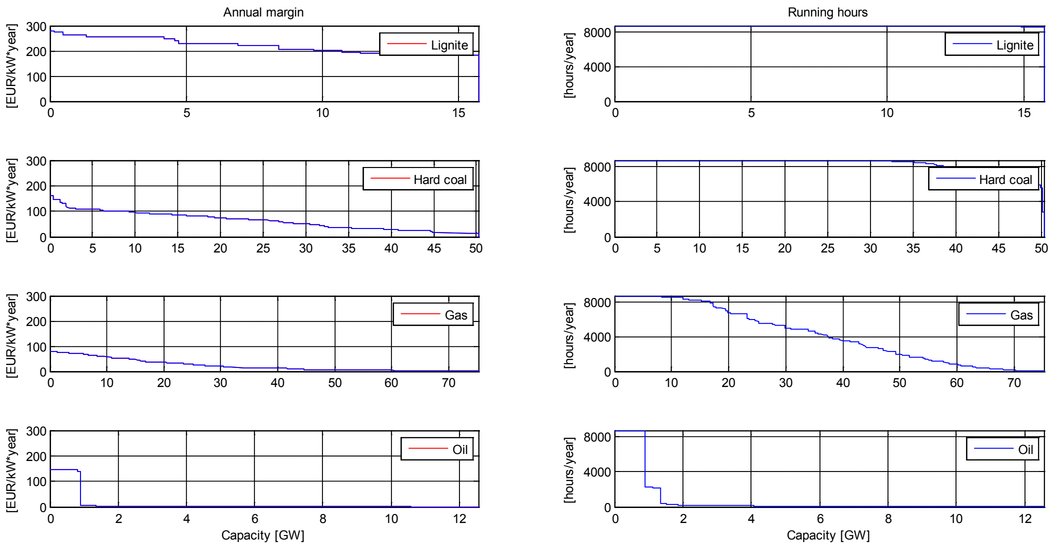
a) Reservoir handling b) Hydro production

Figure 14. Reservoir handling / Hydro production in Norway 2030

5.3 Thermal power production – profit margins / operation hours

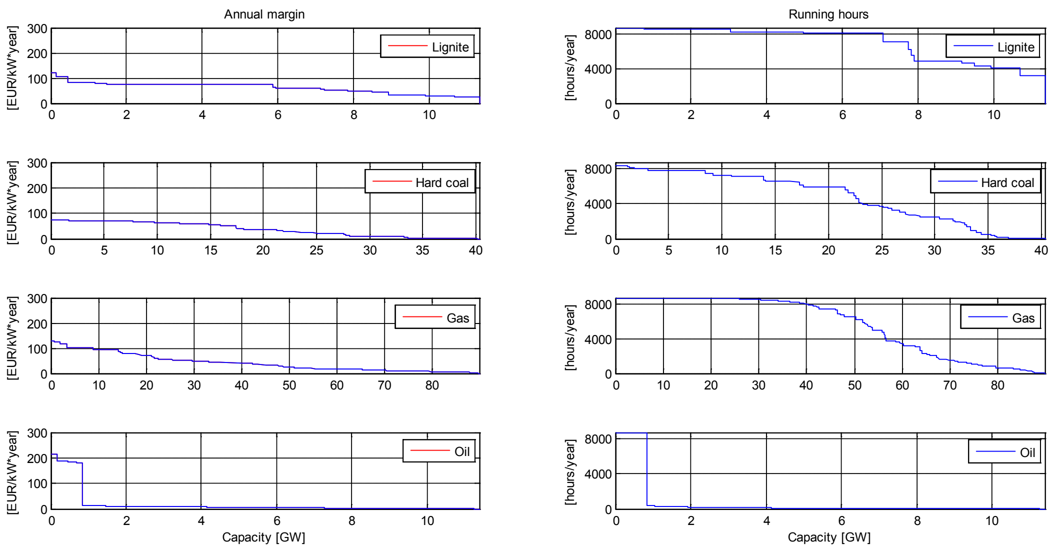
Likewise to the hydro power production, which is situated in the Nordic area, significant changes can be expected for the thermal power production. Figure 16 to Figure 18 illustrate the operation of thermal power plants in the system scenarios of 2010, 2020 as well as 2030. The figures show that overall operation hours of thermal power plants decrease significantly up to 2030. This is especially the case for base load power plants like lignite or hard coal power plants, where nearly none of the power plants is running full time in the 2030 scenario, while there is a reduction of generation capacity as well. In contrast to that decrease, the running hours of gas and oil fired power plants slightly increase, while there also is higher installed generation capacity. As there are no start-up costs or other flexibility constraints included in the simulation, there are only two reasons for the change in the generation mix. The first one are the changing marginal production costs of thermal power plants, where lignite hard coal and gas power plants are expected to have rather equal marginal production costs. The alignment of the productions costs is due to the expected increase in CO_2 cost, while fuel costs are kept constant throughout the analysis. As the CO_2 price impacts the coal based power production more than from gas, the resulting production costs for the different thermal power plant types are on one level and higher than in the 2010 scenario. The second reason is the variable WPP at zero marginal costs, driving thermal power plants out of production, which causes certain hours in which nearly no thermal power plant produces electricity.

The changing generation schedule of the thermal power plants impacts the profit margin of the thermal power plants. This profit margin is defined as the income of power plants due to the sale of electricity minus production costs. To make a thermal power plant profitable, this profit margin needs to be higher than the fixed costs (maintenance, investment costs). The figures (Figure 16 a to Figure 18 a) of the annual profit margins for the thermal power plants show that there is a significant decrease, especially for lignite and hard coal power plants (almost halved profit margin), which have rather high fixed costs. This will evidently challenge their profitability. On the contrary, profit margins for gas- and oil-fired power plants tend to increase, however only for a smaller share of their installed capacity. However, it shows there still is potential for profit in the future scenarios, in order to earn back the fixed costs of a thermal power plant.



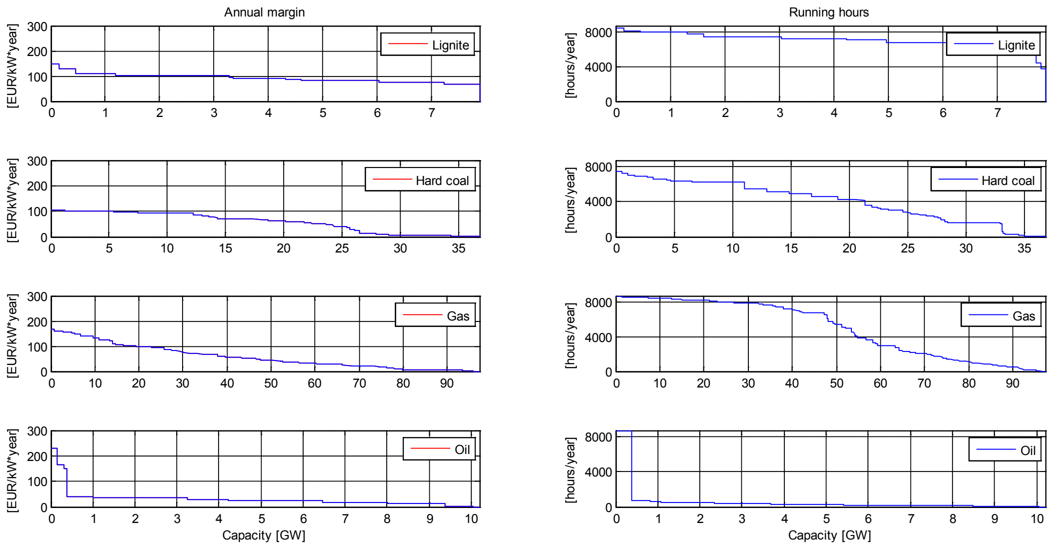
a) Profit margin b) Operation hours

Figure 15. Thermal production 2010



a) Profit margin b) Operation hours

Figure 16. Thermal production 2020



a) Profit margin b) Operation hours

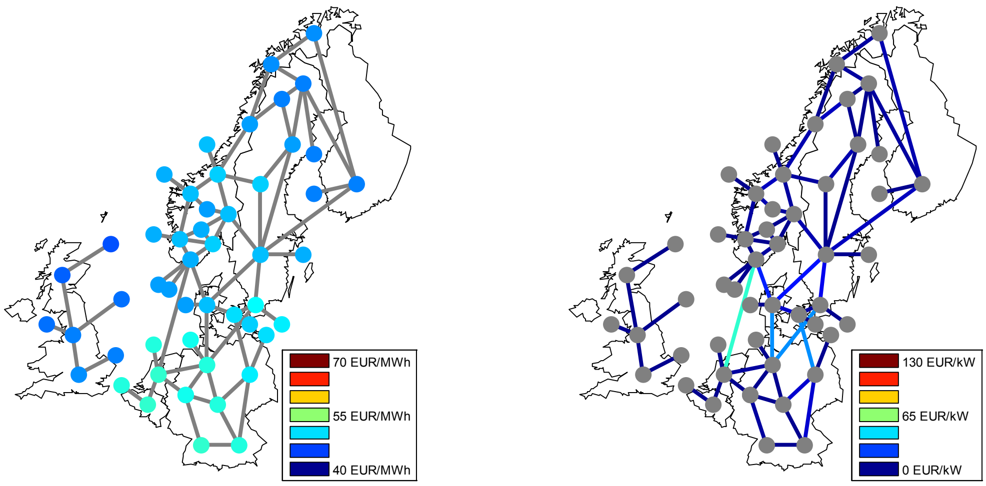
Figure 17. Thermal production 2030

5.4 Geographic overview

The following figures (Figure 19 to Figure 21) give a geographic overview of the simulation results for the three different scenarios. Shown are average area prices as well as the marginal profit (congestion rent) of the transmission corridors, which indicate the congestion in the system. The area prices are given as the average over all 75 climatic years. The marginal profit is given as the average annual marginal congestion rent over all 75 climatic years of the transmission corridor as well.

In 2010 (Figure 19), low prices in the north and high prices in the south are observed, with two minor exceptions, Southern Sweden and Eastern Germany[11]. The congestion rent is highest on the interconnectors between the Nordic area and Continental Europe, especially on the NorNed cable (about 60 EUR/kW per annum). Rather low area prices can be observed in the UK, which is due to a high generation capacity of base load power plants.

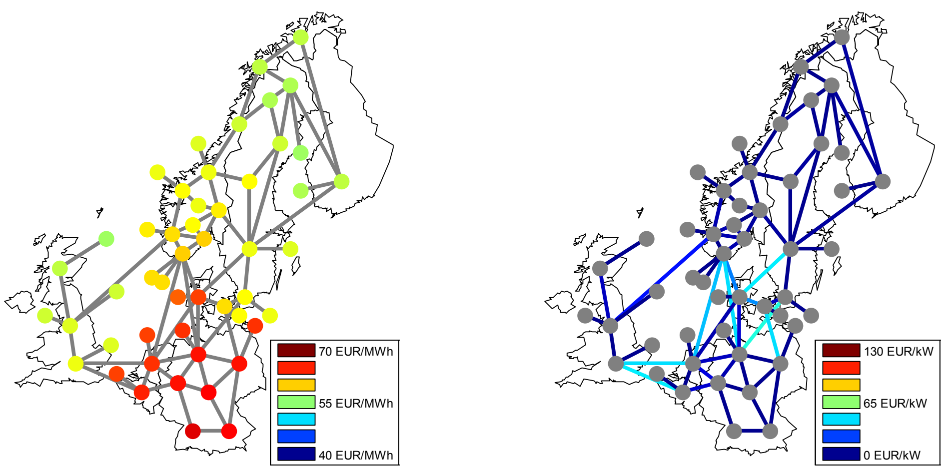
[11] These prices cannot be seen in reality as both Germany and Sweden are one price-area. Since November 2011 Sweden is divided into 4 price areas.



a) Area prices b) Marginal transmission profit

Figure 18. Geographic overview 2010

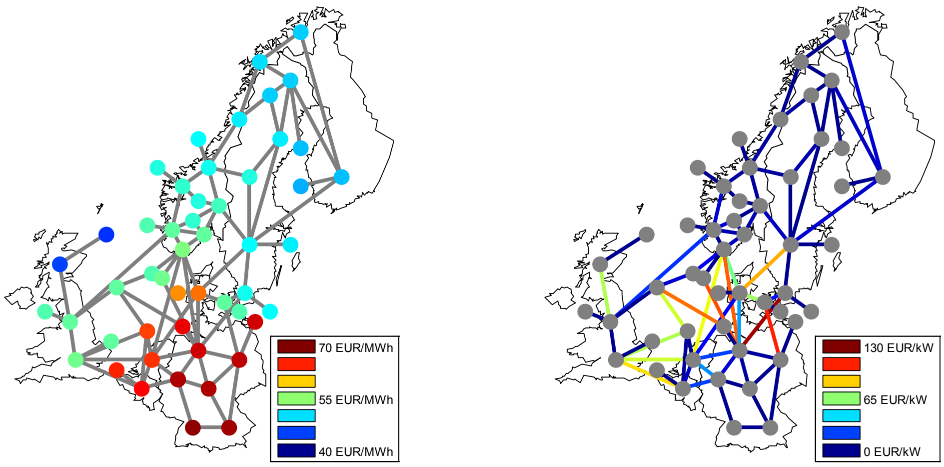
In 2020 (Figure 20), the characteristics are similar, whereat the area prices in Great Britain are still rather low. This is due to a potential overestimation of the thermal capacity in Great Britain. Generally the area prices rise. There is an average price increase by about 10 EUR/MWh in the Nordic area and about 15 EUR/MWh in Continental Europe. Still the connections between the Nordic area and Continental Europe are the most congested ones, while the new connections between Continental Europe and the UK are congested as well. Furthermore, the overall marginal profit of the transmission corridors increases, showing that transmission capacity becomes more important.



a) Area prices b) Marginal transmission profit

Figure 19. Geographic overview 2020

In 2030 (Figure 21), prices increase dramatically in Continental Europe, while there is a certain price decrease in the Nordic area and the UK. This price development is due to the decommissioning of a high share of thermal generation capacity in Continental Europe. On the other side large capacities of WPP are commissioned in the Nordic area (Sweden) as well as the UK (Scotland).
The connections between the Nordic area and Continental Europe are still most congested, whereat the marginal profit increases drastically (it is more than doubled compared to 2010 and 2020). In addition, increased congestion can be observed on the corridor between England and Scotland. These large marginal profits on the transmission corridors show the need for a further expansion of those transmission corridors.



a) Area prices b) Marginal transmission profit

Figure 20. Geographic overview 2030

The development of average electricity prices in the future scenarios is mostly influenced by two factors, the additional power production from RES and the expected increase of production costs of thermal power plants. Figure 21 demonstrates the effect of these two factors:
Curve 2010 represents the basis marginal cost curve for the starting scenario, including the steps RES, Hydro, Lignite, (Hard) Coal, Gas as well as Oil. The demand is assumed to be constant in this example. On the one hand in the case of increased CO_2 cost (CO2+), parts of the production cost curve are shifted up, whereat the biggest shift occurs for lignite and hard coal power plants. On the other hand with increased RES capacity (RES+), the whole cost curve is shifted to the right. For the future scenarios a superposition of both effects is expected, resulting in the combined marginal cost curve (CO2+ & RES+), which is shifted to the right and parts of it up. The resulting price for all of the scenarios is the crossing of the demand and the marginal cost curve. In the figure it is demonstrated, that both effects have an opposite effect on the power price. While increasing CO_2 costs increase the price, increasing RES capacity decreases the price. The resulting price, when combining these two effects as it is expected in the future scenarios quite strongly depends on the impact of each of the effects. In the example in Figure 21 the resulting price is higher than in the basic scenario, which is comparable to what is observed in the previously presented analysis. Our

recommendation for further work is to perform sensitivity analysis on these effects with considering different ranges of e.g. CO2 prices.

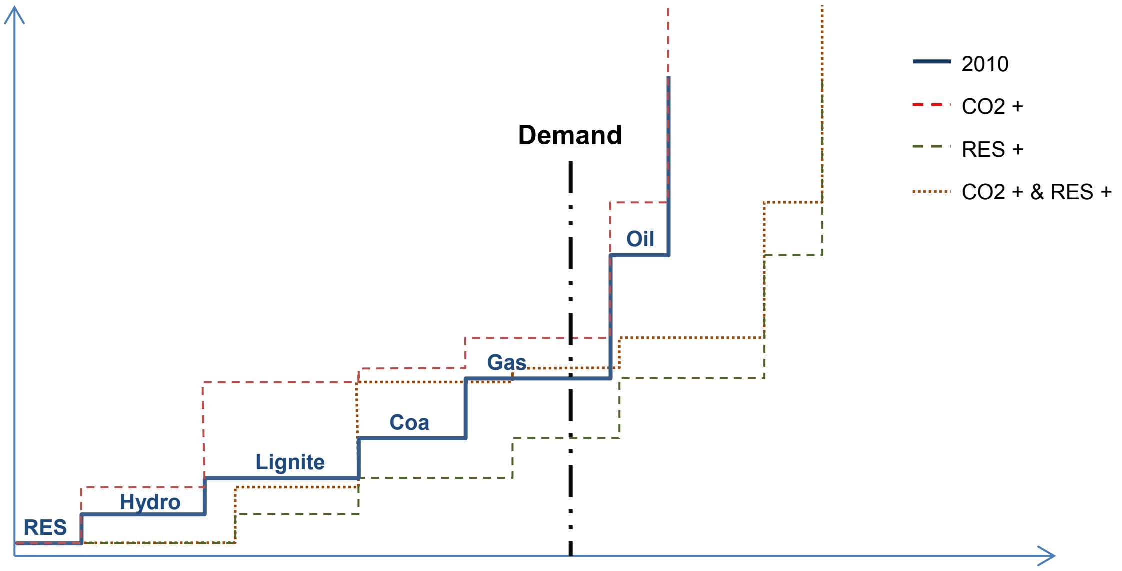


Figure 21. Marginal cost curves for the basic scenario as well as increased CO_2 costs and RES capacity

5.5 Investment analysis

As mentioned in the last section showing the simulation results for the developed 2030 scenario, large marginal transmission profits on the corridors connecting the Nordic area to Continental Europe can be expected. Thus, using this developed scenario for 2030, investment analyses are run. These investment analyses aim at identifying the transmission corridors, which require a further expansion in order to guarantee an efficient operation of the power system. Thus, only expansions of transmission lines/ corridors are considered, while additional investments in generation capacity are neglected. New investments in transmission capacity are handled as merchant lines, i.e., their investment costs have to be covered by the congestion rent. The used investment methodology compares the annualised investment cost with the marginal profit (congestion rent/ avanse) of a transmission corridor and expands the capacity if the annual marginal profit is higher than the annualised investment cost. For a more detailed description see the technical report on the investment methodology [19].

As discussed before, there is a certain trade-off between calculation accuracy and calculation time, when deciding for an aggregated versus a sequential representation of the time steps in EMPS. Hence, the investment analyses are again done with both representations, assessing the difference in the outcome. As illustrated above, in the case of sequential periods price spikes and dips occur more often and become larger, resulting in higher price differences between the single areas. With these price differences the marginal profit of the transmission corridors increases, which eventually results in a larger transmission expansions.

Table 13 shows the numeric results of the investment analyses. The expansion of transmission corridors in 2030 are based on investment costs estimated in [20]. The main transmission expansions in 2030 occur roughly along a corridor around the North Sea from Sweden to Northern Germany, the Netherlands (Belgium) to England and northwards to Scotland. The expansion of this corridor can be observed in both analyses, with aggregated and sequential periods. However, the size of expansion differs significantly.

The largest transmission expansion can be spot on the connection between Southern Sweden and Northern Germany (Baltic cable) and between Scotland and Northern England reaching up to 4GW. This expansion is due to a severe energy surplus in Sweden and Scotland (high amount of WPP capacity) potential energy in the 2030 scenario.

Table 13. Transmission expansion in 2030

From	To	Inv. Cost [EUR/MWa]	Marg. prof [EUR/MWa]	Prof/cost ratio	Expansion [MW]	Marg. prof. [EUR/MWa]	Prof/cost ratio	Expansion [MW]
			Aggregated periods			Sequential periods		
OSTLAND	SOROST	4120	1699	41 %	0	663.5	16 %	0
OSTLAND	HALLINGDAL	9563	165	2 %	0	667.6	7 %	0
OSTLAND	TELEMARK	6616	0	0 %	0	147	2 %	0
OSTLAND	NORGEMIDT	16191	795	5 %	0	883.2	5 %	0
OSTLAND	SVER-MIDT	9939	1152.7	12 %	0	2500.8	25 %	0
SOROST	TELEMARK	6560	5400.2	82 %	0	4420.7	67 %	0
SOROST	SORLAND	7844	2705.3	34 %	0	2389.5	30 %	0
SOROST	VESTSYD	10715	2196.4	20 %	0	2338.6	22 %	0
HALLINGDAL	VESTMIDT	4544	71	2 %	0	50.3	1 %	0
TELEMARK	VESTSYD	4972	3535.4	71 %	0	2440.1	49 %	0
SORLAND	VESTSYD	9953	244.5	2 %	0	172.1	2 %	0
VESTSYD	VESTMIDT	9950	3810.3	38 %	0	2426.8	24 %	0
VESTMIDT	NORGEMIDT	9398	424.5	5 %	0	459.3	5 %	0
NORGEMIDT	HELGELAND	14247	736.4	5 %	0	579.9	4 %	0
NORGEMIDT	SVER-NN2	10299	699.1	7 %	0	1578.3	15 %	0
HELGELAND	TROMS	15694	284.2	2 %	0	197.4	1 %	0

HELGELAND	SVER-ON2	11055	909.4	8 %	0	1264.2	11 %	0
TROMS	FINNMARK	13088	0	0 %	0	0	0 %	0
TROMS	SVER-ON1	11252	74.3	1 %	0	246.4	2 %	0
SVER-ON1	SVER-ON2	5002	0	0 %	0	13	0 %	0
SVER-ON1	SVER-NN1	9020	598.7	7 %	0	1161.8	13 %	0
SVER-ON2	SVER-NN1	6263	0	0 %	0	112.8	2 %	0
SVER-NN1	SVER-NN2	10357	3990.2	39 %	0	4455.2	43 %	0
SVER-NN1	SVER-MIDT	19412	505.6	3 %	0	697.4	4 %	0
SVER-NN2	SVER-MIDT	11423	180.2	2 %	0	851.4	7 %	0
SVER-MIDT	SVER-SYD	11821	10538.5	89 %	0	12751.2	108 %	2080
SORLAND	DANM-VEST	37172	20459.2	55 %	0	29507.1	79 %	0
SORLAND	TYSK-NORD	65051	26818	41 %	0	37210.2	57 %	0
SORLAND	NEDERLAND	55758	26217.9	47 %	0	37166	67 %	0
SORLAND	SORLAN-OWP	70670	5611.5	8 %	0	13025	18 %	0
VESTSYD	GB-MID	83638	8128.8	10 %	0	18816.8	22 %	0
FINNMARK	FINLAND	35536	8965	25 %	0	8776	25 %	0
SVER-ON1	FINLAND	17113	7275.5	43 %	0	7431.1	43 %	0
SVER-MIDT	FINLAND	24394	11015.8	45 %	0	12196.7	50 %	0
SVER-MIDT	DANM-VEST	52251	34700.8	66 %	0	36844.9	71 %	0
SVER-SYD	DANM-OST	6294	1607.3	26 %	0	2248	36 %	0
SVER-SYD	TYSK-NORD	23527	24335.4	103 %	3100	25877	110 %	4010
DANM-OST	DANM-VEST	18973	14758.5	78 %	0	15275.9	81 %	0
DANM-OST	TYSK-OST	53899	21420.8	40 %	0	23872.4	44 %	0
DANM-VEST	TYSK-NORD	18368	4050.2	22 %	0	5428.1	30 %	0
DANM-VEST	NEDERLAND	41726	1785.1	4 %	0	3084.8	7 %	0
TYSK-OST	TYSK-NORD	12972	574.6	4 %	0	1354.3	10 %	0
TYSK-OST	TYSK-MIDT	10600	0	0 %	0	64.5	1 %	0
TYSK-OST	TYSK-SYD	18841	340.3	2 %	0	642.2	3 %	0
TYSK-NORD	TYSK-MIDT	13021	675.6	5 %	0	1694	13 %	0

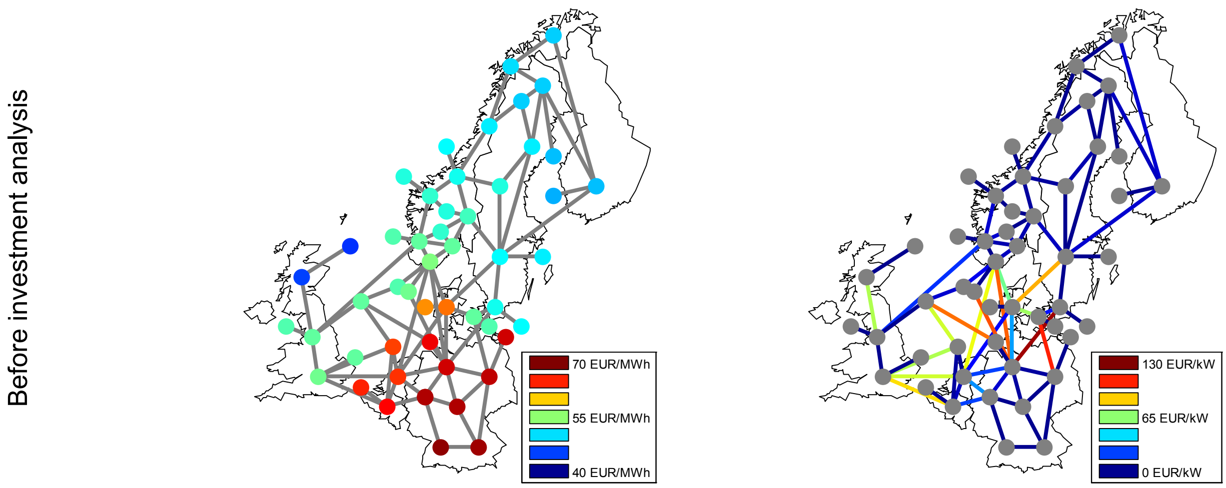
TYSK-NORD	TYSK-VEST	13125	5849.9	45 %	0	6660.5	51 %	0
TYSK-NORD	NEDERLAND	10134	1014.3	10 %	0	1904.1	19 %	0
TYSK-NORD	AEGIR-OWP	84586	29156.2	34 %	0	39826	47 %	0
TYSK-MIDT	TYSK-SYD	12165	0	0 %	0	85.2	1 %	0
TYSK-MIDT	TYSK-VEST	8937	0	0 %	0	129.8	1 %	0
TYSK-SYD	TYSK-SVEST	7900	0	0 %	0	0	0 %	0
TYSK-SVEST	TYSK-VEST	14209	0	0 %	0	0	0 %	0
TYSK-VEST	NEDERLAND	6121	6460.7	106 %	1180	6447.7	105 %	3750
TYSK-VEST	BELGIA	8434	1626.9	19 %	0	2197.8	26 %	0
NEDERLAND	BELGIA	8482	2170.1	26 %	0	2425.4	29 %	0
NEDERLAND	GB-SOUTH	39031	28776.3	74 %	0	39503.4	101 %	2330
BELGIA	GB-SOUTH	52251	35684.2	68 %	0	46592.3	89 %	0
BELGIA	NEDERL-OWP	64766	443.2	1 %	0	593.9	1 %	0
GB-SOUTH	GB-MID	13464	0	0 %	0	291.1	2 %	0
GB-SOUTH	NEDERL-OWP	67968	24370	36 %	0	34996.4	51 %	0
GB-MID	GB-NORTH	14658	16142.8	110 %	1000	15557.1	106 %	4020
SORLAN-OWP	DOGGERBANK	68861	1426.3	2 %	0	6018	9 %	0
TYSK-V-OWP	DOGGERBANK	80311	32144.7	40 %	0	41061.6	51 %	0
NEDERL-OWP	DOGGERBANK	75386	31402.5	42 %	0	40598.8	54 %	0

Figure 22 illustrates the results from the investment analysis (sequential periods) in a geographic perspective. It can be observed, that the transmission expansion evens out area price differences between the different areas, to price levels of the 2020 scenario. In Continental Europe the area prices are reduced by about 10 EUR/MWh, whereat there is a slight price increase in the Nordic area of about 2.5 EUR/MWh. In

England the price level is kept, whereat there is a huge increase of prices in Scotland. This is due to the fact that a significant amount of shut down of WPP can be avoided, but transferred to the load centres in England.

Before the transmission expansion the highest marginal transmission profit can be observed on the interconnector between Southern Sweden and Northern Germany (Baltic cable). The largest expansion is also seen on this interconnector. However, there are also high marginal transmission profits on other interconnectors (e.g. Nordlink, Kontek), which are not expanded. The reason for the missing expansion is the impact of a transmission expansion on the area prices throughout the system. The expansion of especially the Baltic cable reduces the price difference between the Nordic area and Continental Europe significantly, making an investment in other interconnectors unprofitable.

Overall the marginal profit on the transmission corridors is decreased drastically by the transmission expansion. The transmission expansion specifically enables the transfer of surplus energy from Scotland and Northern Scandinavia to the load centres in Southern England and Continental Europe. The area prices in Southern Scandinavia are only influenced to a minor extend. Furthermore, the transmission expansion creates additional social welfare of 350 million EUR per annum.



Sequential investment analysis

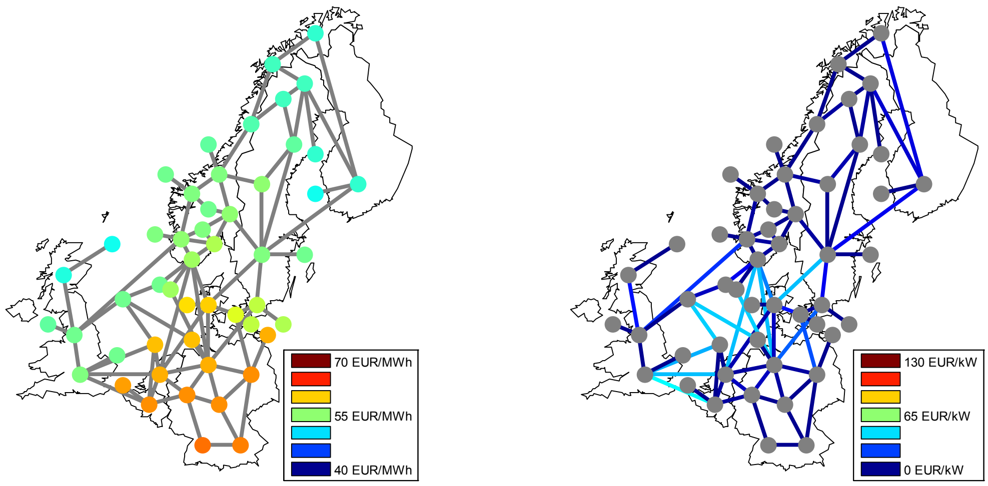


Figure 22. Investment analyses 2030

5.6 Sensitivity analysis – Increased marginal production costs vs. transmission expansion

A highly discussed topic is the result of increasing the transmission capacity between the Nordic area and Continental Europe on importing "Continental electricity prices" to the Nordic area. The following sensitivity analyses shed light on the causes for the future price development in the Nordic area. Hereby it is distinguished between increasing transmission capacity and the marginal production costs of thermal power production mainly located in Continental Europe.

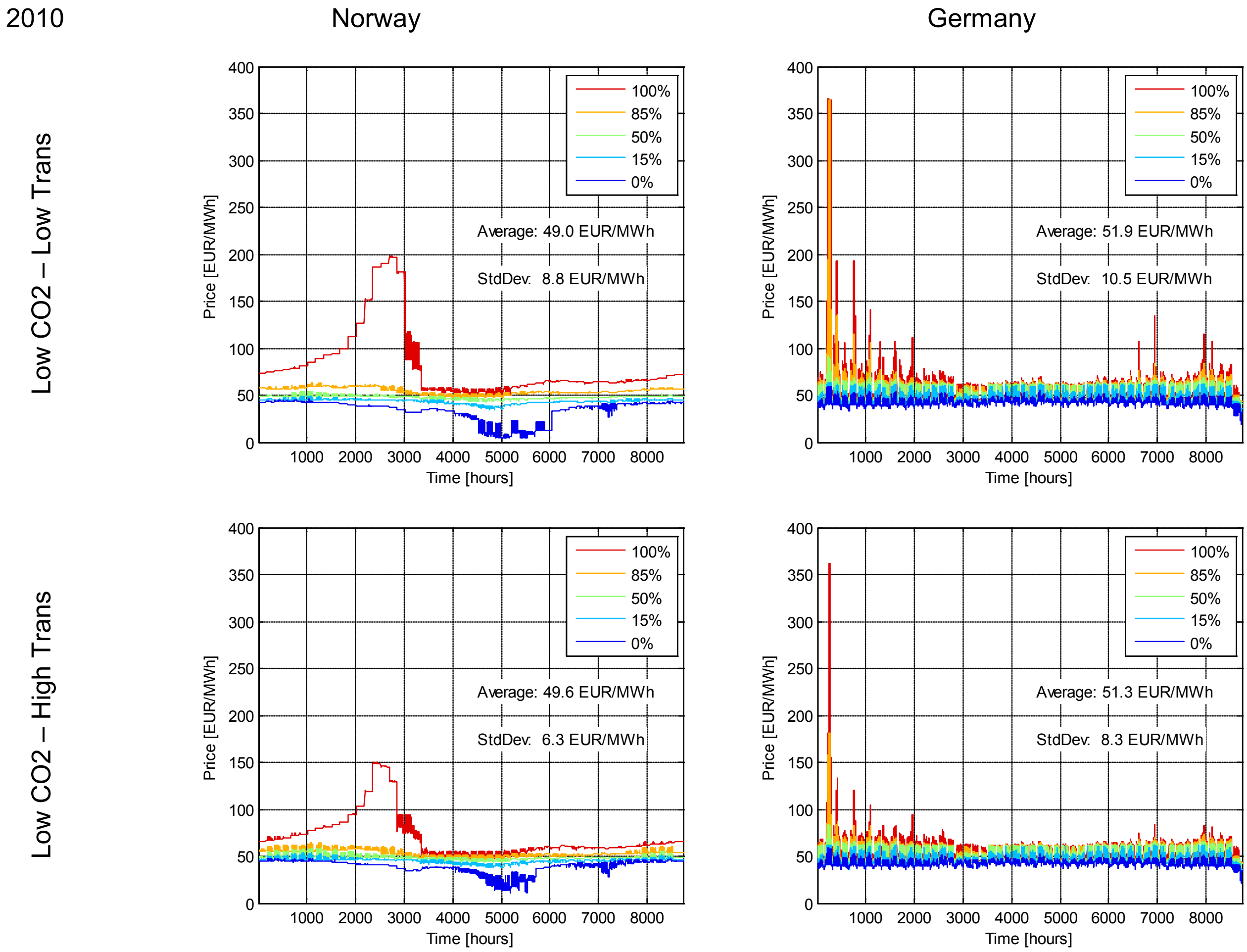
Table 14 shows the different variations of the 2010 and 2030 scenario, which are used to study the sensitivity of the simulation outcomes. The change of the marginal production costs is assumed to be only from the change in CO2 costs. Thereby, low CO2 costs are 13.5 EUR/t (value in the 2010 scenario) and high costs are 44 EUR/t (value in the 2030 scenario). Likewise the transmission capacity is divided into a low and high case. The low/ high transmission refers to the expansion of the HVDC-cables between the Nordic area and Continental Europe as well as the transmission expansion in the Nordic area up to 2030.

Table 14. Sensitivity analysis – defined cases

2010	I	Low CO2 costs	Low transmission	Initial scenario
	II	Low CO2 costs	High transmission	
	III	High CO2 costs	Low transmission	
2030	IV	High CO2 costs	High transmission	Initial scenario
	V	High CO2 costs	Low transmission	
	VI	Low CO2 costs	High transmission	

The effects, which are studied in the sensitivity analysis, are the resulting price levels in Norway and Germany, showing the impact in the hydro and the thermal power system. Figure 23 shows the prices of the different cases for the 2010 scenario.

The effect of the transmission expansions versus the thermal production cost increase is shown clearly. Expanding the interconnection capacity affects the price volatility in both countries, showing a significant reduction in both (Norway and Germany). In Norway the change is mainly a reduced price difference between wet and dry years, while in Germany the short-term price volatility is reduced. The mean prices are nearly the same compared with the initial scenario for 2010 (minor increase in the Nordic area as well as minor price decrease in Continental Europe). Assessing the increased marginal production costs of thermal power plants, due to the increased CO_2 costs, results in an increase of average prices in Norway as well as in Germany. The price increase in both countries is by about 20 EUR/MWh. The price volatility is nearly the same as in the initial scenario.



High CO2 – Low Trans

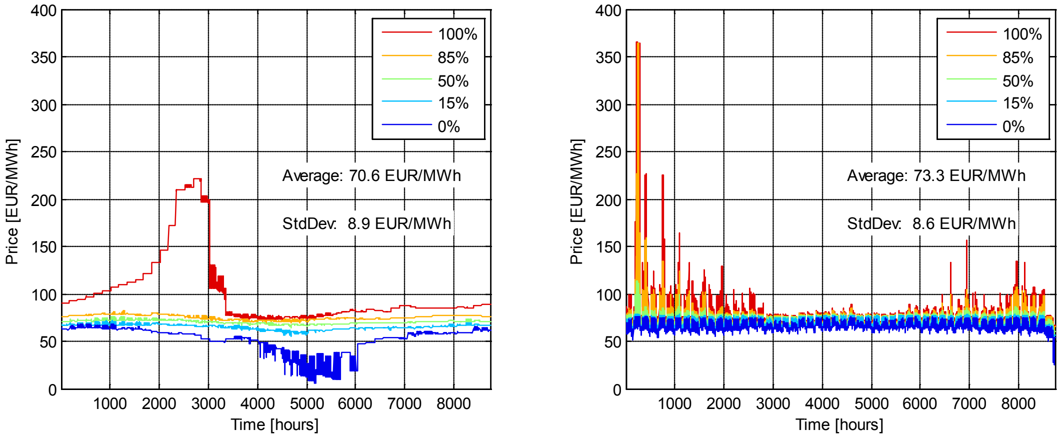


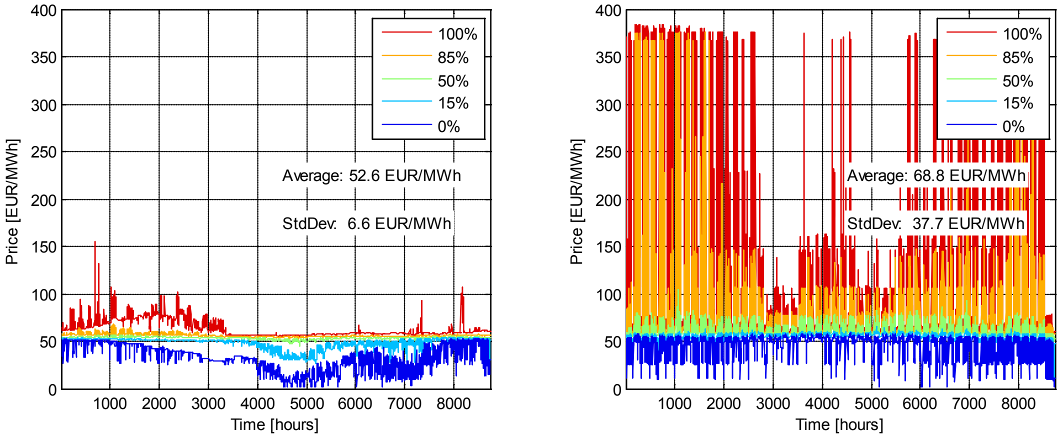
Figure 23. Sensitivity analysis – Scenario 2010

In the 2030 scenario the overall picture for the sensitivity analysis is rather similar. In the case of reduced transmission capacity, the price volatility increases dramatically in both countries, resulting in increased risk of production shortage as well as over production (spillage). However, the change of the mean price levels is slightly higher than in the 2010 scenario.

On the other side reduced production costs of thermal power plants to 2010's levels, reduces price levels significantly. The resulting price levels are actually below the average prices in the 2010 scenario. In addition the price volatility is reduced to some extent.

