Norwegian University of Life Sciences
Faculty of Environmental Sciences
and Natural Resource Management
Research Group of Renewable Energy

Philosophiae Doctor (PhD)
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Emerging challenges in the energy transition in Northern Europe: potentials and impacts

Nye utfordringer i energiomstillingen i Nord-Europa: potensialer og virkninger

Yi-kuang Chen

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Table of Contents

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List of papers

Paper I — Chen, Y.-k., Hexeberg, A., Rosendahl, K. E. & Bolkesjø, T. F. (2021). **Long-term trends of Nordic power market: A review.** *WIREs Energy and Environment*, 10 (6): e413. DOI: 10.1002/wene.413
(Dataset DOI:10.18710/9EJYHX)

Paper II — Chen, Y.-k., Jensen, I. G., Kirkerud, J. G. & Bolkesjø, T. F. (2021). **Impact of fossil-free decentralized heating on Northern European renewable energy deployment and the power system.** *Energy*, 219: 119576. DOI: 10.1016/j.energy.2020.119576
(Dataset DOI: 10.18710/06HSDA.)

Paper III — Chen, Y.-k., Kirkerud, J. G. & Bolkesjø, T. F. (2021). **Balancing GHG mitigation and land conflicts: Alternative Northern European energy system scenarios.** Submitted to *Applied Energy* and under review.

Paper IV — Chen, Y.-k., Koduvere, H., Gunkel, P. A., Kirkerud, J. G., Skytte, K., Ravn, H. & Bolkesjø, T. F. (2020). **The role of cross-border power transmission in a renewable-rich power system – A model analysis for Northwestern Europe.** *Journal of Environmental Management*, 261: 110194. DOI: 10.1016/j.jenvman.2020.110194

Other papers — Bolwig, S., Bolkesjø, T. F., Klitkou, A., Lund, P. D., Bergaentzlé, C., Borch, K., Olsen, O. J., Kirkerud, J. G., Chen, Y.-k., Gunkel, P. A., et al. (2020). Climate-friendly but socially rejected energy-transition pathways: The integration of techno-economic and socio-technical approaches in the Nordic-Baltic region. *Energy Research & Social Science*, 67: 101559. DOI: 10.1016/j.erss.2020.101559.

Gea-Bermúdez, J., Jensen, I. G., Münster, M., Koivisto, M., Kirkerud, J. G., Chen, Y.-k. & Ravn, H. (2021). The role of sector coupling in the green transition: a least-cost energy system development in Northern-central Europe towards 2050. *Applied Energy,* 289: 116685. DOI: 10.1016/j.apenergy.2021.116685.

Summary

The European energy transition has passed the initial stage, and both the speed and scope of decarbonisation are growing rapidly. Decarbonisation progress has been observed in the power sector, but stronger efforts are called for in the non-power sectors. The electricity generated from renewables can potentially supply other energy needs, such as heating and transport, as a clean fuel. Future electricity demand will grow, and more renewable deployment will be required. The growing carbon prices and the declining costs of wind and solar technologies contribute to the economic competitiveness of renewables against fossil-fuel based generation. Nevertheless, the increasing renewable deployment results in new challenges that are beyond the techno-economic aspects. This thesis presents a review of Nordic power market outlooks, followed by three model analyses to investigate how the new challenges might affect future energy systems.

The power market outlook review (Paper I) builds the foundation to narrow down the focus angles for the other model analyses in this thesis. The outlooks often use energy system models, which consist of three key components: demand, supply and interconnection, with techno-economic perspectives. These models perform techno-economic optimisations by system cost minimisation or total social welfare maximisation. The review shows that less attention is put on the demand side compared to the thorough analysis on the supply side, and the focus on end-use sectors is limited. On the supply side, more variable renewable energy is needed, but the onshore wind development might be restricted in the recent outlooks despite its cost competitiveness and the high power price outlooks. One potential barrier is the lack of social acceptance due to concerns over land requirements. All the review outlooks regard cross-border interconnection as a key piece of the energy transition, but some appear less positive than others as a result of welfare redistribution. Based on the review, the three remaining studies of the thesis focus on (i) decarbonisation for heating and impacts to electricity demand, (ii) renewable supply and land use conflicts, and (iii) economic impacts and dilemmas in cross-border electricity trade.

Papers II-IV apply and further develop the energy system model Balmoral. The standard Balmorel framework models the power and district heat sectors in Northern Europe. A new module of the decentralised heating sector is developed in Paper II to show its impact on the power and district heating sectors. The estimation shows that over 80% of the space heating and hot water demand in Northern and Western Europe is supplied by decentralised heating systems, which are yet to be decarbonised despite the already existing mature solutions. The modelling results show that electrification through heat pumps and hybrid systems are the most cost-effective solutions in reaching full decarbonisation. Assuming future heat demand similar as today, heating decarbonisation will need 700 TWh extra fossil free electricity, which consequently quintuples the installed wind capacity and increases winter load significantly. Paper II demonstrates the importance of coupling the power and non-power sectors in making the analyses for decarbonisation.

The other two papers (Papers III and IV) incorporate the non-techno-economic perspectives in the Balmorel model to assess their influences on the energy transition. A disadvantage of renewables is their large land requirement, which is often not explicitly addressed in techno-economic optimisation models like Balmorel. Paper III applies the modelling to generation alternatives concept to Balmorel to search for near-optimal future energy systems that cause the least land conflicts. The results show that the least cost system will require four times today's land use level for energy production. Increases in system costs can reduce land use by shifting the systems with more offshore wind and nuclear power, but the implied annual costs for saving land, €200 k/km^2 to €700 k/km^2, appear substantially high compared to the market prices of non-building land.

Paper IV applies a scenario analysis to quantify the economic potentials of cross-border interconnection. We compared one scenario with the modelled optimal transmission capacity reaching the least system cost to another scenario with given transmission capacity and with no expansion beyond 2030. The results suggest that an addition of 76 GW cross-border transmission capacity can lower system costs by 5% and CO_2 emissions by 40% between 2030 and 2050. Wind and hydro power producers in the Nordics gain the most from increased cross-border power transmission. Based on the model assumptions in this study, their revenues increase by 67%, while the Nordic consumer costs of electricity also increase by 21%. Increased consumer costs in export regions could contribute to significant resistance to increased cross-border electricity trade.

In line with other literature, the results in this thesis show that the energy transition will require a significant amount of electricity and renewable energy deployment. In addition, the thesis demonstrates the need for expanding the scope of energy system analyses, and it illustrates how trade-offs will need to be made to overcome the emerging challenges from non-techno-economic aspects to reach a timely energy transition.

Sammendrag

Det europeiske energisystemet er i rask endring med utfasing av fossil kraft og utbygging av vind- og solkraft som hovedkomponenter. Dette har medført utslippsreduksjoner i kraftsektoren, men for å nå klimamålene kreves det sterkere innsats også i andre sektorer. Direkte elektrifisering basert på fornybar kraft kan potensielt bidra til utslippskutt i andre sektorer som oppvarming og transport. Med en slik utvikling vil fremtidig etterspørsel etter elektrisitet vokse, og utbygging av mer fornybar kraft vil være nødvendig. Økende karbonpriser og synkende kostnader ved vind- og solteknologi bidrar til å bedre den økonomiske konkurranseevnen til fornybar energi mot fossilbasert kraftproduksjon. Den kraftige veksten i fornybar kraftproduksjonen skaper imidlertid nye utfordringer som ligger utenfor de teknoøkonomiske aspektene. Denne avhandlingen presenterer en gjennomgang av de nordiske kraftmarkedsutsiktene, etterfulgt av tre modellanalyser for å undersøke hvordan nye utfordringer knyttet til økende kraftbehov, fordelingsvirkninger og arealbruk kan påvirke fremtidige energisystemer.

En litteraturgjennomgang av langsiktige markedsanalyser for kraftmarkedet (Artikkel I) danner grunnlaget for tre modellanalyser som er gjennomført i denne avhandlingen. De langsiktige markedsanalysene bruker oftest energisystemmodeller, som består av tre nøkkelkomponenter: etterspørsel, tilbud og handel mellom regioner via kraftnett. Modellene legger til grunn tekno-økonomiske optimaliseringer ved kostnadsminimering eller maksimering av samfunnsøkonomisk overskudd. Litteraturgjennomgangen avdekker at det etterspørselssiden i kraftmarkedet har blitt behandlet mindre grundig enn tilbudssiden, og fokuset på sluttbrukssektorer for elektrisitet er som regel begrenset. På tilbudssiden peker analysene på at en kraftig økning av variabel fornybar kraftproduksjon er nødvendig, men utviklingen av landbasert vindkraft er i nyere studier begrenset tiltros for kostnadskonkurranseevnen og høye kraftpriser. En potensiell hindring for landbasert vindkraft er mangel på sosial aksept. De aller fleste analysene anser økt handel med kraft mellom land som en sentral del av energiomstillingen, men noen fremstår som mindre positive enn andre som følge av omfordeling av velferd. Basert på litteraturgjennomgangen omhandler de tre resterende studiene i avhandlingen (i) økt kraftbehov som følge av utslippskutt til oppvarming, (ii) fornybar kraft og (iii) økonomiske effekter og dilemmaer ved økt handel med kraft mellom land.

Artiklene II-IV videreutvikler og anvender energisystemmodellen Balmorel. Det vanlige Balmorel-rammeverket modellerer kraft- og fjernvarmesektorene i Nord-Europa. En ny

modul for den desentraliserte varmesektoren er utviklet i Artikkel II for å analysere varmesektorens innvirkning på kraftsektoren på lang sikt. Analysen viser at over 80% av behovet for romoppvarming og varmtvann i Nord- og Vest-Europa forsynes av desentraliserte varmesystemer, som i liten grad er avkarbonisert til tross for at det finnes eksisterende modne løsninger. Modell resultatene viser at elektrifisering gjennom varmepumper og hybridsystemer er de mest kostnadseffektive løsningene for å oppnå full avkarbonisering. Forutsatt et fremtidig varmebehov som tilsvarer dagens behov, vil avkarbonisering av varmesektoren i Nord-Europa kreve 700 TWh ekstra fossilfri elektrisitet. Ifølge resultatene i artikkel II vil dette bidra til en femdobling av installert vindkapasitet og det øker kraftbehovet i vinterhalvåret betraktelig. Artikkel II demonstrerer viktigheten av å koble kraft- og ikke-kraftsektorene i analysene for dekarbonisering.

De to siste artiklene (III og IV) innlemmer ikke-teknoøkonomiske perspektivene i Balmorel-modellen for å vurdere deres innflytelse på energiovergangen. En ulempe med fornybar kraft er at produksjonen krever større arealer enn fossile alternativer. Arealbehov adresseres som regel ikke eksplisitt i teknoøkonomiske optimaliseringsmodeller som Balmorel. Artikkel III anvender konseptet modelling to generate alternatives på Balmorel for å søke etter løsninger for det fremtidige energisystemet som er nær økonomisk optimale, men som forårsaker mindre arealbrukskonflikter. Resultatene viser at det økonomisk optimale utslippsfrie kraftsystemet vil kreve fire ganger så mye areal som i dag til energiproduksjon. Arealbruken kan reduseres ved å erstatte landbasert vind- og solkraft med mer offshore vind- og kjernekraft, men kostnadene for å utvikle et utslippsfritt energisystem vil da øke. De estimerte impliserte årlige kostnadene for å unngå fornybar energiproduksjon på land varierer fra €200 k/km^2 til €700 k/km^2. Disse arealverdiene er betydelig høyere enn markedsprisene for tilsvarende arealer i dag.

