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Effects of Increased Wind Power Generation on Mid-Norway's Energy Balance under Climate Change: A Market Based Approach

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Abstract: Thanks to its huge water storage capacity, Norway has an excess of energy generation at annual scale, although significant regional disparity exists. On average, the Mid-Norway region has an energy deficit and needs to import more electricity than it exports. We show that this energy deficit can be reduced with an increase in wind generation and transmission line capacity, even in future climate scenarios where both mean annual temperature and precipitation are changed. For the considered scenarios, the deficit observed in winter disappears, i.e., when electricity consumption and prices are high. At the annual scale, the deficit behaviour depends more on future changes in precipitation. Another consequence of changes in wind production and transmission capacity is the modification of electricity exchanges with neighbouring regions which are also modified both in terms of average, variability and seasonality.

Keywords: variable renewable energy; wind; hydro; energy balance; energy market

1. Introduction

The United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement promotes the transition to low carbon economy by replacing conventional by renewable energies such as wind-, solar-, and hydro-power. In Europe, optimistic scenario by the European Climate Foundation foresees 100% renewable energy supply at the horizon 2050 [1]. Some countries such as Sweden, Spain and Austria are already well engaged for reaching this objective even before this deadline [2]. This issue is also relevant at regional scale level as highlighted in Northern Italy by reference (Ref.) [3].

Thanks to its huge resources, Norwegian electricity generation already comes for about 95.3% from hydropower [4]. Norway has an excess of energy at annual scale and presents on average a positive balance between importation and exportation [5]. On account for its high water storage capacity, Norwegian reservoirs are sometimes considered as the future Blue Battery of Europe. Gullberg [6], for instance, explains that thanks to its actual hydropower capacity, Norway might balance power in Europe. In the longer term, new transmission lines and pumped-storage hydropower in Norway would provide a backup capacity to the expected future high solar and wind power capacity in Europe [6,7].

The positive energy balance for Norway hides significant regional disparities. Mid-Norway is the most illustrative example (region 9 on Figure 1). Like the rest of the country, its electricity system is mainly based on hydropower with reservoirs that store high river flow during the snowmelt season in spring and summer, and then generate hydropower in winter (i.e., when electricity consumption and prices are much higher). Mid-Norway experiences an energy deficit almost every year [8]. Residual demand is satisfied with energy import from other parts of Norway and other countries of the Nordic Energy market (Norway, Sweden, Denmark and Finland). Due to high electricity prices, the energy deficit is moreover critical during the winter season since most buildings use electrical heaters. The winter 2002/2003, dubbed as "electricity crisis" by Norwegian media, is the most illustrative example [9]. The low hydropower resource resulting from the exceptionally dry 2002 fall, the high winter energy demand of the cold subsequent winter and the limited transmission lines with the neighbouring regions led electricity prices to double [10]. Even though such a situation is unusual, its frequency and intensity are both expected to increase in the future as a result of the increasing demand from the industry sector and electric cars [9].

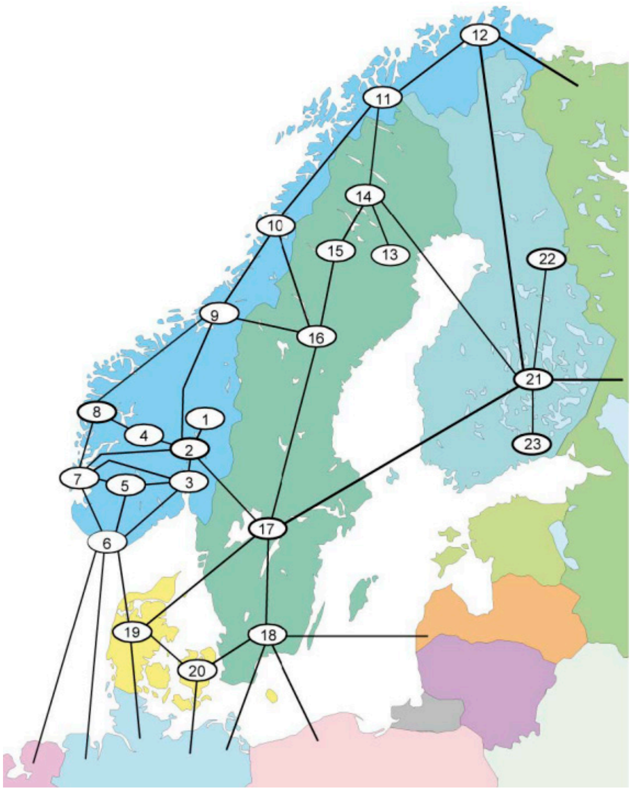


Figure 1. Simplified Nordic energy market grid as seen by EFI's Multi-area Power market Simulator (EMPS) model. Black lines represent transmission lines among the different regions. Mid-Norway region is the region number 9. It is connected to East-Norway, West-Norway, Helgeland and Inndalselven (Sweden) regions (respectively, regions 2, 8, 10 and 16). EFI: Norwegian Electric Power Research Institute.

To reduce the Mid-Norway energy balance deficit and thus the risk of energy shortcuts, local policy makers have been strongly motivated to increase wind power capacity. Wind resource is actually important in Mid-Norway and was estimated to be a relevant supplement to hydropower in Nordic areas (e.g., [11]). Increasing wind power capacity in Mid-Norway is also fully consistent with the objective of the Norwegian-Swedish Electricity Certificate Market aiming to increase the rate of renewable energy in the whole Nordic energy market where conventional energy sources are still used in Sweden and Finland [12]. In the present state, Mid-Norway regularly imports/exports energy from/to neighbouring regions. The high power generation variability obtained with more variable renewable energy obviously requires increasing transmission lines capacity [13]. Upgrading transmission lines is planned between Mid-Norway and West-Norway (http://www.statnett.no). As highlighted during a stakeholder meeting organized for the region within the COMPLEX EU research project (http://owsgip.itc.utwente.nl/projects/complex/), public acceptance for wind power and transmission development is however not straightforward. It is high if the benefits from the project mainly go to the regional industry and trade development. It is however rather low if the generated power has to be exported to neighbouring regions.

The first aim of the present work is to assess the effect of the development of additional wind farms and of the development of a new transmission line on the energy balance of Mid-Norway. Next, it is to explore the alternative question raised by local stakeholders about the finality of wind power development—deficit limitation or export growth?

The second main objective of this study is to assess the ability of the Mid-Norway system to cope with a modification of the energy balance due to climate change. Climate change could first impact the mean energy production via changes in wind- and hydro-power potential. In Nordic countries, change in wind power potential is expected to be very small with a lower than 5% decrease (a strong agreement was obtained between Global Circulation Models (GCMs) as highlighted by Ref. [14]. Changes in hydropower potential are conversely expected to be quite large as a result of both precipitation and temperature increase. The significant increase in precipitation expected for the region [15] should actually lead to an increase in river flows. Regional warming should additionally modify hydrological regimes with shorter winter droughts, earlier and smaller snowmelt flows [16]. On the other hand, climate change could also modify the electricity demand. Regional warming should especially lead to less heating needs in winter and to reduce the demand seasonality. The sensitivity of Mid-Norway system performance to changes in mean precipitation and temperature is thus definitively important to analyse.