2030 Norway Germany

High CO2 – High Trans



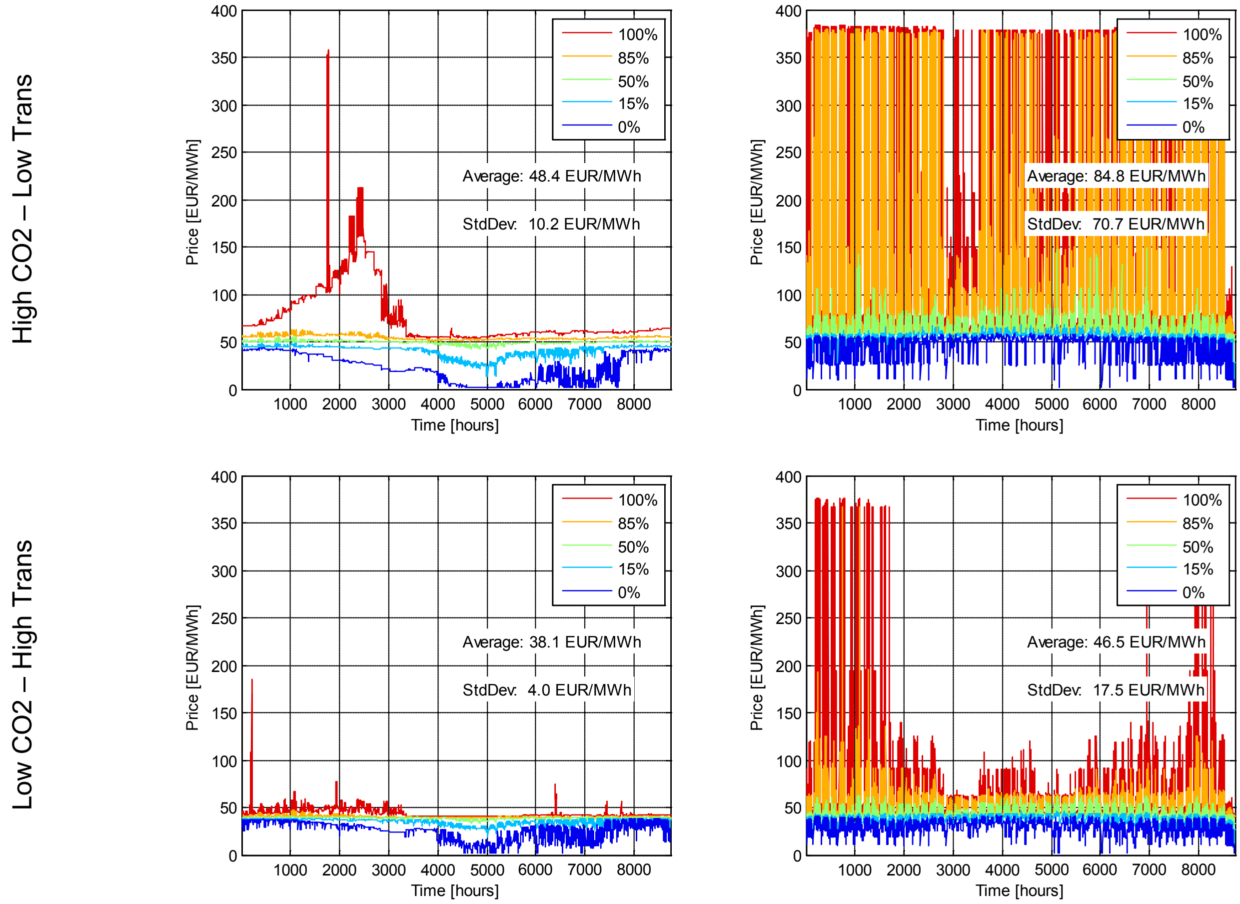


Figure 24. Sensitivity analysis – Scenario 2030

This sensitivity analysis clearly illustrates the reasons for the future development of price levels in Northern Europe. It is shown that the marginal production costs of the thermal power plants also define the price level for hydro power production in the Nordic area, nearly independent of the connection capacity. This is caused by the fact that the water values for the hydro production (which are used as the marginal production costs) are determined by the production costs of alternative power production. In the case of Northern Europe this is thermal power production.

On the contrary, an increase in transmission capacity between the Nordic area and Continental Europe results in a more efficient operation of the power system. Thus, production resources throughout the system can be utilized much better. Hereby, more long-term flexibility is provided to the hydro-system and more short-term flexibility is provided to the thermal system. The increased production flexibility reduces price volatility in the areas.

Part II- DC Power Flow Simulations of the European Power System using PSST (2020 and 2030)

6 Modelling of the European Grid and power market using PSST

The SINTEF *Power System Simulation Tool* (PSST) is a Matlab-based collection of classes and functions [21]. The program is a flow-based electricity market simulation using DC Optimal Power Flow (DCOPF). It takes a detailed grid model as input and computes the optimal generation dispatch and flow along lines consistent with the linear approximation of the power flow equations (also called DC power flow) for each hour. In more technical terms, the optimal solution for each hour is found by minimising the operating cost that essentially expresses the cost of generation based on different marginal generation costs for different countries and generator types. The constraints in the optimisation problem include the power flow equations and other limitations such as generator capacities and transmission capacity constraints across connections between different geographic zones. General references for DC power flow are [22, 23]. The main simulation structure is depicted in Figure 25.

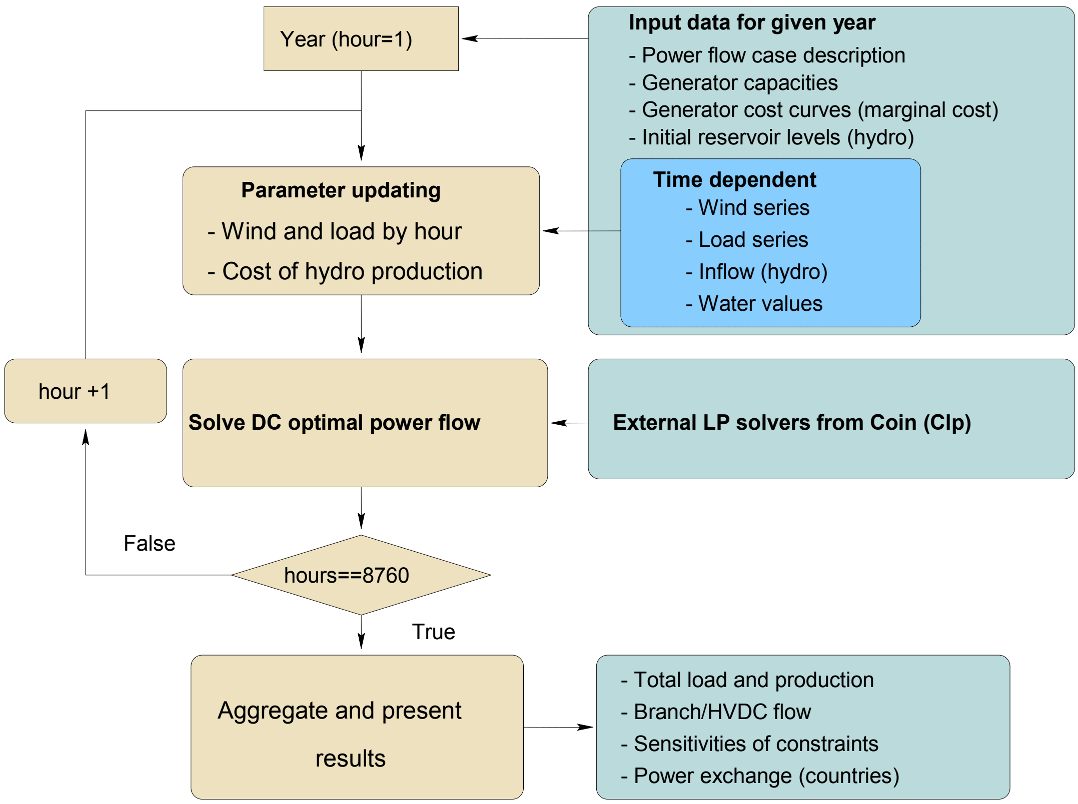


Figure 25. PSST simulation structure [24]

PSST calculates prices in different market areas and the optimal transmission exchange between them. In each market area, there are several suppliers and consumers. The suppliers are categorized by their different fuel types, i.e., nuclear, coal (lignite coal and hard coal), gas-fired, oil, hydro, pump storage, wind, solar and biomass. The market is cleared at each hour of the simulation period. The model includes time dependent varying inputs such as marginal costs of hydro units (water values), hydro inflow, load changes, and forecasted wind power variations for each hour. Production costs and capacities for all production units are given exogenously.

Since there is a limited amount of water storage in hydro reservoirs, its long-term utilisation is essential to be optimised. Therefore, water value calculation is intended for the long-term strategic usage of hydro reservoirs. The dual values of reservoir balancing constraint in each week are the water values for the actual week. The water values reflect the expected future value of hydro power when substituting other production sources [25]. The water values are imported from the EMPS-model[12] and are used as exogenous input to PSST. The EMPS-model is a power market model for hydro-thermal power systems, focusing on the special characteristics of hydro based power production [26]. The water values matrix is a function of reservoir level and the time of year. Figure 26 shows the water value matrix for a reservoir in southern Norway.

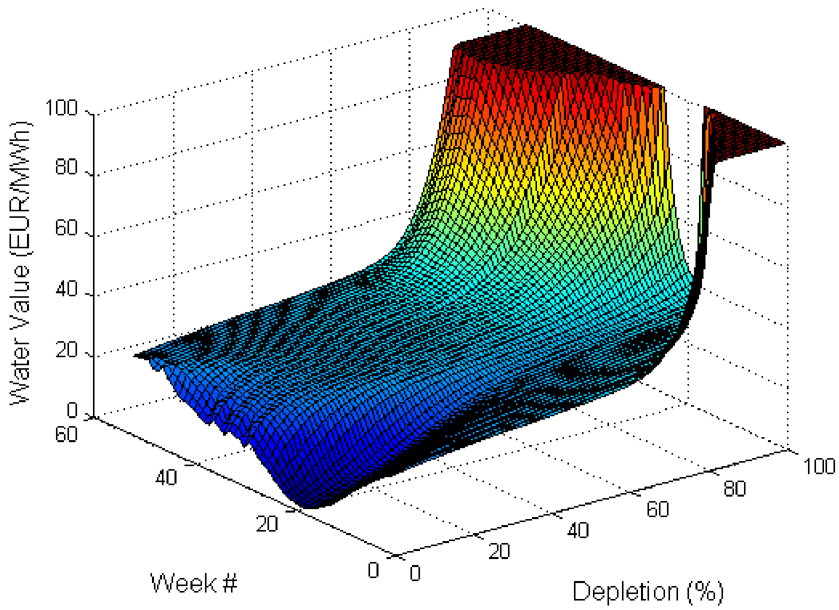


Figure 26. Calculated water values for a reservoir in southern Norway

The program offers the possibility of simulating different inflow scenarios and capturing the effect of inflow seasonal variation. Figure 27 presents the 75 inflow scenarios in the Norwegian electricity system. The thick black line represents the mean inflow values employed in the simulation within this report. Inflow scenarios are allocated to each individual area and divided evenly among the entire hours of a week.

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[12] EFI's Multi-area Power-market Simulator

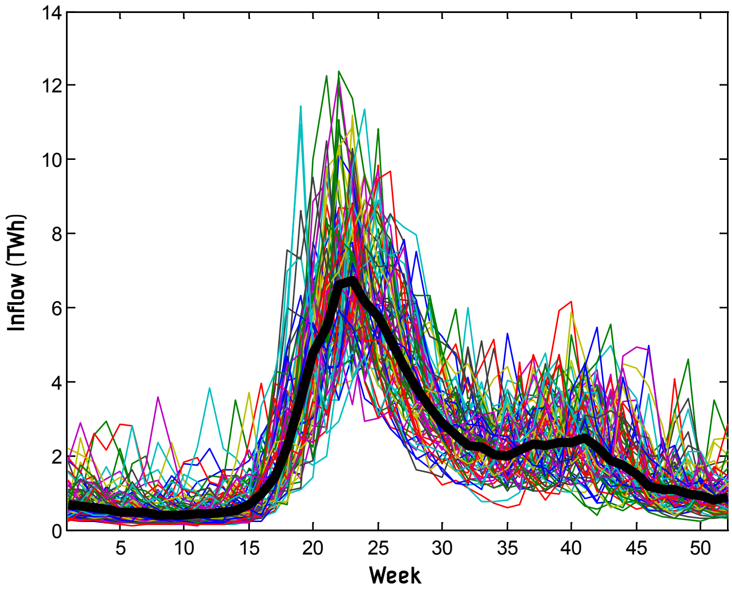


Figure 27. Inflow scenarios in the Norwegian power system

6.1 Mathematical model of PSST

One of the main features of the modelling approach in this part of the report is the use of power flow and the power exchange between the different buses and areas. Power Flow is carried out to calculate the flow of the power in the network (from generators to loads) according to the physical laws, while holding the voltage and current inside allowed intervals. It analyses the power systems in the normal steady-state operation.

The assumption of a linear DC power flow is often used in optimisation problems of power markets when the effect of the transmission networks is taken into account. In most of these models, the focus is on power economics rather than on the exact modelling of the power flow. Instead of using non-linear AC power flow equations, the most critical cases in the transmission network can be captured by the DC power flow approximation. Moreover, the linear DC power flow equations retain the convexity of optimisation problems and are faster to be solved without using iterative processes. This feature is of great value in the operation and planning of electric power systems [22].

The linear optimisation problem given in Equation (1.1) is solved for all iterations of the optimisation loop as depicted in Figure 25.

$$Min\ F = \sum_{i=1}^{N_G} C_i \times P_i^G + \sum_{i=1}^{Nb} C^{rat} \times P_i^L \qquad (0.0)$$

Subject to:

$$P_{i,j}^{Tr} = B_{i,j}(\delta_i - \delta_j) \qquad (0.0)$$

$$P_i^G - \sum_{j=1}^{N_b} P_{i,j}^{Tr} + \sum_{j=1}^{N_b} (P_{j,i}^{hvdc} - P_{i,j}^{hvdc}) - P_i^L = 0 \qquad i = 1 \ldots N_b \qquad (0.0)$$

$$\underline{P}_i^G \le P_i^G \le \overline{P}_i^G \qquad i = 1 \ldots N_G \qquad (0.0)$$

$$\underline{P}_{i,j}^{Tr} \le P_{i,j}^{Tr} \le \overline{P}_{i,j}^{Tr} \qquad i,j = 1 \ldots N_{TR} \qquad (0.0)$$

$$\underline{P}_{i,j}^{hvdc} \le P_{i,j}^{hvdc} \le \overline{P}_{i,j}^{hvdc} \qquad (0.0)$$

$$-NTC_{ba} \le \sum_{i \in Bus_a} \sum_{j \in Bus_b} P_{i,j}^{Tr} \le NTC_{ab} \quad a,b = 1 \ldots N_{area} \qquad (0.0)$$

where:

$B_{i,j}$	The i,j^{th} element of bus susceptance matrix (B)
Bus_a	Set of buses in market area of a
C_i	Marginal generation cost at bus i [€/MWh]
C^{rat}	Rationing cost [€/MWh]
$P_{i,j}^{hvdc}$	Exchange energy on HVDC interconnection between i and j [MWh]
$\overline{P}_{i,j}^{hvdc}$, $\underline{P}_{i,j}^{hvdc}$	Maximum and Minimum transmission capacity of HVDC cable of i,j , respectively
P_i^G	Generated active power at bus i [MWh]
$\overline{P}_i^G$, $\underline{P}_i^G$	Maximum and Minimum generation output at bus i, respectively [MW]
$P_{i,j}^{Tr}$	Exchange energy on AC transmission lines I and j, respectively [MWh]
$\overline{P}_{i,j}^{Tr}$, $\underline{P}_{i,j}^{Tr}$	Maximum and Minimum transmission capacity of lines I and j, respectively
P_i^L	Active power consumption at bus i [MWh]
N_{TR}	Number of transmission lines
N_G	Number of generators
N_b	Number of buses
N_{area}	Number of market areas
NTC_{ab}	NTC (Net Transfer Capacity) from market area a to b [MW]

Equation (1.1) expresses the objective function of the optimisation problem. The cost function is a piecewise linear incremental function including the production costs of thermal units, the water values, as well as the rationing cost of energy not supplied. For each generator the marginal is described by a piecewise linear cost function approximating the quadratic cost of real production (see Figure 28). The respective generator costs are based on a stepwise cost coefficient ranging from 90% of the marginal cost at the minimum production level to 100% of marginal cost at installed capacity. This approach applies to all generator types wind, run of river hydro plants as well as solar power plants. For these production sources a constant cost efficient with a marginal cost close to zero is assumed.

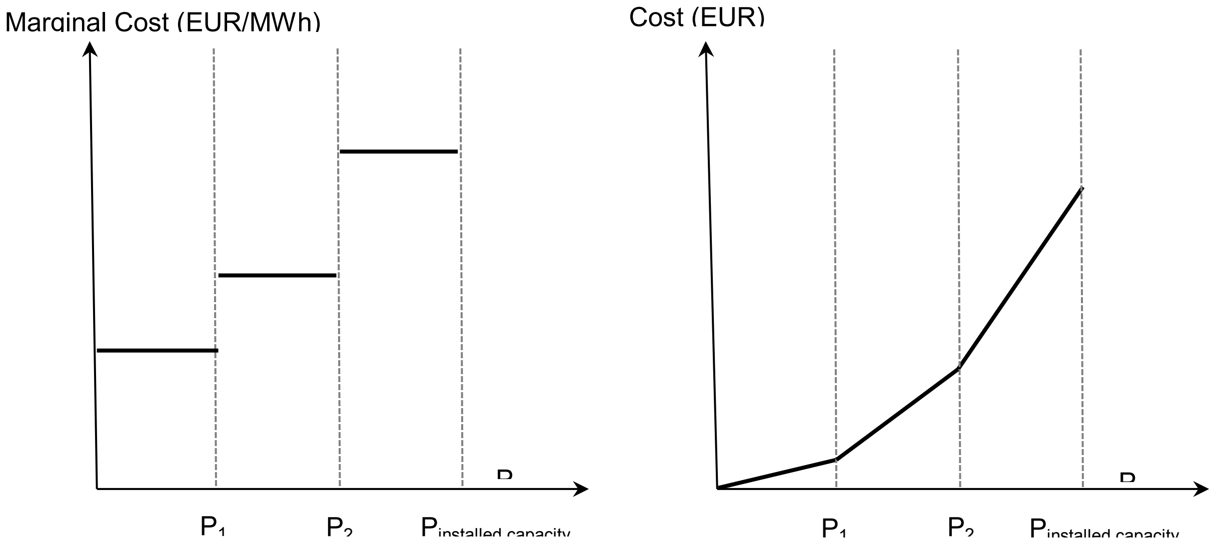


Figure 28. Example of piecewise linear cost function

To ensure that a solution can be found in all situations, a simple version of load shedding (rationing) is included in the model, i.e., the ability to reduce the demand. The associated rationing cost C^{rat} is always exceeds the cost of the most expensive generator. In general, load shedding occurs if there is a mismatch between demand, generation and grid capacity.

The energy exchange between buses *i* and *j* is described by Equation (1.2). Equation (1.3) states the energy balance at each bus. The HVDC flow in Equation (1.3) is modelled by control variables which are determined by the optimisation routines. The HVDC connections are modelled as loads with opposite sign on each side of the connections. Equation (1.4) imposes the power generation limits between the maximum and minimum production capacity. AC and HVDC Line transmission constraints are formulated by Equation (1.5) and Equation(1.6), respectively. Equation (1.7) limits the flows between market areas through the according Net Transfer Capacity (NTC) values. DCOPF does not capture stability constraints, e.g., voltage stability, transient and angular stability. NTC values are established based upon detailed studies of each of the areas in the system, which account for these stability issues or socio-political constraints. These studies are not in the scope of this project, and hence NTC values are considered as inputs to the model. The NTC values are available at ENTSO-E Website[13] for the Continental European system, and for the Nordic system NTC values on zone level are taken from first EMPS model in first part of this report. The NTC constraints are considered in addition to each branch flow constraint, limiting the flow between two areas.

[13] https://www.entsoe.eu/resources/ntc-values/

For each hour the time dependents constraints, i.e., the load, available wind power and hydro generation capacity, are updated before running the optimal power flow. The marginal costs of hydro units (Water value) are a function of the reservoir level and the time of the year. They are updated at each optimisation step. WPP having an hourly time resolution for each area (onshore wind) or node (offshore wind), is defined as the potential wind power output that can be fed into the grid if a sufficient amount of transmission capacity is available.

6.2 Wind power production

Clustered wind farms are modelled as generators with maximum power equal to the available wind power for the specific hour. The available wind power production is provided from wind production time series with hourly time resolution from DTU WP16 Task 16.1. The minimum production is set to zero so that it is possible to reduce the wind power output in constrained areas. The marginal cost is set low, so that wind power plants always will produce if not limited by grid constraints

6.3 Updating hydro reservoir level

Inflow is divided evenly among the hours within the week, and the reservoir level for hydro generators are updated for each hour. The reservoir level is updated each hour, according to the following equation:

$$Rl_i(t+\Delta t) = Rl_i(t) + Q_i(t)\cdot \Delta t - P_i^h \cdot \Delta t \qquad i = 1 \ldots N_h \tag{0.0}$$

where:

- Rl_i Reservoir level of hydro unit *i* (MWh)
- Q_i Inflow to reservoir *i* (MW)
- P_i^h Production at hydro unit *i* (MW)
- Δt Optimisation time step (h)

The inflow is the flow of water into the reservoir, represented as an energy flow (MWh per time step Δt). The production is negative for pumped storage hydro operation. It is also ensured that the maximum production capacity of the hydro unit is limited by the available energy:

$$\bar{P}_i^h(t) = \min\left[P^h_{installed_i}, \frac{Rl_i(t)+Q(t)}{\Delta t}\right] \tag{0.0}$$

Run of river units are implemented as a separate generator type with the maximum production equal to expected non-storable inflow and minimum production set to zero. The same as wind production the marginal cost is set low ensuring that they always will produce provided there is not congestion in the transmission grid.

7 Modelling Development

The European transmission grid model employed in this project consists of five synchronous regions: the Nordic region, RG Continental Europe, Great Britain & Ireland and the Baltic region. The total size of the model for each synchronous area, as they are implemented in the model, is shown in Table 15.

Table 15. Size of PSST simulation model

	# nodes	# generators	# branches
RG Continental Europe	3815	1235	6758
Nordic	451	841	774
Great Britain	1377	316	2071
Ireland	2	6	1
Baltic	6	12	7
SUM	5651	2410	9611

The model encompasses many countries in Continental Europe listed in Table 16.

Table 16. Countries included in TWENTIES study

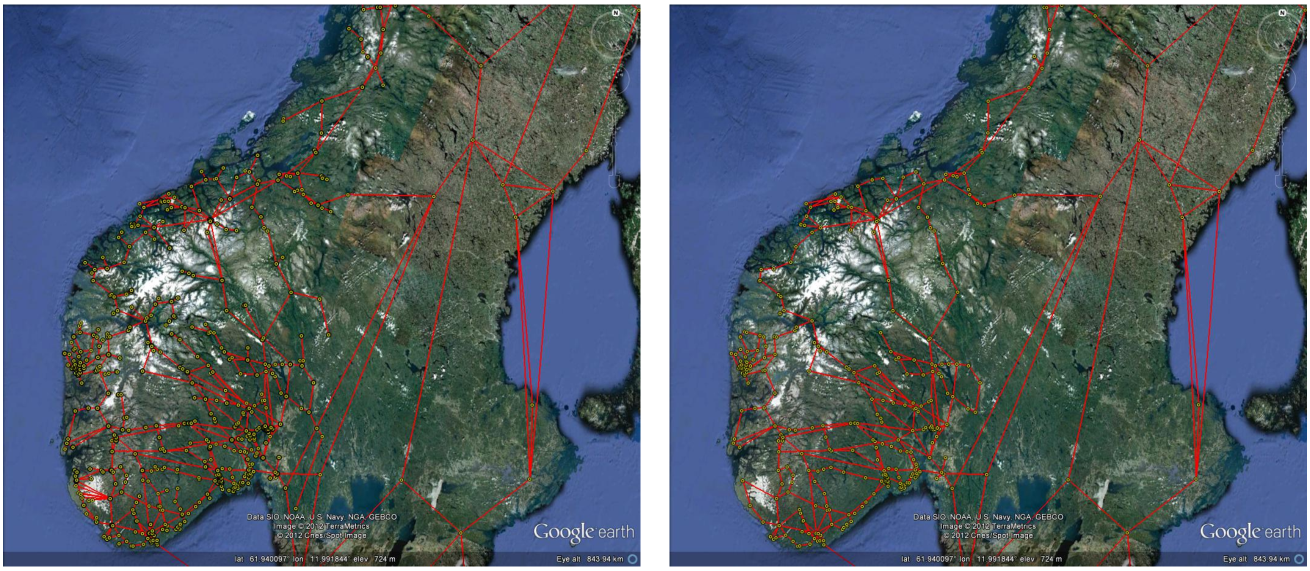
Albania	Finland	Lithuania	Slovak Republic
Austria	France	Macedonia	Slovenia
Belgium	Germany	Monte Negro	Spain
Bosnia-Herzegovina	Great Britain	Netherlands	Sweden
Bulgaria	Greece	Norway	Switzerland
Croatia	Hungary	Poland	Ukraine
Czech Republic	Ireland	Portugal	
Denmark	Italy	Romania	
Estonia	Latvia	Serbia	

7.1 Nordic system

The basis for all calculations performed for the Nordic power system is the Norwegian Water Resources and Energy Directorate (NVE) transmission dataset [1]. The model determines the topology of the grid, and the distribution of loads and generation units except wind. It includes 423 buses in Norway, 22 buses in Sweden, 2 buses in Finland and one bus in Eastern Denmark. The existing model represents an aggregated model based on a full scale model of the Norwegian system. The full scale model consists of 3919 buses and 5818 branches. The aim of aggregation is to leave out the unnecessary details from the NVE-dataset and reduce the computation time. The system aggregation has been implemented in such a way that the model reflects the real power production and the most important bottlenecks in the detailed Nordic power system. This has been implemented in the following steps:

- Removing zero impedance branches
- Cutting of radials
- Aggregate the nodes located at the same location

Removing zero impedance branches aims to remove two buses at both ends of branches with zero impedance and merge them to one bus. Zero impedance branches are frequently used in different power system data sets to model the connection between double bus-bar substations. This reduction does not affect the load flow and can be carried out for all voltage levels. In cutting of radials, all the buses on radial branches are discarded and the according loads and generators connected to those buses are merged in an aggregated connection point. This does not alter the impedance between two points in the rest of the grid and has the potential to remove a large portion of the lower voltage busses, fed from main substations. In NVE dataset many buses are located at the same coordinates. Aggregating these points into one point can change the power flow for the entire grid. We elaborate the effect of this aggregation in the following analyses. Figure 29 shows the Nordic power system model including both the full-scale and aggregated model of the Norwegian power system.



(a) full-scale model of Norwegian power system

(b) aggregated model of Norwegian power system

Figure 29. The Nordic power system model

For a comparison we look at the flow on all branches in the aggregated system to see how the flow compares in the full and the reduced grid. The comparison is presented in Figure 30. We find that 60% of all branches are within ±25% of the original flow, with a small amount of branches lying above or below this value. However, the comparison is implemented in p.u. values and the differences may result from deviations in very small transmission lines.

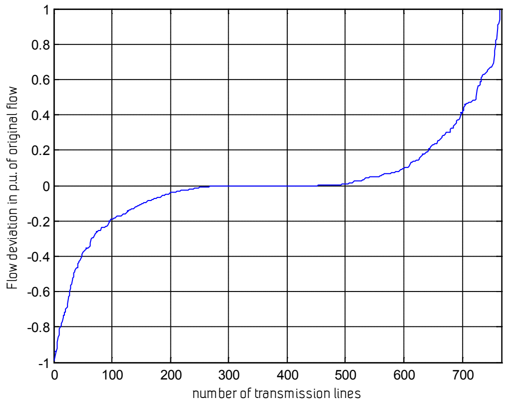
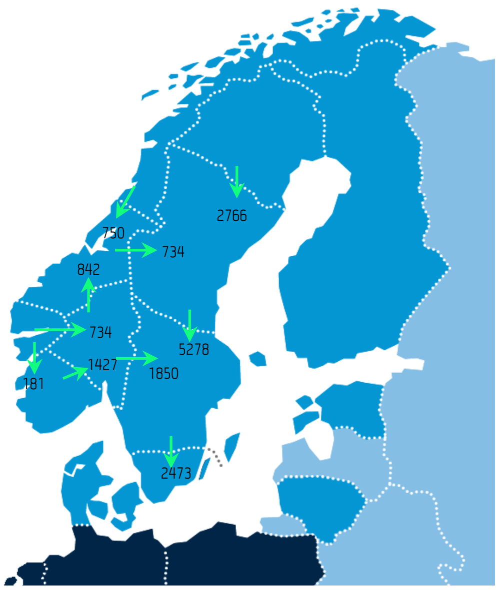
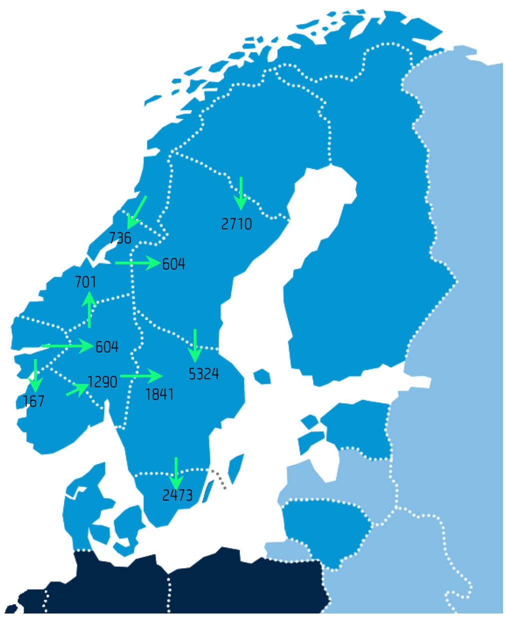


Figure 30. Comparison of the power flow behaviour in full-scale and aggregated model

Figure 31 shows a snapshot of the full-scale model and the aggregated Norwegian system. As shown the power flow corresponds to the flow in a full-scale model with slightly difference. However, the reduced size and good accuracy makes the aggregated model favourable in the context of TWENTIES project. Therefore, the aggregated model is used to reduce the simulations burden in terms of calculation time.



(a) full-scale model



(b) aggregated model

Figure 31. Flow deviation on branches in the aggregated system

The detailed grid model can be aggregated into 11 areas in Norway and six areas in Sweden, corresponding to the EMPS areas defined in Part-I of this report. Figure 1 shows the geographical overview of these areas. The NTC values between the areas are selected corresponding to the values used in EMPS model.

7.2 RG Continental Europe

The system model developed in IEE-EU OffshoreGrid project [5] has been adapted in the TWENTIES project. The UCTE Study Model – Winter (16/01) was employed in OffshoreGrid project. The model represents a snapshot of the power system for that period of year. For the TWENTIES project the same winter scenario is applied while the demand and generation portfolio are provided by other sources.

The focus of this study is to identify how hydro power resources in the Nordic area can support the integration of WPP facilities in the North Sea and the Baltic Sea into the Continental European power system. Therefore, a detailed geographical mapping of the grid data nodes has been performed for countries surrounding the North and Baltic Seas. A detailed mapping of system nodes has been done for Poland, Denmark, Germany, the Netherlands, Belgium, France and Luxembourg. For the remaining European countries the geographical location of grid nodes is less sophisticated.

Due to a lack of information in the original dataset, all the transmission lines within each country were assumed to have unlimited capacity (copper plate model). Only the interconnection lines between two countries have a finite capacity. However, the location of renewable energy generation especially wind facilities strongly depends on regional wind conditions. Hence, the internal congestion in each country can play a significant role to transfer generated power from generation facilities to the load centres. For instance, in Germany significant wind capacities are located in the northern part of the country. On the other hand, electricity demand is mainly located in the mid-western and southern part of Germany. Both aspects will result in an increasing flow of electricity from northern to southern Germany. Therefore, the estimated methodology presented in the DENA grid study [18] and the assumptions made in Part-I for NTC calculation are employed in the model.

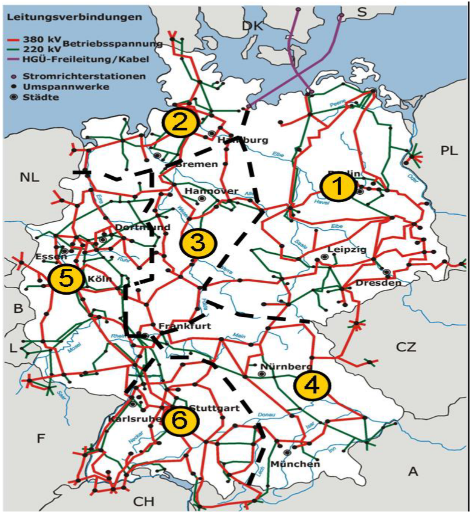


Figure 32. Zones in Germany [24]

Figure 32 shows the German system which is divided into six zones. These areas are determined based on the predicted feed-in of renewable energies and the possible bottlenecks within the German electricity system. The NTC values are determined between each zone.

In order to avoid the effect of loop flow across zones, the transmission capacity on each individual transmission lines has to be determined. An example is the existing bottleneck in the northern border between Germany (DE-2 in Figure 32) and the Netherlands. In mid-west Germany (DE-5 in Figure 32) there are a number of lignite power plants. Neglecting the internal constraints within DE-5 includes the risk that power flows from DE-5 across the Netherlands to DE-2. In this situation the NTCs between those countries limit possible loop flows between the Netherlands and Germany. The transmission capacity is distributed between the transmission lines given in [21] and [27]. Table 17 displays the transmission capacity in Germany.

Table 17. Internal transmission capacity in Germany [MW]

Project-TYNDP	Substation I	Substation II	Voltage [kV]	Capacity [MW]
44. 147	Dollern	Hamburg/Nord	220	312
44. 170	Großgartach	Hüffenhardt	220	500
44. 171	Hüffenhardt	Neurott	220	500
44. 172	Mühlhausen	Großgartach	220	500
	Mühlhausen	Großgartach	220	500
44. 173	Hoheneck	Endersbach	220	500
44. 181	Dauersberg	Limburg	380	950
44. 186	Gütersloh	Bechterdissen	220	500
44. 188	Kruckel	Dauersberg	220	1645
44. A78	Weissenthurm	Niederstedem	220	500
44. A77	Area of South- Wuerttemberg		380	1645

			380	1645
			380	1645
			380	1645
44. 190	Saar-Pfalz-Region		220	500
44. 189	Niederrhein	Utfort	380	950
TradeWind	Dollern	Wilster	380	1316
	Conneforde	Diele	380	1382
	Ovenstädt	Bechterdissen	380	1790
	Grohnde	Würgassen	380	1698
	Wahle	Gronde	380	1790
	Wahle	Hattdorf	380	1790
	Helmstedt	Wolmirstedt	380	1343
	Remptendorf	Röhrsdorf	380	1698
	Remptendorf	Redwitz	380	1659
	Pasewalk	Vieraden	220	343
	Bertikow	Neuenhagen	220	408
	Pulgar	Vieselbach	380	1659
	Bärwalde	Schmölln	380	1659
	Remptendorf	Overhaid	380	1659
	Diele	Oberlangen	380	1382
	Oberlangen	Meppen	380	1382
	Dollern	Landsbergen	380	1369
	Landsbergen	Ovenstädt	380	1698
	Berhausen	Borken	380	1659
	Röhrsdorf	Streumen	380	1659
	EUla	Streumen	380	1659
	Stadorf	Wahle	380	1698
	Großkrotzenburg	Urberach	380	1790
	Gersteinweg	Mengede	380	1698
	Uentrup	Unna	380	1698
	Hanneckenfähr	Gronau	380	1698
	Haneckenföhr	Roxel	380	1698
	Gersteinwerk	Roxel	380	1698

For the future scenarios, the Netherlands is expected to serve as a hub to transfer generated wind energy from the North Sea to the Continental system. In this respect, it is important to consider the inner-Dutch transmission capacity presented in Table 18. The transmission capacity is determined according to the information available in [27] and [28].

Table 18. Internal transmission Capacity in Germany [MW]

Project-TYNDP	Substation I	Substation II	Voltage [kV]	Capacity [MW]
103-439	Borssele (NL)	Geertruidenberg (NL)	400	1645
103-440	Bleiswijk	Wateringen	380	1645
	Bleiswijk	Wateringen	380	1645
	Bleiswijk	Wateringen	380	1645
	Bleiswijk	Wateringen	380	1645
	Wateringen	Westerlee	380	1645
	Westerlee	Maasvlakte	380	1645
103-441	Zwolle (NL)	Hengelo (NL)	380	1645
	Zwolle (NL)	Hengelo (NL)	380	1645
103-442	Krimpen aan de Ijssel (NL)	Maasbracht (NL)	380	1645
	Krimpen aan de Ijssel (NL)	Maasbracht (NL)	380	1645
103-438	Diemen	Ens 380 kV	380	1645
	Diemen	Ens 380 kV	380	1645
	Diemen	Ens 380 kV	380	1645
	Diemen	Ens 380 kV	380	1645
	Oudehaske	Ens	220	953
	Oudehaske	Ens	220	953
	Louwsmeer	Oudehaske	220	953
	Louwsmeer	Oudehaske	220	953
	Louwsmeer	Bergum	220	953
	Louwsmeer	Bergum	220	953
	Bergum	Vierverlaten	220	953
	Bergum	Vierverlaten	220	953
	Vierverlaten	Robbenplaat	220	953
	Vierverlaten	Robbenplaat	220	953
	Vierverlaten	Eemshaven	220	884
	Eemshaven	Robbenplaat	220	953
	Eemshaven	Robbenplaat	220	953
TenneT	Beverwijk	Oostzaan	380	1900
	Crayestein	Krimpen	380	2635
	Crayestein	Krimpen	380	2635
	Dodewaard	Doetinchem	380	1645
	Dodewaard	Doetinchem	380	1645
	Doetinchem	Hengelo	380	1645
	Doetinchem	Hengelo	380	1645
	Eemshaven	Meeden	380	2635
	Eemshaven	Meeden	380	2635
	Ens	Zwolle	380	1645

	Ens	Zwolle	380	1645
	Geertruidenberg	Eindhoven	380	1645
	Geertruidenberg	Eindhoven	380	1645
	Geertruidenberg	Eindhoven	380	1645
	Krimpen	Bleiswijk	380	2635
	Krimpen	Bleiswijk	380	2635
	Krimpen	Diemen	380	1645
	Krimpen	Geertruidenberg	380	1645
	Krimpen	Geertruidenberg	380	1645
	Krimpen	Oostzaan	380	1645
	Maasbracht	Dodewaard	380	1645
	Maasvlakte	Crayestein	380	2635
	Maasvlakte	Crayestein	380	2635
	Oostzaan	Diemen	380	1900
	Zwolle	Meeden	380	2635
	Hessenweg	Ens	220	953
	Hessenweg	Ens	220	953
	Zeyerveen	Hessenweg	220	457
	Schildmeer	Weiwerd	220	884
	Weiwerd	Meeden	220	1525
	Weiwerd	Meeden	220	1525
	Vierverlaten	Zeyerveen	220	457
	Vierverlaten	Zeyerveen	220	457

Figure 33 depicts the internal transmission constraints in the German and Dutch power systems. As shown, the transmission constraints in Germany are considered between the northern and the southern parts. Furthermore, the southern part it is divided into eastern and western areas representing grid constraints for transmitting hydro power from the Alps (Switzerland and Austria) to inland in Germany. The orange lines in the Netherlands represent grid bottlenecks limiting the transmission of WPP from coastal areas to the rest of the Continental European system.

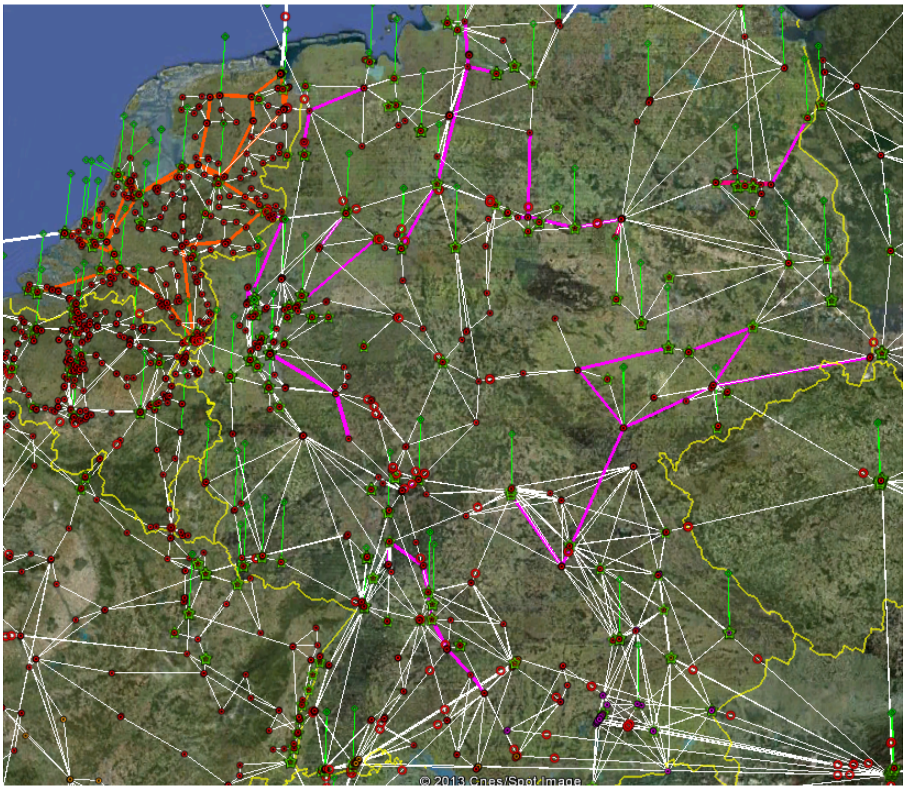


Figure 33. Internal transmission capacity in Germany and the Netherlands (lines in purple are the transmission line in Germany and in orange are the lines in the Netherlands)

7.3 Great Britain & Ireland

Great Britain and Ireland refer to the two geographical islands. Network data for Great Britain describing the transmission system, the demand and the generation by fuel type, is available from the 2009 Seven Year Statement at the National Grid website [29]. For Ireland no data describing the network has been made available to the project. However, as this is a fairly small network, a two bus equivalent, one for the Republic of Ireland and the other for Northern Ireland, was assumed to be adequate enough for the purpose of studying the power markets within this project. With only two buses in the system the value of the impedance between them does not influence the result of the market model since it is assumed lossless. In other words, this part of the system is purely modelled as a transport model.

