Norwegian University of Life Sciences
Faculty of Environmental Sciences
and Natural Resource Management

Philosophiae Doctor (PhD)
Thesis 2023:27

The European energy transition: Economic impacts on Nordic stakeholders in the energy system

Den europeiske energiomleggingen: Økonomiske effekter for nordiske energimarkedsaktører

Niels Oliver Nagel

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Philosophiae Doctor (Ph.D.) Thesis

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List of papers

Paper 1	Kirkerud, J.G., Nagel, N.O., Bolkesjø, T.F., 2021. **The role of demand response in the future renewable northern European energy system**. Energy, 235, 121336.
Paper 2	Nagel, N.O., Kirkerud, J.G., Bolkesjø, T.F., 2022. **The economic competitiveness of flexibility options: A model study of the European energy transition**. Journal of Cleaner Production, 350, 131534.
Paper 3	Nagel, N.O., Böhringer, C., Rosendahl, K.E., Bolkesjø, T.F., 2023. **Impacts of Green Deal policies on the Nordic power market**. Utilities Policy, 80, 101475.
Paper 4	Nagel, N.O., Jåstad, E.O., Trømborg, E., Bolkesjø, T.F., 2022. **Prospects for the 2040 Norwegian electricity system: Expert views in a probabilistic modeling approach**. Submitted to Energy Research & Social Science and under review.

Abstract

This thesis assesses the economic impacts that the European energy transition towards net-zero carbon emissions has on Nordic power system stakeholders. The impacts of climate policies, the role of power system flexibility, and the role of Norway's future power supply and demand are analyzed. This thesis aims to improve the understanding of how Nordic stakeholders will be affected by the energy transition, what opportunities and impediments exist, and what potential conflicts policy makers should be aware of. To answer these research objectives, the partial equilibrium Balmorel energy system model was applied alone, extended by a demand response module, coupled with a general equilibrium model, and linked with an expert survey. The results show that the increasingly ambitious European climate targets will most likely benefit Nordic renewable energy producer revenues and market values in 2030 and beyond. The benefits, however, will depend on the European and national policy choices and producers' technology characteristics. Model results show that flexibility will be critical for the cost-effective decarbonization of the power sector, with the value of flexibility options for reducing system costs increasing exponentially with more ambitious climate targets. In deep decarbonization scenarios for 2030, transmission and sector coupling with the district heating system are particularly important for energy system efficiency. With less ambitious climate targets, demand side management increases system efficiency most. Another finding is that it will also be important to address ambiguous consumer and producer welfare impacts of the energy transition and infrastructure investment. An optimal decision from a societal point of view may, for example, decrease Nordic consumer welfare in some market areas and thereby increase the likelihood of social opposition if not adequately addressed.

Norsk sammendrag

Denne avhandlingen analyserer hvordan den den europeiske energiomstillingen påvirker de økonomiske rammebetingelsene for norske aktører innen fornybar energi. Avhandlingen ser spesifikt på effektene av europeisk klimapolitikk, behov og lønnsomhet i å tilby energisystemfleksibilitet, og inntektsutsiktene for ulike fornybarteknologier. Avhandlingen har som mål å forbedre forståelsen av hvordan nordiske interessenter påvirkes av den europeiske energiomstillingen, belyse muligheter og utfordringer, og analysere hvilke potensielle konflikter beslutningstakere bør være oppmerksomme på. Disse problemstillingene er analysert ved hjelp av den den nord europeiske energisystemmodellen Balmorel. I avhandlingen er Balmorel utvidet med en modul for etterspørselsrespons, koblet med en generell likevektsmodell for EU's økonomi og i en av studien bruker vi også resultater fra en spørreundersøkelse blant energimarkedseksperter som input i modellen. Resultatene viser at de stadig mer ambisiøse europeiske klimamålene mest sannsynlig vil øke inntektene og markedsverdiene til nordiske fornybarressurser mot 2030 og videre. Effektene vil imidlertid avhenge EU og nasjonenes virkemidler i energiomstillingen, og produksjonsteknologiens egenskaper. Modellresultatene viser at løsninger som kan bidra med energisystemfleksibilitet vil være viktig for å oppnå kostnadseffektive utslippskutt i kraftsektoren. Verdien av fleksibilitet øker eksponentielt med mer ambisiøse klimamål. I scenarier med omfattende utslippskutt er utvekslingskabler mellom land og regioner, og sektorkobling med fjernvarmesystemet, spesielt viktig for energisystemets effektivitet. Med mindre ambisiøse klimamål vil styring av etterspørselssiden øke systemeffektiviteten mest, ifølge modellresultatene i denne avhandlingen. Et annet funn er at det også vil være viktig å adressere fordelingseffekter for forbruker- og produsentvelferd ved investeringer i infrastruktur. En optimal beslutning fra et samfunnsperspektiv kan, for eksempel, redusere konsumentoverskuddet i enkelte markedsområder og dermed øke sannsynligheten for sosial motstand mot energiomstillingen.

Synopsis

1. Introduction

1.1. Decarbonizing the power sector – Vital to the European climate ambitions

“By polluting the oceans, not mitigating CO_2 emissions, and destroying our biodiversity, we are killing our planet. Let us face it, there is no planet B”, said French President Emmanuel Macron addressing the US congress in 2018. He went on to speak about the importance of a smooth transition to a low-carbon economy to ensure a life full of opportunity for future generations. The speech underscores the importance of acting now. It aligns with the growing European consensus that the European energy system must be transformed rapidly to limit global warming to well below 2°C as agreed upon in the “Paris agreement” in 2015.

To fulfill the “Paris Agreement” pledge, European milestones have been set and policies developed to achieve the stated ambitions. Relevant decisions aiming, amongst others, at a cleaner energy system in the European Union (EU)[1] were first made in the 1990s when the ratification of the “Kyoto protocol” set binding greenhouse gas (GHG) emission reduction targets for the member states (United Nations). In the following years, EU environmental regulation led to the “Renewables Directives” (2001 and 2003) and to the EU emission trading system (EU ETS) in 2005. The strategies described in “An energy policy for Europe” in 2007 can be seen as the basis for today’s energy policy in Europe (Langsdorf, 2011), addressing challenges such as sustainability, security of supply, and competitiveness. These three key challenges are also the focus of this thesis. The “20-20-20” targets for the year 2020 aimed at cutting GHG emissions by 20% from 1990 levels, having 20% of EU energy from renewables, and improving energy efficiency by 20%. “The 2030 climate and energy framework” (2014) introduced a GHG reduction target of 40% (compared to 1990 levels) by 2030 to help achieve a future target of 80-95% GHG emission reduction previously set in 2009 (European Council, 2009). With these targets not being sufficient to achieve the targets of the “Paris Agreement,” the urgency to act increased, and EU targets have been subject to further change. The “European Green Deal” (2019) was described by European Commissions president

[1] EU energy policy is mostly also applicable to EEA-EFTA states

Ursula von der Leyen as the European "man on the moon moment." It sets out to achieve net-zero GHG emissions by 2050 and a 55% GHG emission reduction in 2030 (compared to 1990). The latest policy proposals by the European Commission include the "Fit for 55" package, which advocates revisions to climate, energy, and transport legislation to reach the updated 2030 targets (European Council, 2022), and the "REpowerEU" plan to reduce the dependence on Russian hydrocarbon (European Commission, 2022c).

EU policies must address the sectors with the highest GHG emissions in order to achieve the stated targets and identify further reduction strategies. The majority of EU GHG emissions result from fuel combustion in the power, heating and cooling, industrial, and transport sectors. Figure 1 displays the largest emitters in the EU by source, indicating that the transition to renewables in the power sector and the shift to direct electrification of cooling and heat, transportation, and industrial processes could result in a large reduction in GHG emissions. Integrating the power sector with the other sectors is a crucial strategy for decarbonization and is also referred to as sector coupling. Besides direct electrification, flexible green (power from renewables) hydrogen electrolysis will likely promote the decarbonization of hard to decarbonize sectors, such as power intense industries. Additionally, energy efficiency measures can reduce the burden on the power sector. Carbon capture and storage (CCS) may be needed to offset residual emissions.

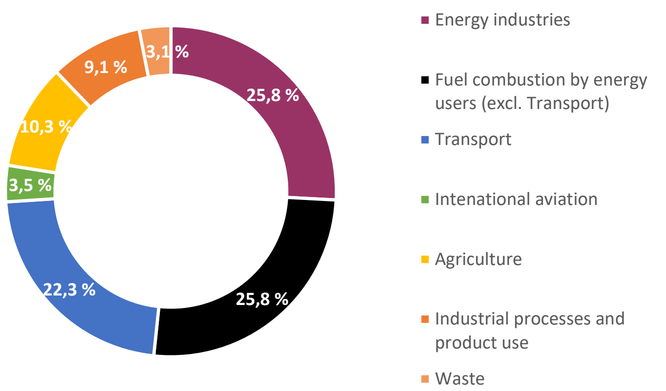

*Figure 1. 2019 GHG emissions by source in the EU-27 (excluding indirect CO2 emissions, land use, land use change, and forestry). Source: (*Eurostat, 2022b*).*

1.2. The evolving Nordic[2] power system

The Nordic power system is increasingly integrated into the European market. Interconnection serves multiple purposes, such as increasing system efficiency, decreasing backup needs, and providing flexibility by balancing supply and demand geographically. Increased transfer capacity results in a greater influence of changes in central European countries and the UK on the Nordic energy system and is thus under public debate in, e.g., Norway, where domestic power prices have increased to new record levels. Despite the EU and the Nordics both moving towards a low carbon power system, the generation mixes are distinctly different, and the composition of renewables in the generation mix results in unique characteristics defining the Nordic energy system. Figure 2 shows both the complete power production mix and the renewable production mix in the EU27 (excl. Demark, Sweden, and Finland) and in the Nordics in 2020.

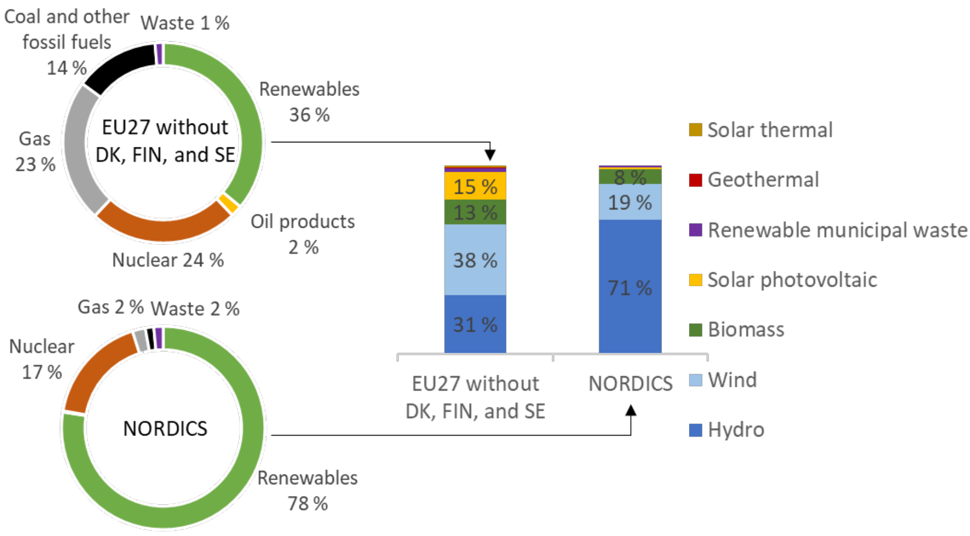

*Figure 2. The power production mix and renewable production mix in the EU27 (excl. Demark, Sweden, and Finland) and the Nordics in 2020. Data source: (*Eurostat, 2022a *).*

The Nordic countries are front-runners in the energy transition. In 2020, 78% of total Nordic power generation was from renewables compared to 36% in the EU27 (excl. Denmark, Finland, and Sweden). Additional nuclear power generation (17%) results in

[2] Nordic countries refer to Denmark, Finland, Norway, and Sweden. The descriptions and calculations exclude Iceland.

a very low GHG emission intensity. The largest share of renewable power generation comes from hydropower (71%), followed by wind power (19%) and biomass (8%). In the remaining EU countries, the largest share of renewable power generation is from wind power (38%), followed by hydropower (31%), solar PV (15%), and biomass (13%). The above-described generation mixes point to two key differences between the European and the Nordic power systems. First, the European power mix still relies on a high share of fossil fuels, while the Nordics already have a power system with low GHG emission intensity (Denmark, 109 gCO2e/kWh, Finland 195 gCO2e/kWh, Norway 0 gCO2e/kWh and Sweden 8.8 gCO2e/kWh compared to 230.7 gCO2e/kWh in the EU27 in 2020 (European Environmental Agency, 2021)). Having excellent wind and hydropower resources and being integrated into the European power system thus allows the Nordics to help decarbonize European power generation. Second, the renewable composition outside the Nordics relies more heavily on variable renewable energy (VRE), while the Nordic renewables provide more flexibility to balance supply and demand, mainly from dispatchable hydropower. Hydropower can provide flexibility to several market areas through interconnection, which helps integrate higher shares of VRE also in connected market areas with less power system flexibility. In the Nordics Norway, Sweden and Finland have large hydropower and biomass resources, while Denmark's power system differs. Denmark holds the status of a leader in wind deployment (59% of total production in 2020) and is subject to more price fluctuations. Here, district heating systems provide flexibility with combined heat and power (CHP), as well as through heat pumps and boilers. The latter two can use excess electricity production from wind for heat production, which shows that power-to-heat (PtH) can help decarbonize the heating system (Kirkerud et al., 2017). With the addition of pit, borehole, or tank storage, PtH for district heating can help shift seasonal loads and facilitate further wind power integration.

In spite of having a low carbon intensity in power generation, the Nordic power system is continuing to evolve. In line with European climate ambitions, the Nordic countries aim to reduce GHG emissions in several sectors. This can be achieved via electrification or by using energy carriers such as renewable-based gas and will increase electricity demand. Additionally, new industries such as data centers or battery factories may also require large amounts of electricity. Future generation capacities are mostly expected to come from VRE, resulting in less power system flexibility in the Nordics. Furthermore, increased market integration of the Nordic region into the European power system, which relies more heavily on VRE, will amplify the need for power system flexibility. The changed production mix in the power sector will result in changes in power prices and power price volatility in the Nordics, with associated risks and opportunities for Nordic stakeholders in the energy system, topics discussed in this thesis.

1.3. Dimensions for analyzing energy transitions

Historically energy transitions were driven by technological innovations, resources, social, political, and economic factors (Millot and Maïzi, 2021). Several of these drivers still play a role today, but the main driver in the European energy transition is the political will to decarbonize. Despite already having a low carbon power system in the Nordics, several challenges are emerging in light of the European climate ambitions. As suggested by Cherp et al. (2018), challenges for analyzing energy transitions arise in three interlinked dimensions: The techno-economic, socio-technical, and political dimensions, shown in Figure 3. The methods applied in this thesis center around the techno-economic dimension, however, this thesis to a lesser degree also discusses and analyses the socio-technical and political dimensions.

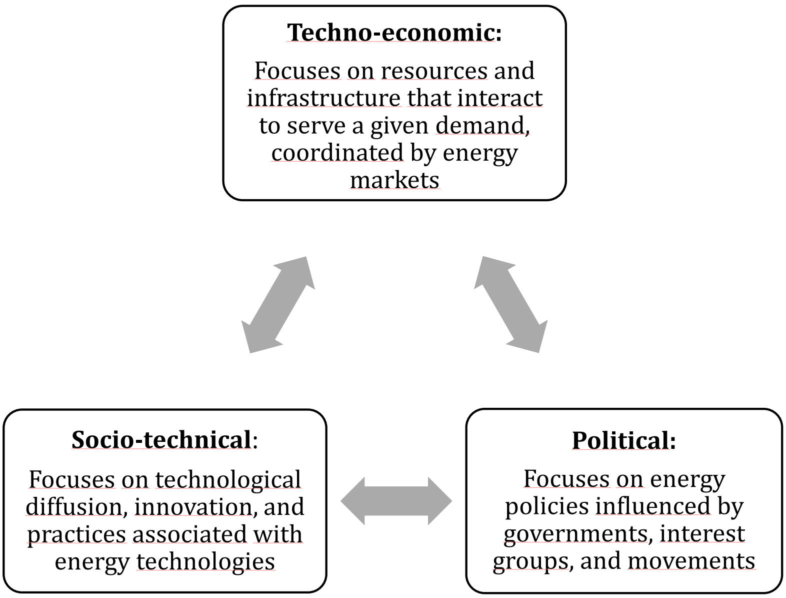

Figure 3. Dimensions for analyzing energy transitions. Source: Own illustration, inspired by Cherp et al. (2018).

The techno-economic dimension focuses on energy flows and conversion processes determined in a market setting. Two major challenges arising in this dimension are the ongoing decoupling of supply and demand with growing VRE generation, and how to efficiently compensate for increasing electricity demand. The electricity demand in the Nordics is expected to increase because of the electrification of the transport, heat, and industrial sectors and demands from new industries. As a result, new infrastructure will be needed to produce, transmit and store electricity from VRE. Power system flexibility, or the ability to adapt to changes in load, will become more critical across seasonal, weekly, daily, and intra-daily timeframes. Power price volatility will increase, affecting market values and profitability for producers. Addressing the challenge of balancing the energy system cost-effectively while maintaining system security, reliability, and competitive electricity prices will shape the future Nordic energy system.

The socio-technical dimension focuses on the technological change and adoption of new technologies. Technology adoption often follows an S-curve with few early adopters, followed by a quick uptake and a subsequent leveling off. The market penetration rate, however, varies between different energy production and end-use technologies, with typically faster build-up rates for technologies with a local dimension and smaller energy impact (Lund, 2006). However, these energy production and end-use technology penetration rates can be affected by policies, subsidies, and taxes. Power system flexibility can be increased by the adoption of demand-side flexibility, e.g., via demand response in households or smart charging of electric vehicles. The hydrogen economy envisioned by the EU could provide seasonal storage, help decarbonize industry and transport, and promote the production of green fertilizers and steel (European Commission, 2020). Further innovations in technologies will likely be adopted as Europe moves towards net-zero emissions. The acceptance and employment of these technological opportunities, however, depend on actors in social networks and infrastructure (Millot and Maïzi, 2021). Challenges here pertain to the displacement of old technologies or frameworks and a swift enough adoption of favorable technologies to help achieve predetermined targets. Uncertainties regarding the adoption of end-use technologies are high since they are not purely driven by economic factors.

The political dimension as it is defined here is consistent with the definition of a state-structural approach by Hall (1993). The political dimension describes policies that relate to the power system and are influenced by the participation of voters, parties, social movements, and lobbies. Policies and political intent on a global, EU, national, and local level affect stakeholders in the Nordic energy system through regulations such as subsidies, taxes, and planning permission. Examples of such policies are the European Green Deal (European Commission, 2021), the European emission trading system (European Commission, 2022b), the Norwegian parliament's decision to ban sales of new cars that are not emission-free by 2025 (Norwegian Government, 2021), and Copenhagen's aim at transforming energy consumption, energy production, and mobility in its efforts to be the world's first carbon neutral capital in 2025 (Damsø et al., 2017). Indirect influences include expectations of paradigm shifts, social movements, and concerns about externalities of new and existing infrastructures.

1.4. Literature overview

The following literature overview categorizes research papers investigating techno-economic, socio-technical, and political aspects related to the energy transition and highlights areas of research that could be further investigated. The literature overview is conducted to position this thesis in a wider scientific context and not as a systematic literature review. It identifies broader research topics relevant to this thesis and lists exemplary scientific papers on these topics published in leading journals.

The cost and price effects associated with the integration of higher shares of VRE into power systems

It is well documented that the cost of VRE from wind and solar PV has fallen significantly and reached levels where these generation sources are economically competitive. In the future, they are likely to have the lowest levelized cost of electricity (LCOE) (IEA, 2020). Their variable production profiles, however, introduce new challenges related to the operation of the power system, backup needs, and new capacity investments. There is vast existing literature on the changes to system costs associated with increasing VRE shares, often referred to as integration costs (Hirth et al., 2015; Holttinen et al., 2011; Joos and Staffell, 2018; Katzenstein and Apt, 2012; Milligan et al., 2011; Milligan and Kirby, 2009). Four main integration cost topics are identified by Heptonstall and Gross (2021): Costs for additional operating reserves for short term balancing (Hirth et al., 2015; Joos and Staffell, 2018; Milligan et al., 2010; Roos and Bolkesjø, 2018), capacity adequacy (Oree et al., 2017; Zhou et al., 2018), profile costs (Hirth, 2013; Ueckerdt et al., 2013), and grid related costs (Held et al., 2018; Schaber et al., 2012; Shen et al., 2020). Additionally, aggregating several of these cost components in system approaches is a common method for analyzing integration costs from higher shares of VRE in energy systems more comprehensively (Batalla-Bejerano and Trujillo-Baute, 2016; Brouwer et al., 2016; Reichenberg et al., 2018; Wiser et al., 2017).

The price effect of rising shares of VRE on the average electricity sales prices from various power producing technologies (market values) is attracting increasing attention in light of the European energy transition (Hirth, 2018; Jåstad et al., 2022; López Prol et al., 2020). Related to this, a recent study by Brown and Reichenberg (2021) highlights that power system flexibility reduces the negative impact of VRE on power producers' market values. While several studies discuss the merit-order-effect (discussed in more detail in section 2), only few studies focus on the market values of VRE and conventional electricity production, specifically in a flexible region such as the Nordics. Examples of such studies are those of Jåstad et al. (2022) and Tveten et al. (2016).

The value of energy system flexibility with increasing shares of VRE has been researched in several studies. Energy system flexibility is defined here in accordance with Papaefthymiou et al. (2014) and refers to the ability of the power system to cost-effectively adapt supply and demand, ensuring a balanced power system across all relevant timescales. The various flexibility options may be categorized according to whether flexibility is provided on the supply side, the demand side, by storage or transmission investment (Deason, 2018). The majority of flexibility studies in the literature focus on the impacts of individual flexibility measures and do not study flexibility holistically. The value of flexibility measures is typically either investigated from a technology point of view (Nitsch et al., 2021; Xu and Tong, 2014) or from a system point of view (Mallapragada et al., 2020; Pudjianto and Strbac, 2017). Another topic discussed is flexibility options' positive impact on VRE market values with increasing shares of VRE (Kirkerud et al., 2017; Tveten et al., 2016). Few studies quantify the economic value of different flexibility options for increasing VRE shares in the Nordics jointly in a system approach with an exception being Kiviluoma et al. (2018). In addition, the economic implications of competition between flexibility options are rarely discussed.

The impact of VRE on power prices is often examined in national reports and outlook studies (Chen et al., 2021a). In the Nordics, Chen et al. (2021a) find that average power prices are likely to increase in future years, and that power price variation can also be expected to increase due to the uncertain production profiles caused by greater VRE generation. Helistö et al. (2017) apply a unit commitment economic dispatch model to model Northern European power prices with varying VRE generation for the years 2030 and 2050. They find that higher new VRE capacity could lead to overcapacity could in the short term, lowering average electricity prices. In the long run these effects will be more moderate as the generation mix adjusts. With respect to Nordic outlook studies, Chen et al. (2021a) found several unaddressed research gaps. They show that the majority of studies focus on investments and operation on the supply side with comparatively little research into the future development of electricity consumption. In additionally, few studies apply uncertainty techniques outside of scenario analyses and few report detailed results on price volatility and market values for power producers.

The European energy policies' effect on the power sector and their consequences

Research on European energy policies is vast. Several large areas of this research are related to shaping the energy transition. One major area of research is on the impacts of renewable support policies, such as the EU ETS or feed-in tariffs, aimed at reducing emissions from the energy sector. Studies discussing renewable support policies typically focus on possible outcomes, perform ex-post analyses, or highlight on potential caveats of these policies (Böhringer and Rosendahl, 2010; Hitaj and Löschel, 2019; Kwon, 2015; Nordensvärd and Urban, 2015). With EU climate policy targets of net-zero emissions by or before 2050, increasing research is focusing on how to achieve these targets in the energy sector in a least cost approach. Jenkins et al. (2018) provide a review of studies with an 80%-100% reduction in carbon emissions from 2018 levels. They find that there are many pathways to achieve net-zero, but they require either dispatchable low carbon generation or seasonal storage to overcome the challenges of a VRE dominated system. Also, by limiting studies to likely winners from today's perspective (e.g., wind, solar PV, and battery storage) the chance of actually achieving said targets may be compromised. Parallel to the further evolution of technologies, energy policies and EU climate targets will evolve, making timely updated studies or studies taking different policy pathways into account important for improving the existing knowledge base. Energy market design is another common area of research that is related to integrating higher shares of VRE. A few commonly discussed topics relate to the European energy market integration (Song et al., 2022), barriers to VRE (Hu et al., 2018), capacity markets (Bucksteeg et al., 2019), and the efficient use of price signals (Yan et al., 2018). Recently, the energy market design has been getting increased attention as the EU is considering short- and long term reforms in response to the energy (price) crisis (European Commission, 2022a). Additionally, energy policies influenced by public opinion and contrasting preferences, such as in land-use conflict (Chen et al., 2022; Hastik et al., 2015) and in the public acceptance of renewable energy projects (Batel et al., 2013; Linnerud et al., 2022; Rygg et al., 2021) are common research topics. There is a lack of studies focusing on the effect of climate policies in smaller geographical areas with distinct generation resource availabilities, such as the Nordics.

1.5. The scope of the Ph.D. project

The scope of this thesis is limited to the elements named in the thesis title, "The European energy transition: Economic impacts on Nordic stakeholders in the energy system".

The main focus of this thesis concerns the power sector in the *European energy transition*. To a lesser degree, interaction with other sectors through sector coupling and the use of combined model approaches are addressed.

The *economic impacts* addressed in this thesis refer to analysis' from a societal perspective where an energy system model minimizing system costs is applied. Flexibility options and power producer profits, revenues, market values, and value factors and their impact on system costs are studied. However, revenues from, e.g., balancing and ancillary services markets are not accounted for in the analysis. From both the producer and consumer perspectives, the electricity price is important.

The Nordic stakeholders in the energy system include a societal perspective, electricity producers, flexibility providers, and electricity consumers in the Nordic countries, with a particular emphasis on Norway, while interdependencies with other European countries are considered.

The techno-economic, as described by Cherp et al. (2018), is the main dimension focused on in this thesis. However, as this dimension is interlinked with the socio-technical, and political dimensions, these too are partially analyzed by applying and coupling method outside of energy system modeling, cf. section 3.

The temporal scope of this thesis includes the milestones in 2030 and 2040 toward the EU zero-emission target in 2050.

1.6. The research objectives

Against the background of the reviewed literature, this thesis is aimed at adding knowledge concerning several research questions relevant to the Nordic energy transition. Pertaining to the Nordics, limited research is found addressing market values with increasing renewables in the European energy system, addressing the system value of flexibility options, competitions between flexibility options, applying uncertainty techniques to analyze the energy transitions effect on power prices and market values, and analyzing the economic impact of European energy policies with respect to smaller geographical areas with distinct resource characteristics (such as the Nordics).

This thesis studies economic impacts of challenges and opportunities on the energy system, flexibility options, producers, and consumers arising from the European energy transition in the Nordic energy system. Based on the identified research gaps an overarching research question concerning flexibility options and power producers is formulated (see below).

> *How do European climate ambitions towards "net zero" affect flexibility options and power producers in the Northern European energy system from an economic perspective?*

To answer this research question the following four sub-objectives are defined (in brackets described where the results of the sub-objectives are discussed in more detail):

1. *What is the economic potential of demand response in the future Nordic energy system? (Section 4.1)*
2. *How do climate targets and interaction between flexibility options affect the value of flexibility? (Section 4.2)*
3. *How will the European Green Deal and climate policies impact the 2030 Nordic power system? (Section 4.3)*
4. *How will 2040 market values for Norwegian power-producing technologies develop under supply and demand uncertainty? (Section 4.4)*

Four research papers are the basis for answering the above-stated research question. Two of these are broader studies, focusing on large geographical areas and a multitude of technologies (paper 2+3). The other two studies are more focused. Paper 1 focuses on the economic potential of demand response for power system flexibility in the Nordics. Paper 4 focuses on the geographical area of Norway and discusses the economic impacts of supply and demand assumptions on Norway's 2040 energy system. The overview of the articles with authorship and publication status is presented below in Table 1:

Table 1. Article overview

	Title	**Journal**	**Publication status**	**Authorship**
1.	**The role of demand response in the future renewable northern European energy system**	Energy	Published	Jon Gustav Kirkerud, Niels Oliver Nagel, Torjus Folsland Bolkesjø
2.	**The economic competitiveness of flexibility options: A model study of the European energy transition**	Journal of Cleaner Production	Published	Niels Oliver Nagel, Jon Gustav Kirkerud, Torjus Folsland Bolkesjø
3.	**Impacts of Green Deal policies on the Nordic power market**	Utilities Policy	Published	Niels Oliver Nagel, Christoph Böhringer, Knut Einar Rosendahl, Torjus Folsland Bolkesjø
4.	**Prospects for the 2040 Norwegian electricity system: Expert views in a probabilistic modeling approach**	Energy Research & Social Science	Submitted, under review	Niels Oliver Nagel, Eirik Ogner Jåstad Erik Trømborg, Torjus Folsland Bolkesjø

2. Theoretical background

This chapter provides definitions and overviews of concepts used to answer the previously defined research questions in this thesis. Different aspects pertaining to the costs of electricity generation, the value of produced electricity and power system flexibility, and policies directly affecting power producers are discussed.

2.1. The costs of producing electricity

The levelized cost of electricity (LCOE) is an indicator commonly used to compare costs of electricity generation from different power-producing technologies (Shen et al., 2020). It represents the revenues needed to break even at the end of the economic lifetime of a specific technology and is calculated as shown in equation 1:

$$LCOE = \frac{Lifecycle\ cost}{Lifetime\ electricity\ production} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where I_t: Investment costs in year t

M_t: operations and maintenance costs in year t

F_t: Fuel costs in the year t

E_t: Produced electricity in year t

r: discount rate

n: expected lifetime of technology

The use of the LCOE as an indicator for energy policies has been criticized as being oversimplified and having several shortcomings, mainly pertaining to the comparison between dispatchable technologies and VRE. For example, there are differences in the contribution of different technologies in providing adequacy, reliability, and quality of electricity supply to power systems. These contributions are not taken into account by the LCOE (IEA, 2020). Neither does the LCOE reflect the impacts on total system costs by different technologies. In addition, the LCOE is very sensitive to assumptions regarding discount rates, fuel prices, taxes, subsidies, geographical locations, and local conditions. Thus, improving the methodology of the LCOE for VRE technologies has been subject to further research. Studies discuss location (Heck et al., 2016; Rhodes et al., 2017), system LCOE (Elliston et al., 2016; Reichenberg et al., 2018; Ueckerdt et al., 2013), and energy policies such as subsidies and taxes (Bruck et al., 2018; Tran and Smith, 2018).

Despite drawbacks, the LCOE of power-producing technologies indicates how competitive VRE technologies have become and why the buildout of new generation capacities in Europe will largely rely upon wind power and solar PV. Figure 4 shows the expected LCOE for renewables, coal, gas, and nuclear in 2025. The range of LCOEs from different future generation facilities over 24 countries is displayed as an error bar, and the median values are displayed as boxes. Onshore wind has the lowest median LCOE, followed by utility-scale solar PV making these the most cost-competitive technologies according to the LCOE indicator. It should be noted that the LCOEs of Figure 4 include assumptions of a carbon tax of 30 USD/tCO_2 and fuel prices in Europe of 75 USD/t for hard coal and 8 USD/MBtu for natural gas. These are very low prices compared to recent 2022 prices experienced in Europe following the economic recovery after Covid19 restrictions and the Russian invasion of Ukraine. Higher taxes and fuel prices will also increase the competitiveness of renewables.

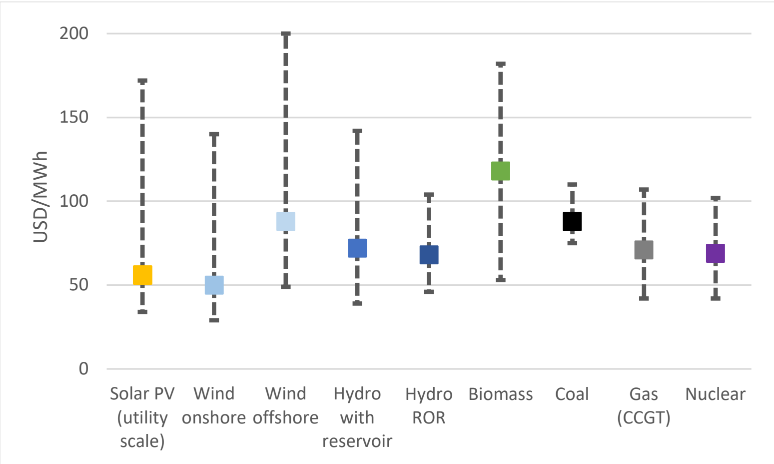

Figure 4. LCOE including a carbon tax of 30 USD/tCO_2 for power-producing technologies in 2025. IEA aggregated data for 24 countries, assuming a 7% discount rate. Source: Own illustration based on IEA (2020).

2.2. The market value of producing electricity

While it is important to understand costs associated with producing electricity, the market value is equally important to power producers for assessing their profitability.

The market value, here, is defined as the income power producers can earn on markets without subsidies (Hirth, 2013). Using this definition, the market value of VRE is primarily affected by weather-determined temporal production profiles and geographical location. The geographic location of production units determines the resource quality, bidding area, and the need for additional infrastructure investment. Another factor impacting market values is forecasting errors, which for VRE typically range from 6-8% of rated capacity one day ahead on a regional market (IRENA, 2019). Forecasting errors require costly balancing, resulting in lower market values for VRE. Flexible dispatchable technologies are only affected by some of the above-mentioned technology characteristics, e.g., by landscape characteristics affecting the potential for hydropower. In addition, flexible technologies can take advantage of economic incentives for adjusting output and can capture more favorable market values than VRE. With the increasing penetration of VRE in power systems, two further concepts affect the market value of VRE technologies, *the merit order effect* and *the correlation effect, as* defined here based on (Hirth, 2013).

The *merit order effect* is a consequence of how European power markets are designed. The merit order in power markets refers to the ranking of production capacity according to the short-run marginal cost (SRMC) of electricity generation. The merit order is applied to optimize electricity supply economically. The production units with the lowest marginal costs are brought online first, and production units with increasingly higher marginal costs are subsequently brought online until demand is met. The production unit producing with the highest SRCM (marginal power plant), which is online to meet demand, is price setting and determines the electricity price. The merit order effect, illustrated in Figure 5, shows that increased VRE production decreases market prices. Because the SRMC of VRE is close to zero, it is preferred in the merit order. Thus, the residual load (load not covered by VRE) determines the need for flexible electricity production from conventional producers. As VRE production increases, the residual load is reduced, and lower SRMC conventional power plants become price setting (Sensfuß et al., 2008). In addition, as the share of VRE in the market increases, the effect on the merit order becomes more pronounced because the residual demand decreases further in certain hours. This may negatively affect market prices (price shift from P to P*) and have negative consequences for both VRE and conventional power producers. However, VRE producers will be stronger affected as they do not have the flexibility to increase output in high price hours.

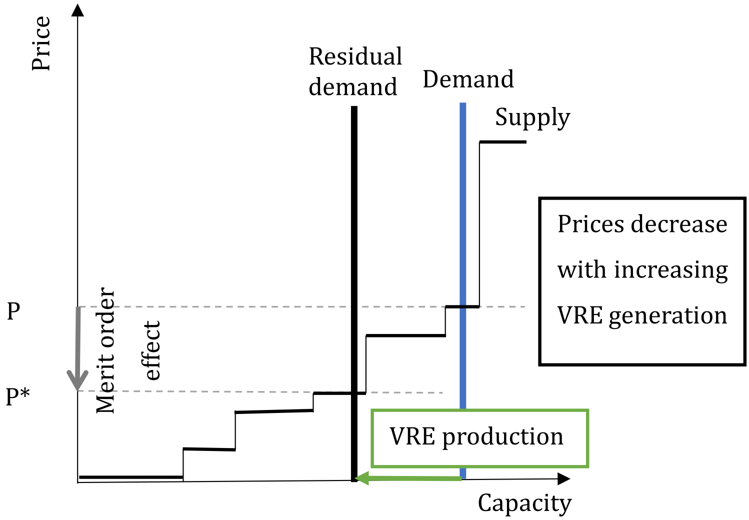

Figure 5. The effect of VRE on the merit order

The replacement of thermal baseload generation capacities by VRE could additionally steepen the merit order curve and result in more extreme prices (high and low) as well as more price volatility. Low prices are experienced when SRMC VRE technologies are price setting, and high price periods are experienced when flexible peak power plants with high SRMC are price setting.

The *correlation effect* describes the interrelationship between VRE production and electricity demand. Seasonal, weekly, and daily variations in production profiles affect the market values of VRE producers differently by technology. A high positive correlation between production and demand will usually result in higher market values than high production in low demand periods. The correlation effect can therefore lead to either higher or lower than average market values. A measure describing the market value of a technology relative to the average price is the value factor. A value factor greater than one indicates production at favorable market prices. Lower value factors signify production in less favorable market conditions. For illustrative purposes, the concept of the *correlation effect* is shown in Figure 6, without representing a specific region. In this example, wind produces in favorable periods where demand is higher than the average demand. This leads to the market price being set by a power plant with a higher SRMC, increasing the market clearing price from P to P*.

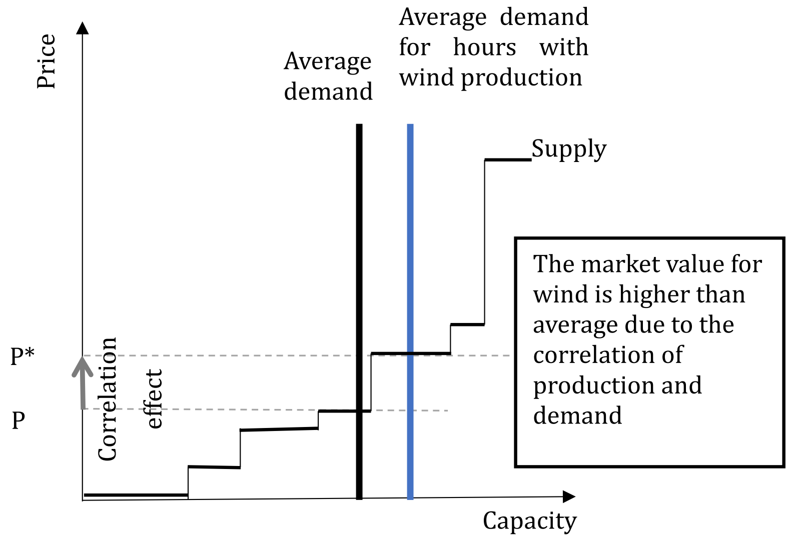

Figure 6. The correlation effect.

The correlation effect differs significantly between regions, depending on consumption profiles and resource availability. For example, Norway typically experiences annual fluctuations, with peak electricity demand in January and the lowest demand in July. Weekly fluctuations show higher demand in the middle of the week than on Sundays, and daily fluctuations show particularly low demand during night hours. Outdoor temperature is a main driver of demand, with a correlation coefficient of 0.8 (Idsø, 2021). In Norway, the seasonal wind power output is positively correlated with electricity demand. Figure 7 shows the normalized monthly aggregated profiles for wind power generation and electricity demand between 2010 and 2021. While daily and weekly variations are not accounted for in the figure, the seasonal correlation between output and demand is apparent and is calculated to be 0.81. The variance is slightly higher for the normalized monthly wind power production (0.04) than for the consumption (0.03).

