Increased Electrification of Heating and Weather Risk in the Nordic Power System

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Abstract

Weather is one of the main drivers of both the power demand and supply, especially in the Nordic region which is characterized by high heating needs and a high share of renewable energy. Furthermore, ambitious decarbonization plans may cause power to replace fossil fuels for heating in the Nordic region, at the same time as large wind power expansions are expected, resulting in even greater exposure to weather risk. In this study, we quantify the increase in weather risk resulting from replacing fossil fuels with power for heating in the Nordic region, at the same time as variable renewable generation expands. First, we calibrate statistical weather-driven power consumption models for each of the countries Norway, Sweden, Denmark, and Finland. Then, we modify the weather sensitivity of the models to simulate different levels of heating electrification, and use 300 simulated weather years to investigate

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how differing weather conditions impact power consumption at each electrification level. The results show that full replacement of fossil fuels by power for heating in 2040 leads to an increase in annual consumption of 155 TWh (30%) compared to a business-as-usual scenario during an average weather year, but a 178 TWh (34%) increase during a one-in-twenty weather year. However, the increase in the peak consumption is greater: around 50% for a normal weather year, and 70% for a one-in-twenty weather year. Furthermore, wind and solar generation contribute little during the consumption peaks. The increased weather sensitivity caused by heating electrification causes greater total load, but also causes a significant increase in inter-annual, seasonal, and intra-seasonal variations. We conclude that heating electrification must be accompanied by an increase in power system flexibility to ensure a stable and secure power supply.

**Keywords:** Power consumption · Heating electrification · Nordic power · Weather risk

1 Introduction

Weather is one of the main drivers of both demand and supply in the power sector, and its impact is increasing (Mideksa and Kallbekken, 2010; Staffell and Pfenninger, 2018). On the demand side, weather conditions mainly affect power consumption related to heating and cooling (Dryar, 1944; Quayle and Diaz, 1980; Hor et al., 2005; Trotter et al., 2016; Rodriguez and Trotter, 2019). On the supply side, weather directly determines wind (Foley et al., 2012) and solar power generation (Shi et al., 2012; Pfenninger and Staffell, 2016; Sanjari and Gooi, 2017), as well as the conditions for hydropower production (Kaunda et al., 2012; Birkedal and Bolkesjø, 2016). Therefore, weather conditions are of fundamental importance in the power sector, and represent a significant source of variation and uncertainty.

At the same time, two ongoing developments may further increase the Nordic power system’s exposure to weather risk. Firstly, the transition away from fossil fuels may result in an increase in electric heating. Due to the cold climate in the Nordic countries
(Norway, Sweden Denmark and Finland), these countries already consume a large amount of energy for heating purposes – approximately 480 TWh in 2012, representing almost half the final energy demand (Fleiter et al., 2016), illustrated in Figure 1. In the four countries combined, 17% of the heating energy in 2012 was provided by electricity and 28% was provided directly by fossil fuels (such as coal, fuel oil and natural gas), but also 85% of the installed district heating capacity, which supplies around 21% of heating energy, relies directly or indirectly on fossil fuels (Fleiter et al., 2016). Therefore, there is a large potential for increased electric heating in the region, especially in the context of a decarbonisation of the energy sector. As a result of increased reliance on electricity as an energy carrier for heating, the power consumption will become increasingly sensitive to weather conditions. Secondly, the share of intermittent renewable generation capacity, such as wind and solar power, is increasing as part of a transition to renewable energy sources. IEA (2016) expect wind power generation in the Nordics to increase around five-fold from 2013 to 2050, and Wråke et al. (2021) project an increase in solar and wind power generation of around three- or four-fold from 2020 to 2040, as illustrated in Figure 3.

Figure 1: Heating energy demand in total final energy demand for the Nordic countries in 2012. Based on data by Fleiter et al. (2016).
Since wind and solar power generation are not \textit{dispatchable} – that is, the operators cannot generally choose whether or not to generate electricity at a given moment – the direct and immediate impacts of weather conditions on power generation also tend to increase as the share of intermittent renewables increases. As a result of these two developments, the Nordic power system may experience an increased exposure to weather risk in the future, which is a cause of concern for system operators, power market participants, investors, regulators, and policymakers. In addition, the Nordic countries were amongst the first countries in Europe to deregulate their power sectors, and risk management in a competitive, deregulated market can have consequences for market stability and resilience.

In order to ensure a stable and secure power supply, it is therefore important to understand how these developments may affect the weather risk faced by the Nordic power system.

In this study, we therefore investigate the impact of heating electrification on the weather risks for the Nordic power system – Norway, Sweden, Denmark and Finland – and analyse its implications, in light of the ongoing energy transition. First, we calibrate statistical power consumption models for these countries that capture the historical rela-

\textbf{Figure 2:} Energy carriers of final energy demand used for heating in the Nordic countries in 2012. Based on data by Fleiter et al. (2016).
Figure 3: Nordic installed power generation capacity for 2020, and projections 2040 for the Carbon Neutral Behaviour (CNB), Carbon Neutral Nordic (CNN), and Nordic Power House (NPH) scenarios of Wråke et al. (2021).

The relationships between weather and power consumption. Second, we modify the temperature sensitivity of the consumption models to represent different levels of heating electrification. In the third step, we use these models to generate consumption projections for the year 2040, using 300 simulated weather years, and also pair the consumption projections with projections for intermittent power generation. This allows us to analyse the impact of heating electrification on consumption under many possible weather conditions. Furthermore, our analysis will also show how power consumption will interact with intermittent power generation, considering the large capacity expansion expected until year 2040. Taken together, this will provide a deeper understanding of how the electrification of heating will affect the weather risk of the Nordic power system, within the context of the ongoing energy transition.

Heating electrification has received increasing research attention lately, as many regions are looking to replace fossil energy with renewable power in order to lower greenhouse gas emissions in response to climatic change. Not only will heating electrification
normally lead to higher power consumption (Watson et al., 2019), but it will also alter the profile of the power consumption (Veldman et al., 2011; Staffell and Pfenninger, 2018). Larger amounts of electric heating would result in power consumption becoming more weather sensitive, which again would cause greater variability and uncertainty in the power consumption (Wilson et al., 2013), and may increase the frequency of unservicable deficits (Quiggin and Buswell, 2016). This would translate into increased variability in system costs, especially in systems with high VRE share (Heinen et al., 2017), and greatly increase the need for power system flexibility (Staffell and Pfenninger, 2018; Thomaßen et al., 2021). Despite these challenges, electrification of heating coupled with a large expansion in VRE generation is considered a viable – and even promising – strategy for reducing emissions in several regions (Kirkerud et al., 2017; Sheikh and Callaway, 2019; Ruhnau et al., 2020; Chen et al., 2021; Sakamoto et al., 2021), although it may only be cost-efficient if emissions are relatively costly (Haghi et al., 2020).