Our analysis is carried out with the decision scaling approach developed by Ref. [17]. This approach is based on sensitivity analyses of system responses to a set of synthetic climate change scenarios. In the present study, we consider changes in mean precipitation and temperature. The objective is to build Climate Response Functions (hereafter noted as CRFs) putting in perspective: (i) either a given statistics of interest or an indicator of success of the considered system obtained via a set of synthetic scenarios implemented with a sensitivity analyses of its drivers (i.e., in our case, temperature and precipitation variables); and (ii) the expected changes of the drivers obtained from GCMs.

We use the EMPS (EFI's Multi-area Power market Simulator, EFI: Norwegian Electric Power Research Institute) power market model for simulating the Nordic energy market for the present and synthetic future climate scenarios and different wind power and transmission line capacities. The main indicator we account for is the one discussed by local stakeholders, namely the energy balance deficit in Mid-Norway. We focus on both the annual scale and the winter season.

The article is organized as follows. Section 2 gives the description of the Mid-Norway case study and of the considered future Mid-Norway electricity system scenario. Section 3 details the database and models used. Section 4 illustrates current situation in Mid-Norway while Sections 5 and 6 give results obtained for future electricity system and future climate. Section 7 concludes and gives some highlights for further research.

2. Case Study

All Nordic countries have liberalized their electricity markets, opening both electricity trading and electricity production to competition. For a given region, this means that regional electricity prices are determined by the energy balance and exchange capacity from/to neighbouring regions.

The Mid-Norway region covers the counties Møre og Romsdal, Sør-Trøndelag and most of Nord-Trøndelag. The region includes a set of fjords and mountains with altitudes ranging from 0 to 1700 m.a.s.l. The climate is relatively wet with annual precipitation ranging with the altitude from

500 mm/year in coastal areas to 3000 mm/year in inland mountains. Temperature also varies along this climate transect with an annual average ranging from +7 to −6 °C according to altitude.

Watercourses range from small coastal waterways to major mountainous rivers in the east, where catchment areas with large hydropower reservoirs are located. The hydrological regime also moves from an Atlantic regime in coastal areas (i.e., major flows in late autumn and winter) to an Alpine regime in the inland areas (i.e., low winter flows and high flows in late spring and summer due to snow melt and rainfall events). The period of snow accumulation lasts several months and the snow melting period usually starts in late March in the lowland regions and in June in high elevation areas.

Primary activities such as agriculture, fishery and forestry play a role in all the counties. Engineering industry, woodworking factories, fish farming, shipping trade and food industry are other important activities in the region. Energy-intensive industries and petroleum activity have large demand of electricity, which has increased over the last 20 years and probably will continue to do so.

The region produces on average 14 TWh per year and consumes about 21 TWh. Mid-Norway region continuously buys electricity from the Nordic market (http://www.Statnett.no). Its storage capacity is about 8% of Norway's total capacity which represents about one third of the annual consumption in the region (i.e., 6.7 TWh).

When this study was initiated in 2014, Mid-Norway wind power capacity equalled 1090 MW. Additional 4552 MW was already under construction or close to be, while concessions for another 1100 MW power capacity were asked (for details see: https://www.nve.no/). In this study, we consider two wind power capacity configurations. The first considers the installed wind power capacity in 2014 (hereafter, this scenario is denoted W1). The second one considers the additional planned and asked wind power capacity (meaning a total wind power capacity equal to 6742 MW, denoted as W2 scenario). Even though all asked concessions might not be accepted, W2 scenario gives a good guess about wind power capacity evolution.

Two transmission line scenarios are also considered. The first scenario, denoted as G1, considers the current line capacity: Mid-Norway is connected with East-Norway, West-Norway, Helgeland and Inndalselven (Sweden) regions (respectively, region 2, 8, 10 and 16 in Figure 1). The second scenario, denoted G2, takes into account the increased transmission line capacity which will be achieved between Mid-Norway and West-Norway within the next few years (see, for example, http://www.statnett.no/). Corresponding transmission line capacities are given in Table 1.

Table 1. Transmission line capacity scenarios between the Mid-Norway and its four neighbouring regions. Numbers in brackets refer to the market areas on Figure 1.

Mid-Norway [9]	East-Norway [2]	West-Norway [8]	Helgeland [10]	Inndalselven [16]
Scenario G1	600 MW	500 MW	900 MW	1950 MW
Scenario G2	600 MW	2000 MW	900 MW	1950 MW

3. Data and Models

The meteorological years used as reference cover 1961–1982. Along this period, the Nordic energy system has been evolving with, among other things, construction of many hydropower plants and water reservoirs. For our analyses, we consider fixed system configurations (we disregard any evolution of the system state during the considered time period). The reference configuration corresponds to the current one: for the whole Nordic market, the hydropower, wind-power and transmission line capacities are those available in 2014.

3.1. Mid-Norway Energy Balance Modelling

The EMPS model is a hydrothermal optimization and simulation model used by most players in the Nordic energy market for long and medium-term price forecasting, hydro scheduling, system and investment analysis. One of the main advantages of this model is that it includes a detailed representation of the hydro-system (i.e., power stations, reservoirs, diversions, etc.). The optimization aims at minimizing the overall system costs via a variant of the so-called water value method (see Ref. [18] for an early reference and Ref. [19] for a recent one). This method aims to balance the income related to the immediate use of stored water against the future income expected from its later use. A mathematical description of both optimization and simulation stages within EMPS modelling is given in Ref. [20].

In this study, the EMPS model is used to simulate consequences of increasing the capacity of: (i) wind power generation; and (ii) transmission lines in Mid-Norway region for the current and a variety of future climates. The model is set up for the whole Nordic energy market, to which Mid-Norway region belongs. The Nordic energy market is divided into 23 areas (Figure 1). Each area is characterized by transmission constraints and hydropower system properties. The different connections among areas reflect physical transmission lines. The Nordic energy market includes more than a thousand reservoirs and several hundred hydropower plants in more than 50 different river systems.

In the considered set up of the EMPS model, input data are: (i) weekly unregulated water discharge time series for a set of river basins in each market area; and (ii) weekly wind power time series for each market area. EMPS model simulations are typically done for an ensemble of historical weather years assumed to have equal probability. The weather years provide physically consistent weather scenarios (i.e., scenarios with consistent space/time correlation among surface weather variables) and in turn physically consistent scenarios for the various hydro-meteorological variables (river discharges, wind, solar radiation, temperature) that affect the energy production, the demand and then the market balance.

Hydro-meteorological time series scenarios required for the climate change impact analysis are obtained with a pattern scaling approach from the observed time series available for the reference period (e.g., [21–23]. This approach is expected to rather well preserve space/time correlations between variables. In the present case, the pattern scaling is carried out on a weekly basis. For river discharge, each reference river basin for which unregulated discharge time series are required in EMPS is considered separately. Fifty-two weekly scale factors C are first estimated from hydro-meteorological simulations forced with a set of future climate change scenarios indexed by i. They are then used to derive future discharge series from the observed ones as follows:

$$Q_{Future}(w, y, k, i) = Q_{Obs}(w, y, k)C(w, k, i) \tag{1}$$

with $Q_{Future}(w, y, k, i)$ the weekly water discharge for the w-th week of year y and the k-th reference river basin; Q_{Obs} is the observed weekly time series water discharge within the EMPS archive and $C(w,k,i)$, k = 1–52 are the scaling factors of weekly river discharges for the 52 calendar weeks.