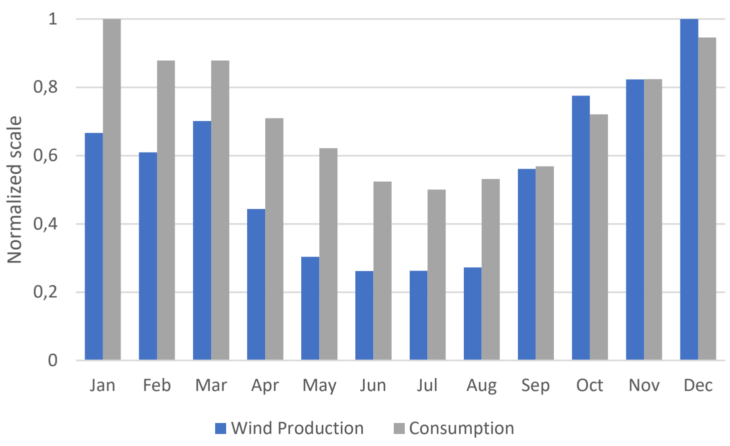

*Figure 7. Monthly profiles of wind power generation and electricity demand in Norway between 2010 and 2021. Source: (*Statistics Norway, 2022*).*

Wind power production is, like demand, greatest in winter months, leading to favorable market values as compared to, e.g., solar PV or hydro run-of-river. Idsø (2021) shows that at present, wind power has a value factor of 1.025 in Norway. This value will change, however, depending on future demand and supply developments. Flexible generation technologies, in Norway's case hydropower with reservoirs, have even higher market values with value factors well over 1. With rising shares of VRE capacity, the merit order effect will increasingly outweigh the correlation effect and increasing VRE capacities will negatively affect VRE market values.

2.3. Policies affecting producer profitability

Energy policies may affect producer profitability directly through subsidies and taxes, or indirectly by influencing competition and expectations pertaining to the future.

The EU emission trading system (EU ETS), first implemented in 2005, is a central climate policy of the EU and directly impacts the costs of fossil fuel-based generation. It puts a cap on CO_2 emissions from electricity and heat generation, energy-intensive industries, and commercial aviation in the European economic area (EEA) (European Commission, 2022b). It also limits the amount of N_2O emissions from nitric, adipic, glyoxylic acids, and glyoxal, as well as the emissions from perfluorocarbons (PFCs) from the production of aluminum. The aim of the EU ETS in the power sector is to cost-effectively incentivize the switch from CO_2-intense power production to less CO_2-intense power production, with the long-term target being zero emissions. The EU ETS is a policy based on the "cap and trade" principle. The cap limits the GHG emissions allowed in the sectors covered for each year. Trade refers to the trade of emission allowances on a market. Emission allowances can be traded, or in other words, bought and sold amongst the participants in accordance with their requirements to cover their emitted GHGs. This mechanism ensures an ongoing reduction of emissions by reducing the emission cap yearly and is a cost-effective measure relying on market principles. In the power and heat sectors, fossil-fueled technologies will need to offset CO_2 emissions with emission allowances. This directly increases the SRMC of such technologies and thus affects the merit order, where low/no- emission technologies become relatively more competitive. When the EU ETS was first introduced, an oversupply of emission permits was allocated, resulting in very low CO_2 prices, c.f. Figure 8. Subsequently, the EU ETS has undergone several revisions, which decreased the oversupply of permits and resulted in increased CO_2 prices, reaching close to record highs of 30 EUR/tCO_2 in 2019. The European Green Deal led to a further tightening of emission permits. Due to recent natural gas price increases, coal has partially replaced natural gas for power generation. This has put an even greater upward pressure on the price of emission permits due to the higher emission intensity of generation. With EU ETS permit prices increasing to more than 90 EUR/tCO_2 in February 2022, the SRMC of fossil-fueled power generation has increased significantly. As a consequence, power prices, too, have increased. The result of the EU ETS can thus be higher market values for producers and increased investment into renewable and low-emission technologies.

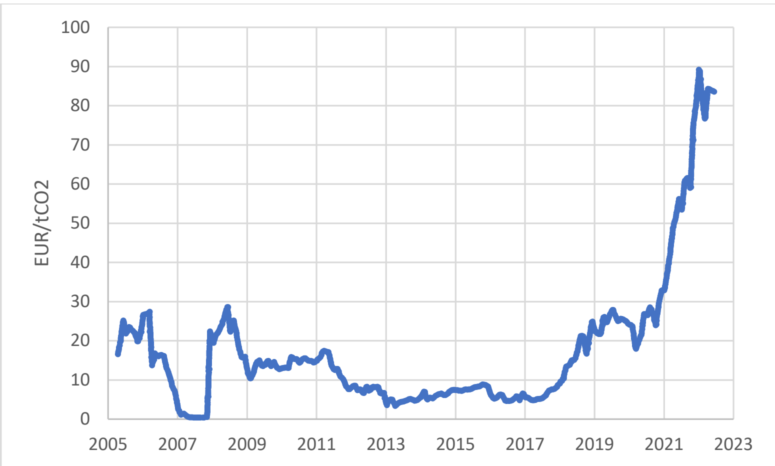

Figure 8. EU carbon permits (EUR/tCO_2). Source: (Trading Economics, 2022)

The EU ETS and its interaction with other energy policies are investigated in this thesis. One of these additional policies is a mandated coal phaseout. Energy-related CO_2 emissions from coal combustion (879 gCO_2e/kWh) are emission intense as compared to, e.g., natural gas (391 gCO_2e/kWh) (Foster and Bedrosyan, 2014). In 2022, therefore, the governments of 23 European countries have proposed a mandated coal phaseout as an effective solution for limiting climate change. When combining measures such as a coal phaseout with a policy instrument such as the EU ETS, it is important to understand how they interact in order to avoid unintended consequences. Anke et al. (2020) and Böhringer and Rosendahl (2022) show that without the cancellation of emission allowances, a coal phaseout would lower the CO_2 price in the EU ETS, and aggregate emissions will remain the same. A lower CO_2 price could, e.g., stimulate coal power generation in countries not joining the coal phaseout (e.g., Poland) because of lower SRMC of production (Keles and Yilmaz, 2020).

Another climate policy that would interact with the EU ETS is the renewable portfolio standard (RPS). An RPS requires electricity suppliers to provide a specific share of their total electricity generation from renewable energy sources over a determined timeframe (Barbose et al., 2015). As with the coal phaseout, the effects of interaction with the EU ETS are ambiguous. Policies stimulating renewables suppress the CO_2 price by increasing the quantity of carbon-free production, which may result in higher shares of coal power production (Böhringer and Rosendahl, 2010). An RPS affects the market values of different technologies because it functions as a subsidy to renewables and a tax to non-renewable producers. This will also impact non-renewable low-carbon technologies such as nuclear power if not politically addressed when implementing the RPS.

2.4. The value of flexibility

In power systems, supply and demand need to be spatially and temporally balanced. In this thesis, the term flexibility is defined in a similar way as by Papaefthymiou et al. (2014) and refers to the ability of the power system to cost-effectively adapt supply and demand, ensuring a balanced power system across all relevant timescales. The value of flexibility in this thesis is measured as the contribution to reducing system costs. The investigated flexibility options are on the supply side, the demand side, storage, and transmission (Cruz et al., 2018).

Supply-side flexibility refers to the ability of power producers to adapt their output to changing load. Supply-side flexibility in the Nordics comes from adjustable thermal power plants and hydropower with reservoirs. With large parts of fossil-fueled thermal electricity production being replaced by VRE, remaining producers must provide more flexibility. Baseload generators have to reduce full load hours, reduce efficiency, and increase operational, maintenance, and fuel costs (de Mars et al., 2020). Flexible mid-merit or peak load power plants and hydropower with reservoirs are well suited for providing flexibility in a market with high shares of VRE. They may increase their future market values significantly if power price variability increases. On the path to net-zero, hydropower with reservoirs possesses special significance. It can reduce the need for fossil-fueled peak power capacity and promotes the efficient utilization of VRE resources (Dimanchev et al., 2021).

Demand side flexibility can be a cost-effective way to improve power system flexibility (Lund et al., 2015). Demand loads can either be shed (reduced) or shifted in time, coordinated by price signals. Besides balancing supply and demand, demand side management can reduce peak load and thus reduce the required backup capacity (Gelazanskas and Gamage, 2014; Strbac, 2008), increase full load hours for less expensive baseload generation (Davito et al., 2010), and shift market power to electricity consumers (Mathieu et al., 2013). The availability of flexible demand differs significantly between regions and time periods. For example, flexibility potentials from air conditioning in Spain are highest in the summer months and lower in other parts of the year. In Norway, however, these potentials from air conditioning are low year around in Norway. Demand side flexibility can be provided by households, the tertiary sector, and industry. In the Nordics, flexibility in hot water and space heating in households and the tertiary sector is high due to the widespread utilization of electric heating. These applications allow loads to be shifted in a limited timeframe without loss of utility. Additionally, industry demands in Norway, Sweden, and Finland are high and can provide further demand-side flexibility. It is estimated that 15-29% of peak load could be reduced by demand side management (Söder et al., 2018). While technical potentials are high, additional economic incentives and new market mechanisms may be needed to increase short-term price elasticity (Lund et al., 2015). This thesis includes an analysis of demand-side management revenues. The revenue is calculated as the arbitrage between hourly wholesale electricity prices at scheduled and realized load, respectively. Additionally, system benefits are analyzed. Here load shedding, associated with a high cost (due to the value of lost load), may be beneficial.

Energy storage is a flexibility option interacting with both the supply and demand sides by shifting supply and demand to temporally match. Energy storage can provide flexibility across different time frames and energy carriers. Its interaction with the power sector is characterized technically by roundtrip efficiencies, storage capacities, and charge and discharge capacities (Lund et al., 2015). From an economic perspective, investment costs, economic lifetime, and regional power price variability (both diurnal and seasonal), in conjunction with technical characteristics of the energy storage, determine the profitability. Energy storages can also provide system benefits by helping integrate higher shares of VRE, increasing market values for VRE, increasing full load hours for baseload generation, and deferring capacity and transmission investments (Strbac et al., 2017). The climate benefits of energy storage, however, may be equivocal. While energy storages allow for higher shares of VRE in the energy mix, cheap emission intense baseload generation from coal may increase due to a reduction in price periods with extreme prices (Nyamdash et al., 2010). The value of energy storage is analyzed in a similar manner as load shifting in this thesis, from an arbitrage and a system perspective.

Spatial interconnection provides flexibility to the system by balancing spatial differences in supply and demand. Intermittent generation and resource locations away from load centers will increase congestion, which can be addressed by reinforcement of the transmission grid. Transmission reinforcement can reduce the curtailment of VRE and utilize existing storage and generation capacities more efficiently (Allard et al., 2020). From a system perspective, system efficiency increases, and price variability decreases with increased transmission investment. However, regional power markets may be affected differently. As an example, from the European perspective, regions with abundant flexible resources and low-cost electricity, such as Norway, may see increased price variability and higher average power prices with higher transmission capacities to less flexible regions. Thus, certain stakeholders in energy systems may benefit from interconnection while others will be negatively impacted, leading to conflicting interests. The value of spatial interconnection in this thesis is analyzed from a system perspective meaning its contribution to decreasing system costs is in focus.

3. Methods

The techno-economic energy system model Balmorel is used in all papers that are included in this thesis. In order to answer the individual, paper-specific research questions, Balmorel was modified and/or combined with other methods. A demand response add-on was developed (paper 1), Balmorel was soft linked with a general equilibrium model (paper 3), and an expert survey was coupled with Balmorel in a probabilistic approach (paper 4).

3.1. Choice of the Balmorel energy system model

Balmorel was chosen over other energy system models because it fulfilled several important criteria for conducting the studies of this thesis:

1. Balmorel has a detailed representation of the Nordic power and district heating sector. It displays market dynamics in the power system with operational and investment insights and high spatial, temporal, and technical resolution. Representing the district heating sector distinguishes it from several other models. The inclusion of this sector is important because district heating plays a significant role in the Nordic energy system, particularly in Denmark, Sweden, and Finland. To decarbonize district heating, further integration with the power sector is a solution by utilizing electric boilers and heat pumps which is well captured in Balmorel.
2. The spatial resolution of Balmorel specifically suits the Nordic region, where power market regions are modeled in accordance with Nordpool bidding zones while district heating is defined on an even more detailed area level, allowing the representation of distinct district heating systems. A detailed spatial resolution is important for analyzing the role of transmission, power prices in Nordpool market areas, capacity investments, geographically dependent market values for power-producing technologies, and the economic value of flexibility options with different availability in different regions. Models including larger regions, e.g., all EU countries, oftentimes model countries as one node not accounting for actual market dynamics.
3. Balmorel has a fine temporal resolution which is essential for analyzing the market values of different technologies and the economic impact of flexibility options. In this thesis, the resolution was chosen to be hourly in order to

accurately capture production profiles from VRE and the variability in power prices. Since the focus of the analysis is not on balancing markets, forecasting errors, or frequency control, an hourly resolution was deemed sufficient.

4. A major advantage of Bamorel over several other models, like TIMES, is that it is open source. This ensures transparency in the spirit of "open science" concerning model assumptions and background data and allows further development and manipulation of the model code as required. Additionally, model code and assumptions can be freely shared with stakeholders.
5. Lastly, an advantage of Balmorel is that it is well-calibrated and tested for the Nordics in numerous Nordic studies that have undergone a rigorous peer review process c.f., Wiese et al. (2018) for applications.

3.2.The Balmorel model

The Balmorel energy system model is a bottom-up partial equilibrium energy system optimization model focusing on the electricity and district heating sector from a societal perspective. The model takes a system approach for minimizing total system costs. Assuming perfect markets, Balmorel optimizes operation and capacity investments in the electricity and district heat systems under given constraints. Outputs for the conducted studies were regional electricity prices, technology-specific regional production levels, transmission levels, new optimal capacity additions, and system costs. Balmorel's spatial and temporal resolution each have three hierarchical levels. The spatial setup covers countries that can consist of several regions, which themselves can consist of several areas. The temporal level covers years, weeks, and hours. Countries represented in this thesis' Balmorel studies are the Nordic and Baltic countries, Poland, Germany, Belgium, the Netherlands, France, and the UK. Policy and economic data are defined at the country level. The Nordic countries consist of several regions which correspond to the Nord Pool bidding areas. On the regional level, transmission capacities and electricity demand are defined. Regions can consist of several areas where, e.g., local resource characteristics and generation units are defined. The hierarchical temporal resolution allows the user to choose certain years, weeks, and hours to be included, which reduces the model size where needed, while still capturing seasonal and hourly variations in supply and demand. Balmorel is an open-source model written in the General Algebraic Modelling System (GAMS) language. The source code has been provided on its homepage since 2001, with the ISC license assigned in 2017. The model and current updates and developments, including input data, are available on a GitHub repository (Balmorel Community). Wiese et al. (2018) provide a detailed introduction to the model.

A simplified schematic representation of the Balmorel energy system model is shown in Figure 9. Balmorel is designed to serve an exogenously defined district heat and electricity demand by utilizing, converting, and storing energy from primary energy sources. Primary energy sources are fossil fuels, nuclear, biomass, municipal waste, solar, geothermal, wind, and hydro. These can either produce heat directly (solar thermal), electricity directly (wind, solar PV, and hydropower), or are utilized as primary fuel sources that need to be converted to heat or electricity. Conversion occurs in condensing power plants, combined heat and power plants, and district heating boilers. Additionally, electricity can serve the heat demand via conversion to heat in heat pumps and boilers. Available heat may be stored and released from heat storage. Electricity supply and demand are balanced with the help of dispatchable generation, imports and exports, electricity storage, and demand side management.

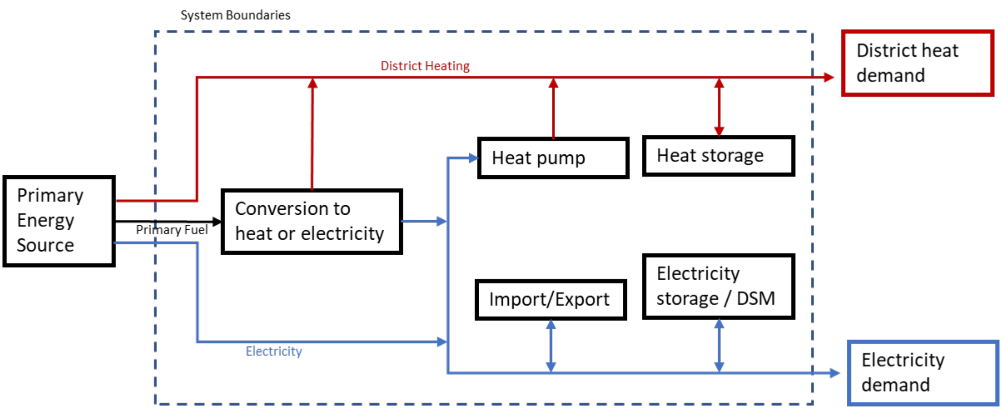

Figure 9. Schematic representation of the Balmorel core structure.

3.3.Method application

The research papers of this thesis apply methods to analyze the three interlinked dimensions suggested by Cherp et al. (2018) for analyzing energy transitions: The techno-economic, socio-technical, and political dimensions. The thesis focuses on the economic impacts on stakeholders in the Nordic energy system in light of the energy transition, using the techno-economic Balmorel model as the core method.

Paper 1: The role of demand response in the future renewable northern European energy system

In this paper, the Balmorel energy system model is extended by a demand response add-on, a modular extension of the core model. The added functionality enables a detailed representation of demand response from several household, tertiary sector, and industry applications with a high temporal and spatial resolution. Two types of demand response are analyzed, load shedding and load shifting. Load shedding refers to a reduction in load, typically associated with high costs, while load shifting moves load to a different point in time. An emphasis was laid on capturing the temporal characteristics of demand response by modeling the load-dependent availability of demand response and the effect of limited shifting times. Additionally, the spatial dependence of the demand response potential is modeled for the Balmorel model regions, and assumptions for the adoption rates of demand response categories are quantified. Here, additional assumptions based on Lund (2006) were needed to estimate the future adoption rates of demand response categories in different sectors. Adoption rates and technology diffusion reflect the socio-technical dimension in the Balmorel model. My contributions lie primarily in the conceptualization of the study, the application of the demand response add-on, the analysis, and the writing of the paper.

Paper 2: The economic competitiveness of flexibility options: A model study of the European energy transition

In addition to the techno-economic dimension, the political dimension plays a more prominent role in this paper, focusing on different climate targets (CO_2 emission restriction level). The paper is a pure Balmorel model study with an innovative approach. It analyzes flexibility along two dimensions. The first dimension is the changing of climate targets for the target year 2030 to analyze how they will affect the value of flexibility options. For this, exogenously determined CO_2 emission caps, reducing emissions compared to 2020 by at least 0%, 60%, 70, 80%, 90%, and 95% are analyzed. This approach ensures robustness and relevance of the results in an environment where tightening of climate targets is a common occurrence. The second dimension is competition and synergies between flexibility options. It is analyzed by restricting one flexibility option at a time and then comparing results for the remaining flexibility options to a baseline. Flexibility analyzed is storage, transmission, and supply- and demand-side flexibility, and its value is analyzed from a system perspective, meaning its impact on system costs. Additionally, revenues and profits for flexibility providers are analyzed, specifically focusing on the competition with other flexibility options. Balmorel is well suited for this study because it has a detailed techno-economic representation of the analyzed flexibility options, allows one to assess them jointly, and is well-calibrated for the analyzed model region. 42 model runs are conducted to analyze 7 different flexibility scenarios at 6 climate targets. My contributions to this paper are the conceptualization of the study, applying the Balmorel model, performing the analysis, and writing the paper.

Paper 3: Impacts of Green Deal policies on the Nordic power market

This paper soft-links a computable general equilibrium (CGE) model for Europe with the computable partial equilibrium model Balmorel. The goal of this approach is to better represent the impacts of the European Green Deal on the Nordic power sector. Here, both the political and techno-economic dimensions are in focus. Due to the system boundaries of the Balmorel model (c.f. Figure 9), however, the effect of the updated climate ambitions on the EU ETS cannot be endogenously determined. The CGE model's strength is that it models all EU countries and all of the CO_2 price relevant sectors treating all energy-intense and trade-exposed industries covered by the EU ETS separately. It furthermore stands out for its detailed bottom-up representation of electricity generation. The CGE model does not, however, provide a detailed representation of the Nordic power and heat system with a high geographical and temporal resolution. Combining the two models is thus the method of choice to alleviate the shortcoming of each individual model. Balmorel's advantages for modeling the Nordic electricity and district heat sector are described in section 3.1. Because the models have different spatial and temporal setups, and different aggregation levels for sectoral heat and electricity demands, they are first calibrated and then linked through relative changes vis-à-vis historical levels. Prices and consumption are anchored at historic 2015 levels. Changes from these historical levels are expressed as percentage changes, as absolute values may differ between the models. Endogenous outputs from the CGE model fed into Balmorel are fuel prices, CO_2 emission prices, and demands for electricity and heat. Outputs from the Balmorel model are operational data, producer revenues, CO_2 emissions, capacity investments, and trade. The linked models are utilized to run several scenarios addressing different climate policies and their interaction with the EU ETS. A visual representation of the workflow using the two models is represented in Figure 10.

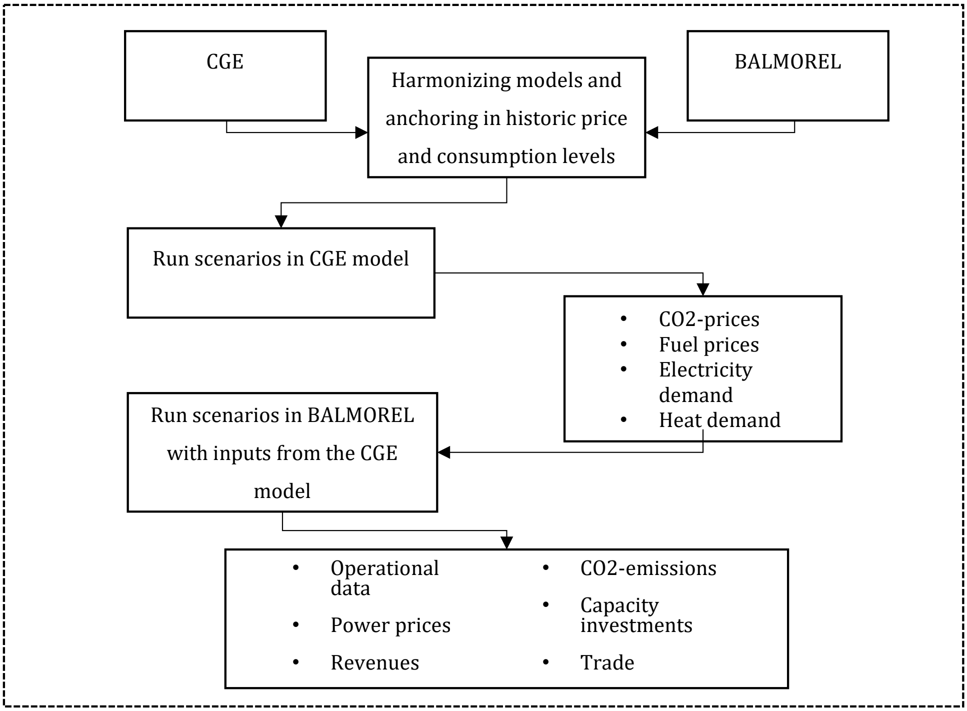

Figure 10. Method of applying the CGE and Balmorel model.

My contributions to this paper are the conceptualization of the study, working with soft-linking the models, applying the Balmorel model, performing the analysis, and writing the paper. The application of the CGE model was performed by Christoph Boehringer and Knut Einar Rosendahl.

Paper 4: Prospects for the 2040 Norwegian electricity system: Expert views in a probabilistic modeling approach

This study combines an expert survey with energy system modeling in the Balmorel model. The idea of combining a survey with energy system modeling is not new and allows an integrated approach for analyzing technical, economic, and social dimensions of energy system transformations, c.f., Heinrichs et al. (2017). However, to the best of my knowledge, combining an expert survey that derives participants' views of future supply and demand developments with probabilistic modeling for analyzing potential outcomes of these views is a novel approach. More precisely the study derives probability distributions for prices, market values, and value factors (based on expert opinions). The chosen approach increases the robustness of the results over scenario approaches based on surveys because it accounts for uncertainties related to the dispersion of respondents' opinions and avoids author bias which is common in scenario development. The workflow of the study is presented in Figure 11 and is explained in the following.

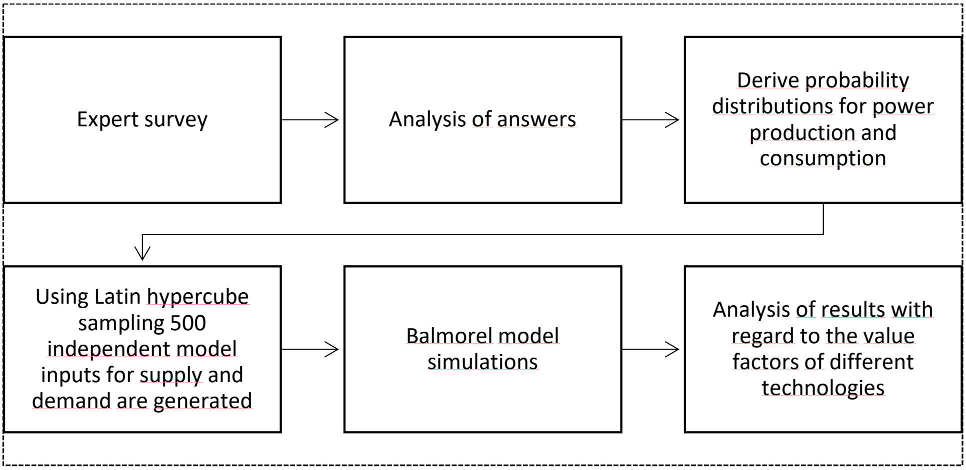

Figure 11. Workflow of combining the expert survey with probabilistic modeling

The survey was sent out to 496 experts. Of these, 24% or 119 experts responded. The expert selection criteria were based on having an occupation in an energy-related job, an understanding of Norwegian society, and work experience. The survey was sent out to contacts in email lists, coming from professors at the Norwegian University of Life Sciences (NMBU) and project partners. The expert survey derives probability distributions from survey participants' projections of the expected production and consumption of electricity in Norway for the year 2040. The responses for the future production and consumption levels are implicitly including probable policy trends and technology adoption of, e.g., hydrogen electrolysis and offshore wind. Additionally, a probability distribution for future Norwegian electricity demand was postulated, also based on the survey results. All probability distributions were treated as independent from one another. Then model inputs were generated using Latin hypercube sampling, based on the probability distributions. Latin hypercube sampling was chosen as it reduces the model runs needed over random sampling to generate accurate results. It divides cumulative density functions into equal partitions and then chooses random data points in each partition, thus reflecting the true underlying distribution well (Olsson et al., 2003). 500 independent model runs were performed with various exogenously fixed supply and demand inputs for Norway. However, system operation and capacity investments were endogenously optimized in surrounding model regions. The outcomes from the model runs are probability density functions for prices and market values. An analysis of the impact of the electricity balance on value factors was performed. My contributions to this paper are the conceptualization of the study, the survey, applying the Balmorel model, performing the analysis, and writing the paper.

4. Results

4.1. Demand response has substantial energy system benefits, but consumers' savings are limited

In this thesis, demand response is defined as the deviation from the regular load by an end user, coordinated by price signals (Albadi and El-Saadany, 2008). Paper 1 first assesses the load-dependent potential for different demand response applications in the Nordics up to the year 2050. After implementing a demand response add-on in the energy system model Balmorel, the effect of demand response on peak load, generation capacity investments, and economic benefits are analyzed.

A high demand response potential is found in Norway, Sweden, and Finland, where electric space heating in households and the tertiary sector accounts for a major share of flexible loads. Denmark has a less flexible system due to more VRE power generation and less available flexibility from demand response due to less electric heating in households and the tertiary sector. As a consequence, in the model results, more loads are shifted in Norway, Sweden, and Finland, with market values between 1.2 and 3.6 EUR/MWh. Higher market values for load shifting are, however, found in Denmark, with up to 8.1 EUR/MWh for load shifting in households. Revenues are calculated as the arbitrage between wholesale power prices of scheduled load and realized load. In this study, total revenues for demand response applications are shown to significantly increase across the Nordics towards 2050 as the adoption of demand response enabling technologies increases. Sweden has the highest projected demand response revenues in 2030 of 36 MEUR compared to 34 MEUR in Norway, 17 MEUR in Finland, and 15 MEUR in Denmark. In 2050 demand response revenues are expected to grow strongly in the household and tertiary sectors, except in Denmark. In 2050 demand response revenues are 93 MEUR in Sweden, 113 MEUR in Norway, 64 MEUR in Finland, and 16 MEUR in Denmark. Despite the growth in revenues for demand response applications towards 2050, the arbitrage revenues are rather small. Instead, the system benefits are shown to be more important. A reduction of up to 18.6% of peak load in 2050, up from 5.3% in 2030, is possible. This would largely be achieved by load shifting from space and water heating (10.9% and 4.7%, respectively) in household and tertiary sectors. As a result, a slight reduction in investments in peak power plants and battery storage can be achieved. From this study, it can be concluded that demand response may lead to less power price variability, increased market values for baseload generation, decreased market values for peak power plants, increased system efficiency, and deferred capacity investments.

4.2. Ambitious climate targets increase the value of flexibility

Climate targets have been subject to change, with the EU recently increasing its 2030 GHG emission reduction target to 55%. The power sector, which is easier to decarbonize than several other sectors, will have to reduce GHG emissions to a greater extent to reach this target. More VRE generation is required, and it will increase the need for flexibility to balance the power system efficiently. Paper 2 looks at how flexibility options affect system costs in the power and district heat sector at different climate targets, and at the competition and synergies between flexibility options for 2030. The geographical scope is limited to the countries modeled in Balmorel described in section 3.2.

System costs increase exponentially with more ambitious climate targets for the analyzed year 2030. There are two main reasons for this: First, generation capacity investments are required in order to provide for sufficient renewable power and heat generation to replace fossil fuels. Second, investments into flexibility options are required to balance the system when shares of intermittent power generation increase. Flexibility avoids the necessity for even higher VRE capacity investments required in order to serve demand 24 hours a day, 365 days a year, and helps avoid VRE curtailment. If 2030 climate targets are moderate or low (80% emission reduction or less in the power sector), short-term flexibility from load shifting via demand side management is the most important flexibility measure for keeping systems costs low. With ambitious climate targets (above 80% reduction), spatial and sectoral flexibility becomes more important for limiting the total system costs. In these scenarios, transmission investment and sector coupling with the district heating system are most beneficial in cost-effectively integrating higher shares of VRE into the European energy system.

Findings show that increasing climate ambitions will increase the market values of production for flexible producers. In the Nordics, particularly hydropower revenues would increase with more ambitious climate targets because of the greater power price variability and the decreased competition from fossil-fueled thermal power plants in high price periods. In the European market, natural gas market values will benefit from increasing the climate target for 2030 up to the 95% reduction model run. Aside from producer flexibility, other flexibility dimensions are also affected by climate targets. While PtH and heat storages benefit increasingly from more ambitious climate targets and more variable prices, demand side management profits are less affected by the climate target because of limited shifting times and shifting capacities. Battery storage only benefits in deep decarbonization scenarios because of high investment costs, which are not optimal in the system cost-minimizing solution with climate targets below 90% emission reduction for 2030.

Competitions and synergies exist between flexibility options, and they affect each other's market values. Transmission provides spatial flexibility by connecting load centers with electricity producers. Flexibility from transmission investments, e.g., has synergies with Nordic hydropower, allowing it to serve a larger region and help balance supply and demand. With more ambitious climate targets, the synergies increase as flexibility becomes a more valuable feature in the power system. With no fixed climate target in 2030, endogenous transmission investments would increase hydropower profits by only 13% when compared to the baseline scenario with the same climate target, which includes only planned transmission by the "Ten Year Network Development Plan" (ENTSO-E, 2018). However, with a 95% reduction climate target, hydropower profits increase by 27%. Transmission investment is, however, in competition with natural gas and biomass electricity generation because it reduces overall price variability in the European energy system and intensifies competition for these producers with other producers from a larger area. Demand side management is competing with battery storage in deep decarbonization scenarios as both provide the ability to shift loads temporally. Since demand side management typically has shorter shifting times, it benefits from no roundtrip efficiency losses and has low investment costs compared to battery storage. Demand side management's impacts on the power system are limited, however, by available capacity in 2030 as the adoption is ongoing, and smart charging capacity will increase more in later years with the assumed diffusion of electric vehicles in the transport sector. By reducing price peaks, demand-side management also decreases profits for hydropower producers. The impact is less strong in deep decarbonization scenarios where there is more need for long-term flexibility and demand side management operates at its modeled capacity limit. Sector coupling between the electricity and the district heating sectors decreases revenues for natural gas and biomass but mainly in the district heating sector. Demand side management and battery storage, which benefit from short-term price variability, compete with flexibility from sector coupling with the district heating sector.

4.3. The European Green Deal increases revenues for renewable Nordic power producers, but increases are dependent on the policy mix

The European Green Deal updated GHG emission reduction targets for 2030 from 40% to 55%. Paper 3 assesses the impact of the European Green Deal, achieved through the EU ETS, and of further conceivable climate policies on the Nordic power and district heating system in 2030. Such further policies include a European coal phaseout in most EU member states, a renewable portfolio standard (RPS) focusing on a mandatory share of renewables in power generation, and increased electrification of further sectors leading to higher electricity demand. The method used combines a general equilibrium model to assess the impacts of the emission reduction targets on the EU ETS, with a partial equilibrium model for a detailed operational analysis of the Nordic power and district heating sector.

Model results show that an increased EU GHG emission reduction target from 40% (BASE scenario) to 55% (PARIS+ scenario) will lead to an increase in the CO_2 price if the ETS is the main policy measure (+35 EUR/tCO_2). This study estimates that the share of carbon permits used by the power sector will decrease from 46% to 35%, showing that reducing emissions in the power sector is more cost-effective than a reduction in other sectors included in the EU ETS. In the Nordics, the increased price of carbon permits in 2030 will not significantly affect the generation mix of power production since production is largely assumed to be from renewables and nuclear by this time. The higher CO_2 price in the PARIS+ scenario does, however, spur a shift in the Nordic district heating mix, replacing fossil fuels with electricity through PtH technologies combined with heat storage. In contrast, a shift from coal and natural gas to VRE generation is observed in the model results for central European countries and the UK. Economically, there is a positive impact of increased emission reduction targets for Nordic power producers. The difference in revenues and market values between the PARIS+ and the BASE scenario is displayed in Table 2. In absolute terms, flexible hydropower benefits the most, and market values increase by 3.1 EUR/MWh in our study results. Nordic nuclear power producers (+3.5 EUR/MWh), wind power producers (+2.4 EUR/MWh), biomass (+2.1 EUR/MWh), and solar PV (+0.1 EUR/MWh) also have an increase in their market values and their total revenues, due to higher power prices (mean 35 EUR/MWh compared to mean 32 EUR/MWh). Nordic natural gas production increases revenues in PARIS+ by 53 MEUR and the market value by 17.1 EUR/MWh because of its ability to produce at peak prices. The revenue increases despite having a low share of the Nordic power generation mix and decreasing production in PARIS+ by 2 TWh.

Table 2. The difference in revenues and market values between the PARIS+ and the BASE scenario.

	Change in revenue (Million EUR)	Change in market value (EUR/MWh)
Biomass	79.3	2.1
Natural Gas	52.7	17.2
Other Fossil	-27.5	28.2
Municipal Waste	36.4	4.9
Nuclear	289.8	3.5
Solar PV	50.8	0.1
Hydropower	717.2	3.1
Wind	357.1	2.4

History has shown that a tightening of the EU ETS is not likely to be the only climate policy the EU or member states will implement to achieve the targets set by the European Green Deal. Former additional policies include pledges to phase out coal or to implement feed-in tariffs for renewables. In combination with the EU ETS, EU and national policies will have different consequences from those shown in the results of the PARIS+ scenario, where the EU ETS is the stand-alone measure to reduce emissions. This study finds that additional policies may significantly affect Nordic power prices, the generation mix, and thus the market values and revenues of Nordic producers. The analysis of a European coal phaseout scenario as a policy measure combined with the EU ETS was performed without the cancellation of carbon permits. Poland, Romania, and Bulgaria were excluded from the coal phaseout analysis because of observed political resistance to the idea. The results show that the coal phaseout in the remaining countries puts downward pressure on the price of carbon permits, reducing them by 16 EUR/tCO_2 as compared to the PARIS+ scenario. This additional policy only slightly affects the power generation mix in the Nordics, lowering solar PV and biomass generation and increasing generation from natural gas. In contrast, the European power generation mix changes more strongly. Here, 86% of coal power generation is substituted by natural gas. Because more flexible production from natural gas is available in Europe, power price volatility decreases there and in the Nordics. In the cost-minimizing solution, less VRE capacity is optimal, and average power prices are slightly reduced. Lower market values and lower average prices lead to decreased revenues for technologies that do not increase their output. In the coal phaseout scenario, compared to the PARIS+ scenario, the market value is reduced for nuclear power by 0.8 EUR/MWh, hydropower by 0.2 EUR/MWh, and wind power by 0.6 EUR/MWh. Market values remained the same for solar PV. The market value for natural gas decreased by 6.5 EUR/MWh, but revenues increased due to higher generation.

The second analysis was performed to assess the effects of a renewable portfolio standard (RPS) in conjunction with the EU ETS to achieve the updated EU emission targets. The RPS acts as a subsidy to renewables and a tax on non-renewable generation to achieve a targeted renewable share in electricity production. A renewable share in power generation of 11% higher than in the PARIS+ scenario was analyzed. This corresponded to 75% renewable power generation in the EU in 2030. The results show that the analyzed RPS affects the Nordic energy mix by increasing solar PV and wind power production. The electricity demand also increases in the Nordics, largely due to increased PtH for district heating which, combined with heat storage, utilizes low-cost electricity generation from VRE. The analyzed RPS leads to lower average electricity prices because of more production from VRE with its low SRMC. Price volatility, however, is higher than that in the PARIS+ scenario. The model results show that the RPS increases the market value of Nordic power production from biomass by 14.1 EUR/MWh, hydropower by 3.9 EUR/MWh, wind power by 0.6 EUR/MWh, and solar PV by 0.5 EUR/MWh. Wind power and solar PV increase production, and consequently, these technologies and hydropower benefit most in absolute terms. Natural gas and nuclear generation are penalized by the EU ETS and the RPS. This, in combination with lower average electricity prices, leads to a decrease in market values for natural gas by 6.5 EUR/MWh and nuclear by 39 EUR/MWh, and negatively affects their revenues in the model simulations.

Despite an expected increase in energy efficiency, European and Nordic power consumption is projected to increase significantly by 2030. One of several reasons for the increasing electricity demand is policies directed at direct electrification of further sectors, such as the transport sector. An analysis of the EU ETS in conjunction with a higher electricity demand of 15% compared to the PARIS+ scenario is performed. The higher demand stimulates renewable and non-renewable power generation, leading to a higher CO_2 price in the EU ETS of 19 EUR/tCO_2 (under the assumption that electrification does not reduce emissions in sectors covered by the EU ETS). In the Nordics, higher electricity demand would lead to higher wind power and solar PV investments and generation. Compared to the PARIS+ scenario, higher production and higher market values of 3.2 EUR/MWh for wind and 0.1 EUR/MWh for solar PV lead to increased revenues of 50% and 66%, respectively. Despite equal total production, revenues of Nordic hydropower producers (+22%) and nuclear power (+17%) increase significantly because of higher market values of 8.7 EUR/MWh and 6.3 EUR/MWh, respectively. In this scenario, natural gas generation increases in the Nordics and has a higher market value of 11.4 EUR/MWh compared to the PARIS+ scenario, leading to a 213% increase in revenues.

4.4. Market values for Norwegian power producers are dependent on the electricity balance and technology characteristics

Future demand and supply development is uncertain and dependent on techno-economic, socio-economic, and political developments. The electricity balance is a key driver of the future electricity price, affecting market values and value factors for power-producing technologies. A negative exponential relationship between Norway's electricity balance and mean electricity prices is found in Paper 4. In the paper, we use a combined approach to analyze market values and value factors for Norwegian power producers in the future 2040 Norwegian energy system. First, an expert survey was conducted to determine supply and demand distributions for Norway in 2040. Then Monte Carlo simulations in Balmorel based on these supply and demand distributions provide insights into the implications of the experts' views with regard to market values and value factors derived from 500 independent model runs. The results from the expert survey show that estimates for 2040, in comparison with 2020 supply and demand, display an increase in renewable power generation by 40 TWh (median) and an increase in electricity demand by 34 TWh (median) in Norway. Uncertainty is high, though, and expert opinions vary between 150 and 255 TWh for supply, and 137 and 250 TWh for demand. The largest increase in supply will most likely come from offshore wind. However, here, the dispersion in the survey results is highest, indicating very high uncertainty as to the level of future offshore wind production in Norway. Demand is likely to increase because of new and existing industries, the electrification of transport, and hydrogen electrolysis. Electricity demand used for hydrogen electrolysis is found to be particularly uncertain.