Great Britain is divided into three zones as depicted in Figure 34. At the B4 boundary the Scottish Hydro Electricity Transmission (SHETL) connect with the Scottish Power Transmission (SPT) having a transfer capacity of 1550 MW in 2010. Likewise, The B6 boundary represents the SPT and the National Grid Electricity Transmission (NGET) interface. The boundary transfer capability in 2010 is 2200 MW [29]. The grid configuration is shown in Figure 34 where the red lines represent the lines with limited capacity according to the data available in [29]. The white lines represent the line with infinitive capacity.

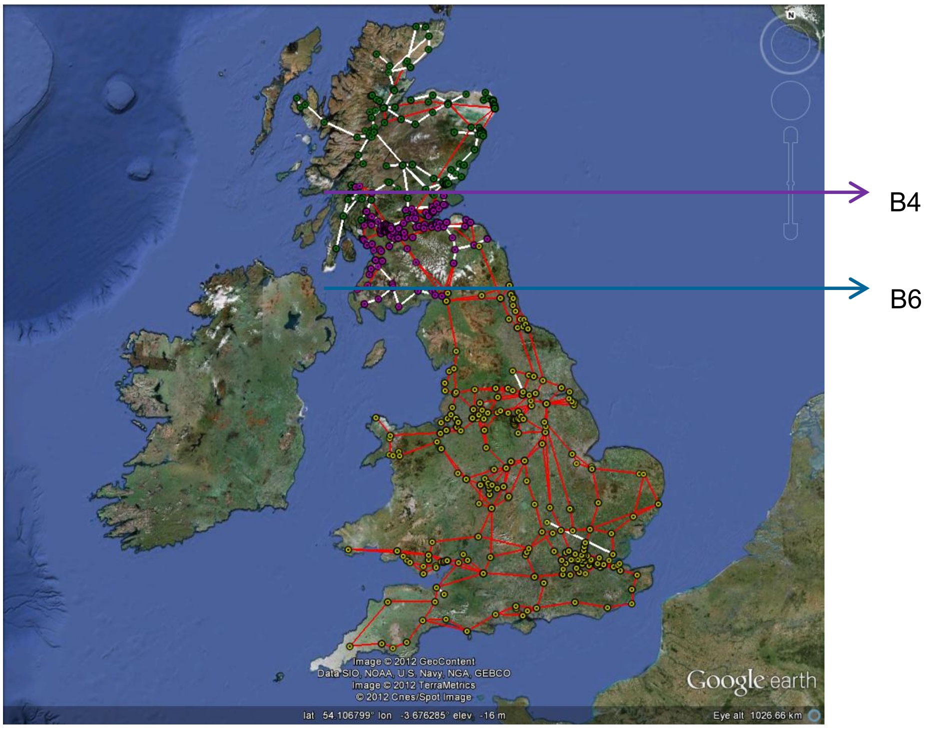


Figure 34. Zones in Great Britain

7.4 Baltic

For the Baltic countries Estonia, Latvia and Lithuania a reduced equivalent model as shown Figure 35 is used. The demand is equally distributed between the four nodes in Estonia, while the main generation is located in Tallinn (hydro), Tartu (lignite coal) and Narva (gas-fired, hard coal, bio mass) [5]. There is also a 350 MW HVDC connection between Finland and Tallinn, connecting the Nordic countries and the Baltic region.

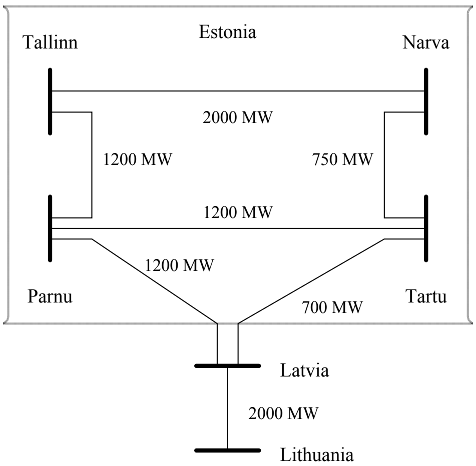


Figure 35. Baltic reduced network equivalent [5]

8 Projected Power Production

The projected production scenarios are prepared based on the outlook of the European Commission [4]. The existing generation portfolio is adapted by the decommissioning of aging generators and the installation of new generators in order to match the net generation capacity presented in[4].

The ADAPT dataset, based on [6], is adapted for the German, the Dutch, the Belgian and the Nordic systems. The thermal generators in the dataset are connected to the geographically nearest bus in the PSST grid model. The total generation cost is computed based on the marginal costs for all the generators in ADAPT dataset. The marginal costs are defined per generator according to:

$$\text{Marginal cost} = \text{fuel cost/fuel efficiency} + \text{CO2 cost} \qquad (0.0)$$

The *CO2 cost* is expected to be increase to 44 EUR/t_{CO2}, both in 2020 and 2030 from 13.5 EUR/t_{CO2} in 2010, while the fuel costs are assumed to be constant from 2010 onwards.

For the other power plants in the Continental system which do not exist in ADAPT dataset, the marginal costs are determined based upon a linear regression of the existing costs taking the production capacities into account. The connection points of these power stations correspond to the proposals from the OffshoreGrid project. The installed capacity per country and type can be found in Table 55 and Table 56 for the future scenarios in 2020 and 2030, respectively. The generation is modelled individually for each power plant based on the data from the ADAPT and the OffshoreGrid input dataset.

8.1 Wind power production

The wind power scenarios for the target years 2020 and 2030 are based on the assumptions made in [14]. The estimated WPP time series includes both, onshore and offshore wind energy production. The dataset covers whole Continental Europe while the installed capacities are scaled up to meet the estimated capacity published in [13]. The scenarios are split in a baseline scenario - the most likely to happen- and a high scenario representing an optimistic scenario. Table 19 represents the scenarios for the installed wind power capacity per country, divided in total installed capacity and offshore wind capacity.

Table 19. Wind power development per country [GW]

Country	2020				2030			
	Total installed Capacity		Offshore wind power		Total installed Capacity		Offshore wind power	
	Base	High	Base	High	Base	High	Base	High
AT	3.50	4	0	0	4.61	5.09	0	0
BE	4.26	4.66	2.16	2.16	6.72	7.01	3.96	3.96

BG	3	3.50	0	0	3.95	4.36	0	0
CH	0.3	0.3	0	0	0.4	0.44	0	0
CZ	1.6	1.8	0	0	2.11	2.33	0	0
DE	49.8	55	8.81	13	78.01	92.01	24.06	32.38
DK	6.51	7.21	2.81	3.21	9.48	11.19	4.61	5.81
ES	39	41	0	0	51.32	56.72	0	0
EE	0	0	0	0	1.7	1.7	1.7	1.7
FI	2.35	2.95	0.85	1.45	5.58	7.34	3.61	5.16
FR	22.93	23.94	3.94	3.94	30.65	34.67	5.65	7.04
GB	30.06	37.68	16.31	22.78	54.29	71.77	36.2	51.77
GR	6.50	8.30	0	0	8.55	9.45	0	0
HU	0.6	0.6	0	0	0.79	0.87	0	0
IE	6.37	7.48	2.12	2.38	8.81	10.66	3.22	4.48
IT	15	17	0	0	19.74	21.81	0	0
LT	0	0	0	0	1	1	1	1
LV	0	0	0	0	1.10	1.10	1.10	1.10
NL	8.8	10.3	5.3	6.80	17.40	22.38	12.79	17.29
NO	3.6	5.14	0.42	1.02	9.49	12.27	5.31	7.64
PL	10.5	12.5	0.5	0.5	18.46	19.84	5.30	5.30
PT	7.5	9	0	0	9.87	10.91	0	0
RO	3	3.50	0	0	3.95	4.36	0	0
SE	9.08	11.13	3.08	3.13	14.76	16.94	6.87	8.22
SI	0.5	0.7	0	0	0.66	0.73	0	0
SK	0.8	1	0	0	1.05	1.16	0	0
sum	235.55	268.67	46.28	60.36	364.41	428.11	115.36	152.84

8.1.1 Onshore wind production

Onshore wind power production values are given per country or per zone. For instance, wind production in Germany was divided into six areas while Ireland was split into the Republic of Ireland and Northern Ireland. The installation scenarios correspond to the OffshoreGrid project [5].

The wind power facilities in each country are scaled up to assure that the total installed capacity within a country/ zone equals the given future scenarios. The distribution of WPP facilities corresponds to the assumptions made in the OffshoreGrid project [5]. The production data is normalised by the installed capacity in each country or zone.

8.1.2 Offshore wind production

For offshore wind farms, the hourly WPP pattern (potential production) was provided by deliverable 16.1 for each individual wind farm. A detailed list of the considered offshore wind farms is presented in [14]. However, some necessary modifications have been implemented for being able to apply the same offshore grid arrangement as the one presented in OffshoreGrid. For instance, the total production in the Dogger Bank offshore node is split into 5 different offshore wind clusters as presented in Table 20.

Table 20. Wind clusters connected to Dogger Bank offshore node

Wind clusters	Offshore node Connection	Installed capacity 2030 [MW]	
		Base line	High
Dogger Bank A	O: GB_DoggerbankA	844	888
Dogger Bank E	O: GB_DoggerbankE	1692	1781
Dogger Bank B	O: GB_HGB001_Dogger Bank B	1688	1777
Dogger Bank C	O: GB_HGB002_Dogger Bank C	1688	1777
Dogger Bank D	O: GB_HGB003_Dogger bank D	1688	1777
Sum		7600	8000

Moreover, two new large wind clusters have been added to the Norwegian power system. These two clusters are listed in Table 21. O: NO_Idunn is connected as coupling point linking Norway and the Dogger Bank offshore node in the UK. This is done to connect oil rigs in the Norwegian sector of the North Sea, i.e., Cod, Ekofisk, West Ekofisk, Tor, Albuskjell, Eldfisk, Edda and Embla. Furthermore, O: NO_Aegir is added connecting the offshore node directly with the Norwegian onshore grid.

Table 21. Additional wind clusters in the Norwegian system

Wind clusters	Offshore node Connection	Installed capacity 2030 [MW]	
		Base line	High
Idunn	O: NO_Idunn	500	720
Ægir	O: NO_AEgir	1100	1100
Sum		1600	1820

8.2 Solar power production

Solar power production is modelled using solar radiation time series and installed solar production capacity. The solar radiation time series are taken from the Susplan project [12], where recorded data is available for 21 years (from 1984 to 2005). The solar power production is modelled for the countries with a significant share of PV. These countries include Germany, Spain, France, Italy, Portugal, and Greece. The existing solar power plants are scaled up to meet the numbers presented in Table 55 and Table 56. A list of generators in each country is presented in Table 22.

Table 22. Installed solar power production per country [GW]

Country	Stations	Installed Capacity [GW]

		2020	2030
Germany	Strasskirchen Solar Park	4.16	5.55
	Lieberose Photovoltaic Park	4.09	5.44
	Kothen Solar Park	3.47	4.62
	Finsterwalde Solar Park	3.24	4.31
	Muldentalkreis	3.08	4.11
	Arnstein	0.93	1.23
	Pocking	0.77	1.03
	Mühlhausen	0.49	0.65
	Bürstadt	0.39	0.51
	Espenhain	0.39	0.51
	Merseburg	0.31	0.41
	Gottelborn	0.31	0.41
	Hemau	0.31	0.41
	Dingolfing	0.25	0.34
	Guenching	0.15	0.20
	Minihof	0.15	0.20
Spain	Olmedilla Photovoltaic Park	1.11	1.35
	Puertollano Photovoltaic Park	0.87	1.05
	Planta Solar La Magascona & La Magasquila	0.64	0.77
	Planta Solar Dulcinea	0.59	0.71
	Merida/Don Alvaro Solar Park	0.55	0.67
	Planta Solar Ose de la Vega	0.55	0.67
	Arnedo Solar Plant	0.55	0.67
	Planta Fotovoltaico Casas de Los Pinos	0.52	0.63
	Planta solar Fuente Álamo	0.48	0.58
	Planta fotovoltaica de Lucainena de las Torres	0.43	0.52
	Parque Fotovoltaico Abertura Solar	0.43	0.52
	Parque Solar Hoya de Los Vicentes	0.42	0.52
	Huerta Solar Almaraz	0.41	0.50
	Parque Solar El Coronil 1	0.39	0.48
	Solarpark Calveron	0.39	0.48
	El Bonillo Solar Park	0.37	0.45
	Huerta Solar Almaraz	0.37	0.45
	Planta solar fotovoltaico Calasparra	0.37	0.45
	Planta Solar La Magascona	0.37	0.45
	Beneixama photovoltaic power plant	0.37	0.45
	Planta de energía solar Mahora	0.28	0.34

	Planta Solar de Salamanca	0.25	0.31
	Parque Solar Guadarranque	0.25	0.30
	Lobosillo Solar Park	0.23	0.28
	Parque Solar Fotovoltaico Villafranca	0.22	0.27
	Monte Alto photovoltaic power plant	0.18	0.21
France	Gabardan Solar Park	0.96	2.31
	Toul-Rosieres	1.64	3.95
	Les Mees	1.28	3.09
	Chateaudun Solar Park	0.71	1.72
Italy	Montalto di Castro Photovoltaic Power Station	0.88	1.52
	Rovigo Photovoltaic Power Plant	0.74	1.28
	Serenissima Solar Park	0.50	0.87
	Cellino San Marco Solar Park	0.45	0.78
	Alfonsine Solar Park	0.38	0.65
	Sant'Alberto Solar Park	0.36	0.63
	Anguillara PV power plant	0.16	0.27
	Priolo PV power plant	0.14	0.24
	Loreo PV power plant	0.13	0.23
	Craco PV power plant	0.13	0.22
	Manzano PV power plant	0.12	0.20
	Gamascia PV power plant	0.10	0.18
	Ragusa PV power plant	0.09	0.15
Portugal	Serpa solar power plant	0.16	0.23
	Moura Photovoltaic Power Station	0.29	0.41
	Beja	1.69	2.40
Greece	Florina	0.02	0.03
	Volos	0.01	0.02
	Thebes	0.01	0.02
	Koutsopodi	0.01	0.02
	Tripoli	0.01	0.02
	Pournari	0.01	0.01
	Pontoiraklia	0.00	0.01
	Kythnos	0.00	0.00
	Sifnos	0.00	0.00
	Tavros, ILPAP Building	0.00	0.00
	Maroussi	0.00	0.00
	Kozani	1.27	1.97
	Megalopoli	0.25	0.39

9 Demand Scenarios

The hourly demand profile together with the demand distribution for each node is based on the according load profile employed in OffshoreGrid project [5] . The total demand in each country is a combination of the data utilised in Part-I of this report and Offshore Grid project. Table 23 presents the assumed consumption per country for the 2020 and 2030 scenario, respectively.

Table 23. Energy consumption development per country [TWh]

Country	2020	2030
AT	71.31	76.38
BA	14.85	16.5
BE	100.62	114.74
BG	36.1	39.48
CH	69.4	75.2
CZ	78.12	86.68
DE	647.64	678.48
DK	37.34	41.64
EE	9.44	10.66
ES	349.4	406.56
FI	93.26	93.26
FR	547.83	604.12
GB	378	399
GR	76.33	86.7
HR	22.73	25.25
HU	46.64	51.94
IE	33.64	38.46
IT	390.03	436.41
LT	12.25	13.49
LU	6.29	6.99
LV	4.23	4.45
MK	7.32	7.7
NL	119.88	125.28
NO	111.73	114.89
PL	164.51	187.83
PT	60.2	70.32

RO	64.68	71.21
RS	44.77	45.01
RU	55.01	55.01
SE	151.62	155.91
SI	17.38	18.22
SK	36.77	41.16
UA	3.65	4.2
NI	8.73	9.7

10 Scenarios for additional hydro capacity in Norway

Stronger interconnections combined with a large-scale development of wind power in neighbouring countries connected with Norway will increase the demand for flexible hydro power production, e.g., to provide balancing services. Increased hydro peaking will have an impact on the local ecosystem due to increased variations of the hydro reservoir level and river regulations. Tougher restrictions on the running of hydro power stations based on local environmental impacts may lead to a more limited utilisation of the hydro reservoirs. In this context, the CEDREN[14] project [3], which is conducted at SINTEF Energy research, is selected as a basis. The study includes 19 specific power plants in southern Norway and analyses the potential of hydro production expansion. The study includes three different case studies ranging from a capacity expansion of 11.2 GW to 18.2 GW. According to the CEDREN report, it is technically feasible to increase the power production of the Norwegian hydroelectric power stations by 18.2 GW without requiring new regulated reservoirs, without violating the existing environmental restrictions while including limits for the highest and lowest regulated water level. This assumptions have been taken into account in [30] for developing scenarios of targeted years, 2020 and 2030. The same scenarios developed in [30] are implemented in the following case studies.

Similar to the EMPS model described in Part-I, the PSST model distinguishes between the expansion of installed production capacity and the expansion of pumping capacity. When the pumping capacity is increased, the hydro production capacity is increased by the identical capacity. The overview of capacity expansion is presented in Table 24 and Table 25. The expanded capacity is proportionally divided among generators in one water course based on their capacity.

Table 24. Hydro power expansion and pumping in southern Norway (11.2 GW)

Cedren Case	Station name	Bus ID (PSST)	Hydro production expansion [MW]		Pumping	Expanded Cap. [MW]
			Existing Cap.	New Cap	[MW]	

[14] http://www.cedren.no/

A2: Tonstad	Tonstad	Nordel: 9287	960	2100	1140	1140
	Solholm	Nordel: 9288	200	460	260	260
B3: Holen	Holen	Nordel: 9124	150	429.26	279.26	279.26
	Holen	Nordel: 9124	226	646.74	420.74	420.74
B6a & B7a: Kvilldal & Jøsenfjorden	Kvilldal	Nordel: 9345	1240	3200	980	1960
	Saurdal	Nordel: 9344	640	1480	420	840
C1: Tinnsjø	Mæl(ÅMÆLA)	Nordel: 9398	34	114	80	80
	Moflåt	Nordel: 9204	25	84	59	59
	Såheim	Nordel: 9208	159	533	374	374
	Vemork	Nordel: 9218	183	613	430	430
	Frøystul	Nordel: 9218	24.5	81.5	57	57
D1: Lysebotn	Lysebotn	Nordel: 9285	210	1610	0	1400
E1: Mauranger	Mauranger	Nordel: 9353	250	650	400	400
E2:Oksala	Oksla	Nordel: 9542	200	900	0	700
E3:Tysso	Tysso 2	Nordel: 9542	180	880	0	700
F1: Sy-Sima	Sy-Sima	Nordel: 9277	620	1320	0	700
G1: Aurland	Aurland	Nordel: 9276	284	506.37	0	222.37
	Aurland	Nordel: 9276	70	124.81	0	54.81
	Aurland	Nordel: 9276	80	142.64	0	62.64
	Aurland	Nordel: 9276	460	820.18	0	360.18
G2: Tyin	TYIN132	Nordel: 9513	194	894	0	700
Sum						11200

Table 25. Hydro power expansion and pumping in southern Norway (18. 2 GW)

Cedren Case	Station name	Bus ID (PSST)	Hydro production expansion [MW]		Pumping [MW]	Expanded Cap. [MW]
			Existing Cap.	New Cap		
A2: Tonstad	Tonstad	Nordel: 9287	960	2100	1140	1140
	Solholm	Nordel: 9288	200	460	260	260
B3: Holen	Holen	Nordel: 9124	150	548.94	398.94	398.94
	Holen	Nordel: 9124	226	827.06	601.06	601.06
B6a & B7a: Kvilldal & Jøsenfjorden	Kvilldal	Nordel: 9345	1240	4600	1680	3360
	Saurdal	Nordel: 9344	640	2080	720	1440
C2: Tinnsjø	Mæl	Nordel: 9398	34	194	160	160
	Moflåt	Nordel: 9204	25	143	118	118
	Såheim	Nordel: 9208	159	907	748	748
	Vemork	Nordel: 9218	183	1043	860	860
	Frøystul	Nordel: 9218	24.5	138.5	114	114
D1: Lysebotn	Lysebotn	Nordel: 9285	210	2010	0	1800
E1: Mauranger	Mauranger	Nordel: 9353	250	650	400	400
E2:Oksala	Oksla	Nordel: 9542	200	900	0	700
E3:Tysso	Tysso 2	Nordel: 9542	180	1180	0	1000
F1: Sy-Sima	Sy-Sima	Nordel: 9277	620	1620	0	1000
G1: Aurland	Aurland	Nordel: 9276	284	506.37	0	222.37
	Aurland	Nordel: 9276	70	124.81	0	54.81
	Aurland	Nordel: 9276	80	142.64	0	62.64
	Aurland	Nordel: 9276	460	820.18	0	360.18
G2: Tyin	TYIN132	Nordel: 9513	194	1194	0	1000
C3: Tinnsjø	MÅR132A	Nordel: 9204	180	2580	2400	2400
Sum						18200

11 HVDC interconnections

In the addition to the existing HVDC interconnections, the 2020 scenario includes the commissioning of the new HVDC links listed in Table 26. The new HVDC lines are based on the transmission expansion plan of ENTSO-E [27].

Table 26. List of new HVDC interconnection in 2020

HVDC Cable Name	Connecting Countries	Capacity [MW]
Skagerrak 4	Norway - Denmark	700
NorGer	Norway - Germany	125
NorBrit	Norway - The UK	1400
NorNed2	Norway-the Netherlands	700
Cobra	Denmark - the Netherlands	700
Nemo	The UK - Belgium	1000
Moyle	The UK - Ireland	500
Sydlink	Norway - Sweden	1100
East Coast	England - Scotland	1800
Fenno-Skan	Sweden - Finland	800
IFA2	The UK - France	1000
HGS-1	Italy - Croatia	1000
HGS-2	Italy - Montenegro	1000
HGS-3	Italy - Greece	500

11.1 Offshore super grid

.A relevant source for establishing of offshore structures in the North Sea and Baltic Sea is the IEE-EU OffshoreGrid project. In the project in-depth analyses of how to build a cost-efficient grid in the North and Baltic Seas were performed [5]. The proposed offshore grid has been used as a basis for the actual simulations. Therefore, the interconnections between countries are extended by the offshore grid design arrangement. In this association, the HVDC interconnections between countries considered in the 2020 scenario are expanded by "The split Design" arrangement in the 2030 (see Figure 5) [5].

The proposed offshore grid configuration includes connections to the major wind hubs in the North Sea. The case study analysis has been carried out for HVDC interconnections including the Dogger Bank hub in the UK, Gaia in Germany, Idunn and Ægir in Norway and Ijmuiden in the Netherlands.

12 Grid reinforcement scenarios

In an analysis of future scenarios including an increasing demand and generation, especially large offshore WPP, it is generally important to include reinforcements in the inland grid to avoid an unrealistic amount of grid bottlenecks constraining the power flow in the system.
It is almost impossible to access each individual line expansion plan. The applied approach is to include grid reinforcements by removing capacity constraints within areas with no detailed grid expansion plan (consider it as copperplate). However, the future projects of transmission capacity expansion published in [16], [18] and [27] are taken into account.

12.1 Norway

The grid reinforcement in Norway is in accordance to Statnett's network development plan [16]. In this report the grid expansion is considered by upgrading the voltage level.
We assume the following transmission capacities for each voltage level per circuit as:

- 132 KV – 150 MW
- 300 KV – 500 MW
- 420 KV – 1000 MW

The expansion mainly focuses to the corridors from northern Norway (Varanger) to central Norway (Sunndalsøra) and further down to the south of Norway (Oslo), including expansions along the southern coast (from Skien to Feda). Furthermore, the grid expansion includes a transmission corridor connecting the existing and the proposed hydro power facilities in Southern Norway. The corridor is represented by the yellow line in Figure 36. The transmission capacity on each line is upgraded to 1GW based on the assumed voltage level of 420 KV.

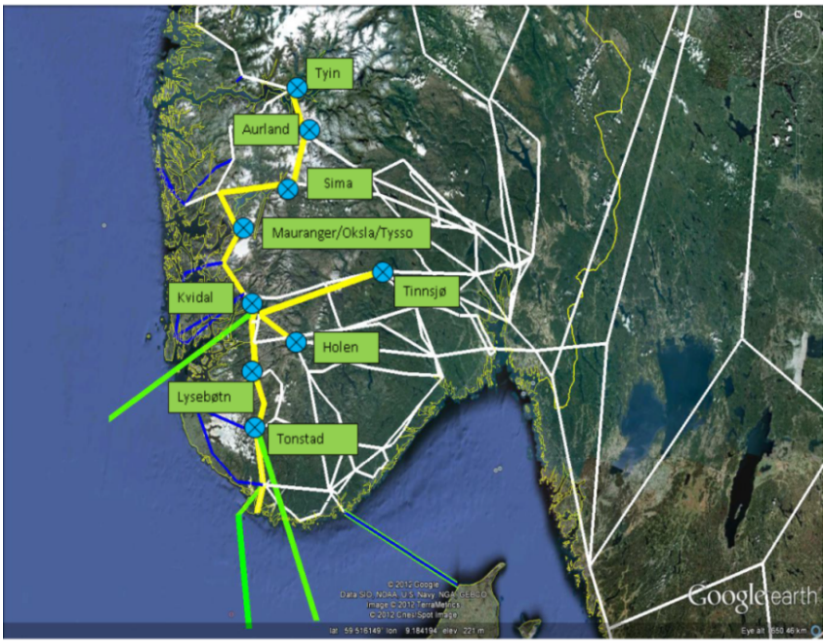


Figure 36. Corridor along the potential increased hydro power capacity in Norway

Besides the internal grid expansion in Norway, the interconnection to Sweden is expanded by increasing the NTC values between countries. This corresponds to the approach described in Part-I. The NTC scenarios are presented in Table 27.

Table 27. NTC values between Norway and Sweden [MW]

From	to	Year		
		2010	**2020**	**2030**
NO_1	SE_5	1800	3200	3200
NO_8	SE_4	900	900	900
NO_9	SE_2	200	1000	1000
NO_10	SE_1	700	1700	1700

12.2 Sweden

In the Swedish System, the main grid expansion is expected to happen in southern Sweden, offering the possibility to exchange more energy with the Continental system by utilizing the existing HVDC connections and the offshore grid in the Baltic Sea [27]. The transmission expansion expressed by NTC values is shown in Table 28.

Table 28. Expansion scenario in Sweden [MW]

From	to	Year		
		2010	**2020**	**2030**
SE_5	SE_6	3500	5200	5200

12.3 Germany and the Netherlands

Germany plays a key role in transmitting offshore wind power from the North and Baltic Sea to the southern part of the Continental system. Therefore, it is important to consider the congestion between the German areas. In this context, the methodology of defining transmission bottlenecks presented in the DENA grid study [18], along with the assumption made in Part-I, using NTC calculations, is employed to define grid constraints between the German areas. The NTC values in Table 29 show the expected transmission expansion between the German areas.

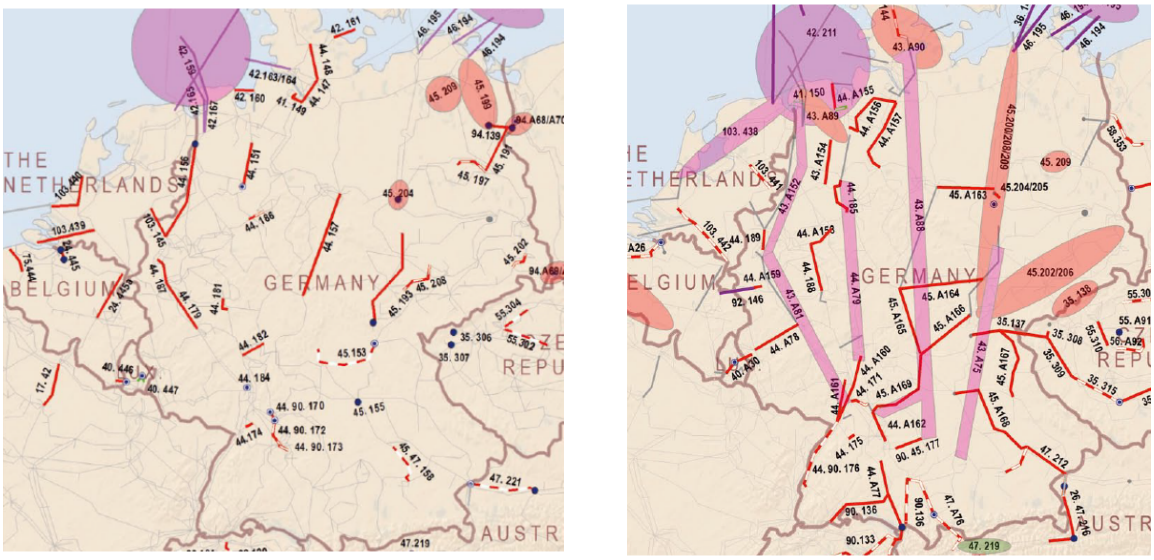
Table 29. Intra-German NTC [MW]

From	to	Year		
		2010	2020	2030
DE1	DE2	0	3100	3100
DE1	DE3	5000	5000	5000
DE1	DE4	2500	9800	9800
DE2	DE3	6450	16050	16050
DE2	DE5	2500	2500	2500
DE3	DE4	3950	3950	3950
DE3	DE5	10925	17125	17125
DE4	DE6	7500	14500	14500
DE5	DE6	10275	13675	13675

The proposed grid expansion projects included in [27] are considered for each individual transmission line in the German and Dutch systems. This includes both, medium term and long term investments according to the "Ten Years Net Development Plan (TYNDP)". The map of medium and long term investment projects are shown in Figure 37. However, as shown in the TSO's grid development plan [31] the proposed plan for long-term investment projects in Germany have been updated.

The HVAC connections proposed in Project 44.A79 have been substituted with HVDC lines. Moreover, the HVDC configuration has been updated. The four HVDC projects shown in Figure 38 are expected to be constructed in the upcoming years, connecting northern Germany to the central and the southern European continent. These corridors facilitate the integration of newly build wind generation from the North and the Baltic Seas to consumption and storage facilities in the European system.

For the Dutch system the expansion is considered based upon TYNDP projects [27], The expansion is aimed to the transmission of WPP from coastal areas to the rest of the Continental European system. Table 30 includes the transmission expansion projects both in German and the Dutch systems.



(a) medium term projects (b) long term projects

Figure 37. Maps of transmission expansion projects in Germany and the Netherlands [27]

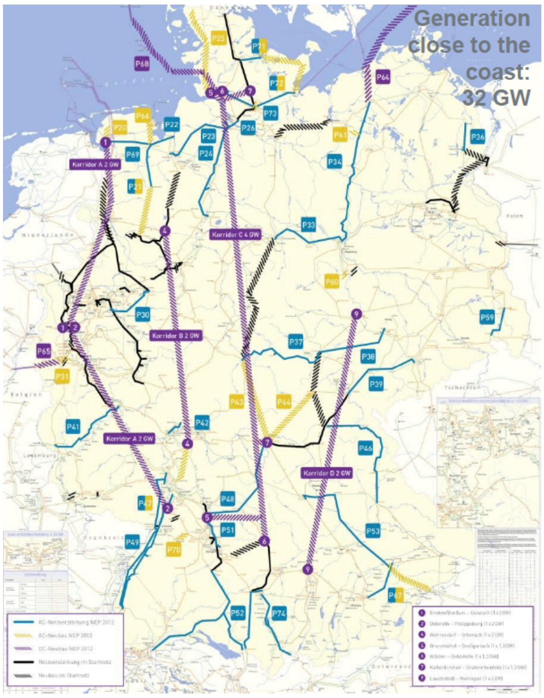


Figure 38. Grid development based upon German TSO's lead scenario B 2022 [31]

Table 30. Proposed transmission expansion project in [27, 31]

TYNDP Investment number	Substation 1	Substation 2	Modification	PSST Buses		Capacity [MW]		Brief technical description
				From	To	Before Expansion	After Expansion	
39. 144	Audorf (DE)	Kassö (DK)	Upgrading the existing capacity	XAU_KA11	D2AUDO11	658	1645	Step 3 in the Danish-German agreement to upgrade the Jutland-DE transfer capacity. It consists of partially an upgrade of existing 400kV line and partially a new 400kV route in Denmark. In Germany new 400kV line mainly in the trace of an existing 220kV line. The total length of this OHL is 114km.
				XAU_KA12	D2AUDO11	658	1645	
41. 149	Dollern (DE)	Stade (DE)		D2WILS11	D2DOLL11	1316	2635	New 400kV double circuit OHL Dollern - Stade including new 400kV switchgear in Stade. Length:14km.
German power grid developme nt [31]	**Emden (DE)**	**Osterath (DE)**	**New HVDC Lines- 2100 km with total capacity of 10 GW**	**D2EMDB21**	**D7OSTR21**	**0**	**2000**	**New DC-lines to integrate new wind generation from The North Sea towards South Europe for consumption and storage along the eastern border of Germany.**
	Osterath (DE)	**Philippsburg (DE)**		**D7OSTR21**	**D4PHIL11**	**0**	**2000**	
	Brunsbütte (DE)	**Großgartacher (DE)**		**D7WEHR12**	**D7URBE22**	**0**	**1300**	**New DC-lines to integrate new wind generation from the North/Baltic Seas towards Central/south Europe for consumption and storage**
	Wilster (DE)	**Goldshöfe (DE)**		**D5BRUN11**	**D4GROG21**	**0**	**1300**	
	Kaftenkirchen (DE)	**Grafenrheinfeld (DE)**		**D2WILS11**	**D4GOHF21**	**0**	**1300**	
	Wehrendorf (DE)	**Urberach (DE)**		**D5NORD11**	**D2GR 11**	**0**	**2000**	**New DC-lines to integrate new wind generation from The North Sea towards South Europe for consumption and storage.**
	Lauchstädt (DE)	**Meitingen (DE)**		**D8LAU_11**	**D7MEIT11**	**0**	**2000**	**New DC-lines to integrate new wind generation from Baltic Sea towards Central/south Europe for consumption and storage**
44. 147	Dollern (DE)	Hamburg/Nord (DE)	Upgrading the existing capacity	D2DOLL11	D5SUED11	313	1635	New 400kV double circuit OHL Dollern - Hamburg/Nord including one new 400/230kV transformer in substation Hamburg/Nord and new 400kV switchgear Kummerfeld. Length:43km.
44. 148	Audorf (DE)	Hamburg/Nord (DE)	New Extension	D2STAD11	D5SUED11	0	1645	New 400kV double circuit OHL Audorf - Hamburg/Nord including two new 400/230kV transformers in substation Audorf. Length: 65km.

44. 151	Wehrendorf (DE)	Ganderkesee (DE)		D7AMEL22	D2GANK11	0	950	New line (length: ca. 95km), extension of existing and erection of substations, erection of 380/110kV-transformers.
44. 157	Wahle (DE)	Mecklar (DE)		D2WAHL11	D2MECK11	0	1645	New 400kV double circuit OHL Wahle - Mecklar including two new substations. Length: 210km.
44. 170	Großgartach (DE)	Hüffenhardt (DE)	Upgrading the existing capacity	D4GROG21	D4OBRI21	500	950	New 380kV OHL. Length: 23km. Included with the project : 1 new 380kV substation, 2 transformers.
44. 171	Hüffenhardt (DE)	Neurott (DE)		D4HUEF21	D4NEUR21	500	950	Upgrade of the line from 220kV to 380kV. Length: 11km. Included with the project : 1 new 380kV substation.
44. 172	Mühlhausen (DE)	Großgartach (DE)		D4GROG21	D4HOHC21	500	950	Upgrading line from 220kV to 380kV. Length:45km.
				D4GROG11	D4HOHC21	500	950	
44. 173	Hoheneck (DE)	Endersbach (DE)		D4HOHC21	D4WDLN22	500	950	Upgrading line from 220kV to 380kV. Length:20km.
44. 174	Bruchsal Kändelweg (DE)	Ubstadt (DE)	New Extension	D4BIRK22	D4PULV13	0	950	A new 380kV OHL. Length:6km.
44. 176	Villingen (DE)	Weier (DE)		D4WEIE22	D4VILL11	0	950	A new 380kV OHL. Length:75km.
44. 179	Rommerskirchen (DE)	Weißenthurm (DE)		D7ROKI23	D7WTHU23	0	950	New line, extension of existing and erection of substations, erection of 380/110kV-transformers. Total line length: 100km.
44. 181	Dauersberg (DE)	Limburg (DE)	Upgrading the existing capacity	D7DAUR21	D7LIMB21	950	1645	New 380kV double circuit OHL, extension of existing of substations, Total line length: 20km.
44. 186	Gütersloh (DE)	Bechterdissen (DE)		D2YBPG21	D7GUET21	500	950	New lines and installation of additional circuits, extension of existing and erection of 380/110kV-substation. Total line length:27km.
44. 188	Kruckel (DE)	Dauersberg (DE)		D7DAUR11	D7OPLA12	1645	2635	New lines, extension of existing and erection of several 380/110kV-substations. Total line length: 130km.
44. A78	Weissenthurm (DE)	Niederstedem (DE)		D7NSTE24	D7WTHU23	500	950	Construction of new 380kV double-circuit OHLs, decommissioning of existing old 220kV double-circuit OHLs, extension of existing and erection of several 380/110kV-substations. Length: 105km.
44. A77	Area of South-Wuerttemberg (DE)	0		D4LAIC12	D4WDLN13	1645	2635	Construction of new 380kV double-circuit OHLs, decommissioning of existing double-circuit OHLs, extension of existing 380-kV-substations. Length: ca. 60km.
				D4DELL12	D4LAIC12	1645	2635	

				D4DELL13	D4LAIC12	1645	2635	
				D4DELL12	D4LAIC12	1645	2635	
44. 190	Saar-Pfalz-Region (DE)	0		D4HUEF21	D4OBRI21	500	950	New lines, extension of existing and erection of several 380/110kV-substations. Upgrade of an existing line from 220 to 380 kV
44. 175	Birkenfeld (DE)	Ötisheim (DE)	New Extension	D4BIRK21	D4PULV13	0	950	A new 380kV OHL. Length:11km.
44. 189	Niederrhein (DE)	Utfort (DE)	Upgrading the existing capacity	D7NRHE21	D7YOSS21	950	1645	New 380kV double-circuit OHL in South-Eastern part of 50Hertz Transmission control area. Total length: 105km.
45. 193	Halle/Saale (DE)	Schweinfurt (DE)	New Extension	D8LAU_11	D2SFT 21	0	1645	New 380kV double-circuit OHL between the substations Vieselbach-Altenfeld-Redwitz with 215km length combined with upgrade between Redwitz and Grafenrheinfeld (see project 153). The Section Lauchstedt-Vieselbach has already been comissioned. Support of RES integration in Germany, annual redispatching cost reduction, maintaining of security of supply and support of the market development. The line crosses the former border between Eastern and Western Germany and is rigt downstream in the main load flow direction. The project will help to avoid loop flows through neighbouring grids.
45. 197	Neuenhagen (DE)	Wustermark (DE)	Upgrading the existing capacity	D8NHG_21	D8WU__21	500	1645	Construction of new 380kV double-circuit OHL between the substations Wustermark-Neuenhagen with 70km length. Support of RES and conventional generation integration, maintaining of security of supply and support of market development.
45. 199	Western Pomerania (DE)	Uckermark North (DE)	New Extension	D8LUB_11	D8VIE_21	0	1645	Construction of new 380kV double-circuit OHLs in North-Eastern part of 50HzT control area and decommissioning of existing old 220kV double-circuit OHLs. Length: 135km.Support of RES and conventional generation integration in North Germany, maintaining of security of supply and support of market development.
45. 200	Lubmin (DE)	Erfurt area (DE)		D8LUB_11	D8VIB_11	0	1645	380-kV-grid enhancement and structural change area Lubmin-Stralsund and area Magdeburg/Wolmirstedt
103. 145	Niederrhein (DE)	Doetinchem (NL)		D7NRHE21	NUF 3	0	1645	New 400kV line double circuit DE-NL interconnection line. Length:60km.