For each market area and each future climate scenario i, scaling factors C are the ratios between future and present average regional runoff. Future regional runoff time series are obtained via hydrological simulation, for each grid cell of each market area, with a distributed version of the GSM-Socont hydrological model [24] (Glacier and SnowMelt—Soil CONTribution model). This model simulates the snowpack dynamic (snow accumulation and melt), water abstraction from evapotranspiration, slow and rapid components of river flow from infiltrated and effective rainfall respectively. For each climate change scenario i, future meteorological scenarios used for the hydrological simulation are obtained with the scaling approach. Historical time series of precipitation and temperatures are modified with a multiplicative (additive) perturbation prescribed from the relative (absolute) change in annual precipitation (temperature) (hereafter denoted as ΔP and ΔT, respectively). As described later, a number of climate change scenarios, in terms of change in mean annual precipitation and temperature, are considered.

Historical precipitation and temperature data comes from the European Climate Assessment & Dataset (ECAD, [25]) with a 0.25° space resolution. The hydrological model required the calibration of some parameters. We use a unique set of parameters for all market areas. It was calibrated by comparing the EMPS discharge archive with the discharges simulated from historical meteorological data.

In EMPS, the energy demand is indexed by the temperature, showing higher consumption during cold days. The energy demand is linked to a lesser extent to price dependent contracts. This link is represented by an additional demand which activates only if the price is low enough. A typical example of price dependent contract is a boiler-power contract where the customer has an oil heater connected in parallel with an electrical heater which is only used when the price is low. At annual scale, this price dependent demand represents about 8% of the temperature dependent demand. For future scenarios, the demand is estimated on a weekly basis from future temperature, obtained from the perturbation approach mentioned above, and from the energy price derived within EMPS for the current simulation time step.

We compute the weekly wind power generation time series with the wind speed database NORA10 [26] (NOrwegian Reanalysis Archive). NORA10 is currently the best near-surface (i.e., 10 m altitude) wind speed reanalysis over Scandinavian countries with a 10 km^2 space resolution. Wind speed data are available from 1957. We used the wind power generation model developed by Ref. [27] at daily time step. This model considers a nonlinear relationship between wind speed u (m·s^{-1}) and wind power generation, hereafter noted P_W (MWh). Below a given threshold (3 m·s^{-1} in this study), the wind speed is not sufficient to enable power generation. The power generation is then a third order polynomial function of wind speed and reaches the maximum wind turbine efficiency at a second threshold (13 m·s^{-1}). Above a third threshold (25 m·s^{-1}), the power generation has to be stopped in order to avoid any damages on the wind turbine. The 70 m altitude wind speed time series used for computing wind power time series were estimated from the 10 m altitude NORA10 wind following the scaling equation:

$$u_1 = u_2 \left(\frac{h_1}{h_2} \right)^{\alpha} \tag{2}$$

with u_1 and u_2 the wind speeds (m·s^{-1}) at the altitudes h_1 and h_2 (m), respectively. α is an air friction coefficient chosen equal to 1/7 (no dimension) [28]. Simulated daily wind power generation time series are then aggregated at weekly time scale.

3.2. Climate Response Functions

CRFs are expressed in a two dimensional climate change space defined from changes in temperature and precipitation. The climate change factors we considered range from −20% to +50% for precipitation (with 10% step) and from 0 to +6 °C for temperature (with 1 °C step) in regards with the reference period 1961–1982. CRFs are built from the 8 × 7 hydro-climatic time series scenarios obtained for these climate change scenarios via the scaling approach presented in the previous section. The reference period corresponds to the scenario with no change in temperature (i.e., +0 °C) and no change in precipitation (i.e., +0%).

Positioning on the CRFs the future projections of climate experiments available from the latest GCMs allows discussing the expected effects of climate change for different future prediction periods. In the present case, changes in future annual precipitation and temperature are estimated from the outputs of an ensemble of 23 GCM projections from CMIP5 experiments [29] (Coupled Model Intercomparison Project Phase 5). Using several GCM projections illustrates uncertainty on precipitation and temperature changes over the next decades and its amplitude in regard to the studied effects.

In recent studies, climate change factors for a given climate experiment are classically estimated from the change of the raw climate model outputs between a future and a reference period. A limitation to the robust estimation of change factors is the critical role of multi-decadal variations in the evolution of the climate system. These low-frequency variations, commonly termed as climate internal variability, can, temporarily, worsen, reduce or even reverse the long-term impact of climate change. Internal variability was found to be a major source of uncertainty in climate projections for the coming decades, especially for regional precipitation (e.g., [30,31]). A robust estimate of expected changes actually requires a noise-free estimate of the climate response from the modelling chains. In the present case, we estimate the climate response of each GCM using all data of the transient simulations available for the model (150 years from 1950 to 2099). For each GCM, a trend model is first fitted to the raw climate projections following Ref. [32] (piece-wise linear function of time for precipitation and a 3rd order polynomial trend for temperature). The expected change for any future period is obtained from the change between trend estimates obtained respectively for this period and for the reference time period. We consider three future 20-year time periods: 2040–2059, 2060–2079 and 2080–2099.

Figure 2 shows annual temperature and precipitation changes expected in Mid-Norway for each future period. Model uncertainty for precipitation changes is very large although a significant increase is consistently foreseen; only one GCM gives a slight decrease in precipitation. Changes in temperature are more univocal showing an increase along the century. Note however that the dispersion among models grows with the projection time horizon.

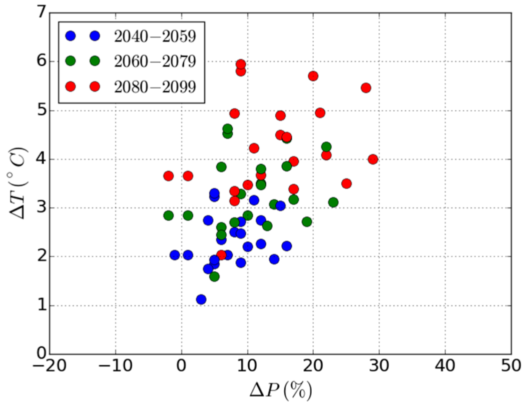


Figure 2. Scatterplot of average changes in precipitation and temperature for 23 GCM projections between control period (1961–1982) and three future time periods (i.e., 2040–2059, 2060–2079, and 2080–2099).