Model simulation results based on the 500 model runs with different supply and demand distributions for Norway show that the mean power price in 2040 ranges from 10-85 EUR/MWh. However, because of the different temporal supply profiles of the analyzed VRE technologies, the mean annual price only gives limited insight into what market values the technologies have. All technologies have higher market values the more negative the electricity balance is (net imports to Norway). However, changes in the competitiveness of technologies, measured by the value factor, are asymmetric. In 2040, dispatchable hydropower has the highest value factors (mean across model runs is 1.58) due to its ability to increase production in market situations with high prices. Despite the decreasing market value, if Norway has an increasingly positive electricity balance, the value factor increases. This shows that market values of hydropower with reservoirs are less susceptible to market conditions where net exports increase than those of the average producer in 2040. The situation is reversed for VRE producers. The results show that the competitiveness of VRE is reduced when the electricity balance becomes more positive. We find that the merit order effect negatively affects the market values of VRE producers. The negative relationship between VRE production and market values is strongest for offshore and onshore wind indicating a stronger impact of the merit order effect on these technologies than on, e.g., solar PV. Nonetheless, the correlation effect for VRE (correlation between production and demand) results in onshore- and offshore wind having higher value factors in the model results (mean of 1.05 and 0.92, respectively) than hydro run-of-river and solar PV (mean of 0.55 and 0.53). While wind power production is correlated with demand in Norway (c.f. section 2.2), hydro run-of-river and solar PV have unfavorable resource characteristics. Hydro run-of-river produces most during the spring flood and in autumn when precipitation is high. In the high-price winter period, precipitation falls as snow in higher elevations and is not available for hydro run-of-river power production. Likewise, solar PV production in Norway is low in winter due to lower irradiation.

An overview of the market values for the individual technologies, as derived from the probability density functions of the 500 model runs, is shown in Table 3. The observed market values in the analyzed BASE scenario are for the 1st and 3rd quartile of prices between 48-64 EUR/MWh for hydro with reservoir, 28-50 EUR/MWh for onshore wind, 24-41 EUR/MWh for offshore wind, 15-24 EUR/MWh for hydro run-of-river, and 14-21 EUR/MWh for solar PV. The BASE scenario assumes SRMC of 100 EUR/MWh for a 2040 large-scale condensing gas power plant.

Table 3. Market values for individual technologies from the probability density functions in the BASE scenario.

Quantile	Hydro reservoir (EUR/MWh)	Hydro run-of-river (EUR/MWh)	Solar PV (EUR/MWh)	Wind onshore (EUR/MWh)	Wind offshore (EUR/MWh)
1st quartile	48	15	14	28	24
Median	55	19	17	38	30
3rd quartile	64	24	21	50	41

Sensitivity runs were performed with higher and lower gas and CO_2 prices and show that the shape of the probability density functions is more sensitive for lower gas and CO_2 prices than for higher prices. If the SRMC of gas production were to increase by 50% in Europe, then the 2040 market values of technologies would only be affected upwards in hours where natural gas is price setting. However, the direction of the insight for the different technologies remains consistent with previous findings. If, however, the SRMC of gas production decreases by 50%, the probability density functions of the market values of all producers across the 500 independent model runs would be closer together. More gas and less VRE generation capacity than in the BASE scenario would be optimal in the European energy system, also leading to fewer low and high price periods in Norway. This would positively affect technologies with low market values and negatively affect technologies with high market values compared to the BASE scenario.

5. Discussion

5.1. Contributions and implications of results

This thesis provides new insight into the development of Nordic market values for power-producing technologies and flexibility options under different European climate and policy pathways towards the year 2050. Together with a detailed analysis of Nordic power generation, conclusions regarding economic impacts are drawn. The results show ambiguous effects of the European energy transition, in dependence on the climate targets, policy directions, market area, and technologies, where some Nordic stakeholders will benefit, and others will face challenges. Additionally, methodological contributions with regard to paper 4 were made.

This thesis finds demand response from applications in households, industry, and tertiary sectors to be well suited for providing short-term flexibility in the Nordics and thereby reducing peak load, system costs, and defer capacity investments. These results are in line with findings from other regions such as the UK (Li and Pye, 2018). The findings of this thesis, however, expand the understanding of demand response for the Nordics. Regions with high renewable flexibility from hydropower and biomass electricity generation (Norway, Sweden, and Finland) also have high technical potentials for demand response. However, the analyzed applications show that these have relatively low market values. Contrary to this, Denmark, having less power system flexibility, has low technical potentials for demand response applications and higher market values. The low market values for demand response in the Nordics (excluding Denmark) highlight a potential pitfall in the adoption of demand response. While system benefits are substantial, individual benefits for participating in demand response in household and tertiary sectors are limited, possibly leading to lower adoption rates. Besides the prerequisite of real-time retail price to provide price signals for demand response, subsidies may be needed to guarantee optimal participation. Similar findings led Voulis et al. (2019) to recommend considering incentivizing demand response financially within the European Energy Tax Framework. Another new finding in this thesis is that demand response makes the system operate more efficiently, irrespective of the future climate target. This, coupled with low investment costs for participation in many load shifting applications, makes demand response a no-regret investment option from a societal perspective. Thus, it seems reasonable that demand response should be incentivized if adoption rates are low.

This thesis finds that dispatchable Nordic hydropower is likely to be one of the largest beneficiaries of the European climate ambition and also contributes to lower societal costs. Previous studies come to similar conclusions by showing that market values for flexible hydropower increase with more VRE generation (Hirth, 2016). However, transmission investment is important to unleash the full potential of Nordic hydropower. This thesis demonstrates that market values for dispatchable hydropower show synergies with transmission expansion. In addition, it increases our understanding of the topic by specifically showing that synergies increase with more ambitious climate targets. These synergies are favorable from a producer, grid owner, and societal perspective in the Nordics. However, the distribution of the economic surplus may shift away from the Nordic consumer who is confronted with higher power prices and more price volatility. This causes concern for the social acceptability of new cross-border transmission lines. Monitoring this development and assessing the need for redistribution of social welfare gains may increase the acceptability of the optimal solution from a societal perspective.

This thesis demonstrates the importance of the domestic electricity balance for electricity prices and market values of power producers in Norway. While a positive electricity balance is favorable from a consumer perspective, it comes with decreased market values for domestic power producers, especially VRE producers. Hirth (2016) shows that the benefit of hydropower for mitigating the merit order effect on wind power market values levels off with increasing wind power production. This thesis also finds wind power market values to be particularly sensitive to changes in the electricity balance. To achieve a highly positive electricity balance or increased production from exogenously determined generation technologies, subsidies may be required. Societal benefits related to the power sector, such as attracting industry through low electricity prices, need to be carefully weighed against the cost-effective operation and investments in the power system. From a European energy transition perspective, it is more efficient to take a Nordic or European planning approach that does not interfere with the markets based on individual nations' interests. If energy policies are designed to achieve national interests, it is important to craft them carefully to avoid unintended consequences such as welfare losses or delaying the European energy transition. Perino et al. (2019) conclude that individual jurisdiction climate policies need to be designed complementary to multi-jurisdiction policies for achieving the targets and objectives. In addition, overlapping policies can also exist in the same jurisdiction and may have wide-reaching consequences for stakeholders in the energy system, which is a topic discussed, e.g., by Böhringer et al. (2016) and Fankhauser et al. (2010). This thesis also shows ambiguous impacts on stakeholders in the energy system by overlapping climate policies related to the European Green Deal. Thus, it is important for climate policies to consider spatial, sectoral, and temporal aspects of regulations to avoid undesired consequences such as, e.g., carbon leakage.

The finding that European climate ambitions will result in more VRE generation and consequently require increased flexibility to operate the power system efficiently in a cost-minimizing approach is in line with previous publications (Akrami et al., 2019). This thesis elaborates further on this common understanding. It shows that short-term intra-daily flexibility from demand side management is more important for system efficiency with less ambitious climate targets to reduce system costs, while sectoral integration with the district heating system, spatial flexibility through new and reinforced transmission lines, and long-term flexibility from, e.g., seasonal storage is more important with more ambitious climate targets. While all flexibility options complement system efficiency, this finding allows policymakers to incentivize essential flexibility options at different stages along the path to net zero to reduce societal costs.

This thesis also contributes to the field of energy analysis by demonstrating an approach that is targeted at better representing possible outcomes of expert opinions in energy system models. Scenario development based on surveys is an approach that has been commonly used which has, however, shortcomings with regard to author bias and representing minority opinions. By using probabilistic modeling expert opinions are better represented, taking majority and minority opinions into account, avoiding author bias, and allowing us to graphically represent and interpret the results for all respondents. This approach additionally allows us to capture uncertainties such as societal barriers and support for future energy infrastructure (according to experts) while maintaining the benefits of a cost-minimizing energy system model.

5.2. Not covered impacts of the pandemic and the European gas shortage

The Nordic power market has been in turmoil since the Covid-19 pandemic. Record low electricity prices in 2020 quickly changed to record high prices in 2022 in the Nordics and across much of Europe. In early 2020 the Nordics experienced high precipitation, warm temperatures, and good wind conditions coupled with a downturn in demand due to the emerging pandemic. Contrary to this, in 2021, a cold winter, unfavorable wind conditions, lower precipitation, and increased global gas demand after the reopening of the economy resulted in surging commodity and power prices. In addition, CO_2 prices in the EU ETS increased significantly, partly due to the more ambitious climate targets, set in the European Green Deal. To add to the perfect storm, the Russian invasion of Ukraine in February 2022 and the following sanctions by much of "the West" led to a further constrained European gas supply. For these reasons, natural gas, other commodities, power prices, and power price volatility surged higher than even most sensitivity scenarios would have suggested. It is important to acknowledge potential changes to the model results discussed in this thesis induced by the recent political developments. However, it should also be emphasized that this thesis does not account for short-term disruptions in the power markets and takes a long-term perspective, allowing for infrastructure investments to balance the system.

The REpowerEU plan to reduce dependence on Russian fossil fuels and fast forward the energy transition may, e.g., lead to long-term price impacts for natural gas, which is considered a bridging technology towards net zero in this thesis. From today's perspective, the price assumptions for natural gas, coal, and carbon in the model runs used in this thesis are low. If updated, study results might indicate that the shift towards more VRE in the cost-minimizing solution would transpire more quickly. In fact, the EU currently assumes shares of VRE to rise faster than previously anticipated. The power demand will also be affected. On the demand side, there will be an increased need for electricity to reduce the dependence on Russian commodities through, e.g., direct electrification and hydrogen electrolysis (European Commission, 2022c). As a result of more VRE and an increased electricity demand, higher price variability can be expected, also in the Nordics. This may affect the results in this thesis regarding market values and amplify the trends observed. The merit order effect might negatively affect VRE market values, but hydrogen electrolysis and sectoral flexibility could provide a price floor, increasing market values in high output periods. It should also be noted that the energy crisis has sparked a renewed discussion on the use of nuclear power in many countries. In this thesis, new nuclear power capacity investment in the Nordics and much of Europe was restricted based on governmental plans and social sentiment at the time the studies were performed. New nuclear power plants could, however, provide valuable flexibility to the energy system. Nonetheless, concerns regarding radioactive waste, long time lags between planning and operation, and social opposition still remains.

5.3.Limitations and further research

Model simulations for assessing future development in the energy sector always include uncertainties regarding modeling assumptions and inputs. While sensitivity scenarios and Monte Carlo simulations have been used to address some of the input uncertainties, the studies conducted neglect the crucial influence of weather uncertainty. This thesis analyzes model simulations using data for a normal weather year (2012) with associated wind, solar, water inflow, and demand profiles. It does not consider changes due to climate change, extreme weather years, or sequential weather years, which, if additionally analyzed, could provide more robust policy recommendations. The correlation between cold temperatures, low wind speeds, low precipitation, and high demand in the Nordics and interconnected countries will stress the energy system more and more as wind shares increase in the power production mix and electric heating becomes more common. Zeyringer et al. (2018) show that energy system planning based on a single weather year can lead to operational inadequacy. Cronin et al. (2018) point out that producers and consumers will be strongly affected by future climate conditions with an increasing frequency and greater variability of extreme weather events. Craig et al. (2022) show a disconnect between energy system modeling and climate modeling. Better integrating energy system models with weather and climate models can be addressed by utilizing and developing weather and climate datasets for various meteorological conditions and future climate developments. The authors stress that a sequential approach, where outputs from climate models are utilized as inputs for energy system models, is not ideal. Instead, a transdisciplinary approach where output variables and spatio-temporal resolutions align is preferable. Based on these findings and the limitations in this thesis regarding weather uncertainty, an avenue to improve the Balmorel energy system model but also other models is to develop multiple weather years based on historical data but also on future estimations for the core model which would greatly improve the robustness of many model study results and open up opportunities for interesting new research utilizing these modeling frameworks.

Balmorel is a deterministic model that was run with perfect foresight for this thesis, potentially overestimating flexibility. Perfect foresight allows “too perfect production” from flexible producers, benefiting these. This is especially consequential for hydropower with reservoirs which has perfect foresight of water inflows and market conditions. In Balmorel, constraints are added that limit hydropower with reservoirs’ flexibility somewhat by limiting the weekly outflow from reservoirs. Limitations regarding the representation of hydropower with reservoirs are addressed in other studies using limited foresight modeling and stochastic modeling approaches. However, there are tradeoffs between computational complexity and run times (Stoll et al., 2017). Another possible improvement affecting mainly hydropower run-of-river could be the better representation of the cascading water availability in the Nordic hydropower system. Hydro run-of-river production, in this thesis, follows deterministic profiles. In reality, production profiles will be partially dependent on water released from upstream reservoirs.

Balmorel was applied with an hourly resolution. Thus, the interpretation of flexibility results was not investigated in more temporal detail, e.g., regarding the responsiveness of different technologies. Short-term flexibility for ancillary services and balancing as well as the market design, as suggested by Kara et al. (2022), were therefore not part of this analysis. Future research could involve coupling methods to also estimate revenues from outside the electricity spot market. This could greatly improve the understanding of the economic feasibility of investments into technologies from a producer or flexibility provider point of view. It also allows the understanding of possible needed subsidies to induce investments.

The increasing integration of further sectors with the power sector is increasingly being studied and will be of great importance for future model studies when analyzing topics such as power system flexibility. Currently, the main focus of Balmorel is on the power and district heating sector. Model advancements allow the assessment of further sectors, such as individual heating (Chen et al., 2021b), renewable gas (Jensen et al., 2020), and private transport (Gunkel et al., 2020). Integrating multiple sectors is shown to help achieve GHG emission reduction targets (Mathiesen et al., 2015). To assess the future impacts of these sectors on the energy system, however, tracking developments as well as updating assumptions on technology diffusion and the adoption rates of end-use applications will be important.

Aside from focusing on model improvements, there is also a need to highlight the importance of societal and land use conflicts, which are often overlooked when working with techno-economic models. Bolwig et al. (2020) point out that energy system analysis for long-term energy transition often focuses on the techno-economic dimension and that there is a need to assess the techno-economic, socio-technical, and political dimensions jointly for long-term energy transition analysis. Although this thesis also focuses primarily on the techno-economic dimension, it presented a method of combining an expert survey with an energy system model in order to capture some of the arising interactions between techno-economic, socio-technical, and political dimensions. The need for more research involving all dimensions in energy system modeling is underlined by Li et al. (2015), but complexity, theoretical validation, and behavioral validation are potential challenges that need to be overcome. In recent years, several innovative approaches have been proposed to assess techno-economic and further dimensions jointly and help address conflicts and tradeoffs encountered in the energy transition. Chen et al. (2022) discuss land use conflicts and systems costs for the Northern European energy system. They use an approach, which partially alters the optimization objectives to minimize land use. Results show that for 2040, a 10% increase in system costs would allow a reduction in land requirements of 60%. Javed et al. (2021) suggest a muti-criterion decision-making approach considering techno-economic and environmental criteria. The optimal result will be based on a ranking of criteria where different priorities lead to different proposed energy systems. The studies mentioned above aim to provide tools and advanced methods for better understanding the energy transition's effects while keeping economic, technical, environmental, and social concerns in mind. More research utilizing energy system models could therefore be conducted developing new approaches focusing on overcoming political barriers hindering the energy transition, such as land-use conflicts, and providing suitable alternative avenues to achieving the set energy transition targets.

Additionally to the broader limitations discussed above, papers 3 and 4 have certain limitations based on the applied method. In paper 3 the coupling of two models with different spatial, temporal, sectoral, and technological configurations means that these models do not perfectly converge, and this shortcoming had to be overcome by linking the model through relative changes vis-à-vis historical levels, c.f., section 3.3. This study also presents results for the Nordics jointly, a limitation that could be overcome by disaggregating the data in a more focused research article. Paper 4 has limitations with regard to the conducted survey and the modeling of the survey results. The sample of the respondent may not be representative of the population of interest because the respondents were contacted based on predetermined selection criteria, c.f., section 3.3. Additionally, individuals with strong opinions or those who are more invested in the topic may have been more likely to complete the survey. The background knowledge also impacts the responses although it is not clear to what extent as no further prescreening of the knowledgebase of the respondents was conducted. Regarding the modeling approach, endogenous model investments into generation capacities in countries surrounding Norway may dampen the effects of extreme exogenously determined supply and demand situations in Norway in some of the model runs. Assumptions on carbon prices, transmission lines, and carbon prices are uncertain and were made based on available literature sources and author judgments. It should also be noted that supply and demand inputs for Norway were assumed to be independent, which in reality is not the case as producers will depend on capturing sufficiently high prices.

This thesis' specific results additionally provide avenues for further research to build on. The finding that short-term intra-daily flexibility from demand side management is more important for system efficiency with less ambitious climate targets to reduce system costs, while sectoral integration, spatial flexibility, and long-term flexibility are more important with more ambitious climate targets could be improved in future research. More detailed analysis of individual technologies, various time horizons, climate targets, and reporting more detailed spatial results would further improve the utility of these results for policy making. Additionally, sensitivities with regard to model assumptions such as weather years, fuel prices, CO_2 prices, and the development of the electricity demand could be further investigated in relation to these findings. The finding that distributional shifts of welfare gains and losses between producers and consumers are likely when optimizing the system from a societal perspective additionally bears questions for further research. Further research could specifically address the impacts of electricity prices on industry competitiveness and new industries for a regionally limited scope and weigh welfare gains from industry for the economy against those of system cost minimizing approaches.

6. Conclusion

This thesis set out to investigate how European climate ambitions towards “net zero” affect flexibility options and power producers in the Northern European energy system from an economic perspective. For the analysis of this overarching research question and its sub-objectives (stated in section 1.5), four research papers were conducted using the Balmorel energy system model and additional methods. The results provide an understanding of the market dynamics affecting Nordic stakeholders by demonstrating the impacts of different drivers of the energy transition, such as climate targets, climate policies, power system flexibility, national political sentiment, and technology adoption. Four key takeaways summarize the findings of this thesis.

First, *the increasingly ambitious European climate targets will benefit Nordic renewable producer revenues and market values in 2030 and beyond*. The extent of the benefit for producers depends on policy choices and technology characteristics. For example, Nordic hydropower producers stand to profit most from increased European climate ambition due to being flexible producers. The results for Nordic producer revenues and market values, presented in this thesis, are sensitive to additional climate policies interacting with the EU ETS. For instance, a coal phaseout without emission permit cancelation in conjunction with the EU ETS would lead to reduced price volatility in the Nordics. A renewable portfolio standard (RPS) may have the opposite effect, and the merit order effect would cause decreasing average prices. This points to the fact that climate policies need to be carefully crafted to avoid unintended consequences.

Second, *the local electricity balance is a primary driver of the producers' market values.* For the case of Norway 2040, all producers’ market values decrease when net electricity exports increase, but the results show that value factors for hydropower with reservoir increase, reflecting its technology-specific characteristics. The flexible nature of this technology allows its market values to decline less than the average electricity price if Norway exports more electricity, giving it a competitive edge over VRE technologies. The opposite is true for on- and offshore wind, where increased net exports result in a disproportionally strong decrease in value factors for these technologies. Solar PV and hydro run-of-river consistently have the lowest market values and value factors. The low market values are due to the poor correlation between their production and demand in Norway, signifying that these technologies produce in unfavorable periods with low electricity prices. These findings imply that disruptions to the supply and demand balance would affect the profitability of technologies, which should be considered if policymakers wish to promote being a large exporter of electricity.

Third, this thesis shows that *flexibility is key to the efficient decarbonization of the power sector.* The value of flexibility options for reducing system costs increases exponentially with more ambitious climate targets. Flexibility decreases the need for capacity investments and leads to a more efficient system operation with less VRE curtailment. For achieving deep decarbonization, spatial interconnection, sector coupling, and seasonal flexibility are particularly beneficial from a system perspective. However, with less ambitious climate targets in 2030, it is demand-side flexibility that offers the most significant system benefits. Synergies and competition exist between different flexibility options. For instance, optimal transmission investment would increase the value of Nordic hydropower by up to 27% in 2030, dependent on the climate target. Contrary to this, increased demand side flexibility will decrease the value of Nordic hydropower. Flexibility options fulfilling similar functions in the power system from a temporal and technical perspective, such as load shifting applications and battery storage, are also found to compete with each other and affect each other's market values.

Fourth, the *climate policy-induced consumer price effects depend on technology investment and the market area*. In Norway, for example, increased international interconnection may lead to higher consumer prices and more price variability due to Norway having historically low average electricity prices and abundant flexibility from dispatchable hydropower. The social acceptance for measures that increase societal welfare but negatively impact consumer welfare may, therefore, be low and adequate redistribution needs to be considered to address arising conflict.

Concluding, the findings of this thesis aim at providing valuable information for power producers, consumers, and policymakers on the energy transition debate in the Nordic countries. The findings need to be interpreted in light of the uncertainties and limitations discussed in chapter 5.3, and underlying data and assumptions will be subject to change as we progress through time. To provide a scientific basis for discussion on the future energy system, research needs to be performed with a high temporal, spatial, and technological resolution but also needs to address the "big picture." It must take techno-economic, political, socio-technical, and environmental concerns into account to give a holistic understanding of the transition pathways under consideration.

7. References

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Paper I

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The role of demand response in the future renewable northern European energy system

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ABSTRACT

Increasing demand response (DR) from households, industry and tertiary sector may provide substantial flexibility in renewable-based energy systems, but the deployment of DR is currently limited. This study examines the future economic potential DR in the renewable rich northern European region, and also analyses power markets impacts of large-scale DR deployment in the region. For the quantifications, the energy system model BALMOREL is used, modified to include a detailed temporal modelling of available DR potentials. Results show that among the DR options analysed, space heating and water heating provide the highest shares of loads shifted. The overall demand response potential is particularly high in Norway and Sweden, due to wide-spread electric space- and water heating. Low variable costs make these DR applications economically feasible for deployment, despite high supply-side flexibility provided by regulated hydro power. DR may contribute to peak shaving of up to 18.6% of total peak load in 2050. Revenues from DR-application yield very different results depending on techno-economic parameters, potentials and the price volatility in the various analysed market areas. Results show an insignificant change in CO_2 emissions between scenarios with and without demand response.

1. Introduction

Active participation of electricity consumers in demand response (DR) may provide much needed flexibility to the energy system for integrating increasing shares of variable renewable energy (VRE) [1]. As loads from end-users are becoming increasingly controllable through smart devices, the load can adapt to electricity price changes or other targeted incentives by a third party. The benefits of utilizing DR may be significant: Reducing load in critical peak hours can avoid costly capacity expansions and ease bottlenecks in distribution and transmission grids [2]. Remote activation of DR resources can provide ancillary services. Use of high marginal cost thermal generators is reduced [3]. Revenues for VRE producers increase and curtailment decreases [4]. Finally, shifting consumption to off-peak periods can increase efficiency of thermal baseload plants through reduced cycling and could help integrate renewables by absorbing overproduction (see Tables 8 and 9).

This paper provides a comprehensive assessment of the economic potential of DR in the large and renewable rich northern European region. The study contributes to the literature in multiple ways. First, the study uses an approach to estimate and parameterize the potentials for flexible loads and implements a realistic representation of these loads' behaviour in an energy system framework in order to calculate system wide effects. Second, very few previous studies include a detailed representation of temporal availability of DR in an integrated modelling approach and thus few assess the economic potential of DR in detail. Third, the majority of studies including a detailed representation of temporal availability of DR are limited to geographical areas no bigger than one country and thus use simplistic assumptions for interdependencies between countries. The present study models interregional and international power exchange endogenously and it is to this end the only quantitative study with a detailed temporal representation found to be tailored towards the low carbon energy systems in the northern European countries.

This study specifically assesses to what extent DR can contribute to shifting peak loads, quantifies the sector specific economic value of DR and analyses the impact on electricity generation and CO_2-emissions. The quantitative model applied (BALMOREL) has been extended with a DR module for this study. This module advances the representation of DR in BALMOREL and is openly available as part of the core model (github.com/balmorelcommunity/Balmorel),

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thus sharing methodology and input data. This allows other researches to transfer the approach to their own models or use it in the existing BALMOREL model framework. The work builds on previous work presented in section 2.

1.1. Previous literature

A comprehensive overview over potentials for DR in the Nordic is given by Söder et al. [5]. They analyse the results from 50+ studies of DR potentials in industry, households and services sector per country. They estimate the technical flexibility potential in the Nordic countries to be as high as 12–23 GW or 15–30% of peak consumption. The high estimated technical potential is explained by a large share of flexible heat load and in addition industry flexibility in the Nordics. It is concluded that Norway and Sweden have a particularly great potential for DR application but there has not been a strong economic incentive to utilize this potential so far, as these countries have vast amounts of flexible hydro power. Reviewed studies use different assumptions, methodologies and levels of detail. Hence, the results include a significant level of uncertainty.

Nyholm et al. [6,7] estimate a high potential for flexible heat. The studies focus on the potential for demand response in electrical space heating loads in Swedish single-family dwellings. Using the building stock model ECCABS, a potential of 5.5 GW in this segment to reduce load is found, which is substantial compared to the national peak load of 27 GW. The storage volume of the thermal inertia in all the buildings is calculated to 19.2 GWh given an indoor temperature increase of 2.8 °C. On the other hand, Meland et al. [8], the most recent study cited for DR potential in electrical heated Norwegian households, find a potential of only 1–1.5 GW. This, even though electric heating is more widespread in Norway.

Gils [9] uses a different approach than Söder in the assessment of demand response potential in Europe. A detailed bottom up mapping of the country level potentials for 30 different load applications are estimated. The approach takes the temporal and temperature dependency of flexible loads into account. Results show that the temporal availability of DR is especially important in the residential and commercial sector. Flexible load per inhabitant is particularly high in Norway, Sweden and Finland due to high shares of electric heating and energy intensive industries. The study does not account for some industrial sectors in the Nordics such as silicon production and has low numbers for demand response potentials in hot water tanks compared to e.g. Sæle et al. [10]. A European-wide study could risk losing local factors for untypical regions such as the Nordics. A study for Finland in 2030 finds the temporal availability for DR to vary heavily between 80 and 5600 MW [11]. This also suggests the importance of detailed modelling of temporal availability for model based quantitative studies.

Quantitative modelling approaches for analysing DR and energy system flexibility are described in the following. Kleinhans [12] develops a framework for modelling the intermittent, time dependent potential of DR. An approach analogue to this is developed for this study. It is described in more detail in the method section. The method includes energy buffers, which work similarly to energy storages, but differ in their specifically defined time dependency. The approach, however, also simplifies the representation of DR as it does not limit the frequency of DR-application. Barton et al. [13] have studied the implication of flexible demands in heating and transport sector for the UK. Their findings are that VRE, transport sector and electric heating will contribute to approximately doubling the range of variation in the net electricity demand. They find flexible demands to reduce peak load in hours with electricity surplus. A drawback of the applied FESA model is that it is a single node model for the UK not capturing transmission restrictions, interdependencies with other countries and capital or operating costs. The concept of “Smart Energy Systems” is presented by Mathiesen et al. [14]. The study describes the advantages looking at an energy system holistically with all involved sectors. This provides cost effective solutions to integrate high shares of VRE and provides large flexibility through sector coupling. Qadrdan et al. [15] quantify the impact of DR on the electricity and gas system in the UK. They find DR to reduce peak electricity demand and subsequently find a reduced need for gas fired peak marginal plant capacity. DR reduces capital and operating costs of the analysed system and the capacity factor of power plants generating in off-peak hours increases. Gils [16] has performed a model-based assessment of the economic potential of DR in a case study for Germany concluding that DR substitutes peak power generation capacity well, while additional VRE integration is low. The study also points out that literature mostly is available on qualitative aspects of DR, modelling methods to describe DR applications, and the estimation of the technical potential. The economic potential across a large geographical area is typically not analysed. Mueller & Moest [17] found that most studies on DR do not consider temporal details of DR availability even though time of day and/or outer temperature largely affect DR potentials. Their study calculates hourly potentials of DR for Germany in a first step. It is noted that DR potentials are sensitive to changes in the market penetration of the analysed technologies. In a second step these potentials are then applied in a quantitative, model-based case study that analyses DR at different RE levels. They find DR to decrease peak load, curtailment of RE and substitute some of the storage utilization. DR cannot integrate high amounts of RE but is instead more suited to balance short term fluctuations. The modelling approach is restricted to Germany, not including interdependencies between countries. Mueller and Moest point out that there is a research gap analysing DR potentials in larger geographical areas together with their transnational interdependencies.

The literature review shows a consensus that DR decreases peak load, replaces peak generation capacity, raises capacity factors of off-peak generation and lowers capital and operating costs of energy systems. A high potential for DR is observed in the Nordic countries due to electric space heating and power intensive industries. Modelling the temporal availability of DR accurately is important. More research is needed covering larger model regions to assess impacts of different market areas on each other.

The following sections of the paper are organized as follows. Section 2 contains the methods, explaining the model framework, the developed DR module and the data collected. Section 3 contains the results and discussion and section 4 contains the conclusion and implications from this study.

2. Materials and methods

The methods section explains the chosen modelling framework, the developed DR module and its underlying data and assumptions.

2.1. BALMOREL model

The quantitative analysis of this study is performed using the BALMOREL model, a bottom-up energy system optimization model (see e.g. [4] or [18] for previous applications). The BALMOREL model is well suited for the analysis, as it has a detailed representation of the Nordic power system and allows for a modular extension. BALMOREL has been calibrated and validated in several previous studies (see [18] for a comprehensive overview of applications).

Fig. 1 covers supply of energy, energy conversion (to heat or electricity), flexibility options (e.g. electricity storage and the DR add-on), heat demand and power demand. The exogenously determined model assumptions include existing generation and transmission capacities, planned capacity changes, commissioning and decommissioning, fuel- and carbon prices, heat- and power demand as well as VRE resource availability. Based on these assumptions the model calculates optimal dispatch, investments in power and heating plants, storages and electricity transmission endogenously by minimizing the total system costs. The problem is solved as a linear programming problem. The objective function links the modelled components of the energy system and is subject to numerous constraints. This ensures a realistic representation of the energy system [19]. An extensive description of the model is provided in previously identified literature [18–20].

The model setup for this study is designed to capture seasonal, weekly and daily variations in energy supply and demand while keeping computing time moderate. For this reason, 26 weeks are modelled, equally spread out over the year. The hours modelled within each week are hours 1–48 and 121–144 to include weekdays as well as a weekend day. The modelled years are 2030, 2040 and 2050 with perfect foresight. The spatial setup includes the Nordic- and Baltic countries, Poland, Germany, Belgium, Netherlands, France and the UK but the analysis focuses only on the Nordics. These countries are subdivided into regions representing the Nord Pool market areas. Linear modelling is chosen over a unit commitment approach for computational reasons.

2.2. Demand response add-on

This study defines DR as the deviation from normal electricity usage by end users, that is induced by electricity price signals [21]. Market based DR applications for emergencies, capacity markets or ancillary markets are not subject of this analysis. Two types of DR are analysed, load shedding and load shifting. Loads that are shed are interruptible loads that are curtailed while load shifting shifts load to an earlier or later point in time.

For the present study, a DR add-on was developed to extend the existing model code of BALMOREL. The DR add-on is specifically suited for the Nordic countries and includes identified flexible loads in households, industry and tertiary sector. The applied methodology for the modelling of the DR add-on in GAMS ensures that specific features, such as the intermittent and time dependent potentials are accounted for.

Fig. 2 represents the core process of the authors contribution to the BALMOREL model and the key output that can be used for analysis. The development of the DR add-on consists of a modelling approach, that is integrated into the BALMOREL model framework. Technical and economic data on DR in the Nordics is collected. This data is then used as an input for the DR-add-on in BALMOREL. Finally, results can be obtained from the extended model. In the following the DR-framework is discussed.

In this study load shifting is modelled as a virtual storage, the difference lies in the time dependency of DR. The storage dynamics follows a similar concept to Kleinhans [12] and the central elements are recited here for informative purposes. The shifting time and variable storage size are included by introducing storage equivalent energy buffers that are filled and emptied depending on the charge rate: the downshifts and upshifts. The charge rate of the energy buffer (Eq. (1)) also shows the use of the load shifting application and is the difference between the scheduled and the realized load:

$$P_c(t) = L_c(t) - R_c(t) \tag{1}$$

where.

c Load shifting category;
Δt_c Shifting time (hours) for category c;
$R_c(t)$ Realized load after load shifting for category c;
$L_c(t)$ Scheduled load for category c;
$P_c(t)$ Charge rate of load shifting of category c for $R_c(t)$.

The energy content of the energy buffer in (t+1) if empty at (t) is equal to the charge rate (Eq. (2)):

$$E_c(t+1) - E_c(t) = P_c(t) \tag{2}$$

where $E_c(t)$ is energy content of load shifting category c for $R_c(t)$.

The boundaries of the energy buffer and charging/discharging are then defined. All loads moved to the latest time step within the

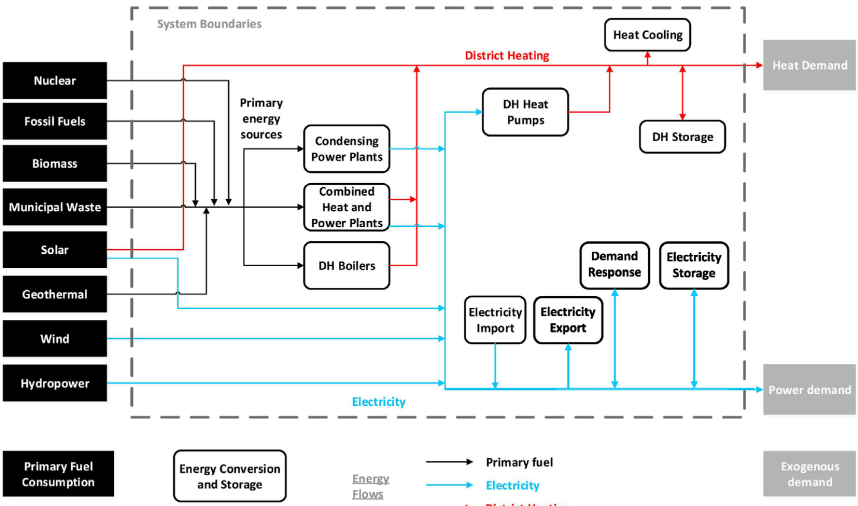

Fig. 1. BALMOREL core structure including demand response [18].

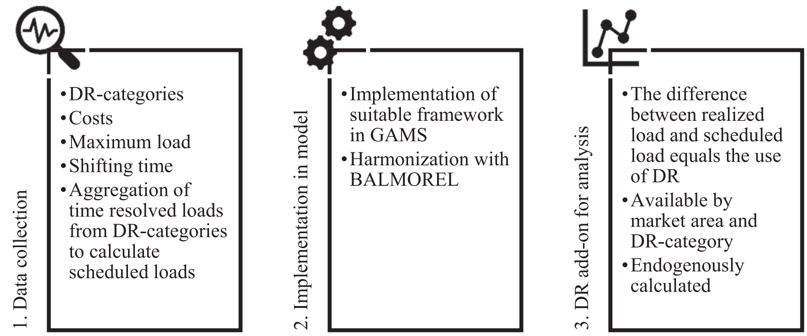

Fig. 2. Implementation of dr in BALMOREL.

set timeframe result in a fully charged energy buffer and are equal to the upper limit of the energy buffer (Eq. (3)). The size of the energy buffer itself is thus dependent on scheduled loads within the timeframe. Upper and lower limits for charge-/discharge rates are defined based on scheduled loads and maximum loads (Eq. (4) and Eq. (5)):

$$E_c^{max}(t) = \sum_{tt} L_c(tt) \quad \forall t \leq tt \leq t + \Delta t_c \tag{3}$$

$$P_c^{max}(t) := L_c(t) \tag{4}$$

$$P_c^{min}(t) := -(\Lambda_c(t)) + L_c(t) \tag{5}$$

where.

tt represents a timestep within the load shifting timeframe;
$\Lambda_c(t)$ is maximum load/capacity for category c.

The introduction of these time dependent buffers and charging-/discharging capacities allows the model to optimize the dispatch of load shifting within a defined corridor. Eq. (6) and Eq. (7) ensure validity within the equation described above. These equations define the energy buffer and the charge rate to be within the upper and lower limits respectively.

$$0 \leq E_c(t) \leq E_c^{max}(t) \quad \forall t, c \tag{6}$$

$$P_c^{min}(t) \leq P_c(t) \leq P_c^{max}(t) \quad \forall t, c \tag{7}$$

For space heating, the buffer size is not determined by shifting time, but is fixed and given directly as an input. Here the energy buffer can take a negative value as demand can be shifted into an earlier point in time (unlike in Eq. (6)). Load shedding is modelled similarly to load shifting but for load shedding it is assumed that load is lost at a defined cost and not shifted.

The methodology described above is chosen for the study because it has a good representation of the temporal characteristics of DR. In addition, the representation did not increase the solving time of the model by a lot. The drawback of not including a limitation to the frequency of DR applications should not affect the results of the study heavily as pointed out in [16]. Limited frequency of DR activation is mostly found in industry which, due to high costs, does not shed much load in the model runs.

2.3. DR-data and scenarios

The available DR-capacity across all sectors is estimated in several steps. First, electricity consumption levels for processes that are assumed to be flexible (Fig. 3) are estimated from annual *Eurostat* consumption data [22] and broken down to different processes based on several sources [9,23–28]. Electric heating constitutes a major share of loads with flexibility potential, mainly in rural parts of Norway, Sweden and Finland, even though district heating dominates space heating in urban parts of the Nordics.

Availability of DR capacity is time dependent and based largely on scheduled loads. Scheduled loads for household appliances are based on the SAVE-E project [29]. Space heating load follows a seasonal pattern with highest consumption during wintertime according to heating degree days. Additionally, the potential technical capacity, future adoption rates and spatial distribution all affect the DR capacity. The technical DR capacity is calculated by first estimating the total electricity demand for each DR category in each area and then estimating the capacity based on typical use patterns.

Adoption of new mass use technology often follows an S-curve. In the current modelling, the maximum share of consumers that are flexible within a DR category is limited by an adoption rate.

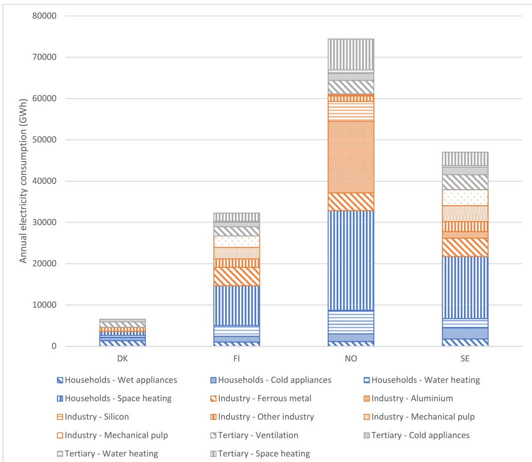

Fig. 3. Annual Electricity Consumption for Loads that are assumed to be Flexible in the Nordic Countries.