Artikkel IV presenterer en scenarioanalyse for å kvantifisere de økonomiske potensialene ved kraftutveksling mellom land i Nord Europa. Vi sammenligner et scenario med optimal overføringskapasitet - ved minimering av systemkostnad - med et annet scenario med gitt overføringskapasitet og uten utvidelse etter 2030. Ifølge resultatene bidrar økt handelskapasitet mellom land til lavere systemkostnader og reduserte utslipp. Med våre forutsetninger finner vi at en økning på i alt 76 GW overføringskapasitet mellom land i nord europa kan redusere systemkostnadene med 5%. Dette vil redusere CO2-utslippene med 40 % mellom 2030 og 2050, sammenlignet med scenarioet uten flere mellomlandsforbindelser. Vind- og vannkraftprodusenter i Norden tjener mest på økt handel over landegrensene, samtidig som inntjeningen økes med 67% ifølge modellresultatene. En annen effekt er at nordiske forbrukerkostnader for elektrisitet også øker med 21%. Økte forbrukerkostnader i eksportregioner kan bidra til betydelig motstand mot økt utvekslingskapasitet mellom land.

Denne avhandlingen viser, det store behovet for fornybar elektrisitetsproduksjon som vil kreves i for å omstille til et mer klimavennlig energisystem – og dette er i tråd tidligere litteratur. I tillegg viser avhandling til nye viktige avveininger vi står overfor i omstillingen til et klimavennlig energisystem.

Synopsis

1 Introduction

1.1 The energy transition in Northern Europe

Combating climate change has become a global consensus, of which the energy sector is at the centre. Over the past decade, renewable energy deployment has increased, and the costs of wind and solar power generation have declined substantially. Levelised costs of electricity (LCOE) from PV declined by 85%, onshore wind by 56% and offshore wind by 48% between 2010 and 2020, and the reduction trends will likely continue (IRENA, 2016; IRENA, 2021). Furthermore, carbon taxes and quota markets have been introduced nationally and internationally to internalise the costs of greenhouse gas (GHG) emissions for fossil-based producers. In recent years, auction prices for solar PV and onshore wind projects have become cost competitive with fossil-based generation (Figure 1). Transition towards a low-carbon energy sector is not only driven by policies but also by gaining strong economic motives.

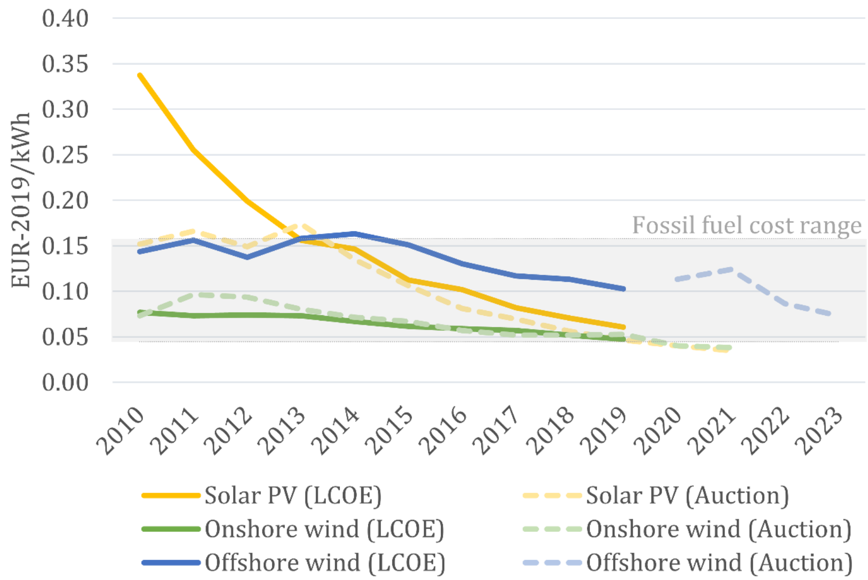

Figure 1. Weighted average costs of solar PV, onshore wind and offshore wind in the IRENA Renewable Cost Database. The grey band represents the range of fossil fuel-based power generation costs. Source: IRENA.

Renewables have become important sources of energy in Europe. In addition to the substitution of carbon-intensive generation, renewables also need to fill the gaps for nuclear power discontinuation in several countries. Shares of renewable electricity generation have doubled over the past decade. Wind power tripled its generation and became the biggest renewable electricity provider, and solar power generation grew rapidly from only 7.4 TWh in 2008 to 123 TWh in 2018. Consequently, CO_2 emissions from electricity and heat producers in Europe dropped 28% from 2008 to 2018 (IEA, 2021), and the overall share of renewables in the EU reached 20%, meeting its 2020 climate targets. In response to the observed progress and climate urgency, the EU has strengthened its 2030 climate targets and proposed the EU Green Deal, laying foundations towards the 2050 goal of carbon neutrality (European Commission, 2019a). Further efforts to expand the speed and scope of decarbonisation will be required in the coming decades.

Northern European countries are front runners in achieving low carbon energy systems. Renewable shares in the Nordics already reached 73% in electricity and 40% in overall energy consumption by 2018. The region has abundant hydro and bioenergy resources and great potential for wind power development. Wind energy has contributed to the major increase in electricity renewable shares; thus, providing flexibility to balance demand and variable renewable generation is one of the current challenges (Bird et al., 2016; Huber et al., 2014; Impram et al., 2020). Traditionally, hydropower in Norway and Sweden and district heating systems with combined heat and power (CHP) plants in Sweden and Denmark support system flexibility. Besides regulating supply and demand, system flexibility can also be provided via relocating the energy temporally through storage or spatially through power transmission. The current costs of battery storage are still high, although downward trends are expected (IRENA, 2017). Increased transmission levels are especially relevant to Northern Europe. Besides increasing system flexibility, these increased levels enable the Nordics to share the renewable resources with neighbouring countries, such as Germany and the UK, where the scales of energy systems are much larger. Such cooperation is beneficial to efficient decarbonisation.

The need for renewable electricity might exceed the previous estimation. Around 60% of CO_2 emissions in Europe in 2018 were from other non-power sectors, such as transport, heating and industry. Compared to the power sector, they have shown little mitigation progress. With rising renewable shares, electricity is becoming an important source of clean fuel for other sectors. New challenges will emerge in the coming phase of the energy transition, which requires substantial renewable deployment to ensure a clean, secure, and affordable supply of energy. The goal of this thesis is to provide insights for constructive discussions to proceed further towards a low carbon future.

1.2 Research scope and objectives

1.2.1 Scope of the energy transition in this thesis

The scope of the energy transition in this thesis refers to the transformation of energy systems towards low or zero carbon by 2050. Rosenbloom (2017) proposed three core dimensions, including biophysical, techno-economic and socio-technical, in low-carbon transition pathways, and this thesis focuses on the techno-economic dimension, linking the current system to the future. The inertia in the techno-economic dimension follows neoclassic economic assumptions and emphasises rational economic factors such as costs (Cherp et al., 2018; Rosenbloom, 2017).

Millot and Maïzi (2021) argue that drivers beyond economic interests are required for the transition to carbon neutrality. Multiple aspects are co-evolving in an energy transition (Foxon, 2011), and besides the techno-economic dimension, there are also social-technical and political perspectives to consider (Cherp et al., 2018). The social-technical perspective focuses on broader societal change, such as knowledge stocks and niches in energy technologies, technology lock-in and actors' behaviour. The political perspective focuses on change in political actions and policy interests. These dimensions are all interlinked.

The European energy transition has entered a 'breakthrough' phase (Rotmans et al., 2001), where variable renewable shares in electricity generation accelerate rapidly, and new research and policy focus is required (Markard, 2018). In this next phase of the energy transition, renewable energy technologies are getting mature, costs have declined and focus has turned to enhancing system and sectoral integration. Energy transition research must take into account new challenges, such as escalating struggles due to conflicting interests and social acceptability (Markard, 2018; Millot & Maïzi, 2021; Papadis & Tsatsaronis, 2020).

This thesis takes the techno-economic perspective to maximise social welfare as the dominating approach, and the main components of energy systems in this thesis are energy flows and markets. Many quantitative analyses have been conducted with energy system models, with detailed representations of energy flows, conversion processes and markets for balancing supply and demand. Figure 2 illustrates the scope of the analyses within this thesis. The figure shows an example of the structure of an energy system model, covering primary energy supply (the black block), demand (grey blocks), conversion technologies (green blocks), energy flows (arrows) and examples of input constraints and outputs (arrow blocks). Although not explicitly analysed, the non-techno-economic perspectives (social-technical and political) are embedded in the given assumptions. Challenges in the non-techno-economic perspectives and how they affect energy flows of demand and supply and cross-border interconnection are prioritised in this thesis. This approach encapsulates the technical complexity in energy systems and delivers the equilibrium electricity prices, which are important information for timely low-carbon transition to policymakers and society (Markard, 2018; Papadis & Tsatsaronis, 2020).

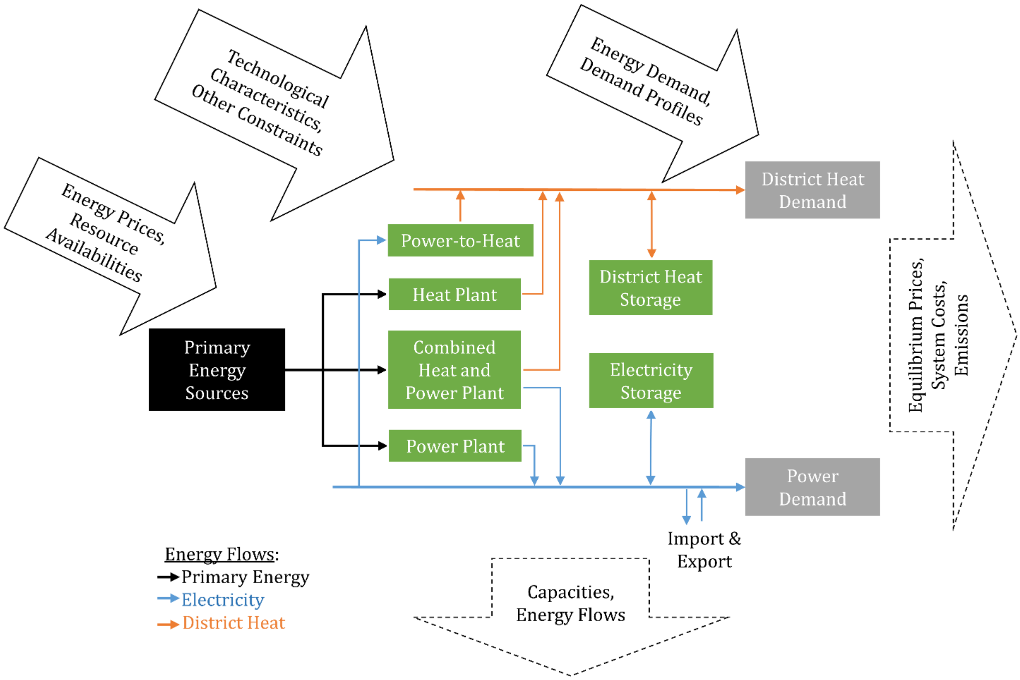

Figure 2. Illustration of the components (blocks), inputs (block arrows) and outputs (block arrows with dash outlines) of an energy system model.

1.2.2 Perspectives in long-term power markets

Affordable, reliable and low-carbon electricity plays a crucial role in the energy transition. Power market outlooks reflect the perspectives of their publishers, and these materials serve an important role in energy planning and investment decision making. To identify the main challenges transiting from current to a low-carbon energy system, we have conducted a thorough review of recent Nordic power market outlooks. Several Nordic power market stakeholders publish market outlooks regularly, and a holistic review reveals which, and in what way, these materials address the challenges. In total, we have reviewed 43 scenarios in 15 power market outlooks published by Nordic transmission system operators, regulators and research institutes between 2016 and 2019. See Paper I for the full list and lessons learned. Based on the review, we have identified potential improvements in sectoral coverage and the need for further investigation of non-techno-economic aspects in the energy transition. The following paragraphs summarise some of the key findings from the demand, supply and cross-border interconnection aspects.