In the context of the literature on heating electrification, our study makes two main contributions. Firstly, we focus on the Nordic region, which has not been the main focus of any earlier heating electrification studies. Although the Nordic region has been included in the study on Northern Europe by Chen et al. (2021) and partly considered by Thomaßen et al. (2021), there are compelling reasons to focus exclusively on this region. Due to the harsh climate in this region, heating is a basic need and the heating requirements are relatively large. In addition, the Nordic region has ambitious emissions reductions targets, as the countries target carbon neutrality between 2030 and 2050 (Wråke et al., 2021). This makes the Nordic region particularly interesting to study in the context of heating electrification. Secondly, none of the earlier heating electrification studies focus explicitly on weather risk, even though most agree that it is of great interest. Some studies incorporate some degree of weather variability by considering several historical weather years – such as Quiggin and Buswell (2016), Heinen et al. (2017), Staffell and Pfenninger (2018) and Watson et al. (2019) – but we devote greater attention to this aspect than previous studies on heating electrification by estimating outcome densities.

\footnote{The target year for carbon neutrality in Norway is 2030, 2035 in Finland, 2045 in Sweden, and 2050 in Denmark.}
Weather risk in power systems has been extensively studied previously, outside the context of heating electrification. The professional community was early to incorporate weather into load forecasting (Dryar, 1944; Heinemann et al., 1966). The meteorological community was also early to study the link between weather and power demand (Thom, 1954; Quayle and Diaz, 1980), and the econometric community quickly followed (Fisher and Kaysen, 1962; Halvorsen, 1975). Lately, the focus has gradually shifted from point forecasts to probabilistic forecasts, which in some sense represent weather risk (Veall, 1987; McSharry et al., 2005; Hyndman and Fan, 2010; Sideratos and Hatziargyriou, 2012; Tastu et al., 2014; Trotter et al., 2016; Wang et al., 2017). As climatic change gained importance on the research agenda, the forecasting horizon also increased from hours, days or weeks to decades (Parkpoom et al., 2004; Hyndman and Fan, 2010; Trotter et al., 2016; Fan et al., 2019; Silva et al., 2020). A growing number of studies have also been concerned with modelling and forecasting wind power generation (Foley et al., 2012; Tobin et al., 2015; Kiviluoma et al., 2016; Garrido-Perez et al., 2020) and solar power generation (Shi et al., 2012; Wild et al., 2015; Pfenninger and Staffell, 2016; Sanjari and Gooi, 2017; Castillejo-Cuberos and Escobar, 2020). While earlier studies often considered each of these elements in isolation, many recent studies analyse various elements in combination, such as wind and solar (Heide et al., 2010; Bremen, 2010; Widen, 2011; Jerez et al., 2013; Bett and Thornton, 2016; Solomon et al., 2016; Miglietta et al., 2017), solar and hydro (Siala et al., 2021), wind and load (Sinden, 2007; Leahy and Foley, 2012; Baringo and Conejo, 2013; Coughlin et al., 2014; Bell et al., 2015; Thornton et al., 2017), or even wind, solar and hydro (Canales et al., 2020). Some studies incorporate additional elements, including the impacts of weather on thermoelectric power plants (Tobin et al., 2018), prices (Suomalainen et al., 2015), and tidal power generation (Coker et al., 2013). Engeland et al. (2017) and Widén et al. (2015) present more comprehensive reviews of the literature on the variability of renewable power generation. In a particularly interesting pair of studies, van der Wiel et al. (2019b) use a large number of weather simulations to investigate the risk of extreme shortfalls between renewable power production and...
demand in Europe, and van der Wiel et al. (2019a) further establish that the risk increases during blocked circulation patterns, such as “Scandinavian blocking” and “North Atlantic Oscillation negative”. Interestingly, the authors show that changes due to climate change are substantially smaller than interannual weather variability. Further, focusing on the meteorological variables, Ramsebner et al. (2021) also explore the correlations between renewable generation and proxies for heating/cooling needs in Europe. These studies all concern the impact of weather on the power system. Although some of the studies present long-term projections (such as Hyndman and Fan (2010), Trotter et al. (2016) and Rodriguez and Trotter (2019)) and even specifically investigate weather risk (such as McSharry et al. (2005) and van der Wiel et al. (2019b)), the studies in this line of research have not yet addressed the question of heating electrification.

Compared to the existing literature on weather risk in power systems, which generally implicitly assumes that weather sensitivity remains constant, our study therefore contributes by simulating scenarios where the weather sensitivity of the power system increases. Our study not only calibrates the statistical models and presents projections, but also modifies the models to represent fundamental changes in the underlying reality – the electrification of heating – and thereby creating and comparing alternate scenarios. As such, our study contributes to a deeper understanding of how heating electrification may affect weather risk, and of the future of the Nordic power system in particular, which is relevant to researchers, policymakers and market participants – particularly in light of the ongoing energy transition.

This study is divided into four sections, including this introduction. The following section details the methodology of our investigation, whereas the third section presents, synthesizes and discusses the results of our experiment. The fourth and final section summarizes the main conclusions of the investigation, and offers suggestions for future investigations.
2 Methodology

The objective of this study is to analyse the weather risks of the Nordic power system, under conditions of increased heating electrification and increased variable renewable power generation. Our strategy to achieve this consists of three main steps:

First we calibrate power consumption models for each of the Nordic countries – Norway, Sweden, Denmark and Finland – using historical consumption and weather data. Throughout, we work at an hourly resolution so that we capture intra-day variations in both consumption and variable renewable generation.

Secondly, we modify the calibrated power consumption models in order to simulate increased levels of heating electrification in the Nordic countries for the year 2040.

Thirdly, we use the consumption models together with a large amount of simulated weather scenarios to generate a large number of possible joint paths for power consumption and variable renewable generation for 2040. This will show how differing weather conditions impact the power consumption and variable renewable power generation at different levels of heating electrification, and allow us to estimate the density functions of key figures such as total annual power consumption, annual peak power consumption, and annual peak residual demand, which is the remainder when we subtract wind and solar generation from consumption. Analysing the load duration curves of the different electrification scenarios will also provide further insight into how heating electrification impacts weather risk.

We now explain each step of our methodology in greater detail.