4. Mid-Norway Energy Balance in the Current System

This section presents the results obtained by EMPS for the control configuration, i.e., with W1G1 scenario for the control climate (2014 wind power and transmission capacity, observed meteorological forcing). We first note that weekly wind and hydropower generation are much more variable than the demand (see coefficients of variation in Table 2). This result agrees with the literature related to the variability of renewable energies (e.g., [33]). In Mid-Norway, unregulated wind power generation is positively correlated with electricity consumption; the winter generation is higher than the summer one (Figure 3b,d). Mid-Norway reservoirs are handled so that stored inflows are mainly released during the winter season, making winter hydropower generation higher (see energy storage scheme and hydropower generation time series on Figure 3a,c). On average, the total production (i.e., sum of hydro and wind power) is not sufficient to supply the load, neither at yearly scale nor for winter and summer seasons (Table 2). As a result of the reservoirs' management, the average energy balance deficit is higher in summer than in winter (Table 2). However, summer deficit is less critical than winter deficit since market prices are lower in summer (Figure 3e). For some years, electricity prices collapse, falling to 1 €cent/kWh during the spring and summer seasons. These situations correspond to periods where reservoirs are almost full and present a high risk of spill. When looking at the statistical distribution of the energy balance on Figure 3f, we note that only 10% of winter weeks present a positive energy balance while this number is lower than 5% during the summer season. Considering the whole year, less than 10% of all weeks have a positive energy balance.

Table 2. Average yearly, winter and summer Mid-Norway weekly energy balance components for W1G1, W2G1 and W2G2 scenarios and for the control period 1961–1982. Number within brackets give coefficient of variation (CV, defined as the ratio between the standard deviation and the mean).

W1G1 Scenario	**Year**	**Winter (Week 43 → 10)**	**Summer (Week 21 → 35)**
Hydro Power P_H	273 GWh (0.48)	372 GWh (0.25)	145 GWh (0.48)
Wind Power P_W	61 GWh (0.60)	84 GWh (0.45)	35 GWh (0.55)
Total Consumption	497 GWh (0.19)	590 GWh (0.06)	380 GWh (0.08)
Energy Balance	−163 GWh (0.60)	−134 GWh (0.74)	−200 GWh (0.36)
W2G1 Scenario	**Year**	**Winter (Week 43 → 10)**	**Summer (Week 21 → 35)**
Hydro Power P_H	272 GWh (0.47)	365 GWh (0.25)	152 GWh (0.48)
Wind Power P_W	160 GWh (0.63)	222 GWh (0.49)	90 GWh (0.52)
Total Consumption	499 GWh (0.19)	592 GWh (0.06)	381 GWh (0.08)
Energy Balance	−66 GWh (1.84)	-5.8 GWh (20.7)	−137 GWh (0.62)
W2G2 Scenario	**Year**	**Winter (Week 43 → 10)**	**Summer (Week 21 → 35)**
Hydro Power P_H	273 GWh (0.47)	366 GWh (0.25)	150 GWh (0.48)
Wind Power P_W	160 GWh (0.63)	222 GWh (0.49)	90 GWh (0.52)
Total Consumption	499 GWh (0.19)	592 GWh (0.06)	381 GWh (0.08)
Energy Balance	−66 GWh (1.88)	−4.5 GWh (27.4)	−141 GWh (0.59)

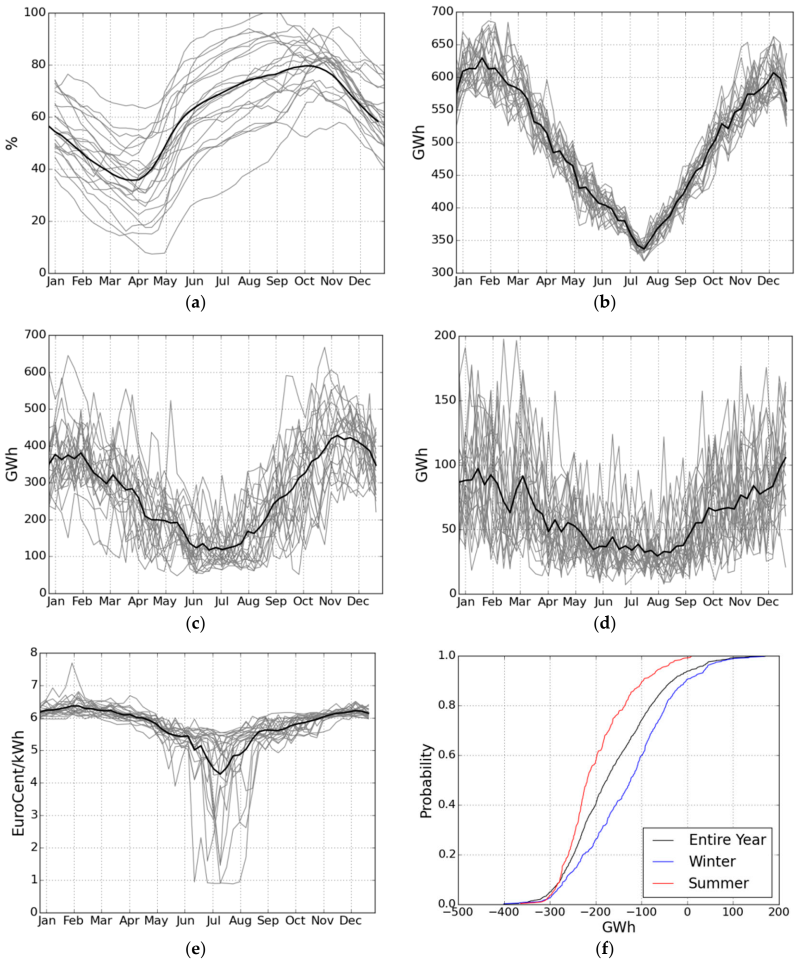
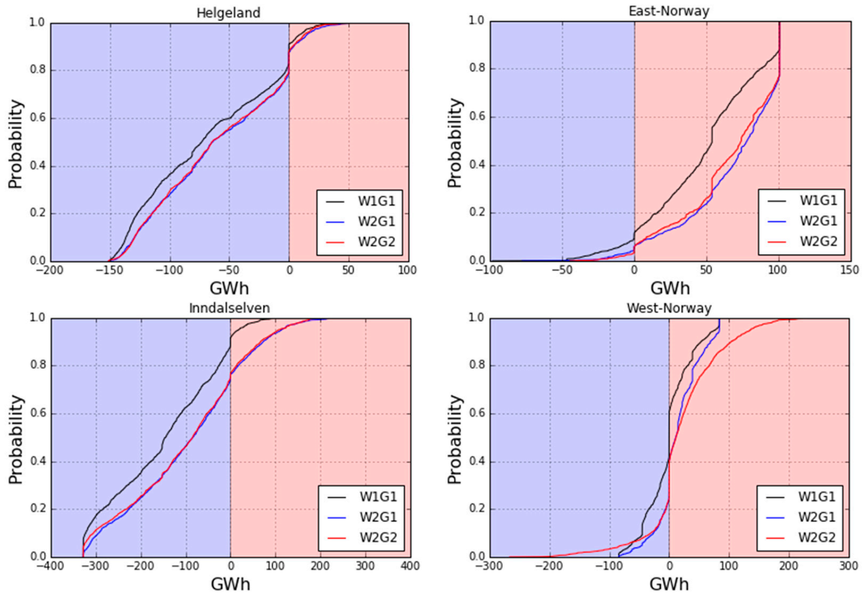
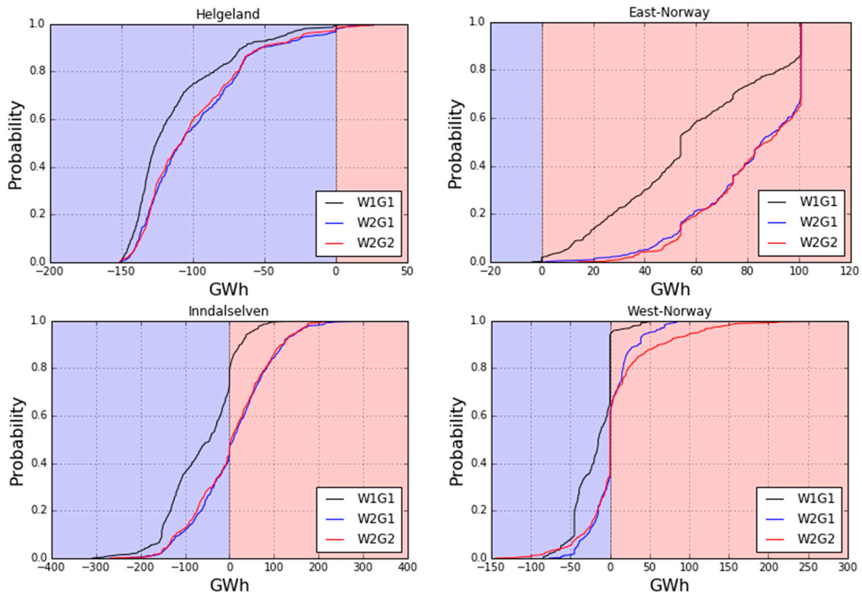