- Demand

Electricity demand is an important factor to the scale of a power system. Traditionally, electricity demand is considered inflexible, and power balance relies more on supply-side operations. Thus, the energy system models applied in these market outlooks generally had more detailed descriptions on the supply side than on the demand side. It was common practice to simplify demand development as constant, adjusted according to GPD and population projections, or downwards, based on the assumptions of efficiency improvement. In the very recent years, the demand side has received more attention. On the one hand, growing shares of variable renewable energy (VRE) lowers supply-side flexibility; on the other hand, further decarbonisation benefits from coupling different energy sectors, which enhances demand-side flexibility. Nonetheless, among the reviewed outlooks, only the Swedish energy agency explicitly analyses a high electrification scenario (Energimyndigheten, 2019). In this scenario, the electricity consumption will increase by 38% from 2020 to 2050, resulting from the electrification in heating, transport and industry sectors. The high fuel and emission price scenario (Hög) in the outlook from Svenska Kraftnät (Brunge et al., 2019) shows 26% growth in electricity consumption from 2020 to 2040, and it assumes that the new industry sector, including data centres and battery factories, contributes the most. Overall, future electricity consumption in rest of the reviewed scenarios is simplified and potentially underestimated. (Figure 3).

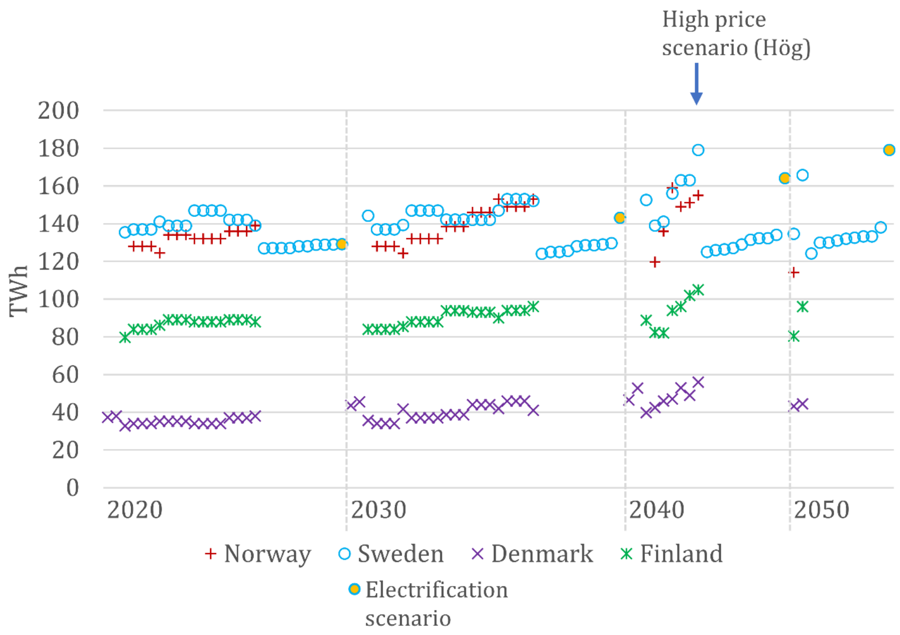

Figure 3. Electricity consumption from the reviewed outlooks in Paper I. Each column represents one scenario.

- Supply

The reviewed outlooks generally shows that Northern Europe will gradually phase out coal and limit nuclear power, and steadily increase their VRE shares in the electricity mix towards 2050. There are two types of approaches in the reviewed outlooks to estimate future installed capacities – exogenously defined assumptions or a mixture of input assumptions and output results. Most reviewed outlooks apply the former approach, which might fail to capture the long-term dynamics of price signals and investment decisions. The latter approach reflects a market that is closer to perfect than the former, but it might underestimate the impact of the non-economic factors, such as policy and social acceptance.

Overall, regardless the approach, the reviewed outlooks show increasing wind deployment, and the newer outlooks often modify the future installed wind capacity upwards from their previous versions. The reviewed outlooks agree that onshore wind power does not require policy support. Despite the low costs of onshore wind, there is a tendency of more emphasis on offshore than in onshore wind in the newer outlooks. The Danish transmission system operator (TSO), Energinet, updated their assumptions to assign more increase in nearshore wind and less increase in onshore wind due to declining offshore costs and increasing local opposition (Energinet, 2017). The Swedish TSO, Svenska Kraft, included additional scenarios to investigate the effect of large-scale offshore wind expansion in the southern part of Sweden (Brunge et al., 2019). The Norwegian TSO, Statnett, and regulator, NVE (Norges vassdrags-og energidirektorat), regard future wind energy development in Norway more uncertain than in the other Nordic countries, and the latest publication mentions particularly the "encroachment on nature" (*naturinngrep* in Norwegian) as one major factor to restrict the onshore wind development (Gogia et al., 2019).

Power price outlooks are important indicators for capacity expansion investments, and the reviewed scenarios suggested that power prices after 2040 might be more than 40 or 50 €/MWh, as a result of the assumptions of growing fuel and emission quota prices. This price level will be beyond the long-run marginal costs of onshore wind in the Nordics – around 30-35 €/MWh in Norway (Bøhnsdalen et al., 2018) and 37-56 €/MWh in Sweden (Energimyndigheten, 2019). The self-cannibalisation effect of wind energy maybe be one explanation of the mismatch, or it might suggest that there are non-techno-economic factors impacting future generation capacity.

- Cross-border interconnection

Cross-border interconnection plays an important role in Northern European power markets. National energy systems are interlinked with neighbouring countries through physical transmission lines and integrated power. The reviewed Nordic outlooks included dedicated sections to describe energy system development in Continental Europe, which indirectly affects the Nordics through transmission lines. By connecting to larger markets, Nordic wind resources can assist the energy transition in Europe. Nordic hydro resources could also become the "battery" for Europe and overcome the flexibility challenges of VRE integration. All reviewed outlooks agreed on the need for power transmission, with slightly different statements. Outlooks from Dansk Energi emphasised the importance of transmission to Denmark with a section title "Denmark is not an island" (*Danmark er ikke en ø* in Danish) in its 2018 and 2019 outlooks (Capion et al., 2018, p.10; Poulsen et al., 2019, p.12). Its 2019 outlook allowed for transmission investment in the Blue and Green scenarios and stated that transmission connections would contribute to lower electricity prices and backup needs. Outlooks from Statnett, Svenska Kraft and the Norwegian regulator NVE (Norges vassdrags-og energidirektorat) adopted more conservative views for transmission and did not consider new connections that were not under construction. Statnett and Svenska Kraft argued that market outlooks should acknowledge the need for more power transmissions, but not intend to signal further grid development without a more thorough analysis. NVE stated that Norway would experience larger price variations by being more connected to Europe by 2030, but further development beyond that would be quite uncertain. These findings suggest that increased international electricity trade will bring overall welfare in the energy transition but might encounter barriers due to unevenly distributed benefits among the stakeholders.

1.2.3 Research objectives

Taking into account the identified barriers and gaps in the literature, the main research objective of this thesis is as follows:

> *To investigate the emerging challenges in the energy transition and their roles in shaping the future Northern European energy systems.*

Some of the findings in Paper I, which reflect the perspectives of power market stakeholders, form the basis of the sub-objectives. In the demand aspect, the focus is narrowed down to decentralised heating, which takes large shares in final energy use in Northern Europe, but is yet to be decarbonised. In the supply and cross-border interconnection aspects, we focus on non-techno-economic barriers. Bolwig et al. (2020) has summarised the challenges faced by onshore wind and power transmission in Northern Europe from the social-technical perspective. Despite their climate friendliness, the literature shows that these technologies are facing social opposition originating from concerns of health, impact on environment and landscape, and distributional effects. The following sub-objectives in each are thus defined to address the emerging challenges:

- To assess the impact of heating decarbonisation on the power sector by integrating decentralised heating into the centralised power and heat model.

- To analyse how prioritising avoiding land conflicts affects future energy systems and investigate alternative solutions.
- To quantify the impact of utilising the economic potential of cross-border transmission in future energy systems.

The sub-objectives are investigated through three modelling studies. Through the manuscripts and the sub-objectives, this thesis adds insight into the research field of energy system analysis and provides rational support in addressing emerging challenges in the energy transition.

2 Emerging Challenges in the Energy Transition

This section describes the background and literature review related to the sub-objectives under electricity demand and the decarbonisation of end-use sectors, renewable supply and land conflicts, and dilemmas in cross-border interconnection.

2.1 Demand: Decarbonisation beyond the power sector with clean electricity

Little mitigation progress has been observed in other energy sectors compared to electricity generation (European Commission, 2019b). CO_2 emissions from electricity and heat producers declined by 32% between 2008 and 2018, while those from residential, services, transport and industry decreased by only 10% during the same period (IEA, 2021). Most of these emissions are not covered by the EU's Emission Trading System (ETS). In 2018, 17% of the CO_2 emissions in the EU were from residential and services sectors, 29% from transport and 13% from industry (IEA, 2021). Legally binding national targets for 2030 are set for emissions from sectors outside of the ETS under the Effort Sharing Regulation (European Union, 2018), and stronger changes in the non-ETS sectors are expected in the coming decades.

Electricity from renewables is a promising mitigation strategy. A 2050 baseline scenario by PRIMES model analysis showed a strong increase in electricity demand, led by electrification in heating, cooling and transport, and an increase in demand in IT and leisure appliances, despite the decrease in total energy production (European Commission, 2018). In addition to increasing the overall scales of electricity demand, these sectors will most likely influence the electricity demand hourly profiles and peak loads (Kannan, 2018; Zeyen et al., 2021; Østergaard et al., 2015).

From the end use viewpoint, residential and services sectors take the highest share, around 40% of the final energy consumption in the EU, followed by 31% for transport and 25% for industry (IEA, 2021). The main energy need in residential and services sectors, especially in Northern Europe, is domestic heating, for which several decarbonisation solutions are mature. The transport and industry sectors require more advanced forms of energy, including petroleum products, synthetic fuels and high temperature heat, and those services are more challenging to decarbonise. It is our impression that many researchers focus on difficult topics, such as decarbonising transport and industry sectors. Nonetheless, decarbonising heating in residential and services sectors is a low hanging fruit with a lower techno-economic threshold than decarbonising other energy services in transport and industry sectors. The impact of heating decarbonisation on the overall energy system should not be overlooked considering the scale of demand.

Heating can be supplied by centralised district heating networks and decentralised individual heating systems. Centralised heating systems are relatively well-developed in Northern European countries. Except for Norway, 28% to 37% of the national final energy consumption in the residential sector in Northern Europe is from district heat, compared to the 8.5% average share in the EU in 2019 (Eurostat). That share is less than 7% in Germany, and less than 1% in the UK. While it is possible to expand the district heating system and shift from decentralised to centralised heating, the incentives are low with shrinking heat demand (Lygnerud, 2018). Much of the heat relies on decentralised heating systems, such as boilers, direct electric heating, stoves and furnaces, and heat pumps; however, these systems have been overlooked. As indicated in Paper I, only some of the models applied in the outlooks endogenously model district heat in addition to electricity. Decentralised heating tends to be simplified and embedded in the electricity demand assumption, if not ignored.

Electricity is regarded as the energy carrier that can be decarbonised first, and sector coupling and electrification are important solutions to decarbonise other sectors with decarbonised electricity (Gea-Bermúdez et al., 2021; Papadis & Tsatsaronis, 2020; Van Nuffel et al., 2018). Existing energy transition studies emphasise the benefits of system flexibility from coupling electricity and transport, gas and district heat (Helgeson & Peter, 2020; Jensen et al., 2020; Kavvadias et al., 2019; Thellufsen & Lund, 2017), and recent literature has started to integrate decentralised heating into the analysis (Brown et al., 2018; Gea-Bermúdez et al., 2021; Kavvadias et al., 2019). It is important to retain the characteristics of decentralised systems, such as individual preferences (Li et al., 2018) and limited long-term storage, as they might affect the energy system in different ways. Paper II expands the scope of the demand side in energy system modelling to cover the decentralised heat and assesses the impact on the energy system for reaching the long-term mitigation targets.