Based on [30] the maximum adoption of DR applications in residential and tertiary sector is calculated from a market penetration rate (β), total potential (V^*) and remaining potential at time step t ($V(t)$). The market penetration rate largely determines the pace of adoption of different technologies and thus helps set the upper limit for available DR capacity. For the household and tertiary sector, the DR categories are divided into three groups with high ($\beta = 38.9\%$/yr), medium ($\beta = 24.2\%$/yr), and low ($\beta = 15.4\%$/yr) market penetration rates. Table 1 shows the assumed market penetration rate and total potential for the DR categories in household and tertiary sector derived from comparable technologies in [30].

The market share or share of potential realized (f(t)) is then calculated as follows:

$$f(t) = \frac{1}{1 + e^{-\beta t + \alpha}} \tag{8}$$

where α represents the integration constant: $\alpha = \beta t_0 + \ln(a_0)$ where $a_0 = \frac{1-f(t_0)}{f(t_0)}$.

In the industry sector the "Mechanical pulp" process' potential is already fully utilized, and the other industry categories follow a linear growth path from around 60% adoption in 2019 to 100% adoption in 2050.

The adoption of different DR categories for household, industry and tertiary sector is visualized in Fig. 4. The assumed adoption rate largely impacts the available DR capacities across the researched time. Adoption rates in this study are subject to the underlying assumptions and contain a level of uncertainty.

This study analyses the likely impact and value of DR by comparing the model results for two scenarios: A no demand response scenario (NODR-scenario) and a demand response scenario (DR-scenario). The DR-scenario is introduced using assumptions that the authors regard as a likely representation of future developments. However, uncertainties regarding the underlying assumptions such as adoption rates and techno-economic assumptions exist. The NODR-scenario, on the other hand, excludes the option of DR for optimization. This scenario acts as a point of reference to ultimately determine the impact and value of DR. The techno-economic assumptions for the DR-scenario are summarized in Tables A1 (a)-(c) of the appendix (excl. availability, adoption rate and technical potential which are discussed above).

DR applications in households and tertiary sector are available for load shifting, enabling shifting energy consumption in time without affecting the gross energy consumption. The largest potential is identified in space heating. Load shifting in space heating assumes use of the building's thermal mass as an energy buffer. The temperature can deviate by 1 °C from the initial temperature level without causing a utility loss for the user. In winter months with high energy demands shifting times are shorter than on milder days, leading to less flexibility potential from this category. Load shifting is associated with no/low variable cost, as processes requiring energy are mostly rescheduled without a loss in utility. Only space heating in the residential and service sector is associated with efficiency losses.

Load shedding is a reduction in electricity consumption that cannot be compensated for by an increase at a different point in time. The load shedding categories identified in this study are the industry processes in power intensive industries such as aluminium, pulp and paper, silicon and ferrous metals. The maximal time of interference in the identified DR categories is 3–4 h. The variable costs of load shedding, which are the opportunity costs, are assumed to be between 200 and 2000 EUR/MWh, dependent on the sector (detailed information in Table A1 (b)). No investment costs are assumed since necessary infrastructure, such as smart metering and data exchange equipment is mostly already in place [32].

Table 1
Market penetration rate and total potential.

DR category	Market penetration rate (β)	Total potential (V[a])
HH- Cold appliances	38.9%/yr	100%
HH- Wet appliances	38.9%/yr	50 %[a]
HH- Water heating	24.2%/yr	100%
HH- Space heat	15.4%/yr	100%
TER- Ventilation	24.2%/yr	100%
TER- Cold appliances	24.2%/yr	100%
TER- Water heating	24.2%/yr	100%
TER- Space heating	24.2%/yr	100%

[a] Wet appliances requires changes in user behaviour and therefore total potential is set to 50% in this category [31].

3. Results and discussion

The results and discussion section present the findings from a DR-scenarios and NODR-scenario.

3.1. Activation of demand response

Fig. 5 illustrates the modelled up- or downshifting of load by DR for all modelled countries and technologies in the DR scenario for an average winter Monday and Tuesday in 2030, 2040 and 2050. As expected, the modelled upshifts and downshifts increase in weight towards 2050 driven by a higher capacity through exogenously determined adoption and an increased intermittent generation. Fig. 5 confirms findings in previous studies that DR has a smoothing effect on the total load. In instances where demand is close to the peak load, the load is reduced by downshifts (e.g. hour 9–19) while instances with lower demand show an upshift through DR (e.g. hour 24–30).

When comparing average Mondays and Tuesdays for winter and summer days in 2050, differences in shift patterns are apparent between the seasons (Fig. 6). On an average winter day demand rises in the morning hours and hits the peak demand around 9 a.m. and then stays high until 7 p.m. before declining in the night hours. During these hours with high demand, downshifts outweigh upshifts (Fig. 4, hours 9–19). During the night-time, when demand is low (hours 23 to 31), upshifts fill the energy buffers for the downshifts during the next day. In summer, the general demand pattern is similar with demand hitting the peak slightly later around 12 a.m. and then gradually declining before dropping off in the night hours. With regards to an average summer week, solar PV additionally influences up- and downshifts. In the morning hours when load rises there is a strong downshift. This situation is reversed after 12 a.m., due to an increase in generation from solar PV that is largely based on generation from central Europe and helps meet the demand. In the early evening hours, the situation changes again when generation from solar PV declines. Downshifts help even out supply and demand. Finally, at night-time when demand is low, upshifts outweigh downshifts again and the energy buffers in the DR categories can be filled once again.

Table 2 shows the change to load by the analysed DR-categories and the contribution to downshift in the peakhour for 2030 and 2050. The total shifts increase for the Nordic countries from 2030 to 2050 by over threefold. In 2030 the household sector has the largest impact by shifting 3.6 TWh, the highest volume coming from water and space heating. The industry sector is shifting 123 GWh while the shedding volume is relatively small due to high costs (see

Fig. 4. Assumed Adoption Rates of different DR-Categories.

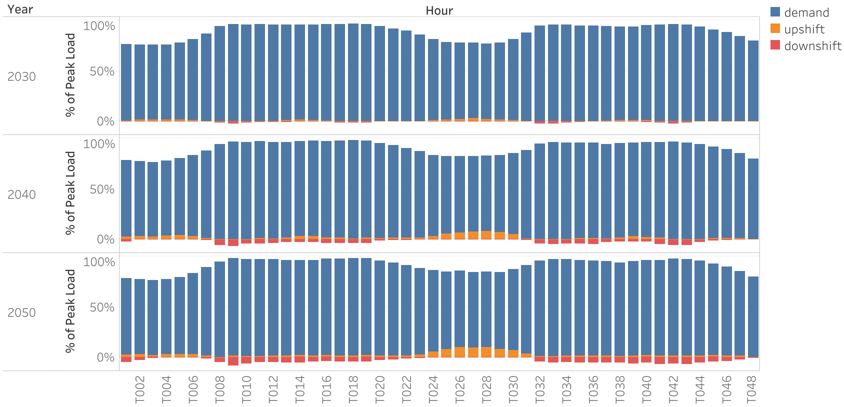

Fig. 5. Demand, Up- and Downshift in relation to the Peak Load on an average Winter Monday and Tuesday for 2030, 2040, and 2050.

Table A1 (b)). The shifts in tertiary sector amount to 1.3 TWh in 2030 with space heating contributing the largest amount. In 2050 the industry sector shifts 98 GWh or less than 1% of total shifts, while households shift 10.8 TWh or 63% and tertiary sector the remaining 6.1 TWh or 36%. While the overall sector shares have largely stayed the same, there are particularly strong changes within the household sector. Downshifts in peak hours are one of DR's main system contributions because it lowers price spikes and decreases the need for high cost backup capacity. However, since the capacity of DR largely depends on the load, not all DR-capacity is available in peak hours. For 2030, DR shifts down load by 5.3% in the hour with the highest electricity price. For 2050 the corresponding number is 18.6%, as more consumers are assumed to participate in DR. In 2030, the largest peak contribution comes from household space heat, and pulp- and paper industry contributing 1.3% each. In 2050, household space heating contributes to peak reduction the most with 7% of the total load, followed by household water heating (4.5%) and teritary space heating (3.9%). In total, water and space heating from household and tertiary sector contribute with 14.3 GW in 2050, while other loads contribute with a 2.6 GW reduction in the peak load hour.

Overall, the results show that shifts increase in magnitude towards 2050 and provide higher downshifts in the peak hour, thus contributing more significantly to lowering peak demand. The bulk of shifted electricity is provided by household and tertiary sector, and here particularly the space heating and water heating categories contribute the largest shares.

3.2. 3.2 power generation and investments

The modelled power generation mix for the Nordic countries differs in the composition of generation between the analysed scenarios (Table 3). In 2030, with DR, generation from baseload technologies such as nuclear and coal is increased. This effect is observed because less hours with very low prices occur in the DR scenario, increasing operating hours of baseload technologies. In

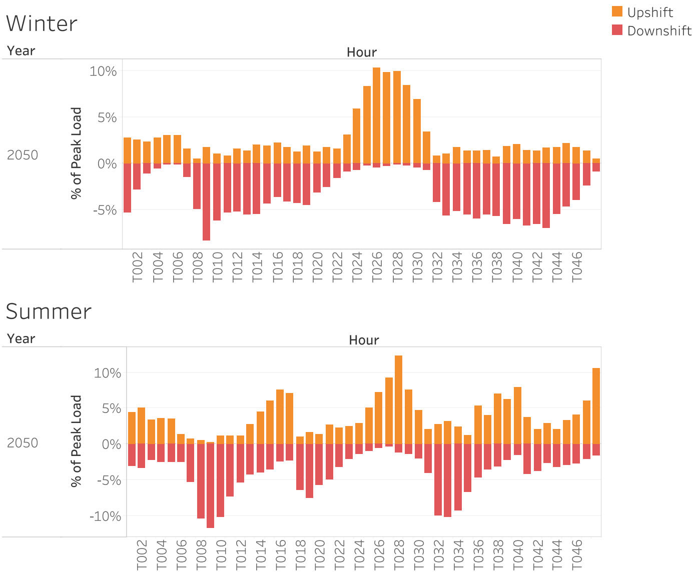

Fig. 6. Up-and Downshift in relation to the Peak Load on an average Winter and Summer Monday and Tuesday in 2050.

Table 2
Overview of impact of DR categories in 2030 and 2050.

Sector	DR Category	DR Type	Total shift (GWh)		Net downshift in peak hour (relative to peak load)	
			2030	2050	2030	2050
Industry	Aluminium	Shed	4	–	0.2%	0.0%
	Silicon	Shed	2	2	0.2%	0.0%
	Pulp and paper	Shed	4	4	0.7%	0.6%
	Pulp and paper	Shift	123	92	1.3%	0.8%
	Other	Shed	0	–	0.0%	0.0%
Households	Wet appliances	Shift	864	899	0.5%	0.8%
	Cold appliances	Shift	312	136	0.1%	0.0%
	Water heating	Shift	1099	4048	0.4%	4.5%
	Space heating	Shift	1327	5706	1.3%	7.0%
Tertiary	Ventilation	Shift	183	954	0.3%	0.7%
	Cold appliances	Shift	89	529	0.1%	0.1%
	Water heating	Shift	120	653	0.1%	0.2%
	Space heating	Shift	910	3925	0.4%	3.9%
Total			5036	16 949	5.3%	18.6%

2040, generation from coal phases out and the DR scenario uses less generation from flexible gas power plants, decreasing the total fossil fuel generation. The use of battery storage can only be observed in the NODR scenario, as more flexibility is required. In 2050 there is no fossil fuel generation in either scenario but the NODR scenario relies more on flexible power plants and storage.

Differences in new capacity investments between 2030 and 2050 can be observed (Table 4). For both scenarios, onshore wind power represents the major share of total new investments. Other technologies that are invested in are offshore wind (far and near), subcritical steam turbines, internal combustion engines (ICE), gas turbines, and in the NODR scenario battery storage. In light of the European energy transition, the effects of DR on investments can be viewed as having a small positive impact since the DR scenario shows higher investment into renewable energies from onshore wind and less investment into fossil fuel based backup generation (gas turbine, ICE, and steam turbine subcritical). Additionally, high cost battery storage is not invested in the DR scenario, as sufficient flexibility is provided by DR.

Table 3
Power generation in the Nordic countries (TWh).

	2030		2040		2050	
Fuel	DR	NODR	DR	NODR	DR	NODR
Biogas	0.2	0.2	1.2	2.1	5.1	6.1
Biomass	32.6	33.1	34.2	34.8	29.6	30.3
Municipal Waste	8.1	8.1	9	9	9.7	9.7
Wind	112.2	117.5	133.9	136.8	161.1	158.2
Solar PV	0.8	0.8	0.8	0.8		
Hydro	228.7	228.7	228.7	228.7	228.7	228.7
Nuclear	72	69.5	46.2	43.9	15.1	14.8
Fossil Fuels	2.2	2	0.4	0.6		
Battery Storage				0.3		0.3

Table 4
Investments in new generation capacity (GW) in the nordic countries between 2030 and 2050.

Technology	Scenario	
	DR	NODR
Battery storage	0	0.2
Gas turbine	0	0.4
ICE	3.9	5
Steam turbine subcritical	6.4	6.6
Offshore wind (far)	2.3	2.3
Offshore wind (near)	1.1	1.1
Onshore wind	44.9	44.1

3.3. Revenue and value of flexibility from DR

The DR contribution to revenue is defined as the profits from downshifts minus the costs of upshifts in load at the corresponding electricity price over the analysed timespan. For the Nordic countries, revenues by sector are presented in Fig. 7. In all countries the overall revenues from DR rise from 2030 to 2050, even though the industries contribution stays equal or declines. There are, however, large variations between the countries. While Denmark only increase its revenues moderately from 2030 to 2050, Finland, Norway, and Sweden see a large increase in revenues based on the use of DR in households and tertiary sector. These countries have high shares of electric space heating as well as electric water heating offering cost efficient untapped DR potential. In Finland, total revenues from DR increase during the timespan 2030 to 2050 from 17 to 64 million EUR and the increase in households and tertiary sector is 38 and 12 million EUR respectively. Norway has the largest total increase in revenue from 34 to 113 million EUR. Contributions from DR in households rise by 56 and from the tertiary sector by 29 million EUR in Norway. Sweden increases its total revenue from 36 to 93 million EUR from 2030 to 2050. The household sector's increase is 44 and the tertiary sector's increase amounts to 20 million EUR.

The estimated revenue per unit shows how much the cost of electricity per process can be reduced by actively utilizing DR (Table 5). The value of DR for different technologies differs largely between the regions. The highest values are in the household categories space heat, water heating, and wet appliances in Denmark with savings of above 8 €/MWh in 2030. However, in Northern Scandinavia the savings per unit is lower. This can be attributed to more supply of flexibility in this area e.g. from hydropower. Results also differ between household and tertiary sector for the same technologies e.g. water heating. This is largely explained by the different demand profiles but also the costs for realizing the technical potentials differ. Towards 2050 the uncertainty of the results increases but model outcomes show revenue per unit to be continuously highest from household hot water heating.

3.4. CO_2 emissions

DR affects capacity investments and power generation and consequently also influences CO2 emissions of the power system. Table 6 shows the CO2 emissions for 2030 and 2040 for the DR and NODR scenarios. In 2050 the emissions are zero in both scenarios as the model is set to find a carbon neutral system.

In 2030, the total CO2 emission are higher in the DR scenario driven by steam turbines mainly involved in industrial activity. It should be noted that the emissions per generated electricity is low in both scenarios (~4 g/kWh). Towards 2040, emissions fall for all technologies and DR is seen to reduce emission from gas turbines, which usually covers the peak load in the power system. The negative influence of DR on emission reductions in 2030 can be explained by the fact that there is lower investment in additional wind generation capacities and a higher utilization rate of coal power plants since the number of hours with very low prices are reduced in this year. However, until 2040 this situation changes as more wind capacities are installed in the DR scenario and subsequently the emissions fall below the NODR scenario.

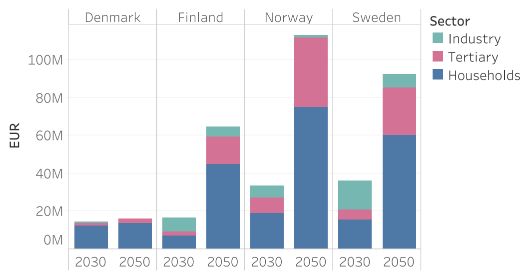

Fig. 7. Revenue from dr by sector and country.

Table 5
DR revenue per unit 2030 (€/MWh).

		DK	FI	NO	SE
Industry	Aluminium			0.3	0.4
	Silicon			0.4	
	Pulp and paper (Shed)		0.5	0.6	0.7
	Pulp and paper (Shift)		2.2	2.7	3.2
	Other	1.0			
Households	Wet appliances	8.1	2.6	3.1	3.6
	Cold appliances	2.8			1.2
	Water heating	8.3	2.6	2.8	3.5
	Space heating	7.5	2.3	2.7	3.2
Tertiary	Ventilation	4.1	1.2	1.3	1.5
	Cold appliances	5.1	1.6	1.7	2.0
	Water heating		4.6	5.0	6.1
	Space heating		5.2	5.4	6.8

Table 6
CO_2 emissions in nordic countries (kilotons of CO_2).

	DR		NODR	
	2030	2040	2030	2040
Combined cycle	300		282	
Internal combustion engines	17		9	
Gas turbines	35		51	98
Steam turbines	979	237	894	263
Total	1331	237	1236	361

3.5. Sensitivity analysis

Model runs have been conducted testing the sensitivity of results to changes in assumptions as described in Table 7.

The sensitivity scenarios are analysed for investments and revenues, giving an indication of the robustness of the overall results to these uncertain inputs. The modelled investments for all scenarios are shown in Fig. 8.

In 2030 the investment results are not very sensitive to changes in the adoption rates or costs. In 2040 and 2050 faster adoption rates have a very small impact on investments compared to the DR scenario. Lower adoption rates, on the other hand, will moderately increase investments in onshore wind in 2040 and decrease investments in 2050. New capacity investments are not sensitive to changes in adoption costs. In 2040 and 2050 the maximum difference in capacity investments between the Cost + scenario and

Table 7
Sensitivity scenarios.

Scenario	Description
Adoption +	High adoption rates are assumed for all DR technologies
Adoption −	Low adoption rates are assumed for all DR technologies
Cost +	Adoption costs are increased by 50%
Cost −	Adoption costs are reduced by 50%

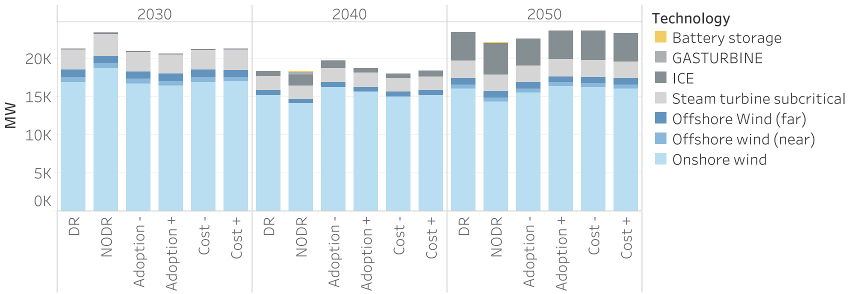

Fig. 8. New capacity investments (sensitivity analysis).

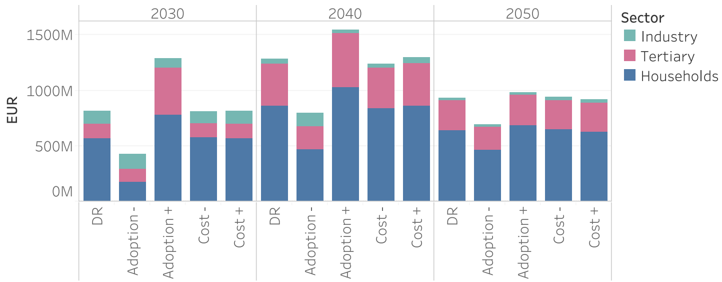

Fig. 9. Revenues in the nordics (sensitivity analysis).

the DR scenario is 162 MW, and in the Cost − scenario 400 MW.

Revenues for the analysed countries differ substantially among the sensitivity scenarios. Fig. 9 represents the revenues for the DR- and sensitivity scenarios in 2030, 2040, 2050 for the Nordic countries. The individual countries are not represented in Fig. 9 as the effect of the analysed sensitivities on revenues follows a similar pattern across the analysed countries.

Revenues are affected positively by higher adoption rates. The results are sensitive to higher and lower adoption rates as this will particularly increase or decrease revenues. Somewhat surprisingly, also lower adoption rates will lead to higher revenues in 2040 compared to the DR scenario (utilization of DR in the industry sector increases) but in total (2030 and 2050) to lower revenues. Lower adoption costs, counterintuitively, affect revenues negatively in 2040 making the revenue sensitive to changes in adoption costs. This is explained by the fact that associated with lower adoption costs high peak prices are decreased, leading to a lower revenue overall. The volume of demand response shifts, however, is greater. For higher adoption costs the results are the opposite of the lower adoption costs. This also indicates that DR revenues will be sensitive to overall system flexibility and can be affected by other flexibility measures, as these could compete directly with the analysed DR categories or decrease price volatility. It should be noted, however, that the current model setup already includes the largest forms of readily available flexibility from hydroelectric generation and PtH in the district heating system. Further flexibility from sector coupling as discussed in a Smart Energy Approach by e.g. [14] would likely increase competition for DR by integrating the transport and gas sector and could affect revenues negatively.

4. Conclusion

This study confirms that DR holds the potential, technically and economically, to provide substantial amounts of flexibility in the future energy system. Based on a detailed assessment of the DR potentials in different sectors and regions the study shows that space heating in households and tertiary sector as well as heated water in households will be major sources of DR flexibility in the Nordics. Somewhat surprisingly, the model results show that the activation of DR will be largest in the hydro power dominated countries Norway and Sweden since these countries have large DR potentials from electric heating appliances. The use of DR in the analysed regions reduces the need for battery storage and other storage technologies as well as flexible natural gas fired generation capacity, but the impacts of DR on optimal power generation investments and GHG emissions are minor. DR may play a vital role in terms of security of power supply and the efficiency of the energy system since the need for costly back up power as well as battery storage is reduced. Sensitivity studies show the optimal generation capacity investment levels are relatively robust to the assumptions regarding DR technologies, but the total revenues for DR activation is affected by the assumed adoption rates and adoption costs of the DR technology. DR may contribute to significant savings, particularly in space and water heating in household and tertiary sector. In Denmark, the region with the highest share of VRE and lowest share of hydropower, revenues per unit from DR are estimated to be in the order of several EUR per MWh of consumed electricity. Although DR will play a role in providing flexibility in the future northern European energy system, other flexibility options, like e.g. power to heat in flexible district heating and increased transmission line capacities, seem to have a larger economic potential. Finally, it should be noted that this study does not assess DR at distribution grid level and the benefits of DR could potentially be higher in lower grid levels than at the level analysed here.

Credit author statement

Jon Gustav Kirkerud: Conceptualization, Software, Validation, Formal Analysis, Writing — Original Draft, Visualization. Niels Oliver Nagel: Conceptualization, Software, Validation, Formal Analysis, Writing — Original Draft, Visualization. Torjus Folsland Bolkesjø: Conceptualization, Writing - Review & Editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Nomenclature

Table 8
Abbreviations.

Abbreviation	Description
RE	Renewable Energy
VRE	Variable Renewable Energy
DR	Demand Response

Table 9
Parameter and variable description.

Variable/Parameter	Description
C	Load shifting categories
Δt	Time frame of load management (h)
R(t)	Realized load after load shifting (MW)
L(t)	Scheduled load (MW)
P(t)	Charge rate of storage equivalent energy buffer (MW)
E(t)	Energy content of storage equivalent energy buffer (MWh)
$\Lambda(t)$	Maximum load (MW)
β	Market penetration rate (%/yr)
V*	Total potential for DR (%)
f(t)	Market share of DR potential realized (%)

APPENDIX

Table A1

(a). Techno-economic assumptions for demand response in households

DR-application	Wet appliances	Cold appliances	Water heating	Space heat
Type: Shift/Shed	Shift	Shift	Shift	Shift
Cost for realizing technical potential, EUR/MW	5000	50 000	5000	33 333
Shifting time, h	4	1	6	
Storage loss per hour				3%
Buffer size positive, MWh/MW installed capacity				0.97
Buffer size negative, MWh/MW installed capacity				0.97
Limit to up and down regulation, % of installed capacity				50%

(b). Techno-economic assumptions for demand response in industry

DR-application	Ferrous metal	Aluminium	Silicon	Other	Mechanical pulp	Mechanical pulp
Type: Shift/Shed	Shed	Shed	Shed	Shed	Shed	Shift
Cost for down regulation, EUR/MWh	2000	1000	200	2000	200	10
Shifting time, h						2
Time of interfere, h	3	3	4	4	4	3
Minimum load, % of installed capacity	33%	75%	75%			

(c). Techno-economic assumptions for demand response in tertiary sector

DR-application	Ventilation	Cold appliances	Water heating	Space heat
Type: Shift/Shed	Shift	Shift	Shift	Shift
Shifting time, h	1	1	6	
Storage loss per hour				3%
Buffer size positive, MWh/MW installed capacity				0.97
Buffer size negative, MWh/MW installed capacity				0.97
Limit to up and down regulation, % of installed capacity				50%

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Paper II

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The economic competitiveness of flexibility options: A model study of the European energy transition

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ABSTRACT

The European energy transition towards renewable energy is increasingly ambitious and climate targets have been reinforced. Options to increase the flexibility of the energy system are expected to become more valuable with higher shares of variable renewable energy. This paper analyzes the economic benefits of key flexibility options in the Northern, Western and Central European energy system under six increasingly ambitious climate targets towards 2030. The value of and competition between flexibility options is investigated by comparing total system costs and profits. The BALMOREL energy system modeling framework is applied, minimizing system costs. The study results show the increasing value of all flexibility measures with increasingly ambitious climate targets. Demand side management has a large impact on system costs when climate targets are low, while sector coupling with the district heat sector and interconnector investments have an increasing impact with more ambitious climate targets. Biomass is essential for achieving deep decarbonization.

1. Introduction

The European energy transition towards a sustainable energy system increases challenges concerning reliability, economical operation and investment decisions. The European Green Deal's ambition for a climate neutral continent in 2050 will require the economy to change rapidly towards more sustainability (European Commission, 2019). In recent years the power and heat sector has contributed the largest share to reducing greenhouse gas emissions (Eurostat, 2019). Recent discussion of tightening the 2030 climate targets as part of the European Green Deal suggests that renewable electricity deployment and electrification will continue to lead the efforts in reaching climate targets in the near future (European Commission, 2020).

Substituting large quantities of thermal baseload generation with variable renewable energy (VRE) has resulted in the need for flexibility to balance supply and demand (Brunner et al., 2020; Denholm and Hand, 2011). It is thus essential for a successful energy transition that the most adequate flexibility options are available to the market. Energy system flexibility can be provided by different resources and actors. Spatial interconnection, sector coupling, flexible generation, flexible demand, and storage can address flexibility shortages. The wide range of different available flexibility options increases the importance of understanding the specific role of each flexibility option in high VRE systems. Uncertain cost developments, potentials and new market actors constitute risks to market participants. Benefits, drawbacks, substitution effects and synergies between flexibility options should thus be better understood for planning the future energy system (Mikkola and Lund, 2016).

The importance of flexibility for future energy systems is increasingly at the center of many research papers. Typically, qualitative research papers in this field review, analyze and map results in literature, sometimes supported by expert panels and opinions (Bloess et al., 2018; Sinsel et al., 2020; Wang et al., 2017). Quantitative research on flexibility options is usually model based, sometimes applying unit commitment models to capture operational restrictions accurately.

The role of flexibility has been examined comprehensively by Lund et al. (2015). The review paper maps possibilities to increase energy system flexibility. For this they analyze sources of flexibility such as demand and supply side measures, grid extension, market design and flexibility provided by sector coupling and conclude that energy systems have high inherent capabilities to handle VRE. Babatunde et al. (2020) review power system flexibility and underline the importance of further research on the economic significance offered by both operational and technical flexibility. Various scientific approaches for analyzing flexible demand from European energy system studies are reviewed and categorized by Kondziella and Bruckner (2016). The review finds that few

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studies address the market potentials of flexibility measures. Alizadeh et al. (2016) performed a comprehensive review of literature on flexibility requirements and options for improving flexibility in energy systems. A classification system based on different flexibility requirements is introduced and barriers for flexibility are addressed. Steps for creating a flexible power system with high shares of VRE are identified by Papaefthymiou and Dragoon (2016). The steps include policies and technical changes for different stages of VRE integration.

A quantitative study by Ulbig and Andersson (2015) analyzes the operational flexibility of individual power system units by applying the Power Nodes modeling framework with unit commitment. Different flexibility metrics e.g. power ramp-rate, power and energy capability are calculated and can be aggregated to understand joint effects and deficiencies when pooling different flexibility options. Belderbos and Delarue (2015) conduct a model-based analysis of the optimal set of generation units to serve a given demand. Results show a shift from baseload to mid- and peak-load generation units with higher shares of wind generation. Mathiesen et al. (2015) assess least cost solutions for integrating VRE into 100% renewable energy systems. The paper argues for the importance of harnessing the flexibility benefits of sector coupling instead of focusing on the power system alone. Mikkola and Lund (2016) present an optimization modeling framework to manage the integration of large quantities of VRE including electric and thermal loads. The model is tested, and results are presented for a case study on Helsinki. A quantitative comparison of flexibility options in the Nordic and Baltic countries by Kiviluoma et al. (2018) focusses on the system benefits and advantages for VRE through flexibility options. Their approach couples the investment planning model BALMOREL with the unit commitment and economic dispatch WILMAR Joint Market Model. Several scenarios with different combinations of flexibility options are compared to a scenario with no flexibility measures. Results show a decrease in system cost and an increase in value for VRE with more system flexibility, particularly for transmission and sector coupling between the power and heat sector.

Many studies can be found focusing on the use of individual flexibility options. Kirkerud et al. (2017) show the positive impact of power-to-heat (PtH) for VRE competitiveness. Nuytten et al. (2013) assess a combined power and heat system with thermal energy storage. They show that centrally located heat storages in district heat systems offer more flexibility compared to individual units. Demand response (DR) potential, availability and economic implications have been evaluated in a European context in several studies (Gils, 2014, 2016; Müller and Möst, 2018). Flexibility by controlled charging of electric vehicles (EVs) is shown to be a viable option for short term supply and demand balancing of energy systems (Mills and MacGill, 2018). Battery storage for grid application is extensively researched in literature. Davies et al. (2019), for example, show the importance of modeling choices for the accuracy of calculating potential revenues of battery storage for the Californian energy grid.

The reviewed literature shows that few studies analyze the economic implications and market potential of flexibility options. Additionally, looking at flexibility options comprehensively in energy system scenarios with a multi-regional model framework is rare. Many quantitative studies rather assess operational aspects or focus on individual flexibility options. This model-based research paper focuses on economic aspects of flexibility options with regard to system costs and producer profits in a large geographic region which includes the Nordics, Baltics, Western and Central European countries and the UK. This is believed to capture the benefits and competition flexibility options face in an ever more integrated European market. The multi-regional BALMOREL model has the additional benefit of taking power flows between regions into account. A special emphasis is laid upon the interplay of flexibility options for an energy system adapted to achieve different climate goals. Thus, the uncertainty in the level of emission reduction in power and district heat generation is taken into account. A strong tie between emission reduction levels and power price variability can be expected (Hirth, 2013) and thus the importance of flexibility options is expected to increase with higher climate ambitions. The goal of this study is to expand existing knowledge on the importance of power system flexibility by analyzing a comprehensive set of flexibility options utilizing the latest model developments and an updated representation of flexibility options within the BALMOREL model framework.

This paper aims at answering following research questions:

- What is the role of flexibility options for reaching increasingly ambitious climate targets?
- How are profits for suppliers of flexibility affected by climate targets?
- How does competition between flexibility options affect profitability?

Flexibility options included in this study are transmission, electricity storage, heat storage, DR, PtH, EV smart-charging, and supply side flexibility from power producers. The analyzed scenarios assess the flexibility options in a competitive setting by restricting investment in only one flexibility option at a time. The analysis is performed for the year 2030 as it is an important point along the way towards the 2050 goals and represents an energy system in transformation. Results are compared to a baseline in which full flexibility apart from endogenous transmission investment is permitted. The authors believe that this approach will better represent the true value of a flexibility options in a highly complex energy system, than making model runs only including one flexibility option at a time.

The remainder of this paper is organized as follows. Section two describes the BALMOREL model framework, the model setup and the scenarios used. Section three presents the results from the model runs and discusses these. Finally, a conclusion summarizes main findings, limitations and explores a need for future research.

2. Method

2.1. BALMOREL model

The results of this paper are based on the open source BALMOREL modeling framework written in GAMS. BALMOREL is a partial equilibrium model well suited for simultaneous operation and investment optimization for the power and district heating sector (Wiese et al., 2018). The modelling framework converts, stores and unstores primary energy inputs to match an exogenously defined power and district heat demand, minimizing system costs. Recent model extensions allow the assessment of further challenges for the energy system, such as the impact of EVs or DR. BALMOREL has been tested and calibrated in numerous studies for the Nordic and Baltic countries, where most of the institutions applying and developing this model framework are located. The spatial resolution is defined on three hierarchical levels. On the country level, policy and economic data, such as fuel prices and emission restrictions are defined. On a regional level, which in the Nordics and Baltics corresponds to the Nord pool market's bidding zones, electricity demand and transmission are defined. On an area level, generation units, district heat loads and local resource characteristics (e.g., for wind) are defined. The temporal resolution is currently at its most resolved level on an hourly basis. A linear modeling approach is chosen over a mixed integer approach with unit commitment due to its lesser requirements on computational time, allowing to maintain a high level of detail with regards to the temporal and spatial setup. To represent VRE accurately in models it is of high importance to run the model with a high temporal resolution, since currently no best practice for aggregation of time slices of VRE exists (Cao et al., 2019). The temporal setup for this study is designed to capture seasonal, weekly and hourly variations in energy supply and demand. Twelve weeks are modeled, equally distributed over the year. Within each week the hours 1–72 and 121–144 are modeled to include weekdays, as well as a weekend day. The modeled year is 2030. The spatial setup (Fig. 1) includes Norway,

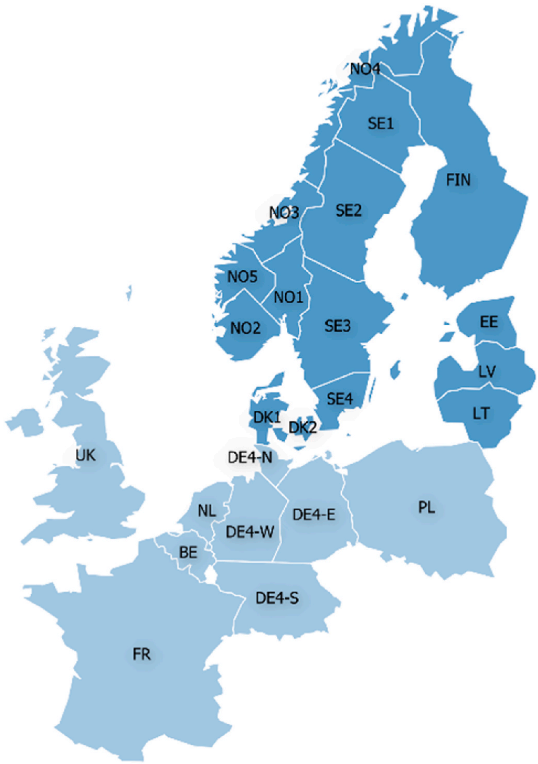

Fig. 1. Country and regional setup in BALMOREL.

Finland, Sweden, Denmark, Estonia, Lithuania, Latvia, Poland, Germany, Belgium, Netherlands, France, and the UK. Regions in the Nordics and Baltics are defined as the bidding zones in the Nord pool market. Germany is divided along transmission bottlenecks. Other countries are defined and one node.

2.2. Scenario description

The term flexibility can address different topics in energy systems analysis. In this paper, flexibility is defined as the ability of the energy system to deploy resources in order to respond to changes in the residual load (Lannoye et al., 2012). The residual load is the load not served by VRE generation and can be negative if generation exceeds demand. To analyze flexibility, seven different scenarios for the year 2030 are studied. Each scenario is run with six different CO_2 emission restriction levels (in the following referred to as climate targets), making a total of 42 runs. To evaluate the impact of each individual flexibility option, the study compares the model results from a BASE scenario, where all flexibility options are included simultaneously, to results from model scenarios, in which one single flexibility option is removed from the full set of available options. In addition, two extreme scenarios are included to illustrate the energy system in case of (i) very high availability of flexibility, where endogenous transmission line investments are also allowed, and (ii) extreme lack of flexibility, where all analyzed flexibility options are restricted simultaneously. In line with the study objective, the results of the scenario runs are analyzed with regard to economic implications. Capacity investments and operational aspects, however, were also taken into consideration in order to achieve deeper insights. Table 1 gives an overview of the different scenarios including a short description.

Table 1
Scenario description.

Scenario	Description
BASE	All flexibility options are available, except for endogenous transmission investment
noTrans	No transmission investment in planned projects after the year 2023
moreTrans	Endogenous transmission investment allowed
noDSMflex	No demand side management (DSM) from EV smart charging and no potentials for DR are available
noBat	No investment in battery storage is available
noHeat	Investment in heat storage and power-to-heat technologies is restricted
noFlex	All above mentioned flexibility options are restricted

Each scenario is modeled using the following exogenously defined climate targets: CO_2 emission reduction by 0%, 60%, 70%, 80%, 90% and 95% compared to calculated 2020 CO_2 emission levels. The model runs are labeled using the following format: Scenario_climate target. Thus, for example, BASE_60 describes the BASE scenario with a 60% CO_2 emissions reduction target.

The BASE scenario is used as a base line for comparison in the analysis. It includes flexibility from generation capacities, planned transmission investment from the "Ten-Year Network Development Plan" by ENTSO-E (2018) (TYNDP), DR, EV smart-charging, battery storage investment, PtH investment and heat storage investment. An overview of technoeconomic assumptions in BALMOREL for investable technologies in 2030 can be found in table A1 of the appendix. Production and use of hydrogen are not part of this analysis as the scope is limited to the power and district heat sector where hydrogen in test runs proved not to be cost competitive with other flexibility options, due to high costs and low roundtrip efficiencies. The value of hydrogen may, however, lie in the flexible nature of its applications outside of the scope of the applied model framework.

Transmission scenarios include the noTrans and moreTrans scenarios. Transmission is modeled on a regional level. Planned transmission projects between regions are based on ongoing and planned projects from the TYNDP. The noTrans scenario only includes planned projects up to the year 2023 in order to reflect existing uncertainties for projects in the more distant future. The moreTrans scenario includes all projects planned until 2030 and can invest in additional transmission capacities between model regions to minimize system costs. Cost assumptions for endogenously invested transmission are based on cost estimates of former or planned transmission projects.

Two demand side flexibility sources, which are disabled in the noDSMFlex scenario, are addressed in this study. One is the charging scheme of EVs, which is defined here as the interface for sector coupling between the power and the private transport sector. The other source of demand side flexibility regards DR from load shifting or load shedding. The BASE scenario assumes smart-charging, where load is controlled by price signals (subject to restrictions). EV smart-charging profits are calculated as the sum of the savings from downshifts and the costs from upshifts in load at the spatial and temporal respective electricity prices, plus variable and fixed cost components. Additionally, BASE assumes DR from household, industry and tertiary sector to be available. The noDSMFlex scenario restricts charging to uncontrolled charging. When plugged in, EV's are charged at full charger capacity until the maximum capacity is reached. This charging scheme adds significant load to peak hours and further increases the need for flexibility in the energy system. Also, in noDSMFlex DR is disabled. Fig. 2 displays the schematic approach for calculating demands and availability of EV charging schemes, which is based on recent work by (Gunkel et al., 2020). First the EV and plug-in hybrid EV (PHEV) stock is estimated. The electricity demand and the daily driving patterns are assumed. These are aggregated for the estimated fleet to then calculate the load in one of the two analyzed charging schemes. The representation of EVs is limited to the private transport sector and covers only home charging. Demands from

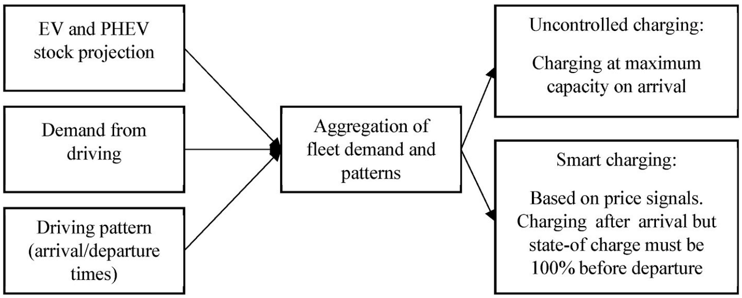

Fig. 2. Schematic representation of EV charging schemes in BALMOREL.

public charging are disregarded.