2.1 Consumption Model Calibration

A separate consumption model will be calibrated for each of the four countries – Norway, Sweden, Denmark and Finland – at hourly resolution. The consumption models will relate hourly power consumption to the temperature at a set of $n = 5$ weather stations in each country through heating degree hours (HDH) and cooling degree hours (CDH), with cut-off temperatures of $17^\circ$C and $22^\circ$C, respectively. We further include two important socio-economic indicators in the models: gross domestic product (GDP) and population (POP).
In order to capture seasonalities at different timescales, we include dummy variables for each hour of the day (HR), each month of the year (MTH), each day of the week (WD), and an indicator for holidays (HOL), as well as a trend variable (T). We base the model on the natural logarithm of consumption, income and population, and calibrate the model using ordinary least squares. As such, the estimated models can be represented in the following functional form:

\[
\ln(\text{Cons}_t) = a \ln(\text{GDP}_t) + b \ln(\text{POP}_t) + \sum_{i=1}^{24} c_i \text{HR}_t^i + \sum_{i=1}^{12} d_i \text{MTH}_t^i + \sum_{i=1}^{7} e_i \text{WD}_{i,t} + hT_t + j\text{HOL}_t.
\]

The data is first split into training and validation samples, consisting of 75% and 25% of the sample. We calibrate the models on the training samples using ordinary least-squares regression, and measure the in-sample accuracies, as well as the out-of-sample accuracies using the validation sample. The out-of-sample accuracies will give an indication of how the models perform on data outside of the training set.

To measure the model accuracies, we calculate several error indices: root mean squared error (RMSE), mean absolute error (MAE), mean absolute percentage error (MAPE) and symmetric mean absolute percentage error (sMAPE). We then recalibrate the model on the full dataset, and measure the in-sample accuracy, before using the models for creating projections. In addition, we measure the relative importance of each group of model inputs by estimating the effect sizes with Cohen’s \( f^2 \) (Selya et al., 2012), in order to verify that weather is in fact an important determinant of power consumption.

### 2.2 Electrification and VRE Scenario Design

To simulate increased heating electrification, we modify the coefficients related to the power consumption for heating purposes, specifically the coefficients for heating degree hours, HDH. By applying a certain percentage increase to the HDH coefficient, we increase
the weather-sensitivity of the power consumption, which is one of the main effects of heating electrification on power consumption (see, for instance, Wilson et al. (2013); Quiggin and Buswell (2016); Heinen et al. (2017); Thomaßen et al. (2021)). Based on available data from 2012 (Fleiter et al., 2016), we calculate the percentage to increase the HDH coefficients such that they represent the replacement of a certain proportion of the fossil-based heating. Although more recent data may be available, we design the electrification scenarios based on numbers from 2012 because it was a fairly typical year for the Nordic power sector, and because it is within the later part of the calibration period of the consumption models, ensuring that the designed scenarios are consistent with the calibrated consumption models. This means, however, that some recent developments, such as the recent increases in the use of biofuels for heating, are not entirely reflected in the scenarios.

In order to calculate the percentage increase for the HDH coefficients, we must first determine how much power will be needed to replace fossil-based heating. We distinguish between three main uses of fossil fuels in the heating sector: direct heating of space and water, use in district heating, and for process heat. We assume that space/water and district heating are temperature sensitive, whilst process heat is not. Therefore, only replacement of fossil fuels in space/water and district heating contributes to increasing the temperature-sensitivity of power demand. In addition, some of the fossil fuel heating may be replaced by electric heat pumps, leading to efficiency gains. Assuming that fossil fuels for heating have around 90% efficiency, and that 75% of the temperature-sensitive fossil fuel heating is replaced by heat pumps with a coefficient of performance (COP) of 3 (Wilson et al., 2013), whereas 25% is replaced by resistive heating, then 1 J of fossil fuel can be replaced by 0.475 J of electricity. Table 1 shows the amount of fossil space/water and district heating in each of the Nordic countries in 2012 (Fleiter et al., 2016). By multiplying the sum of these by 0.475, we find how much electricity will be needed to replace the temperature sensitive fossil-based heating. Comparing the replacement electricity to the direct electric heating, we find how large a percentage increase this would imply for the temperature sensitivity. For instance, we assume that
Table 1: Calculation of consumption model modifications. Temperature sensitive fossil-based heating (space/water and district heating) could be replaced by a combination of electric heat pumps (75%) with a COP of 3 and electric resistive heating (25%). Such a replacement implies that temperature sensitive power consumption would increase by a given percentage to provide the additional power. Based on data by Fleiter et al. (2016).

|                     | Norway  | Sweden  | Denmark | Finland |
|---------------------|---------|---------|---------|---------|
| Fossil Space/Water Heating | 9.7 TWh | 11.0 TWh | 16.9 TWh | 17.9 TWh |
| Fossil-based District Heating | 0.9 TWh | 0 TWh   | 18.1 TWh | 36.4 TWh |
| **Total Temp. Sensitive Fossil** | **10.6 TWh** | **11.0 TWh** | **35.0 TWh** | **54.3 TWh** |
| Replacement Electric | 5.0 TWh | 11.0 TWh | 35.0 TWh | 54.3 TWh |
| Direct Electric S/W Heating | 29.0 TWh | 21.5 TWh | 2.7 TWh | 20.0 TWh |
| **Implied Temp. Sensitivity Increase** | **17.4%** | **24.3%** | **615.7%** | **129.0%** |
| Fossil Process Heat | 17.6 TWh | 25.4 TWh | 11.9 TWh | 24.9 TWh |

5.0 TWh of electricity could replace 10.6 TWh of temperature sensitive fossil heating (space/water and district heating) in Norway, which would represent a 17.4% increase in existing direct electric space/water heating (29.0 TWh).

We assume that process heat will be replaced with electricity at the same efficiency rate, with a flat profile over the year.

Based on these assumptions, we define three different scenarios for 2040, characterised by how large share of fossil fuels are substituted by power in the heating sector:

**Business-As-Usual (BAU)** is a baseline scenario that will serve as a basis for comparison. In this scenario, the temperature sensitivity of the original consumption models will remain unchanged, and no additional process heat is explicitly electrified.

**Half Electrification (HALF)** assumes that half of the heating from fossil fuels will be replaced by electric heating in 2040. Table 2 shows the increase in temperature sensitivity and the additional baseload applied to the power consumption models for this scenario.

**Full Electrification (FULL)** assumes that all the heating that was based on fossil fuels in 2012 is electrified, again with 75% of the temperature sensitive heating being replaced by heat pumps and 25% being replaced by resistive heating, and the process heat being replaced with a flat consumption over the year. This implies, as shown in Table 2, an increase in the temperature sensitivity for Norway of 17.4%, Sweden
Table 2: Increase in the heating-related coefficient and the constant in the power consumption model for the different scenarios.

| Country    | Half Electrification | Full Electrification |
|------------|----------------------|-----------------------|
|            | Temp. Sens. Increase | Constant              | Temp. Sens. Increase | Constant              |
| Norway     | 8.7%                 | 8.8 TWh               | 17.4%                 | 17.6 TWh               |
| Sweden     | 12.2%                | 12.7 TWh              | 24.3%                 | 25.4 TWh               |
| Denmark    | 307.9%               | 6.0 TWh               | 615.8%                | 11.9 TWh               |
| Finland    | 64.5%                | 12.5 TWh              | 129.0%                | 24.9 TWh               |

Table 3: Assumed wind and PV capacities for 2040, from the Carbon Neutral Nordic (CNN) scenario of the Nordic Clean Energy Scenarios (Wråke et al., 2021).

| Country    | Wind Generation Capacity 2040 | PV Capacity 2040 |
|------------|-------------------------------|------------------|
| Norway     | 7.2 GW                        | 0.03 GW          |
| Sweden     | 21.8 GW                       | 7.1 GW           |
| Denmark    | 20.0 GW                       | 9.1 GW           |
| Finland    | 7.4 GW                        | 7.5 GW           |

of 24.3%, Denmark of 615.8%, and Finland of 129%.