Figure 3. Weekly: (**a**) Aggregated energy storage expressed as ratio of the total storage capacity; (**b**) total electricity consumption (i.e., temperature and price dependent consumptions); (**c**) hydropower (from regulated + unregulated power plants); (**d**) wind power generation; and (**e**) electricity prices time series in Mid-Norway for the period 1961–1982. Note that only the fraction of electricity consumption temperature dependent is plotted. Grey curves represent week-to-week values for each year and the black curve represents the average annual cycle; (**f**) Cumulative distribution function of Mid-Norway weekly energy balance. Winter season is defined as from Week 43 to Week 10 of the following year and summer season from Week 21 to Week 35.

As a result of the deficit, Mid-Norway imports electricity from the regions of Inndalselven and Helgeland over, respectively, 90% and 70% of the weeks (Figure 4). Meanwhile, the region exports electricity to East-Norway 90% of the time. The line between Mid- and West-Norway is used for both importing and exporting electricity. Note that 20% of the weeks the transmission line is not used at all (Figure 4). Similar distributions are obtained during winter season. Note that these simulated results are consistent with the current deficit and exchange situation of the region as presented in the previous sections.



(**a**)



(**b**)

Figure 4. Cumulative distribution functions of weekly energy exchanges between Mid-Norway and the neighbouring regions during: (**a**) the whole year; and (**b**) the winter season only. Negative (blue background) and positive (red background) values, respectively, show importation to and exportation from Mid-Norway. Note than only the line with West-Norway is reinforced in G2 scenario. Note that some distributions clearly show when the full capacity is reached for the whole week (e.g., East-Norway).

5. Increasing Wind Power and Transmission Capacities

This section focuses on the evolution of the energy balance by considering, firstly, an increase of wind power capacity in Mid-Norway (i.e., W2G1 scenario), and secondly, an increase of both wind power capacity and transmission line capacity between Mid- and West-Norway (i.e., W2G2 scenario).

Additional wind power capacity almost triples the average generation from 61 to 160 GWh per week. The weekly generation increases from 84 to 222 GWh in winter season and from 35 to 90 GWh in summer (Table 2). Higher energy generation obviously reduces the energy balance deficit (Table 2). For winter, the deficit is close to 0 (i.e., −5.8 GWh/week). It remains rather important in summer (−137 GWh/week) as well as at annual scale (−66 GWh/week). Comparing W1G1 and W2G1 scenarios, we note that, on average, Mid-Norway exports every week 2 GWh more, which corresponds to roughly 2% of the additional wind generation. In winter, average export reaches 10 GWh (about 7% of the additional generation at this season). One can note that this exported electricity could have been used to further reduce Mid-Norway deficit.

Wind power generation being highly variable (see CV in Table 2), increasing wind power generation implies a higher temporal variability of the energy balance (the CV of the weekly energy balance increase by a factor of 3 during the whole year and by a factor 28 during the winter season; Table 2). Such variability requires systematically more important energy exchanges between Mid-Norway and all its neighbouring regions (Figure 4), even when the average deficit is close to 0 as it is the case during the winter, for instance. Transmission lines are effectively more often used for exporting energy and they are more often used at full capacity. For instance, Mid-Norway exports at full capacity to East-Norway during more than 25% of the weeks during the year (35% in winter). Another example is the number of winter weeks during which Mid-Norway exports electricity to West-Norway (60% of the weeks for W2G1 against roughly 40% for W1G1).

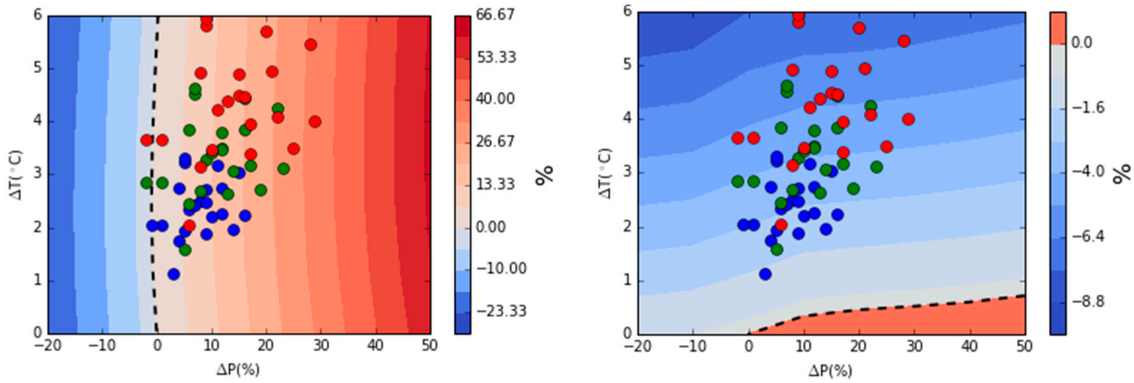
The increased transmission capacity of the line between Mid- and West-Norway (i.e., W2G2 scenario) has no significant effect on the mean annual deficit (Table 2). Note that the winter deficit slightly decreases to −4.5 GWh/week. Energy exchange distribution functions obtained with W2G2 scenario roughly overlap the ones obtained with W2G1 except for the reinforced line (Figure 4). Although the increased capacity is only used about 10% and 15% of the time, it allows exporting an important amount of energy. This mainly occurs during high wind power generation periods and/or when reservoirs are close to full in spring.