A schematic representation of DR in BALMOREL is presented in Fig. 3 and is based on the work of Kirkerud et al. (2021). In the first step, common DR applications in industry, household and tertiary sector are identified. For each of these DR applications, technical potentials are derived. The likely adoption of each application is assessed to calculate the actual potential for every year. Techno-economic data relates to the cost of the technology adoption, variable cost for use of DR, temporal availability, shifting time, losses and limits to up and down regulation. From this a load dependent potential that takes hourly availability and associated costs for each DR-category into account is calculated.

The noBat scenario does not permit additional investment into battery storage as a flexibility option. The battery technology considered in this study are lithium-ion batteries for peak storage units and for grid application. Assumptions are based on technology data for energy storage by the Danish Energy Agency and Energinet (2018) and are represented in table A1. Costs for battery storage are subject to a high level of uncertainty as technology developments and cost reductions might exceed predictions by Energinet. The study is limited to the effects of battery storage for balancing supply and demand. Other important system benefits of battery storage such as its role in ancillary services or an upgrade deferral on the distribution grid level are not part of this study.

The noHeat scenario restricts endogenous investment in PtH and heat storage technologies, such as electric boilers, heat pumps, pit or tank storage. Assumptions for these technologies are based on Danish Energy Agency and Energinet (2020).

The noFlex scenario restricts all previously mentioned forms of flexibility, making the system reliant on already available flexibility or investment in generation capacities.

3. Results and discussion

3.1. Impact of flexibility options on total system costs

Fig. 4 shows the changes in system costs, in dependence on the analyzed scenarios and the climate targets. The values are relative to the BASE scenario without emission restrictions and are calculated by subtracting the system costs in BASE_0 from the system costs of the different scenarios at the specified climate target. Increasingly ambitious climate targets lead to decreased system flexibility as fossil fuel based thermal power- and heat generation are phased out. Compared to BASE_0, stricter climate targets increase the changes in system costs exponentially across all scenarios, as seen in Fig. 4. Restricting flexibility increases system costs further, with the highest increase observed in the noFLEX scenario. Endogenous transmission investment (moreTrans) increases system flexibility and decreases system costs compared to the BASE scenarios. The noFLEX scenario demonstrates the economic relevance of system flexibility with more ambitious climate targets. System costs, for example, increase by 60% in noFlex_95 when compared to BASE_95. The relative importance of specific flexibility measures is dependent on the climate target. At less ambitious climate targets, demand side management (DSM) is particularly valuable for increasing system efficiency (grey bars compared to orange). With ambitious climate targets, the roles of endogenous transmission investment (black bars) and sector coupling with the heat sector (yellow bars) are the most effective flexibility options to guarantee an efficient power and heat system. Battery storage (light blue bars) is not invested in most scenarios below the 90% climate target and thus only increases system efficiency to a small extent in the deep decarbonization scenarios.

3.2. Effect of climate targets on producer profits

Profits for each technology or group of technologies are calculated jointly for the power and heat sector at the analyzed climate target. Profits are analyzed in the BASE scenario. This scenario allows for all flexible investment options to be utilized, except for endogenous transmission investments. Flexible generation technologies, which are also considered flexibility options, are analyzed separately from other flexibility options due to their disproportionally larger changes in profits.

Profits for flexibility options change at different climate targets largely due to price volatility, new capacity investments and restrictions on CO_2 emission intensive power generation. This results in changes of

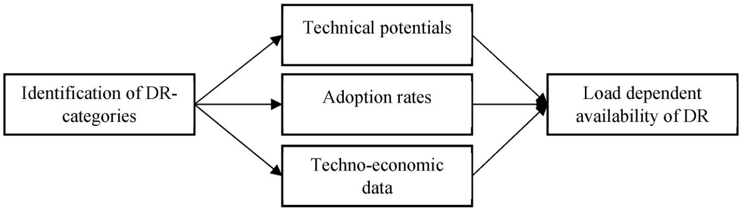

Fig. 3. Schematic representation of DR in BALMOREL.

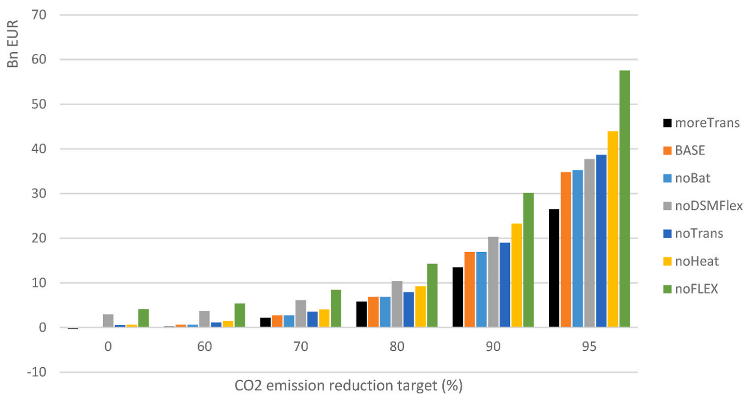

Fig. 4. Changes in system costs compared to the BASE scenario with 0% emission reduction cap.

activation or generation from flexibility measures. Price volatility and more extreme prices (high and low) increase with more ambitious climate targets. As an example of this observation, a box and whisker plot for one of the model regions, in this case NO1, is displayed in Fig. 5. The horizontal line in each box represents the median power price, the lower and upper borders of the box the 25th to 75th percentile, and the whiskers the power price at the 10th and 90th percentile. It is observed that with more ambitious climate targets, the 90th percentile prices increase while the 10th percentile and the median prices decrease.

3.2.1. Flexible generating technologies

Dispatchable generation technologies provide supply side flexibility. Profits in 2030 for the BASE scenario from these technologies are represented in Fig. 6. Renewable energy sources in this category are hydropower from reservoirs and biomass. Biomass includes generation from biogas, biooil, straw, wood, woodchips, wood pellets and wood waste. Fossil based thermal generation accounts for the remaining supply side flexibility. Supplemental data on the electricity- and heat generation mix as well as profits per MWh can be found in table A2 of the appendix.

Total profits for hydropower generation are highest and increase with more ambitious climate targets due to higher profits per MWh. Total generation remains unchanged. Higher profits per MWh are

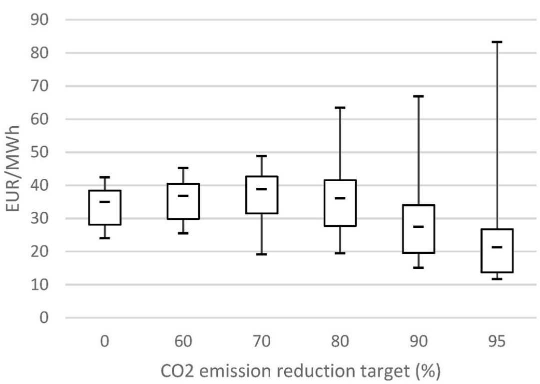

Fig. 5. Box and whisker plot for power prices in the BASE scenario in region NO1
(Whiskers represent the 10th to 90th percentile, boxes represent the 25th to 75th percentile, the horizontal line within a box is the median).

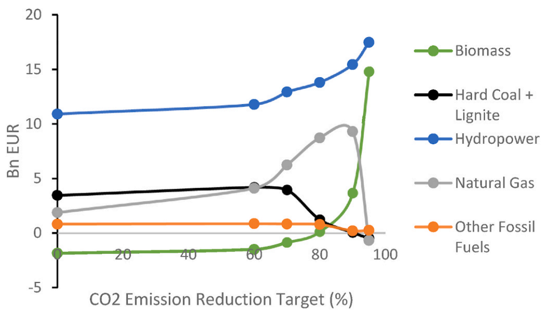

Fig. 6. Change in profits of flexible generation technologies at increasing decarbonization targets in 2030 (BASE).

realized due to increasing price volatility with more ambitious climate targets. Profits for biomass increase exponentially towards the climate target with 95% CO_2 emission reductions, due in large part to increased power and heat generation from biomass and higher prices received. Particularly in the heat sector competition from fossil generation decreases with higher climate targets. Total profits for generation from hard coal and lignite remain almost constant up to the BASE_70 scenario. This is true despite a strong decline in generation by 53% compared BASE_0. Increasing profits by almost 300% per MWh produced counter this effect in terms of total profits. At more ambitious climate targets, profits decrease due to lower generation and annualized fixed costs, which outweigh the increased profits per MWh. Total profits for flexible natural gas generation increase up to the BASE_90 scenario due to a slower decrease in generation compared to hard coal and lignite coupled with increasing profitability because of flexible generation at peak prices. Natural gas generators are beneficiaries during the transition towards a cleaner energy system. In very deep decarbonization scenarios, however, generation from natural gas will become obsolete. Hydropower and biomass can be seen as winners in the transition towards a low carbon energy system. Hard coal and lignite as well as other fossil fuels will experience declining profits when the climate target exceeds 70% reduction.

3.2.2. Flexibility options

The analyzed flexibility options serve multiple purposes in the energy system, among the most important: Lowering overall system costs by matching supply and demand more efficiently, decreasing peak load and increasing supply in peak hours. Additionally, the investment in system flexibility decreases curtailment at ambitious climate targets because negative residual load can be partially absorbed (see Figure A1 in the appendix for detailed curtailment data). Fig. 7 shows the total profits for PtH, heat storage, battery storage, DR and EV-smart charging.

Total profits for the analyzed flexibility options mostly increase with stricter climate targets. PtH profits increase by up to 349% from the BASE_0 to the BASE_90 scenario. In BASE_95 profits decrease but remain higher than the profits for the 80% reduction levels. This is partially explained by investments in other flexibility options that increase competition (such as battery storage) in the BASE_95 scenario. The high increases in PtH profits with more ambitious climate targets are driven largely by volume, as heat generation from electricity increases from 70 TWh for the BASE_0 to 247 TWh for the BASE_95 scenario. Heat storage profits increase by 269% from the BASE_0 to the BASE_95 scenario. Profits are driven by a 251% increased activation of heat storages. There is no investment in battery storage before the BASE_90 scenario, and its capacity is only increased significantly at the 95% climate target. At this climate target, battery storage is very profitable because it takes advantage of extreme power price variations. At lower climate targets battery storage is outcompeted by DR and EV smart-charging, which essentially perform the same function of load shifting at lower investment costs. With higher demand for flexibility, however, these flexibility options are restricted by available capacity and reach their shifting limits. In the BASE_90 scenario battery storage begins to fill the flexibility gap. DR profits are not strongly affected by the climate target. EV smart-charging profits even decrease by 15% from the BASE_0 to the BASE_95 scenario. More competition at ambitious climate targets outweighs benefits from increased price variation. Of the analyzed flexibility options in Fig. 7, EV smart-charging generates the highest profits up to the 80% climate target due to high availability and low investment costs, after this PtH generates the highest profits.

3.3. Competition and synergies between flexibility options

Competition and synergies between flexibility options are measured by the changes in earned profits. The results of the different scenarios are compared to the BASE scenario. This is done by subtracting the results of the BASE scenario at the different climate targets from the results of the respective analyzed scenario, for example, moreTrans_90 – BASE_90. This gives an understanding of how adding/removing a certain flexibility option affects the profits of other flexibility options. The analysis includes the moreTrans scenario to investigate the role of transmission investment, the noHeat scenario to understand the role of power and heat sector coupling, and the noDSMFlex scenario to analyze the effect of DR and EV- smart charging on other flexibility options.

3.3.1. Endogenous transmission investment

Endogenous transmission investment addresses bottlenecks in the planned transmission system and largely affects imports and exports between regions. As an example, Fig. 8 shows the change in net electricity exports, calculated by subtracting the net exports Base_90 from the net exports moreTrans_90.

Endogenous transmission investment leads to the Nordic and Baltic countries and France exporting more electricity. Additional generation is largely from wind and solar PV which has favorable resource conditions in these regions. Other western and central European countries import more electricity. Changes in transmission capacity result in changes to the generation mix and power prices. This also affects profits for suppliers of flexibility. More detailed import and export data for this example can be found in tables A3 and A4 of the appendix.

Fig. 9 displays the change in profits for flexible generation (left) and other analyzed flexibility options (right) in the moreTrans compared to the BASE scenario for the different climate targets. Profits for hydropower increases with more ambitious climate targets. Price volatility is “imported” via transmission into hydropower heavy market regions, and flexible hydropower can serve a larger demand from several market regions. Endogenous transmission investment increases hydropower profits in moreTrans_0 by 1,4 Bn EUR, corresponding to a profit increase of 13% in comparison to profits in BASE_0. With more ambitious climate targets absolute profits increase even more and result in additional profits of 4,7 Bn EUR, i.e. a 27% increase at the 95% climate target. This shows that synergies between transmission investment and hydropower profits exist. For the thermal baseload technologies hard coal and lignite, the results are mixed. Profits are nearly the same in the moreTrans 0–70% scenarios, higher in 80–90% scenarios, and lower in the 95% climate target scenario when compared to the respective BASE scenario. Baseload technologies may profit from providing cheap electricity to a larger interconnected region, leading to fewer time periods with extremely low electricity prices. On the other hand, they face higher competition from cheap renewable generation. Depending on the climate target, hard coal and lignite may display either synergies or competition with transmission investment. Endogenous transmission investment decreases price volatility in market areas with lower amounts of inherent flexibility. This leads to substantially lower profits from dispatchable electricity generation from biomass and natural gas with higher climate targets. Transmission can thus be described as a competitor for providing flexibility with these technologies. In the moreTrans_95 scenario profits from flexible biomass generation decrease most notably by 7.4 Bn EUR or 50% compared to BASE_95.

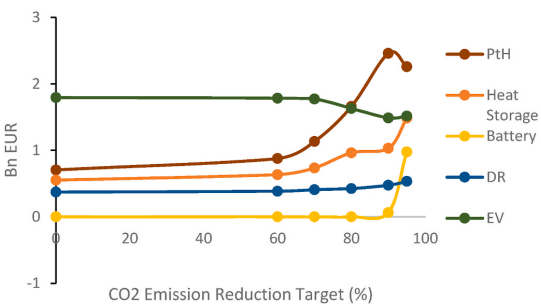

Fig. 7. Change in profits for flexibility options at increasing decarbonization targets in 2030 (BASE).

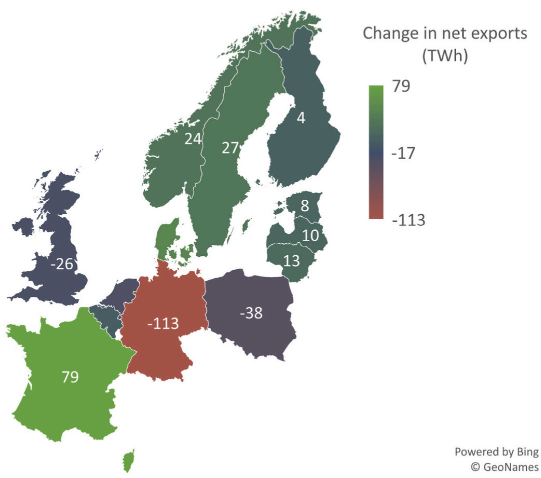

Fig. 8. Change in net exports on a country level between BASE_90 and moreTrans_90.

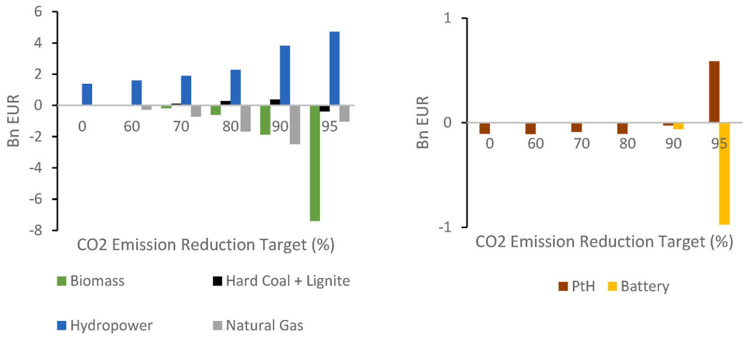

Fig. 9. Change in profits of flexible generation technologies (left) and other flexibility options (right) in the moreTrans compared to the BASE scenario in 2030.

Other flexibility options affected by endogenous transmission investment are PtH and battery storage. PtH displays lower profits by up to 15% or 108 M EUR up to the 90% climate target (Fig. 9, right side). In moreTrans_95, however, profits increase strongly to 585 Million EUR or by 26% compared to BASE_95. This is because PtH helps to fill the heat generation gap left by fossil fuels and has access to low cost renewable electricity generation from a larger region. Transmission investment, as a flexibility option and enabler, outcompetes battery storage for providing flexibility. The moreTrans scenario displays no profits for battery storage, while the BASE scenario shows profits for battery storage at the 90% and 95% climate targets. Results for heat storage, DR and EV smart charging are inconclusive as profits differ only slightly from the profits in the BASE scenario and no clear patterns are evident. Table A5 in the appendix gives a complete overview with absolute and percentage changes in profits.

3.3.2. Sector coupling with the district heat sector

The comparison of the noHeat scenario to the BASE scenario is used to analyze competition and synergies caused by sector coupling with the heat sector (via PtH with additional heat storage). In the noHeat scenario PtH and heat storage are disabled. Table A6 in the appendix gives a complete overview with absolute and percentage changes in profits between the noHeat and the BASE scenario at the respective climate targets.

Fig. 10 shows the change in profits for flexible generation (left) and other flexibility options (right) in the noHeat compared to the BASE scenario. Compared to the BASE scenario, the noHeat scenario shows increasing profits for biomass with stricter climate targets: From 113 M EUR at the 0% to 6,9 Bn EUR at the 95% climate target. Total biomass electricity generation between the noHeat and BASE scenario stays constant. Heat generation increases by 26 TWh, however, in the noHeat_0 scenario and by up to 199 TWh in the noHeat_95 scenario in comparison with the respective BASE scenarios. This is because biomass faces little competition from other flexibility sources to provide heat in the noHeat scenario at ambitious climate targets. These results are sensitive to the availability of biomass. In the noHeat scenarios, hard coal and lignite profits stay neutral or may even decrease with stricter climate targets in comparison to the respective BASE scenarios, thus displaying neither strong competition nor synergies. Natural gas is in competition with PtH and heat storages. Additional profits in the noHeat scenario are particularly high for natural gas in the 70–90% reduction scenarios, with up to 3,9 Bn EUR. Hydropower displays synergies from sector coupling with the heat sector, as additional power demand leads to small increases in profits at all climate targets.

The right side of Fig. 10 shows that battery storage is in competition with PtH for cheap electricity. It has 100 M EUR higher profits in the noHeat_90 and 35 M EUR higher profits in the noHeat_95 scenario in comparison to the respective BASE scenarios. Also, both DR and EV smart-charging are in competition for cheap electricity with PtH and have higher profits at 0–90% climate targets in the noHeat scenario. At the 95% climate target, the system is operating at its flexibility limits. Thus, in both noHeat and the BASE scenarios DSM is used to its full potential. Here, the differences between the noHeat and the BASE scenarios regarding profits are small.

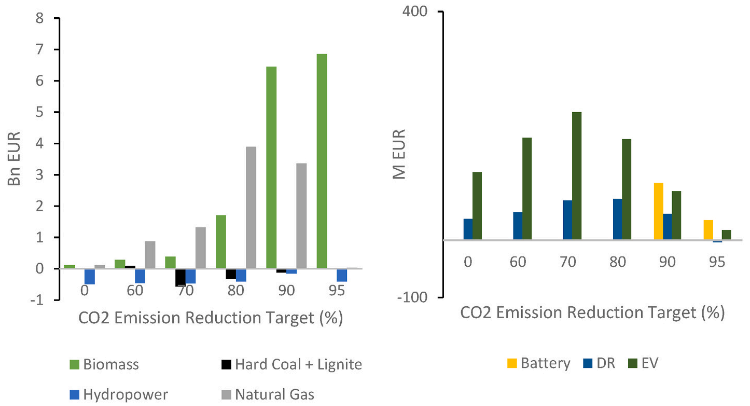

Fig. 10. Change in profits of flexible generation technologies (left) and other flexibility options (right) in the noHeat compared to the BASE scenario in 2030.

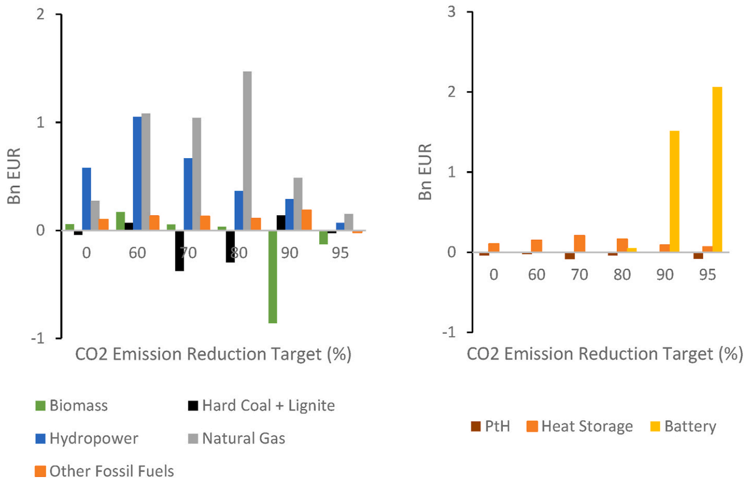

Fig. 11. Change in profits of flexible generation technologies (left) and other flexibility options (right) in the noDSMFlex compared to the BASE scenario in 2030.

3.3.3. Demand side management

DSM is represented by DR and EV smart-charging in this study. Table A7 in the appendix gives a complete overview of absolute and percentage changes in profits between the noDSMFlex and BASE scenarios at the respective climate targets.

Fig. 11 shows the change in profits of flexible generation technologies (left) and other flexibility options (right) in the noDSMFlex compared to the BASE scenario. Biomass profits increase slightly at the 0–80% climate targets, indicating competition for peak load generation between biomass and DSM measures. At the 90–95% climate targets profits are lower, indicating that with stricter climate targets DSM and biomass benefit each other. Hard coal and lignite do not display a clear trend with regard to profits between the scenarios at different climate targets. Natural gas is in strong competition with DSM for providing peak load generation. The results show that natural gas profits increase by 5–26% in the noDSMFlex scenario compared to the BASE scenario depending on the climate target. In absolute numbers, natural gas profits increase most at the 60–80% climate targets (up to 1,5 Bn EUR). Hydropower is in competition with DSM flexibility, as shown by an increase in profits for hydropower of up to 1,1 Bn EUR at the 70% climate target. In deep decarbonization the competition decreases but is still observed.

Results for other flexibility options (Fig. 11 right side) show that PtH is hardly affected by DSM. Heat storage and battery storage on the other hand are in competition with DSM flexibility. Like DSM, both technologies shift loads. Heat storages, however, are only indirectly affected by sector coupling of the power and district heat sectors. Thus, competition between DSM and heat storage is small. In the BASE scenario, battery storage is outcompeted by DSM because of lower investment costs. Battery storage is only utilized when DSM flexibility is used to its full potential. In noDSMFlex battery storage gains importance, as competition is reduced, and profits increase at the 80% and higher climate targets.

4. Conclusion

This paper analyzes the economic effects and competitiveness of various energy system flexibility options for Northern, Western and Central European countries. The BALMOREL model results illustrate how the value of flexibility options strongly increases with stricter emission reduction targets. The flexibility options analyzed in this study may contribute to reducing system costs by 60% on the deep decarbonization pathway (95% climate target) compared to the noFLEX scenario, underlining the importance of system flexibility. Of the analyzed flexibility alternatives, transmission investment and sector coupling with the district heat sector have a particularly large impact on lowering system cost in deep decarbonization. If the modeled countries pursue less ambitious climate targets, however, the results suggest that DSM increases system efficiency most. At ambitious climate targets winners on the producer side, which offer flexibility are dispatchable renewable generation from hydropower and biomass. This is due to higher price variability, less competition with fossil fuel generation and, in the case of biomass, more generation at ambitious climate targets. Natural gas power is found to be a profitable bridging technology during the transition to a deeply decarbonized system. Despite decreasing total generation, profits from natural gas increase up to the 90% climate target. As expected, we find that producer profits for providers of flexibility increase more with more ambitious climate targets (except for fossil generation). Synergies and competition between flexibility options, however, affect producer profits of the individual flexibility options unequally. In particular, transmission line investments are found to have strong synergies with hydropower in terms of profits, since more interconnectors allow for better utilization of the highly flexible hydropower located in Norway and Sweden. On the other hand, sector coupling through PtH displays strong competition with heat generation from biomass and natural gas. PtH takes advantage of low electricity prices and can therefore partially outcompete biomass and natural gas. DSM competes with battery storage but is restricted by capacity limits. DSM also decreases profits for flexible generation from hydropower and natural gas across all climate targets as peak loads are shifted.

Based on the lessons learned in this model study, we recommend more studies addressing competition and synergies of flexibility options in transitioning energy systems. Study limitations regarding the accuracy of the modeling results can be addressed by using a finer granularity in timesteps, as far as computationally feasible. Unit commitment in a smaller model set-up could improve operational insights. Adding further sectors like individual heating, commercial transport, or power-to-X to model a more integrated system could reveal further synergies and competition and would allow a more holistic view. Adding more weather years would further increase insights into the issues of flexibility needs, competition and synergies among flexibility options. Lastly, it should be mentioned that system flexibility provides value that exceeds the analyzed economic impacts. Reliability, grid stability and the need for backup generation are just some of the aspects that should be considered when discussing benefits of system flexibility holistically.

CRediT authorship contribution statement

Niels Oliver Nagel: Conceptualization, Software, Validation, Formal analysis, Writing – original draft, Visualization. **Jon Gustav Kirkerud:** Conceptualization, Software, Writing – review & editing. **Torjus Folsland Bolkesjø:** Conceptualization, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

Table A1
Overview of technoeconomic specifications of investment technology and assumptions in BALMOREL*

Technology	Efficiency	Inv. Cost	Fixed operation cost	Variable operation cost	Fuel cost
		M€/MW	€/kW	€/MWh	€/GJ
Heat storage					
District heat pit storage centralized	0.7	0.0027	0.003		
District heat pit storage decentralized	0.7	0.0004	0.003		
Heat pump					
Air source heat pump (4 MW)	3.3039	0.6656	2.0231	1.8208	
Excess heat pump (4 MW)	12	0.5804	1.96	1.666	
Ground source heat pump (4 MW)	3.8	0.5804	1.96	1.666	
Boiler					
Electric boiler for district heat (10 MW)	0.99	0.0588	0.9996	0.98	
Battery storage					
Lithium ion for grid-scale application (10 MW)	0.9	0.3218	0.2965		
Lithium ion for peak power application (100 MW)	0.9	0.3358	2.1279		
Biogas					
Back pressure, internal combustion engine (1 MW)	0.9391	0.882	9.114	6.86	12.7158
Condensing, internal combustion engine (1 MW)	0.45	0.882	9114	6.86	12.7158
Straw					
Heat only boiler (6 MW)	1.04	0.6579	36.8271	1.023	7.16
Back pressure, steam turbine subcritical (132 MW)	0.9989	2.4432	107.8	1.8878	7.16
Condensing, steam turbine subcritical (132 MW)	0.31	2.4432	107.8	1.8878	7.16
Wood chips					
Heat only boiler (6 MW)	1.17	1.1341	36.7942	1.2648	From 4.154 (Stepwise price increasing with demand)
Back pressure, steam turbine subcritical (600 MW)	1.1429	3.075	49	3.728	From 4.154
Condensing, steam turbine subcritical (600 MW)	0.29	3.075	49	3.728	From 4.154
Wood pellets					
Heat only boiler (6 MW)	1.02	0.9074	31.1136	1.004	10.6522
Back pressure, steam turbine subcritical (80 MW)	0.9818	2.7133	117.6	1.641	10.6522
Condensing, steam turbine subcritical (800 MW)	0.33	1.8868	39.2	1.5153	10.6522
Extraction, steam turbine subcritical (800 MW)	0.33	1.8868	39.2	1.5153	10.6522
Natural gas					
Heat only boiler (500 KW)	1.06	0.049	1.862	0.98	8.3241
Backpressure, internal combustion engine (1 MW)	0.9648	0.882	9.114	4.998	8.3241
Backpressure, Combined cycle (40 MW)	0.8826	0.5488	18.228	4.116	8.3241
Condensing, internal combustion engine (1 MW)	0.48	0.882	9.114	4.998	8.3241
Condensing, gas turbine (40 MW)	0.43	0.5488	18.228	4.116	8.3241
Condensing, combined cycle (100 MW)	0.61	0.8134	27.244	4.116	8.3241
Condensing, steam turbine subcritical (400 MW)	0.47	1.274	37.24	0.8036	8.3241
Extraction, combined cycle (100 MW)	0.61	0.8134	27.244	4.116	8.3241
Extraction, Steam turbine subcritical (400 MW)	0.47	1.274	37.24	0.8036	8.3241
Hard coal					
Condensing, steam turbine subcritical (400 MW)	0.52	1.9502	60.368	2.156	2.6729
Extraction, Steam turbine subcritical (400 MW)	0.52	1.9502	60.368	2.156	2.6729

*Focused on large scale unit size if multiple similar generation technologies are available for investment in 2030. Contains only technologies directly investigated in this study.

Table A2
Power and heat generation and economic data

CO_2 reduction target	Category	Fuel						
		Biomass	Hard Coal + Lignite	Hydropower	Natural Gas	Other Fossil Fuels	VRE	Municipal Waste
0%	Total profit (Million EUR)	−1851	3463	10905	1870	812	8964	505
	El. generation (TWh)	49	179	323	373	19	770	28
	Heat generation (TWh)	89	84		254	20	2	78
	EUR/MWh (El. + Heat)	−13	13	34	3	21	12	5
60%	Total profit (Million EUR)	−1498	4211	11779	4106	862	9910	660
	El. generation (TWh)	53	113	323	327	15	892	32
	Heat generation (TWh)	104	66		233	17	3	91
	EUR/MWh (El. + Heat)	−10	23	36	7	27	11	5
70%	Total profit (Million EUR)	−859	3962	12929	6243	823	11183	906
	El. generation (TWh)	59	71	323	271	11	1003	35
	Heat generation (TWh)	130	52		196	13	3	103
	EUR/MWh (El. + Heat)	−5	32	40	13	34	11	7
80%	Total profit (Million EUR)	133	1234	13803	8720	777	12255	1217
	El. generation (TWh)	69	25	323	245	9	1089	36
	Heat generation (TWh)	166	9		164	10	3	106
	EUR/MWh (El. + Heat)	1	36	43	21	41	11	9
90%	Total profit (Million EUR)	3675	57	15447	9304	201	15107	1962
	El. generation (TWh)	131	13	323	125	5	1217	35
	Heat generation (TWh)	220	2		84	1	2	103
	EUR/MWh (El. + Heat)	10	4	48	45	32	12	14
95%	Total profit (Million EUR)	14792	−486	17470	−676	252	19943	2651
	El. generation (TWh)	163	9	323	43	5	1318	35
	Heat generation (TWh)	242	1		55	1	2	103
	EUR/MWh (El. + Heat)	37	−50	54	−7	44	15	19

Table A3
Electricity exports BASE_90

Imports	BE	DK	EE	FIN	FR	DE	LV	LT	NL	NO	PL	SE	UK
Exports													
BE	–	0.00	0.00	0.00	5.02	3.45	0.00	0.00	14.10	0.00	0.00	0.00	2.14
DK	0.00	–	0.00	0.00	0.00	20.76	0.00	0.00	2.77	4.14	0.00	6.43	4.82
EE	0.00	0.00	–	1.85	0.00	0.00	6.55	0.00	0.00	0.00	0.00	0.00	0.00
FIN	0.00	0.00	2.87	–	0.00	0.00	0.00	0.00	0.00	0.10	0.00	2.29	0.00
FR	27.00	0.00	0.00	0.00	–	57.42	0.00	0.00	0.00	0.00	0.00	0.00	24.25
DE	1.51	5.22	0.00	0.00	4.13	–	0.00	0.00	8.41	3.44	14.07	3.87	2.05
LV	0.00	0.00	0.67	0.00	0.00	0.00	–	9.61	0.00	0.00	0.00	0.00	0.00
LT	0.00	0.00	0.00	0.00	0.00	0.00	0.22	–	0.00	0.00	4.14	0.75	0.00
NL	3.92	0.90	0.00	0.00	0.00	41.65	0.00	0.00	–	2.04	0.00	0.00	2.17
NO	0.00	6.51	0.00	2.80	0.00	6.40	0.00	0.00	3.16	–	0.00	15.07	12.26
PL	0.00	0.00	0.00	0.00	0.00	14.60	0.00	3.07	0.00	0.00	–	1.67	0.00
SE	0.00	7.83	0.00	18.20	0.00	5.20	0.00	3.07	0.00	2.10	2.60	–	0.00
UK	3.02	3.14	0.00	0.00	12.79	5.96	0.00	0.00	2.79	7.78	0.00	0.00	–

Table A4
Electricity exports moreTrans_90

Imports	BE	DK	EE	FIN	FR	DE	LV	LT	NL	NO	PL	SE	UK
Exports													
BE	–	0.00	0.00	0.00	6.30	3.56	0.00	0.00	9.81	0.00	0.00	0.00	4.43
DK	0.00	–	0.00	0.00	0.00	23.11	0.00	0.00	40.42	3.07	0.00	13.25	4.95
EE	0.00	0.00	–	8.32	0.00	0.00	12.50	0.00	0.00	0.00	0.00	0.00	0.00
FIN	0.00	0.00	4.70	–	0.00	0.00	0.00	0.00	0.00	0.39	0.00	6.34	0.00
FR	22.91	0.00	0.00	0.00	–	136.22	0.00	0.00	0.00	0.00	0.00	0.00	26.24
DE	0.68	1.60	0.00	0.00	0.08	–	0.00	0.00	2.79	4.06	15.35	1.98	1.20
LV	0.00	0.00	3.08	0.00	0.00	0.00	–	24.13	0.00	0.00	0.00	0.00	0.00
LT	0.00	0.00	0.00	0.00	0.00	0.00	1.63	–	0.00	0.00	26.74	1.38	0.00
NL	3.22	1.59	0.00	0.00	0.00	42.16	0.00	0.00	–	0.74	0.00	0.00	1.26
NO	0.00	2.76	0.00	2.13	0.00	13.81	0.00	0.00	2.94	–	0.00	11.85	45.44
PL	0.00	0.00	0.00	0.00	0.00	20.11	0.00	2.13	0.00	0.00	–	5.83	0.00
SE	0.00	19.14	0.00	15.07	0.00	8.73	0.00	1.61	0.00	6.90	25.22	–	0.00
UK	9.52	1.18	0.00	0.00	13.50	5.90	0.00	0.00	2.26	12.88	0.00	0.00	–

Table A5
Changes in profits in the moreTrans scenario compared to BASE

CO_2 reduction target	Category	Fuel/Flexibility option									
		Biomass	Hard Coal + Lignite	Hydropower	Natural Gas	Other Fossil Fuels	PtH	Heat Storage	Battery	DR	EV
0%	M EUR	3	−40	1364	−50	47	−108	4	0	−9	−14
	% Change	0	−1	13	−3	6	−15	1	0	−2	−1
60%	M EUR	−10	−1	1578	−270	73	−110	25	0	24	32
	% Change	−1	0	13	−7	8	−13	4	0	6	2
70%	M EUR	−195	110	1887	−724	72	−90	5	0	19	−4
	% Change	−23	3	15	−12	9	−8	1	0	5	0
80%	M EUR	−596	274	2270	−1672	47	−108	−66	0	25	134
	% Change	−449	22	16	−19	6	−7	−7	0	6	8
90%	M EUR	−1867	378	3817	−2492	39	−29	163	−63	−108	−255
	% Change	−51	667	25	−27	20	−1	16	−100	−23	−17
95%	M EUR	−7395	−383	4717	−1029	−189	585	−65	−977	−60	−56
	% Change	−50	−79	27	−152	−75	26	−4	−100	−11	−4

Table A6
Changes in profits in the noHeat scenario compared to BASE

CO_2 reduction target	Category	Fuel/Flexibility option							
		Biomass	Hard Coal + Lignite	Hydropower	Natural Gas	Other Fossil Fuels	Battery	DR	EV
0%	M EUR	113	13	−492	116	43	0	38	119
	% Change	6	0	−5	6	5	0	10	7
60%	M EUR	287	91	−457	873	123	0	50	179
	% Change	19	2	−4	21	14	0	13	10
70%	M EUR	385	−573	−469	1324	217	0	70	224
	% Change	45	−14	−4	21	26	0	17	13
80%	M EUR	1707	−338	−412	3891	−205	0	72	177
	% Change	1287	−27	−3	45	−26	0	17	11
90%	M EUR	6446	−123	−150	3357	35	100	46	86
	% Change	175	−217	−1	36	18	158	10	6
95%	M EUR	6856	−3	−404	30	0	35	−3	18
	% Change	46	−1	−2	4	0	4	−1	1

Table A7
Changes in profits in the noDSMFlex scenario compared to BASE

CO_2 reduction target	Category	Fuel/Flexibility option							
		Biomass	Hard Coal + Lignite	Hydropower	Natural Gas	Other Fossil Fuels	PtH	Heat Storage	Battery
0%	M EUR	56	−41	578	273	98	−42	102	0
	% Change	3	−1	5	15	12	−6	18	0
60%	M EUR	168	70	1052	1082	130	−24	148	0
	% Change	11	2	9	26	15	−3	23	0
70%	M EUR	52	−375	668	1040	128	−85	205	0
	% Change	6	−9	5	17	16	−7	28	0
80%	M EUR	32	−296	363	1471	108	−39	160	49
	% Change	24	−24	3	17	14	−2	17	0
90%	M EUR	−859	137	288	484	187	9	88	1512
	% Change	−23	242	2	5	93	0	9	2388
95%	M EUR	−126	−25	70	151	−18	−83	65	2061
	% Change	−1	−5	0	22	−7	−4	4	211

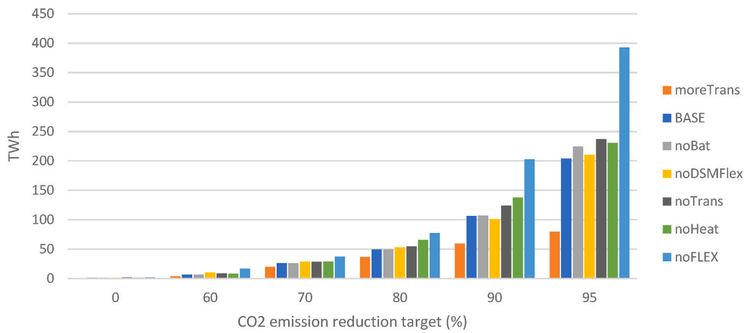

Fig. A1. Curtailment of electricity generation

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Paper III

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Full-length article

Impacts of green deal policies on the Nordic power market

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ABSTRACT

This study analyzes how the Green Deal affects the Nordic electricity and district heat market, considering carbon pricing alone and in combination with policy measures such as a coal phaseout, a renewable target, or an electrification strategy. Our findings show that the Green Deal targets significantly increase CO_2 prices and power price variability. The Green Deal has a minor impact on Nordic electricity production, while a switch to increased power-to-heat is observed in the district heating sector. However, if the EU ETS is supplemented with other policies, generation mix, producer revenues, and CO_2- and power prices are significantly impacted.