103. 438	Eemshaven (NL)	Diemen (NL)	Upgrading the existing capacity	NENS-A1	NDIM-A1	1645	5300	New 175-200km AC overhead line with capacity of 2x2650 MVA of 380kV.
				NDIM-A1	NDIM-B1	1645	5300	
				NLLS-A1	NDIM-B1	1645	5300	
				NENS-B1	NLLS-A1	1645	5300	
				NOHK-A2	NENS-A2	953	5300	
				NOHK-B2	NENS-B2	953	5300	
				NLSM-A2	NOHK-A2	953	5300	
				NLSM-B2	NOHK-B2	953	5300	
				NBGM-A2	NLSM-A2	953	5300	
				NBGM-B2	NLSM-B2	953	5300	
				NVVL-A2	NBGM-A2	953	5300	
				NVVL-B2	NBGM-B2	953	5300	
				NVVL-A2	NRBB-A2	953	5300	
				NVVL-B2	NRBB-B2	953	5300	
				NEEM-F2	NVVL-A2	884	5300	
				NEEM-D2	NRBB-A2	953	5300	
				NEEM-C2	NRBB-B2	953	5300	
103. 439	Borssele (NL)	Geertruidenberg (NL)		NBSL 3	NGT-B11	1645	5300	New 100-130km double-circuit 380kV OHL with 2x2650 MVA capacity.
103. 440	Maasvlakte (NL)	Beverwijk (NL)		NLD 3	NZT 3	1645	2650	New 380 kV double-circuit mixed project (OHL+ underground cable) including approximately 20km of underground cable for 2650 MVA. The cable sections are a pilot project. The total length of cable at 380kV is frozen until more experience is gained.
				NLD 3	NVB 3	1645	2650	
				NVB 3	NDHG 3	1645	2650	
				NRW 3	NDHG 3	1645	2650	
				NWL 3	NRW 3	1645	2650	
				NMVL-I1	NWL 3	1645	2650	

<table>
<tr><td rowspan="2">103. 441</td><td rowspan="2">Zwolle (NL)</td><td rowspan="2">Hengelo (NL)</td><td rowspan="4"></td><td>NZL-A11</td><td>NHGL-A1</td><td>1645</td><td>5300</td><td rowspan="2">Upgrade of the capacity of the existing 60km double circuit 380kV OHL to reach a capacity of 2x2650 MVA.</td></tr>
<tr><td>NZL-B11</td><td>NHGL-B1</td><td>1645</td><td>5300</td></tr>
<tr><td rowspan="2">103. 442</td><td rowspan="2">Krimpen aan de Ijssel (NL)</td><td rowspan="2">Maasbracht (NL)</td><td>NEHV-B1</td><td>NMBT-B1</td><td>1645</td><td>5300</td><td rowspan="2">Upgrade of the capacity of the existing 150km double circuit 380kV OHL to reach a capacity of 2x2650 MVA.</td></tr>
<tr><td>NEHV-A1</td><td>NMBT-A1</td><td>1645</td><td>5300</td></tr>
</table>

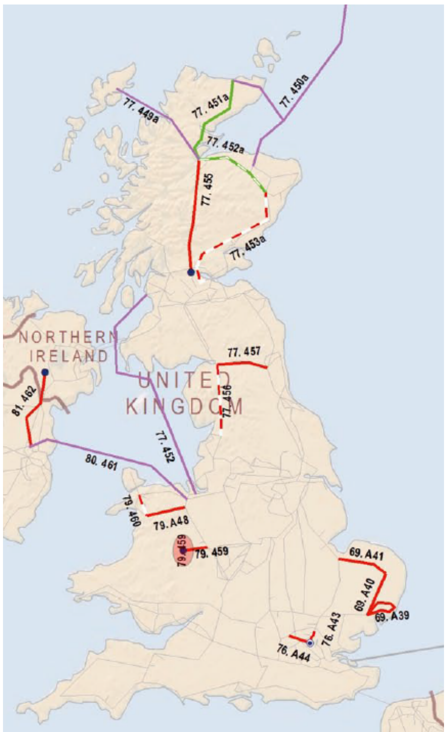
12.4 Great Britain

Transmission expansion between areas in Great Britain is expressed as NTC values presented in Table 31. According to [29], the generation to north of SHETL is expecting to increase over time due to the high volume of newly contracted RES requiring a connection to the SHETL area. Consequently, the inter-area transfer capacities are also expected to increase with time. Accordingly, the transmission lines across the area boarders between SPT and NGET are expected to be expanded due to contracted RES developments throughout Scotland.

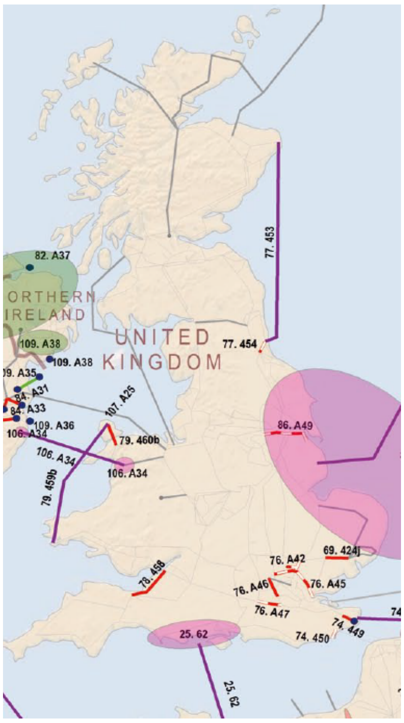
Table 31. NTCs in Great Britain [MW]

From	To	Year		
		2010	2020	2030
GB_SHETL	GB_SPT	1550	4850	4850
GB_SPT	GB_NGET	2200	8000	8000

The detailed list of transmission expansion planning based upon TYNDP within the UK areas is presented in Table 32. These projects are shown schematically in Figure 39. The projects in red are the new transmission lines added to the British system.



(a) medium term projects



(b) long term projects

Figure 39. Maps of transmission expansion projects in the UK [27]

Table 32. Proposed transmission expansion project in the UK [27]

TYNDP Investment number	Substation 1	Substation 2	Modification	PSST Buses		Capacity [MW]		Brief technical description
				From	TO	Before Expansion	After Expansion	
69. 424j	Bramford (GB)	Twinstead (GB)	Upgrading	NORW40	SIZE40	1590	2780	New 400kV double circuit
69. A39	Sizewell C (GB)	Bramford (GB)	Upgrading	BRFO40	SIZE40	1590	2780	Reconductor Sizewell C-Bramford-Sizewell
69. A41	Walpole (GB)	Bramford (GB)	Upgrading	NORW40	WALP40	1390	2780	Reconductoring Norwich Main-Walpole and Bramford-Norwich Main
76. A42	Pelham (GB)	Waltham Cross (GB)	Upgrading	BRIM2A	WALX21	1090	2780	Reconductor Pelham-Rye House-Waltham Cross
76. A43	Hackney (GB)	Waltham Cross (GB)	Upgrading	HACK2A	TOTE22	535	1090	Uprate to 400kV Hackney-Tottenham-Waltham Cross
76. A44	Hackney (GB)	St. John's Wood (GB)	New Extension	HACK40	WHAM40	0	1600	New 400kV St. John's Wood-Hackney double circuit
			New Extension	CITR41	WHAM4A	0	1412	
76. A45	Tilbury (GB)	Elstree (GB)	Upgrading	TILB22	WARL20	1180	2010	Uprate to 400kV Tilbury-Warley-Elstree
			Upgrading	ELST21	WARL20	760	2010	
			Upgrading	ELST21	WATS21	760	2010	
76. A46	St. John's Wood (GB)	Wimbledon (GB)	Upgrading	SJOW2A	WISD20	760	2010	New 400kV St. John's Wood-Wimbledon cables
			Upgrading	WIMB20	WISD2B	740	2010	
76. A47	West Weybridge (GB)	Beddington (GB)	Upgrading	BRLE40	WWEY4A	1390	2010	Uprate to 400kV West Weybridge-Chessington-Beddington
			Upgrading	BRLE40	WWEY4B	1390	2010	
			Upgrading	BEDD22	CHSI20	945	2010	
			Upgrading	BEDD21	CHSI20	760	2010	
77. 456	Harker (GB)	Quernmore (GB)	Upgrading	HARK40	HUTT40	1390	2010	Reconductor Harker-Hutton-Quernmore
77. 451a	Dounreay (GB)	Beauly (GB)	Upgrading	ARDR2Q	BEAU21	535	1090	String a second 275kV OHL circuit on existing towers.
			Upgrading	ARDR2Q	STRB20	535	1090	
77. 452a	Beauly (GB)	Kintore (GB)	Upgrading	BEAU21	DAAS20	525	1090	Reconductor existing 275kV overhead line route.
			Upgrading	BLHI22	DAAS20	525	1090	
			Upgrading	BLHI22	KINT21	525	1090	
77. 453a	Blackhillock (GB)	Kincardine (GB)	Upgrading	KINT22	KINB21	764	1500	Reinsulate existing 275kV route for 400kV

								operation and establish three new 400kV substations en-route.
77. 455	Beauly (GB)	Denny (GB)	Upgrading	BEAU11	FASN10	126	2780	New double circuit 400kV OHL (220km) with new terminal substations and substation extensions en route.
			Upgrading	FASN10	FAUG1Q	133	2780	
			Upgrading	ERRO1A	FAUG10	132	2780	
			Upgrading	BRAC1Q	ERRO11	132	2780	
			Upgrading	BRAC1Q	BONB11	126	2780	
			Upgrading	BONB11	BONN10	132	2780	
			Upgrading	BONB12	BONN10	132	2780	
77. 457	Harker (GB)	Stella West (GB)	Upgrading	HARK22	STEW20	775	2010	New 400kV series and shunt compensation at a number of locations across the Anglo-Scottish border.
78. 458	Hinkley (GB)	Seabank (GB)	New Extension	HINP40	SEAB40	3200	0	New 60km double circuit 400kV OHL
79. A48	Trawsfynydd (GB)	Treudyyn (GB)	Upgrading	TRAW40	TREU4A	1710	2560	Reconductor Trawsfynydd-Treuddyn
			Upgrading	TRAW40	TREU4B	1710	2560	
79. 459	New Substation (GB)	Legacy-Shrewsbury Tee (GB)	Upgrading	LEGA4B	SHRE4A	2400	3280	New 400kV double circuit OHL and new 400kV substation in Mid-Wales
79. 460	Pentir (GB)	Trawsfynydd (GB)	Upgrading	PENT40	YWER4A	4960	3800	Upgrage Pentir-Trawsfynydd to double circuit
			Upgrading	YGAR4A	YWER4A	1220	3800	
			Upgrading	TRAW40	YGAR4A	1160	3800	
79. 460b	Wylfa (GB)	Pentir (GB)	Upgrading	PENT40	WYLF40	2780	3600	New 400kV Wylfa-Pentir double circuit

12.5 Other Countries

The NTC values for the other countries in Continental Europe are taken from OffshoreGrid project and are presented in Table 33. These values are assumed to be identical for the 2020 and the 2030 case studies.

Table 33. NTC Values [24]

From	To	Capacity [MW]		From	To	Capacity [MW]	
AT	SI	900	900	FR	IT	2650	995
AT	IT	220	285	GR	BG	300	600
AT	DE	2000	2200	GR	MK	300	350
AT	CH	1200	1200	GR	AL	200	150
AT	HU	400	800	GR	IT	500	500
AT	CZ	1200	2180	IT	SI	650	650
BE	FR	5300	6400	RO	HU	1400	600
BE	NL	5400	5400	RO	BG	600	600
BA	HR	700	570	RO	RS	600	300
BA	RS	480	400	RS	MK	350	350
BA	ME	500	380	RS	BG	300	350
CH	IT	4240	1810	RS	HU	600	600
CH	DE	3200	1500	RS	ME	400	400
CH	FR	2300	3200	RS	AL	200	200
HR	SI	1000	1000	ME	AL	250	250
HR	HU	1500	1000	MK	BG	250	450
HR	RS	400	350	SK	HU	1250	600
CZ	DE	2300	800	SK	PL	500	600
CZ	PL	800	2000	UA	SK	400	400
CZ	SK	1700	1000	UA	HU	800	800
DE	FR	3050	2800	UA	RO	550	400
DE	PL	2200	2100	DK	DE	2500	1950
DE	SE	600	610	SE_1	FI_2	1600	1200
DE	DK_E	550	550	SE_6	DK_E	1350	1750
DE	NL	5850	5000	LV	LT	2500	2500
ES	FR	500	1300	RU	FI_1	1300	0
ES	PT	1500	1300	SE	PL	0	600

13 2030 Case Study

The described baseline grid scenario for 2030 is generally an extrapolation of today's system. Furthermore, it includes already started and unquestionable future transmission expansion projects.
In this section, two different grid cases for 2030 have been evaluated. The main focus of those cases is the internal grid development in the Norwegian system, including:

- Case I: The influence of the offshore grid (see Figure 5) **with** expansion in a transmission corridor according Figure 36.
- Case II: Influence of the offshore grid (see Figure 5) **without** expansion in a transmission corridor according Figure 36.

13.1 Energy Mix of European System in 2030

The total energy mix for electricity production in the system is illustrated in Figure 40. It is essentially determined by the marginal costs and generator capacities with limitations imposed by the transmission grid. The general trend is a change from fossil fuel based generation to renewable generation. The annual European wind energy production is expected to equal 1033 TWh which corresponds to 25% of the total energy production in Europe.

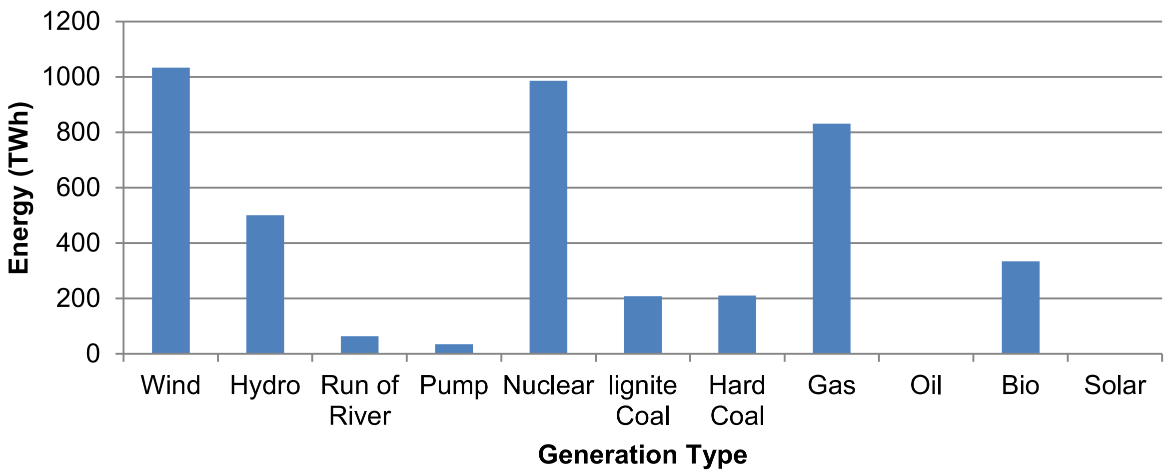


Figure 40. Energy mix in the Continental European electricity system in 2030

Figure 41 shows the expected wind development for on- and offshore wind energy production in the Continental European system in 2030. The share of offshore wind production is expected to increase significantly in the neighbouring countries of the North and the Baltic Seas.

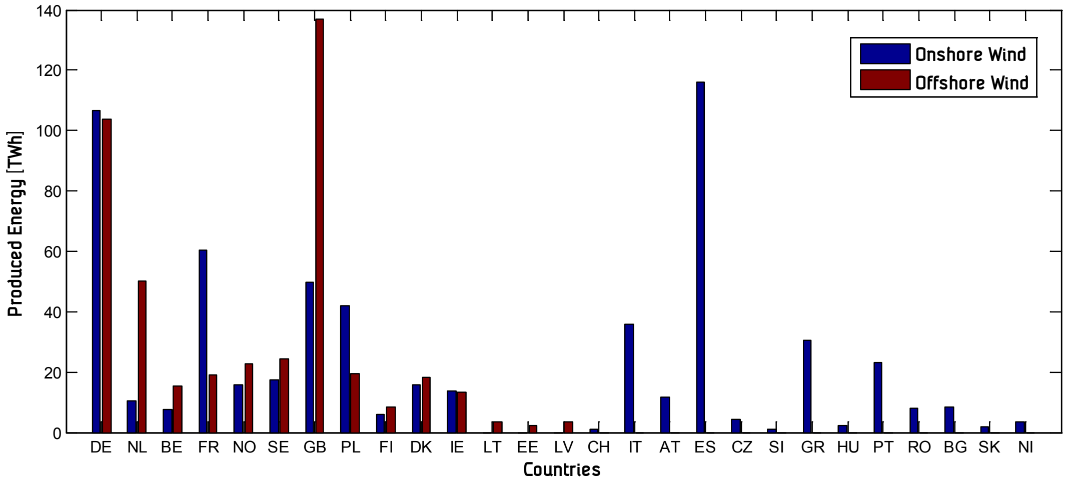


Figure 41. Wind energy production per country in 2030

13.2 Reservoir Trajectory in Norway in 2030

A comparison between the simulated reservoir trajectory in Norway and the recorded data in Figure 42 indicates that the simulated reservoir (black curve) follows the seasonal variation. While the hydro reservoirs are drained during the winter months, the reservoir level increases during spring and summer time.

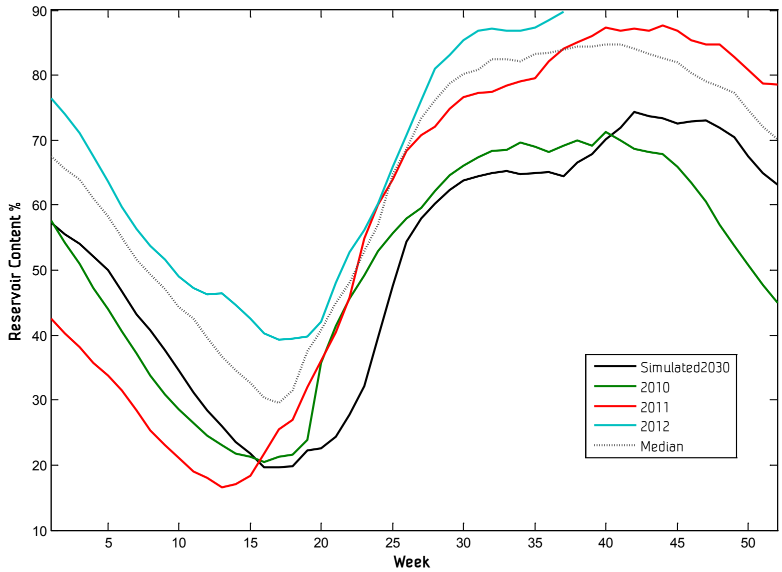


Figure 42. Simulated and recorded reservoir content for Norway[15]

The 2030 studies are based on the second hydro capacity scenario with hydro capacity expansion of 18.2 GW (see Table 25). The reservoir trajectories for each individual reservoir in Southern Norway are depicted in Figure 43. The figure shows that the reservoirs are handled in a strategically efficient way. When examining the hydro reservoir level for the areas connected to the NorNed and the NorGer HVDC cables (NO_5), very small fluctuations can be noticed throughout the year. One of those reservoirs is located in Tonstad which is expected to facilitate a new pump storage unit.

[15] NordPool Website - http://wwwdynamic.nordpoolspot.com/marketinfo/rescontent/norway/rescontent.cgi

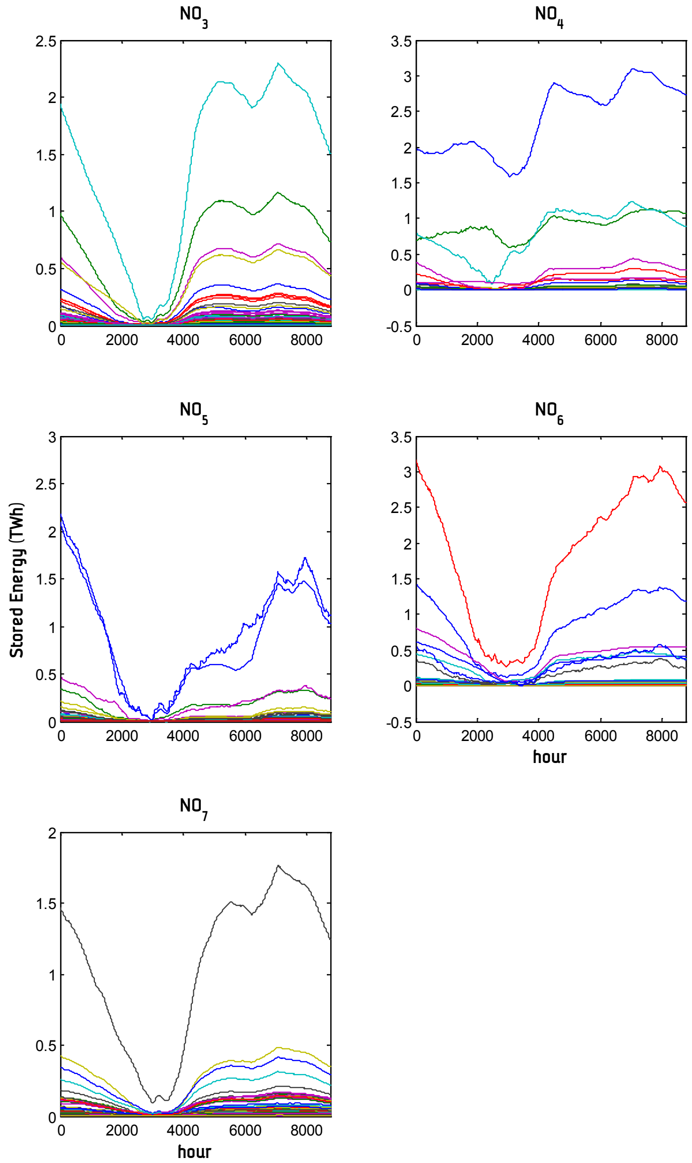


Figure 43. Reservoir trajectory of each individual reservoir in Southern Norway (Case I)

Tonstad is directly connected to the HVDC cable to Germany (NorGer). The NorGer HVDC link is depicted by the orange line in Figure 44. As shown, the cable is connected to two offshore wind production facilities in Germany. These two offshore wind fields are DanTysk and NordseeOst.

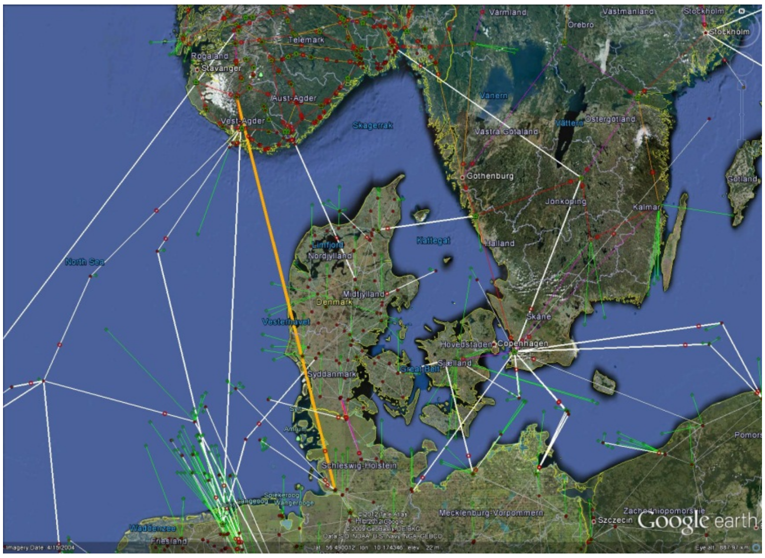


Figure 44. NorGer HVDC cable

The simulated reservoir trajectory in Tonstad is shown in Figure 45. The reservoir is drained very fast during winter time until hour 3000. From hour 3000 to 6000 the reservoir is filled based on a high natural inflow. The small fluctuations in the reservoir level result from the WPP variations in Germany, which directly affect the pump storage production pattern of the Tonstad power plant.

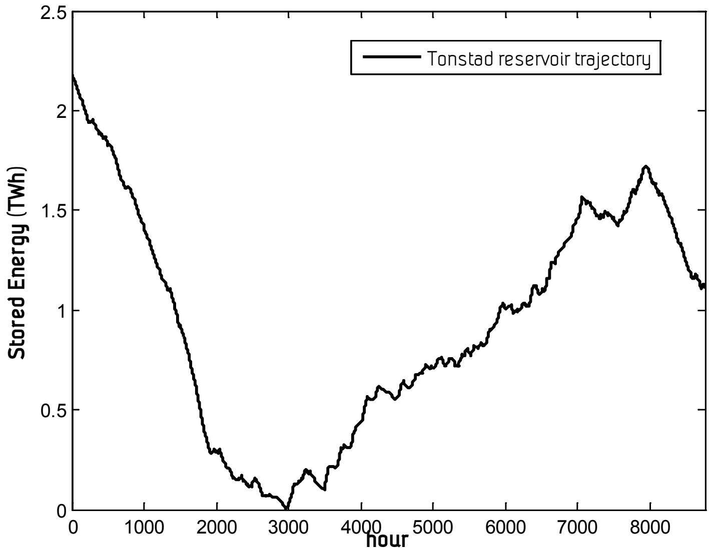


Figure 45. Tonstad simulated reservoir trajectory

Figure 46 shows the variation of stored energy in Tonstad reservoir versus the wind production variability in the two German offshore wind facilities which are directly connected to the NorGer link. As shown, there is a high correlation between wind power production and reservoir level variation. During the hours with high wind production, i.e., 1 p.u., the power plant pumps water to the reservoir while during times with the low WPP the power plant acts as a generator depleting the reservoir.

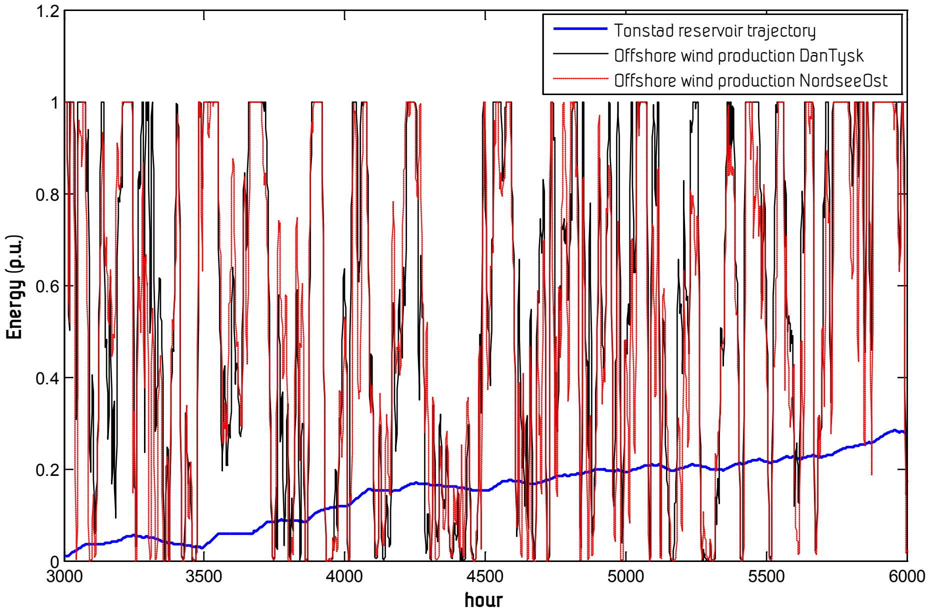


Figure 46. Wind power production in German offshore wind facilities and reservoir change in Tonstad

Reservoir filling is affected by two factors, i.e., natural inflow and hydro pumping. The reservoir variation versus the inflow and the pumping pattern is illustrated in Figure 47. Inflow is supposed to be constant for the entire week. Negative inflow indicates water evaporation or using bypass tunnels to utilize the stored water for other purposes than electricity production. The pumping pattern is shown by the red line. The black dotted line represents the reservoir variations where negative values indicate hydro production while positive values represent the natural inflow and water pumped back to the reservoir.

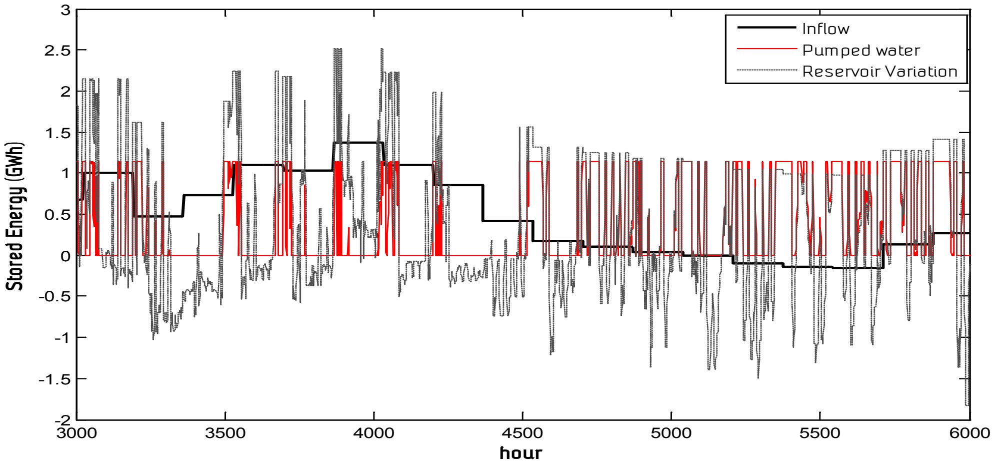


Figure 47. Reservoir variation versus natural inflow and pumped water

Figure 48 illustrates the correlation between the Tonstad pumping pattern and the German offshore wind production at wind facilities connected to NorGer HVDC cable. These results indicate that in the future power system with a large penetration of wind energy, the pumping strategy in the Nordic region will not only be influenced by seasonal inflows but also by the variability of wind production around the North Sea.

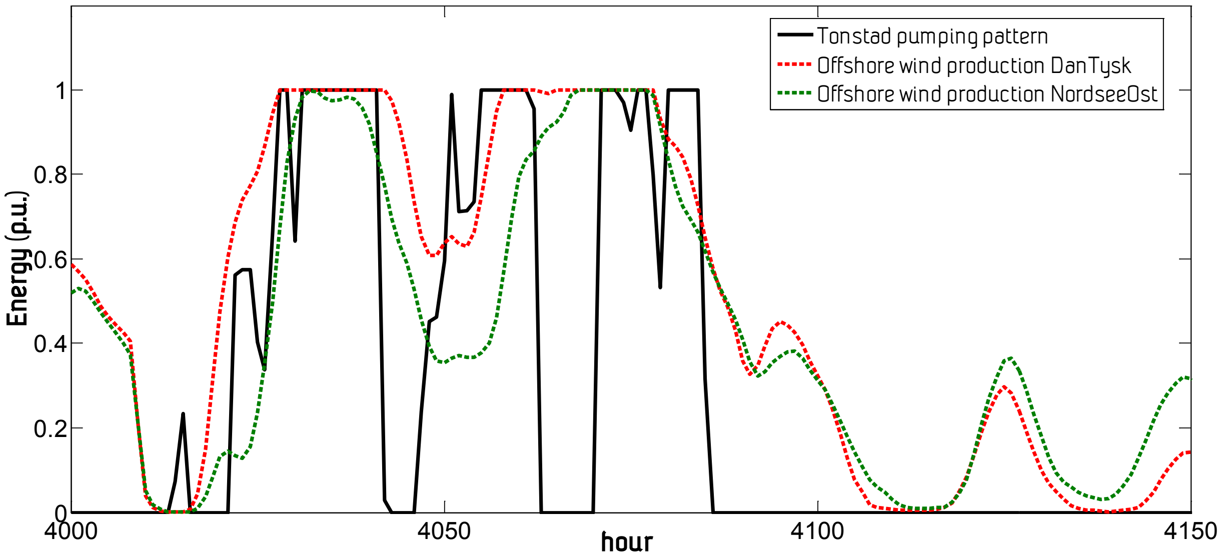


Figure 48. WPP of German offshore facilities connected to the NorGer HVDC cable vs. pumping pattern in Tonstad

13.3 Grid Expansions

One of the main goals of the TWENTIES project is to remove barriers which prevent the power systems from integrating more contribution of wind energy in electricity supply. Grid bottlenecks are one of the greatest barriers to avoid integration of wind energy in power systems. Congestion in the power grid avoids the efficient exchange of power and increases the system costs.

As mentioned previously, the simulation tool PSST runs an optimal power flow analysis for each hour, where the objective function is to minimise the total generation cost. Generation cost is computed as the sum of power output times and the specific marginal cost for all generators. The main factors determining the generation costs are therefore the marginal generator costs and the energy mix. Grid congestion imposes an implicit effect on the total cost by avoiding the procurement of cheaper generation sources. Table 34 represents the system operating cost for Case I and Case II. Comparing the operating cost for both cases reveals that the internal grid bottlenecks in Norway impose EUR 73 million extra costs annually.

Table 34. System operating costs for Case I and Case II

Cases	Case I	Case II
Operating Cost [M€]	90915	90988

Figure 49 illustrates the reservoir trajectory in southern Norway for Case II. As shown, the internal bottleneck in the Norwegian system prevents the efficient use of hydro energy. Accordingly, spillage has been observed in the NO_4 and the NO_6 areas. Spillage occurred in Nordel: 9353 (Mauranger), Nordel: 9696 and Nordel: 9524 (Tinnsjø). The spillage of water indicates that even though there is a potential to provide energy from cheap hydro resources in the middle of Norway, the grid implications avoid exploiting this potential in an optimal way.

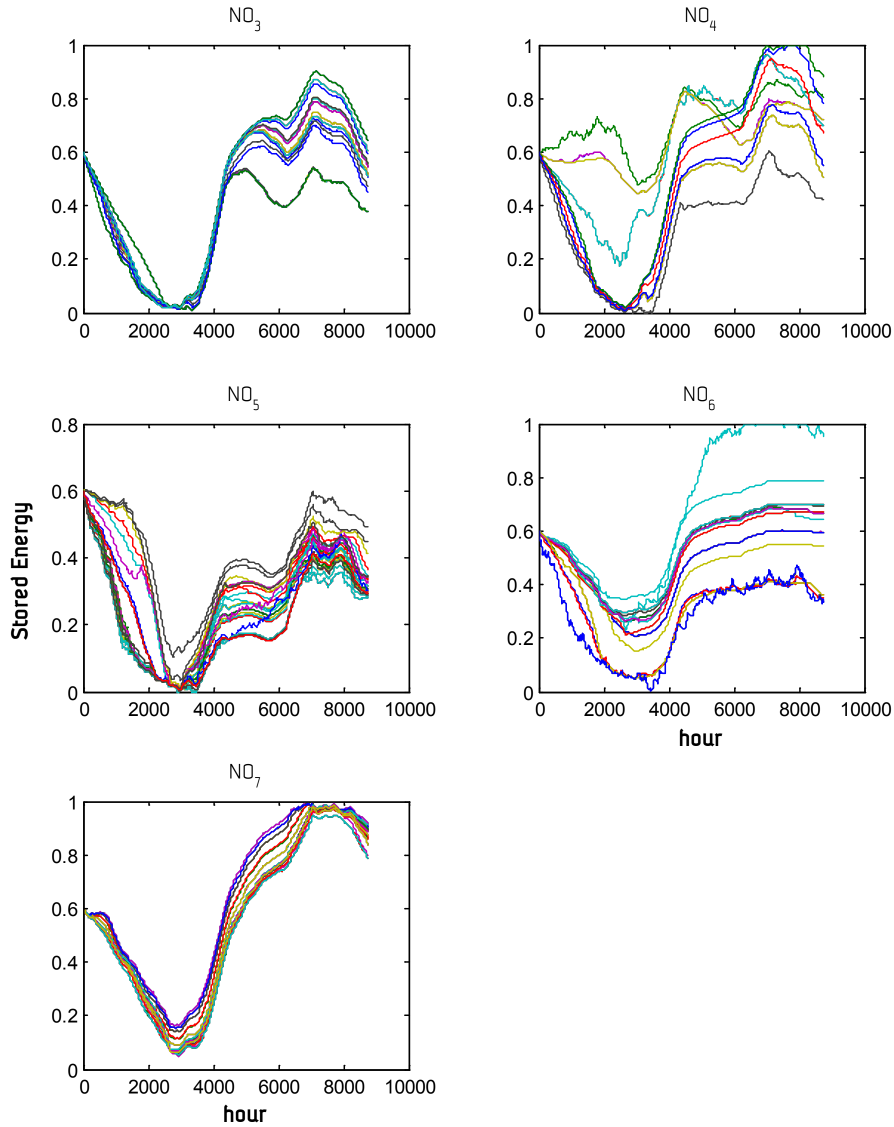


Figure 49. Reservoir trajectory of each individual reservoir in Southern Norway (Case II)

13.4 Exchange between Norway and the UK

Figure 50 shows the snapshot of power exchange between the Norwegian and British offshore nodes, i.e., "O:NO-Idunn" and "O: GB-DoggerbankE", respectively within 200 hours' time span. The simulations include an expanded transmission corridor in Norway according to Figure 36. Figure 50 shows that during times with a drastic reduction of WPP at both nodes, i.e., hours 300 - 340, there is a large export from the Norwegian system to the British system. Looking at the correlation between hydro production in the Norwegian system and dips in WPP illustrates that during the low-wind hours the hydro production supports the British system in balancing production and consumption.

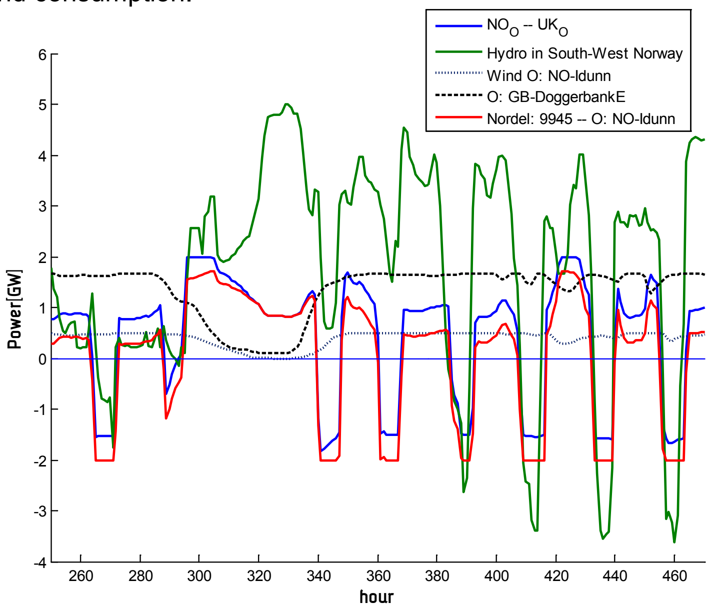


Figure 50. Power exchange between Norwegian and British offshore nodes – with transmission corridor

On the other hand, the influence of a constrained Norwegian transmission system is shown in Figure 51. The Figure represents the identical situation of wind production as depicted in Figure 50. However, the internal corridor along the expanded hydro power units in the Norwegian system has not been expanded. In contemporary to the previous case, the internal congestion in the Norwegian system does not allow the hydro producers to support the British system.

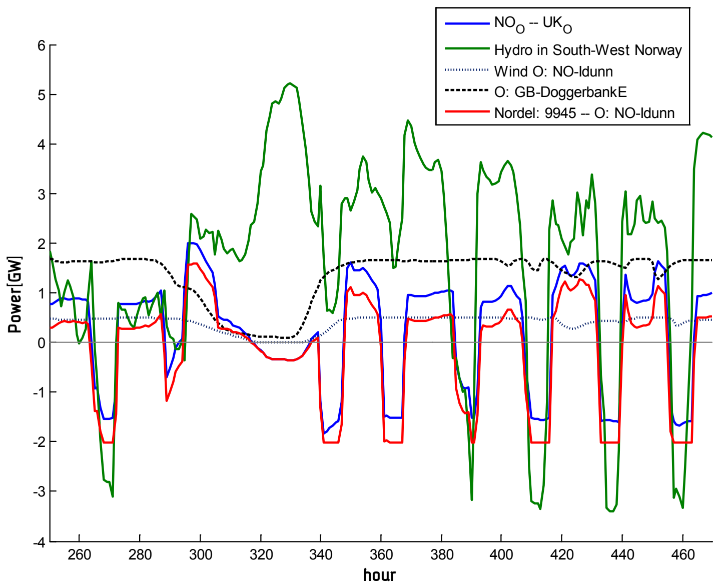
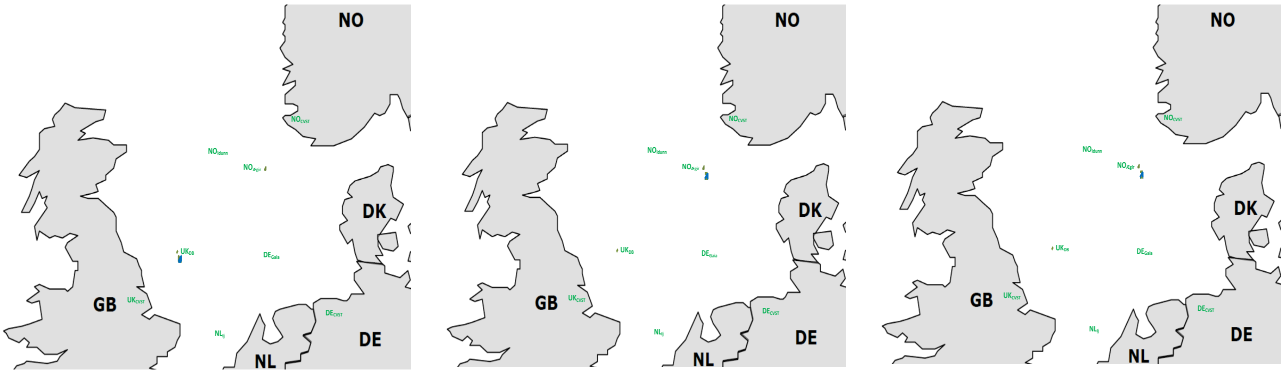


Figure 51. Power exchange between Norwegian and British offshore nodes –without transmission corridor

13.5 Different Grid Case Studies in 2030

In this section different grid case studies are elaborated for different offshore grid topologies and onshore grid constraints for the 2030 scenario. Our main focus is to have detail techno-economic analysis of the role of offshore grid working as North Sea power wheel and power can circulate in various ways all around the North Sea. It will be interplay between offshore WPP and hydro storage possibilities. The offshore grid structure is taken directly from OffshoreGrid project. In offshoreGrid Project, the increase capacity of hydro power was not considered whereas in our simulation for 2030, we have assumed very large increased hydro capacity in southern Norway. Therefore it is important to consider further alternatives for offshore grid topology to exploit this potential increased hydro in an optimal way. Three different offshore grid structures are considered including:

- Case A: Original offshore grid according to the OffshoreGrid project without any connection between the Ægir offshore wind farm in Norway and the other parts of the grid
- Case B: Offshore grid with connection between the Ægir offshore wind farm and Eemshaven, a seaport in northern Netherlands
- Case C: Offshore grid with connection between the Ægir wind farm and the Gaia offshore wind farm in Germany



a) Case A b) Case B c) Case C

Figure 52. Offshore grid alternatives

Figure 52 shows different offshore grid alternatives in this study. Case A is similar to the design considered in OffshoreGrid project. In Case B, there is a direct connection between Norwegian offshore node and onshore grid in the Netherlands, which can transfer additional hydro capacity directly to the onshore grid. Case C completes the offshore loop between Norway, British system and Germany, where power can circulate in the offshore grid among those countries.