These scenarios are highly stylized and deliberately simplify the possible range of outcomes of the energy transition, as well as many technical and economic aspects regarding the efficiency and adoption of heat pumps and resistive heating. Nonetheless, we believe that the simplicity of the scenarios will serve to draw clearer insights from this thought experiment, and that these scenarios are capable of representing and illustrating the potential impacts in a broad sense.

In order to explore the interaction between consumption and variable renewable power generation, we also require assumptions regarding wind and solar power generation capacities in 2040. When combined with weather data, these assumptions will allow us to calculate residual demand, which is the power consumption minus wind and solar power generation. We rely on the Nordic Clean Energy Scenarios (Wråke et al., 2021) for projections of the wind and solar power generation capacities in 2040, which are shown in Table 3. When consumption and the generation in different regions are aggregated, we assume for simplicity that there are no transmission restrictions or losses (“copperplate transmission”).

Comparing the projected probability distributions from the simulations of partial or full heating electrification (HALF or FULL) to the simulations of no further heating
Heating Electrification and Weather Risk

Heating electrification (BAU) should illustrate clearly what effects heating electrification will have on power consumption, and the residual demand will show how variable renewable power generation will interact with the power consumption.

2.3 Weather Scenarios

For our strategy for investigating weather risk, we generate 300 simulated weather paths using the shifted date method, which has been shown to produce accurate probabilistic load forecasts (Xie and Hong, 2018). In the shifted date method, we use entire historical weather years that are shifted backwards or forwards by a certain number of days, which ensures that each weather scenario is geographically and temporally consistent. Although this method does not capture long-term changes that may be occurring in the climate, van der Wiel et al. (2019a) have shown that changes due to climate change are substantially smaller than interannual weather variability, which is the main focus of our study. We then feed the weather paths into the consumption models, together with population and GDP projections for 2040, in order to create a large amount of consumption scenarios for 2040 at hourly resolution under differing weather conditions.

Scenarios for variable renewable power generation – wind and solar power – are coupled with the consumption scenarios, that is, based on the same weather paths. The scenarios for wind and solar are based on the capacity factors used by Grams et al. (2017). Using consumption paths coupled with wind and solar power generation based on the same weather conditions will show how power consumption and VRE generation interact, and provide a deeper understanding of how heating electrification will affect the weather risk of the Nordic power system within the context of the large expected expansion in VRE generation capacity.

2.4 Data Sources and Preprocessing

Hourly power consumption data have been provided by each countries’ power grid operator. Historical and projected GDP data have been retrieved from the long-term real GDP forecast published by OECD (2018), whereas historical and forecasted population was re-
trived from the OECD.Stat database\(^2\). The GDP and population data were transformed to hourly data by linear interpolation.

Hourly weather data at five locations for each of the countries from 1985 to 2016 was retrieved from the ERA5 reanalysis data on single levels, provided by Hersbach et al. (2018) through the Copernicus Climate Change Service (C3S) Climate Data Store (CDS). Reanalysis data are convenient for this study, as this ensures that the data is complete and consistent.

Hourly capacity factors for wind and solar power generation were provided by Grams et al. (2017). To calculate the power generation projections, the capacity factors were multiplied by their respective projections for installed capacity.

3 Results and Discussion

3.1 Consumption Model Estimation

We calibrate the hourly power consumption models for each of the countries and calculate accuracy metrics as discussed in Section 2.1. The regression results are shown in Appendix A, whereas the accuracy metrics are shown in Table 4. Generally, the mean absolute percentage error (MAPE) appears to be around 5% for these countries, with only small differences between the training sample, the validation sample and the full sample. The models do not appear to suffer from overfitting, since the performance on the training and validation samples are very close.

Overall, the accuracy of the models is reasonable for such simple models, although a little lower than efforts with a greater focus on model accuracy (such as McSharry et al. (2005); Hor et al. (2005); Hyndman and Fan (2010); Trotter et al. (2016); Rodriguez and Trotter (2019)), which often achieve a MAPE of around 2%-3%. We believe it would be possible to achieve a similar accuracy in our case, but this would introduce additional model complexity which may not necessarily be appropriate for our purposes. For the

\(^2\)Historical population available at [https://stats.oecd.org/Index.aspx?DataSetCode=HISTPOP](https://stats.oecd.org/Index.aspx?DataSetCode=HISTPOP), and population projections at [https://stats.oecd.org/Index.aspx?DataSetCode=POPPROJ](https://stats.oecd.org/Index.aspx?DataSetCode=POPPROJ), accessed Oct. 20, 2021.
Table 4: Consumption model accuracy metrics. Ordinary least squares regression.

| Country  | Training Sample | RMSE  | MAE   | MAPE | sMAPE |
|----------|-----------------|-------|-------|------|-------|
| Norway   |                 | 760.3 MWh | 584.0 MWh | 4.2% | 4.2%  |
| Sweden   |                 | 862.8 MWh | 687.0 MWh | 4.4% | 4.4%  |
| Denmark  |                 | 276.6 MWh | 217.8 MWh | 5.6% | 5.6%  |
| Finland  |                 | 593.5 MWh | 429.5 MWh | 4.9% | 4.8%  |

| Country  | Validation Sample | RMSE  | MAE   | MAPE | sMAPE |
|----------|-------------------|-------|-------|------|-------|
| Norway   |                   | 759.1 MWh | 582.7 MWh | 4.2% | 4.2%  |
| Sweden   |                   | 869.4 MWh | 691.8 MWh | 4.4% | 4.4%  |
| Denmark  |                   | 277.0 MWh | 218.7 MWh | 5.6% | 5.6%  |
| Finland  |                   | 599.9 MWh | 432.2 MWh | 5.0% | 4.9%  |

| Country  | Full Sample       | RMSE  | MAE   | MAPE | sMAPE |
|----------|-------------------|-------|-------|------|-------|
| Norway   |                   | 760.1 MWh | 583.8 MWh | 4.2% | 4.2%  |
| Sweden   |                   | 864.4 MWh | 688.2 MWh | 4.4% | 4.4%  |
| Denmark  |                   | 276.6 MWh | 218.0 MWh | 5.6% | 5.6%  |
| Finland  |                   | 595.2 MWh | 430.4 MWh | 4.9% | 4.8%  |

for purposes of this study, we are satisfied with the accuracy offered by these relatively simple models.