1. Introduction

In 2019, the European Union (EU) announced its European Green Deal (European Commission, 2019), aiming at a 55% reduction of greenhouse gas (GHG) emissions by 2030 (compared to 1990 emissions levels) and climate neutrality by 2050. In July 2021, the European Commission presented its 'Fit for 55′ program with more specific details on how to achieve the GHG emission reduction target (European Commission, 2021). The Green Deal involves numerous climate-related initiatives to supplement the EU Emissions Trading System (EU ETS) as the key policy instrument for curbing GHG emissions (sometimes referred to as overlapping climate policy, see, e.g., Böhringer et al. (2016) and Fankhauser et al. (2010). At the EU level, targets for the share of renewables and energy efficiency improvements are proposed, together with large-scale subsidies for low-emissions technologies. At the national level, EU Member States pursue domestic climate policy measures such as renewable support schemes (Swedish Energy Agency and NVE, 2018), coal phaseout schedules (Bundesregierung, 2020), or programs to further electrify energy services in the industrial and residential sectors (Regjeringen, 2021).

The Nordic energy system differs from the remaining European energy system by having larger shares of dispatchable renewable generation from hydropower and additionally having a large percentage of low carbon baseload electricity generation from nuclear power (Wråke et al., 2021). Despite the high proportion of low carbon generation, the Nordics will still be affected by EU climate policies as these policies affect the EU ETS, commodity prices, and electricity imports and exports.

We analyze how the European Green Deal affects the Nordic electricity market and investigate impacts on the district heating sector. These impacts depend crucially on what policies are implemented to reach the proposed emissions reduction targets. Being the cornerstone of climate policy, the EU ETS has the potential to affect the electricity market substantially, aiming at incentivizing production switches from higher to lower carbon intensity and eventually phasing out fossil fuels entirely. The ETS price has varied considerably over time, though. From 2012 to 2017, the price was consistently below 10 Euro per ton of CO_2, in which case the EU ETS had quite limited impacts on the electricity market. Since 2018, however, the price has increased substantially, reaching 80 EUR/tCO_2 by the end of 2021.[1] The ETS price directly affects electricity prices as fossil-based power generation becomes more expensive. In the Nordics, too, the ETS price qualifies as a key driver of electricity prices, not least due to the integration of the Northern European power market with other regions (Chen et al., 2020).

When CO_2 pricing is combined with other policies or measures, as proposed in the European Green Deal, the market effects may be quite different and often less intuitive than CO_2 pricing alone (Böhringer et al., 2016; Fankhauser et al., 2010). One important example is a direct support scheme for renewables. In the 'Fit for 55′ proposal, the has increased the target for renewable energy in 2030 to 40% of the EU's

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[1] This is partly due to regulatory changes in 2018 (i.e., amendments of the Market Stability Reserve of the EU ETS – see e.g., Gerlagh et al. (2021), and partly due to the EU's (anticipated) strengthening of its GHG targets.

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primary energy consumption (European Commission, 2021a), which most likely lifts the share of electricity generation by renewable energy sources (RES-E) to well beyond 50%.[2] Whereas the EU ETS tends to push up electricity prices by raising the costs of fossil-based power, renewable support tends to bring the market price of electricity down by reducing the net costs of renewable energy.[3] However, renewable support in the shape of renewable portfolio standards (RPS), which requires a certain percentage of generation or consumption from renewables, may have ambiguous effects. Fischer (2010) finds that the impact of an RPS on the electricity price varies because it acts as a subsidy to renewables and a tax to non-renewable producers. When the subsidy effect is more impactful, electricity prices are pushed down, while when the tax effect is more impactful, the prices increase. In fact, Böhringer and Rosendahl (2010) find that supporting renewables when an ETS is already in place could stimulate coal power production by lowering the ETS price.

The second example of an additional policy measure to the EU ETS is the mandated phaseout of coal power. Several studies point out that without an accompanying cancellation of emissions allowances, a national coal phaseout would depress EU ETS prices since aggregate emissions remain unchanged (Anke et al., 2020; Böhringer and Rosendahl, 2022). This situation stimulates natural gas power production and coal power generation in countries without phaseout policies, cf. Keles and Yilmaz (2020). However, if allowances are canceled, phasing out coal would contribute to further emissions reductions, and the impacts on the electricity market would be different with lower increases in other fossil-based generation. A third example is the electrification of energy services in the transport, building, and industry sectors, often referred to as sector coupling (IRENA, n.d.). Sector coupling may provide increased demand-side flexibility, which does not necessarily result in lower GHG emissions, as less CO_2-intense backup generation might be partially substituted by more CO_2 -intense baseload generation (Kirkerud et al., 2021). However, sector coupling via electrification in CO_2-intense sectors can unlock demand-side flexibility, promote renewable integration, and reduce GHG emissions (Chen et al., 2021; Gea-Bermúdez et al., 2021). Sector coupling is expected to increase electricity demand significantly (IEA, 2020), but the speed will depend on policies to accelerate sector coupling, and the emission impact depends on the development of the power generation mix and the interactions between the power market with the ETS. Sector coupling between the power and district heating sectors also creates new competition between technologies. Lindroos et al. (2021) find that heat pumps, e.g., can decrease bioenergy investments for heat production. The study also highlights that optimal local investment decisions may differ from the system optimum, causing potential conflicts.

To investigate the impacts of the European Green Deal on Nordic power prices, generation mix, and producer revenues, we make use of two numerical models: First, a computable general equilibrium (CGE) model of the European economy, which we use for simulating the EU ETS and fuel prices as well as electricity consumption under different climate policy scenarios. Second, these prices and consumption levels are fed into a detailed Nordic electricity and district heat market model, which we use to simulate the policy-induced changes in electricity prices and the structure of power and heat generation. Our quantitative results show that the impacts on the Nordic power market depend on the overall emission target's stringency and on how the target is reached. A somewhat similar approach is taken by Abrell and Rausch (2016), who integrate high-frequency electricity dispatch into a static CGE model, studying impacts on renewable electricity, electricity trade, and CO_2 emissions in Europe under different scenarios for 2020 and 2030.

The impacts of GHG emissions policies on the power sector in Europe have been widely studied (European Commission, 2011, 2018, 2020; Korkmaz et al., 2020; Simoes et al., 2017). The scenarios of previous studies, however, mainly cover the former 40% GHG emissions reduction target for 2030. However, studies such as Pietzcker et al. (2021) covering the updated EU targets can be found. They explore technological and economic implications, including changes to the generation mix based on the new GHG reduction targets for the EU. The study covers a broad European spatial scope, representing countries as single nodes. ETS interaction between the power and other sectors is included via marginal abatement cost curves. Our study also considers the updated 55% reduction target for 2030 and accounts for interactions between the power sector and the ETS by additionally applying a general equilibrium model. Then interactions between the EU ETS and several other policies are analyzed on a more detailed spatial level for the Nordic countries utilizing a partial equilibrium power and district heating model. Some of these interactions between the EU ETS and climate policies are also examined in the study by Anke et al. (2020) in the context of the European power market. However, they do not account for ETS emissions outside the power market (which we do by applying a CGE model of the broader economy). Also, they do not cover the updated 'Fit-for-55′ target. There is thus a research gap in studying the effects of possible climate policy pathways consistent with the European Green Deal at a spatially detailed level for the Nordic region. Also, we observe that most studies focus on emissions impacts and/or the electricity generation mix and not so much on how policies may affect market values, i.e., competitiveness, of specific power generation technologies. There is growing literature on the market value of renewables, especially concerning the market share of variable renewable energy (VRE) (Eising et al., 2020; Hirth, 2015), and we examine how the different climate policy scenarios affect market values. The market value in this paper is defined as the revenue averaged over each unit of energy produced. Policy-induced changes in the market values of technologies are of utmost importance to future investment decisions in the energy transition. Finally, the studies mentioned above mainly focus on the EU jointly, but the energy system in different regions will be affected differently, making regional studies important. As far as we know, there are no previous studies analyzing the possible impacts of the European Green Deal on the Nordic energy system.

2. Method

2.1. Combining a CGE model and an electricity market model

To analyze the implications of the European Green Deal for the Nordic power market, we combine a static economy-wide computable general equilibrium (CGE) model for the European economy with a computable partial equilibrium model of the electricity and district heat market in Northern Europe (Balmorel). The two models are described in more detail in sections 2.2 and 2.3 below, and a schematic representation of the soft linking is shown in Fig. 1. The approach's strength is that it utilizes the advantages of both models, which are necessary to achieve the research objective of investigating the impacts of climate policies related to the European Green Deal on Nordic power prices, generation mix, market values, and producer revenues. The CGE model is necessary to calculate EU ETS prices, electricity demands, and heat demands. It covers the whole economy, including interactions between sectors, and obtains price and demand levels derived from economy-wide responses across the analyzed policy scenarios endogenously, for which a power sector model cannot be used. The Balmorel model outputs detailed temporal and spatial operational and investment data for the Nordics, which is required to address the above-stated research objectives. Balmorel was chosen over other energy system models for several reasons. First, it has a detailed representation of the Nordic power market, where market areas are modeled in accordance with Nordpool bidding zones,

[2] According to Agora Agora Energiewende, 2019, the existing overall target for renewable energy at 32% implies a renewable energy share in the electricity sector of more than 50%.

[3] The price paid by (some) electricity consumers may still increase though if the renewable support is financed via an electricity tax, which is the case in many countries (e.g., in Germany).

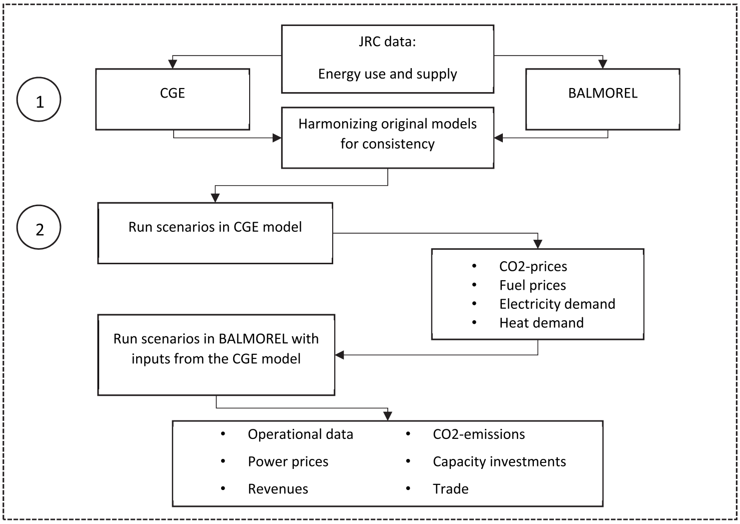

Fig. 1. Schematic overview of the soft linking process.

and also allows for a high time resolution. Second, it is one of few open-source energy system models with a long history of development, allowing users to trace model assumptions and interact with the code. Third, the model is well calibrated to the Nordics in numerous studies (see Wiese et al. (2018) for applications) and provides detailed underlying data, which provided the basis for the model setup.

First, the two models are calibrated using Baseline Global Energy and Climate Outlook (GECO) data for energy use and supply in 2030 by the EU Joint Research Center (JRC) (Keramidas et al., 2018). Both models are anchored in historic (2015) price and consumption levels while being linked through relative changes vis-à-vis historical levels to bridge spatial and temporal resolution differences and data aggregation. Thus the output of the CGE model, e.g., for the power demand, is utilized in Balmorel by first calculating the percentage change from 2015 to 2030 in the CGE model and then applying this percentage change to historic 2015 values in Balmorel to arrive at 2030 values. Both models were adjusted for consistency in several iterations before implementing the model scenarios to ensure robust results. Adjustments included, e.g., supply and price elasticities for different technologies. One noteworthy adjustment for consistency between the models was defining an inflexible fixed nuclear production level in Balmorel to 85% of its capacity (capacity factor based on Lorenczik et al. (2020)). This adjustment leads to nuclear power generation that does not change between modeled time steps or scenarios and does not respond to changes in electricity prices. Because nuclear is a baseload technology with moderate flexibility, presented results for technologies other than nuclear are only moderately impacted by this assumption. Results for nuclear power may be more favorable than this study's results, as ramping in response to electricity prices would increase nuclear market values.

Second, the CGE model is run for each scenario, both the baseline scenario consistent with JRC and several policy scenarios (cf. Section 3). Outputs from the CGE model are then fed into the Balmorel model. More specifically, fuel price and CO_2 emission (EU ETS) prices, along with national electricity and heat demands, which are endogenous in the CGE model, are used as exogenous inputs in Balmorel. Balmorel is then run to derive detailed operational and investment decisions in Northern Europe's electricity and district heat markets. Due to the temporal resolution, at an hourly level, the Balmorel can also readily track the volatility of power prices across time.

2.2. CGE model

The multi-sector, multi-region CGE model adopts a standard top-down structure representing production, consumption, and trade cf. Böhringer et al. (2018) and Böhringer and Rosendahl (2022) but stands out for a more detailed bottom-up representation of electricity generation. The model distinguishes discrete technologies that produce electricity (including heat) by combining inputs of fuel, material, labor, capital, and natural resources such as water, wind, sun, or biomass. For each technology, power generation takes place with decreasing returns to scale and responds to changes in electricity prices according to technology-specific supply elasticities, cf. Böhringer and Rosendahl (2022) for more details. Within each region of the model, electricity output from different technologies is treated as a homogeneous good. Instead of explicitly modeling transmission capacities between countries, bilateral trade for electricity (as for other goods in the model) is based on the Armington assumption of product heterogeneity, where domestic and foreign goods are distinguished by country of origin (Armington, 1969). The Armington assumption provides a tractable solution to various problems associated with the standard neoclassical (Heckscher-Ohlin) perspective of trade in homogeneous goods (Whalley et al., 1985): (i) it accommodates the empirical observation that a country imports and exports the same good (so-called cross-hauling); (ii) it avoids over-specialization implicit in trading in homogeneous goods; and (iii) it is consistent with trade in geographically differentiated products.

Base-year data provided by the Joint Research Centre (JRC) of the EU Commission (Keramidas et al., 2018) are used together with elasticities taken from the empirical literature (Koesler and Schymura, 2015) to parameterize the model. The JRC data includes detailed accounts of production, consumption, and bilateral trade and information on physical energy flows and CO_2 emissions for 40 regions and 31 sectors covering the world economy. The electricity sector in the JRC dataset is decomposed by region into 11 discrete power generation technologies. The dataset provides baseline projections of economic activities and energy use in five-year intervals until 2050, which we use to establish our baseline scenario for 2030 as the central (target) year of our policy analysis.

The dataset distinguishes between primary and secondary energy carriers: Coal, crude oil, natural gas, refined oil, and electricity. We keep all these energy carriers in the composite dataset for our analysis to capture differences in CO_2 intensity and the degree of inter-fuel substitutability. Furthermore, we treat all energy-intense and trade-exposed industries covered by the EU ETS separately. These are at the fore of policy concerns about structural change triggered by ambitious emissions pricing. The ETS is modeled as a standard static auction-based cap-and-trade system and is equivalent to a CO_2 tax adjusted to reach a specific emissions target.[4]

Last but not least, we maintain the detailed description of the electricity supply provided in the JRC dataset. All remaining sectors in the original data set are aggregated into two composite sectors (services and all other goods). The coverage of regions in our composite dataset reflects our focus on Europe's electricity market and climate policies. The EU is divided into 12 regions based on country size and location. The rest of the world is divided into one non-EU European region[5] and four individual or composite regions. Table A1 in the appendix provides an overview of the sectors in the CGE model (incl. Power technologies) and regions.

2.3. Balmorel model

Balmorel is a partial equilibrium model that simultaneously optimizes operation and investment decisions in power generation and district heating. The model has been calibrated and validated in numerous studies, and a detailed model description with strengths and weaknesses can be found by Wiese et al. (2018). Balmorel is cast as a linear optimization problem to minimize the total system costs under physical, economic, and regulatory constraints. The model determines the least-cost allocation of generation technologies, energy storage, and electricity transmission between neighboring regions to meet exogenous heat and electricity demands. The model distributes the generation of heat and electricity from existing technologies with sunk costs and new generation units that incur investment costs. Electricity prices are calculated as the marginal cost of production by the marginal power plant. The decommissioning of power plants is based on technical lifetimes and national plans. National plans leading to decommissioning before 2030 in the Balmorel model countries are limited to a nuclear phaseout in Germany (Federal Ministry for Economic Affairs and Climate Action, 2016) and a coal phaseout in Denmark and France (European Commission, 2022). The model covers a large variety of power and heat technologies based on inputs of coal, lignite, fuel oil, natural gas, wind, solar, hydro, biomass, and uranium (as well as electricity used for heat generation). The unit input price of fossil fuels, biomass, and uranium is taken as exogenous for a given year based on the input from the CGE model. Wind, solar, and hydropower have no direct exogenous fuel costs, but there are indirect costs through investment costs and fixed and variable maintenance costs. For onshore wind and solar power, capacity constraints reflect more stringent land-use trade-offs and reduced social acceptance as deployment increases.

Balmorel includes both exogenously and endogenously defined changes in generation and transmission capacities. Hydropower is assumed to have reached its capacity limit, and no construction or decommission is assumed. However, the model can endogenously choose how much of the installed capacity will be utilized. Each technology is characterized by technology-specific data on thermal efficiency, emission factors, operation and management costs, investment costs, and the technical lifetime. Biofuels and municipal waste are considered renewable and are not assigned emission factors. The model covers district heat and electricity markets in Northern and Central Europe (Belgium, Germany, Denmark, Estonia, Finland, France, Lithuania, Latvia, Netherlands, Norway, Poland, Sweden, and United Kingdom). The four Nordic countries are modeled at a high level of spatial detail where the countries are subdivided into regions corresponding to the Nord Pool market bidding zones. Germany is split along transmission bottlenecks. The assumed interconnector capacities between the countries are based on the current grid capacities plus known investments from the "Ten Year Network Development Plan" (TYNDP) (ENTSO-E, 2018) that will take place until 2030. The key techno-economic assumptions for the Balmorel model are listed in Table A2 of the appendix. Additional background data can be found openly available on GitHub (https://github.com/balmorelcommunity/Balmorel_data). In this study, Balmorel is run with perfect foresight for the target year 2030. Twelve weeks and hours 1 to 48 and 121 to 144 of each week are simulated, resulting in a total of 864 time slices. This approach allows us to represent seasonal, weekly, and daily variability, including weekdays and weekend days, while keeping the model size manageable.

2.4. Policy scenarios

The reference point for the quantitative impact analysis is a baseline scenario (BASE) consistent with the EU's initial 2030 target of a 40% GHG emissions reduction compared to 1990 emissions. The 40% reduction target aligns with the average emissions reduction pledge that the EU member states made in 2015 under the Paris Agreement. The BASE scenario in the CGE model is calibrated to JRC data for 2030, meaning CGE model outputs are calculated based on JRC assumptions on future energy use and supply. Our four other scenarios entail a 55% GHG emissions reduction as proposed by the European Green Deal. The EU has not yet decided how the more stringent 2030 target will be split between ETS and non-ETS sectors. Thus, we assume that both ETS and national non-ETS emissions are reduced proportionally by 25% vis-à-vis BASE in all scenarios (only CO_2 emissions from the combustion of fossil fuels are accounted for).

However, the four policy scenarios differ in the policy measures undertaken to achieve this additional emissions reduction. Scenario PARIS + curbs emissions, similar to the BASE scenario, only through emission pricing.[6] The remaining three scenarios impose additional policy measures targeted at the electricity and heat sectors. Scenario RENEW examines the impact of introducing a mandatory renewable energy target in the EU-wide electricity and heating sectors that significantly exceeds the share in the PARIS + scenario (i.e., without any additional renewable support). In the latter scenario, the renewable share in the EU is 64%, and somewhat arbitrarily, we consider a mandatory share of 75% in the RENEW scenario, which is reached in the CGE model via a uniform subsidy for renewable electricity (and heat) throughout the EU and through a renewable energy constraint exogenously determining the renewable energy share in electricity and district heating sectors, which acts as a subsidy to renewables and a tax to non-renewables in Balmorel.[7] 75% is chosen because it represents a substantial increase to the PARIS + scenario, while no precise EU renewable energy target for the electricity sector has yet been communicated. It reflects an increased ambition by the EU to tackle GHG emissions in the

[4] Consequently, the model abstracts from some important elements of the EU ETS, such as allocation of free allowances to mitigate carbon leakage (Böhringer et al., 2018) and dynamic features including banking of allowances and the significance of the Market Stability Reserve (Gerlagh et al., 2021).

[5] Norway is included in this region, cf. JRC dataset. For the CGE analysis, this should be a minor issue as Norway accounts for a small share of EU ETS emissions.

[6] In non-ETS, regional CO_2 prices are set sufficiently high to meet the non-ETS targets in each region.

[7] As Balmorel only covers a subset of the EU countries, we need to adjust the mandatory share when we run Balmorel. From simulations with the CGE model, we find that the share of renewables in the Balmorel regions is 62% in PARIS+ and 72.7% in RENEW. Hence, when we run RENEW in Balmorel, we set the renewable target constraint 10.7 percentage points higher than in the PARIS + scenario.

Table 1
Scenario overview for 2030.

Scenario label	Emissions reduction vis-à-vis 1990	Description of policy measure
BASE	40%	Baseline scenario (based on JRC)
PARIS+	55%	Emissions pricing only
RENEW	55%	Emissions pricing & mandatory renewable energy target of 75% – implemented via subsidy to renewables and tax on generation from non-renewable resources in Balmorel
PHASEOUT	55%	Emissions pricing & coal phaseout in most EU countries
ELEDEMAND	55%	Emissions pricing & 15% higher electricity demand – implemented via subsidy to electricity consumption

emission-intense power sector. As seen in Australia, for example, a renewable energy target might be deemed a solution to curb emissions and increase clean electricity generation (Government, 2018). Scenario PHASEOUT proposes an EU-wide coal phaseout by 2030 (except in Poland, Romania, and Bulgaria, where a domestic coal phaseout faces stiff political resistance, cf. Böhringer and Rosendahl (2022)). It is modeled by restricting coal power production exogenously to zero in the phaseout countries in both models. Scenario ELEDEMAND calls for increased electrification of energy services in transport, heating, and industrial processes. It assumes that policymakers throughout the EU incentivize electrification beyond what follows from CO_2 prices. Again, somewhat arbitrarily, we consider a scenario with a 15% electricity demand increase over PARIS + levels, implemented via a uniform subsidy to electricity consumption throughout the EU in the CGE model. In Balmorel the electricity consumption is changed based on the CGE output. Table 1 provides a summary of our scenarios.

We discuss the simulation results for scenarios BASE and PARIS + for the year 2030 in section 3.2. Below, comparing them also with observed and modeled 2020 results. Our primary interest thereby lies in the implications for the Nordic power and district heat sectors. In Section 3.3., we compare the remaining scenarios with PARIS + to investigate the impacts of different policies to reach the same EU emissions target. In Sections 3.3. and 3.4., we discuss revenue impacts from power generation across technologies and implications for electricity trade.

3. Simulation results and discussion

3.1. Effects of strengthening the emissions target in 2030

In the BASE and PARIS + scenarios for 2030, we assume that CO_2 pricing alone is used to reach the EU ETS targets. Our scenarios mimic the long-term effects on the energy system induced by changes to CO_2 prices after investments and divestments.

Higher climate ambition in the PARIS + over the BASE scenario leads to an increase in the CO_2 price. Table 2 shows the CO_2 price in the EU ETS for the two scenarios, as simulated by the CGE model, and the average price in 2020 (23.6 EUR/tCO_2). The CO_2 price is almost three times higher in PARIS + than in BASE (52.2 versus 17.9 EUR/tCO_2)[8], reflecting that marginal CO_2 reductions become much more costly when moving from 40% to 55% emission reductions. The power sector is relatively easier to decarbonize than other EU ETS sectors, such as the industry sector, as there are more abatement options at moderate costs

[8] Since the beginning of 2021, futures of ETS prices for 2029 have varied between 35 and 105 Euro/tCO_2, partly reflecting EU's stricter emissions target for 2030, but also uncertainty about the future economic activity and other drivers of emissions as well as regulatory changes to the EU ETS. This study does not look at immediate short-term impacts but long-term effects including effects on investments.

Table 2
EU ETS price and share of ETS used by the power sector for observed 2020 value, BASE, and PARIS + scenarios in 2030.

Scenario	ETS prices(Euro$_{2015}$/tCO_2)	Share of ETS used by the power sector
2020	23.6	
BASE	17.9	46%
PARIS+	53.2	35%

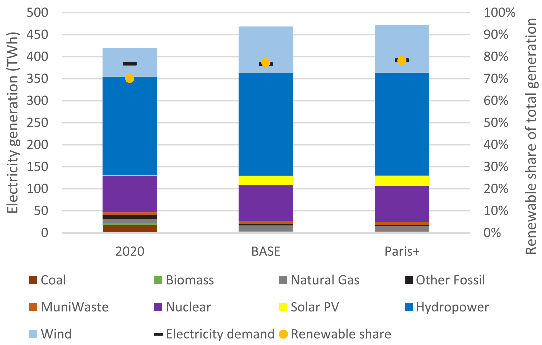

Fig. 2. Modeled Nordic electricity generation for 2020 and the 2030 Base and PARIS + scenarios.

(e.g., switching from coal to gas or fossil to renewable generation). The results in Table 2 underline this and show that the share of emissions in the EU ETS from the power and heat sectors decrease from 46% in the BASE scenario to 35% in PARIS + as a consequence of the higher CO_2 price.

Since the BASE scenario already has a relatively small share of fossil-based generation in the Nordics in 2030, the results for PARIS + show only minor changes in the power generation mix (cf. Fig. 2). In either scenario, the shares of wind and solar PV generation increase strongly compared to modeled 2020 levels, with the BASE scenario having slightly higher natural gas generation. The renewable share in power generation is 77% in BASE and 78% in PARIS+. Instead, in PARIS+, the Balmorel results show significantly increasing shares of wind and solar PV generation in regions outside of the focus area of the study, in Germany, the United Kingdom, France, and Poland. Notably, a shift from coal to natural gas and renewables is observed in Germany and Poland.

The generation mix in the Nordic district heat sector, displayed in Fig. 3, changes substantially more between the analyzed scenarios than the generation mix in the electricity sector. According to the BASE scenario, Nordic district heat will use less coal and peat (categorized as Other Fossil) and, to some degree, biomass, and much more power-to-heat (PtH) in 2030 than observed in 2020.[9] Electrification of the heat sector increases further in PARIS+, with PtH accounting for almost half of total heat generation, taking advantage of the low costs of generation from VRE. Heat storage and biomass use also increase compared to BASE, while natural gas and other fossil fuels are replaced as heat generation sources due to the much higher CO_2 price and the need for flexibility to match supply and demand efficiently, which heat storage provides. Overall, the share of renewables increases strongly in PARIS + over the BASE in Nordic district heating. The simulation results suggest that the increased emissions reduction target in PARIS + mainly spurs a shift from fossil fuels to electricity in heating in the Nordic region, a region that stands out for large capacities of renewables in power generation already today.

[9] Note that heat demand is assumed to develop in line with electricity demand in the different scenarios as it is not clearly distinguishable in JRC data.

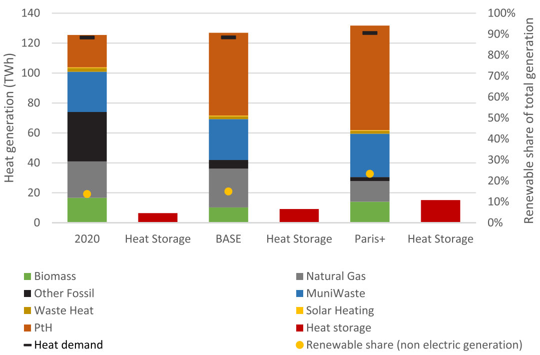

Fig. 3. Modeled Nordic district heat generation and storage for 2020 and the 2030 Base and PARIS + scenarios.

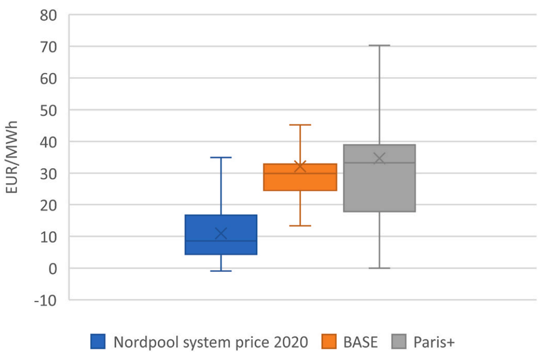

Fig. 4. Observed 2020 price (Nord Pool, 2021) and the modeled electricity prices (average of the Nordic countries) for the 2030 BASE and PARIS + scenarios (EUR/MWh). X = mean, line = median, box = Q1-Q3, whiskers = upper/lower values calculated using the interquartile range (IQR) (upper value = Q3+1.5*IQR; Lower value = Q1-1.5*IQR), outliers are defined as being outside the upper and lower values and are not represented in the figure.

Electricity prices in the two scenarios for 2030 are, on average, much higher than the observed prices in 2020 (Fig. 4) but only marginally higher than the mean price over the last five years (30 EUR/MWh). The BASE scenario has an average price of 32 EUR/MWh across the Nordic price zones, whereas higher climate ambition in the PARIS + scenario increases the average price to 35 EUR/MWh in 2030. A more pronounced difference is observed in the price volatility, which is significantly higher in the PARIS + scenario. For instance, Fig. 4 shows that the price range between the first and third quartile is 21 EUR/MWh in PARIS+, compared to 8 EUR/MWh in BASE. Moreover, the distance between upper and lower price values (upper and lower whiskers) is substantially higher, underlining that more extreme prices are present. More VRE generation and less short-term flexibility provided by natural gas contribute to this situation, despite the Nordics having a high share of dispatchable renewable generation from hydropower with reservoirs. High prices can be interpreted as a scarcity signal indicating less flexibility in the system.

Differences in price patterns strongly depend on the season due to different demand and production patterns. The prices for hours modeled in spring, summer, autumn, and winter weeks, sorted high to low, of the aggregated Nordic regions, are given in Fig. 5. In PARIS+, spring and autumn prices are moderately higher than in BASE in most instances where the BASE price is over 30 EUR/MWh. The higher prices in PARIS + compared to the BASE scenario are mainly attributed to the CO_2 price increasing production costs for generation from fossil fuels. In summer, when electricity demand is lower in Northern Europe, high prices are slightly higher in the PARIS + scenario. However, PARIS + also has more hours with low prices due to increased renewable production. In winter, with high demand, prices above 30 EUR/MWh deviate more strongly between PARIS+ and BASE than in other seasons. High price differences are observed between the scenarios in winter when prices are high, indicating more flexibility scarcity in PARIS + than in BASE. Higher fossil-based generation in BASE, particularly in countries interconnected with the Nordics, provides flexible generation, which moderates prices.

3.2. Impacts of additional policies

In this section, we consider the effects on the Nordic power and district heat sectors when CO_2 pricing through the EU ETS is supplemented with additional policy measures in scenarios PHASEOUT, RENEW, and ELEDEMAND (cf. section 3.1.).

As shown in Table 3, the CO_2 price is quite different in the PARIS+ from the three policy scenarios with additional policy measures, even though the emissions level is identical.

Policy measures designed to induce a more rapid decarbonization in the power market, either by forcing out coal power or stimulating renewables, lead to lower CO_2 prices as the demand for emissions allowances decreases compared to the PARIS + scenario. A mandated coal phaseout in most EU countries reduces the CO_2 price from 52 to 37 EUR/tCO_2. As a consequence of the coal phaseout, emissions in the power sector are reduced, and allowances used by the power sector as a share of total EU ETS allowances decline from 35% in PARIS + to 32% in PHASEOUT.

The impacts of the RENEW scenario are even more significant. Increasing the overall share of renewables in the EU's power and heat sectors from 64% In PARIS + to 75% in RENEW[10] leads to a substantial drop in the CO_2 price to merely 10 EUR/tCO_2. This policy induces a shift away from fossil-based power generation towards more wind and solar PV generation (cf. Fig. 6).

Policies stimulating a higher electricity demand (ELEDEMAND) lead to a higher CO_2 price (72 EUR/tCO_2). Increased demand stimulates power production, including fossil-based power, implying increased demand for emissions allowances. It should be noted that electrification, to some degree, involves the substitution of fossil fuels for electricity in sectors such as manufacturing industries or the transport sector, implying decreased demand for emission allowances.

Electricity generation in the PARIS+ and policy scenarios in the Nordics is shown in Fig. 6.

A widespread coal phaseout in the EU has only minor effects on Nordic power generation. It leads to a slightly lower share of renewables with 5 TWh more gas power and 4 TWh less solar PV generation compared to PARIS+. The explanation is that there is already no coal power in the Nordics in either scenario in 2030, so this scenario only indirectly affects the Nordic energy system through the CO_2 price and interconnectors. Natural gas power benefits from a lower CO_2 price and less competition from dispatchable mid-merit coal power plants located in Poland and Germany. The ETS price effect in this scenario is critical for gas power across the entire EU, as 86% of the phased-out coal power generation in the EU is replaced by gas power.

An EU-wide renewable energy stimulus has a more notable impact on Nordic power generation than the coal phaseout. Even though the Nordics already have a large share of renewables in PARIS+ (exceeding the EU-wide target in RENEW), the joint support scheme leads to a significant increase in power generation from wind (+48 TWh) and solar

[10] In the Balmorel model, the renewable share for the Balmorel regions is increased from 64% in PARIS + to 75% in RENEW.

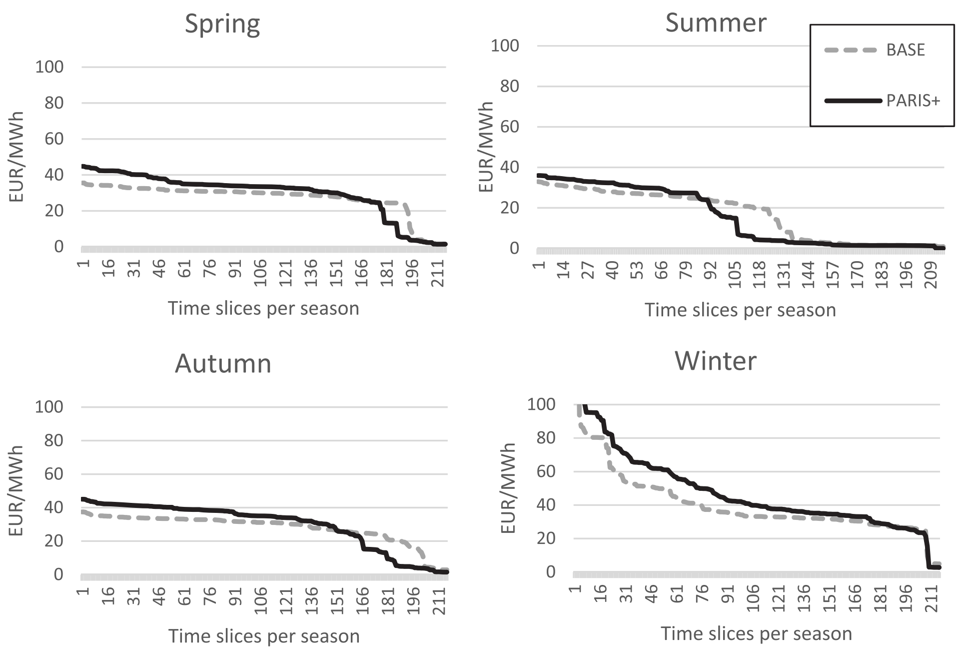

Fig. 5. Seasonal prices (sorted high to low) in BASE and PARIS+ in the Nordics (EUR/MWh).

Table 3
EU ETS price and share of ETS used by the power sector for the policy scenarios.

Scenario	ETS prices (Euro$_{2015}$/ tCO_2)	Share of ETS used by the power sector
PARIS+	53.2	35%
PHASEOUT	37.3	32%
RENEW	9.9	31%
ELEDEMAND	72.0	38%

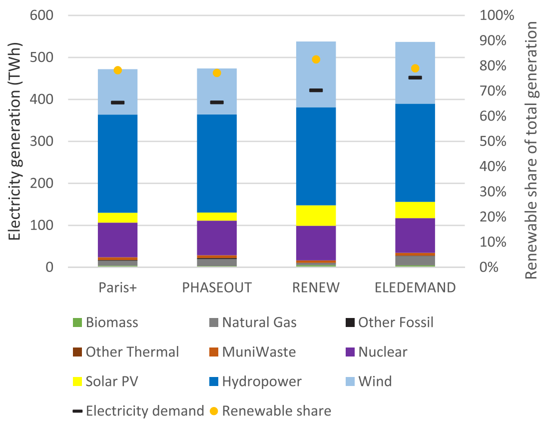

Fig. 6. Modeled Nordic electricity generation in the 2030 policy scenarios.

PV (+25 TWh) in the Nordics. Nordic natural gas-based generation decreases by 7 TWh. Although gas power is less penalized by lower CO_2 prices, it declines due to competition with renewable generation.[11] The share of renewables in the Nordics power sector increases from 78% (PARIS+) to 83% (RENEW). Lower electricity prices stimulate electricity demand and electrification in the district heating sector. This increase in electricity consumption is greater than the increase in generation in the Nordics, leading to reduced net exports out of the Nordics of 16 TWh. However, total exports and imports out of and into the Nordic region increase, and more price periods with substantial price differences between Nordic regions and interconnected regions are observed.

Increased electrification (ELEDEMAND) stimulates more power generation in the Nordics (compared to PARIS+), with more generation based on wind (+39 TWh) and solar PV (+15 TWh). In addition, generation based on natural gas also increases in this scenario (+10 TWh), which is the main difference from the RENEW scenario. Exports and imports remain similar between the ELEDEMAND and the PARIS + scenario, indicating that a mix of increased VRE and natural gas generation can provide sufficient supply and flexibility to cover the increase in demand.

District heat generation between the scenarios differs strongly in the Nordics, particularly regarding sector integration via PtH (Fig. 7).

A mandated coal phaseout leads to only moderate changes in the district heat generation mix. There is slightly less use of PtH and biomass while more use of natural gas for heating (+8 TWh), again induced by a lower CO_2 price. There is also somewhat less utilization of heat storage, indicating less need for flexibility.

Again, the most significant changes are seen in the RENEW scenario.

[11] At the EU-level, the renewable support in RENEW leads to more coal power and less gas power generation, consistent with the findings in Böhringer and Rosendahl (2010). The explanation is that coal power benefits particularly from the lower CO_2 prices in the RENEW scenario.

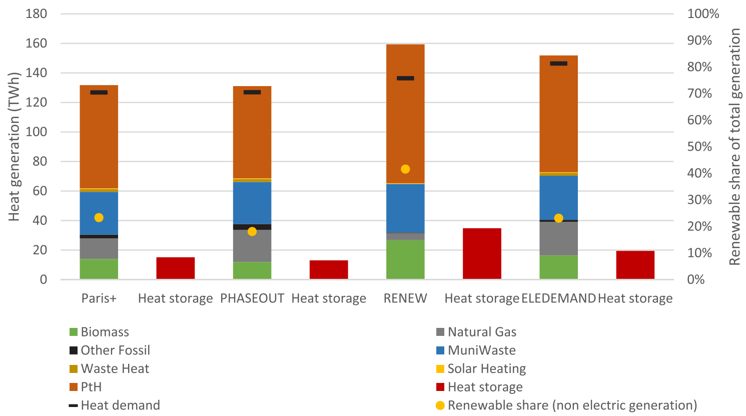

Fig. 7. Modeled Nordic district heat generation and storage in the 2030 policy scenarios.

The renewable target eliminates most fossil heat generation in the Nordics, replacing it with PtH (+24 TWh) and biomass (+13 TWh) in combination with more heat storage (compared to PARIS+). Natural gas-based heat production declines by 9 TWh. Total heat production is highest in this scenario, mainly due to losses during heat storage periods and higher overall demand for electricity and heat than in PARIS+ (+8%).

A further increase in electricity and heat demand (ELEDEMAND scenario) leads to increased heat generation from biomass, natural gas, and PtH compared to PARIS+. The use of natural gas increases despite the higher CO_2 price, whereas other uses of fossil fuels decline (from an initially low level). The use of heat storage for flexibility is increased. The high level of flexibility provided by gas, biomass, and PtH with heat storage is noteworthy. It shows that flexibility issues with growing demand and renewable generation can be effectively dealt with using a combination of flexible generation and flexibility options.

Supplementing CO_2 prices with other measures affects Nordic electricity prices, as visualized in Fig. 8.

A mandated coal phaseout leads to less price variability than PARIS+, which is explained by more natural gas and less VRE generation (cf. Fig. 8). Thus, supply-side flexibility is increased. The average price is about the same because extraordinarily high and low prices are reduced (cf. Range between whiskers in Fig. 8).