Long term strategies for the development of offshore and onshore grids expansion must be done in a coordinated way to ensure optimal developments. In order to study the effect of onshore constraints, we superimpose the scenarios for onshore grid constraints on offshore grid alternatives. The scenarios for onshore grid constraints are clustered in three categories including:

- No constraint (NC)
- Internal Constraint (IC)
- Internal Constraint with Expansion (ICE)

The NC scenario represents the case without considering the internal constraints in the ENTSO-E grid. In this case, the internal grid in each country is considered as a cupper plate, whereas cross-border grid constraints are considered by limiting the transmission capacity for each individual cross-border transmission line and NTC values for the corridors linking countries and areas inside Germany. The NTCs used between areas inside Germany are taken from the dena Grid study – II [18].

The IC scenario includes the onshore grid with today's internal grid limitations in the German, the Dutch, the British and the Scandinavian systems.

On the other hand, the ICE scenario represents the expanded grid described in Section 12. The expansion includes the grid reinforcements in Norway, indicated by the yellow corridor in Figure 36, as well as the grid expansions in the German and Dutch systems depicted in Figure 37 and the expansions in the UK illustrated in Figure 39

Table 35 presents the annual operating cost for the three mentioned cases. The analysis for each of these cases is carried out, taking the internal congestion in the onshore grid into account. Looking at the NC scenario reveals that the optimal offshore grid structure in terms of operational savings is "Case B". Moving from Case A to Case B results in annual saving of approximately 96.4 MEUR.

Table 35. Annual operating costs for 2030 case studies (baseline wind scenario)

Onshore Grid Constraints in the ENTSO-E and the UK	Offshore grid Cases	Cost [bn€/a]
No constraint	Case A	92.8462
	Case B	92.7498
	Case C	92.7665
Internal Constraint	Case A	95.5779
	Case B	95.5273
	Case C	95.517
Internal Constraint with Expansion	Case A	92.9928
	Case B	92.9288
	Case C	92.9274

For the IC scenario, the results show a different picture with respect to offshore grid topologies. The optimal offshore grid topology appears to be Case C. It turns out that moving from Case A to Case B and from Case B to Case C results in annual savings of approximately 50.6 MEUR and 10.3 MEUR, respectively. Therefore, the accumulated savings is approximately 60.9 MEUR.

The savings in the ICE scenario is approximately 64 MEUR when moving from Case A to Case B and about 1.4 MEUR from Case B to Case C. Therefore, the best alternative to an offshore grid in terms of monetary savings (65.4 MEUR=64+1.4) appears to be "Case C". This applies for the IC as well as for the ICE scenarios.

According to investment estimation in [20], the investment cost for offshore HVDC grid is expected to be 1700 EUR/(MW.km). The distance between the Norwegian and the German offshore wind farms is roughly assumed to be 350 km. This value is approximately 500 km between the Norwegian offshore wind farm and Eemshaven in the Netherlands. The connection capacity is expected to be 1000 MW. In this regards, the investment cost for the tie-line in Case B and Case C are approximated to be 850 MEUR and 600 MEUR, respectively. Taking into account 100 MEUR for the costs of DC/AC converters, switchgears, transformers [20], the overall cost of the interconnections are roughly expected to be 950 MEUR and 700 MEUR for Case B and Case C, respectively. The *Life Time Factor (LFT)* for the life time of 30 years and 5% discount rate is $\sum_{n=1}^{30}\left(\frac{1}{(1+0.05)^n}\right)=15.3725$. This factor allows a comparison of the operational savings accumulated throughout the life time of grid project, which is annual savings×15.3725. The accumulated savings for NC, IC and ICE cases are ~1225 MEUR, ~936 MEUR and ~1005 MEUR, respectively. Comparing these numbers with investment for all expanded corridors indicates that all accumulated savings are greater than investment cost for each corridor. Therefore, it turns out that making investment in those corridors is profitable in comparison with the accumulated savings throughout the life time of the corridors.

Using the invers value of LFT, gives us the Capital Recovery Factor (CRF). This factor allows us to compare annul operating saving with annualised investment cost. The CRF for the previous investment in HVDC cables are 1/15.3725=6.5%. The annualised investment cost for Case C is therefore equal to 700 MEUR×6.5% which is 45.5 MEUR. If we consider IC case representing the onshore grid with today's internal grid limitations, Case C results in 60.9 MEUR compare to Case A. Therefore, installation HVDC cable combining Ægir wind farm in Norway and the Gaia offshore wind farm in Germany gives 60.9-45.5= 15.4 MEUR net profit to the power system. According to [20], investment estimation in onshore overhead AC lines is expected to be 500 EUR/(MW.km). Therefore, the net benefit from offshore grid expansion by additional 1GW offshore HVDC capacity (case A-C), allowing increased wind penetration and use of flexible hydro power, is equal to 30800 (km e MW) onshore transmission "equivalent" investment for the Baseline wind scenario and 131128 (km × MW) onshore transmission "equivalent" investment for the High wind scenario.

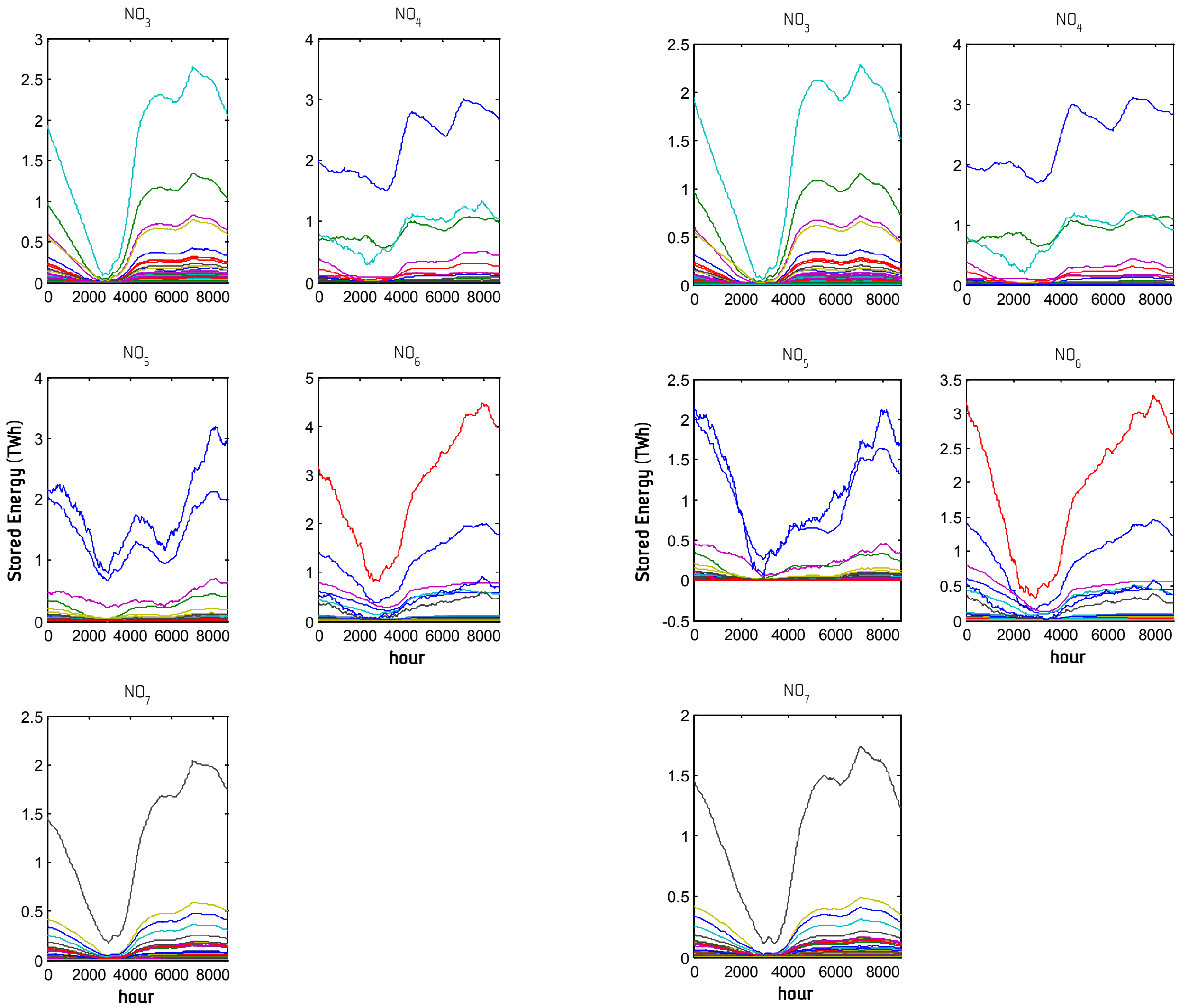
The difference in installed capacity at offshore wind farms around the North Sea between the Baseline and High wind scenario is 3185 MW (See Section 15 below for details). These (km × MW) onshore transmission "equivalent" figures quantify the relative value of offshore grid expansion with respect to onshore transmission expansion.

The onshore grid constraints in the German and the Dutch system constrained the transmission of wind and hydro production to the load centres inland, hence increasing the operating cost. On the other hand, the internal constraints enforce load shading at peak hours in the IC group. The total amount of the shed load for the three assumed cases is presented in Table 37. As shown, Case C results in minimal load shedding. This leads to a reduction of the operating costs.

Table 36. Annual load shedding [GWh]

Case	Load Shading
Case A	31.11
Case B	30.87
Case C	30.81

Figure 53 depicts the reservoir trajectory of hydro power plants for both cases - with internal grid constraint and with extended transmission capacity. Comparing Figure 53 (a) and (b), reveals that in the IC scenario, reservoirs end up with higher reservoir level at the end of the year. This behaviour especially appears for the reservoirs situated in the southern part of Norway, i.e., NO_5, NO_6 and NO_7. One of the reasons is that the internal grid bottlenecks in the Central European power grid prevents the transmission of hydro power production from the Nordic to the European power system, even though there is enough cross-border transmission capacity available.
Furthermore, the internal grid bottlenecks in the German system limit the transmission of wind energy from offshore wind facilities in the North Sea to the load centres located in southern Germany. Thus, surplus power production is transmitted towards the Nordic system largely affecting the production behaviour and the reservoir levels of pump storage facilities in southern Norway.



(a) IC case (b) ICE case

Figure 53. Reservoir trajectory of each individual reservoir in Southern Norway

Figure 54 illustrates the simulated reservoir trajectory at Tonstad, which is directly connected to the NorGer HVDC cable. The figure illustrates significant differences between the reservoir trajectory for the IC scenario and the ones in the NC and the ICE scenarios. As for Figure 53, this behaviour at Tonstad results from transmission bottlenecks in the internal grid in Germany.

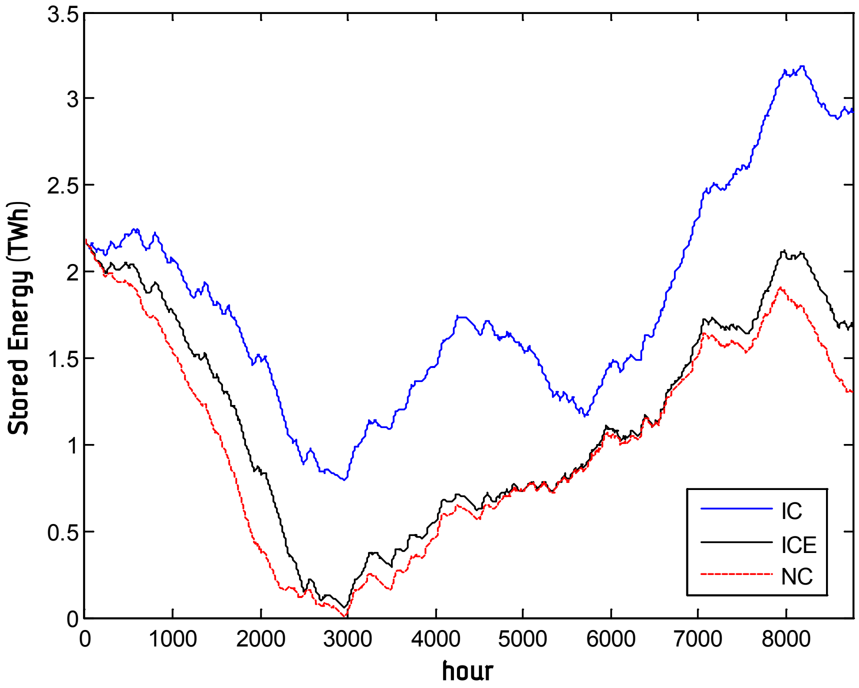


Figure 54. Simulated reservoir trajectories at Tonstad for the IC, ICE and NC scenarios

The annual amount of pumped hydro is presented in Table 37. The pumped hydro energy increases by 16% from the IC to the ICE scenario and by 22% from the NC to the ICE scenario. It appears that the internal grid constraints in the German system result in an export of surplus WPP from the North Sea to the Norwegian hydropower system.

Table 37. Annual pumped hydro

Case	Annual pumping [TWh]
IC	3.2916
ICE	2.7179
NC	2.0992

13.6 Flows in Offshore Grid

This section examines the detailed effect of onshore grid bottlenecks on the power flow across offshore grid. The three cases for onshore grid restrictions are in accordance with Section 13.5. These cases are “No Constraint (NC)”, “Internal Constraint (IC)” and “Internal Constraint with expansion (ICE)”. According to analysis in Section 13.5, it appears that the most optimal offshore grid topology with respect to operating cost results are Case B in the NC scenario and Case C in the IC and the ICE scenarios.

Table 38 presents the utilisation of the HVDC links. The utilisation of the transmission cables is divided into three columns namely "Total", "From" and "To". "Total" shows the total utilisation of the cable. "From" represents the cable utilisation in the direction of flow from-bus to to-bus, and "To" indicates the flow in the opposite direction so from to-bus to from-bus.

Table 38. The Utilisation of Bilateral HVDC Connection between Countries and Offshore Grid Multi Terminal Connection (Baseline Wind Scenario)

No.	Transmission line		Capacity [MW]	Utilisation [%]								
				NC			ICE			IC		
	From	To		Total	From	To	Total	From	To	Total	From	To
1	**NO**	**UK**	1400	97.8	88.5	9.3	97.1	84.4	12.7	96	85.0	11.0
2	**NO**	**NL**	1400	96.6	95.8	0.8	75	61.4	13.7	74.2	48.1	26.1
3	**NO**	**DE**	1200	92.8	80.1	12.7	91.5	80.9	10.6	83.5	52.7	30.8
4	**DK**	**NL**	700	87	67.3	19.7	91	17.0	74.0	84.7	54.0	30.7
5	**NO**	**DK**	1700	76.5	50.4	26.1	83.3	67.6	15.7	78.2	40.7	37.5
6	**NL**	**UK**	1290	92.7	11.2	81.5	85.3	1.7	83.6	82.7	7.3	75.4
7	**SE**	**DK**	485	94.5	86.9	7.6	97.7	92.3	5.4	93.8	65.1	28.7
8	**NO_{Idunn}**	**NO_{CVST}**[16]	2010	59.9	21.5	38.4	65.1	24.1	41.0	64.1	15.5	48.6
9	**NO_{Idunn}**	**UK_{DB}**	2000	63.9	42.7	21.2	66.5	44.6	21.9	68.9	56.0	12.9
10	**UK_{DB}**	**UK_{CVST}**	3600	65.85	40.7	25.2	75.2	55.2	20.0	79.55	67.5	12.1
11	**UK_{DB}**	**NL_{IJ}**	1000	91.4	86.2	5.2	88.4	68.2	20.2	80	66.2	13.8
12	**UK_{DB}**	**DE_{Gaia}**	1000	64.6	44.4	20.2	69.2	35.4	33.8	75.9	27.8	48.1
13	**DE_{Gaia}**	**DE_{CVST}**	1710	87	85.8	1.2	98.9	98.7	0.2	87.3	84.9	2.4
14	**NO_{AEgir}**	**NO_{CVST}**	500	63.7	14.5	49.2	74.1	36.8	37.3	72.9	29.9	43.0
15	**NO_{AEgir}**	**DE_{Gaia}**	1000	-	-	-	57.7	53.5	4.2	65.7	62.7	3.0
16	**NO_{AEgir}**	**NL**	1000	85.1	84.8	0.3	-	-	-	-	-	-

As shown in Table 38, the connections between the converter substation on main land and offshore wind facilities are not only used to transfer power from offshore wind facilities to shore, but are also used to transfer power from shore to the offshore grid. In this way the offshore grid is used as a corridor transferring power between the countries around the North Sea. This is especially the case for the Norwegian offshore

[16] NO_{CVST} is a converter substation (CVST) on mainland to which the offshore wind farm is connected

wind facilities (Idunn and Ægir) indicating that the offshore grid contributes to transfer flexible hydro production from southern coast of Norway to the adjacent countries around the North Sea.

Figure 55 shows the differences in the cable utilisation difference for the NC and the ICE scenarios (NC-ICE). A comparison of the total cable utilisation for the three different onshore grid scenarios shows that moving from the NC to the ICE scenario substantially reduces the utilisation of the direct connection between Norway and the Netherlands by about 21.6%. Generally, the utilisation of connections between offshore wind facilities and the convertor substation has been increased. Likewise, the exchange between Norway and Denmark and the offshore nodes in the UK and Germany increases.

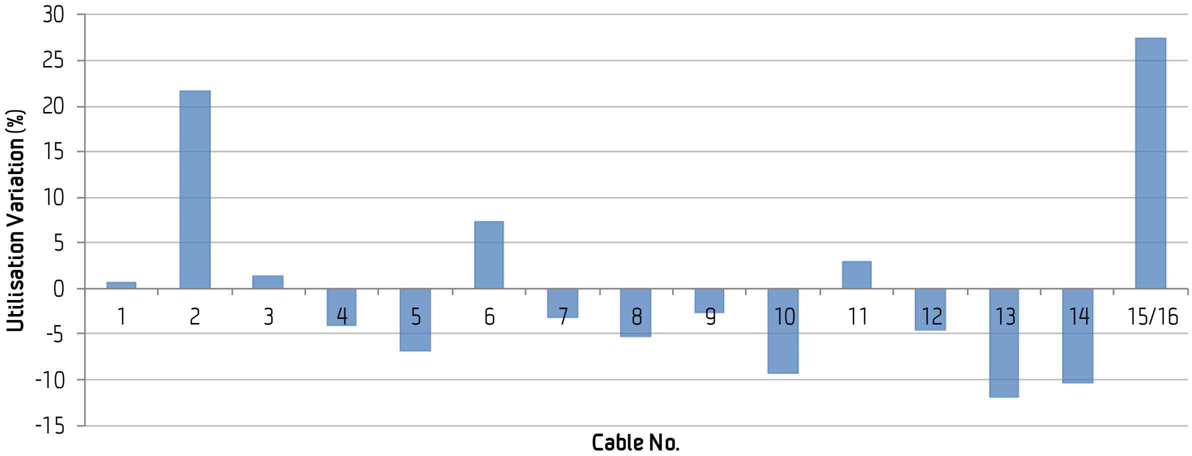


Figure 55. Variations in cable utilisation when moving from NC to ICE (Baseline Wind Scenario)

Figure 56 illustrates that moving from the ICE to the IC scenario results in a substantial decrease in the cable utilisation except for the connections between N_{OIdunn}-UK_{DB}, UK_{DB}-UK_{CVST}, UK_{DB}-DE_{Gaia} and NO_{AEgir}-DE_{Gaia}. It turns out that the internal constraint in the onshore grid limits the energy exchange between the countries. Hence, the utilisation of the cables decreases significantly. In general, the more congested the onshore grid, the less utilisation is observed in the offshore grid.

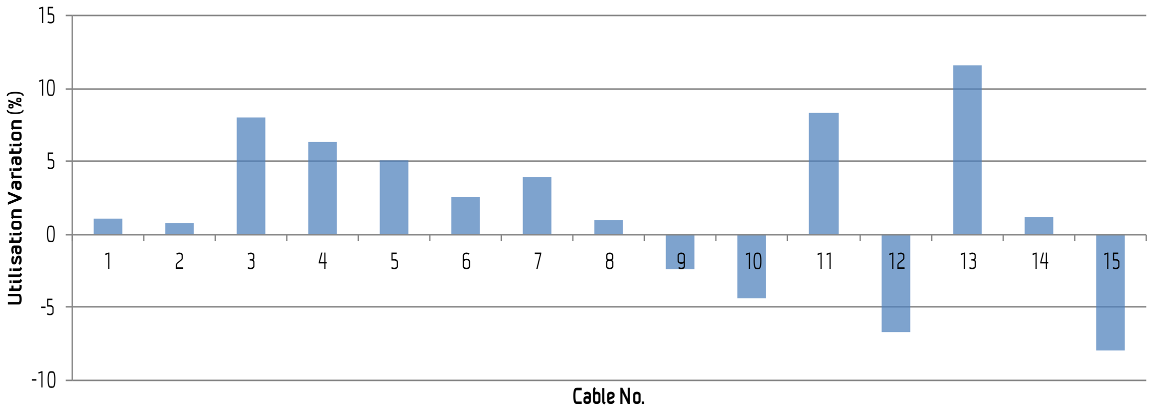


Figure 56. Variations in cable utilisation when moving from ICE to IC (Baseline Wind Scenario)

Figure 58 schematically shows the utilisation of each HVDC cable and the mean direction of the exchange between two nodes. The blue lines represent the direct connection between two countries while the green lines are the connection between offshore nodes. The arrows on the lines represent the flow direction of the average exchange. In case of bi-directional arrows balanced exchange is indicated.

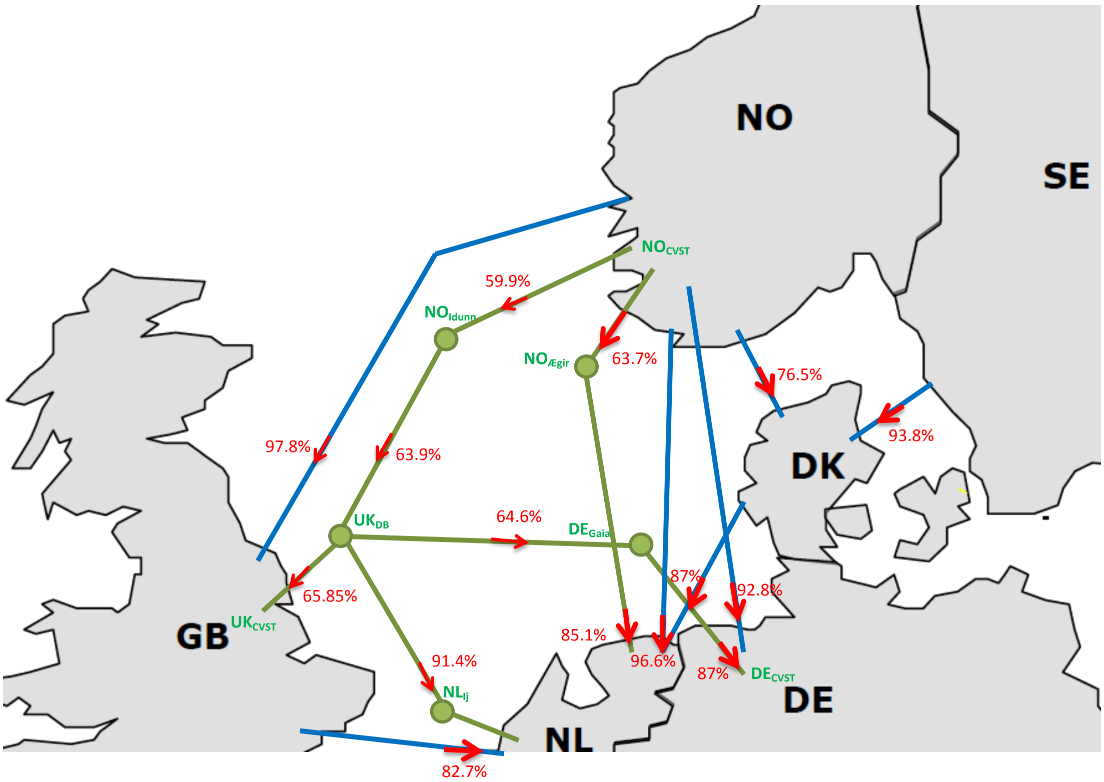


Figure 57. Exchange of power across the offshore grid for the NC scenario

The arrow's location represents the line utilisation in that direction. The closer the arrow to the end of the line, the more power has been transferred in that direction. For instance, the arrow on the cable between $NO_{Ægir}$-DE_{Gaia} is very close to DE_{Gaia} showing that this cable is very much used to transfer power from $NO_{Ægir}$ to DE_{Gaia}. This result can be observed in Table 38 as well that the cable has been used in this direction for 92.8%. The number on the arrow indicated the overall utilisation of the according HVDC cable.

As it can be observed in Figure 57, the general flow direction is from the Northern to the Southern parts of Europe. The cables between offshore wind farms and substations in Norway have been predominantly used to send power from shore to the offshore nodes and further down to the German and Dutch power systems. The cables between Denmark and its northern neighbours Sweden and Norway are mainly used to transfer power to the Danish system, while the cable between Denmark and the Netherlands is used to transfer power to the Dutch system. The cables between UK_{DB} and DE_{Gaia} are mainly used to transfer power from the British to the German offshore node and further down to the main land system.

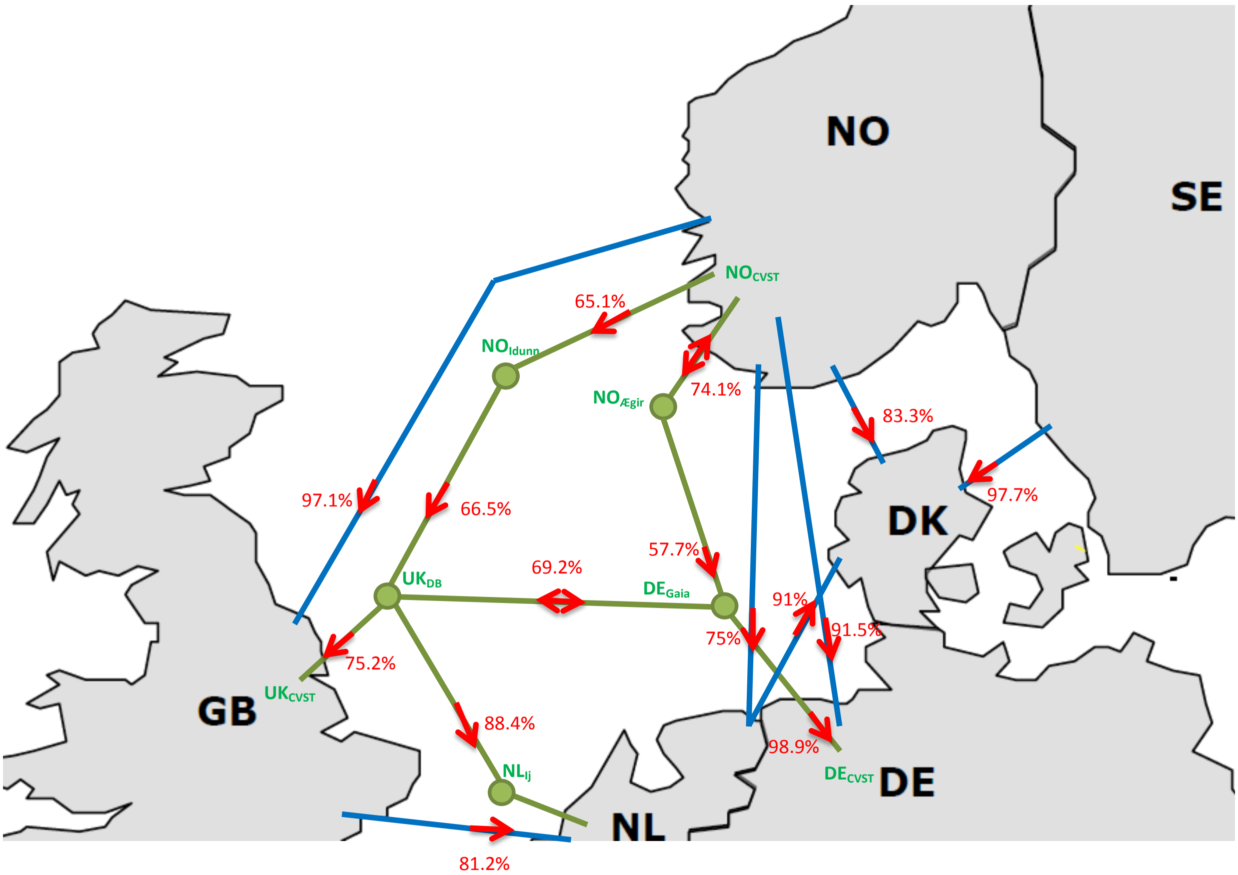


Figure 58. Exchange of power across the offshore grid in the ICE scenario

Figure 58 shows similar behaviour as Figure 57. However, the distance between the arrows at the southern nodes has been increased, leading to the conclusion that the flows from the Northern to the Southern parts have been decreased due to the effect of the internal onshore grid constraints. In this context, the flow across the bilateral connections decreases while the exchange on DK-NL connection has changed the direction, now transferring power from the Netherlands to Denmark. This is due to the internal bottlenecks in the Dutch system. The average exchange between UK_{DB} and DE_{Gaia} now is in the direction towards UK_{DB}.

Figure 59 reflects the effect of internal constraints more than the previous figures. The exchange from Norway to the Danish system has been significantly changed and similarly the exchange across UK_{DB}-DE_{Gaia} redirected towards the British system. The Internal constraints in the German system avoid the high penetration of offshore wind from the North Sea thus redirect the flow towards the British system. Also, the exchanges between Norway and both the German and the Dutch systems have decreased substantially.

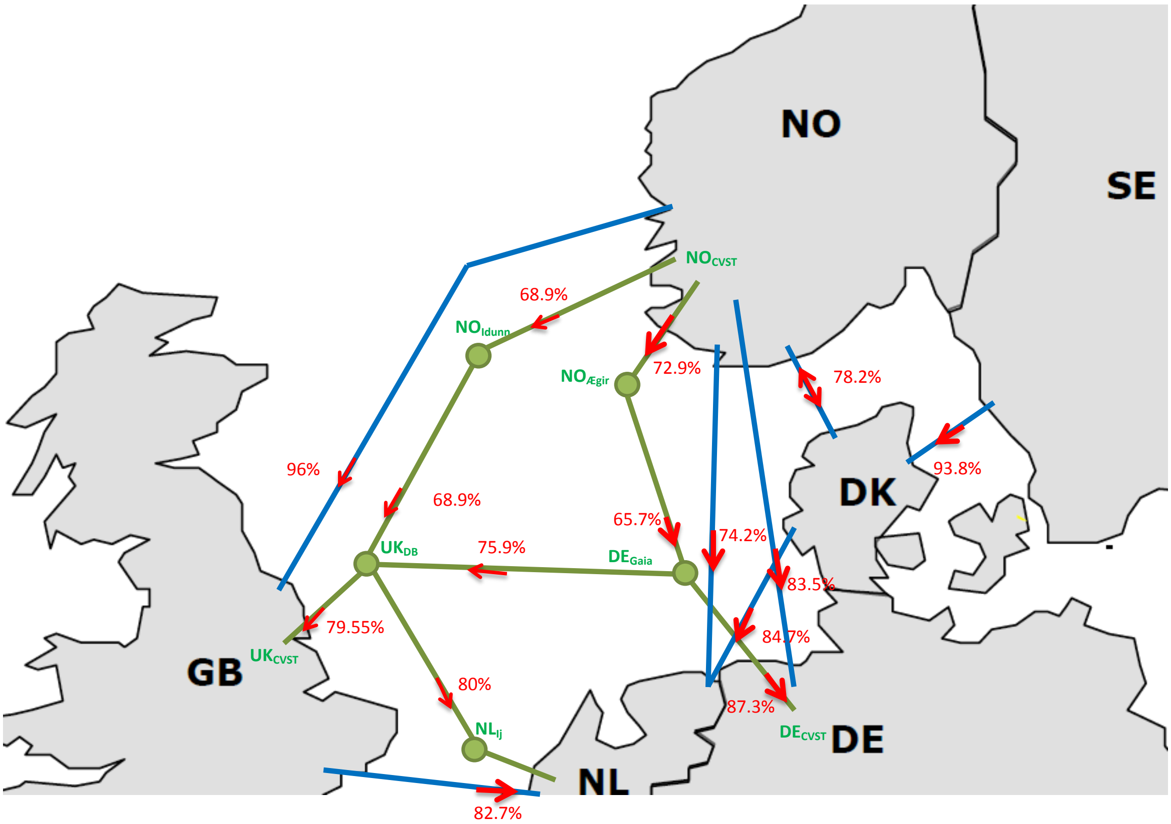


Figure 59. Exchange of power across the offshore grid in the IC scenario

Figure 60 depicts the offshore cable utilisation. The general trend in the first row and the first two graphs in the second row indicate that the internal grid has reduced the cable utilisation on the direct connections. The exchange pattern has changed between Denmark and the neighbouring countries in ICE scenario. This indicates that Denmark plays pivotal role to transfer potential WPP from the North Sea and hydro power from the Norwegian to the Central European power system.

Looking at the second and third rows shows that the internal onshore grid constraints in the German and Dutch systems change the flow direction towards the British system. This can be explicitly observed in the first two figures of the third row showing the cable utilisation between UK_{DB} – NL_{lj} and UK_{DB} - DE_{Gaia}. The increased flow on the cable between Gaia (The German offshore node) and onshore substation (DE_{CVST}) in the ICE and the IC scenario is due to the fact that in those cases Gaia is directly connected to the Norwegian offshore node (Ægir), providing more opportunity to transfer power from the offshore node to the onshore power system. As shown in the second last graph in the third row, the exchanged power between the Norwegian offshore node and the onshore substation has been decreased in the ICE and IC scenarios.

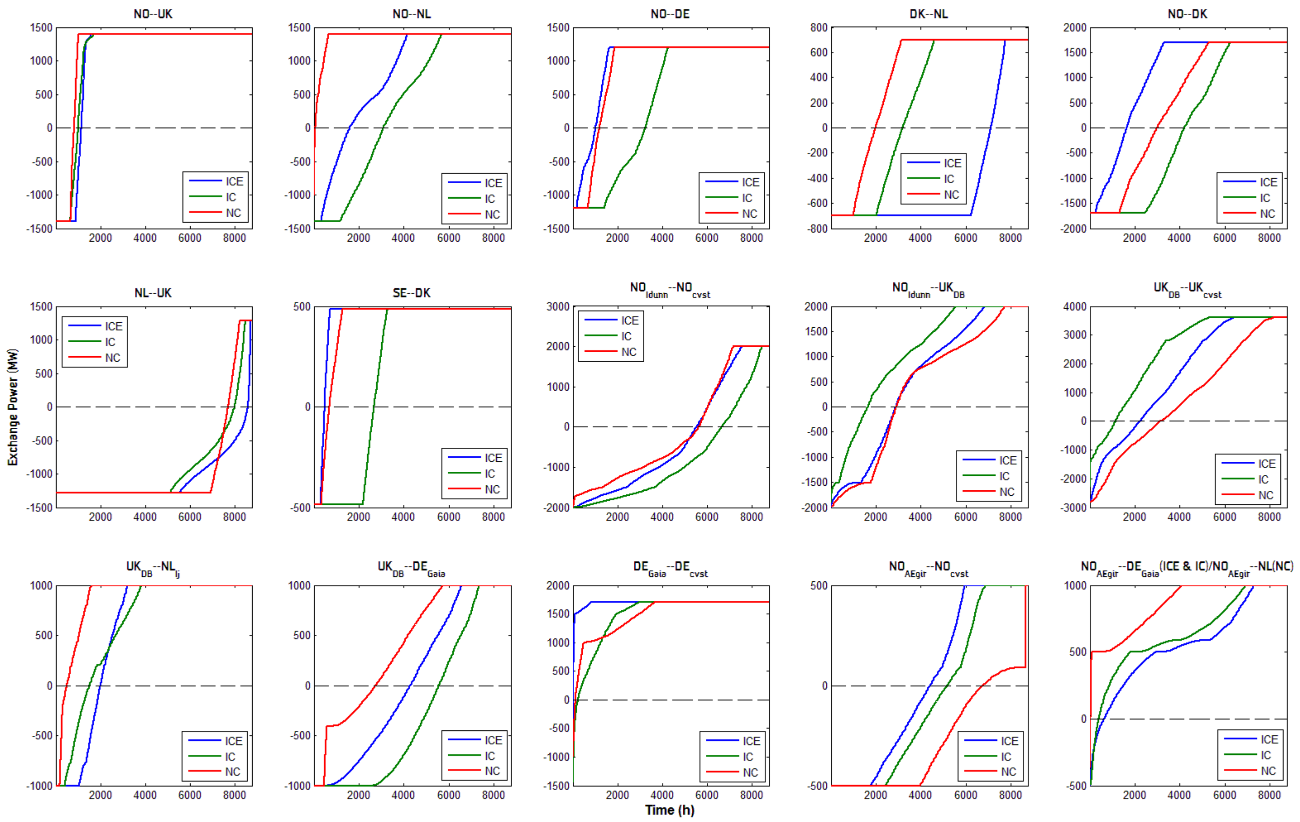


Figure 60. Duration curve of the offshore cable utilisation (Baseline Wind Scenario)

14 2020 case study

In the 2020 case study, it is assumed that the offshore grid will not yet be commissioned. However, the transmission capacity between countries has been increased from today's situation. Apart from the existing cross-border transmission lines, additional transmission lines are assumed to be commissioned according to available data from TYNDP 2012 [27]. The overview of cross-border HVDC links in 2020 is depicted in Figure 61.

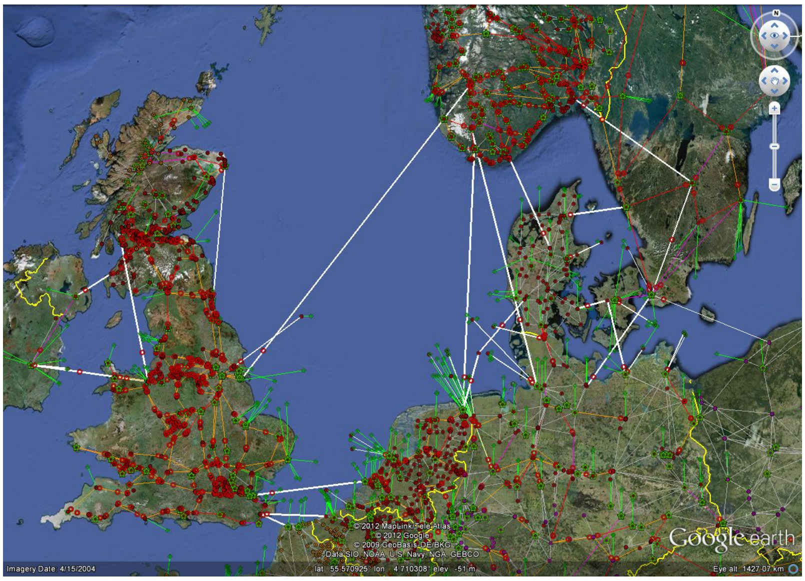


Figure 61. Overview of cross-border connections in the North Sea in 2020

The total energy mix for electricity production in 2020 is illustrated in Figure 62. The energy mix is essentially determined by the marginal costs and generator capacities with limitations imposed by the transmission grid. The main trend in the energy mix is similar to 2030, illustrating the shift from fossil fuel based generation to renewable generation. The annual wind energy production is equal to 761.9636 TWh which represents 20% of the total European energy production.

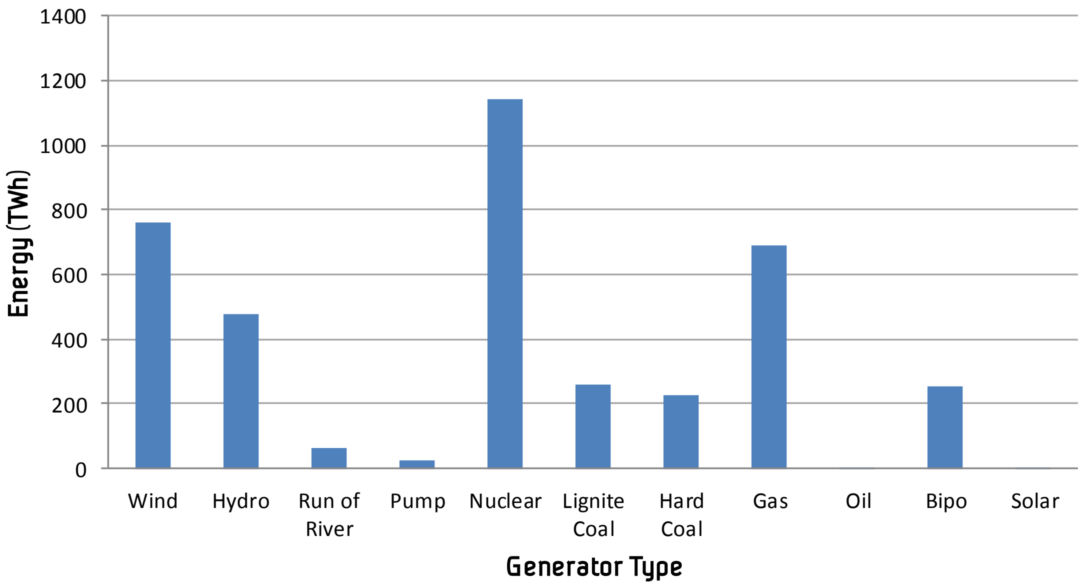


Figure 62. Energy mix in the Continental European electricity system in 2020

Figure 63 illustrate the projected wind energy production across the Continental European system in 2020. As shown, the offshore wind production increasingly contributes to the annual production, especially in the countries around the North Sea and the Baltic Sea.