6. Evolution of Mid-Norway Energy Balance in a Changing Climate

This section focuses on climate change impact on Mid-Norway energy balance. As discussed in introduction, climate change is expected to impact both the average and the time variability of electricity generation and consumption. Considering changes in temperature and precipitation, two components of the energy balance are modified: the river flows and the electricity consumption. This section presents first the raw changes in these two components and secondly the impacts on Mid-Norway energy balance and exchanges.

6.1. Climate Change Impacts on River Flows and Electricity Consumption

The main driver of change in river flow is precipitation; higher precipitation giving higher river flows. As illustrated on Figure 5a, river flow increases linearly with precipitation change and higher temperatures increase evaporation and in turn reduce river flow. The effect of increasing temperature on mean annual discharge is rather weak. For instance, river flows slightly increase up to ΔT equal to +2 °C and then decrease when temperatures rise above this threshold. In any case, river flow modification is less than 5% whatever the change in temperature. However, increasing temperature significantly reduces river flow seasonality with higher discharges values in winter (due to a higher ratio of liquid precipitation resulting from higher temperatures) and lower values during the spring and summer seasons (due to less snowpack; not shown). Annual temperature and precipitation changes provided by 23 GCMs are also plotted on Figure 5a for three different future time periods. The CRF shows anticipated changes in water discharge as a function of temperature and precipitation estimates for each future period and each GCM. For instance, accounting for changes in temperature and precipitation obtained by most GCMs, future river flow would increase by 30% for the 2080–2099 time period. Only one GCM shows a small decrease in average water discharges related with a decrease in precipitation.



(**a**) (**b**)

Figure 5. Climate Response Functions (CRFs) of the average annual changes (%) in: (**a**) river inflows; and (**b**) electricity consumption (obtained for W1G1 scenario) compared with control period. The dashed black curves show the "no change" edge. Dots show expected annual changes in temperature and precipitation change obtained from 23 GCM, as illustrated in Figure 2, for 2040–2059 (blue), 2060–2079 (green) and 2080–2099 (red).

Figure 5b shows the CRF obtained for the average annual electricity consumption. By construction, electricity consumption decreases almost linearly when temperature increases. Interestingly, increasing precipitation induces a slight increase of electricity consumption actually linked to price dependent contracts. More abundant water resource makes lower electricity prices (not shown) and stimulates consumption. Annual temperature changes obtained from the selected GCMs show a decrease in average electricity consumption, up to 8% for the time period 2080–2099.

6.2. Climate Change Impacts on Energy Balance and Exchanges in Mid-Norway

We only focus on differences between W1G1 and W2G2 scenarios considering that climate should change once wind power generation and transmission line capacity will be both developed.

Changes in water discharges and electricity consumption will modify the Mid-Norway energy balance deficit at both annual and winter season scales (Figure 6). Precipitation is the main factor of the deficit modification. Considering the current Mid-Norway electricity system (i.e., W1G1 scenario), the energy balance remains negative whatever the changes in precipitation and temperature. The energy balance might become positive during the winter season if changes in precipitation and temperature are quite drastic (from +40% to +50% in annual precipitation and from +4 to +6 °C in annual temperature).

When considering climate change with additional wind generation and stronger transmission lines (i.e., W2G2 scenario), the annual energy balance might become positive with less drastic changes than for the W1G1 scenario. For instance, the annual balance might become positive with 25% precipitation more and whatever the annual increase in temperature. Below 25% increase in precipitation, annual temperature must increase enough to reduce electricity consumption and to make the balance positive. For instance, an increase in annual temperature of +3.5 °C is required if precipitation increases by only 10%. During the winter season, the energy balance becomes positive but when precipitation decreases significantly or when a decrease in precipitation is conjugated with a low rise in temperature (which does not decrease significantly the electricity consumption). However, these two later configurations are not likely to appear according to GCMs projections as illustrated on Figure 6.

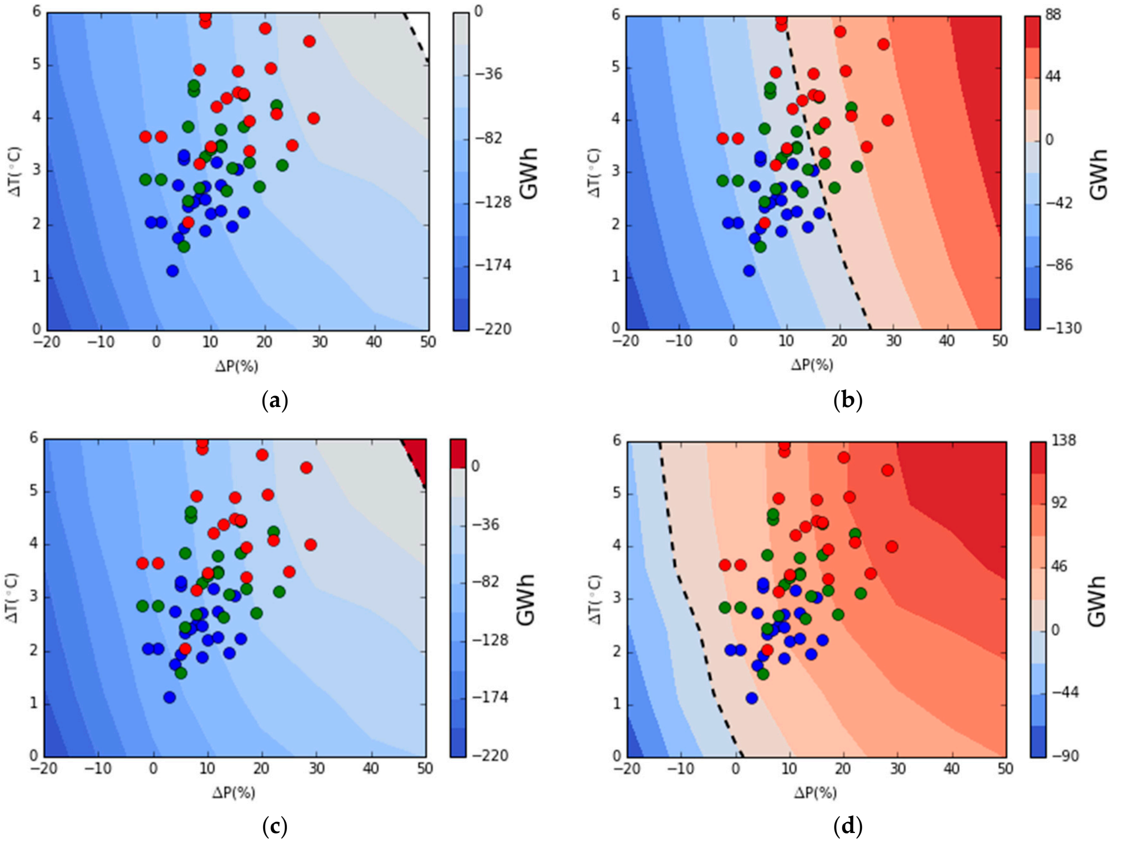


Figure 6. CRFs of the Mid-Norway weekly energy balance (GWh) obtained with the: (**a**) W1G1 scenario for the whole year; (**b**) W2G2 scenario for the whole year; (**c**) W1G1 scenario for the winter season; and (**d**) W2G2 scenario for the winter season. Nil energy balance curves are highlighted with dashed black lines. The coloured dots give temperature and precipitation changes from the 23 considered GCMs and three considered future time period (blue: 2040–2059; green: 2060–2079; and red: 2080–2099).