In order to verify the importance of weather in the power consumption models, we calculate the effect size of the different elements in the model, using Cohen’s $f^2$ (Selya et al., 2012). The results are illustrated in Figure 4, which shows that the importance of the HDH variables are second only to the hourly profile for Norway, Sweden, and Finland. For Denmark, in which much less of the heating is electric, the HDH variables are of lower importance, as the hourly, weekday, monthly and holiday profiles have a higher importance. However, since these seasonalities are entirely deterministic, this nonetheless confirms that weather is the most important non-deterministic driver of power consumption in the Nordic countries.

Therefore, we are satisfied that the consumption models that we have calibrated are both capable and appropriate for the purposes of simulating increased heating electrification in the Nordic region, and proceed to running the simulations for year 2040, described in Sections 2.2 and 2.3.
3.2 Total Annual Consumption

We now turn to the results from simulating the heating electrification scenarios. For each of the three heating electrification scenarios, 300 simulations are run with different weather conditions, generated using the shifted date method. From these simulations, we calculate key figures – such as total and peak consumption – then examine and compare their distributions between each of the heating electrification scenarios.

Total consumption measures how much energy is consumed in the course of a year, calculated by summing the power consumption over all hours of the year. The distributions of total consumption for each of the three heating electrification scenarios are illustrated in Figure 5, where a Gaussian kernel has been used to create smooth density estimates. In the figure, heating electrification can be seen to have two distinct effects on the total consumption. Firstly, the electrification of heating increases the level of total consumption, since the entire distributions for the half and full electrification scenarios shift to the right. Secondly, the electrification of heating also widens the distributions for
Figure 5: Projected densities of the projected total annual electricity consumption in the Nordic countries in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

total consumption considerably. This shows that heating electrification not only causes increased power consumption, but also substantially higher weather-based variation in annual power consumption.\(^3\)

In order to explicitly quantify the impacts of heating electrification, we calculate the mean, standard deviation, and conditional value-at-risk at the 5% level (CVaR\(_{5\%}\)) of the distribution of total annual consumption over all the weather scenarios for each of the heating electrification scenarios. In this context, the CVaR\(_{5\%}\) can be interpreted as a typical one-in-twenty occurrence. Table 5 shows these key indicators.

The mean of the total consumption in the full electrification scenario is around 155 TWh (30%) higher than the business-as-usual (BAU) scenario. The CVaR\(_{5\%}\) of total consumption, however, is almost 178 TWh (34%) higher in the full electrification scenario compared to the BAU scenario. This shows that full heating electrification can cause a large increase in total power consumption in a normal year, but an even greater increase

\(^3\)The impacts on individual countries in the region are similar, as shown in Appendix B, all of which show both a right shift and a widening of the probability distributions with increased heating electrification.
Table 5: Summary of the simulation results.

| Total Consumption (TWh) | Scenario               | Mean  | Std. dev. | CVaR 5% |
|-------------------------|------------------------|-------|-----------|---------|
|                         | Business As Usual      | 512.1 | 7.7       | 528.9   |
|                         | Half Electrification   | 586.7 | 11.9      | 612.9   |
|                         | Full Electrification   | 667.2 | 17.7      | 706.6   |

| Peak Hour Consumption (GWh) | Scenario             | Mean  | Std. dev. | CVaR 5% |
|-----------------------------|----------------------|-------|-----------|---------|
|                             | Business As Usual    | 88.6  | 5.0       | 102.8   |
|                             | Half Electrification | 108.8 | 8.4       | 133.0   |
|                             | Full Electrification | 134.8 | 14.3      | 176.6   |

| Peak Hour Residual Demand (GWh) | Scenario            | Mean  | Std. dev. | CVaR 5% |
|----------------------------------|---------------------|-------|-----------|---------|
|                                  | Business As Usual   | 79.7  | 5.0       | 92.5    |
|                                  | Half Electrification| 98.9  | 8.1       | 118.4   |
|                                  | Full Electrification|123.8 | 13.4      | 154.8   |

during an unusually cold year.

In comparison, the Nordic Clean Energy Scenarios (NCES) developed by Wråke et al. (2021) project a total consumption between 378 and 423 TWh in year 2040, as the Nordic region transitions to carbon neutrality in year 2050. These projections are even below our business-as-usual scenario, even though they incorporate consumption increases from additional sectors, such as transport and datacenters. The main reason that the NCES project lower total consumption, appears to be that they explicitly assume a greater increase in efficiency, and a transition to non-electric district heating (for instance waste). The carbon neutral scenario of IEA (2016) expects a total consumption of around 375 TWh in year 2040, which is also below our projections as they assume a large increase in the efficiency of electric heating. Our scenarios, however, do not make explicit assumptions regarding increased efficiency of the existing electric heating, only for the heat pumps that replace fossil-based heating. However, a study by Halvorsen and Larsen (2013) claims that Norwegian consumers entirely offset the saved energy by increased consumption when replacing resistive heating with heat pumps, such that the increased efficiency does not lead to energy savings. As such, it is not certain that increased efficiency will lead to large drops in total consumption. If this turns out to be the case, the consumption projections by both IEA (2016) and Wråke et al. (2021) will turn out to be too low, and, furthermore,
our electrification scenarios might also underestimate total consumption.

The long-term outlook report by the Norwegian power grid operator Statnett (Statnett, 2020), however, projects a Nordic consumption of 579 TWh in year 2040, which also includes contributions from the transport sector and datacenters, as well as increased electrification in other sectors. Discounting the transport and datacenter sectors, consumption is projected at 479 TWh. This is relatively close to the mean of our business-as-usual scenario at 512.1 TWh, but significantly below our scenarios with heating electrification – especially for a one-in-twenty year.

Counting both electrification in existing sectors and new power consuming sectors such as transportation, datacenters, and hydrogen, The Norwegian Water Resources and Energy Directorate (NVE) projected a total Nordic consumption of about 480 TWh in year 2040 in their 2020 report (Noregs vassdrags- og energidirektorat (NVE), 2020), but revised their projections to 526 TWh in their 2021 report (Noregs vassdrags- og energidirektorat (NVE), 2021). These figures are relatively close to our business-as-usual scenario. However, they include contributions from new sectors that have not been explicitly accounted for in our projections, which simply assume a continuation general trend that has been observed in the last few decades. Even though the upcoming changes projected by NVE appear to imply greater consumption increases in the coming decades than has been experienced in the last few decades, our projections still appear to be higher than the projections by NVE.