2.2 Supply: Gaps between wind energy potential and social acceptance

Wind and solar energy play key roles in a low-carbon future. In Northern Europe, wind energy has a more advantageous seasonal generation profile than solar energy, with more winter production than summer, in line with seasonal demand patterns (Holttinen, 2005). Surveys in the early 2000s showed high public support of wind power in Europe (EWEA, 2003), and countries have implemented policy frameworks to attract investments. Through technology learning and economies of scale, onshore wind energy technologies have become increasingly cost competitive, as mentioned in Section 1.1.

One disadvantage of wind energy is the low installed capacity density. The wind capacity density is affected by the physical requirements for wind turbines and the wind farm layout. The amount of power that can be harvested by a wind turbine is calculated as follows:

$$\frac{1}{2}\rho v^3 \times \frac{\pi}{4} d^2 \times \eta,$$

where ρ is the air density, v is the wind speed, d is the turbine diameter and η is the efficiency factor. The best efficiency factor of a turbine is 16/27 under the Betz limit. The power density is derived by dividing the above equation by the surface area, which depends on the layout design of a wind farm. Assuming a simple square layout where turbines are placed with a spacing distance five times the turbine diameter, air density of 1.3 kg/m^3, a rated wind speed of 12 m/s, and an efficiency of 0.5, the installed capacity density is 17.6 W/m^2, which is equivalent to 0.057 km^2 per MW installed. This is a simple estimation, and a wide range of wind capacity densities have been reported – 1.5-20.5 MW/km^2 for onshore wind and 3-12 MW/km^2 for offshore wind – depending on the assumptions of turbine design, layout and the definitions of a wind farm area (Enevoldsen & Jacobson, 2021). Solar energy also has low installed capacity density, but the land impact issue is less severe.

Typical installed capacity density assumptions of solar PVs range from 85 MW/km^2 on rooftops to 300 MW/km^2 in open fields (Ruiz et al., 2019). Among wind, solar and hydro energy, wind energy is perceived as the most negative and has the biggest landscape and visibility impact (Ioannidis & Koutsoyiannis, 2020).

The total installable wind capacity can be estimated by the installed capacity density multiplied by the eligible areas. Areas of cultural or natural importance and areas close to infrastructures or buildings are restricted for wind projects. Besides weather conditions, accessibility to grid connections, terrain and land rents are some of the local factors to consider in wind energy development (Ryberg et al., 2019). Owing to different assumptions of installed capacity density, criteria of suitable areas for wind energy, wind conditions, and social and political ambience, a wide range of onshore wind potential estimates is found in the literature (Child et al., 2019; Enevoldsen et al., 2019; Osorio et al., 2020; Ruiz et al., 2019; Ryberg et al., 2019). Figure 4 and Table 1 summarise the definitions and levels of onshore wind potential estimations by country in recent literature. Overall, the existing literature shows that there is sufficient onshore wind potential for the energy transition, especially in the Nordic countries.

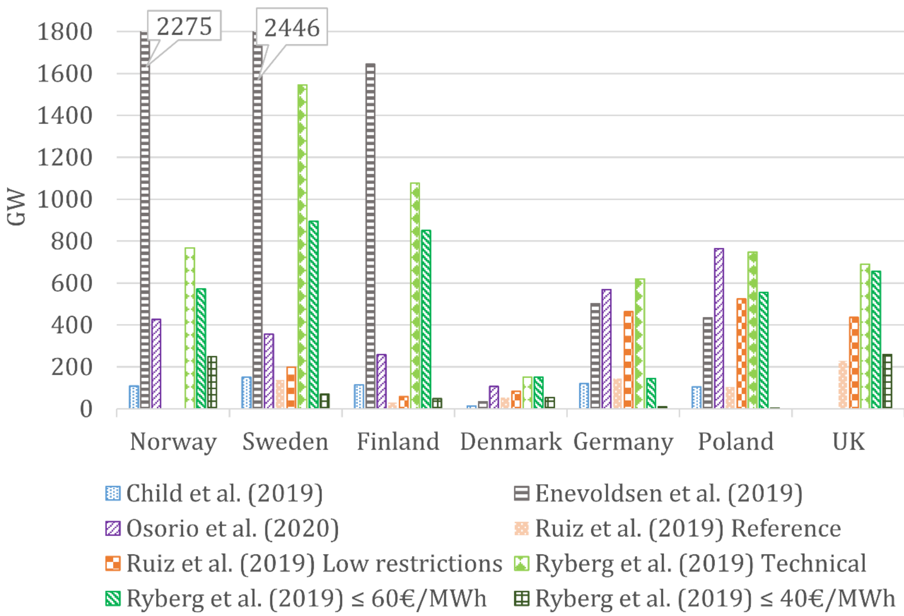

Figure 4. Onshore wind installed capacity potential by country in existing literature.

Table 1. Lists of onshore wind installed capacity density and the definitions of potentials in literature.

Literature	Capacity density (MW/km^2)	Potential definition
Child et al. (2019)	8.4	4% of the total territory assumed eligible for onshore wind.
Enevoldsen et al. (2019)	10.7	Exclusion zones by own assumptions of setback distances from infrastructure, buildings and protected areas.
Osorio et al. (2020)	5	Area within 80 km to nearest large load or power plants, excluding protected, urban and high-elevation areas, or certain land cover types.
Ruiz et al. (2019)	5	Reference scenario: Current legal requirements for exclusion zones and setback distances. EU-wide low restrictions: A hypothetical scenario in which the exclusion of surfaces for wind converges in all countries to 400 m.
Ryberg et al. (2019).	9.9	Technical potential: own assumptions of land eligibility, taking into account turbine placement and site-specific designs. Two cost levels filtering economic limitation.

Public perceptions can vary over time, space, roles, and personal experience (Dugstad et al., 2020; Mytilinou et al., 2017; Warren et al., 2005), and in recent years the social acceptance of onshore wind has become less optimistic. Large scale deployment raises concerns about land competition with agriculture, human activities, wildlife protection and preservation of nature landscapes (Bolwig et al., 2020). Concerns for land conflicts have become a barrier for onshore wind development (Palmer-Wilson et al., 2019). According to an expert survey by Suškevičs et al. (2019), 'encroachment into the landscape' is the strongest resistance factor in Northern and Western Europe against wind energy. A survey in Norway showed a significant decrease of positive public perceptions of onshore wind from 84% in 2011 to only 36% in 2020 (Livgard, 2020). The lack of acceptance can lead to delays or rejections of planned projects, and in 2021, the director of Norwegian regulator (NVE) acknowledged that it is unlikely to see strong development in onshore wind in Norway in the next decade (Amundsen, 2021). Social acceptance and public concerns are becoming decisive for future onshore wind deployment.

Perspectives of wind energy affect energy transition pathways. Most of the power market outlooks reviewed in Paper I regard future wind deployment as input assumptions, and market mechanisms for wind energy investments are omitted. By contrast, future wind deployment can also be an output result generated by an energy system optimisation model. The assumptions of wind energy potential and costs are important under this approach, as the optimisation will land on the most cost-effective solution until reaching the potential constraints. Recent observations have shown that future wind deployment will likely be constrained by lack of social acceptance long before exhausting the potential, and it may lead to cost increase and consequently shift generation towards more local or costly solutions (Bolwig et al., 2020). In Paper III, we first quantify the land requirement in the least-cost solution. Instead of targeting wind energy directly, we explore alternative solutions that minimise land conflict concerns with little cost increase.

High shares of wind energy also introduce challenges in energy systems and market integration. The variable generation of wind increases the need for system flexibility to ensure energy security. The inflexible generation of wind cannibalises its market value. Paper IV focuses on the potential of increased interconnection, which provides system flexibility and mitigates parts of the wind market value cannibalisation by offering the supply to larger markets.

2.3 Cross-border interconnection: Overall benefits hindered by distributional effects

Electricity interconnection brings socio-economic values through enhancing the efficiency of electricity systems, security of supply and job creation. The EU has set targets under its climate and energy framework to promote cross-border transmission, aiming at transmission capacities that enable sending 10% of the national generation abroad by 2020 and 15% by 2030 (European Commission, 2015; European Commission, 2017). Existing literature has shown the benefits of electricity interconnection in cost reduction, reducing the need for backup power, system adequacy and renewable integration (Becker et al., 2014; Cao et al., 2021; Directorate-General for Energy, 2019; Rodríguez et al., 2014; Schlachtberger et al., 2017). Child et al. (2019) claim that interconnection is especially relied upon by areas with rich wind, solar or hydropower resources and areas with high demand. Northern Europe, with its well-integrated power markets, good wind conditions and abundant hydro resources, has seemingly good prerequisites for cross-border cooperation through increased interconnection.

Cross-border interconnection is nonetheless facing increasing challenges. Besides concerns originating from physical electric cables causing health, visual and environmental impact, some concerns originate from shared electricity markets. As shown by the different attitudes of various power market stakeholders in Paper I, although increased market cooperation plays an overall positive role in the energy transition, some might benefit more than others, and some might be worse off. Figure 5 illustrates the merit order effect of connecting two electricity markets. Market A represents a high price (P_A) area with large demand and limited VRE generation, and market B represents a low price (P_B) area with lower demand and more VRE generation. When the two markets are connected by transmission lines, power can flow until the two markets reach the same market clearing price, or until power flow reaches the bottleneck, constrained by the transmission capacity. In Figure 5, the consumers in market A benefit from the price drop to P^*_A thanks to the imported low-cost power from market B. In market B, it is the producers, especially the VRE producers, that receive higher revenues as the market clearing price increases to P^*_B, but the consumers also have to pay higher prices. The transmission grid owner profits from the price differences (P^*_A - P^*_B) multiplied by the exchanged power flows. Depending on the roles in power markets, cross-border power transmission is more welcomed by some than others.

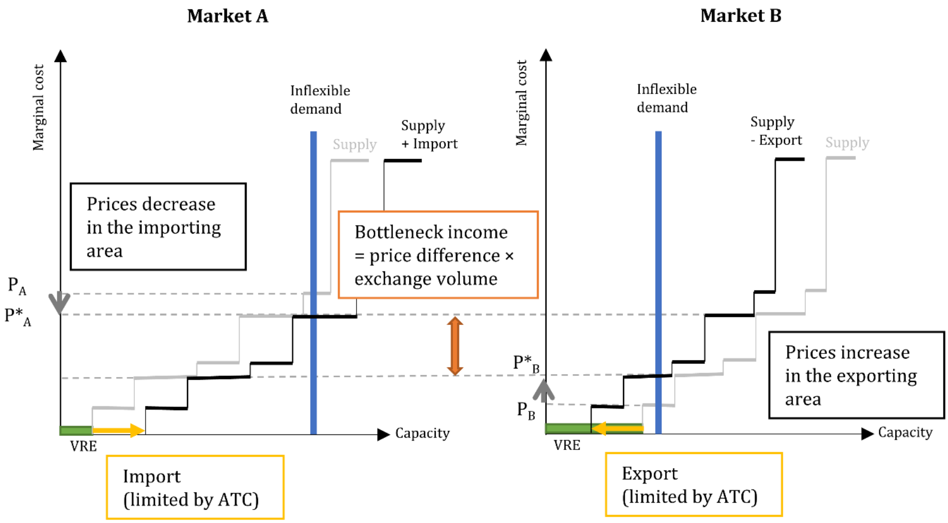

Figure 5. Illustration of power market effect of interconnection two markets, where the transmission volume is limited by the available transfer capacity (ATC).

The geographical and sectoral welfare redistribution causes challenges in promoting interconnecting the electricity markets in different countries. For example, the NorthConnect project, listed as one of the EU's 'Projects of Common Interest' linking Norway and Scotland, caused fear of raising electricity prices for household and industry consumers and was put on hold by the Norwegian government.