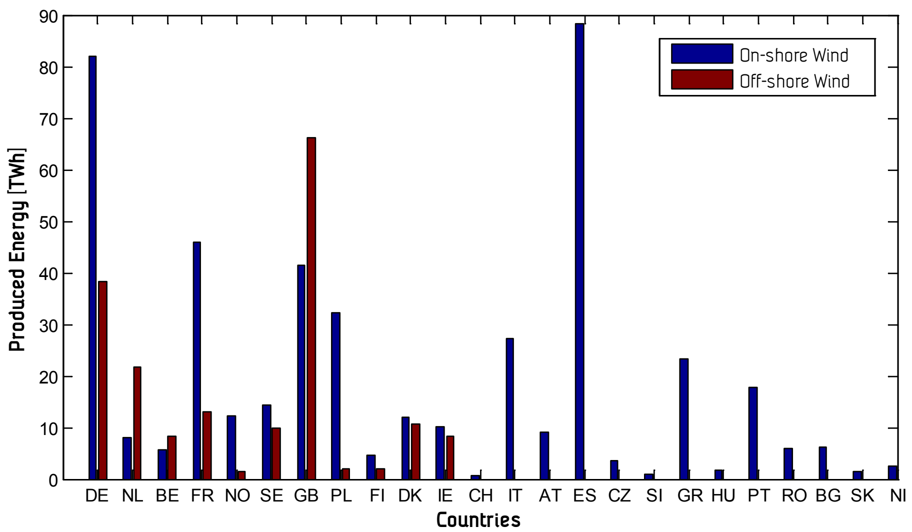


Figure 63. Wind energy production per Country in 2020

14.1 Reservoir Trajectory in Norway in 2020

The first hydro capacity scenario with an assumed capacity expansion of 11.2 GW presented in Table 24 is considered for the simulations in 2020. Figure 64 represents the comparison between the simulated reservoir trajectory in Norway and recorded data from 2010, 2011, and 2012. As indicated, the simulated reservoir (black curve) follows the seasonal variations. The reservoir level at the end of the year corresponds to the initial reservoir level at the beginning of the year, therefore reflecting the strategic use of hydro power throughout the year.

During the period of depletion (week 1 to week 18), the simulated reservoir level is reduced below the median and the 2011 trajectory. However, it fills up faster due to the contribution of pump storage plants in the filling period(week 22 to week 31).

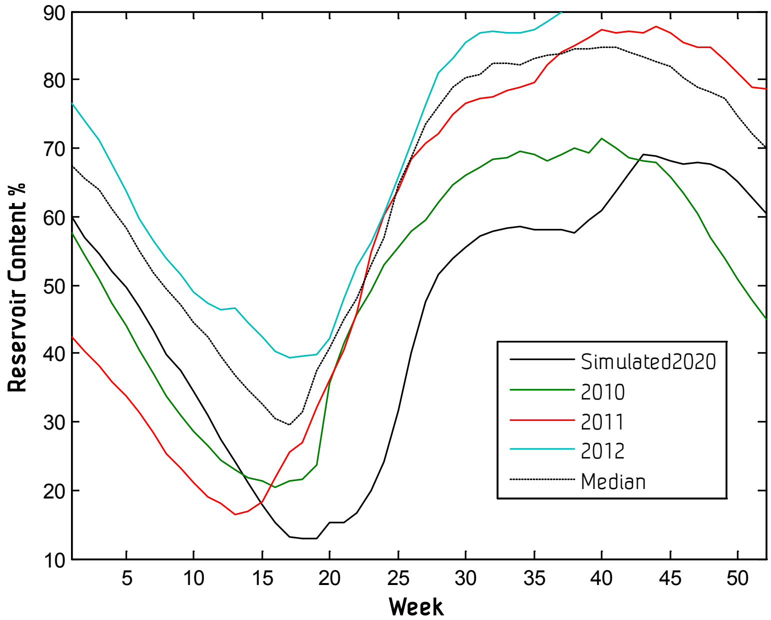


Figure 64. Simulated and recorded reservoir content for Norway in 2020

In this section, different case studies are investigated to capture the effects of bottlenecks in the ENTSO-E transmission system, notably in Germany, the Netherlands and the UK as well as in the Norwegian transmission system. Overall, four case studies are analysed to study the influence of grid congestion on the previously mentioned transmission systems.

Table 39 presents the annual operating cost for the case studies. The analysis for each of these cases is carried out taking the internal bottlenecks in one or both of the hydro and the thermal dominated power systems in consideration. Comparing the "IC" and "ICE" scenarios reveals that expanding transmission capacity in the ENTSO-E and the UK systems results in annual savings of approximately 302 MEUR and

313 MEUR, respectively. The cases with and without grid expansion in the Norwegian system result in savings between approximately 6.8 MEUR and 17.9 MEUR, respectively.

Table 39. Annual operating costs for 2020 case studies

Grid Constraints in the ENTSO-E and the UK	Grid Constraint in the Norwegian system	Cost [bn€/a]
Internal Constraint	With Yellow Corridor	92.3344
	Without Yellow Corridor	92.3412
Internal Constraint with Expansion	With Yellow Corridor	92.0206
	Without Yellow Corridor	92.0385

Figure 65 shows the simulated hydro reservoir filling levels throughout the year in the Nordic system. In the IC scenario, the Norwegian hydro level slightly increases and ends in a higher level compared to the ICE scenario. This shows that the expanded grid introduces more opportunities to produce and transfer hydro energy to the Central European system. Consequently, the expanded grid in Germany and the Netherlands provide a flexible infrastructure to exchange hydro energy from the Nordic system to the European power system.

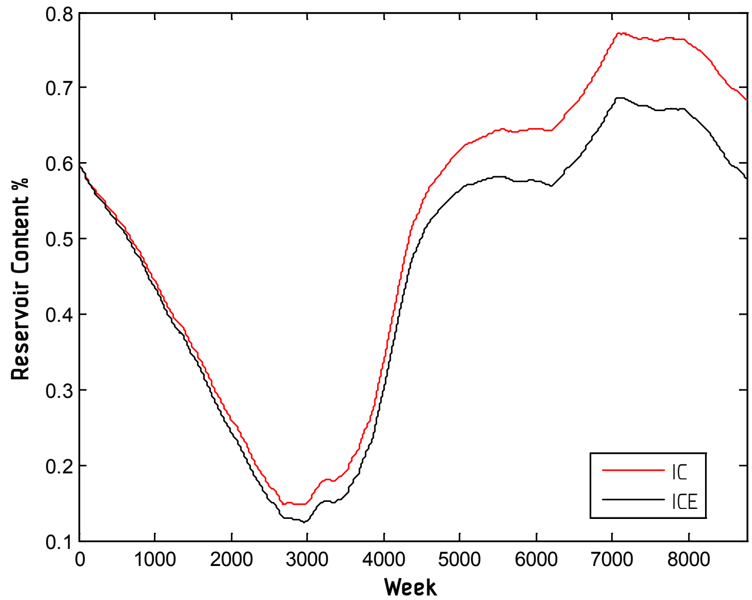
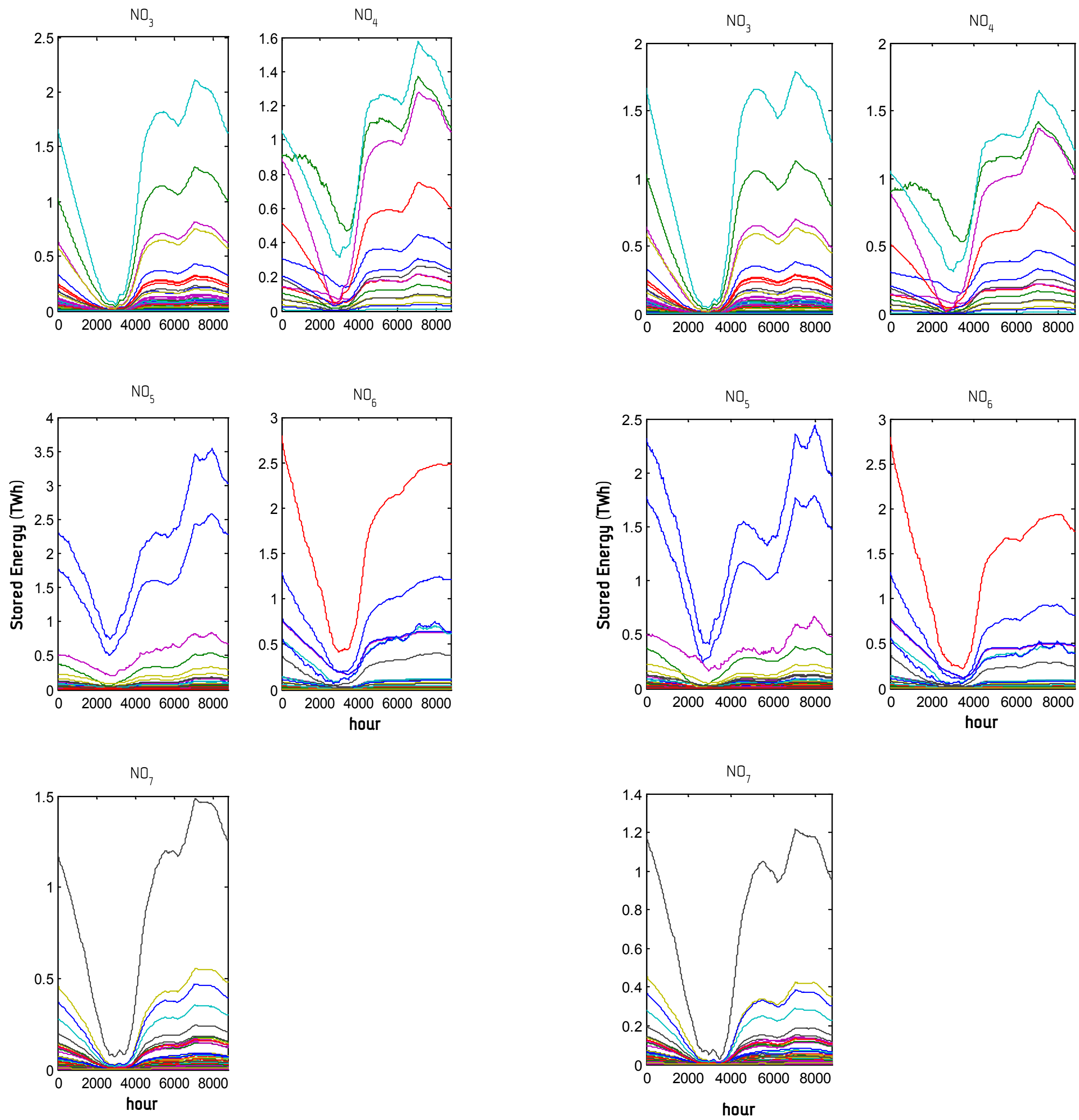


Figure 65. Simulated reservoir trajectory in the Nordic area for the IC and the ICE scenario in 2020

Figure 66 depicts the reservoir trajectory in both cases with internal grid constraint and extended transmission capacity similar to the case in 2030. As shown, reservoirs end up with a higher reservoir level in the case with non-expanded internal grid. Similar to 2030, this can be explained by the fact that the internal grid bottlenecks in the central European power system avoid transmitting hydro power from the Nordic system to the European system.



(c) IC scenario

(d) ICE scenario

Figure 66. Reservoir trajectory of each individual reservoir in Southern Norway (2020)

Figure 67 presents the comparison of reservoir trajectory curves at Tonstad. The results largely correspond to the 2030 cases. The reservoir trajectory is significantly different in the case including Internal Constraints (IC). The results reflect the fact that grid reinforcements in Germany result in a higher flexibility in the transmissions system and offer the opportunity to transfer wind energy as well as imported energy from the Norwegian power system.

Comparing Figure 54 and Figure 67 reveals that the reservoir variations in 2020 are smoother than in 2030. An increasing transmission capacity between the Norwegian and the Continental power systems, results in a higher utilization of pump storage power plants in Norway. Therefore, especially the reservoirs directly connected to the cross-border HVDC links are expected to experience more fluctuations of the reservoir level.

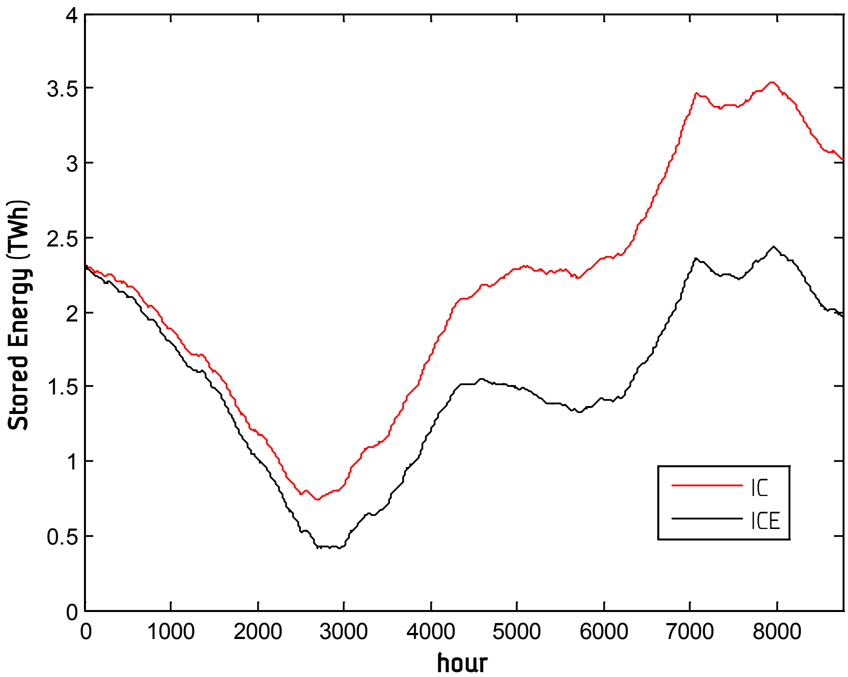


Figure 67. Tonstad simulated reservoir trajectory (2020)

Figure 68 depicts the pumping pattern at Tonstad and the WPP of German wind facilities connected to the NorGer cable. Unlike in 2030, the pump pattern is not correlated to the wind power variations. This can be explained with a lack of transmission capacities between the two areas in 2020.

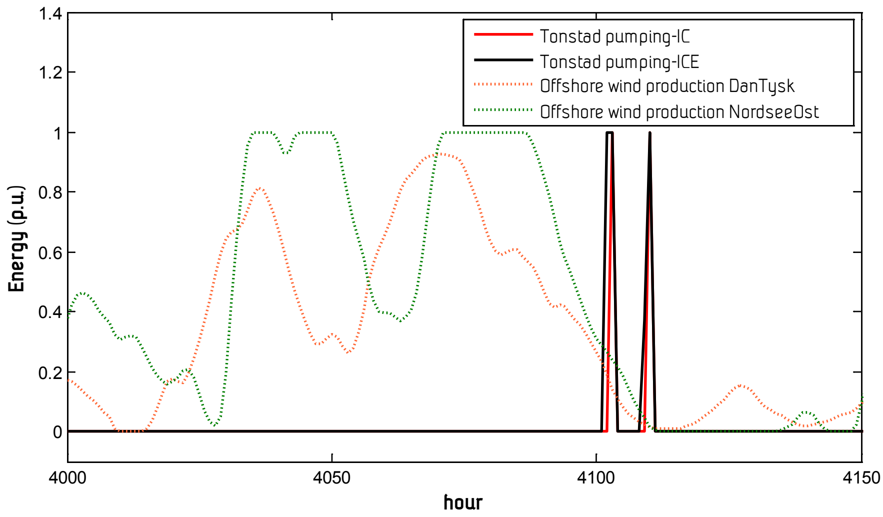
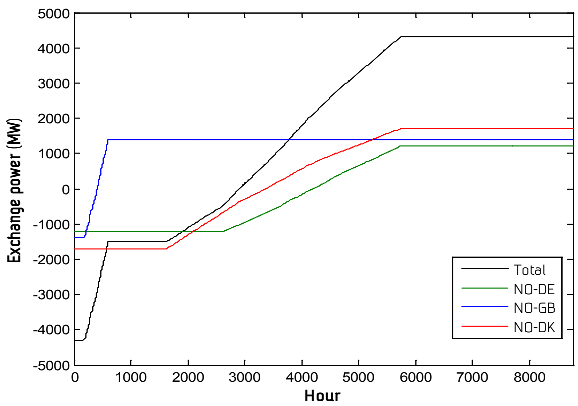


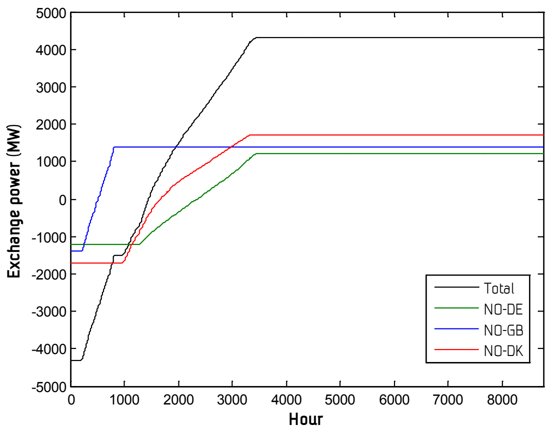
Figure 68. Simulated Offshore WPP in Germany vs. pumping patterns at Tonstad for the IC and ICE in 2020

The duration curves illustrating the annual exchange of energy through the cross border HVDC links between Norway and its neighbouring countries are shown in Figure 69. The HVDC utilisation of the connections between Norway and Germany or between Norway and Denmark have been shifted to the left hand side in (b) showing that grid reinforcement paves a way to export hydro power from Norway to Germany and to Denmark, leading to a higher production flexibility in this case.

When comparing the 2020 data in Figure 69 with 2030, it can be resulted that during a predominant number of hours the HVDC transmission lines are congested. This illustrates the need for a further offshore grid expansion in the North Sea.



(a) IC scenario



(b) ICE scenario

Figure 69. Utilisation of the HVDC interfaces between Norway and its neighbouring countries in the North Sea

15 Different Wind Power Scenarios

Similar to [14], two different wind cases including a baseline and a high scenario are investigated for the 2020 and the 2030 scenarios. The baseline scenario is assumed to be the most likely future construction scenario while the high scenario represents an optimistic case for the future wind power development. Table 40 presents the annual European wind energy output for the different wind scenarios. As shown, the total wind production in the 2030 high scenario is more than twofold the wind energy production in the 2020 baseline scenario. Therefore, the high scenario will be more challenging with respect to power transmission and might require further grid expansions for an optimal power exchange between countries.

Table 40. Annual European wind energy output

Year	Scenario	Wind Energy Output [TWh]
2030	Baseline	1073.67
	High	1294.77
2020	Baseline	645.44
	High	754.65

Figure 70 compares the duration curves of the total wind power output for different wind scenarios. As shown, the wind energy production in the high scenarios exceeds 146 GW and 84 GW for more than 4000 hours in 2030 and 2020, respectively. For the baseline scenarios the according wind energy production corresponds to 121 GW and 71 GW for 2030 and 2020, respectively.

It is evident from the figures that the distribution of WPP facilities in Europe leads to geographical smoothing effects, reducing the variability of the European wind production pattern.

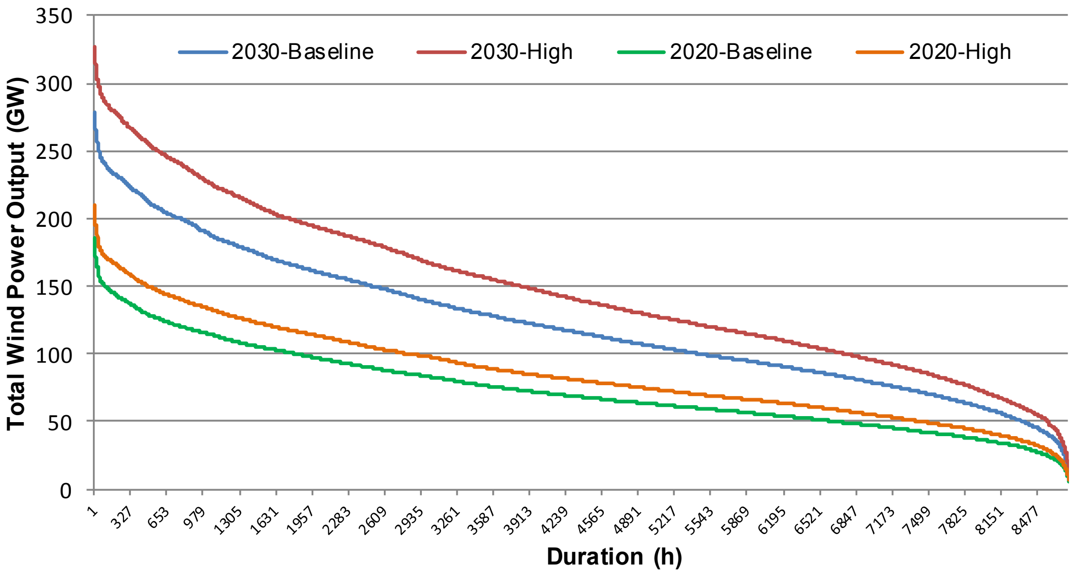


Figure 70. Duration curves of simulated European wind power output for 2020 and 2030 scenarios

Figure 71 shows the duration curves for all wind facilities in the 2030 medium scenario. By comparison of Figure 70 with Figure 71 it is evident that there is a significant smoothing of wind power output when considering the European WPP as a whole.

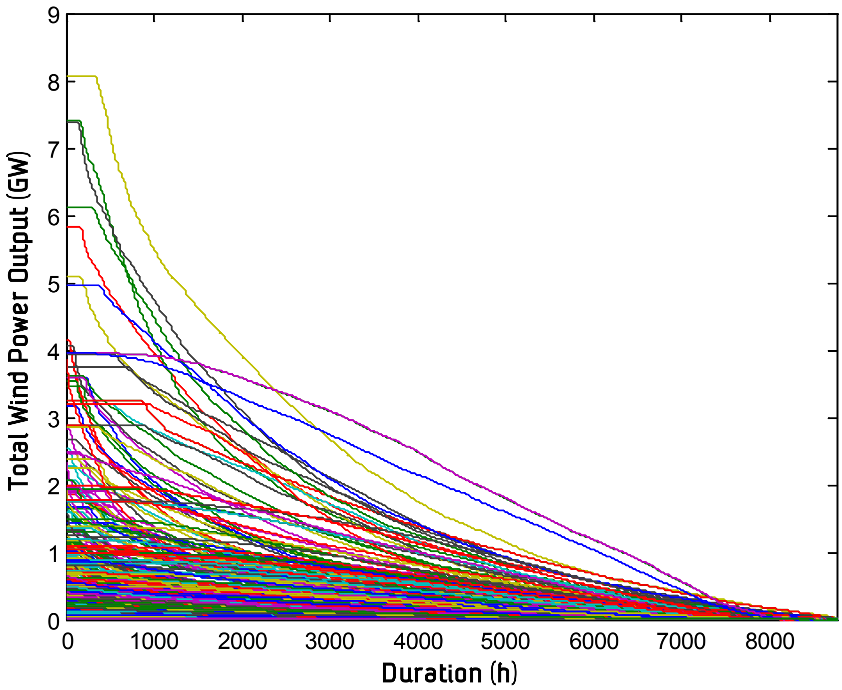


Figure 71. Duration curves of simulated wind power output for each of wind facilities in 2030

Figure 72 depicts the installed offshore wind capacity at the offshore nodes connected to Norway, the UK, Germany and the Netherlands. The installed capacity is shown for both, the baseline and the high wind scenarios. Comparing this two wind scenarios illustrates the significant increase in the high wind scenario. Especially the nodes in the UK (Dogger Bank), Germany (Gaia) and the Netherlands (Ijmuiden) will contribute to the respective installed capacity. This information is important to analyse the effects of the high wind scenario on the power exchange between the offshore nodes.

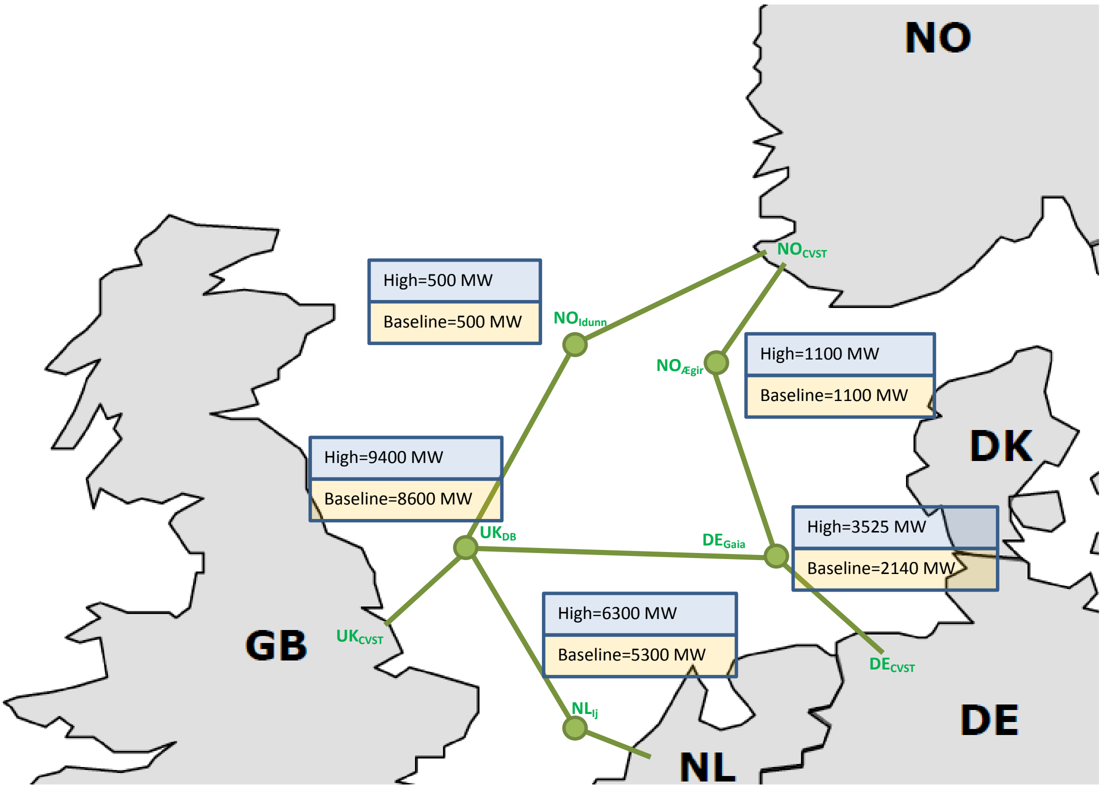


Figure 72. Installed wind power capacity at each offshore node

Likewise the case for medium wind scenarios, the same case studies as in Section 13.5 is conducted for the 2030 scenario. These case studies are clustered in order to capture the effect of the offshore grid as well as internal onshore grid bottlenecks in the European power system. Therefore, the simulations are split into two interrelated steps capturing the impact of both offshore and onshore grid bottlenecks. The first step studies the effect of offshore grid on the power flow. This scenario is divided into three cases the same as Figure 52:

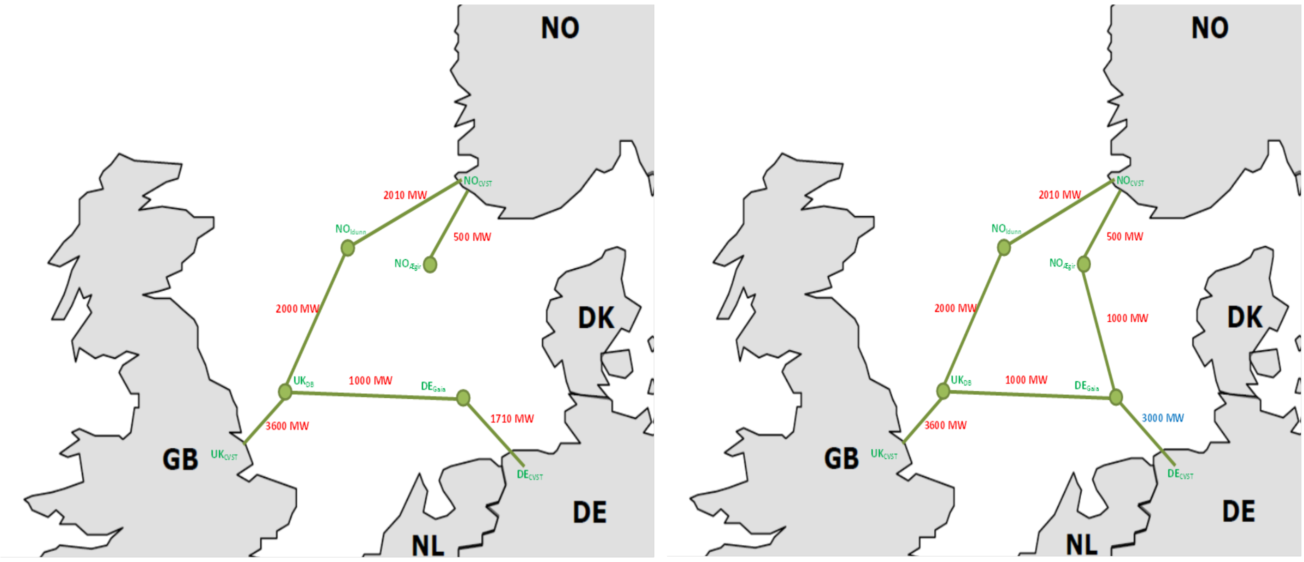
- Case A
- Case B
- Case C

The next step includes case studies of internal grid bottlenecks in Germany, the Netherlands and the UK. Overall this step consist of three case studies, i.e., “No constraint (NC)”, “Internal Constraint (IC)” and “Internal Constraint with Expansion (ICE)”.

Looking at the updated wind power potential at Gaia offshore wind farm reveals that the transmission capacity from the offshore node to shore is not enough to transmit the all of the potential wind energy. The grid topologies and the proposed transmission capacity of each HVDC cable are described in Figure 73. The proposed offshore grid topology and the transmission capacity of HVDC cables are shown in Figure 73 (a). The wind power production at each offshore node in Norway and Germany is illustrated in Table 41. Comparing the High and the Baseline scenarios shows that the mean wind production at Gaia (German offshore node) is increased by 686 MW. Thus, HVDC capacity across the link from Gaia to onshore is increased by 700 MW to accommodate the increased wind production. On the other hand, it can be possible that the produced wind energy at Ægir (German offshore node) is transferred to the onshore grid in Germany through the same HVDC link. Therefore, the capacity of the HVDC connection is further increased by 600 MW, resulting in an overall capacity increase of 1300 MW. The total capacity of the HVDC appears to be approximately 3000 MW. The updated grid topology along with the transmission capacities are shown in Figure 73 (b).

Table 41. Installed wind capacity and mean wind production at each offshore node in Figure 73

Offshore node	High scenario [MW]		Baseline Scenario [MW]	
	Installed capacity	Mean Production	Installed capacity	Mean Production
Gaia	3525	1769	2140	1083
Ægir	1100	569.4	1100	569.4



(a) Proposed Offshore Grid capacities in [5]

(b) Updated offshore grid topology and transmission capacity

Figure 73. Proposed offshore grid capacities

15.1 Monetary Savings

In this section, the operational savings for the previously described cases studies are presented and compared against each other in Table 42. The results are based on the High wind scenario. Looking at "No constraint" scenario reveals that the optimal offshore grid topology in terms of operating savings is "Case C". This is different from the baseline wind scenario where "Case B" was the best proposed alternative. While moving from Case A to Case B results in annual savings of approximately 105 MEUR, the step from Case B to Case C results in annual savings of about 72 MEUR resulting in total saving of 177 MEUR.

In the "Internal Constraint" scenario, the optimal offshore grid topology is "Case C". Moving from Case A to Case B and further on, from Case B to Case C results in annual savings of approximately 41 MEUR and 70 MEUR, respectively. There, the total saving is about 111 MEUR. The savings in the "Internal Constraint with Expansion" scenario is approximately 41 MEUR when moving from Case A to Case B and approximately 146 MEUR from Case B to Case C. Therefore, the best alternative for the offshore grid in terms of monetary saving is "Case C" with total saving of 189 MEUR. Comparing the savings with the baseline wind scenarios shows that the savings increase significantly in the high wind scenario and can very well compensate the cost for offshore corridors.

Table 42. Annual operating costs for 2030 case studies (high wind scenario)

Grid Constraints in the ENTSO-E and the UK	Offshore grid Cases	Cost [bn €/a]
No constraint	Case A	85.9255
	Case B	85.8199
	Case C	85.7482
Internal Constraint	Case A	89.8057
	Case B	89.7651
	Case C	89.6946
Internal Constraint with Expansion	Case A	86.4399
	Case B	86.396
	Case C	86.2502

15.2 Power Flows in Offshore Grid

Table 43 shows the offshore grid utilisation based on the high wind scenario. Similar to Section 13.6, the effect of three onshore cases are studied for the most optimal offshore grid topology which appears to be "Case C".

The utilisation for each scenario is shown in three columns, illustrating the total utilisation as well as the direction dependent utilisation. The direction of flow from-bus to to-bus indicated by "From", and "To" illustrates the utilisation in the opposite direction from to-bus to from-bus. The transmission capacity between the German offshore node and onshore substation has been increased to 3000 MW as described earlier.

Table 43. Utilisation of Bilateral HVDC Connections between Countries and Offshore Grid Multi Terminal Connections (High Wind Scenario)

No.	Transmission line		Capacity [MW]	Utilisation [%]								
				NC			ICE			IC		
	From	To		Total	From	To	Total	From	To	Total	From	To
1	**NO**	**UK**	1400	94.9	75.1	19.1	92.1	64.8	27.3	84.5	61.8	22.7
2	**NO**	**NL**	1400	97.5	97.1	0.4	71.7	57.1	14.6	73.9	48.6	25.3
3	**NO**	**DE**	1200	94.8	79.8	15.0	90.1	76.1	14.0	82.7	50.4	32.3
4	**DK**	**NL**	700	90.2	74.6	15.6	92.8	16.8	76.0	87.4	53.5	33.9
5	**NO**	**DK**	1700	79	46.8	32.2	82.7	60.4	22.3	80	33.3	46.7
6	**NL**	**UK**	1290	90.3	25.2	65.1	82.8	1.9	80.9	79.4	8.3	71.1
7	**SE**	**DK**	485	93.2	75.9	17.3	95.9	84.1	11.8	94	53.9	40.1
8	$\mathbf{NO_{Idunn}}$	$\mathbf{NO_{cvst}}$	2010	67.9	28.0	39.9	67.2	27.2	40.0	66.2	23.4	42.8
9	$\mathbf{NO_{Idunn}}$	$\mathbf{UK_{DB}}$	2000	66	40.5	25.5	65.5	41.2	24.3	68	47.7	20.3
10	$\mathbf{UK_{DB}}$	$\mathbf{UK_{cvst}}$	3600	57	40.1	16.9	72.8	56.8	16.0	74.5	63.8	10.7
11	$\mathbf{UK_{DB}}$	$\mathbf{NL_{Ij}}$	1000	90.3	81.7	8.6	90.5	51.5	39.0	86.5	51.7	34.8
12	$\mathbf{UK_{DB}}$	$\mathbf{DE_{Gaia}}$	1000	79.3	48.2	31.1	76.3	48.5	27.8	78.3	37.0	41.3
13	$\mathbf{DE_{Gaia}}$	$\mathbf{DE_{cvst}}$	3000	87.5	87.0	0.5	89.7	89.7	0.0	78.5	77.4	1.1
14	$\mathbf{NO_{AEgir}}$	$\mathbf{NO_{cvst}}$	500	82	37.2	44.8	83.8	35.3	48.5	81.5	34.1	47.4
15	$\mathbf{NO_{AEgir}}$	$\mathbf{DE_{Gaia}}$	1000	61.8	58.2	3.6	63.9	60.8	3.1	64.6	60.1	4.5

Figure 74 illustrates the change in cable utilisation results when moving from the baseline to the high wind scenario. As shown, the exchange between the offshore nodes in the UK and Germany (UK_{DB}-DE_{Gaia}) has increased significantly. This indicates that the extra power produced in the Dogger Bank area is transferred to Germany via the Gaia offshore node. On the other hand, the exchange towards the UK has been decreased. Therefore, the utilisation of direct connections between Norway and the UK, the Netherlands and the UK as well as between the British offshore node and the onshore substation (UK_{DB}- UK_{cvst}) decreased. Furthermore, the cable utilisation of the connections between the Norwegian offshore node and the onshore substation has been increased.

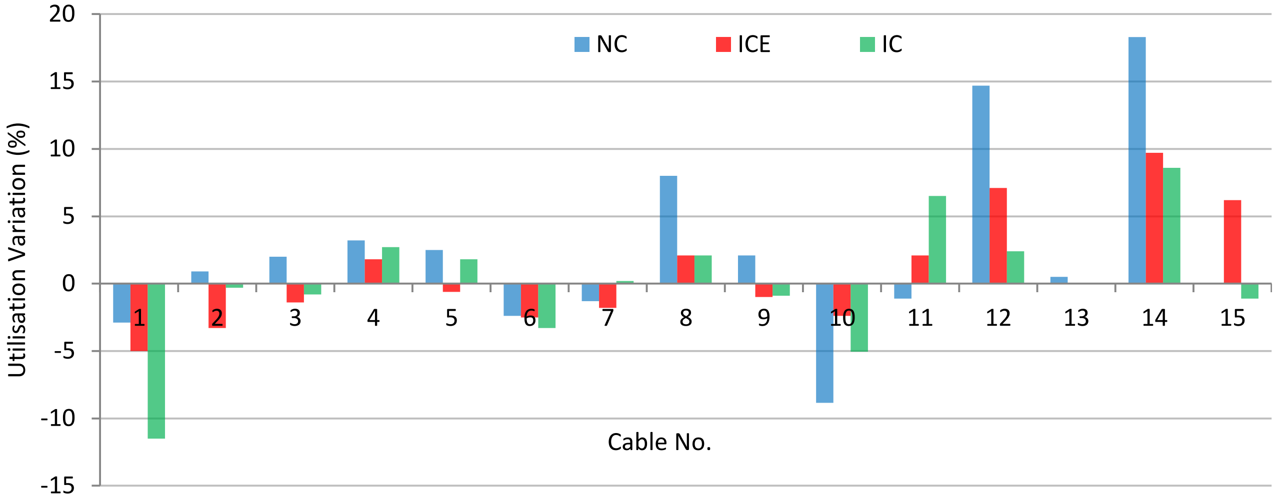


Figure 74. Differences in the HVDC cable utilisation between baseline and high wind scenario

Figure 75 compares the reservoir level for the high and the baseline wind scenarios. In case of the high wind scenario the reservoir at the end of the simulation period appears to be higher than in the beginning. This indicates that the surplus wind energy is stored in the Norwegian hydro reservoir by pumping the water from low to high altitude reservoirs. The stored water can be released to generate power when demand is high and WPP is low.

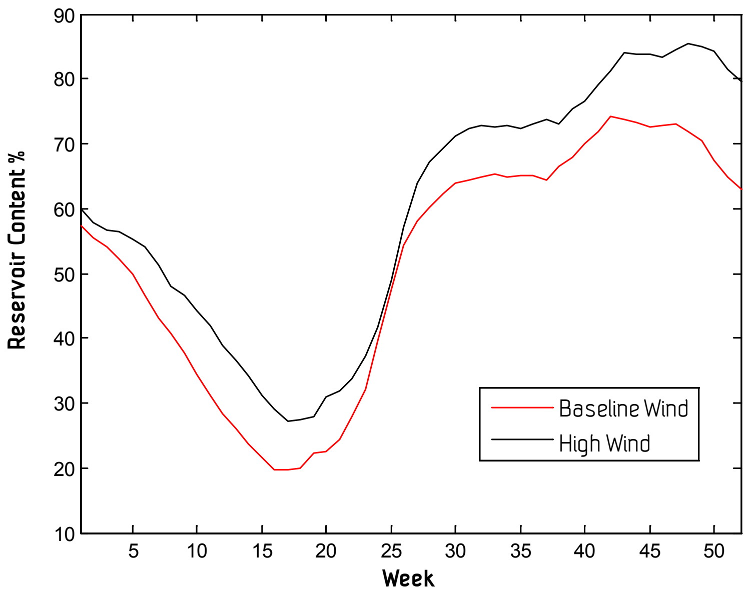


Figure 75. Comparison of reservoir content in Norway for high and baseline wind scenario in 2030

Figure 76 shows the utilisation and the direction of the mean flow exchange between two nodes across each HVDC cable. The blue lines represent the direct connection between two countries while the green lines are the connection between offshore nodes. Similar to Figure 57, the arrow location expresses the utilisation in that direction. Likewise Figure 57, the general flow direction is from the Northern part of Europe to the Southern parts. The cable between Denmark and Norway or Sweden is mainly used to transfer power to the Danish system and further south to the German and the Dutch power systems. The cables between UK_{DB} and DE_{Gaia} are mainly used to transfer power from the British offshore wind farm to the German offshore node and further down to the Continental system. However, when compared to Figure 57 the cables between the Norwegian offshore nodes and the substations are more frequently used to transfer power from offshore nodes to shore. The surplus power is stored in form of hydro energy in the Norwegian reservoirs.