Therefore, our results imply a total consumption that is considerably higher than previous estimates, especially in the scenarios with heating electrification – and even more so in a cold year: for a one-in-twenty year in the full electrification scenario, total consumption is almost 90% above the lowest scenarios by IEA (2016), and still more than 45% higher than the comparable projection by Statnett (2020). In that sense, it is possible that heating electrification may present significantly larger challenges for the Nordic power system than previously believed.
3.3 Peak Consumption and Peak Residual Demand

Peak consumption is a key figure for planning purposes, since the power system must be designed to withstand peak load. The two central features we observed with total consumption are also present in peak consumption, illustrated in Figure 6: heating electrification shifts the distribution to the right, and at the same time widens the distribution. Full electrification increases the consumption in the peak hour in the Nordic countries from 88.6 GWh in the BAU scenario to 134.8 GWh in the full electrification scenario, an increase of about 52%, for a normal weather year. For a one-in-twenty year, however, the full electrification scenario is almost 72% above the BAU scenario. This shows that the effects of electrification are even more serious for peak consumption than for total consumption.

In comparison, Statnett (2020) project a peak load of 95 GW in year 2040, which is close to the mean of our business-as-usual scenario, but significantly lower than the electrification scenarios and our estimates for a typical one-in-twenty weather year. This
also implies that the challenges posed by heating electrification may be greater than previously believed.

Comparing the peak consumption to installed power generation capacity is a simple and intuitive way to check if it will be possible for the power system to supply the peak load. Wråke et al. (2021) project an installed power generation capacity between 142 and 161 GW in year 2040, which at first sight appears to be adequate for all but a one-in-twenty weather year with full heating electrification. Generation capacity projections by Statnett (2020) are slightly higher, at 175 GW in year 2040.

However, some of the power generation also depends directly on weather conditions and is not dispatchable – it is not certain that this capacity can be relied on to produce sufficient power to supply the peak. In the projections by Wråke et al. (2021), installed capacity drops to about 70 GW if we exclude solar and wind power. Excluding non-dispatchable capacity from the projections of Statnett (2020) gives a generation capacity of around 68 GW.

With this in mind, we calculate the residual demand, which is the power consumption minus solar and wind power generation. The residual demand therefore gives an idea of how much energy must be produced by generation sources apart from the variable renewable sources. The distribution of the residual demand in the peak hour is shown in Figure 7, and some summary statistics are shown in Table 5. The figure shows that the peak residual demand shares the two main features of total and peak consumption: heating electrification causes the distribution to shift to the right, and the distribution becomes significantly wider – higher levels and increased risk. For all three electrification scenarios, the mean of the peak hour residual demand is about 10 GWh lower than the corresponding peak hour consumption. That implies that when they are needed the most – in the peak consumption hour – variable renewable sources are only providing about 12%-13% of their nameplate capacity. The residual demand must then be supplied by power generation from other sources. It therefore appears that the projected non-VRE generation capacity of around 70 GW would be unable to supply the residual demand during the peak hour of a typical weather year for none of the three electrification scenarios – business-as-usual
In addition, when calculating the aggregate peak residual demand in the entire Nordic region, we have assumed that there are no limitations or losses related to transmission within the region (“copperplate transmission”). There could be greater variation at the local level, such that the situations at the local level would likely be more serious if one were to take transmission constraints and losses into account.

Since projected non-VRE generation capacity would be insufficient to supply the residual demand during the peak hour, the Nordic countries could perhaps import power from other countries during these critical periods. Wråke et al. (2021) project an import capacity around 20 GW, bringing the non-VRE supply capacity to around 90 GW, implying that the system could in principle rely on imports from other countries – but only during a fairly typical weather year with lower levels of heating electrification. With full heating electrification, a one-in-twenty weather year would require 154.8 GWh during the peak hour, which exceeds the Nordic non-VRE supply capacity projected by Wråke et al. (2021). This means that the Nordic power system might struggle to ensure a stable and
secure power supply during peak hours during a normal year with no further heating electrification, and could face serious shortages at higher levels of heating electrification and during colder weather years.

Therefore, our results suggest that increased electrification of heating in the Nordic countries would require a substantial expansion in the power system compared to what is expected in earlier studies. In particular, the increase in weather risk caused by heating electrification implies that special attention should be paid to ensuring sufficient flexibility to meet peak power demand in periods with little wind or solar power generation.

### 3.4 Load Duration

Load duration curves are an essential power system planning instrument, which illustrates the duration at which the power system load is at or above a certain level. Figure 8 shows the load duration curves for a typical year and a typical one-in-twenty year, for each of the three heating electrification scenarios.
We can see from the figure that heating electrification causes the load duration curves to become much steeper, which implies a far greater variability in the consumption. The increase in steepness is much more pronounced for the typical one-in-twenty year.

Furthermore, the figure illustrates another serious aspect of the impacts of heating electrification: the large increase in consumption that we observed in the total annual consumption is in fact very disproportionally allocated throughout the year: the periods with already high consumption also receive the largest increase in consumption. As such, the periods that already experience the highest consumption will experience even higher consumption, whereas low-consumption periods will experience little change.

This disproportional impact means that the power system will not only need to be designed to serve a higher peak consumption, but that the power system must be designed to withstand larger seasonal differences, longer continuous periods of high consumption, and larger consumption variations at every timescale. As such, the insights from this study may have large consequences for the design of the future Nordic power system.

3.5 Discussion

In our results, we have highlighted the increase in the level, variability, and uncertainty in Nordic power consumption caused by heating electrification, and we have compared our results to existing projections for the Nordic power system. This has revealed that existing projections might have underestimated the impact that heating electrification would have on the Nordic power system, and suggests that heating electrification must be accompanied by large increases in power system flexibility at every timescale. Qualitatively, these findings mirror many of the conclusions in the existing scientific literature.

By and large, our results are consistent with the findings of Wilson et al. (2013), who analysed two years of historical gas and power consumption data to show that migrating even a small proportion of natural gas heating to power in Britain would cause a large increase in the level, variability, and uncertainty of the power consumption. Staffell and Pfenninger (2018) also support this conclusion in their projections of UK power consumption in year 2030, showing increased year-to-year, seasonal and intra-seasonal
variability due to heating electrification. Our results show that electrifying heating would have similar impacts in the Nordic countries. Quiggin and Buswell (2016) further imply that several official projections for the UK do not adequately account for the effects of heating electrification, which may cause balancing issues for the UK power system in year 2050. Although Watson et al. (2019) believe that Quiggin and Buswell (2016) overestimate the peaks, they still agree on the main aspects of how heating electrification will change power consumption in the UK. Similar to Quiggin and Buswell (2016), our results suggest that the serious impacts of heating electrification on power consumption may be underestimated in the projections for the Nordic power system in year 2040.