Notably, whether a market is an importer or exporter is fluid, especially with increasing shares of renewables. The market clearing prices depend on the residual demand, that is how much demand is left after subtracting the must-run units and the VRE generation, which is affected by weather conditions. Take Norway as an example of a typical net exporting country with abundant hydropower. Figure 6 shows the hydropower production, net export and spot prices in Norway between 2009 and 2019. In most years, Norway was a net exporting country with electricity prices of less than 30 øre/kWh. This was not the case in 2010, a cold and dry year. Hydropower produced less than usual, and Norway had to import more than it exported, with the spot price reaching over 45 øre/kWh. This example shows that no market participant is always only benefiting or losing from cross-border interconnection. Such cooperation enforces weather resilience and offers long-term flexibility, which is much needed under the impact of climate change.

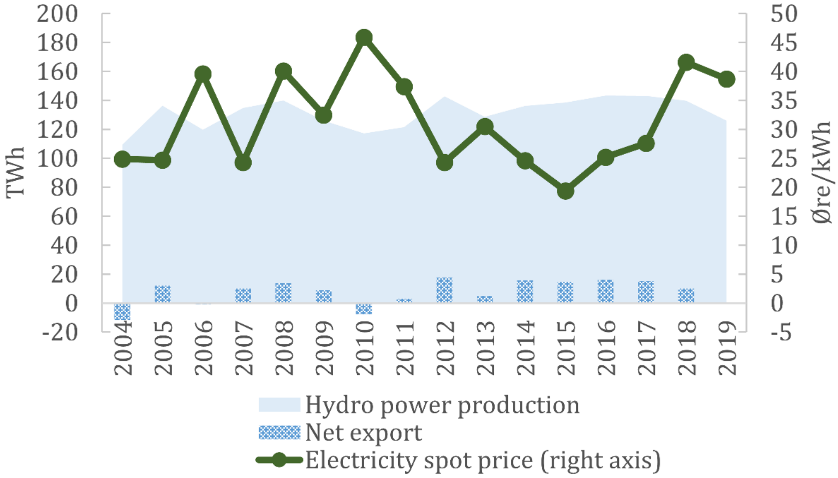

Figure 6. Hydropower power production, net export, and spot prices in Norway from 2009 to 2019. Source: Statistics Norway

Without sufficient cross-border interconnection in energy systems, the process of the energy transition will be slower and more burdensome. Schlachtberger et al. (2017) demonstrate the benefits of highly interconnected electricity grids in a low-carbon Europe, where onshore wind becomes the main source of electricity. However, if the possibility of utilising interconnection is restricted, the system shifts towards more solar power plus storage and overall costs and emissions increase (Cao et al., 2021; Schlachtberger et al., 2017). Limiting transmission expansions adds disadvantages to wind development (Bolwig et al., 2020; Neumann & Brown, 2021). Paper IV focuses on the benefits and costs brought about by cross-border transmission in power markets, and it aims to provide quantified support for addressing the welfare distribution challenge.

3 Methods

3.1 Energy system modelling

Energy system models are quantification tools for analysing complex problems in the energy sector. System boundaries are drawn, within which the real world is simplified and expressed by equations and parameters. The need for complex energy system models increases in response to addressing the increasing complexities of issues involving multiple aspects. Different models and model topologies have been developed and proposed, and following the logic proposed by Després et al. (2015) and Ringkjøb et al. (2018), the following criteria are identified for the modelling tool to be used for the research objective in this thesis:

- Purpose: Investment decision support, Scenario

The thesis investigates how future energy systems might be shaped and the model must provide investment decision support for energy infrastructure, including generation, storage and transmission technologies. The installed capacities of technologies are modelling outputs reflecting various scenarios of the energy transition.

- Point of view: system approach

The research topic is addressed from a system viewpoint, in opposition to private actors' interests. Climate change is a global problem, and thus the modelling tool takes a central planner's perspective. An optimal solution is found when the total system costs are minimised. The society as a whole benefits, although it might not be in the best interest of some private actors.

- Approach: partial equilibrium and bottom up

Power markets provide important signals to energy sector investors, and thus the model is expected to focus primarily on the power markets and to show power market data, such as day-ahead prices. A partial equilibrium approach is applied, while the rest of the economy is not modelled. A bottom-up (or hybrid) approach is desired to describe adequate technological details in the system.

- Represented energies: electricity and heat

The model must be able to capture the interactions between electricity and district heat. District heating systems are common in urban areas in Northern Europe, and they couple power systems through CHP plants and power to heat technologies. Coverages of other energy forms are additional benefits.

- Spatiotemporal resolution

The spatial resolution should be at least at the country level and preferably reflect the system bottlenecks, such as the price regions in Nord Pool. The research objective requires long-term analyses up to 2030 or 2050, and hourly resolution is preferred for day-head markets with high VRE shares.

- Support of open research

This thesis supports an open research spirit. An open-source model is beneficial to the science community for continuous development. Transparency is crucial to the interpretation and communication of analysis results.

Meeting all the above-mentioned criteria, the Balmorel model is applied for the analyses in this thesis. Modelling tools with the first three characteristics are often referred to as energy system optimisation models (ESOMs), which generate results of future energy systems, including installed capacities, utilisation, costs and emissions. The Balmorel energy system model is suitable for this thesis; it has been widely used in Northern European energy system studies and contains rich background data through continuous development since its first release (Wiese et al., 2018).

The Balmorel model describes Northern European power and heat systems with a bottom-up approach using partial equilibriums and assumes perfect competition in liberalised power markets. The model is formulated in linear programming (or mixed integer programming in some studies). The model is designed to have flexible settings, and new features and versions are continuously developed, which are available on the Github repository (The Balmorel Open Source Project). Balmorel, written in the General Algebraic

Modelling System (GAMS) language, is programmed to minimise the total system costs under a set of constraints. The objective function is defined by annualised investment costs of endogenously invested technologies, annual fixed and variable operation and maintenance costs, fuel costs and other costs such as taxes and grid tariffs in some cases. Energy balance equations are the most important constraints, which require electricity and heat demand, assumed inelastic in this thesis, to be met through the generation, loading and unloading of the storage technologies, or energy flow exchange at all times. The electricity and heat prices are obtained by the marginal values of the balance equations. Other important equations include equations describing energy transformation processes and resource availabilities. A thorough introduction of the model can be found in Wiese et al. (2018) and the papers included in this thesis.

3.2 Model development in this thesis

The model, including the framework and data, has been developed and updated continuously throughout the research period. The model versions and settings differ from one paper to another. As part of the thesis, new features are developed for the models applied in Paper II (decentralised heating) and Paper III (MGA technique). The model applied in Paper IV is based on the version that includes a new method of transmission modelling, developed during the research project Flex4RES, which focuses on the flexibility challenge in a renewable rich system (Nordic Energy Research).

3.2.1 Decentralised heating

To evaluate the influence of a fully decarbonised heating sector, the Balmorel model is expanded to include additional energy forms of decentralised heat in the residential and commercial sectors. The industrial heat demand is not included because it often has high and/or specific temperature requirements. Two new types of energy demand, space heat and hot water, have to be met, respectively, and their model structures form in parallel to the electricity and district heat sectors (Figure 7).

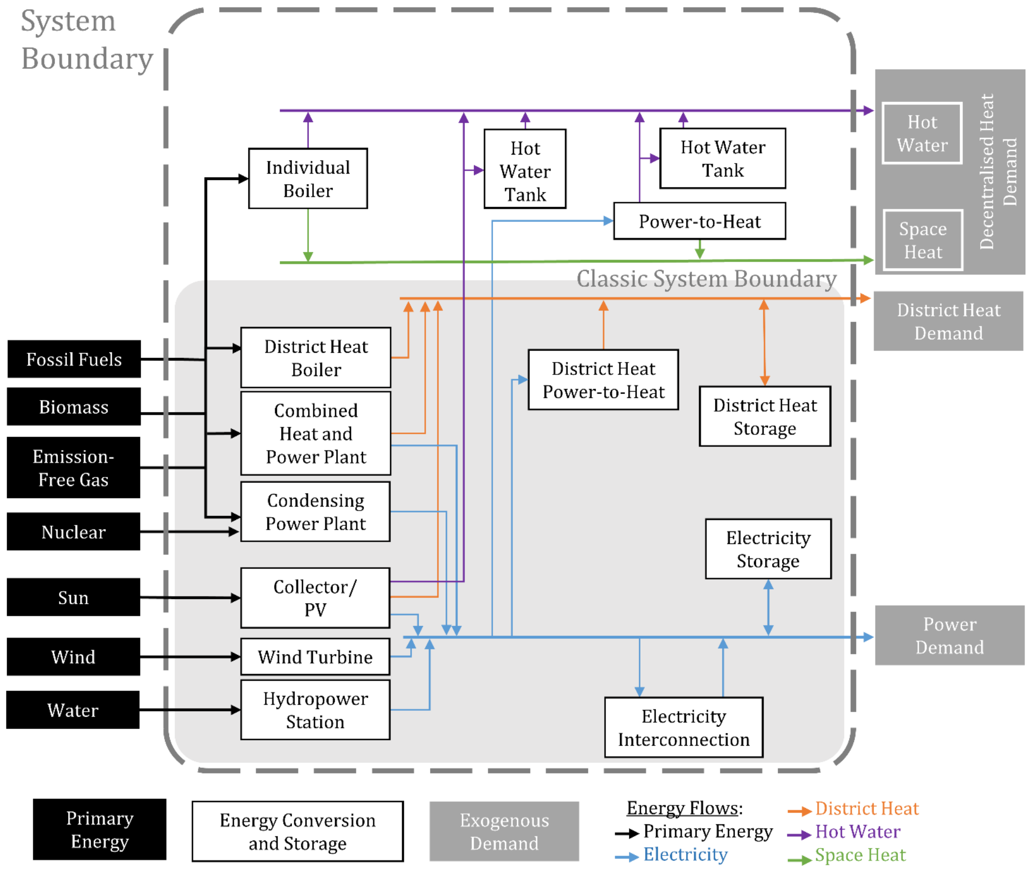

Figure 7. Illustration of the Balmorel model structure adding decentralised heating.

A top-down approach is applied in the decentralised heating sector. The residential and commercial consumers are aggregated by given sets of heating technologies, which include single or hybrid solutions of various types of boilers, solar heating, electric heating or heat pumps. The decentralised heating sector is coupled with the electricity sector through electric heating and heat pumps. No interaction between the centralised and decentralised heat sectors is modelled based on the assumption of limited district heating expansion in the modelling countries. Maximum rates of technology shift every decade are applied to presume the heterogenous willingness to shift among consumers. Within the shifting rates, decentralised heating consumers opt for heating solutions that achieve the least system costs. Measures of building efficiency improvement are considered exogenously, and scenarios with various heating demand developments are analysed. Further methodology and data description can be found in Paper II.

3.2.2 MGA technique and land use

Two types of uncertainties exist in an energy system optimisation mode: parametric and structural. The former type relates to imperfect knowledge of input values, and the latter type originates from the imperfect equations describing the system (DeCarolis et al., 2017). The modelling to generate alternatives (MGA) technique handles structural uncertainties. Other than attempting to perfect the model formulation, searching for alternatives in the near-optimal space might offer insights under structural uncertainties.

The MGA technique explores the near-optimal space and finds alternative systems that differ substantially from the optimal solution. The near optimal space is defined by a given slack value to increase the original objective value in a minimisation problem or to decrease the objective value in a maximisation problem. Several search directions for the alternatives have been proposed. The Hop-Skip-Jump method applied in DeCarolis (2011) and DeCarolis et al. (2016) minimises the weighted sum of decision variables appearing in the previous solutions. Another algorithm in the study by Price and Keppo (2017) looks for the furthest alternatives from the previous solutions. The third method, such as that used in the study by Neumann and Brown (2021), looks for plausible extrema – the maxima and minima values of the predefined groups.