Changes in Mid-Norway energy balance deficit imply modifications of energy exchanges with the neighbouring regions. Energy imports from Helgeland should grow over the next decades (not shown). This results from both higher production in Helgeland (due to increasing precipitation) and lower consumption (due to higher temperatures; not shown). In association with higher in-situ generation, Mid-Norway region is able to export more electricity and then to strengthen its hub role in the Nordic energy market. As a consequence, electricity exports to East-Norway linearly increase with precipitation (and thus with hydropower generation) within Mid-Norway region (not shown). Note that East-Norway does not produce electricity. We note on Figure 7 that for both W1G1 and W2G2 scenarios, Mid-Norway keeps importing on average electricity from Inndalselven region at annual scale. However, thanks to the development of wind generation, the region might export more electricity to Inndalselven than it imports during the winter season (Figure 7). As discussed in the previous section, Mid-Norway imports and exports electricity from/to West-Norway, with a slightly negative balance, especially during the winter season. With the W2G2 scenario under future climate, exports from Mid-Norway to West-Norway are expected to increase significantly. We note that temperature changes impact average exportation from Mid-Norway to West-Norway more than the reinforcement of the line (Figure 7).

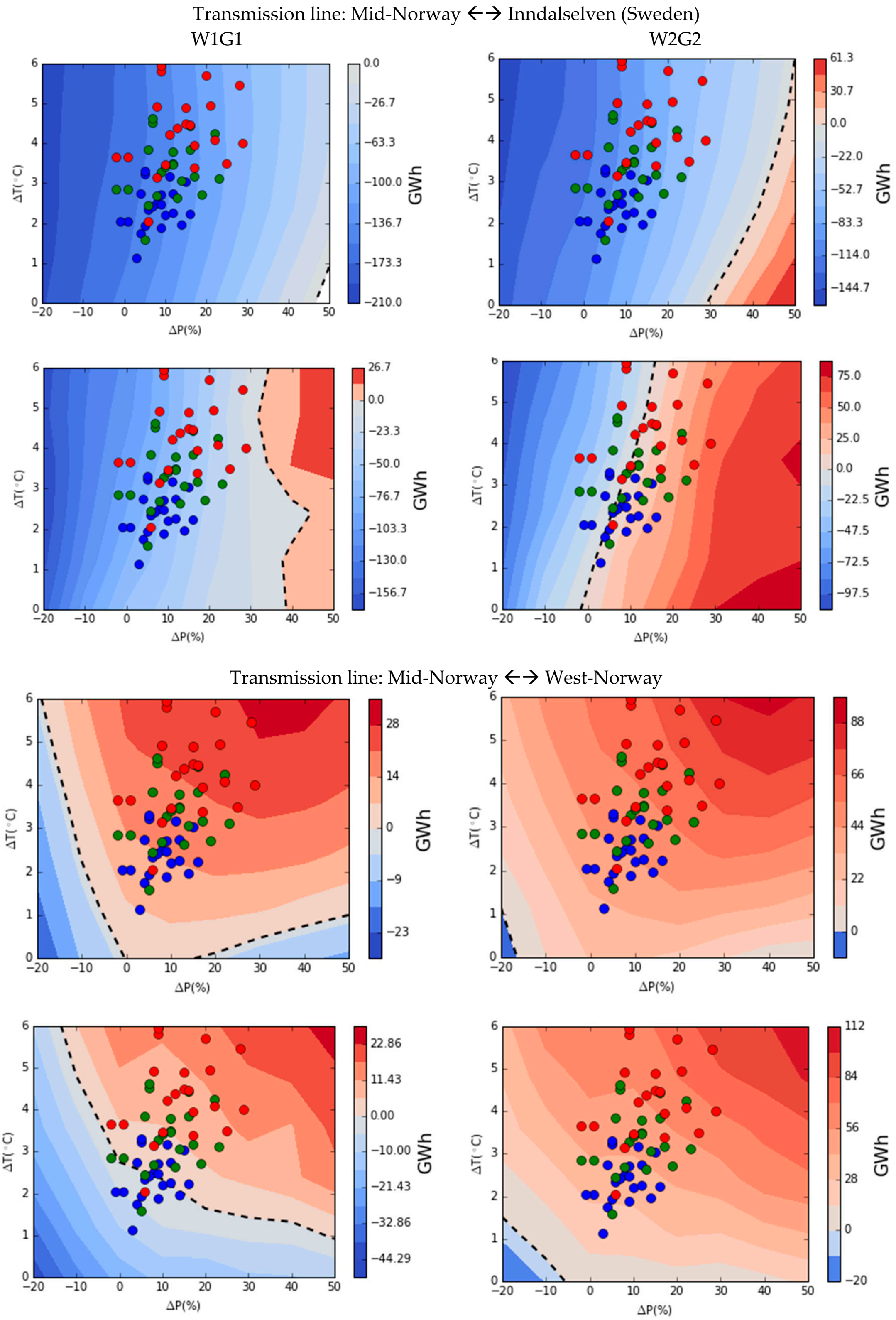


Figure 7. CRFs of the Mid-Norway energy exchanges with: Inndalselven (Sweden) (**top**); and West-Norway (**bottom**). CRFs left and right columns are obtained with W1G1 and W2G2 scenarios respectively. For each transmission line, top CRFs are for the whole year and the bottom for the winter season. Nil energy balance curves are highlighted with dashed black lines. For more details, see Figure 6 caption.

7. Discussion and Conclusions

Norwegian reservoirs are likely to be used as backup capacity for increasing wind and solar power in Europe. However, important space variability exists and some regions show an important energy balance deficit such as Mid-Norway.

Using the EMPS model to simulate the Nordic energy market, we show that increasing wind power capacity in Mid-Norway can reduce the energy balance deficit. The deficit becomes almost nil during high consumption/price period, i.e., in winter, although the deficit remains important at yearly scale (Table 2). Simulations also show that generation from new wind power plants in Mid-Norway is almost totally used for reducing the deficit. Only 2% of the additional wind generation is exported during the whole year (7% during winter season). Such a result should please Mid-Norway stakeholders about the finality of on-going wind power plant construction.

Increasing transmission line capacity between Mid- and West-Norway does not change drastically the export/import patterns from/to Mid-Norway. The increased capacity is actually used only few times during the year (less than 15% of the weeks for exporting and less than 10% for importing electricity; Figure 4). Although this increased capacity is not often used, it limits spillage when the reservoirs are full, in spring season especially.

Regarding climate change impact in Mid-Norway region, temperature is expected to rise in the next decades as well as precipitation (only one GCM out of 23 gives a slight decrease of annual precipitation; Figure 2). These changes have positive impact on Mid-Norway energy system components. More precipitation makes higher river flows and thus higher hydropower potential and higher temperatures lead to lower electricity consumption.