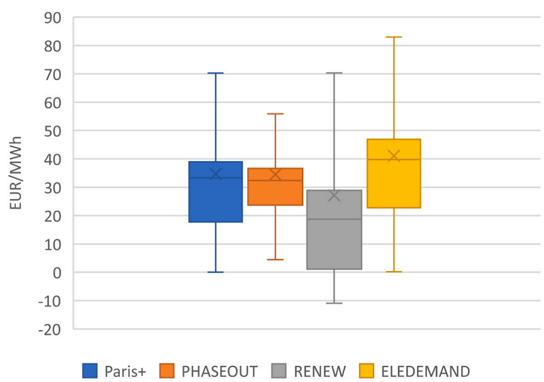

Fig. 8. Modeled electricity prices (average of the Nordic countries) in the 2030 policy scenarios (EUR/MWh). X = mean, line = median, box = Q1-Q3, whiskers = upper/lower values calculated using the interquartile range (IQR) (upper value = Q3+1.5*IQR; Lower value = Q1-1.5*IQR), outliers are defined as being outside the upper and lower values and are not represented in the figure.

A higher renewables target increases price variability strongly in the Nordics compared to PARIS+, with negative prices more than 20% of the time. Negative prices are observed due to the modeling approach where a level of exogenously determined renewable generation is required, which may make it optimal to avoid curtailment in times with negative prices to satisfy this constraint. The mean and median electricity prices are significantly lower than in the other scenarios (the mean price is 8 EUR/MWh, and the median price is 15 EUR/MWh lower than in PARIS+) due to stimulating renewable electricity.

Whereas RENEW stimulates mostly supply, ELEDEMAND stimulates electricity demand, resulting in the highest electricity prices across scenarios with a mean price of 41 EUR/MWh and a high price of 83 EUR/MWh (not including outliers). In comparison, in PARIS+, the electricity price is below 40 EUR/MWh more than 75% of the time. Price variability increases compared to PARIS+, as most additional generation comes from wind and solar PV but is slightly lower than in RENEW.

3.3. The economics of electricity generators

The different policies affect the producer profits for Nordic electricity generators by changing revenues and costs. Revenues from other technologies are affected via impacts on total generation and market values. The electricity price varies substantially over the year, with price differences increasing with more ambitious climate targets (c.f. Fig. 4), and the ability to produce electricity flexibly is an advantage. Table 4 shows the difference in modeled total revenues and market values for the analyzed technologies in the Nordics when the emissions reduction target is strengthened from 40% (BASE) to 55% (PARIS+).

In PARIS+, revenues increase for all electricity generators except those based on oil and peat (grouped in 'other fossil'). Total revenues

Table 4
The difference in revenues and market value grouped by fuel in PARIS + compared to BASE.

	Change in revenue (Million EUR)	Change in market value (EUR/MWh)
Biomass	79.3	2.1
Natural Gas	52.7	17.2
Other Fossil	−27.5	28.2
MuniWaste	36.4	4.9
Nuclear	289.8	3.5
Solar PV	50.8	0.1
Hydropower	717.2	3.1
Wind	357.1	2.4

increase the most (in absolute terms) for hydropower, wind, and nuclear, the technologies with the highest generation shares in the Nordics. This situation, combined with higher average prices in PARIS + compared to BASE, increases revenues substantially. Market values from power generation based on fossil fuels increase the most (+17.2 EUR/MWh for natural gas, +28.2 EUR/MWh for other fossil), as they produce flexibly with low full load hours and consequently capture high prices. Price volatility is much higher in PARIS + than in BASE, of which these fossil-based generators take advantage. However, changes in total revenues are limited due to decreasing fossil-based generation in PARIS+ (gas power generation decreases by 2 TWh).

With supplemental policies, the impacts on revenues are significantly changed compared to the PARIS + scenario. Table 5 displays the difference in revenues and market values in the policy scenarios compared to PARIS+.

In the PHASEOUT scenario, natural gas-based power generation is most affected by the modeled coal phaseout. Natural gas total revenues increase due to more production (compared to PARIS+), but market values are negatively affected in the Nordics due to more stable prices with fewer price spikes. Total revenues for renewables in PHASEOUT are negatively affected due to less production, but market values are relatively stable.

A renewable energy target increases revenues for renewable producers in the Nordics and decreases revenues for non-renewable generation. Here we assume that the renewable target is implemented via a combination of a subsidy for renewable generation and a tax on generation from non-renewable resources in Balmorel (since the target is a constraint on the relative share of renewables). Despite the subsidy to renewables, market values increase only slightly for solar PV (0.5 EUR/MWh) and wind (0.6 EUR/MWh), cf. Table 5. This finding is explained by the increased volatility that mainly affects VRE revenues negatively, as low or negative prices correlate with high VRE generation. Negative prices become more common due to less curtailment with the binding renewable target constraint in the RENEW scenario. It should also be noted that there are regional differences in revenues within the Nordics. For instance, wind revenues in RENEW compared to PARIS + increase more in Denmark and Finland than in Norway and Sweden. Total revenues for hydropower increase by 907 MEUR in the RENEW scenario compared to the PARIS + scenario, whereas nuclear revenues decline because of the combination of a non-renewable tax and lower average prices (−3261 MEUR). Natural gas is negatively affected, too, due to much lower generation, but this is partly offset by a substantial increase in market value (+37 EUR/MWh), despite the tax on generation from non-renewable resources. Biomass increases revenues compared to PARIS+. Being a flexible renewable generation technology, its market value increases (+14 EUR/MWh) due to the subsidy and higher price volatility in the RENEW scenario.

The ELEDEMAND scenario increases market values across all technologies. Fossil generation, followed by hydropower, increases average sales prices the most. Total revenues increase the most for hydropower, wind, and natural gas. Thus, in the Nordics, an increase in electricity demand would be most beneficial for the largest producers in terms of volume and those that provide producer flexibility since both the average price and price variations increase compared to the PARIS + scenario.

In some cases, changes to revenues and market values might not be enough to offset the reduced utilization rates and thus cover fixed costs. Costs affecting profits that change between the analyzed scenarios are, e.g., CO_2 taxes, fuel costs, and variable operating and maintenance costs. A precise cost analysis in this section is not intended due to the grouping of different types and sizes of power plants, several fuels (e.g., 'other fossil'), and multiple regions. Additionally, we use a model approach with no active decommissioning before the end of a power plant's lifetime, which may lead us to overreport annualized fixed costs. Nevertheless, the following calculation of producer profits in the electricity sector indicates which technologies profit most from the different policies from a producer standpoint, cf. Table 6. We find higher climate targets in PARIS + compared to BASE to benefit all producers apart from generation from coal and oil products grouped in other fossil. In the policy scenarios, generation from biomass increases profits significantly in the RENEW and ELEDEMAND scenarios. In these scenarios, there is more generation from biomass, and additionally, the market value increases over PARIS+, c.f. Table 5.

Natural gas is most profitable in ELEDEMAND, where natural gas has a high market value and generates the most electricity. Natural gas, other fossil, and nuclear generation are least profitable in RENEW due to lower generation and a tax on generation from non-renewable resources. In this scenario, the estimated profits for VRE and nuclear power must be interpreted in light of inflexible nuclear power generation levels, as described in section 2.1 above. VRE and nuclear power market values would increase if nuclear producers reduced output in hours with negative prices. Hydropower stands to be the single biggest winner of increased climate ambition from BASE to PARIS+. A renewable energy target or higher electricity demand may increase profits additionally.

3.4. Limitations

This study's results have certain limitations attributed to this paper's modeling and geographical scope. First, the utilized models differ in spatial, temporal, sectoral, and technological setups, where perfect convergence between the models is not feasible. However, it is important for this study that the exogenous inputs in Balmorel (CO_2 and fuel prices, as well as the electricity demand) are derived endogenously from the CGE model, which is run assuming the same policy scenario (not just adjusting prices and demand arbitrarily). Second, the results are presented jointly for the Nordics, but regional findings may differ due to different regional power generation. For example, Denmark's energy system has less dispatchable renewable generation from hydropower and more wind generation. Also, regional power prices within countries with multiple price zones deviate. Third, as previously mentioned, nuclear flexibility is restricted in this study, potentially underestimating nuclear revenues and affecting VRE results in the RENEW scenario. Lastly, the economic modeling results are limited revenues from selling electricity at shadow prices; the results mimic spot market prices but do

Table 5
The difference in revenues from electricity sales and market values (grouped by fuel) (plus subsidies minus taxes in RENEW) in the policy scenarios compared to PARIS+.

	Change in revenue (Million EUR)			Change in market value (EUR/MWh)		
	PHASEOUT	RENEW	ELEDEMAND	PHASEOUT	RENEW	ELEDEMAND
Biomass	−38.6	151.3	74.6	1.5	14.1	5.7
Natural Gas	312.6	−409.1	1149.6	−6.5	37.2	11.4
Other Fossil	27.0	−40.8	−0.1	−11.3	58.3	30.6
MuniWaste	−6.2	44.7	52.9	−1.1	14.6	6.8
Nuclear	−64.7	−3260.9	519.1	−0.8	−39.5	6.3
Solar PV	−86.5	528.3	311.9	0.0	0.5	0.1
Hydropower	−35.1	906.9	2026.9	−0.2	3.9	8.7
Wind	−28.2	1616.7	1684.4	−0.6	0.6	3.2

Table 6
Estimated producer profits from electricity sales excl. Capital costs in the Nordic countries for different power technologies (MEUR).

	BASE (Million EUR)	PARIS+ (Million EUR)	PHASEOUT (Million EUR)	RENEW (Million EUR)	ELEDEMAND (Million EUR)
Biomass	171.9	251.2	212.7	402.5	325.8
Natural Gas	967.1	1019.8	1332.4	610.6	2169.4
Other Fossil	157.4	129.9	157.3	89.2	129.6
MuniWaste	241.5	277.9	271.8	322.6	330.8
Nuclear	261.4	551.2	486.5	−2709.7	1070.3
Solar PV	310.7	348.8	284.0	752.0	582.7
Hydropower	6457.1	7140.1	7116.6	8032.7	9151.0
Wind	2059.9	2382.4	2355.7	3751.0	3855.4

not include additional revenues from, e.g., ancillary service and balancing markets.

4. Conclusion and policy implication

The current study assesses how the renewable-rich Nordic region would be affected by rising emissions reduction ambitions in light of the European Green Deal. The EU ETS is essential here, but other energy policies complimentary to the ETS are also analyzed. These include a politically forced coal phaseout, a renewable energy target, and accelerated electrification leading to more electricity demand. A novelty of the study lies in combining an economy-wide CGE model for the EU region and a partial equilibrium model for the Nordic electricity market with a fine granularity in time, space, and technology options.

The model results show that the CO_2 price in the EU ETS is strongly affected by the future direction of the EU energy policy. Raising the EU ambition from 40% to 55% GHG emissions reduction would increase the CO_2 equilibrium price in 2030 from 18 to 53 EUR/tCO_2, according to the model simulations conducted in this study.

Higher CO_2 prices cause more investments in renewable power generation capacities. However, for the Nordic region, the impacts on new investments are surprisingly low in this study, given that new transmission capacity is limited to the plans of the “Ten Year Network Development Plan” (TYNDP) (ENTSO-E, 2018). The long-term mean price impact of the increased climate ambition is +3 EUR/MWh in the Nordic region, however, price volatility increases significantly.

Policies assessed in addition to the EU ETS include a strict renewable energy share target of 75% across the EU, a general phaseout policy for coal power, and an electrification strategy increasing electricity consumption by 15%. We find that a renewable energy target supplementing the EU ETS would cause substantially lower CO_2 prices due to stimulated renewable generation. We assume the target is reached via a subsidy for renewable electricity and a tax on generation from non-renewable resources in Balmorel. The increased renewable electricity supply leads to lower but more volatile electricity prices. Thus, the net revenues for renewable electricity increase only moderately, while natural gas is affected less due to its flexibility and, thus, ability to exploit the increased price volatility. A coal phaseout mainly benefits the natural gas power producers, which increases generation revenues by 31% compared to the scenario without the coal phaseout. Such a policy does not affect the economics of renewable generation technologies significantly. Instead, the game change lies in policies for increased electrification causing higher electricity demand. In such a scenario, the EU ETS price may exceed 70 EUR/tCO_2, and the modeled Nordic power price averages around 40 EUR/MWh with a very high price variation between peak and off-peak periods. The high-demand scenario causes significantly more investments in wind power and solar PV in the Nordics. Wind and gas power receive increasing revenues due to larger volumes produced and higher prices captured. The increasing prices in peak periods are particularly favorable for Nordic hydropower, which increases its revenues from power sales by 22%, compared to the PARIS + scenario.

Overall, the study points to several energy system impacts relevant to future policymaking: First, the EU ETS price appears sensitive to the increased emissions reduction targets from 40% to 55%. Second, the higher emissions reduction target mainly spurs a shift from fossil fuels to electricity in heating in the Nordics if the EU ETS is the primary policy measure. Third, in the Nordics, producer revenues for wind, hydro and nuclear power are higher with the increased emissions reduction targets. Fourth, due to increasing producer market values, total revenues from natural gas power do not decrease despite moving from a 40% to a 55% target. And fifth, additional policies to the EU ETS affect the CO_2 price, producer market shares, electricity prices, and consequently, revenues of the different generation technologies. For instance, the analyzed coal phase-out would lead to more stable prices in Northern Europe. With the mandatory renewable energy target, Nordic renewable production would increase substantially while market values for renewable technologies would not decline, leading to significantly higher renewable producer revenues. An increased electricity demand would mostly be covered by increased wind and solar PV power generation in the Nordics, significantly increasing revenues for these technologies.[12]

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgment

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[12] Focused on large scale unit size if multiple similar generation technologies are available for investment in 2030. Contains most important technologies in this study. Nuclear, hydroelectric and lignite power plants are constrained of new investments.

Appendix

Table A 1
Sectors and regions in the CGE model (acronyms provided in brackets)

Sectors and commodities[a]	Countries and regions
Primary energy sectors	EU countries/regions
Coal (COA)	Germany (DEU)
Crude Oil (CRU)	United Kingdom + Ireland (GBR)
Natural Gas (GAS)	France (FRA)
Emissions-intensive and trade-exposed sectors	Poland (POL)
Chemical Products (CRP)	Spain + Portugal (SPP)
Non-Metallic Minerals (NMM)	Italy + Malta (ITA)
Iron and Steel (I_S)	Greece + Cyprus (GRE)
Non-Ferrous Metals (NFM)	Belgium + Netherlands + Luxemburg (BNL)
Refined Oil (OIL)	Sweden + Denmark + Finland (SCA)
Paper Products, Publishing (PPP)	Bulgaria + Romania (SEU)
Air Transport (ATP)	Estonia + Latvia + Lithuania (BAL)
Electricity generation and distribution	Central European countries (CEU)[b]
Coal-fired (TCOA)	Non-EU countries/regions
Oil-fired (TOIL)	Rest of Europe and Turkey (RET)
Gas-fired (TGAS)	United States of America (USA)
Nuclear (TNUC)	China (CHN)
Biomass (TBIO)	Russia (RUS)
Hydroelectric (THYD)	Rest of the World (ROW)
Wind power (TWIN)	
Photovoltaics (TSOL)	
Transmission and distribution (ELE)	
Other sectors	
Services (SER)	
All other goods (AOG)	

[a] All sectors except transmission and distribution, services, and all other goods are regulated by the EU ETS.
[b] CEU includes Austria, Czech Republic, Slovakia, Hungary, Slovenia, and Croatia.

Table A 2
Overview of techno-economic specification of investable technologies and assumptions in Balmorel

Technology	Efficiency	Inv. Cost	Fixed operation cost	Variable operation cost	Fuel cost
		M.EUR/MW	EUR/kW	EUR/MWh	EUR/GJ
Heat storage					
District heat pit storage (centralized)	0.7	0.0027	0.003		
District heat pit storage (decentralized)	0.7	0.0004	0.003		
Heat pump					
Air source heat pump (4 MW)	3.3039	0.6656	2.0231	1.8208	
Excess heat pump (4 MW)	12	0.5804	1.96	1.666	
Ground source heat pump (4 MW)	3.8	0.5804	1.96	1.666	
Boiler					
Electric boiler for district heat (10 MW)	0.99	0.0588	0.9996	0.98	
Battery storage					
Lithium-ion for grid-scale application (10 MW)	0.9	0.3218	0.2965		
Lithium-ion for peak power application (100 MW)	0.9	0.3358	2.1279		
Biogas					
Back pressure, internal combustion engine (1 MW)	0.9391	0.882	9.114	6.86	12.7158
Condensing, internal combustion engine (1 MW)	0.45	0.882	9114	6.86	12.7158
Straw					
Heat-only boiler (6 MW)	1.04	0.6579	36.8271	1.023	7.16
Back pressure, steam turbine subcritical (132 MW)	0.9989	2.4432	107.8	1.8878	7.16
Condensing, steam turbine subcritical (132 MW)	0.31	2.4432	107.8	1.8878	7.16
Wood chips					
Heat-only boiler (6 MW)	1.17	1.1341	36.7942	1.2648	From 4.154 (Stepwise price increasing with demand)
Back pressure, steam turbine subcritical (600 MW)	1.1429	3.075	49	3.728	From 4.154
Condensing, steam turbine subcritical (600 MW)	0.29	3.075	49	3.728	From 4.154
Wood pellets					
Heat-only boiler (6 MW)	1.02	0.9074	31.1136	1.004	10.6522
	0.9818	2.7133	117.6	1.641	10.6522

(continued on next page)

Table A 2 (*continued*)

Technology	Efficiency	Inv. Cost	Fixed operation cost	Variable operation cost	Fuel cost
		M.EUR/MW	EUR/kW	EUR/MWh	EUR/GJ
Back pressure, steam turbine subcritical (80 MW)					
Condensing, steam turbine subcritical (800 MW)	0.33	1.8868	39.2	1.5153	10.6522
Extraction, steam turbine subcritical (800 MW)	0.33	1.8868	39.2	1.5153	10.6522
Natural gas					
Heat-only boiler (500 KW)	1.06	0.049	1.862	0.98	Fuel price changing with the scenario
Backpressure, internal combustion engine (1 MW)	0.9648	0.882	9.114	4.998	
Backpressure, Combined cycle (40 MW)	0.8826	0.5488	18.228	4.116	
Condensing, internal combustion engine (1 MW)	0.48	0.882	9.114	4.998	
Condensing, gas turbine (40 MW)	0.43	0.5488	18.228	4.116	
Condensing, combined cycle (100 MW)	0.61	0.8134	27.244	4.116	
Condensing, steam turbine subcritical (400 MW)	0.47	1.274	37.24	0.8036	
Extraction, combined cycle (100 MW)	0.61	0.8134	27.244	4.116	
Extraction, Steam turbine subcritical (400 MW)	0.47	1.274	37.24	0.8036	
Hard coal					
Condensing, steam turbine subcritical (400 MW)	0.52	1.9502	60.368	2.156	Fuel price changing with the scenario
Extraction, Steam turbine subcritical (400 MW)	0.52	1.9502	60.368	2.156	
Wind					
Wind onshore (5 MW)	Full load hours depending on the location	1.0192	12.348	1.4014	
Wind offshore (6–12 MW) **Techno-economic specifications are very site-dependent*		1.5474–2.3117	31.7990–35.33194	2.352–2.646	
Solar PV	Full load hours depending on the location				
Solar PV (8 MW)		0.294	5.684	0	
Municipal waste					
Heat-only boiler (35 MW)	1.06	1.814	74.7644	6.2304	
Back pressure, steam turbine subcritical (220 MW)	1.04	7.2875	147	5.6810	
Condensing, steam turbine subcritical (220 MW)	0.24	6.1944	147	23.6709	

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Paper IV

Prospects for the 2040 Norwegian electricity system: Expert views in a probabilistic modeling approach

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Abstract

This study examines expert opinions on power demand and supply developments for 2040 in Norway based on a combined survey and modeling approach. The survey responses show that production and consumption will likely increase, with most respondents assuming a positive energy balance in 2040 Norway. Capacity expansion uncertainty between expert opinions is particularly high for offshore wind on the production side and electricity demand from hydrogen electrolysis on the consumption side. The survey results are combined with a Monte Carlo modeling approach to estimate solution spaces for electricity prices, value factors, and market values for power generating technologies in the energy system model Balmorel. The model results show that electricity prices are strongly influenced by the energy balance, with a negative exponential relationship between the electricity price and an increase in the energy balance. The value factors for hydropower with reservoirs are consistently the highest across the model runs, while solar PV and hydro run-of-river have the lowest value factors. An increasingly positive energy balance increases hydropower with reservoirs' value factor and decreases the value factor for all other technologies. This indicates an additional competitive advantage for hydropower with reservoirs if production development outpaces demand and vice versa.

Keywords: Monte Carlo Simulation, Balmorel, energy system modeling, Norway, expert survey

1. Introduction

The European political will to accelerate the energy transition is increasing uncertainty about future supply and demand developments in the power sector. Norway, traditionally a country with low electricity prices, little price variation, and mostly renewable power generation, is not exempt from change.

International power market outlook studies are released frequently to shed light on the status of the energy transition, progress, opportunities, challenges, and future pathways to reach ambitions. Well-established international studies are released, for example, by the IEA (IEA, 2021) and IRENA (Gielen et al., 2021), as well as by many large actors in the energy space, think tanks, and intergovernmental organizations. They point to several key themes of how the European power markets will be affected by the efforts to reach the Paris Agreement targets. Some of the most important ones are: The transition to more intermittent power generation will accelerate. Electricity demand will increase as a result of electrification and new industry demands. The shifts in supply and demand side will increase the significance of power system flexibility. Energy efficiency measures to limit electricity demand are key. And finally, carbon capture and storage (CCS) will likely be required to achieve zero GHG emissions. The results for these international outlook studies come mostly from in-house qualitative assessments and detailed energy system modeling using scenarios to capture different pathways and future uncertainty.

Looking at a smaller region, Norway, we find more detailed information on certain metrics such as power prices in the regional power market outlook studies. Scenario-based model assessments by Statnett and NVE map the future of the Norwegian energy system. Statnett describes in its "Long-term market report" a scenario that depicts the most likely production and consumption levels for 2030, 2040, and 2050 (Statnett, 2020). The level of detail in this report is high and describes consumption by sector and production by fuel with extensive reasoning for future developments. Similarly, NVE produces an annual "long-term power market report" (Birkelund et al., 2021). This report provides a detailed outlook on how the Nordic power sector will likely develop, with a special focus on Norway. Several other outlook studies for other Nordic countries exist, analyzing European and Nordic trends and developments with a special focus on the domestic markets (Brunge et al., 2021; Poulsen and Kromann, 2021).

Scenario studies, as described above, have the advantage of providing internally consistent assessments of what the future could look like. Alternative expectations and identified key drivers or uncertainties can be addressed in different scenarios (Carter et al., 2001). However, there are also disadvantages to using scenarios. Scenarios are based on assumptions and are therefore subject to bias. This may lead to ruling out unpopular opinions or unlikely events and could reflect the authors' opinions, past experiences, or their wish for broadly accepted storylines to be reflected in the scenarios (Alcamo and Henrichs, 2008).

There are multiple uncertainties affecting future energy systems that are not always fully accounted for in national and international power market outlooks- or energy system model studies. Chen et al. (Chen et al., 2021a) review Nordic power market outlooks and identify social acceptance, technology development, and new policies such as subsidies and taxes as major sources of uncertainty for future power prices. It is also noted that future power prices are strongly affected by gas and emission quota prices. Heinrichs et al. Heinrichs et al. (2017) finds a research gap concerning the integration of quantitative empirical social research and technical energy system models, which if addressed can provide more robust findings on the energy transition debate. They, therefore, suggest an approach that couples a survey, an input-output model, and an energy system model to provide new information on the German coal phaseout. Jåstad et al. (Jåstad et al., 2022) use a probabilistic approach to determine risk factors for future power prices and market values in the Nordic energy system. They find the natural gas price, carbon price, and electricity demand to be some of the determining drivers for power prices whereas, e.g., investment costs for renewables play a smaller role. Cebulla et al. (Cebulla et al., 2018) highlight the importance of acknowledging uncertainties in planning processes, e.g., social opposition. They use the tradeoff between transmission and energy storage as sources of flexibility as an example. Chen et al. (Chen et al., 2022) use a model approach to balance land use from new generation capacities, economic aspects, and GHG emission reductions to generate alternative future scenarios for Northern Europe. This can provide robust results taking social acceptance issues and environmental concerns into account and the study shows that a 10% increase in system costs from the optimum could reduce 58% of the required land area.

Surveys may serve as a method to track uncertainties arising, e.g., from social acceptance issues. Leieren et al. (Leiren et al., 2020) and Aasen et al. (Aasen et al., 2019) published climate surveys tracking Norwegians' attitudes in response to climate policy. Here, it is found that in the past, society's view of onshore wind was more positive, and in recent years skepticism has increased. This may lead to social opposition to new capacity investment. Karlstrøm and Ryghaug (Karlstrøm and Ryghaug, 2014) more holistically assess public attitudes towards renewable energy technologies. The importance of a better understanding of public opposition to renewable energy projects is highlighted here. They find that attitudes can be shaped by interests apart from the environmental stance such as industry and economic development. Surveys are additionally frequently used to provide subjective probabilities on topics concerning the economy. Eliciting experts, e.g., in the "Survey of Professional Forecasters", a survey on macroeconomic indicators, provides a useful data source to identify industry expectations (European Central Bank, 2022). According to the European Central Bank (ECB), these expectations additionally serve to provide probability distributions that are interpreted as quantitative assessments of risk and uncertainty (European Central Bank, 2022).

The reviewed literature shows that energy system model-based studies typically minimize system costs or maximize social welfare in scenarios. However, they oftentimes fail to address emerging issues such as, e.g., lack of social acceptance of certain technologies, distributional effects as a barrier (to interconnectors), and land-use conflicts. Surveys can provide this information and are useful to gather opinions and projections of a population of interest. This study suggests a method of coupling a survey among experts with probabilistic modeling. Social aspects and techno-economic impacts of the energy transition are represented jointly providing an enhanced understanding of how the future Norwegian energy system could look like according to the elicited experts. The objective of this study is to map out the expert view of the future development of the Norwegian energy system by the year 2040 and understand how this projection would impact power prices, value factors, and market values of power generating technologies. The method's advantage, over a more standard approach of combining an expert survey with scenario analysis, is that it allows us to assess solution spaces for the analyzed outputs that take all expert responses into account. This is achieved via probability distributions that also account for minority opinions which are often not well represented in scenario analysis. The approach avoids author bias which would affect the scenario development.

The rest of this paper is structured as follows: First, the method consisting of the expert survey combined with model simulations in the energy system model Balmorel is addressed. Then, the results of the expert survey, followed by the model results, are explained and discussed. Limitations of the study are discussed. Finally, the findings are summarized in the conclusion.

2. Method

The method applied is a coupling of an internet-based expert survey to derive inputs regarding power production and consumption in Norway and Monte Carlo simulations in the energy system model Balmorel.

2.1. Survey

The web-based survey was sent out on 3rd May 2021 to 496 experts working in energy-related fields. The survey was sent out to contacts in email lists, coming from professors in the field of energy at the Norwegian University of Life Sciences (NMBU) and project partners. Of the 496 identified experts contacted, 119 responded, resulting in a 24% response rate. The criteria for contacting the participants were threefold: Work experience in an energy-related job, Norwegian speaking with a good understanding of Norwegian society, and preferably several years of work experience. These criteria were developed to ensure that the participants would have a good knowledge base on the Norwegian energy system and Norwegian society. It should be noted that no further pre-screening to ensure the understanding of the topic was conducted. Of the 119 respondents, 10 or more are working in each of the following areas: Industry/power consumers (27), power producers (23), public authorities (21), research institutions (12), and consultancies (12). Most of the respondents are educated as engineers (71), while some have a background in economics and business administration (33), cf. Figure 1. The respondents were experienced in their field, with only 14 having five or fewer years of experience and 42 having more than 20 years of experience.

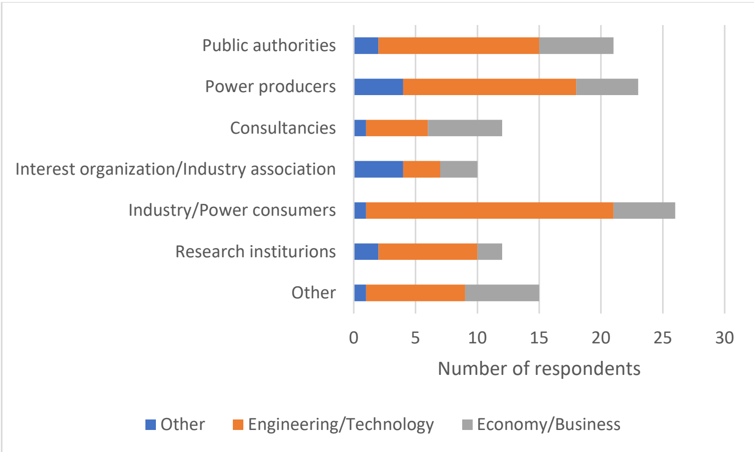


Figure 1. Respondents' background.

The respondents were asked to reply to three types of questions: First, they were asked to rank statements on a Likert scale from 1 to 7, with 1 being not likely and 7 being very likely. Likert scales produce ordinal data allowing us to measure respondents' attitudes/opinions toward certain topics. Seven steps were chosen to give respondents sufficient variety in the choices to make a precise estimate rather than ending up with a "nearby" choice, which is more likely with a 1 to 5 scale (Dawes, 2008; Joshi et al., 2015). Second, respondents were asked to give precise estimates of future electricity supply by producer, and electricity demand by sector with the option of choosing "don't know." The idea of precise estimates was that experts would implicitly take limitations and support, e.g., based on public opposition, into account. 2020 values were given as a reference to anchor responses in a reasonable range. Third, one open question was asked where reasoning was possible. This study focuses on demand and supply-related responses, but further questions for other areas of research were asked. The full questionnaire is attached, translated to English in Table A 1 and in the original language in Table A 2 of the appendix.

2.2. Balmorel

The energy system Balmorel is applied to calculate electricity prices, value factors, and market values for production from different technologies. Inputs from the expert survey are production and consumption distributions in Norway, described in Table 3 of section 3.1.5.

The partial equilibrium Balmorel energy system model optimizes operation and investment for the electricity and district heating sector. Balmorel has been calibrated and tested in numerous studies and is described in detail by Wiese et al. (Wiese et al., 2018). It is an open-source model written in GAMS (available at https://github.com/balmorelcommunity) and has a detailed spatial granularity for the Nordic countries where each Nordpool market area (European price zones) is modeled. All Balmorel model regions are shown in Figure 2.

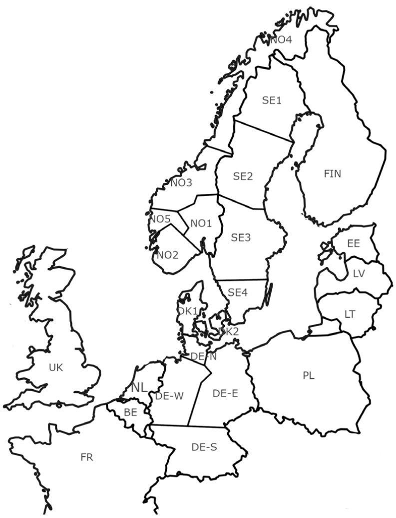


Figure 2. Bamorel model regions

The Balmorel model is an operational and investment model that uses linear optimization as a means of minimizing the overall costs of the system while adhering to physical, economic, and regulatory constraints. The objective of the model is to ascertain the most efficient allocation of power generation technologies, energy storage, and transmission between regions, in order to meet the demand for electricity and district heat at any given point in time in any model region. The prices of electricity are computed as the variable cost of the marginal power plant. A large range of power and heat technologies are considered. These utilize inputs such as coal, lignite, fuel oil, natural gas, wind, solar, hydro, biomass, and uranium, as well as electricity used for heat generation. The main techno-economic assumptions for investable technologies are represented in Table A 3. The temporal resolution of the model is on an hourly level. To reduce model complexity, only 864 timesteps are modeled. These consist of 72h (two weekdays and a weekend day) in 12 weeks evenly spread across the year. The temporal setup allows the model to retain information on seasonal and hourly variations while reducing model size. The model year is 2040. The 2012 weather year is the foundation for wind, solar PV, hydropower generation/inflow profiles, and heat demand from the district heating sector. Extreme weather years will thus lead to results deviating from this study.

To derive a probabilistic solution space for power prices and market values, we apply a Monte Carlo simulation altering Norwegian production and consumption levels in Balmorel using Latin Hypercube sampling (McKay, 1992). Latin Hypercube sampling minimizes the number of model runs or simulations required compared to random sampling to accurately represent underlying distributions. This is achieved by dividing the cumulative density function of the underlying distribution into equal partitions and choosing random data points in each partition (Olsson et al., 2003). Typically, capacity investments are endogenously calculated in Balmorel. Yet, for the sake of this study, production in Norway from hydro, onshore wind, offshore wind, and solar PV is exogenously defined based on the distributions from the expert survey. Natural gas power capacity investments are deemed unlikely and therefore not allowed in Norway. In the other model regions, capacity investments are calculated endogenously, and electricity demand development is assumed to align with NVE's "Long-term power market report 2021" (Birkelund et al., 2021). In Norway, we use triangular distributions for production, cf. Table 3, where the distribution is between a minimum and maximum value (excluding outliers[3]), with the median representing the most likely value in this distribution. Triangular distributions were chosen because they include definitive cutoff values that cannot be exceeded, and skewed distributions are easily represented. We deem this approach suitable because it excludes unrealistic values, e.g., that hydropower capacities will significantly be reduced from today's levels. A normal distribution represents the electricity demand in Norway. Here the responses fit a normal distribution closely and no skew was observed. For this analysis, the variables are treated as being independent of one another. Based on the derived probability distributions, 500 cases were generated via Latin Hypercube sampling, leading to results from 500 independent model runs.

3. Results

3.1. Survey results

3.1.1. Drivers and barriers to Norwegian electricity production

For analyzing drivers and barriers to the production side in Norway, the survey participants were asked to give their opinion to selected statements by the authors on a 7-step Likert scale, where 1 is "strongly disagree," and 7 is "strongly agree" cf. Figure 3. The statements reflect developments that could lead to major changes on the production side of the 2040 Norwegian energy system.

[3] Outliers are defined as being outside the 1.5 inter quartile range (IQR)

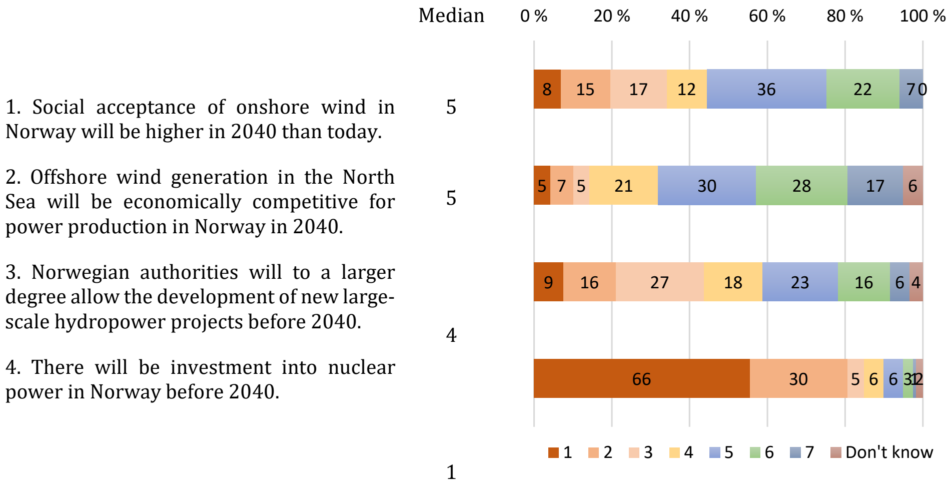


Figure 3. Electricity production and social acceptance. 1 is "strongly disagree," and 7 is "strongly agree" with the statement.

The experts' view on the development of social acceptance of onshore wind power towards 2040 shows a high level of uncertainty. The median value and the mode are 5, indicating that the respondents lean towards that acceptance of onshore wind power will increase. However, 40 out of 119, with 2 choosing not to answer, believe that the social acceptance of wind power will decrease further in future years. The range of results shows that opinions vary, and there is little certainty based on the reported responses. More of a consensus in expert opinion is that offshore wind will be an economically competitive technology in 2040. Here too, the median and mode are 5, yet the number of experts disagreeing with the statement is far lower at 17 out of 119, with 6 choosing not to answer. Opinions are split on the statement that the Norwegian authorities will allow large-scale expansion of hydropower projects by 2040. The median is 4, but slightly more respondents disagree (52) than agree with the statement (45). Upgrades of existing hydropower may only provide limited new generation capacity and the development of new large-scale hydropower projects needs to combine economic, environmental, and social acceptability aspects. There is a clear consensus that investments into nuclear power plants are not likely by 2040, with more than half of respondents very strongly disagreeing with the statement in question 4 of Figure 3.

3.1.2. Drivers of electricity consumption

The survey participants were asked to give their opinion on trends and public discussion points that we deemed important as they could accelerate the future growth of electricity demand in Norway. Statements and responses on a 7-step Likert scale are summarized in Figure 4.

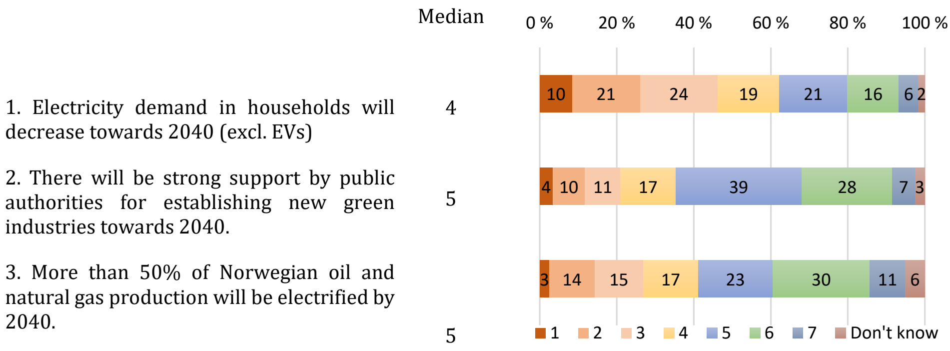


Figure 4. Electricity demand development in different sectors. 1 is "strongly disagree," and 7 is "strongly agree" with the statement.

Respondents are undecided on the development of electricity consumption (excl. electric vehicle consumption), with 55 out of 119 thinking the electricity consumption in households will increase and 45 thinking it will decrease. The median is 4 while the mode is 3, underscoring that only a slight majority disagrees with the statement. There is more of a consensus that public authorities will strongly support the development of new green industries such as hydrogen electrolysis or battery factories in Norway. The median is 5 and 74 out of 119 more agree with the statement than not, with 20 being undecided or choosing "don't know." Similarly, there is a consensus that oil and gas production will be electrified. Both these statements indicate that the future electricity demand could rise significantly in future years.

3.1.3. Norwegian electricity production

The experts were asked to give their best predictions of the annual production from different power generating sources in Norway in 2040. To anchor the respondents' answers, 2020 values were given as a source of reference. The observed 2020 levels and median of the expert opinions for 2040 are displayed in Figure 5. Outliers, defined as being outside the 1.5 interquartile range (IQR), are screened out before calculating results. Total median production is estimated at 191 TWh in 2040. The 1.5 IQR of responses gives a high (Q3 + 1.5*IQR) and low value (Q1 - 1.5*IQR). The high value is 255 TWh and the low value is 149.5 TWh for total production. The error bar in Figure 5 represents these values and is interpreted as the uncertainty in the results.