Paper III in this thesis uses the MGA technique with search directions for minimum land impacts. Increasing opposition has been observed against certain renewable technologies due to the potential impact related to land or space. We modify the Balmorel model by applying the MGA technique to investigate the strategies that favour least land impact and the resulting costs of land saving.

New objective functions are defined to minimise land impact within the given additional system costs. First, an original Balmorel model is executed to determine the least cost level and the system configuration. A small percentage, referred to as the slack value, is then added to the system cost as an upper limit, while the new MGA objective functions are optimised. Figure 8 illustrates the methodology. Land impact is represented by the area requirement for the generation and storage installed capacities and fuel consumptions multiplied.

Initial Formulation

min.

$$C_{min} = \sum_{i \in I} c_i \cdot x_i$$

s.t.

$$x_i \in X$$

$\longrightarrow$

MGA Iteration $\forall\ \boldsymbol{m}, \boldsymbol{n}$

min

$$g_m(x_i) = \sum_{i \in I} land_{i,m} \cdot x_i$$

s.t.

$$x_i \in X$$

$$\sum_{i \in I} c_i \cdot x_i \leq C_{min} \times (1 + slack_n)$$

Where

c	costs factors	$m \in M$	set of land impact functions
C_{min}	minimum system cost	$n \in N$	set of slack values
g	land impact functions	$slack$	slack values
$i \in I$	set of decision variables	x	decision variables
$land$	land impact factors	X	set of feasible alternatives

Figure 8. Illustration of the methodology applying the MGA technique to search for the alternatives with minimum land impact.

Paper III defines five MGA objective functions to reflect the subjectiveness of impacted area boundaries and of land value. For example, the objective in the MinLand scenario searches for the alternative that requires overall the least land in all modelling countries combined, while the objective in the LowImpact scenario finds the alternative with the lowest sum of the ratio of the required area to the potential land area, excluding unfeasible or crop or wood land, in each country. The methodology can be applied to investigate other non-techno-economic aspects, such as job creation and equality. Paper III, which includes detailed methodology and data descriptions, is the first study to apply the MGA technique to the Balmorel model.

3.2.3 Flow-based transmission modelling

To ensure efficient use of grids, there is a push towards a flow-based (FB) market coupling approach. In current Nordic power markets, the net transfer capacities (NTC) between the bidding zones are calculated by TSOs by forecasting the overall grid situations to ensure the grid operational security while maximising total social welfare. With increasing shares of VRE generation, uncertainties add challenges in forecasting grid situations and meeting both grid operational security and maximal social welfare. The idea of the FB approach is to model the real limitation of the grid, i.e. thermal limits and Kirchhoff's circuit law, more accurately to bridge the gap between market flows and physical power flows. As illustrated in Figure 9, the FB approach has more relaxed transmission capacity constraints than the NTC approach and enables better grid utilisation (NEMO Committee, 2020; Nordic Regional Security Coordinator (RSC), 2020).

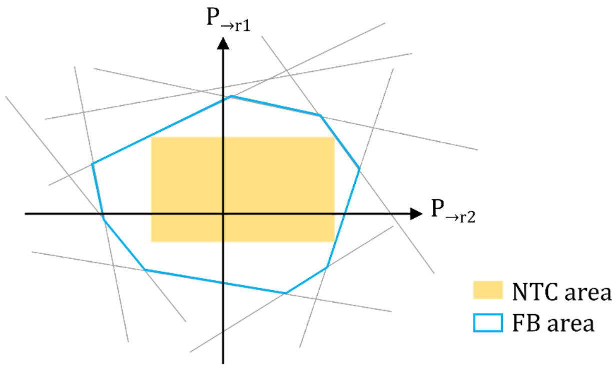

Figure 9. Illustration of the feasible areas in an AC grid of two power flows from one node to region r1 and to region r2 in the NTC approach (yellow) and the FB approach (blue). Black lines are the flow constraints from different transmission lines in the grid.

Energy system optimisation models, such as Balmorel, often have simplified power transmission modelling using the NTC approach. There are three levels of geographical resolution: country, region and area in Balmorel, where transmissions are defined as power exchanges between pairs of regions. For a good representation of the Northern European power markets, the Nordic countries consist of regions following the Nord Pool bidding zones, Germany consists of four regions and each of the other countries is one region. The amount of power exchange is constrained by the aggregated NTC for both AC and DC grids.

The FB approach for transmission modelling in Balmorel for AC grids is developed and applied in Paper IV. The maximum power exchange between regions is bounded by the actual thermal limit of the lines, and the flows are distributed following power transfer distribution factors (PTDFs) and net energy balances at each hour. Three AC subsystems – Scandinavia, Baltic and Central Europe – are clustered in the Balmorel model for current AC grids. DC grids and new transmission capacities still apply the NTC approach for simplification. Figure 10 illustrates the AC and DC transmission network setup in Balmorel, and further methodology and data descriptions can be found in the study by Gunkel et al. (2020) and in Paper IV.

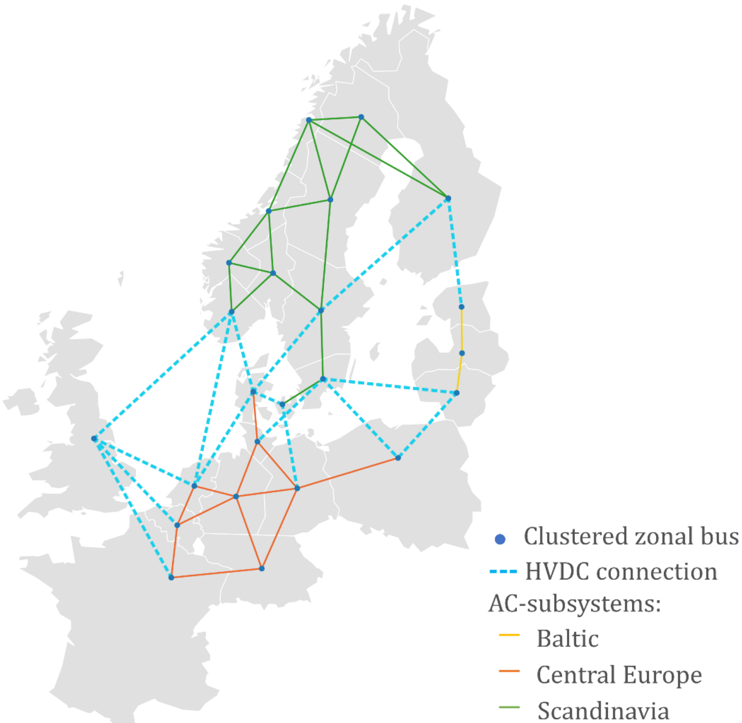

Figure 10. Transmission network setup the Balmorel model. The blue points correspond to the clustered zonal buses, the blue dash lines are high-voltage DC lines, the green, red and yellow lines are the lines within the 3 AC subsystems. Source: Gunkel et al. (2020).

4 Results

4.1 Decentralised heating decarbonisation boosts electricity demand and seasonality challenges

Paper II analyses the effect of full decarbonisation of heat by expanding the scope of the Balmorel model to cover decentralised heat as well as centralised power and heat production. Emission caps that comply with the EU's 2030 targets of both ETS and non-ETS sectors, followed by linear reduction to zero CO_2 emissions by 2050, are set. Paper II analyses five scenarios: three (HIGH, LOW and DH) varying in heating demand development, one (CLEANGAS) with emission-free gas and one (NOIDVH) without decentralised heating sector as a comparison. The current scale of the decentralised demand in the modelling country is estimated at around 2214 TWh, in addition to the 483 TWh of district heat demand. Towards 2050, electrification through heat pumps and hybrid systems is found to be an optimal and robust decarbonisation solution across the scenarios.

Overlooking decentralised heating, decarbonisation is likely leading to underestimation of future electricity demand. In the HIGH scenario, where no significant change in heating efficiency improvement or in district heating expansion is assumed, almost 700 TWh of electricity will be required for heating, three times higher than today's level. In the LOW scenario, assuming a 43% decrease in demand for space heating, there is still 465 TWh of electricity required for heating. In addition to the annual electricity demand, the peak load is much higher than without considering decentralised heating decarbonisation. The modelling results show Germany as the most impacted country, where the peak load in the HIGH scenario is 47% higher than that in the NOIDVH scenario.

The need for electricity stimulates more renewable installed capacities, especially for wind. In the NOIDVH scenario, four times today's wind capacity is installed by 2050, reaching 573 GW, and another 167 GW of wind will be required in the HIGH scenario. Even with the assumptions of building efficiency improvement or district heat expansion, an additional 41-63 GW of wind, compared to the NOIDVH scenario, will be installed in the DH or LOW scenarios. Such an amount of wind power installation might face strong opposition. Heating demand has strong seasonality, which is especially challenging in decentralised heating, where seasonal storage solutions are limited compared to centralised systems. Seasonal price differences become extreme, but the excess electricity generation in summer, if addressed well, offers opportunities for power-to-X applications and seasonal storage solutions.

4.2 Land required for energy grows four times in the least-cost solution, and seeking alternatives adds costs and risks

Paper III addresses the opposition originating from land conflicts by searching for the alternatives in the near optimal space of the least-cost solution given by the Balmorel model. It is assumed that the electricity demand increases by 48% in 2040 from today's level, and an emission cap is applied. The least-cost solution suggests that, in total, 1428 GW power generation capacity is installed by 2040, including 588 GW solar PV, 448 GW onshore wind, 67 GW nuclear and 44 GW offshore wind. With the assumed land factors, 1.2% land area will be used for energy production in 2040, four times today's level. The share of required land in the least-cost solution remains low compared to 26.2% of land eligible for onshore wind in Europe, as shown by the result in the land eligibility analysis by Ryberg et al. (2020).

When the optimisation objective alters to find the system with the least land requirement, nuclear energy and offshore wind play bigger roles, and fewer installed capacities are needed. Increasing the system costs by 1% reduces the land requirements by 16%, while a 10% increase in system costs reduces the land requirements by 60%. Dividing the cost increase by land avoidance shows that the cost of land avoidance ranges from €200 k/km^2 with a 1% increase in system costs to €550 k/km^2 with a 10% increase in system costs. The resulting costs are significantly high compared to the market prices of non-building land or the compensation to landowners for environmental reasons. Prioritising nuclear power and offshore wind over PV and onshore wind for the energy transition might ease land conflicts, but they are neither controversy-free solutions. Construction is more complex, investment costs are higher and there are safety and environmental concerns associated with these alternatives.

Countries take different approaches to limit land impact depending on their energy policies, nature resource conditions and the perceived importance of land preservation of various land types. Belgium, the Netherlands and Germany are the top three countries that have the highest shares (3-4%) of land for energy production with the least-cost solution. Latvia, Sweden and Norway have the lowest shares (0.1-0.2%). In the MinLand scenario, none of the countries use more than 2% of the land for energy production. The LowImpact scenario assumes that the countries prefer to occupy fewer shares of land use over agricultural and forest areas. This assumption of land type preference has limited impact on the UK, where some onshore wind and PV capacities remain. By contrast, many capacities in Nordics shift offshore in the Low Impact scenario. In the EcoSystem scenario, the UK shifts production offshore, but PV in the Continent and onshore wind in the Nordics retain their shares. Local assessments are needed for land conflict studies to give more tailored solutions, but Paper III illustrates the compromises in cost-effective energy transition and mitigating land conflicts.

4.3 Asymmetric benefits and costs of increased cross-border transmission

Paper IV analyses the effects of cross-border transmission on the power market and energy systems by comparing a scenario with endogenous transmission investments (optimal) to a scenario with only existing and planned projects (planned). A moderate growth in ETS quota price from 17 €/tCO_2 in 2020 to 54 €/tCO_2 in 2050 is assumed. The modelling results show that the optimal system will give an additional 76 GW cross-border transmission by 2050 on top of the 21 GW that is already planned between 2020 and 2030. Figure 11 shows a comparison of the given capacity assumptions and the optimal investment results. The largest expansions connect the Nordics and West-central Europe, such as between Denmark and the Netherlands, Norway and the UK, and a new line between Sweden and Poland. With the additional transmission capacities, total system costs are 5% lower, and CO_2 emissions are 40% less than in the planned scenario between 2030 and 2050.