We assess the joint effect of increasing wind and transmission capacities with climate change with the Decision Scaling approach as developed by Ref. [17]. The Cumulative Distribution Functions (CDFs) of the weekly energy balance, calculated from changes in precipitation and temperature given by the GCMs, are illustrated in Figure 8. For the considered GCMs, the average energy balance deficit should decrease in time, highlighting that Mid-Norway climate will become increasingly favourable to the local balance between demand and generation. For instance, at annual scale, one third of the considered GCMs foresee an average positive balance during the 2060–2079 time period and two thirds during the 2080–2099 time period (Figure 8a).

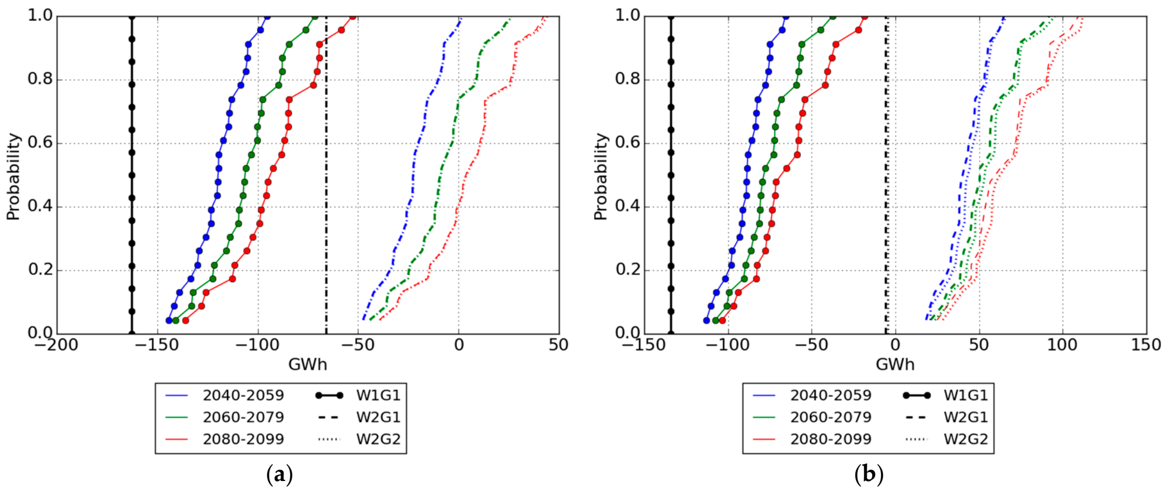


Figure 8. Cumulative distribution function (CDF) of the weekly energy balance for the whole year (GWh) (**a**) and for the winter season (**b**) calculated from annual changes in precipitation and temperature provided by GCMs (blue: 2040–2059; green: 2060–2079; red: 2080–2099). Vertical solid dotted, dashed and dotted black lines shows energy balance values obtained under present climate for W1G1, W2G1 and W2G2 scenarios, respectively. Note that for the whole year, CDFs of W2G1 and W2G2 scenarios are overlapping.

Returning to the question that motivated this study, we conclude that coupling effects from both climate change and increasing wind power and transmission lines capacities appear to lead to a win-win situation: Mid-Norway average energy balance deficit is reduced and would become positive in the next decades allowing the region to increase its exportation, especially during winter season when prices are high.

To our knowledge, this work was the first attempt to applying the Decision Scaling approach to electricity systems analysis. The variety of the results and the easiness of CRF reading can make Decision Scaling an interesting tool for any stakeholder willing to assess its system's vulnerability under climate change. Further research might consider applying the Decision Scaling approach in other climate conditions and or other market contexts (e.g., remote area with no transmission line, using other renewable energy sources such as solar power). This work is based on a number of assumptions, data and modelling choices which potentially lead to some degree of uncertainty in the presented results. Although comprehensive analysis of these uncertainties is out of the scope of this study, it is worth mentioning them.

First, the current consumption modelling within EMPS model does not account for cooling system usage during hot days. The reason is that, regarding of temperature range at Nordic latitudes, the usage of such systems is not common nowadays. However, expected temperatures for the next decades might lead to a growth in cooling system equipment and usage. This could slightly modify consumptions in summer and, eventually, the electricity prices at this period. These effects might deserve specific works although load modification should be weak at these latitudes. Accounting for the non-climatic factors that are also likely to influence the demand (e.g., demand-side management) would be obviously of interest for a more comprehensive view of possible changes in the future electricity balance.

Next, extended and deeper analyses should probably be based on other and/or additional weather scenarios. For instance, the scaling approach we used for generating time series of future weather might be reconsidered. Even though it presents the advantage to preserve the correlation in space and time among weather variables, it does not allow estimating changes in variability. This might be an important issue, especially for precipitation. In Nordic countries, a warmer climate is for instance likely to lead to much more convective precipitation events than today. Although this change in precipitation regime should be, somehow, smoothed by high reservoir capacity, its impacts on energy balance requires further investigation.

This study analyses only changes in generation due to mean changes in precipitation and temperature. Although the change in mean wind potential and in weekly wind variability should remain low over the next decades in this area [14], quantifying their impact on system performance would be valuable.

Accounting for the sub-weekly variability of wind power generation should also be considered. In the current EMPS set up, the sub-weekly variability of wind is disregarded. Wind power generation is estimated on a weekly basis and equally distributed along the week. High frequency variability of wind power generation could obviously limit wind integration into the grid resulting in an energy deficit in Mid-Norway larger than the one obtained in this study. Transmission lines from/to Mid-Norway would also play a major role in wind power integration, which is also impossible to check at weekly time scale.

In addition to climate change analyses, further analyses should also consider the low-frequency variability of weather variables, resulting from the internal variability of the climate system. The year to year to multi-decadal variability of weather variables, precipitation and river flow especially are expected to have a large influence on the potential of renewable and on system performance (e.g., [34]). This would be worth extra investigation. The weather generator developed by Ref. [35] could be considered for such an assessment in future works.

Since this study mainly focuses on aggregated indicators (i.e., computed over the whole period), adding forecast within the considered analysis framework should not significantly improve climate change impact assessment, as shown by Ref. [36]. However, future researches should also consider investigating on the effects of extreme events/periods. High wind power generation periods as illustrated on Figure 3d may have impact on the whole energy systems and especially on the energy exchange among regions. Considering the likely increases in extreme events, further analyses on their impact are required (McInnes et al. [37] give for instance an increase by more than 10% of extreme wind speed in Mid-Norway). Improving forecast of such events and integrating them in the analysis framework is also an important research perspective of this work.

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Author Contributions: Baptiste François designed the methodology, carried out the wind power and discharge modelling, analysed the market modelling results and wrote the article. Sara Martino ran the market optimization modelling and contributed to the results' analysis and to composing the final text. Lena S. Tøfte collected hydrological and wind speed data and contributed to the final text. Benoit Hingray carried out the climate change scenario modelling, and contributed to the results' analysis and composing the final text. Birger Mo contributed to setting-up the market modelling. Jean-Dominique Creutin coordinated the project and contributed to the results' analysis and composing the final text.

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