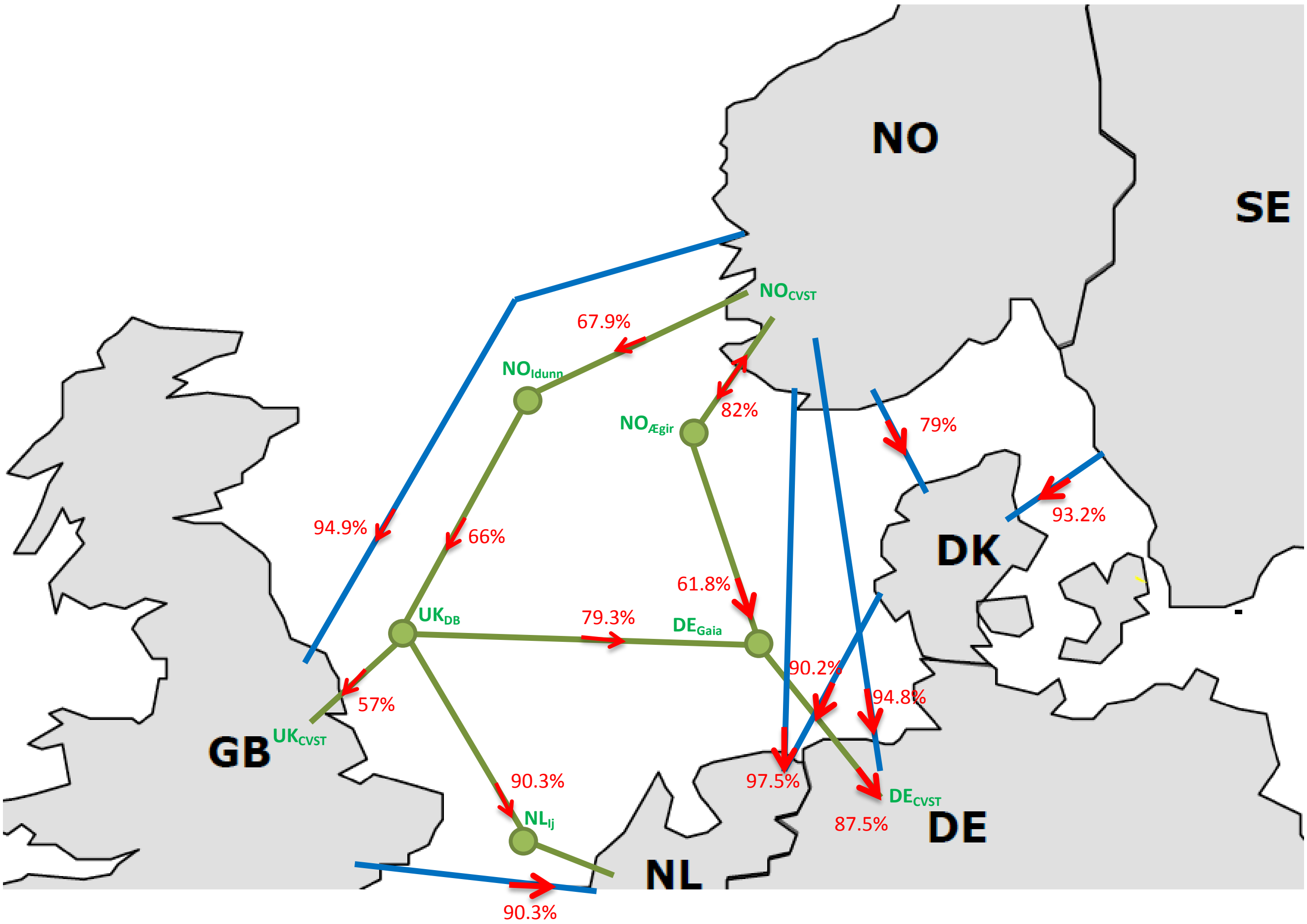


Figure 76. Exchange of power across the offshore grid in the NC scenario (High wind scenario).

Figure 77 depicts the cable utilisation in the case of the ICE onshore grid scenario. The flow pattern is similar to Figure 58 whereas the exchange between UK_{DB} and DE_{Gaia} follows the same pattern as in Figure 76, meaning that an energy surplus is exported from the UK to the German system. When compared to Figure

76 the flows from the Northern to the Southern parts have been decreased due to the effect of the internal onshore grid constraint. The internal bottleneck in the Dutch system caused the exchange from Denmark to the Netherlands to change direction, now exporting power from the Netherlands to Denmark.

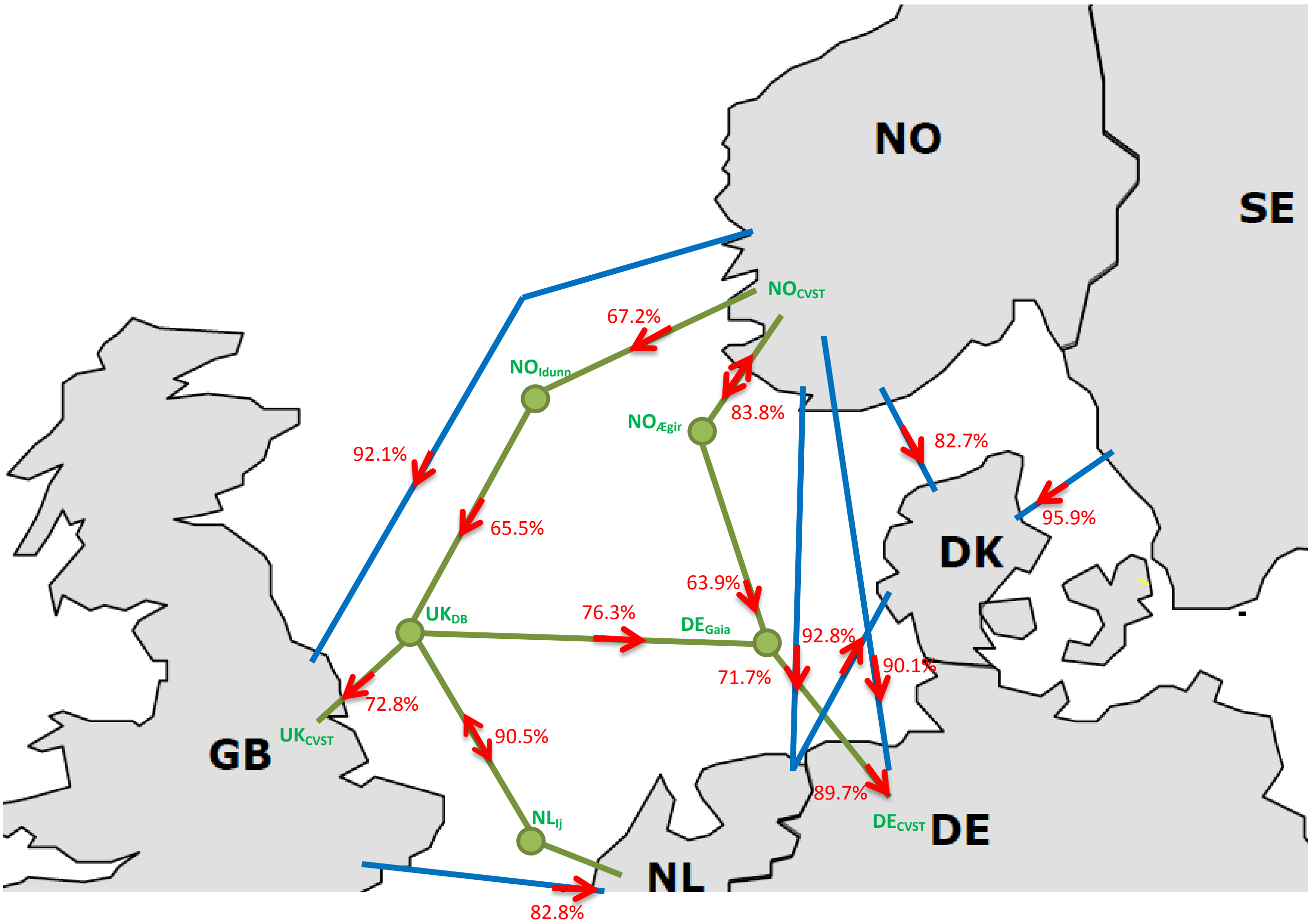


Figure 77. Exchange of power across the offshore grid in the ICE scenario (High Wind Scenario).

Figure 78 shows the effect of internal constraints in case of the IC scenario. The exchange pattern from Norway to the Danish system has changed significantly, when compared to the previous figures. The cable is more frequently used to import wind energy from the Danish system to the Norwegian system. The internal constraints in the German and Dutch systems push the power flow towards the Northern part of the system including Denmark, Sweden and Norway.

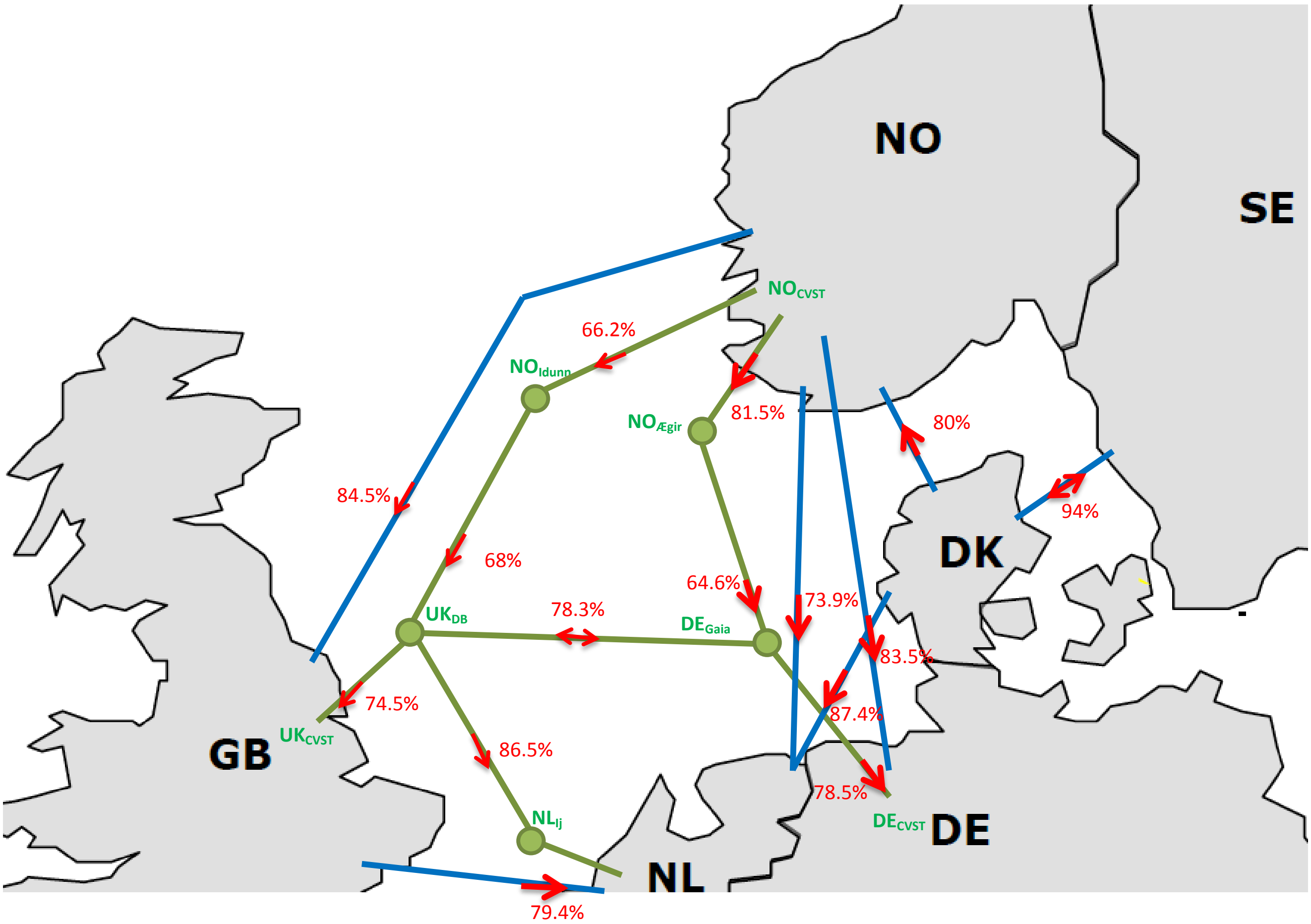


Figure 78. Exchange of power across the offshore grid in the IC scenario (High Wind Scenario).

Figure 79 depicts utilisation of offshore cables. The general trend is similar to Figure 60. The major difference is related to the exchange on the UK_{DB}-NL_{Ij} and the UK_{DB}-DE_{Gaia} connections. The flow from the Netherlands to the UK (UK_{DB}-NL_{Ij}) has increased significantly, especially in the ICE and IC scenarios. Moreover, the increased wind energy produced at Dogger Bank in UK_{DB} is forwarded to the German system through UK_{DB}-DE_{Gaia}. Thus, the duration curves have shifted to the left when compared to Figure 60.

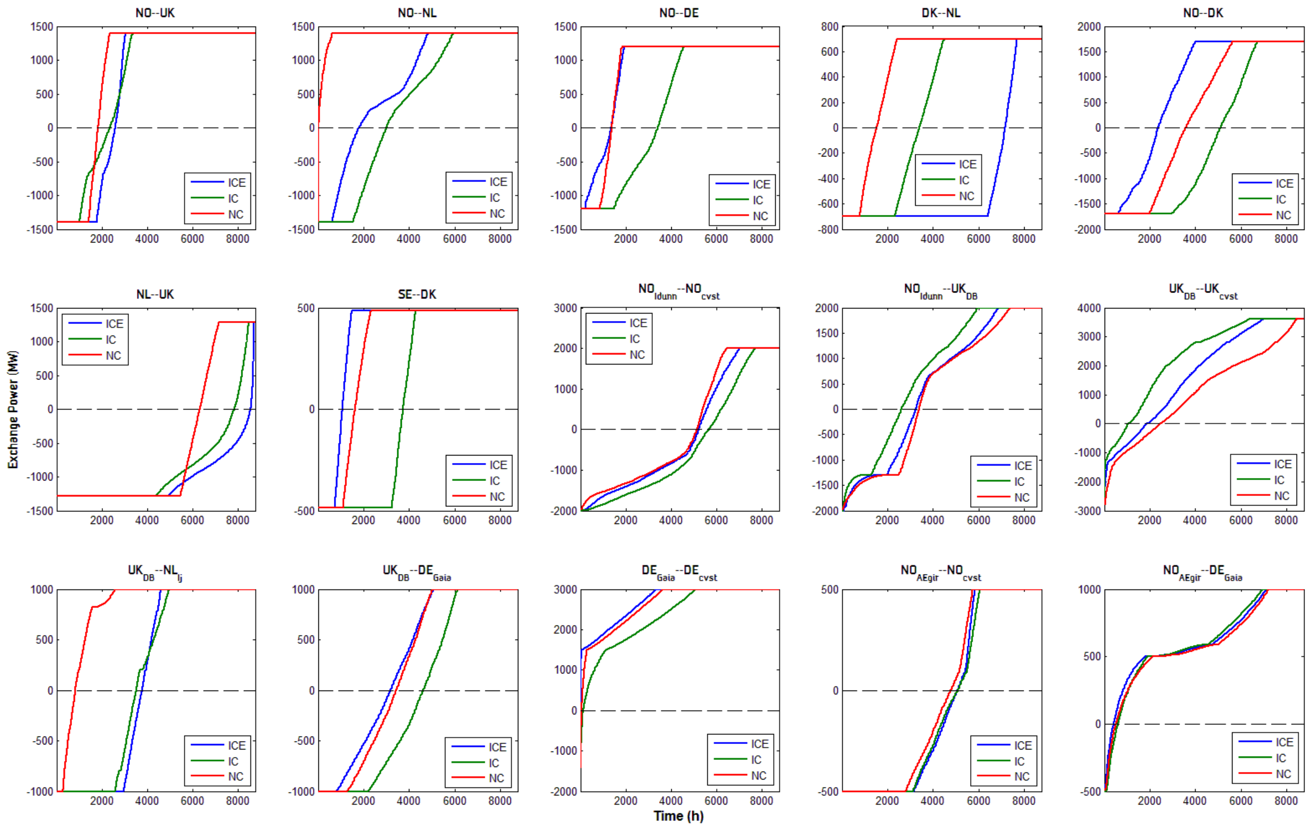


Figure 79. Duration curves of the offshore cable utilisation (High Wind Scenario)

16 Inflow Scenarios

The inflow scenarios are based on hydrological data over 75 years. This inflow scenario represents the stochastic environmental variable in the Nordic hydro system. These stochastic variables are inflow to reservoirs (storable inflow) and inflow directly used at power stations (e.g. run-of-river). As shown in Figure 27, there are significant differences among inflow scenarios. However, the main characteristics are the same, with high inflow during late spring, summer and early autumn whereas the inflow is low during the rest of the year. Thus the year is split in a filling and a depletion season of hydro reservoirs.

To study the effects of different hydrological years, a wet and a dry year are selected as representative scenarios. These differences have an impact on the overall operation of the power system, which is illustrated by the net energy exchange with Continental Europe. Figure 80 illustrates the inflow values over weeks within wet, dry and normal hydrological year and Table 44 represents the annual amount of inflow in terms of energy to the Norwegian hydro reservoirs for different hydrological years. Inflow scenarios of the previous studies are assumed to reflect a normal hydrological year, however in the further studies the inflows for the wet and dry years will be studied.

Table 44. Inflow in terms of energy for the whole hydrological year

Hydrological year	Inflow [TWh]
Wet	162.28
Normal	114.5
Dry	85.22

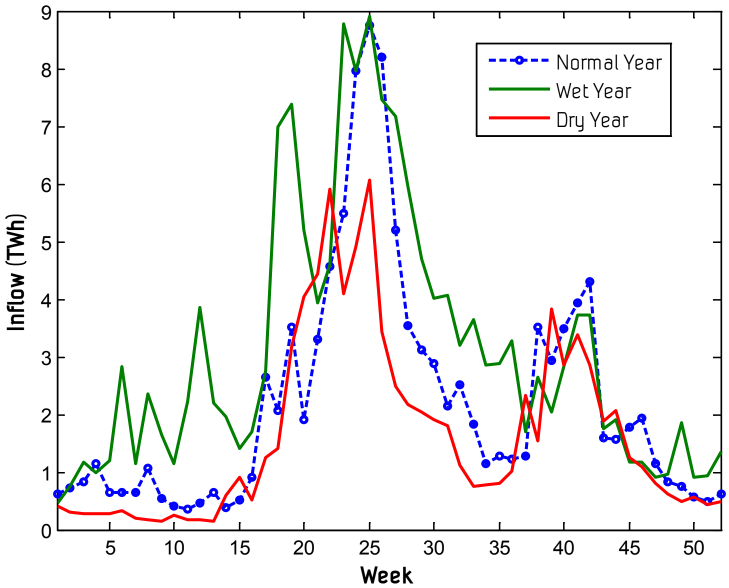


Figure 80. Hydro inflow patterns used for simulating normal, wet and dry years

16.1 Monetary Savings

The operational savings of different hydrological years taking into account the onshore transmission grid constraints are presented in Table 45. In all case studies, "Case C" is selected as offshore grid topology. Looking at the "wet year" scenario reveals that moving from IC to ICE results in an annual saving of approximately 2.745 bnEUR. Moving from the ICE to the NC scenario results in annual savings of approximately 256 MEUR.

For the “dry year” scenario, moving from IC to ICE and further from ICE to NC results in annual savings of 2.367 MEUR and 153 MEUR, respectively.

The above comparison shows that for the high wind case along with the “wet year” scenario there is a higher chance to obtain more operational savings by onshore transmission expansion in the northern Continental European power systems. On the other hand, comparing wet and dry years reveals an annual difference of approximately 2 bnEUR. The inflow situation in the Norwegian power system substantially affects the water values and therefore the electricity prices. It also affects the thermal production within the Nordic system as well as Continental European system and therefore the operating costs.

Table 45. The annual operating cost for different hydrological years in 2030

Hydrological Year	Offshore grid Cases	Cost [bn €/a]
Wet Year	IC	94.954
	ICE	92.209
	NC	91.953
Dry Year	IC	96.663
	ICE	94.296
	NC	94.143

Figure 81 compares the Norwegian reservoir trajectory for different hydrological years. It is obvious that all the curves follow the same pattern including filling period during late spring, summer and early autumn and the depletion period for the rest of the year. However, depending on the hydrological year a significant difference between the reservoir levels is noticeable.

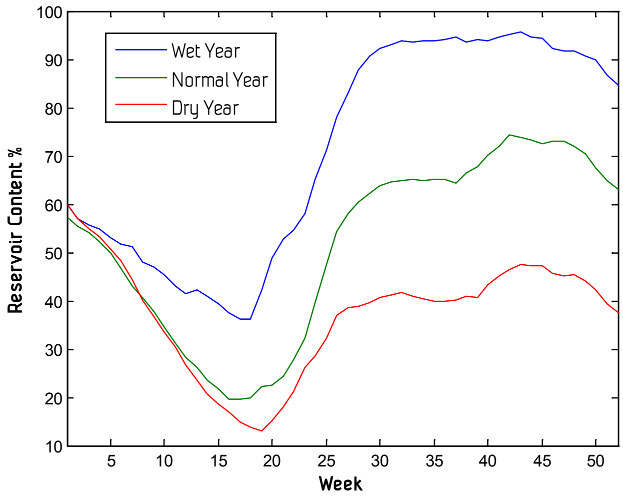


Figure 81. Simulated reservoir content in Norway for normal, dry and wet years

Similar to Figure 54, Figure 82 shows the simulated reservoir trajectory at Tonstad for a wet and a dry year. These two curves are based on a simulation with expanded onshore grid (ICE scenario) along with the "Case C" offshore grid topology. As it can be seen, the reservoir trajectories differ significantly for these two hydrological years. In a wet year, the reservoir filling is very steep, caused by a large amount of inflow between week 17 and 30 (hour 3000 to 6000) (see Figure 80). In addition, some small fluctuations are observed which are caused by pumping water into the reservoir. In a dry year, the reservoir is filled very smoothly. However, more small fluctuations can be observed than in a wet year.

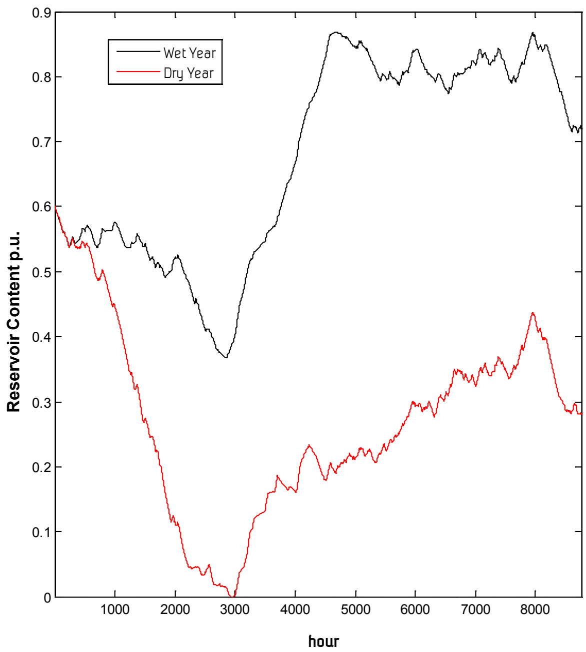


Figure 82. Tonstad simulated reservoir trajectory for wet and dry years

Figure 83 depicts the pumping patterns in different hydrological years. It is obvious, that pumping occurs more frequently in a dry year than it does in a wet year. Thus, the Continental European wind energy can support the Norwegian system in dry years when the availability of hydro energy is limited. Moreover, the surplus wind energy is imported and stored in the Norwegian reservoir. In this way, the wind energy can compensate the lack of hydro energy resulting from a low precipitation.

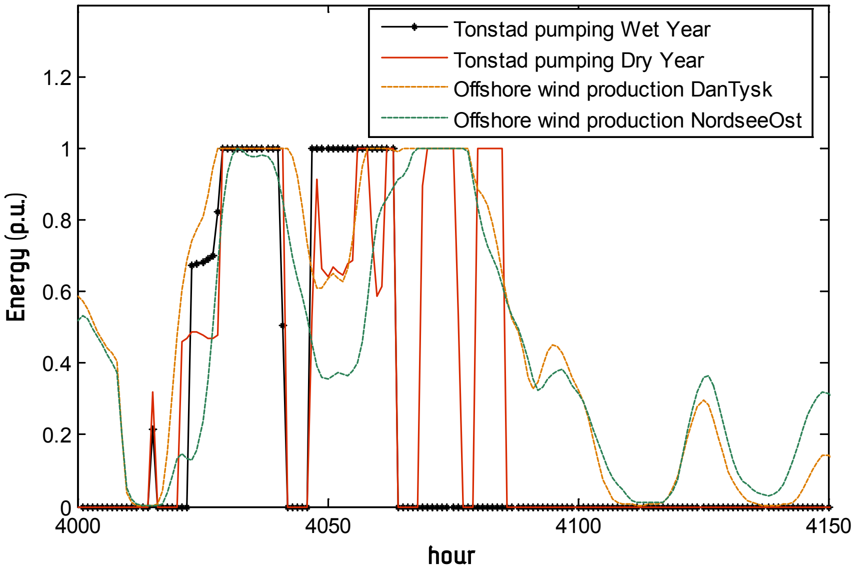


Figure 83. Simulated Offshore WPP in Germany vs. pumping patterns at Tonstad for wet and dry years

16.2 Power Exchanges across the Offshore Grid

Table 43 shows the offshore grid utilisation in wet and dry years. The effect of different hydrological years is studied using the "Case C" offshore grid along with an onshore grid with expansion (ICE). Similar to previous results, the respective cable utilisation is shown in three columns representing the total utilisation as well as utilisation in the direction of flow from-bus to to-bus indicated by "From", and "To" and for the opposite direction from to-bus to from-bus. Besides a slight increase of the total utilisation on some cables, the utilisation of the cables from the Norwegian system has increases in a wet year and reduces in a dry year. Figure 84 illustrates the difference for wet and dry years for the cable utilisation in the "From" direction. It can be observed that the utilisation has been increased from approximately 10% to 20% across the cables from the Norwegian system.

Table 46. The Utilisation of Bilateral HVDC Connection between Countries and Offshore Grid Multi Terminal Connections (Hydrological Years)

No.	Transmission line		Capacity [MW]	Utilisation [%]								
				Wet Year			Normal Year			Dry Year		
	From	To		Total	From	To	Total	From	To	Total	From	To
1	NO	UK	1400	96.6	88.2	8.4	97.1	84.4	12.7	96.4	78.7	17.7
2	NO	NL	1400	77.7	68.3	9.4	75	61.4	13.7	73	56.5	16.5
3	NO	DE	1200	95.8	90.5	5.3	91.5	80.9	10.6	91.8	77.7	14.1
4	DK	NL	700	91.2	16.6	74.6	91	17.0	74.0	92.3	15.2	77.1
5	NO	DK	1700	87.8	75.9	11.9	83.3	67.6	15.7	80.2	59.3	20.9
6	NL	UK	1290	85.3	2.0	83.3	85.3	1.7	83.6	85.5	1.6	84.0
7	SE	DK	485	97.5	91.7	5.8	97.7	92.3	5.4	97.4	89.6	7.8
8	NO_{Idunn}	NO_{cvst}	2010	66.7	17.8	48.9	65.1	24.1	41.0	67.3	31.1	36.2
9	NO_{Idunn}	UK_{DB}	2000	70.2	54.2	16.0	66.5	44.6	21.9	63	36.5	26.5
10	UK_{DB}	UK_{cvst}	3600	76.55	60.4	16.1	75.2	55.2	20.0	73.55	50.5	23.0
11	UK_{DB}	NL_{Ij}	1000	88.7	68.4	20.3	88.4	68.2	20.2	87.7	67.8	19.9
12	UK_{DB}	DE_{Gaia}	1000	67.1	35.9	34.6	69.2	35.4	33.8	69.4	33.6	32.3
13	DE_{Gaia}	DE_{cvst}	1692	99	98.8	0.2	98.9	98.7	0.2	98.8	98.6	0.2
14	NO_{AEgir}	NO_{cvst}	500	73.5	39.8	40.2	74.1	36.8	37.3	76.6	34.7	35.1
15	NO_{AEgir}	DE_{Gaia}	1000	60.8	57.5	3.3	57.7	53.5	4.2	54.5	49.4	5.1

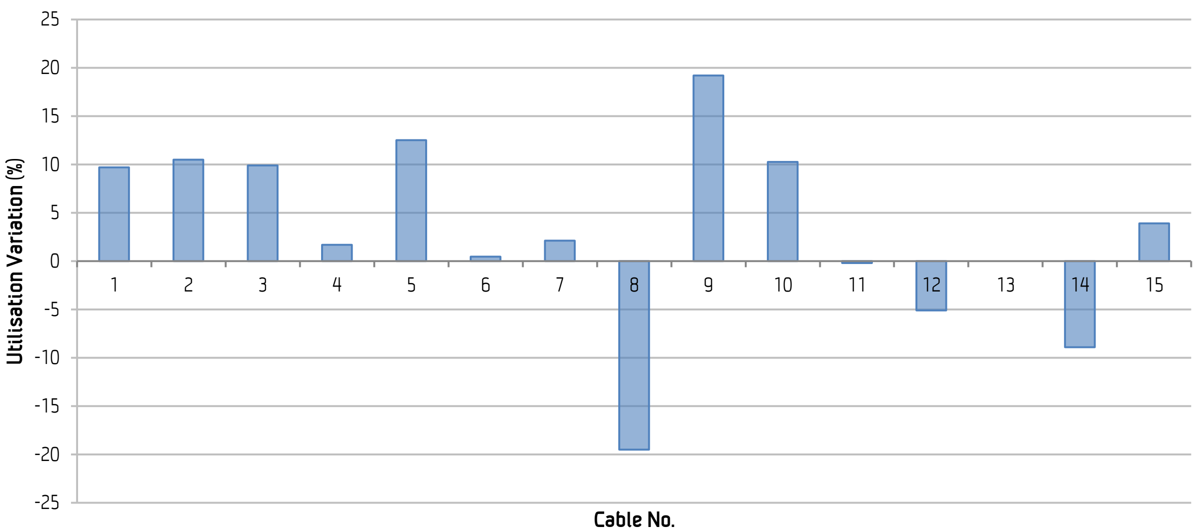


Figure 84. Variations in cable utilisation variation resulting from different hydrological years (wet-dry)

Figure 85 shows the duration curve for the offshore cables taking into account different hydrological years, i.e., wet and dry years. As mentioned before, generally the utilisation of cables from the Norwegian system has been increased. The positive values in all curves indicated the utilisation of the assumed cable in the direction of the name written above the graph. For instance, in the first graph of the first row, the positive values illustrate the flow from NO to the UK.

The exchange across (NO_{Idunn}-NO_{CVST}) is increased in a wet year from the onshore substation to the offshore node (NO_{Idunn}). This increase also affects the exchange across NO_{Idunn}-UK_{DB}, UK_{DB}-UK_{CVST} and UK_{DB}-DE_{Gaia}.

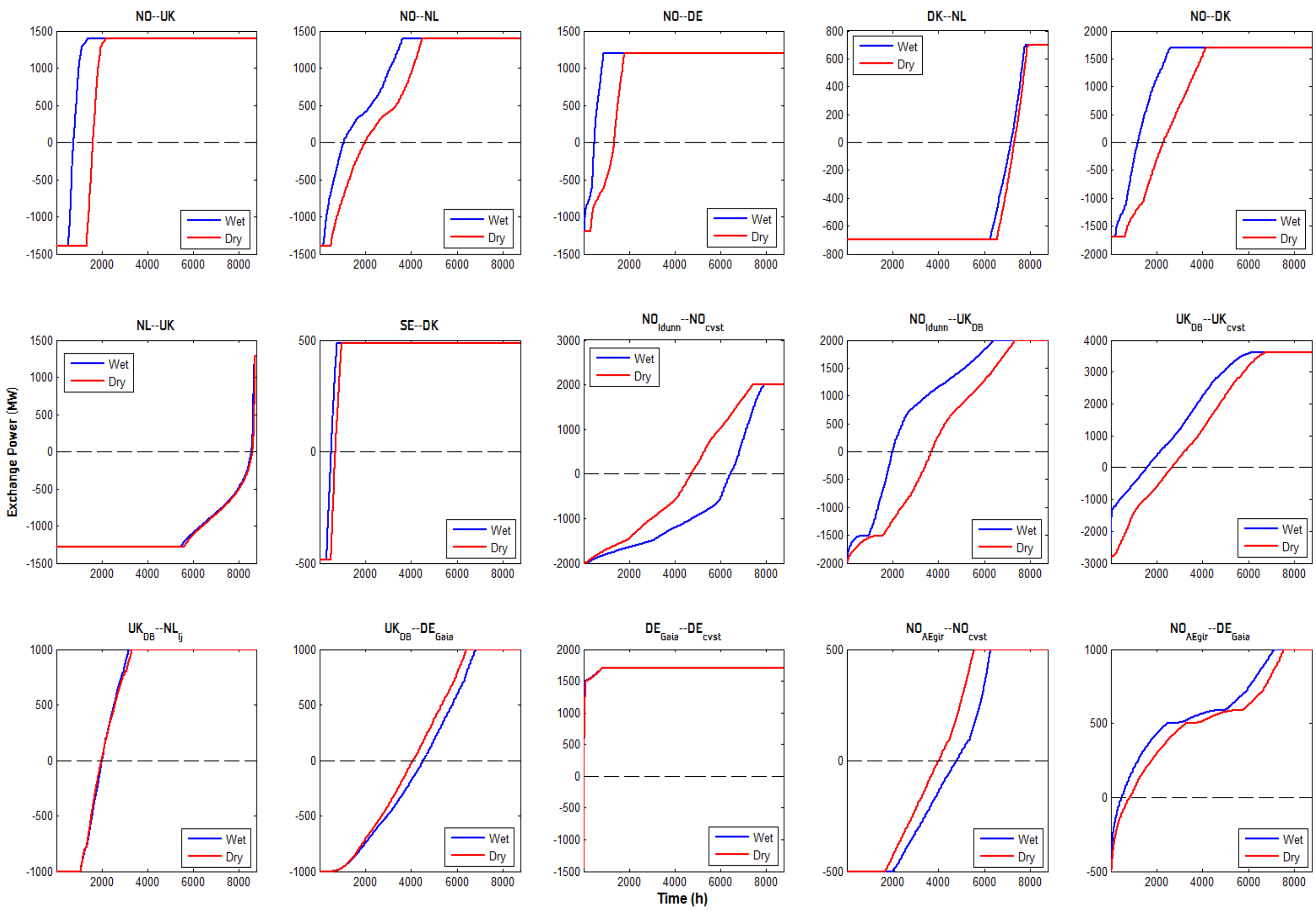


Figure 85. Duration curve of the offshore cable utilisation (wet and dry hydrological years)

Figure 86 schematically shows the exchange variations across the offshore grid in the North Sea for a wet and a dry year. As can be seen, the offshore grid provides an infrastructure to export surplus energy from the Norwegian system to the countries around the North Sea. For instance the connection between NO_{Idunn} and

UK_{DB} provides a possibility to exchange surplus energy in a wet year between these two nodes and redistribute this energy between the British and the German system further down across UK_{DB}-DE_{Gaia}.

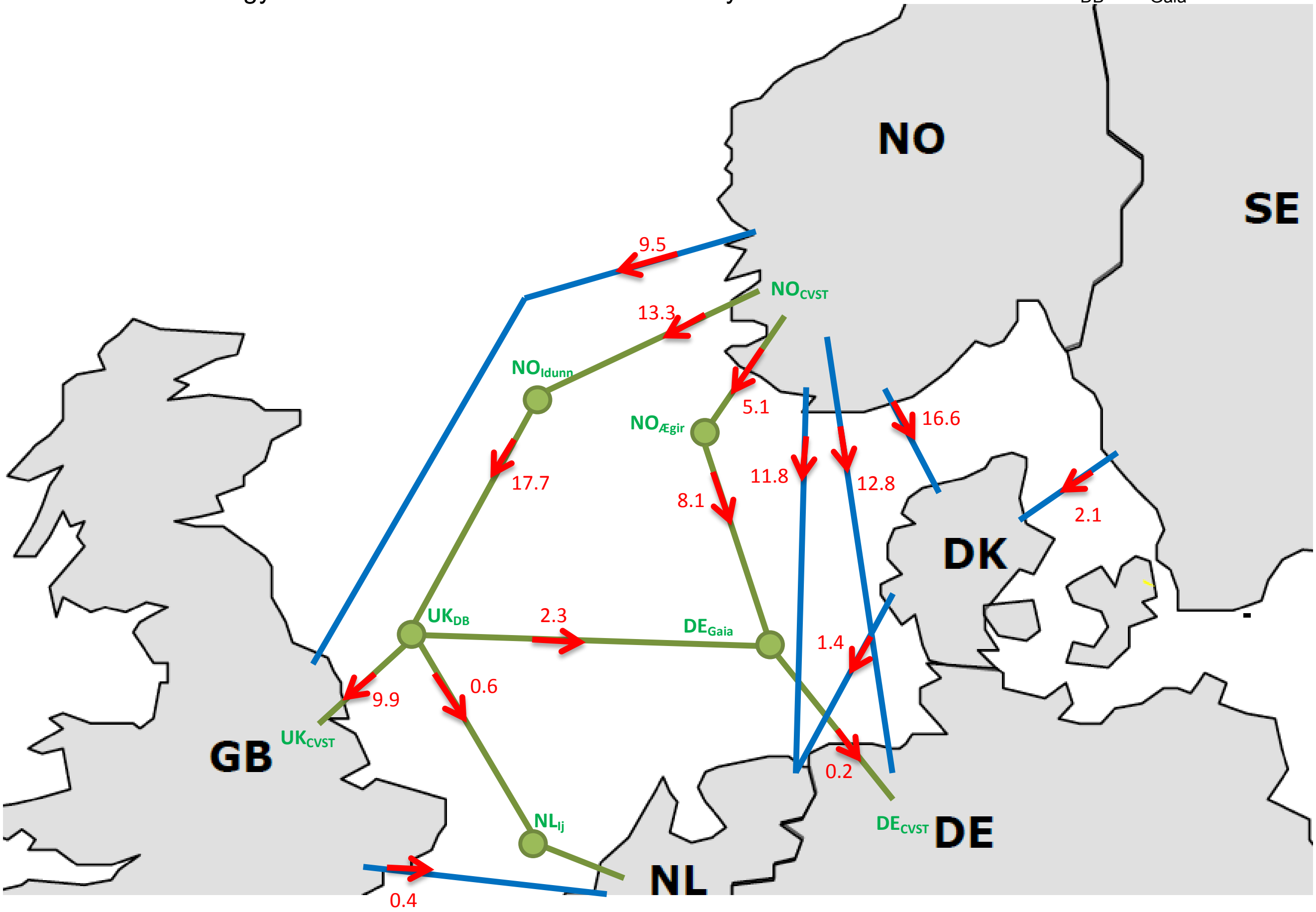


Figure 86. Exchange variation from dry to wet year [%]

17 Dry Year and High Wind Scenario

As a final analysis, we study the effect of the high wind scenario on the Norwegian system along with a dry hydrological year. The inflow scenario is the same as the scenario used in the previous section. The high wind scenario corresponds to the one used in Section 15. The case study is based on Case C for the offshore grid topology and case ICE for the onshore grid configuration.

Simulating this scenario shows that there is a significant operational saving of approximately 6.78 bnEUR per year, when compared to a dry year with a baseline wind scenario. This savings demonstrate that not only the hydro power stations in the Norwegian system can help to balance WPP variability, but that WPP can also help the Norwegian hydro system during dry years. Figure 87 shows the influence of the baseline and the high wind scenarios on the Norwegian reservoir levels. As seen, the surplus of wind energy production is stored in the Norwegian reservoir.