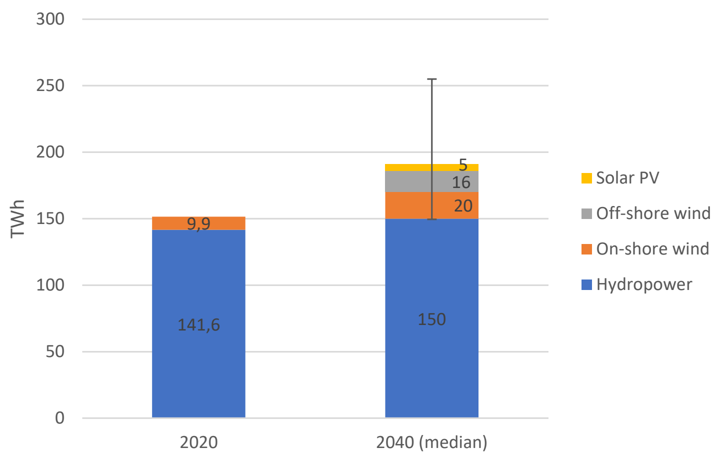


*Figure 5. Observed (*source SSB) and projected power production.*

Hydropower production is expected to increase only moderately from 141.6 TWh in 2020 to 150 TWh in 2040. This indicates that new large-scale hydropower projects are seen as unlikely, and increased production may come from increased inflow or upgrades to existing hydropower. The index of dispersion in Table 1, measured as the variance divided by the mean, normalizes the data and shows how dispersed the answers are. Hydropower has the lowest index of dispersion among the generating technologies, indicating a high level of agreement among experts. A stronger increase in production is expected from wind power by 2040. The median of expert opinions is that onshore wind accounts for 20 TWh and offshore wind for 16 TWh in 2040. However, the variability regarding wind power generation is very high in these results. The 1.5 IQR of results extends to 13 TWh and 30 TWh for onshore wind and 0.3 TWh and 50 TWh for offshore wind. The index of dispersion is particularly high for offshore wind, indicating that experts are uncertain to what extent offshore will be deployed. Large-scale solar PV is expected to account for around 5 TWh, up from close to zero today. The index of dispersion is high here, too, indicating uncertainty within the experts' views.

Table 1. Index of dispersion for production from power generating technologies.

Producer	Index of dispersion
Solar PV	9.5
Offshore wind	48.4
Onshore wind	3.7
Hydropower	0.5

Respondents were also asked about the future of fossil-based power production with CCS and the role of biomass in district heating generation. Many do not see fossil-based power production with CCS as a viable future option for electricity production, with the median of respondents saying there will be 0 TWh produced. The mean value is at 1.6 TWh showing some experts have a more positive stance on using CCS for power production. Biomass is assumed to produce heat for district heating in the order of 3 TWh (median).

3.1.4. Norwegian electricity consumption

Similarly to production estimates, the survey participants gave precise estimates for electricity consumption, split by sector/consumer, cf. Figure 6.

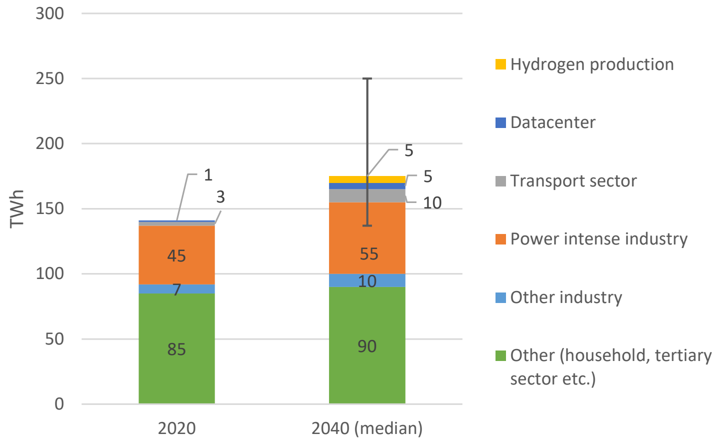


*Figure 6. Observed (*source SSB) and projected electricity consumption.*

Total Norwegian electricity consumption is estimated to increase mostly as the result of new industries' demands (+10 TWh), increased electrification of existing industry (+13 TWh), and transport (+10 TWh). Aggregating the estimates for power consumption by different demand sources, the median demand is 175 TWh in 2040. The responses concerning total consumption vary strongly among respondents. Most results are found in the range of 160-179 TWh (36 respondents), followed by 180-199 TWh (26), 200-219 TWh (17), and 140-159 TWh (15). The high and low values (High value=Q3+1.5*IQR; Low value=Q1-1.5*IQR) range from 137 TWh to 250 TWh (indicated by the error bar in Figure 6), which highlights the uncertainty surrounding the future power demand. The index of dispersion shows particularly high uncertainty in the answers regarding hydrogen production, where responses range from being very optimistic to very pessimistic on the demand development. There is less variability in the answers for the other categories, indicated by a lower index of dispersion, cf. Table 2..

Table 2. Index of dispersion for power consumption.

Consumer	Index of dispersion
Hydrogen production	16.5
Datacenter	5.0
Transport sector	2.6
Power intensive industries	4.3
Other industry	5.6
Other	2.0

3.1.5. Energy Balance and probability distributions

The term energy balance in this study is defined as a term to describe the net electricity exports from a given country. Norway in 2040 is estimated to have a median supply exceeding the median demand. However, this conclusion is uncertain due to the range of responses. The high and low values show possible supply from 149.5 – 255 TWh (Figure 5) and possible demand from 137 – 250 TWh (Figure 6). Respondents were additionally asked to rate on a Likert scale how the energy balance will develop, decrease or strengthen (Figure 7). Here, 35 respondents think Norway's energy balance will decrease from today's levels, 17 think the energy balance will develop neutral and 59 respondents think Norway will have a moderate to strong strengthening of the energy balance, exporting more electricity. This means that many experts assume that future power production developments will outpace consumption, leaving room for more exports.

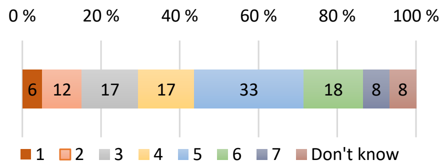
	Median	
How will Norway's energy balance (net export) change by 2040? Pay attention to your answers from parts 2 and 3.2040.	5	

Figure 7. Norwegian energy balance. 1 is "strongly decrease," and 7 is "strongly increase."

The supply and demand results were used to derive probability distribution for the Monte Carlo simulations. For power production, low and high values are based on the 1.5 IQR, and for demand, a normal distribution was laid over responses regarding total power consumption, cf. Table 3. The median, mean, and standard deviation were calculated after screening out outliers.

Table 3. Monte Carlo input distributions.

	Onshore wind	Offshore wind	Solar PV	Hydropower	Demand
Distribution	Triangular	Triangular	Triangular	Triangular	Normal
Min	13	0.3	0.2	136	
Median	20	16	5	150	
Max	30	50	15	160	
Mean					182
Standard deviation					26

3.2. Model results

3.2.1. Power prices

Modeled Norwegian power prices, here calculated as the annual average of the five Norwegian price zones, are closely correlated to the observed energy balance. As Norway does not have fossil fuel-based power generation in 2040, the impact of the CO_2 price and natural gas price is not the center of the expert survey, and distributions were not derived. However, since both are power price drivers in the Northern European energy system, the impact on Norway from varying these prices is addressed via additional model runs. A case with a 50% increase in the short-run marginal costs (SRMC) of natural gas generation and a case with a 50% decrease in the SRMC are conducted[4]. The BASE scenario assumes an SRMC of 100 EUR/MWh for an average large-scale 2040 condensing gas power plant. In the BASE case, we see an exponentially falling mean price in the model simulations as the Norwegian energy balance increases, cf. Figure 8. The graph shows how additional generation reduces mean prices while higher consumption from electrification or new industry demands will increase mean prices. The shape of the graph shows that power prices are more affected by changes in the energy balance when Norway is a net importer than with an export surplus. However, it should be pointed out that in the tails of Figure 8, with extreme levels of exports, prices are also more affected by every additional unit of export than in more balanced supply and demand situations. Thus, balancing new demands and supply is important to avoid strong price effects. The median of the average prices in the 500 model runs is 34 EUR/MWh in 2040, with a median net export of 5 TWh. If the SRMC of natural gas increases by 50% (light green line), a small downshift in the price curve compared to BASE (dark green line), with the shape staying similar, is observed. The reason for similar results is that the generation mix in surrounding countries, from BASE to the +50% SRMC of natural gas scenario, is only slightly changed. Production from low marginal cost renewables remains at similar levels, natural gas production is comparatively lower, and power generation from biomass is higher as it gains a competitive advantage when the SRMC of natural gas increases. If, however, the SRMC of natural gas fell by 50% compared to the BASE case, natural gas generation would increase its competitiveness in interconnected countries such as Germany and the UK. The countries invest less in variable renewable energy (VRE) capacities (affecting mostly solar PV) and have higher power production from natural gas. This increased flexible production leads to fewer price spikes, but lower VRE capacities also lead to fewer very low-price periods. For Norway, this results via interconnection in a flattened price curve (yellow line). As such, it should be noted that these results must be

[4] The increase/decrease in the SRMC is achieved in equal parts through a change in the fuel costs and the price of CO_2

interpreted as long-term effects where generation capacities have adapted to new long-term cost levels of gas and emissions rights. The short-term response to changes in gas and carbon prices would be different.

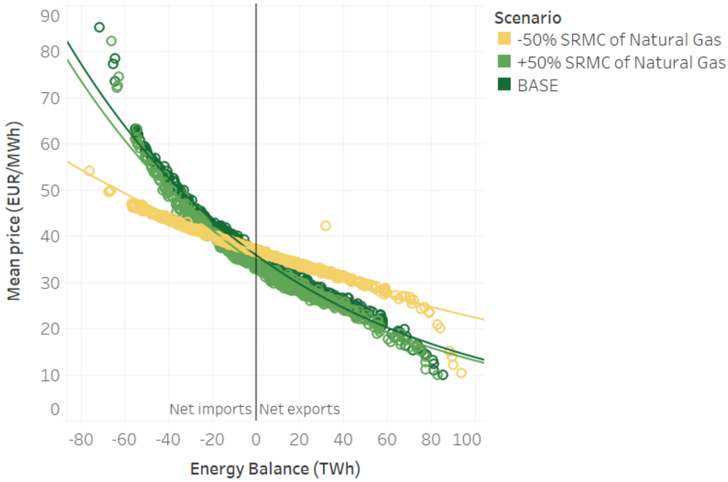


Figure 8. Mean Norwegian power prices at different energy balance levels in 2040.

Figure 9 shows price distributions based on the Monte Carlo simulations in the BASE case. The different PDFs show some measures commonly found in a boxplot, consisting of 10% quantile, 25% quantile, median, mean, 75% quantile, and 90% quantile. To assess the variability of the respective PDF, we look at the 1st quartile, the median, and the 3rd quartile, cf. Table 4. Since the PDFs are skewed, the standard deviation would not provide much value as a measure of variability and we deem quartiles suitable to give us insights.

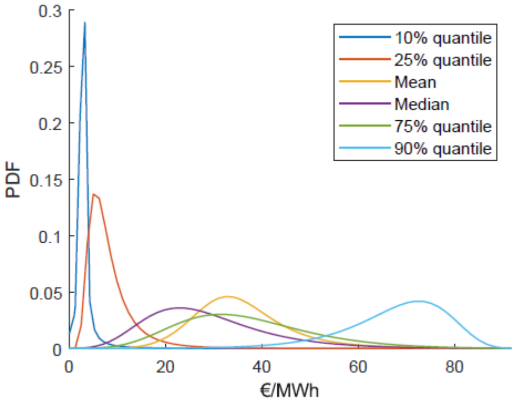


Figure 9. Probability Density Function of electricity prices in Norway.

According to the model runs for the BASE scenario, the average price will likely (50% of our model runs) be between 29 and 42 EUR/MWh (1st and 3rd quartile), with the median of the mean modeled price being 34 EUR/MWh. The median price curve is to the left of the mean price curve, indicating that the mean is skewed right and more extreme prices to the upside are observed compared to extremely low prices in the simulations. The PDF of low prices (25% quantile of prices) is at the median 8 EUR/MWh. Prices are observed in a narrow range, indicating less uncertainty for low prices. The price between the 1st and 3rd quartile is between 5 and 11 EUR/MWh. The PDF of high prices (75% quantile) is at the median of these modeled prices 33 EUR/MWh, but the uncertainty is larger than in the 25% quantile. The price is likely between 27 and 45 EUR/MWh (1st and 3rd quartile). The price range indicates that in the BASE scenario, the elevated price levels are affected more by supply and demand developments in Norway than the lower price levels. Imagine a fully flexible consumer with full load hours of less than 25% during the year. This consumer can most likely use electricity for below 11 EUR/MWh. However, the situation differs if this consumer has high full load hours, which increases the dependency on the mean price. The mean price will be more heavily impacted by decisions regarding the supply and demand side making forward guidance more difficult, cf. the wider PDF for mean prices in Figure 9. A fully flexible producer with less than 25% full load hours during the year, unlike the flexible consumer, faces higher uncertainty, cf. 75% quantile in Figure 9. The wide PDF of the 75% quantile indicates that producer flexibility gives less certainty over future sales prices. Similarly, to the 75% compared to the 25% quantile, the uncertainty regarding the 90% quantile is much higher than in the 10% quantile.

Table 4. Analysis of electricity price PDF (BASE).

	10% quant.	25% quant.	Median	Mean	75% quant.	90% quant.
1st quartile	2.6	4.7	20	29	27	63
Median	2.9	7.5	25	34	33	72
3rd quartile	3.4	11	36	42	45	76

The PDFs for electricity prices in 2040 with a 50% decrease (left) and a 50% increase (right) in the SRMC of electricity generation from natural gas are shown in Figure 10 (note the different scales on the x-axis).

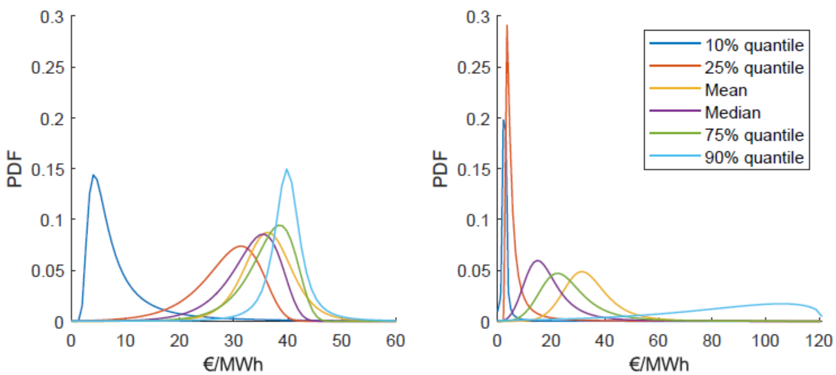


Figure 10. Probability Density Function of electricity prices in Norway with 50% decrease (left) and 50% increase right in the SRMC of natural gas production (right).

It is observed that a decrease in the SRMC of natural gas would lead to less extreme prices with the different PDFs more centered around the mean. Also, the PDFs for the median and higher prices are steeper than in BASE displaying a smaller range of observed results between the different model runs. Thus, lower natural gas SRMC gives a higher certainty to future Norwegian power prices irrespective of domestic supply and demand developments. If the SRMC of natural gas increases by 50% compared to BASE, the PDFs remain similar to the BASE scenario. One major difference is that very high prices (90% quantile) are observed to be higher with higher SRMC of natural gas because import electricity prices increase when natural gas is price setting in connected price regions.

3.2.2. Value factors

The value factors of different technologies shed light on the comparative advantage of technologies over others. It assesses the power price captured by a technology, also referred to as market value, compared to the average price. A value factor of over 1 indicates that prices captured are higher than the average price, while lower value factors indicate production in less favorable periods. Low market values may also indicate the "merit-order-effect" negatively impacting captured prices. Again, the sensitivity to the SRMC of natural gas is considered by additional runs assuming a 50% decrease or 50% increase in the SRMC of natural gas. In the model simulations, we observe that Norway's energy balance is the main driver of change for power prices and value factors. The value factors for the analyzed technologies in relation to the energy balance are represented in Figure 11. The slope of the curves indicates if market values are relatively more affected by changes in the energy balance than power prices or not. The shape of the curve is not always linear and shows stronger or less strong changes in the value factor at different energy balance levels. The intercepts between technologies indicate where a competitive advantage of one technology over another changes with changes in the energy balance.

Dispatchable power generation from hydro reservoirs has the highest value factors (mean in BASE 1.58) of all technologies across all three scenarios. The positive slope of the value factor with increasing energy balance indicates a competitive advantage when there are high net exports and low average power prices. In these model simulations, hydropower with reservoirs can capture relatively higher prices than other technologies as low-price periods can be avoided due to temporal flexibility in production. Absolute market values will also decrease with increasing energy balance, but mean power prices are affected relatively more strongly than the market value. The scenario with a 50% increase in the SRMC of natural gas leads to higher value factors than BASE. In comparison, a 50% reduction in the SRMC of natural gas would decrease the value factor for hydropower with reservoirs.

Hydro run-of-river (ROR) and solar PV (mean in BASE 0.55 and 0.53 respectively) have the lowest observed value factors. Both technologies have negative slopes indicating lower market values relative to the average power price with increasing energy balance. With a positive energy balance, these technologies produce in unfavorable price periods with high competition from other renewable generation and low demand. In the BASE scenario, the captured prices of the technologies intersect at a negative 10 TWh energy balance, with solar PV having a steeper slope and being more competitive with negative energy balances and hydro ROR being more competitive with positive energy balances. The sensitivity scenarios show that with lower SRMC of natural gas, particularly hydro ROR profits with a positive energy balance while the results for higher SRMC are similar to the BASE scenario.

Wind power in Norway, both off- and onshore, has higher value factors (mean in BASE of 0.92 and 1.05, respectively) than other intermittent technologies as the seasonal production profile correlates with seasonal power consumption. In the BASE scenario, the slopes are strongly negative, indicating that with an increasing energy balance, market values will decrease faster than the average power price. The slope of onshore wind is steeper negative than that of offshore wind suggesting a higher effect of the energy balance on onshore wind market values. In the BASE scenario, the value factors intersect around an energy balance of +50 TWh. With lower SRMC of natural gas, the value factors of both onshore and offshore wind are mostly flat with changing energy balance and onshore wind captures slightly higher value factors than offshore wind. With higher SRMC of natural gas, the slopes are steeper and the intersection between onshore and offshore wind is observed around an energy balance of +30 TWh. The differences in the three scenarios show that changing costs of natural gas generation and resulting generation mixes in surrounding countries will strongly affect the value factor of Norwegian wind production.

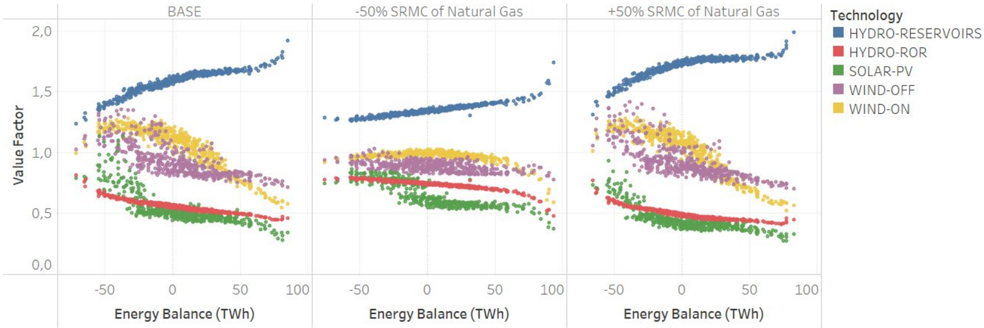


Figure 11. Value factors at different energy balance levels.

3.2.3. Market Values

The probability of capturing specific market prices by different technologies across the model simulations, according to the expert projection, can be understood by looking at the PDFs of the market values, cf. Figure 12.

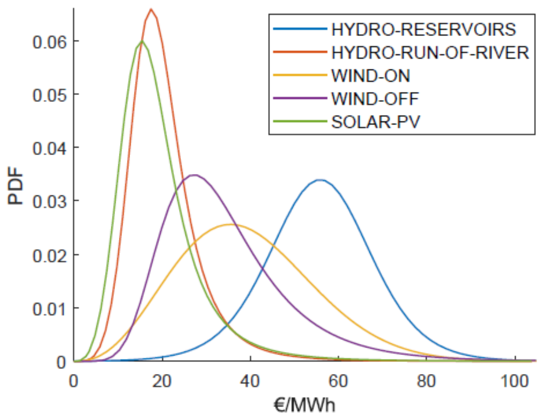


Figure 12. The market value of produced electricity by different technologies in Norway (BASE).

In the BASE scenario, solar PV followed by run-of-river hydro captures the lowest market values with median market values of 17 and 19 EUR/MWh, respectively. Both are intermittent energy sources with unfavorable characteristics for capturing high market values in Norway. Solar PV produces most in summer when electricity prices are lower and thus does not profit as much from the seasonal price patterns. Also, some daily price peaks are not served in the morning and evening hours. ROR hydropower produces most in spring (spring flood) and autumn (high precipitation). In winter, with the highest prices, production is lower due to snowfall in higher altitude areas. Both technologies have a relatively steep PDF indicating less uncertainty than other technologies in the BASE scenario. Solar PV market value from the 1st to 3rd quartile ranges from 14 EUR/MWh to 21 EUR/MWh. ROR hydropower's market value from the 1st to 3rd quartile ranges from 15 EUR/MWh to 24 EUR/MWh. Wind power in Norway captures higher prices. For offshore wind, the median price captured is 30 EUR/MWh and the market value is most hours between 24 EUR/MWh and 41 EUR/MWh (1st and 3rd quartile). Based on expert opinions, the range of the future production distribution is between 0.3 and 50 TWh. This large uncertainty and new investments mostly being placed in regions NO2 and NO5 lead to value factors being negatively affected by increased offshore wind generation, cf. Figure 13. Similar price cannibalization is not observed in other technologies.

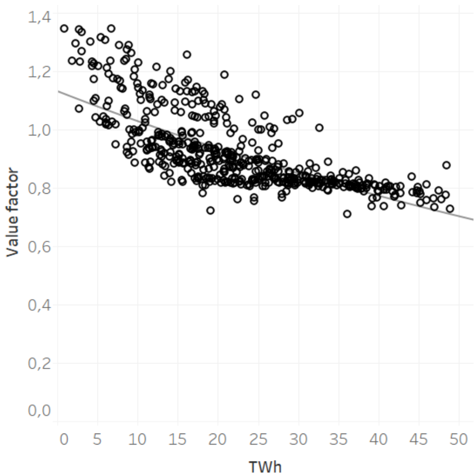


Figure 13. Offshore wind's value factors at different levels of offshore wind production (BASE).

The PDF of onshore wind is mostly to the right of offshore wind indicating a higher market value than for offshore wind in Norway (Figure 12). The distribution of the 2040 generation is assumed to be between 13 and 30 TWh, and investments are split more evenly across market areas in Norway. The median market value for onshore wind is 37 EUR/MWh, with the market value likely being between 28 and 50 EUR/MWh (1st and 3rd quartile). The PDF of onshore wind is wider than for offshore wind indicating a wider range of market values, thus more uncertainty, in the model simulations. Flexible generation from hydropower with reservoirs has the highest market value. Flexibility allows it to generate most electricity in higher price periods than intermittent technologies, both in model runs with a negative or positive energy balance. The median market value in the Monte Carlo simulation is 55 EUR/MWh, and the 1st quartile and third quartile are 48 and 64 EUR/MWh. An overview of the market values discussed is found in Table 5.

Table 5. Analysis of market value PDF (BASE).

Quantile	Hydro reservoir	Hydro ROR	Solar PV	Wind onshore	Wind offshore
1st quartile	48	15	14	28	24
Median	55	19	17	38	30
3rd quartile	64	24	21	50	41

The sensitivity scenarios reveal that a decrease in the SRMC of natural gas generation changes market values significantly from the BASE scenario. An increase in the SRMC only shifts the high-end market values slightly higher, cf. Figure 14 compared to Figure 12.

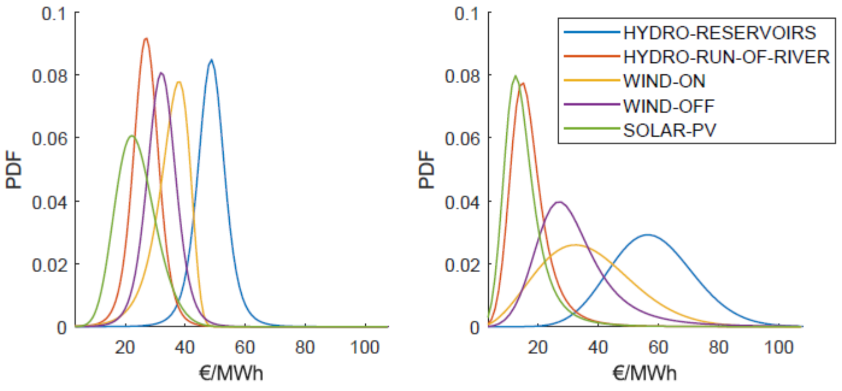


Figure 14. Probability Density Function of market values in Norway with 50% decrease (left) and 50% increase (right) in the SRMC of natural gas production.

With lower costs of natural gas, price stability increases, and all PDFs except for solar PV become steeper, indicating less variability in the market values across the scenarios. The PDF of technologies with low market values shifts right (solar PV and hydro ROR) and the PDF of technologies with high market values shifts left (hydro reservoirs).

4. Limitations and areas for further research

There are several limitations to consider when analyzing the results of the survey conducted in this study. Firstly, the sample size may not be representative of the entire population of interest. While efforts were made to include a diverse range of experts, the final sample was still subject to selection based on certain criteria, such as having relevant experience in the energy sector. This means that the views and experiences of individuals who do not meet these criteria are not represented in the results. Furthermore, the sample was only prescreened with regard to incomplete responses and unattainable responses (e.g., 1000 TWh solar PV production in Norway in 2040.) This could potentially lead to a biased sample, as those who are more invested in the topic or who have strong opinions may be more likely to complete the survey. Additionally, outlier responses that fell outside the interquartile range were excluded from the analysis. While this is a common statistical practice, it means that the perspectives of these individuals are not included in the final results.

In terms of the modeling conducted in this study, the probabilistic approach assumed exogenously determined supply and demand inputs in Norway to be independent of one another. In reality, production capacity investment will be dependent on capturing high enough prices. In countries surrounding Norway, it is important to note that we allowed the model to endogenously invest in generation capacities. This means interconnected countries respond to Norway's energy balance, potentially smoothening the impacts of model runs with extreme energy balances. Electricity prices in all market areas are calculated endogenously in the model based on the marginal cost of production of the marginal power plant. However, in Norway, the exogenously determined production influence these prices significantly. Additionally, several other key assumptions, affecting all model runs, were exogenously determined. These concern carbon prices, future transmission investments, and fuel prices, which impact the model results. The impacts of varying carbon and natural gas prices have been addressed via sensitivity model runs.

Overall, there are several areas for further research that could help to address the limitations of this study. For example, conducting a larger, more representative survey that includes prescreening and a wider range of participants could provide a more comprehensive view of the issues at hand. Modeling efforts could also be improved by incorporating further assumptions about the behavior of surrounding countries and future developments in the energy market. Further research could aim to explore the sensitivity of the results to different assumptions about e.g., transmission lines. These limitations and areas for further research should be taken into account when interpreting the results.

5. Conclusion

This study addresses questions on the future Norwegian energy system by coupling an expert survey with a probabilistic approach. The expert survey allows several conclusions on its own. First, Norway's electricity production in 2040 is expected to increase to a large degree based on a combination of onshore and offshore wind. However, agreement amongst experts on the expected production of offshore wind is low, with estimates ranging from 0.3 to 50 TWh and a high degree of variation in the responses. Second, Norway's electricity demand is expected to increase substantially due to new industries and the electrification of transport. Particularly hydrogen production is a "wild card" where the dispersion in survey responses is high. Third, Norway will likely maintain a positive electricity balance with low electricity prices in an international context. A small majority of respondents conclude that the energy balance is more likely to strengthen towards 2040 than weaken.

The probabilistic model analysis models the survey responses using a Monte Carlo approach. It looks deeper into what the expert views would mean for power prices, value factors, and market values of power generating technologies. Findings show an exponentially falling relationship between the mean price in Norway and an increasing energy balance, meaning a change from today's status as a net exporter to potentially becoming a net importer would result in significantly higher prices. However, exporting more electricity from today's levels would only moderately decrease power prices. Market values differ significantly in the model runs depending on the assumed supply and demand developments in Norway. There are additional differences between technologies concerning the range of market values, shown by the steepness of PDFs in this study. Hydro ROR and solar PV market values are most certain, with a relatively small difference in the market value from the 1^{st} to the 3^{rd} quartile of 9 EUR/MWh and 7 EUR/MWh, respectively. The range of uncertainty for onshore wind is highest at 22 EUR/MWh, followed by offshore wind at 17 EUR/MWh and hydropower with reservoirs at 17 EUR/MWh.

We believe the present study provides new insights into the expected range, development, and dependencies of power prices, value factors, and market values of different technologies in the future Norwegian energy system as perceived by experts working in the industry. This study's results can be useful for policymakers in understanding whether their assumptions align with those of experts and whether plans for the future energy system have been communicated effectively. This study offers industry experts an overview of the agreement and disagreement among their peers on the topic of the future Norwegian energy system. The dispersion in responses may be interpreted as an indication of uncertainty about future developments. The demonstrated approach is suitable for studies in which survey results are to be analyzed or visualized using energy system modeling. It has the advantage of including a wider range of opinions compared to traditional scenario-based approaches, while also allowing the authors to visualize the results of majority and minority opinions in probability density functions. The use of a probabilistic approach that is not based on preconceived assumptions by the authors makes the results representative of the survey participants' opinions, removing author bias.

Acknowledgment

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Appendix

Table A 1. Expert survey (English translation).

Category	Question	Response type
Occupation	Occupation	Drop down
Experience	Experience in a field connected to energy	Drop down
Education	Your educational background	Drop down
Power production	Social acceptance of onshore wind in Norway will be higher in 2040 than today.	Likert scale
Power production	Offshore wind generation in the North Sea will be economically competitive for power production in Norway in 2040.	Likert scale
Power production	Norwegian authorities will to a larger degree allow the development of new large-scale hydropower projects before 2040.	Likert scale
Power production	There will be investment into nuclear power in Norway before 2040.	Likert scale
Power production	Annual 2040 onshore wind power production will be (was approx. 13 TWh in 2020)	Exact number
Power production	Annual 2040 offshore wind power production will be (was close to 0 TWh in 2020)	Exact number
Power production	Annual 2040 hydropower production will be (136 TWh in 2020)	Exact number
Power production	Annual 2040 biomass-based heat/electricity production from district heating companies will be (1.6 TWh in 2020)	Exact number
Power production	Annual 2040 solar PV production will be (was approx. 0.14 TWh in 2020)	Exact number

Power production	Annual 2040 fossil-based power production with CCS will be (was close to 0 TWh in 2020)	Exact number
Power consumption	Electricity demand in households will decrease towards 2040 (excl. EVs)	Likert scale
Power consumption	There will be strong support by public authorities for establishing new green industries towards 2040.	Likert scale
Power consumption	More than 50% of Norwegian oil and natural gas production will be electrified by 2040.	Likert scale
Power consumption	Annual 2040 power consumption in power-intensive industries will be (was approx. 45 TWh in 2020)	Exact number
Power consumption	Annual 2040 power consumption from data centers will be (was close to 1 TWh in 2020)	Exact number
Power consumption	Annual 2040 power consumption from hydrogen electrolysis will be (was close to 0 TWh in 2020)	Exact number
Power consumption	Annual 2040 power consumption in all industry will be (was approx. 52 TWh in 2020)	Exact number
Power consumption	Annual 2040 power consumption in transport will be (was approx. 3 TWh in 2020)	Exact number
Power consumption	Annual 2040 remaining power consumption outside of industry and transport (was approx. 85 TWh in 2020)	Exact number
Power consumption	The total annual 2040 Norwegian power consumption will be:	Exact number
Energy balance	How will Norway's energy balance (net export) change by 2040? Pay attention to your answers from parts 2 and 3.	Likert scale
Flexibility option	What flexibility solutions will be important for the 2040 Norwegian power system	Comment

Norwegian energy system	Between 2030 and 2040 new DC transmission connections between Norway and other European countries will be built, increasing transmission capacity.	Likert scale
Norwegian energy system	Social acceptance of transmission lines to other European countries will be higher in 2040 than today.	Likert scale
Norwegian energy system	Norwegian power prices will remain low in an international context.	Likert scale
Prices	The EU-ETS price of carbon will be higher than 500 NOK/t.	Likert scale
Prices	The EU-ETS price of carbon will be higher than 1000 NOK/t.	Likert scale
European Energy system	The EU will reach its goal of cutting 55% of GHG emissions in 2030 compared to 1990 levels.	Likert scale
European Energy system	The EU will reach its goal of climate neutrality in 2050.	Likert scale
European Energy system	The EU will reach its target from the hydrogen strategy of 40 GW renewable electrolyzer capacity in 2030.	Likert scale
European Energy system	The EU's power consumption will increase by more than 50% by 2050 compared to 2020 levels.	Likert scale

Table A 2. Expert survey (Norwegian original).

Kategori	Spørsmål
Virksomhet	Virksomhet
Erfaring	Erfaring med oppgaver knyttet til energi
Utdanning	Din utdanningsbakgrunn
Kraftproduksjon	Sosial aksept av vindkraft på land i Norge vil være høyere i 2040 enn i dag.
Kraftproduksjon	Havvind/Offshore vindkraft i Nordsjøen vil være en økonomisk konkurransedyktig teknologi for leveranser til Norge i 2040.
Kraftproduksjon	Norske myndigheter vil i større grad tillatte utbygging av nye vannkraftprosjekter innen 2040
Kraftproduksjon	Det vil bli investert i ny kjernekraft i Norge innen 2040.

Kraftproduksjon	Årlig produksjon av vindkraft på land i 2040 (var ca. 13 TWh i 2020)
Kraftproduksjon	Årlig produksjon av havvind/offshore vind i 2040 (tilnærmet 0 i 2020)
Kraftproduksjon	Årlig produksjon av vannkraft i 2040 (136 TWh i 2020)
Kraftproduksjon	Årlig varme-/kraftproduksjon basert på biomasse i fjernvarmeselskapene i 2040 (1,6 TWh i 2020)
Kraftproduksjon	Årlig produksjon av solkraft i 2040 (var ca. 0,14 TWh i 2020)
Kraftproduksjon	Årlig fossilbasert kraftproduksjon med CCS i 2040 (tilnærmet 0 i 2020)
Kraftforbruk	Forbruket av elektrisitet i husholdningene vil avta frem mot 2040 (se bort fra forbruket til elbiler)
Kraftforbruk	Det vil være en sterk, offentlig støtte til etablering av nye, grønne industrier i 2040.
Kraftforbruk	En vesentlig del (mer enn 50%) av norsk olje- og gassproduksjonen vil være elektrifisert i 2040.
Kraftforbruk	Kraftforbruket i kraftkrevende industri i 2040 (Ca. 45 TWh i 2020):
Kraftforbruk	Kraftforbruket i datasentre i 2040 (Ca. 1 TWh i 2020):
Kraftforbruk	Kraftforbruket til hydrogenproduksjon i 2040 (var tilnærmet 0 i 2020):
Kraftforbruk	Samlet kraftforbruk i industrien i 2040 (Ca. 52 TWh i 2020):
Kraftforbruk	Kraftforbruket i transportsektoren i 2040 (Ca. 3 TWh i 2020):
Kraftforbruk	Kraftforbruket utenom industri og transport i 2040 (Ca. 85 TWh i 2020):
Kraftforbruk	Samlet kraftforbruk i Norge i 2040 vil være rundt:
Energibalanse	Hvordan vil Norges energibalanse i form av netto eksport være endret i 2040? Vær oppmerksom på svarene dine fra del 2 og 3.
Kommentar	Hvilke fleksibilitetsløsninger tror du blir viktige for det norske kraftsystemet i 2040?
Energisystem Norge	I perioden 2030 til 2040 vil det bygges flere DC sjøkabler mellom Norge og utlandet (dvs økt overføringskapasitet).
Energisystem Norge	Befolkningens aksept for kraftkabler til utlandet være høyere i 2040 enn i dag.
Energisystem Norge	Norske kraftpriser vil forbli lave sammenlignet med det europeiske prisnivået.
Priser	Kvoteprisen for karbon i 2030 vil være høyere enn 500 NOK/t
Priser	Kvoteprisen for karbon i 2030 vil være høyere enn 1000 NOK/t
Energisystem Europa	EU vil nå målet om 55% utslippskutt i 2030, sammenlignet med 1990.
Energisystem Europa	EU vil nå målet om 100% klimanøytralitet i 2050.

Energisystem Europa	EU vil implementere sin hydrogenstrategi som innebærer 40 GW kapasitet av fornybar elektrolyse av hydrogen i 2030.
Energisystem Europa	EUs forbruk av elektrisitet vil øke mer enn 50% innen 2050 sammenlignet med 2020-nivå.

Table A 3. Techno-economic assumption on investable technologies in 2040 in Balmorel (only large unit sizes represented below).

Technology	**Efficiency**	**Inv. Cost**	**Fixed operation cost**	**Variable operation cost**
		M.EUR/MW	**EUR/kW**	**EUR/MWh**
Heat storage				
District heat pit storage (centralized)	0.7	0.0013	0.003	
District heat pit storage (decentralized)	0.7	0.0004	0.003	
Heat pump				
Air source heat pump (4 MW)	3.4343	0.6323	2.0231	1.7702
Ground source heat pump (4 MW)	3.95	0.5513	1.96	1.617
Boiler				
Electric boiler for district heat (10 MW)	0.99	0.0588	0.9506	0.98
Battery storage				
Lithium-ion for grid-scale application (10 MW)	0.95	0.2414	0.2224	
Lithium-ion for peak power application (100 MW)	0.9	0.2518	1.5959	
Biogas				
Back pressure, internal combustion engine (1 MW)	0.96	0.8575	8.722	
Condensing, internal combustion engine (1 MW)	0.46	0.7289	8.722	6.37
Straw				
Heat-only boiler (6 MW)	1.02	0.784	44.933	0.588
Back pressure, steam turbine subcritical (132 MW)	0.9938	2.3267	102.9	0.5852
Condensing, steam turbine subcritical (132 MW)	0.31	1.9777	102.9	1.8878
Wood chips				

Heat-only boiler (7 MW)	1.15	0.6076	29.645	0.882
Back pressure, steam turbine subcritical (600 MW)	1.14	2.9284	49	
Condensing, steam turbine subcritical (600 MW)	0.29	2.4891	49	3.728
Wood pellets				
Heat-only boiler (6 MW)	1.001	0.6664	29.6081	0.45
Back pressure, steam turbine subcritical (800 MW)	0.98	2.058	57.281	
Condensing, steam turbine subcritical (800 MW)	0.33	1.5273	39.2	1.5153
Natural gas				
Heat-only boiler (5 MW)	1.06	0.049	1.764	1.029
Backpressure, internal combustion engine (1 MW)	0.9849	0.8575	8.722	2.401
Backpressure, Combined cycle (10 MW)	0.9257	1.127	26.362	2.17
Condensing, internal combustion engine (1 MW)	0.49	0.7289	8.722	4.9
Condensing, gas turbine (40 MW)	0.435	0.4498	17.934	4.018
Condensing, combined cycle (100 MW)	0.62	0.6789	26.362	4.018
Extraction, combined cycle (100 MW)	0.62	0.7987	26.362	2.491
Hard coal				
Condensing, steam turbine subcritical (400 MW)	0.53	1.616	60.368	2.156
Extraction, Steam turbine subcritical (400 MW)	0.53	1.9012	60.368	1.1427
Wind				
Wind onshore (5.5 MW)	Full load hours depending on the location	0.9604	11.3602	1.2152
Wind offshore (14 MW)		1.7792	33.369	2.45
Solar PV				

Solar PV (8 MW)	Full load hours depending on the location	0.2548	5.194	0
Municipal waste				
Heat-only boiler (35 MW)	1.06	1.7622	71.2911	6.2452
Back pressure, steam turbine subcritical (220 MW)	1.6167	6.8319	137.2	5.6975
Condensing, steam turbine subcritical (220 MW)	0.245	5.8072	137.2	23.2554

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Errata

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Errata.list:

Page	**Line**	**Change from**	**Change to**
49	Second paragraph last sentence. I believe lines 21-23	Climate policies such as a European coal phaseout would affect the European energy mix and result in changes to electricity prices also in the	Remove sentence as it is incomplete and all content is previously mentioned.

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