In a study of the power system in Ireland in 2030 with increased electrical heating and VRE share, Heinen et al. (2017) find that weather would cause considerable variation in system costs and that cold and windless weather define the most critical periods, which is consistent with our results. The authors further suggest that pre-heating and the thermal inertia of buildings could lower the power consumption peaks and, consequently, system costs. We agree with this point, although our results show that heating electrification not only increases the peaks, but also increases power consumption for longer durations, requiring flexibility sources beyond the short term alleviation provided by thermal inertia.

Both Kirkerud et al. (2017) and Ruhnau et al. (2020) find that increased use of electricity for heating raises the wind market value, considering district heating in Northern Europe in the former study and heat pumps in the UK in the latter. However, the results in both studies imply that the wind-driven electric heating is to a large degree mediated by storage, and not driven directly by wind power generation. In addition, when Chen et al. (2021) found that electric heat pumps combined with wind power expansion would be a promising decarbonisation strategy for Northern Europe, they also pointed out that such a solution would require large increases in power system flexibility. In that light, it is also not surprising that Haghi et al. (2020) found that heating electrification combined with an expansion of natural gas power generation would be a cost-effective solution for reducing emissions in the UK, since natural gas generation is normally relatively flexible compared to wind power. Thomašen et al. (2021) argue that some EU27+UK countries –
mainly with warm climates – may already be well prepared for full electrification of heating, but warn that many others – often characterised by colder climates – currently have insufficient firm generation capacity for large-scale heating electrification. On the whole, the results from these studies are consistent with the conclusions of our study: we have shown that the wind power output in the Nordic countries is relatively low during the most critical periods, which means that substantial increases in power system flexibility would be required.

Therefore, our qualitative findings are well established within the context of the existing scientific literature on heating electrification – even though we have arrived at them by different means and for a region that has not previously been explicitly considered. However, comparing our results with existing projections for the Nordic power system shows that the effects we have identified do not appear to be appropriately incorporated, and therefore may not have been sufficiently well established until now. Furthermore, beyond the qualitative conclusions we have reached, the magnitudes of the effects that we have presented are also interesting and relevant to planners and policymakers, and provide a deeper understanding of how heating electrification and VRE expansion will impact weather risk in the Nordic power system.

### 3.6 Study Caveats

Given our stylised approach and the fact that we consider a year that is nearly two decades in the future, it is important that the results of this study are interpreted correctly, and therefore we discuss some of the main caveats of the study.

Firstly, the structure of power consumption may change in the future compared to the calibration period of the consumption models. The impacts of the various model elements are not fixed in reality, but change over time in response to the underlying technological and social conditions. Policies affecting the calibration period, such as the Norwegian ban on mineral oil for heating in 2020, might not impact year 2040 – and policies that we have not yet imagined may have a large impact in 2040. Technological change may also cause large differences between the calibration period and year 2040. For instance, we have not
explicitly considered how improvements in buildings’ thermal efficiency may affect our results. Until 2040, older buildings with low thermal efficiency will be replaced with new buildings, we might see increased adoption of heat pumps, and further improvements in building techniques – all of which will lower power consumption for heating, and is not explicitly considered in the historical/statistical power consumption models. However, our power consumption models do contain a trend variable, so this is only relevant if these changes occur at a different rate than in the calibration period. New power consuming sectors such as transportation, datacenters, hydrogen production, and so forth, are also not explicitly represented in our approach. On the one hand, these sectors may come to represent a large proportion of power consumption. On the other hand, there is little historical data available to directly make quantitative estimations about the impacts of these developments. As such, we have refrained from making explicit assumptions about such structural developments in order to focus exclusively on heating electrification.

We may also see greater adoption of load-shifting and demand response technologies in the future, which may reduce consumption in the peak hours. Although this could contribute greatly to balancing the system in critical periods, such technologies are not necessarily capable of contributing during sustained periods of high consumption and low VRE production. Such periods would remain challenging, and further research is needed on how to address these challenges.

Secondly, we suspect that the resampling method we used for generating the weather scenarios may not be very well-suited for analysing extreme events, since few or no extreme events of a particular type may have occurred in the historical dataset. Although Xie and Hong (2018) have established that the shifted date method is a good choice for load forecasting purposes, we suspect that simulated weather conditions from numerical weather prediction models – such as those used by van der Wiel et al. (2019b) – might actually provide a more comprehensive foundation for risk assessments, although at the cost of greater complexity.

Thirdly, the possible impacts of climatic change are outside the scope of our study, but if there are increases in temperature, then heating needs would naturally decrease.
van der Wiel et al. (2019b) have concluded, however, that interannual weather variability far exceed the impacts of climate change, and we therefore believe that this consideration would not substantially alter our results.

Finally, generation cost or other system implications have also been outside the scope of this study. This has allowed us to simplify the consumption models and the renewable generation capacity projections greatly – as if they were exogenous to the power market. However, in reality both consumption and capacity investments are endogenously determined in an interaction with a complex energy market and an even more complex political and social environment. In particular, persistent high or low prices will affect consumer behaviour, the development and adoption of different technologies, or investments in different types of generation capacity.

Although the simplifications we have made affect the results of our experiment, they do not affect the main qualitative conclusions we have drawn: increased heating electrification in the Nordic countries will lead to a relatively large increase in total power consumption, and an even larger increase in weather risk due to the increased weather sensitivity, whereas variable renewable sources seem to contribute little to mitigating the risk. Nor do we believe that the simplifications invalidate the additional implications we have inferred from our experiment: if heating is to be electrified, the Nordic power system must not only be designed to supply a greater total load, but also to endure much larger inter-annual, seasonal and intra-seasonal variations.

4 Conclusion

We have shown that replacing heating based on fossil fuels with electric heating in the Nordic countries will result in a considerably higher total power consumption in 2040. More importantly, however, we have shown that it will lead to greater inter-annual, seasonal and intra-seasonal variability in power consumption, and the increased sensitivity to weather conditions resulting from the electrification implies an increased exposure weather risk. Compared to existing power system projections, our calculations suggest that both the magnitude of the consumption increase caused by heating electrification
and the increase in weather risk may previously have been underestimated. As such, a large expansion in power system flexibility will be necessary if heating is electrified in the Nordic countries. Although variable renewable generation capacity is projected to increase substantially in the future, these sources appear to contribute little during the periods of the highest consumption, which underlines the importance of ensuring sufficient flexibility in the power system.

Given these considerations, we suggest that future research focuses on determining how the Nordic power system can be developed to provide sufficient flexibility to handle the changes we have identified. Such an analysis would ideally consider multiple competing sources of flexibility, both on the demand side and the supply side, and use techniques that could appropriately account for variability, uncertainty, and contingency in a realistic manner.

This research is fundamental for designing a robust and resilient energy system that accounts for the increased weather risk in power consumption and production, while at the same time contributing to reduced greenhouse gas emissions.