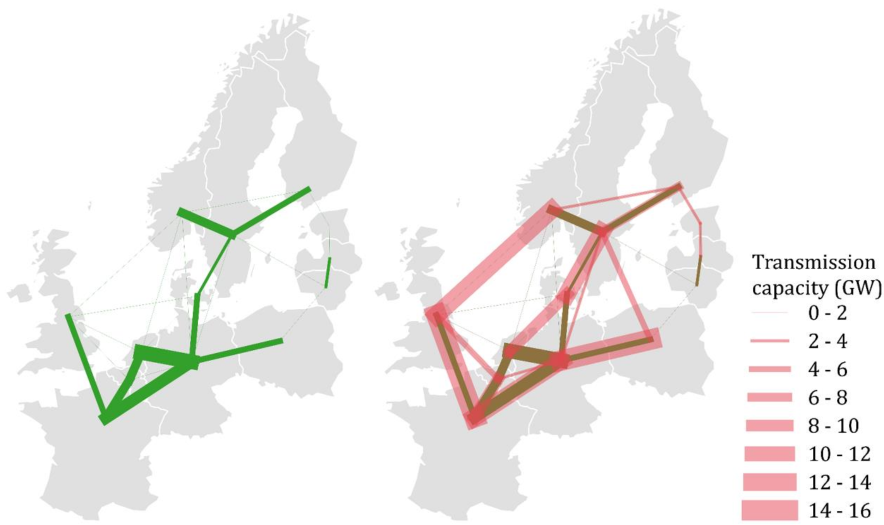

Figure 11. Cross-border transmission capacity in the planned scenario (left) and in the optimal scenario (right) in 2050.

While the systemwide benefits are clear, not all power market stakeholders gain equally from increased cross-border transmission. As explained in Section 2.3, producers benefit more in the low price areas, and consumers benefit more in the high price areas. For the analysis in Paper IV, the countries are aggregated to north and west regions. The north region, covering the Nordic and Baltic countries, has good hydro and wind resources, and the west region has larger electricity demand, better solar resources and some shares of power generation from fossil fuels. In the optimal scenario, 36% of the cross-border transmission capacities connect a country in the north to another in the west region. They enable better utilisation of renewable resources to substitute for coal- and gas-based generation. The generation portfolio shows that 30 GW of fossil fuel-based generation capacity in the west region is replaced by 39 GW of wind, two-thirds of which is installed in the north region. Wind power producers in the north region receive 67% higher revenues in the optimal scenario than in the planned scenario. Hydropower producers are another power market stakeholder that benefits the most from increased cross-border transmission. Even under the assumption of no capacity expansion, the flexible hydropower production receives 68% higher revenues in the optimal scenario than in the planned scenario. Increased transmission speeds up the energy transition and renewable integration. Gas power is less needed, and its producer revenues are 57% less in the optimal scenario.

Consumers experience the opposite. With more cross-border transmission, consumer costs of electricity in the north region are 21% higher, but those in the west region are 6% lower.

Paper IV shows that cross-border transmission bring overall benefits, especially to wind power deployment. No significant electrification is considered in Paper IV, and little change in demand is assumed. Paper II shows the importance of wind power in heating decarbonisation and the seasonality challenges. The benefits of cross-border transmission will be stronger with more electrification. Nevertheless, it is important to address the concerns of asymmetrically distributed benefits through, for example, international cooperation or policy design.

5 Discussion

5.1 Contributions and comparisons with existing literature

In light of the energy transition, this thesis contributes insights from thorough modelling analyses of the identified emerging challenges that have been relatively less discussed. The sub-objectives are defined after the Paper I review of Nordic power market outlooks, which reflect the respective perspectives of the key power market stakeholders. The direct expert survey by Sovacool et al. (2018) shows that the integration of renewables and the electrification of transport are the most frequently mentioned challenges in the Nordics' energy transition, and public opposition or political will are among the least mentioned challenges. The technical aspect of renewable integration is addressed by the reviewed outlooks with the use of advanced energy models, which nevertheless fall short of covering final energy products beyond electricity and district heat. The impact of electrification is thus limited to the assumptions of increasing electricity demand in some of the reviewed scenarios. Although the survey did not show significant social challenges, there are recent examples of social opposition hindering project realisation. The non-techno-economic aspects are translated to input assumptions and restrictions in the energy system analysis and affect output results. As Pfenninger et al. (2014) point out, addressing the human dimensions is among the new challenges for energy system models, but there is still room for improvement in this regard in the reviewed outlooks. Thus, Papers II to IV focus on the challenges related to electrification and human dimensions.

The importance of electrification of the non-power sector is receiving increasing attention towards deep decarbonisation. One of the key messages of the recent project Nordic Clean Energy Scenarios (Wråke et al., 2021) concludes that direct electrification is the centrepiece of carbon neutrality. The importance of expanding sectoral coverage of energy system analyses is twofold. On the one hand, sector coupling provides system flexibility that are beneficial to renewable integration. On the other hand, the total scales and hourly profiles of electricity demand will alter due to various end-use purposes. A recent survey by Chang et al. (2021) also shows the trend of increasing cross-sectoral coverage in energy system models, especially transport and district heating. Paper II covers the gap in international studies of decentralised heating, which takes a large share in final energy consumption but has yet to be decarbonised. The human dimension in Paper II is represented by introducing parameters to delay the technology switch to mimic the (un)willingness of the individual users to shift. The finding that heat pumps are the most cost-effective technology to supply decarbonised decentralised heating is in line with Knobloch et al. (2019), excluding solar heating. In terms of peak load, the report by Kavvadias et al. (2019) estimates winter peak will be 41% higher than today in full heating electrification, and according to Paper II it will be, on average, 21% higher than without modelling decentralised heat decarbonisation. Allowing endogenous investment, Paper II also reveals that the required renewable capacity, especially wind energy, might be significantly higher after considering decentralised heating decarbonisation.

Some climate-friendly technologies bring benefits in the techno-economic aspects of the energy transition but encounter challenges in the social-political dimensions, and in Northern Europe, wind turbines and transmission lines are such examples (Bolwig et al., 2020). With an endogenous investment methodology, the results in Papers II and III show the importance of wind energy in a cost-efficient low-carbon future, especially when the demand growth due to electrification is taken into account. In the study by Bolwig et al. (2020), the lack of social acceptance is translated as added investment costs to the targeted technology (onshore wind) before the optimisation looking for the most cost-efficient solution. In Paper III, the approach tackles land impact, which is the presumed reason for the lack of social acceptance. Cost efficiency is no longer the sole objective, and extra costs can be allocated to the investment options that cause less land impact. While the quantified results are sensitive to the assumptions of costs and land impact in both approaches, they reach the same conclusion that restricting onshore wind will likely shift the generation mix towards more solar PV, offshore wind or nuclear power (Paper III). The ranking of land use is not indisputable depending on the definition. For example, Dijkman and Benders (2010) find that in Northern Europe, the distance driven with electric vehicles powered by wind is more than double that powered by solar PV of the same land use. The alternative options are neither impact free. Radioactive waste disposal and safety have been major concerns of nuclear power. Whether the environmental and social impact of offshore wind installation is less than onshore is inconclusive because of limited knowledge of the offshore field, and impact assessments should be done on a case-by-case basis (Kaldellis et al., 2016).

Paper IV demonstrates the positive correlation between cross-border transmission and wind energy, in line with findings in Roques et al. (2010) and Neumann and Brown (2021). The optimal transmission capacity by 2050 for cost saving is four times today's level in the NTC approach in Paper IV, which is in line with the findings of the four times in Child et al. (2019), the nine times in Schlachtberger et al. (2017), and for the strongest balancing reduction, the 11.5 times in Rodríguez et al. (2014). The majority of the benefit can be achieved with less than half of the optimal capacity expansion (Rodríguez et al., 2014; Schlachtberger et al., 2017), and the important message is to identify the no-regret investment (Wråke et al., 2021). The transmission grid expansion is crucial to timely energy transition in bringing system-wide benefits, which is not mutually exclusive from other flexibility measures (Allard et al., 2020; Gea-Bermúdez et al., 2021; Thellufsen & Lund, 2017). While the benefits of cross-border transmission are well understood, Paper IV also quantifies the concerns for welfare distribution in the power market, which is not mentioned in the above mentioned literature. Understanding the concerns is the first step, and international cooperation and adequacy policy and market designs are required to overcome the challenges.

5.2 Limitations and future research

The three modelling studies include some of the emerging challenges in the European energy transition. Uncertainty has been one of the main concerns for energy transition research, and the studies in this thesis address uncertainties using deterministic scenarios and the MGA technique. One weakness is the lack of advanced assessment of parametric uncertainties, especially considering the wide ranges of future fuel and emission quota price assumptions in the reviewed scenarios and their high dependency on power prices shown in Paper I, as illustrated in Figure 12. Future research can address parametric uncertainties through global sensitive analysis and Monte Carlo analysis (DeCarolis et al., 2017; Yue et al., 2018). A Finish case study by Pilpola and Lund (2020) using Monte Carlo analysis highlights that the optimal system based on single deterministic assumptions may become unreliable under variation in the model inputs.

Weather stochasticity is omitted in the three deterministic modelling studies, and on top of it, climate change adds uncertainties on both supply and demand sides. A case study by Seljom and Tomasgard (2015) with stochastic modelling of wind power generation shows lower wind power investments than using a deterministic approach. Golombek et al. (2022) soft-link an equilibrium and a stochastic European energy model, to take into account the impact of the uncertain load and VRE generation on investments, and the results show that a pure deterministic approach underestimates the need for transmission and battery capacity. Future energy transition research should ensure that the proposed strategies are robust to weather and climate uncertainties and assess the associated risks.

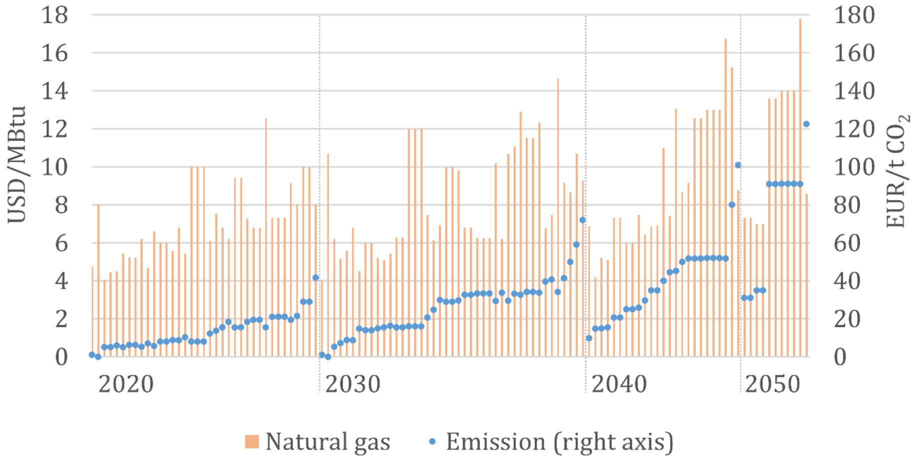

Figure 12. Illustration of the gas and emission price assumptions of the reviewed scenarios in Paper I. Each column represents one reviewed scenario.