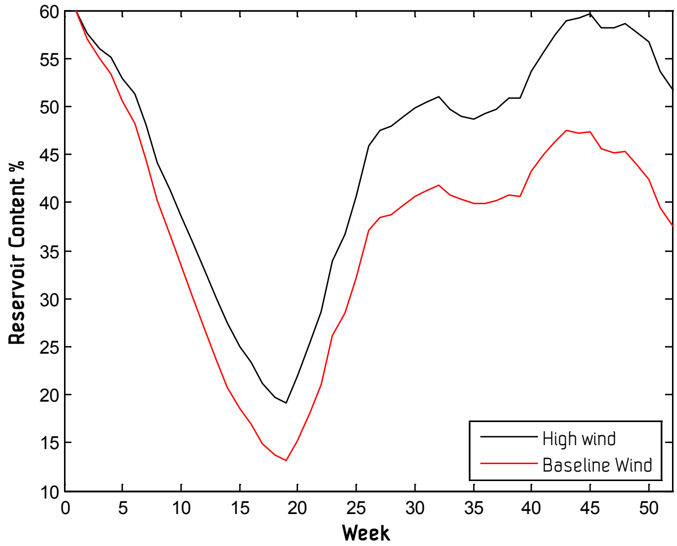


Figure 87. Simulated reservoir content in Norway comparing high and baseline wind along with dry year scenario

Figure 88 illustrates the simulated reservoir trajectory at Tonstad for the high wind and the baseline wind scenario assuming a dry year. As seen, the reservoir trajectories show significant differences for the two scenarios. In the high wind scenario, the lack of inflow to the reservoir is compensated by pumping back the water to the reservoir. Therefore, the reservoir in high wind scenario is not depleted completely and ends with much higher reservoir level than in the baseline wind scenario.

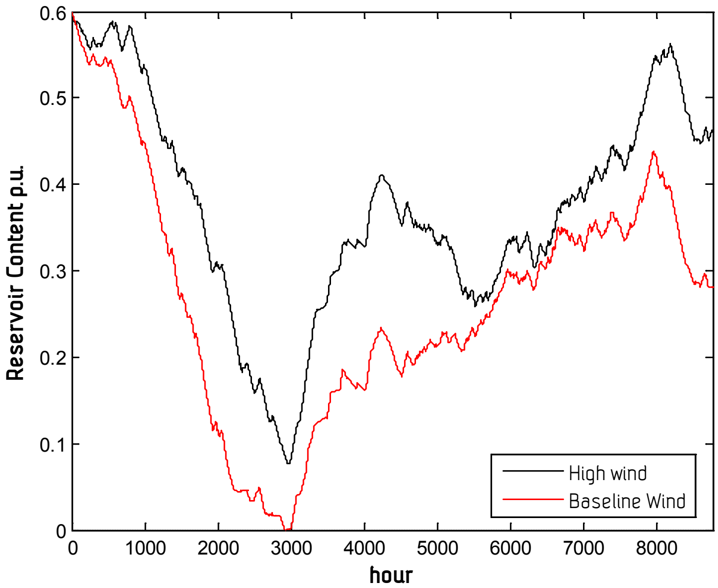


Figure 88. Comparing Tonstad simulated reservoir trajectory with high and baseline wind scenarios

Table 47 shows the offshore grid utilisation in dry year with baseline and high wind scenario. It confirms the similar effect as Figure 87, where the wind production in the European power system helps the Norwegian system in a dry year.

Table 47. Utilisation of bilateral HVDC connections between countries and offshore grid multi terminal connections based on the baseline and high wind scenarios in a dry year

No.	Transmission line		Capacity [MW]	Utilisation Dry Year [%]					
				Baseline Wind			High Wind		
	From	To		Total	From	To	Total	From	To
1	**NO**	**UK**	1400	96.4	78.7	17.7	91.2	62.5	28.7
2	**NO**	**NL**	1400	73	56.5	16.5	69.8	58.0	11.8
3	**NO**	**DE**	1200	91.8	77.7	14.1	90	74.5	15.5
4	**DK**	**NL**	700	92.3	15.2	77.1	93.9	15.2	78.7
5	**NO**	**DK**	1700	80.2	59.3	20.9	80.9	58.0	22.9
6	**NL**	**UK**	1290	85.5	1.6	84.0	82.8	1.6	81.2
7	**SE**	**DK**	485	97.4	89.6	7.8	95.6	82.5	13.1
8	$\mathbf{NO_{Idunn}}$	$\mathbf{NO_{cvst}}$	2010	67.3	31.1	36.2	69.3	31.9	37.4
9	$\mathbf{NO_{Idunn}}$	$\mathbf{UK_{DB}}$	2000	63	36.5	26.5	65.9	37.9	28.0
10	$\mathbf{UK_{DB}}$	$\mathbf{UK_{cvst}}$	3600	73.55	50.5	23.0	75.4	62.2	13.2
11	$\mathbf{UK_{DB}}$	$\mathbf{NL_{Ij}}$	1000	87.7	67.8	19.9	90.4	53.9	36.5
12	$\mathbf{UK_{DB}}$	$\mathbf{DE_{Gaia}}$	1000	69.4	37.1	32.3	79.4	29.7	49.7
13	$\mathbf{DE_{Gaia}}$	$\mathbf{DE_{cvst}}$	1692	98.8	98.6	0.2	99.2	99.2	0.0
14	$\mathbf{NO_{AEgir}}$	$\mathbf{NO_{cvst}}$	500	76.6	41.5	35.1	82.1	49.3	32.8
15	$\mathbf{NO_{AEgir}}$	$\mathbf{DE_{Gaia}}$	1000	54.5	49.4	5.1	46.7	31.8	14.9

Figure 89 schematically shows the exchange variations across the offshore grid in the North Sea for a dry year including numbers for the high wind and the baseline wind scenario. The Offshore grid provides the infrastructure to transmit produced wind energy between the countries around the North Sea. Furthermore, the Norwegian system can be supported during dry years. Therefore, the mean power flow across almost all interconnections is towards the Nordic system.

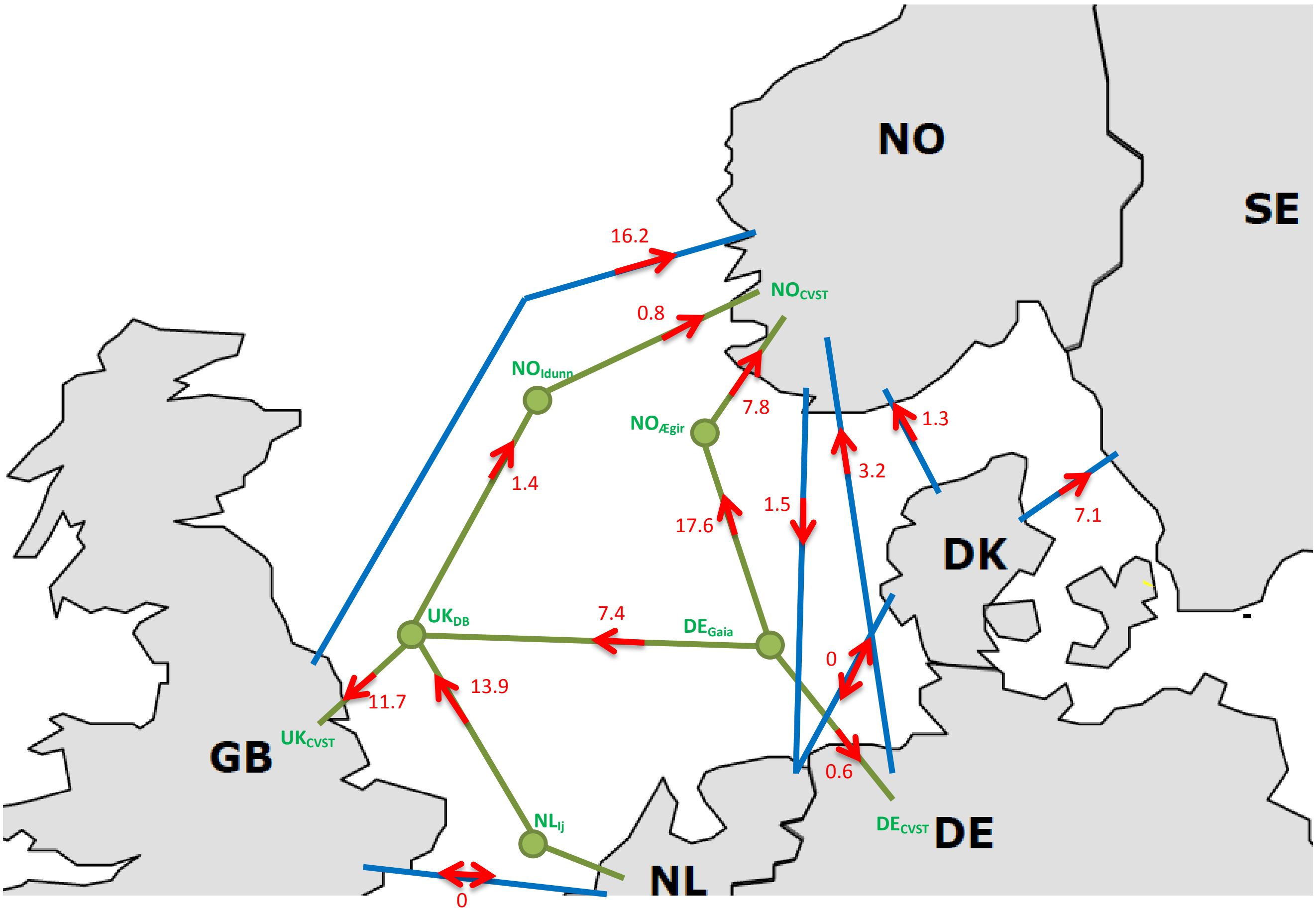


Figure 89. Exchange variations caused by the high wind scenario [%]

18 Conclusion

This report presents analysis of future Scenarios for the European power system in 2020 and 2030. Market and grid models of the European power system are used including up-to-date relevant data for load, generation and transmission. These models have been used to assess the flexibility of hydropower in the Nordic power system as well as possibilities of usage of hydro power to support the European system under the influence of a high share of variable energy production from RES in the 2020 and 2030 scenarios considered. The report is divided into two parts. Part - I presents results regarding strategic use of hydropower flexibility potential presented in D16.2 in the Nordic power system by calculation of water values. Also results of a transmission expansion analysis are presented, assessing the need for additional transmission grid expansion from existing investment plans, due to the additional hydropower flexibility considered in the Scenarios here. From the investment analysis for additional transmission grid expansion, we conclude that although significant congestion rent appear across connection in the North Sea, the high investment costs considered do not make further investments profitable form a merchant line point of view. We therefore conclude that existing publicly available investment plans, considered as input to the investment analysis, are sufficient. The analysis is carried out using the EMPS model. Part - II focuses on a DC Power Flow analysis of the European power system. The results of the simulation in Part I are verified based upon flow-based power market simulations with a detailed grid model in Part II. Furthermore, in Part II optimal generation dispatch and flow along lines consistent with DC power flow equations are calculated in detail for the European power system. The effect of the offshore grid structure is considered. Also detailed analysis on the effect of internal constrains is performed.

For future power system scenarios a significant increase in installed wind generation capacity as well as in transmission capacity is assumed. This includes the installation of a new offshore grid in the North Sea. The installation of new WPP facilities results in a significant change of the remaining generation portfolio and the overall generation mix. The Norwegian hydropower system has ideal characteristics to add generation flexibility to the Continental European power production. In order to effectively utilise this resource, a sufficient amount of transmission capacity has to be available between the Nordic region and Continental Europe.

18.1 The results of Part I

Part I comprises the development and the analysis of three different scenarios for the Northern European power system, including the years 2010, 2020 and 2030. The simulations are based on the EMPS model, developed by SINTEF Energy Research.

The assessment of the simulation results shows severe changes in the outcome of the Northern European power markets. The main results predict an increasing price level along with an increase in short-term price volatility in Continental Europe. In general, for the analysis of future scenarios, a superposition of both main effects (increase of installed capacity of RES (RES+) and increase of the CO2 price (CO2+)) will affect the marginal cost curve (CO2+ & RES+). The resulting price for all of the scenarios is the crossing of the demand and the marginal cost curve. While increasing CO_2 costs increase the price, increasing RES capacity decreases the price. The resulting price, when combining these two effects, depends quite strongly on the relative values used for the different parameters used to model both effects (CO2+ & RES+). Our recommendation for further work is to perform sensitivity analysis on these effects by considering different ranges of e.g. CO2 prices. The CO2 prices used in this work are: 13 EUR/tonneCO2 (2010) and 44 EUR/tonneCO2 (2020 and 2030).

Furthermore, the marginal profit of transmission corridors, connecting the Nordic area with Continental Europe and the UK increases significantly, which provides an incentive for a further expansion of the transmission capacity.

A transmission investment analysis is executed, identifying the most profitable transmission corridors for grid expansion, along with the required transmission capacity expansion. The analysis results propose a corridor around the North Sea with a transmission capacity of up to 4GW. Such an expansion would reduce price levels in Continental Europe significantly and allow a further integration of WPP in the power system.

Finally a sensitivity analysis is executed, assessing the effect of increasing transmission capacities and changing marginal production costs of thermal power plants on the development of electricity prices in Northern Europe. The sensitivity analysis illustrates, that increasing marginal production costs result in an increase of electricity prices in the Nordic area, nearly independent from the transmission capacity. On the other side, an increase of transmission capacity has only a minor effect on the price level, but reduces price volatility significantly.

18.2 The results of Part II

The simulations are carried out using the Power System Simulation Tool (PSST), developed by SINTEF Energy Research. The simulation tool runs an optimal power flow problem for a given power system model for each hour of a year. The optimal power flow minimises the total generation cost, using a detailed grid representation and with the assumption of a perfect market. The European grid model that is used in the simulations consists of separate power flow data files for the Continental European system, the Nordic system, The British & Irish system and the Baltic system. However, the main focus of the simulations is on the Northern European power system including the countries around the North Sea. The simulated scenarios include the years 2020 and 2030.

The generation mix for the 2030 scenario is based on the outlook of the European Commission. The predicted production portfolio for each country includes nuclear, coal (lignite coal and hard coal), gas-fired, oil, hydro, wind, biomass and solar power plants. The marginal costs for hydro units called water values are imported from Part-I as a result of the EMPS model. Water values are time dependent functions taking the reservoir level, inflow, power production and spillage into account. Therefore, the optimisation problems for the different time steps must be solved chronologically. Pumped hydro operation is included in the model. Wind power scenarios for all relevant countries have been constructed in the TWENTIES work package 16, Task 16.1 [14].

The onshore grid is upgraded based on the ten-year network development plan (TYNDP 2012) and the dena Grid study-II. In addition, the offshore grid topology proposed in the IEE-EU OffshoreGrid project is incorporated. The offshore grid includes the Dogger Bank wind farm area in the UK, serving as a hub for the connections to offshore wind farms in Norway, Germany and the Netherlands. Furthermore, a connection of offshore wind farms along the Continental coastline in the North Sea is considered.

The results presented in this part of the report cover grid implications regarding the offshore grid and the HVDC links between the Nordic, the British and the Northern Continental European power systems. Furthermore, internal grid constrains in Norway are considered. Besides, issues regarding internal constrains in Germany, the UK and the Netherlands are studied. A detailed discussion of results related to the operational cost of the offshore grid structure and the internal onshore constraints are presented, highlighting the operational benefits of an offshore grid. The different grid configurations are quantified based on the respective operational savings. It has been shown that extension of the offshore corridor between the Norwegian offshore wind farm (Ægir) and the Continental European power system, brings annual saving between 61 MEUR to 97 MEUR depending on the level of onshore grid constraints considered. These annual savings significantly increase in high wind scenarios, 111 MEUR to 189 MEUR depending on the level of onshore grid constraints considered.

The net benefit from this offshore grid expansion by additional 1GW offshore HVDC capacity allowing increased wind penetration and use of flexible hydro power, is equal to 30800 (km × MW) onshore transmission "equivalent" investment for the Baseline wind scenario and 131128 (km × MW) onshore transmission "equivalent" investment for the High wind scenario. The difference in installed capacity at offshore wind farms around the North Sea between the Baseline and High wind scenario is 3185 MW. These (km × MW) onshore transmission "equivalent" figures quantify the relative value of offshore grid expansion with respect to onshore transmission expansion.

The evaluated results clarify and quantify the impacts of Norwegian hydro flexibility and transmission grid expansion on the European power system. The following points have been made and discussed in detail within this report:

- Grid expansions, including onshore and offshore connections, increase the utilisation of cheaper energy sources. New wind power facilities largely affect the power flow in the system. Different grid configurations result in different power flows. This is important for e.g. determining which connections require upgrading.

- With an increasing wind penetration level, hydropower as well as pump storage possibilities (located around the South of Norway) provide generation flexibility to compensate for the variability of wind generation.

- For the planned NorGer HVDC link, the analysis demonstrates correlation between the pumping pattern at the hydro power station of Tonstad, at the Norwegian end of the link, and German (offshore) wind production connected to the German end of the link. This indicate that in the future power system with a large penetration of wind energy, the pumping strategy is not only influenced by seasonal inflows in the Nordic region, but also by the variability of wind production around the North Sea

- The internal bottleneck in the Norwegian system will prevents the efficient utilisation of potential hydro energy stored in the Norwegian reservoirs. Consequently, in order to harvest the potential increase in potential hydro production in Norway, it is recommended to expand the corridor in Figure 36. This expansion is in line with existing plans published by the Norwegian TSO Statnett.

- The internal grid expansion in the German system provides possibilities to transfer wind energy from the offshore wind facilities in the North Sea to the load centres located in southern Germany

- A sensitivity analysis related to high wind production indicates that the offshore grid infrastructure enables the exchange of power among the countries around the North Sea. Also, the Norwegian reservoirs end up in higher levels indicating that the surplus of wind energy is stored in the Norwegian hydro reservoir by pumping the water from low to high altitude reservoirs. As shown in Figure 87, in the high wind scenario, the Norwegian reservoir level ended 15% higher than a dry year with baseline wind scenario.

- Sensitivity analysis related to the different hydrological years confirms the fact that the Continental European wind energy can support the Norwegian system in dry years when the availability of hydro energy is limited. In wet years the utilisation of the cables from the Norwegian power system are increased from 10% to 20% to export the energy surplus to the adjacent countries.

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20 Appendix

20.1 Generation capacity

Table 48. Generation capacity per country, fuel type and report [GW] - 2010

		Nuclear	Lignite	Hard coal	Gas	Oil	Bio-mass	Solar	Wind	Hydro
BE	Offshore	5,94	0	1,48	6,32	1,49	0,96		0,38	0,12
	ENTSOE	5,94	8,6				1,02	0,76	0,88	1,4
	EU Ener	5,94	1,47		7,1	0,65	0,8	0,15	1,06	1,2
	EMPS	-	0	1,48	6,32	0,75	0,8	0	1,022	-
DE	Offshore	15,52	20,9	27,69	26,93	7,14	13,49		23,96	4,25
	ENTSOE	20,3	69,3				4,2	16,6	26,6	10,3
	EU Ener	15,5	47,8		26,9	5,3	5,0	8,4	27,7	4,2
	EMPS	-	21,03	27,52	27,47	3,16	4,9	4,0	25,0	-
DK	Offshore	0	0	5,27	2,23	1,02	0,95		3,49	0
	ENTSOE	0	8,867				0	0	3,8	0
	EU Ener	0	5,27		2,23	1,02	0,93	0,02	3,72	0,01
	EMPS	-	0	5,05	1,87	0,55	0,31	0	3,702	-
FI	Offshore	2,69	0	5,63	2,94	1,03	2,01		0,18	2,99
	ENTSOE	2,64	9,0				2,05	0	0,2	3,1
	EU Ener	2,69	5,62		3,07	0,90	2,0	0	0,28	2,99
	EMPS	-	0	4,61	3,24	0,97	2,29	0	0,35	2,45
NL	Offshore	0,50	0	4,19	14,35	2,58	1,55		2,22	0,04
	ENTSOE	0,48	22,0				0,60	0,07	2,27	0,04
	EU Ener	0,50	4,18		15,93	0,99	1,45	0,09	3,08	0,04
	EMPS	-	0	4,72	13,82	1,28	1,2	0,08	2,82	-
SE	Offshore	9,68	0	0,69	0,89	3,4	3,17		1,02	16,46
	ENTSOE	9,15	5,03				3,1	0	2,16	16,2
	EU Ener	9,68	0,68		1,09	3,2	3,17	0,015	1,46	16,4
	EMPS	-	0	0,34	1,30	3,71	1,0	0	1,25	16,82
U+I	Offshore	10,7	0	26,3	34,5	5,11	2,15		4,2	1,5

UK	ENTSOE	10,6	62,5				-	0	2,6	3,8 iP
UK	EU Ener	10,7	-	26,3	35,2	4,3	2,1	0,04	6,5	1,5 eP
GB	EMPS	10,9	-	27,0	33,1	5,2	0,05	-	7,5	1 (2,7)
NO	Offshore	0	0	0	0,9	0,1	0,1		0,33	29,2
	ENTSOE	0	1,16				0	0	0,45	30,16
	EU Ener	-	-		-	-	-	-	-	-
	EMPS	0	0	0			0	0	0,547	30,6

iP – including pump storage

eP – exluding pump storage

Table 49. Generation capacity per country, fuel type and report [GW] - 2020

		Nuclear	Lignite	Hard coal	Gas	Oil	Bio-mass	Solar	Wind	Hydro
BE	Offshore	5,94	0	1,15	6,46	1,73	1,71		4,09	0,14
	EU Ener	5,94	1,08		7,24	0,99	1,99	0,24	3,57	0,14
	EMPS	-	0	1,09	7,16	1,3	1,6	0	2,95	-
DE	Offshore	4,05	16,63	29,09	36,03	11,97	25,44		51,25	4,43
	EU Ener	4,05	44,70		35,84	6,20	7,67	22,47	56,93	4,43
	EMPS	-	16,13	30,51	34,75	5,99	7,3	22,47	57,37	-
DK	Offshore	0	0	3,5	2,38	0,39	1,07		6,15	0
	EU Ener	0	3,32		2,17	0,38	1,23	0,11	5,73	0,01
	EMPS	-	0	3,21	1,87	0,55	1,12	0	5,98	-
FI	Offshore	4,55	0	5,1	3,97	0,64	2,51		2,09	3,05
	EU Ener	4,21	5,1		3,09	0,35	4,46	0,08	1,34	3,10
	EMPS	-	0	5,11	2,99	0,76	4,29	0	3,02	2,45
NL	Offshore	0,50	0	8,53	11,75	1,90	2,2		9,6	0,04
	EU Ener	0,50	8,53		12,43	0,78	2,13	0,15	9,72	0,04
	EMPS	-	0	8,48	12,89	0,82	2,0	0,08	10,48	-
SE	Offshore	10,55	0	0,58	0,89	2,32	3,58		8,97	16,77
	EU Ener	10,55	0,58		10,9	2,05	4,44	0,08	5,32	17,01
	EMPS	-	0	0,34	1,3	2,236	4,0	0	7,045	17,96

UK IRE	Offshore	6,0	0	15,0	46,6	3,1	4,3		29,05	1,5
UK	EU Ener	6,0	11,18		43,99	1,48	6,78	0,21	36,26	1,6
GB	EMPS	-	0	11,16	48,78	1,39	2,33	-	16,278	1,23
NO	Offshore	0	0	0	0,9	0,1	0,5		4,1	29,6
	EU Ener	-	-		-	-	-	-	-	-
	EMPS	-	0	0			0	0	5,3	45,2

Table 50: Generation capacity per country, fuel type and report [GW] - 2030

		Nuclear	Lignite	Hard coal	Gas	Oil	Bio-mass	Solar	Wind	Hydro
BE	Offshore	0	0	4,67	10,37	1,93	1,71		6,29	0,15
	EU Ener	0	5,48		11,04	1,17	1,68	0,28	4,97	0,15
	EMPS	-	0	5,09	11,06	1,3	1,2	0	5,83	-
DE	Offshore	0	13,55	29,15	38,19	10,03	33,29		73,25	4,69
	EU Ener	0	35,62		42,54	8,11	10,04	29,93	75,62	4,69
	EMPS	-	11,12	24,49	42,79	8,09	10,0	29,88	78,01	-
DK	Offshore	0	0	3,46	2,55	0,12	1,45		8,08	0
	EU Ener	0	3,10		2,52	0,12	1,76	0,16	6,53	0,012
	EMPS	-	0	3,21	2,47	0,27	1,72	0	9,48	-
FI	Offshore	4,97	0	3,22	4,30	0,39	4,38		5,55	3,11
	EU Ener	4,39	2,74		3,41	0,18	5,26	0,15	1,98	3,14
	EMPS	-	0	2,66	3,39	0,64	5,19	0	5,58	2,45
NL	Offshore	1,11	0	8,53	11,51	1,65	2,62		18,12	0,04
	EU Ener	0,59	8,53		11,71	0,77	2,41	0,24	11,19	0,04
	EMPS	-	0	8,48	12,08	0,81	2,4	0,24	17,39	-
SE	Offshore	10,55	0	0,29	2,96	1,12	4,88		17,52	17,09
	EU Ener	10,54	0,18		2,24	0,42	4,74	0,16	6,28	17,09
	EMPS	-	0	0,34	2,2	0,57	4,8	0	14,76	17,96
UK IRE	Offshore	12,64	0	15,21	42,6	2,62	8,0		58,32	1,5
UK	EU Ener	12,6	9,79		43,11	1,29	7,48	0,57	39,76	1,71
GB	EMPS	-	0	10,46	45,20	0	5,33	0	53,31	1,23
NO	Offshore	0	0	0	0,9	0,1	0,9		15,4	29,9
	Eu Ener	-	-	-	-	-	-	-	-	-
	EMPS	-	0	0			0	0	7,39	45,2

20.2 Generation mix

Table 51: Generation mix per country [GWh] - 2010

		Nuclear	Coal	Gas	Oil	Bio-mass	Solar	Wind	Hydro	Cons
BE	EU Ener	48002	6125	22708	1005	3838	118	2529	366	
	ENSTOE	45729	35845			5134	237	1260	1659	88619
	EMPS	44040	7782	21024	3	4295	1870		0	88265
DK	EU Ener	0	13297	10167	352	4865	6	7938	21	
	ENSTOE	0	26294			2623	0	7813	23	35640
	EMPS	0	28492	3860	24	1698	9236		0	35900
FI	EU Ener	23248	14270	14056	834	13070	7	525	13206	
	ENSTOE	21884	30961			10353	0	293	12765	87467
	EMPS	22198	24149	6055	406	12227	591		12459	87500
DE	EU Ener	131452	275951	117806	4032	24412	8146	48827	21054	
	ENSTOE	133373	344278			26262	10874	36665	21698	547422
	EMPS	140547	194931	87505	2370	26038	48324		20420	616800
NL	EU Ener	3942	21513	59549	2910	8931	87	7160	99	
	ENSTOE	3755	99539			6396	0	3995	0	116460
	EMPS	3690	27333	51054	3	6445	6418		0	108000
SE	EU Ener	66208	2264	4242	2097	9816	4	3328	67600	
	ENSTOE	55626	7803			11907	0	3479	66215	147090
	EMPS	60966	1914	7182	2993	5334	2765		63306	143038
UK	EU Ener	62408	130670	160359	1511	15680	38	15295	4682	
UK	ENSTOE	58203	261758			291	0	6523	5794	335709
GB	EMPS	42500	151483	129054	1170	256	8885		5000	350000
NO	ENTSOE	0	5267			84	0	808	117286	129792
	EMPS	0	0	0	0	0	1561		113607	104357

Table 52: Generation mix per country [GWh] - 2020

		Nuclear	Coal	Gas	Oil	Bio-mass	Solar	Wind	Hydro	Cons
BE	EU Ener	48092	7309	18144	188	7828	232	9844	408	
	EMPS	48083	2324	27156	3	8593	6454		0	
DK	EU Ener	0	8116	7715	203	6008	102	14964	29	
	EMPS	0	10028	2594	1465	6063	15630		0	
FI	EU Ener	36244	10007	8012	136	19761	81	3426	13396	
	EMPS	36233	1606	3484	374	22766	4987		12713	
DE	EU Ener	34576	249575	119102	8980	36759	22121	131872	22349	
	EMPS	35099	194727	132411	1666	39165	163454		20420	
NL	EU Ener	3971	33750	54729	2864	11745	149	28925	99	
	EMPS	3968	35065	68961	1	10738	25219		0	
SE	EU Ener	60243	587	2606	1179	20704	82	14567	68100	
	EMPS	61199	732	6011	1182	21311	17410		62761	
UK	EU Ener	48031	97722	129300	1854	28996	199	104447	4958	
	EMPS	60000	30024	259479	425	12606	21305		5163	
NO	EU Ener									
	EMPS	0	0	0	0	0	0	16821	110053	

Table 53: Generation mix per country [GWh] - 2030

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<tr><th></th><th></th><th>Nuclear</th><th>Coal</th><th>Gas</th><th>Oil</th><th>Bio-mass</th><th>Solar</th><th>Wind</th><th>Hydro</th><th>Cons</th></tr>
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<tr><td>EMPS</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td colspan="2">30834</td><td>109686</td><td></td></tr>
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20.3 Area prices

Table 54: Mean area prices in 2020 and 2030 [EUR/MWh]

	2010	Inc. Trans.	Inc. CO_2	2020	2030	Investment	Red. Trans.	Red. CO_2
OSTLAND	49.22	49.83	71.05	58.96	52.73	55.14	49.02	38.19
SOROST	49.53	50.28	71.43	59.94	53.97	55.99	49.89	39.07
HALLINGDAL	48.13	48.59	69.5	57.88	51.79	54.06	47.7	37.52
TELEMARK	48.58	49.17	70.05	58.52	52.42	54.52	48.78	38.08
SORLAND	48.52	49.39	69.96	60.07	54.78	55.81	49.85	39.67
VESTSYD	48.89	49.65	70.43	59.43	54.02	55.25	49.63	39.22
VESTMIDT	48.86	49.41	70.15	58.56	52.48	54.58	48.43	38.16
NORGEMIDT	49.54	49.99	71.39	58.13	51.62	54.35	47.41	37.47
HELGELAND	48.28	48.71	69.58	56.96	50.48	53.24	45.73	36.63
TROMS	47.75	48.13	69.2	56.66	49.9	52.86	45.03	36.1
FINNMARK	47.56	47.9	69.22	56.82	49.39	52.31	43.58	35.51
NORGEM-OWP	49.24	49.58	70.95	57.53	51.09	53.78	46.91	37.07
VESTMI-OWP	48.56	49	69.72	57.96	51.93	54.02	47.93	37.76
VESTSY-OWP	48.38	49.13	69.71	58.81	53.46	54.68	49.11	38.81
SORLAN-OWP	48.21	48.98	69.53	59.58	53.1	53.97	49.33	38.75
AEGIR-OWP	48.21	48.98	69.53	59.58	54.42	55.44	49.57	39.4
SVER-ON1	47.38	47.82	68.9	56.35	49.56	52.62	44.67	35.72
SVER-ON2	47.11	47.57	68.34	56.11	49.53	52.56	44.53	35.83
SVER-NN1	48.04	48.5	69.64	57.14	50.31	53.47	45.38	36.41
SVER-NN2	49.35	49.84	71.43	58.63	51.89	55.03	47.43	37.64
SVER-MIDT	48.91	49.37	70.88	58.17	51.18	54.41	46.21	37.03
SVER-SYD	50.83	50.81	72.66	58.71	51.55	56.85	51.67	37.21
SVER-N-OWP	47.09	47.52	68.48	55.76	49.04	52.07	44.2	35.34
SVER-M-OWP	48.61	49.07	70.45	57.56	50.65	53.85	45.73	36.64
SVER-S-OWP	50.51	50.5	72.21	58.1	51.02	56.26	51.13	36.82
FINLAND	47.22	47.65	69.34	56.77	49.2	51.98	44.58	35.03
FI-OWP	46.93	47.35	68.92	56.18	48.69	51.44	44.11	34.66
DANM-OST	50.24	50.29	72.13	59.4	53.88	57.48	54.57	37.68
DANM-VEST	48.84	49.26	70.79	64.12	62.76	59.79	73.99	43.02
DANM-O-OWP	49.72	49.77	71.39	58.79	53.33	56.89	54.01	37.28
DANM-V-OWP	48.33	48.75	70.07	63.46	62.11	59.18	73.23	42.57
TYSK-OST	50.56	49.94	72.09	65.67	68.19	61.97	83.9	45.98
TYSK-NORD	51.71	51.14	72.84	65.49	67.49	61.38	83.5	45.59
TYSK-MIDT	51.96	51.33	73.27	66.15	68.45	62.18	84.5	46.26
TYSK-SYD	52	51.37	73.34	66.34	68.93	62.65	84.77	46.57
TYSK-SVEST	52.51	51.87	74.08	67.03	69.64	63.29	85.64	47.06
TYSK-VEST	52.08	51.46	73.54	66.6	69.11	62.75	85.22	46.73
TYSK-IVEST	51.53	50.92	72.78	65.92	68.39	62.1	84.34	46.24
TYSK-O-OWP	50.22	49.58	71.64	64.99	67.48	61.33	83.04	45.5
TYSK-V-OWP	51.37	50.8	72.38	64.81	66.8	60.75	82.64	45.11
NEDERLAND	52.24	51.62	73.12	64.73	64.73	61.4	82.37	44.53
NEDERL-OWP	51.89	51.28	72.65	64.06	64.06	60.76	81.53	44.07
BELGIA	52.38	51.74	73.27	65.02	65.99	62.26	83.9	45.46
BELGIA-OWP	51.83	51.21	72.52	64.35	65.3	61.62	83.04	44.99
GB-SOUTH	47.43	47.35	73.39	58.2	54.32	54.86	50.97	40.34
GB-MID	46.92	46.85	72.75	57.66	53.76	54.28	50.44	39.94
GB-NORTH	46.36	46.3	72.27	56.45	45.16	51.96	43.22	33.32
DOGGERBANK	46.63	46.79	72.29	57.06	53.6	54.1	49.92	39.69
GB-N-OWP	45.88	45.82	71.52	55.86	44.69	51.41	42.77	32.97

GB-M-OWP	46.43	46.36	71.99	57.06	53.2	53.72	49.92	39.52
GB-S-OWP	46.92	46.85	72.64	57.59	53.76	54.29	50.44	39.92

20.4 Generation Capacities

Table 55. Generation capacity [GW] per country and type 2020[4]

Country	hydro	nuclear	l.coal	h.coal	gas	oil	oil_gas	Bio	wind	not	R. river	solar	Sum
AT	10.30	0	0	1.60	3.69	0.26	0.20	1.69	2.34	0	0	0	20.08
BA	2.46	0	2.26	0	0	0	0	0	0.39	0	0	0	5.10
BE	0.14	5.94	0	1.08	6.37	1	0.87	1.99	3.57	0	0	0	20.96
BG	2.19	2.87	0	3.28	0.45	0.25	0.07	0.25	1.73	0.01	0	0	11.10
CH	17.50	3.20	0	0	0.70	0	0	0.55	0	0	0	0	21.95
CZ	1.07	4.26	7.63	1.71	1.08	0.20	0.25	0.53	1.12	0	0	0	17.84
DE	4.43	4.05	16.26	28.44	32.62	6.21	3.21	7.67	56.93	0.17	0	22.47	182.46
DK	0.01	0	0	3.32	2.17	0.39	0	1.23	5.73	0	0	0	12.85
EE	0.01	0	0	1.92	0.24	0	0	0.16	0.93	0	0	0	3.25
ES	14.29	6.99	3.12	7.41	31.47	4.86	0.26	4.12	31.40	0.24	0	11.59	115.74
FI	3.10	4.21	0	5.10	2.89	0.35	0.20	4.46	1.34	0	0.23	0	21.89
FR	20.77	66.27	0	3.85	12.47	8.43	0.76	5.89	22.57	0.65	0	4.59	146.24
GB	1.62	6.01	0	11.18	43.13	1.49	0.86	6.78	36.26	2.50	0	0	109.82
GR	2.87	0	4.38	0	6.74	1.94	0	0.51	5.14	0.03	0	1.60	23.21
HR	2.20	0	0	0.50	0.80	1.50	0.40	0	0.55	0	0	0	5.95
HU	0.44	2.17	0.78	0.16	4.14	0.18	0.13	0.97	0.62	0.02	0	0	9.61
IE	0.23	0	0	1.18	5.85	0.03	0	0.20	3.69	0.26	0	0	11.43
IT	17.44	1.58	0	10.25	46.37	3.53	1.52	6.26	22.26	0.79	0	4.18	114.17
LT	0.15	0.76	0	0	2.18	0.31	0	0.18	0.66	0	0	0	4.24
LV	1.53	0	0	0.23	0.63	0.05	0	0.24	0.40	0	0	0	3.08
MK	0.90	0	0.85	0	0.35	0.20	0	0	0.05	0	0	0	2.35
NL	0.04	0.50	0	8.53	10.42	0.79	1.01	2.13	9.72	0.04	0	0	33.17
NO	37.09	0	0	0	0.93	0.10	0	0.50	1.33	0	3.70	0	43.64
PL	1.19	1.52	7.76	18.74	1.48	0.38	0.27	2.21	1.71	0.02	0	0	35.28
PT	4.73	0	0	1.81	5.23	1.42	0.02	1.42	5.60	0.29	0	2.15	22.67
RO	7.59	2.11	6.28	1.89	3.52	0.98	0.05	0.44	1.62	0.01	0	0	24.47
RS	2.93	0	5.56	0	0.34	0	0	0	0	0	0	0	8.82
RU	17.01	10.55	0.58	0	1.09	2.05	0	4.45	5.32	0	0	0	41.05
SE	14.79	0.71	0	1.09	0.21	0	0.27	0.31	0.25	0	2.30	0	19.67
SI	1.86	2.81	1.07	0.22	1.14	0.12	0	0.50	0.58	0.01	0	0	8.31
SK	1.86	2.73	0.77	0.79	0.82	0.19	0.14	0.19	0.57	0	0	0	8.06
UA	0.03	0	0	0	0	0	2.44	0	0	0	0	0	2.47
NI	0.04	0	0	0	0.70	0	0	0.06	0.21	0	0	0	1.01
LU	0.04	0	0	0	0.72	0	0	0.10	0.19	0	0	0	1.05

Table 56. Generation capacity [GW] per country and type. 2030[4]

Country	hydro	nuclear	l.coal	h.coal	gas	oil	oil_gas	Bio	wind	not	R.river	solar	Sum
AT	10.78	0	0	0.73	3.73	0.19	0.06	1.67	3	0.01	0	0	20.17
BA	2.87	0	2.97	0	0	0	0	0	0	0	0	0	5.84
BE	0.15	0	0	5.48	10.59	1.17	0.46	1.68	4.97	0	0	0	24.50
BG	2.34	3.82	0	3.04	0.35	0.13	0.07	0.32	2.26	0.02	0	0	12.35
CH	20.10	3.20	0	0	1.30	0	0	0.80	0.60	0	0	0	26
CZ	1.09	5.42	7.73	1.86	1.89	0.17	0.16	0.65	1.48	0	0	0	20.45
DE	4.69	0	11.30	24.32	40.22	8.11	2.32	10.05	75.63	0.17	0	29.93	206.74
DK	0.01	0	0	3.10	2.52	0.12	0	1.76	6.53	0	0	0	14.05
EE	0.01	0	0	1.90	0.46	0	0	0.20	1.30	0	0	0	3.87
ES	15.01	4.11	2.55	6.63	34.14	4.47	0.28	5.34	45.41	0.56	0	14.08	132.58
FI	3.14	4.40	0	2.74	3.20	0.18	0.21	5.26	1.99	0	0.23	0	21.35
FR	21.32	57.69	0	1.25	27.62	6.18	0.66	6.22	27.89	1.73	0	11.07	161.63
GB	1.71	12.68	0	9.80	42.41	1.30	0.70	7.48	39.76	4.21	0	0	120.04
GR	3.33	0	4.06	0	10.12	1.58	0	0.65	7.19	0.07	0	2.49	29.47
HR	2.30	0	0	0.70	1.80	0	0.10	0	3	0	0	0	7.90
HU	0.51	2.17	0.95	0	3.74	0.09	0.13	1.25	0.91	0.10	0	0	9.86
IE	0.23	0	0	1.18	5.82	0.20	0	0.21	3.94	0.78	0	0	12.35
IT	17.44	10.77	0	8.86	44.75	3.63	1.42	9.07	24.42	1.12	0	7.20	128.67
LT	0.16	1.52	0	0	1.91	0.08	0	0.23	1.06	0	0	0	4.94
LV	1.67	0	0	0.30	0.66	0.05	0	0.32	0.59	0	0	0	3.59
MK	1.20	0	1	0	0.50	0.20	0	0	0	0	0	0	2.90
NL	0.04	0.59	0	8.53	10.96	0.77	0.75	2.41	11.19	0.14	0	0	35.38
NO	48.17	0	0	0	0.93	0.10	0	0.90	15.45	0	3.70	0	69.25
PL	1.20	2.15	8.96	20.66	1.53	0.21	0.24	3.51	2.70	0.02	0	0	41.18
PT	5.08	0	0	0.57	5.21	0.77	0.02	1.66	6.69	0.67	0	3.04	23.72
RO	7.68	2.84	2.85	0.85	2.70	0.37	0.03	0.47	2.24	0.02	0	0	20.05
RS	3	0	6.18	0	0.36	0	0	0	0.20	0	0	0	9.74
RU	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	17.09	10.55	0	0.18	1.87	0.42	0.37	4.74	6.28	0	2.30	0	43.79
SI	1.20	1.52	0.61	0.06	0.51	0	0	0.31	0.38	0	0	0	4.58
SK	1.86	3.41	0.56	0.56	1.39	0.12	0.13	0.60	1.04	0.01	0	0	9.69
UA	0	0	0	0	0	0	2.57	0	0	0	0	0	2.57
NI	0	0	0	0	1.70	0.80	0	0	0.93	0	0	0	3.43
LU	0.04	0	0	0	0.87	0	0	0.06	0.27	0	0	0	1.25

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