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## A Appendix: Consumption Model Regression Results

| Model | Country          | R²      | Adjusted R² | F Statistic | Residual Std. Error |
|-------|------------------|---------|-------------|-------------|---------------------|
|       |                  |         |             |             |                     |
| C(Weekday) | Norway         | 0.942   | 0.942       | 55654.711   | 0.054               |
| C(Weekday) | Sweden          | 0.937   | 0.937       | 5277.823    | 0.056               |
| C(Weekday) | Denmark         | 0.898   | 0.898       | 8077.907    | 0.073               |
| C(Weekday) | Finland         | 0.832   | 0.832       | 12877.293   | 0.087               |
| Note: |                  |         |             |             |                     |
|       |                  |         |             |             |                     |
| R²    |                  | 0.942   | 0.937       | 0.898       | 0.832               |
|       |                  | (0.010) | (0.005)     | (0.001)     | (0.001)             |
|       |                  | (0.010) | (0.005)     | (0.001)     | (0.001)             |
|       |                  | (0.010) | (0.005)     | (0.001)     | (0.001)             |
|       |                  | (0.010) | (0.005)     | (0.001)     | (0.001)             |

**Dependent variable: ln(Cons)**
B Appendix: Country-specific Results

Figure 9: Projected densities of the projected total annual electricity consumption in Norway in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

Figure 10: Projected densities of the projected total annual electricity consumption in Sweden in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.
Figure 11: Projected densities of the projected total annual electricity consumption in Denmark in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

Figure 12: Projected densities of the projected total annual electricity consumption in Finland in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.
Table 6: Summary of the projected total consumption for 2040 for the three heating electrification scenarios.

| Country   | Mean (TWh) | Std. dev. (TWh) | CVaR95% (TWh) |
|-----------|------------|-----------------|---------------|
| Norway    | 113.9      | 2.3             | 18.4          |
| Sweden    | 130.1      | 2.6             | 13.5          |
| Denmark   | 37.1       | 0.3             | 3.7           |
| Finland   | 231.0      | 2.7             | 23.7          |
| Nordic    | 512.1      | 7.7             | 528.9         |

| Country   | Mean (TWh) | Std. dev. (TWh) | CVaR95% (TWh) |
|-----------|------------|-----------------|---------------|
| Norway    | 124.9      | 2.5             | 130.0         |
| Sweden    | 146.0      | 3.0             | 152.5         |
| Denmark   | 52.0       | 1.5             | 54.8          |
| Finland   | 263.9      | 5.1             | 275.6         |
| Nordic    | 586.7      | 11.9            | 612.9         |

| Country   | Mean (TWh) | Std. dev. (TWh) | CVaR95% (TWh) |
|-----------|------------|-----------------|---------------|
| Norway    | 136.1      | 2.8             | 141.8         |
| Sweden    | 161.9      | 3.4             | 169.4         |
| Denmark   | 70.1       | 3.7             | 77.2          |
| Finland   | 299.2      | 8.1             | 318.3         |
| Nordic    | 667.2      | 17.7            | 706.6         |

Figure 13: Projected densities of the Norwegian electricity consumption in the peak hour in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.
Figure 14: Projected densities of the Swedish electricity consumption in the peak hour in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

Figure 15: Projected densities of the Danish electricity consumption in the peak hour in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.
Figure 16: Projected densities of the Finnish electricity consumption in the peak hour in 2040 for the three heating electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

Table 7: Summary of the projected consumption during the peak hour in 2040 for the three heating electrification scenarios.

| Country  | Mean (GWh) | Std. dev. (GWh) | CVaR_{95\%} (GWh) |
|----------|------------|-----------------|-------------------|
| Norway   | 21.4       | 1.4             | 24.8              |
| Sweden   | 24.8       | 1.8             | 29.3              |
| Denmark  | 6.3        | 0.2             | 6.7               |
| Finland  | 38.2       | 1.8             | 42.9              |
| Nordic   | 88.6       | 5.0             | 102.8             |

| Country  | Mean (GWh) | Std. dev. (GWh) | CVaR_{95\%} (GWh) |
|----------|------------|-----------------|-------------------|
| Norway   | 23.4       | 1.6             | 27.2              |
| Sweden   | 27.7       | 2.2             | 33.1              |
| Denmark  | 11.5       | 1.2             | 14.5              |
| Finland  | 49.6       | 3.8             | 59.4              |
| Nordic   | 108.8      | 8.4             | 133.0             |

| Country  | Mean (GWh) | Std. dev. (GWh) | CVaR_{95\%} (GWh) |
|----------|------------|-----------------|-------------------|
| Norway   | 25.5       | 1.8             | 29.8              |
| Sweden   | 30.8       | 2.6             | 37.1              |
| Denmark  | 20.5       | 3.7             | 30.3              |
| Finland  | 63.9       | 6.8             | 81.3              |
| Nordic   | 134.8      | 14.3            | 176.6             |
Figure 17: Projected densities of the Norwegian residual electricity demand in the peak hour in 2040 for the three electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

Figure 18: Projected densities of the Swedish residual electricity demand in the peak hour in 2040 for the three electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.
Figure 19: Projected densities of the Danish residual electricity demand in the peak hour in 2040 for the three electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.

Figure 20: Projected densities of the Finnish residual electricity demand in the peak hour in 2040 for the three electrification scenarios (business-as-usual, half and full replacement of fossil fuels by electricity), under varying weather conditions.
Table 8: Summary of the projected residual demand during the peak hour in 2040 for the three heating electrification scenarios.

| Country   | Mean (GWh) | Std. dev. (GWh) | CVaR\(_{95\%}\) (GWh) |
|-----------|------------|-----------------|------------------------|
| Norway    | 20.1       | 1.3             | 23.0                   |
| Sweden    | 22.5       | 1.8             | 26.7                   |
| Denmark   | 5.8        | 0.2             | 6.1                    |
| Finland   | 36.8       | 2.0             | 41.1                   |
| Nordic    | 79.7       | 5.0             | 92.5                   |

| Country   | Mean (GWh) | Std. dev. (GWh) | CVaR\(_{95\%}\) (GWh) |
|-----------|------------|-----------------|------------------------|
| Norway    | 22.0       | 1.5             | 25.5                   |
| Sweden    | 25.3       | 2.1             | 30.2                   |
| Denmark   | 10.2       | 1.0             | 12.1                   |
| Finland   | 48.0       | 4.1             | 57.4                   |
| Nordic    | 98.9       | 8.1             | 118.4                  |

| Country   | Mean (GWh) | Std. dev. (GWh) | CVaR\(_{95\%}\) (GWh) |
|-----------|------------|-----------------|------------------------|
| Norway    | 24.1       | 1.7             | 28.0                   |
| Sweden    | 28.3       | 2.4             | 33.9                   |
| Denmark   | 18.4       | 3.3             | 24.0                   |
| Finland   | 62.2       | 7.1             | 79.3                   |
| Nordic    | 123.8      | 13.4            | 154.8                  |