On the demand side, besides decentralised heating, deep decarbonisation of transport and industry sectors will also impact the electricity system through electrification and sector coupling. These end-use demands are not fully represented in Paper II, although smart charging of private electric vehicles and simplified demand response are included as flexibility options. An analysis covering all end-use sectors provides more comprehensive insights into challenges in further decarbonisation. Based on the seasonality challenge shown in Paper II, future energy transition research can also investigate which strategies mitigate peak demand, such as building retrofitting (Zeyen et al., 2021), or which offer seasonal storage solutions, such as hydrogen (Petkov & Gabrielli, 2020).

On the supply side, future research can identify alternative system configurations minimising other types of impact, such as inequality or use of materials (Sasse & Trutnevyte, 2020), using a similar method as in Paper III. One improvement of this methodology is to take heterogenous values and renewable resources into account. For example, applying assumptions based on local surveys and using GIS tools can deliver a more tailored analysis. Papers III and IV show the benefits and compromises deviating from the cost-optimal systems. The next step is to deliver them to the public with full transparency and identify the no-regret options, such as through iterations of modelling studies and public consultations. Nevertheless, it is still important to maintain larger geographic coverage to avoid overlooking the spillover effect.

6 Conclusions

This thesis has investigated three emerging challenges for achieving speedier and broader decarbonisation of the Northern European energy system. Electrification with electricity from renewables is one major mitigation strategy for the non-power sectors. This mitigation strategy will affect the power demand profile and increase the scale of electricity demand. Meeting the new demand levels will require more renewable energy deployment. Despite the declining technology costs, increasing challenges from non-techno-economic perspectives have been observed. One social concern against renewable technologies has risen from their low installed power densities, leading to increasing land impact and land-use conflicts. There have been doubts against international cooperation via power transmission. Despite the overall increase in system efficiency and flexibility, benefits are distributed asymmetrically among countries, and electricity costs increase for consumers in low price areas. The review in Paper I reveals that these challenges have not been thoroughly addressed in the Nordic power market outlooks published between 2016 and 2018. Thus, this thesis includes three modelling studies to respectively analyse the effect of non-power sector decarbonisation (focusing on decentralised heat), the options to minimise land use conflicts and the trade-offs of cross-border power transmission.

The modelling results in Paper II show that electrification through heat pumps and hybrid systems supplies the most cost-efficient decarbonised heat. The amount of additional electricity demand varies depending on the assumptions of building efficiency improvement and district heating development, but all the scenarios show that decentralised heating decarbonisation affects future electricity demand and the need for renewables, particularly wind power. In the HIGH scenario, almost 700 TWh extra electricity will be needed for heating decarbonisation, and 740 GW wind plus 189 GW solar should be installed in the modelling countries. Future electricity demand will likely inherit the strong seasonality from heating demand, causing higher winter peak loads, potentially excess electricity in summer and significant seasonal power price differences. Countries such as Germany and the UK, where a large amount of heat is currently supplied by fossil fuels, are the most impacted.

The results in Paper III suggest that onshore wind and solar PV take the largest shares in the electricity mix under the least-cost solution. Although the rising renewable deployment will require larger land and space than the current system, the overall percentage of land use for energy facilities remains at 1.2% in the modelling scope. Potential land conflicts can be mitigated by shifting towards costlier systems with higher shares of offshore wind and nuclear power. Nonetheless, neither offshore wind nor nuclear power are controversy-free options, with higher risks in costs and safety than onshore wind and solar PV. The implied costs per land avoided are considerably high compared to the compensation for ecosystem conservation reasons or to the land market prices.

Paper IV demonstrates that allowing for transmission investments to increase cross-border interconnection can contribute to lower costs and emissions in future energy systems. The model invests 76 GW cross-border transmission capacities on top of the existing and planned capacities between 2030 and 2050. Through power transmission, resources can be utilised more efficiently. The cooperation is particularly beneficial to wind power development in the Nordics, where good wind resources can be sent south to substitute fossil-based generations. Regional power price differences decrease, which causes the opposite impact to producers and consumers. Hydropower and wind producers in the Nordics receive 67% growth in revenues, while consumers will have to pay 21% higher prices. Although power prices in the Nordics increase, they remain relatively low in an international context. The asymmetric distributed benefits indicate the need for interconnection and proper policy designs to overcome the barriers and utilise the system-level benefits of cross-border power transmission.

A main conclusion in this thesis is that there is a significant need for electricity from renewables, but the challenges faced by the relevant technologies are shifting from techno-economic towards non-techno-economic aspects. Research-based analysis provides the basis for rational discussions. For a successful and timely energy transition, clear communication of trade-offs and compromises of various choices will be crucial.

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ADVANCED REVIEW

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Long-term trends of Nordic power market: A review

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Abstract

The Nordic power system will play an important role in a future carbon-neutral European power market. In this study, 43 scenarios in 15 Nordic power market outlooks published between 2016 and 2019 are reviewed. Most scenarios see high future power prices with substantial correlation with assumed gas and emission quota prices. The underlying uncertainties in gas and emission quota prices are passed on to future power prices. The power prices are well above the cost of wind power, indicating that the wind deployment is either underestimated or might be largely dependent on non-market factors. The models used for the outlooks have limited sector coverage and trade-offs are made between computational resources and complexity. A set of recommendations for future outlook publications are proposed based on this review experience. Moving towards a low-carbon future, more attention should be put to the demand side, especially with increasing importance of sector coupling and electrification. Also, to assess the profound uncertainties in the energy transition period, techniques besides scenario analysis can be applied. Explicit assessments on impacts of emerging topics, such as social oppositions to particular technologies and increased awareness of sustainability indicators besides clean energy, will add values for long-term decision making in the power markets. Last but not the least, best efforts of clarity and transparency should always be ensured.

This article is categorized under:

- Energy Systems Economics > Economics and Policy
- Energy Systems Analysis > Economics and Policy
- Energy Policy and Planning > Economics and Policy

KEYWORDS

energy scenarios, fuel prices, market outlooks, Nordic power market, power prices

1 | INTRODUCTION

Both public and private organizations in the energy sector issue publications with regard to long-term power markets. These publications with various objectives come in different names such as "prospects," "outlooks," "projections," and "scenarios". Authority-commissioned reports are used to endorse or evaluate energy and climate policies (ENTSOG & ENTSO-E, 2018; IEA et al., 2016). Private firms release reports to support their strategies and attract investors. Regardless of the primary intention, these publications often provide basis of further analyses, for example, as business decision-making support, or as assumption references or research motivation support for the research communities (Braunreiter & Blumer, 2018).

The official 2050 carbon-neutrality target endorsed by the European Parliament aims to keep the global temperature rise to 1.5°C (European Commission, 2020). A drastic transition from conventional thermal power plants to a large share of variable renewable energy (VRE) unfolds and will continue in the coming decades. The abundant renewable energy resources in the Nordic[1] countries can benefit from a future fossil-free Europe through integrated power markets. Large amounts of Nordic wind power generation and exports are expected in studies of the European energy market that includes high renewable penetrations. For example, the optimal transmission scenario for 2050 in Schlachtberger et al. (2017) shows the scale of wind generation in Denmark reaching as much as 4.5 times its domestic demand, in Norway reaching 2 times its demand, and in Sweden reaching 1.5 times its demand. Child et al. (2019) find the ratio of net electricity export to demand in Denmark to be 52%, and 40% in Norway in a 100% renewable energy system in Europe by 2050. In addition to the abundant VRE resources, Norway, Sweden, and Finland combined had 217 TWh hydropower production in 2019, which contributed more than half of the Nordic power production (Gogia et al., 2019). Hydropower expansion potentials are limited by environmental regulations; however, its ability to provide flexibility may become more valuable (Tveten et al., 2016). Through physical transmission power lines and market integration, the Nordic energy market plays an essential role in the European energy transition (ENTSO-E, 2018).

To grasp the complexity of modern energy systems, a common practice in long-term energy market studies is to use an energy system model (or an electricity market model) with a set of input parameters to analyze several scenarios. A modern energy system analysis often combines traditional economics-oriented top-down and technology-oriented bottom-up approaches (Tol, 2000). References from well-recognized institutes or own assumptions are applied for parameters involving conditions outside of the modeling scope, such as international fuel prices. Finally, scenario analysis is a popular practice for exploring plausible futures. Each plausible future is formed under its storyline and can differ in, for example, fuel price levels, nuclear power development, or climate targets. In a modeling context, the diverting energy scenarios may originate from two main reasons: (a) differences in the models applied, due to, for example, different optimization objectives, geographical scope or time resolution, and (b) differences in input assumptions to the model. The scenarios along with their assumptions represent the interests and perspectives of the publishers. While there are several review publications on different methodologies or modeling tools (Fattahi et al., 2020; Gils et al., 2019; Prina et al., 2020; Ringkjøb et al., 2018), the parametric variations seem to have received less attention from the research community.

Power market outlook studies provide substantial value to medium-term and long-term decision-making in the energy sector. Meanwhile, publishers of outlook studies have significant influence, as the information that they provide can shape the future depending on how decision makers and power companies use this information. The Nordic region has a long history of deregulated power trading, and the markets have already been integrated through the Nord Pool power exchange since 2000. Market data are transparent and available on their website, offering great opportunities for liberalized power market research. Nordic power market outlooks can be seen as examples of information that is currently shared by major stakeholders in an integrated and low-carbon market. A comprehensive review of these outlooks summarizes the lessons-learned and reveals their strengths and weaknesses. A set of recommendations is subsequently listed based on the review experience and the recent discussions on a low-carbon future. We hope to increase the value of the information presented by future outlook publications in the time of energy transition.

Against this background, this study aims to summarize the insights of the power markets and lessons-learned stemming from various recent Nordic power market outlooks for the period toward 2050. This review has a parametric emphasis on the main market drivers, coupled with an assessment of differences in their scopes and methodologies. The Nordic focus adds values to European energy transition, as the well-functioning Nordic power markets with vast renewable penetration are likely to serve as a pioneer in deep decarbonization of the energy sector. Several stakeholders in the Nordic power market publish outlook reports, and many of them release updates regularly. The analysis aims to inspire regional and European energy system planners and investors, but also to make readers of outlook reports aware of differences in focus in such reports, and that results can be quite different with different methodologies and input data. This study also hopes to contribute as feedback to outlook and energy model developers for future outlook publications to provide insightful discussions towards a low-carbon future.

2 | LITERATURE REVIEW

There is a large literature on cross-scenario analyses related to the energy sector. In this section we give a brief overview, indicating what they have been focusing on. Trutnevyte et al. (2016) reviewed 12 scenario exercises released from 1978 to 2002 on the UK energy future and focused on scenario formations. They note a methodological shift from predictive to explorative or normative and argue that recent scenarios are more able to capture a wider scope of uncertainties. Laugs and Moll (2017) reviewed 30 scenarios with a global perspective and focused solely on the energy mix. The scenarios are clustered into two, and they find limited energy mix bandwidth within each cluster; however, other variables than the energy mix (e.g., prices) are not addressed in the study. Another study by Söderholm et al. (2011) studied 20 low-carbon energy scenarios covering global or regional aspects. They focused on low carbon policy measures, and CO_2 price in 2050 was the only parameter discussed explicitly across scenarios. An older, but thorough, review from Martinot et al. (2007) commented on different input parameters from a large selection of literature. They focused on future possible amounts of renewable energy with various geographic coverage, while reviewing several socioeconomic and technological parameters. They note large ranges of renewable shares and parameters across scenarios but lack further elaboration of the linkages among them. The aforementioned literature does not emphasize power prices in their reviews. A meta-analysis by Cochran et al. (2014) concentrated on high renewable penetration in a review of 12 scenarios. They compare data inputs including demand and costs as well as scenario outputs on generation mix and projected electricity costs. Nevertheless, most scenarios cover quite different geographic scopes, and it is difficult to discuss the comparison beyond that. Uncertainties across scenarios can be analyzed using computational techniques. For example, Guivarch et al. (2016) identified important uncertain factors of shared outcomes across 432 scenarios using a scenario discovery technique. Nevertheless, computational techniques are less suitable for regional power market outlooks due to insufficient sample size; thus, they are not applied in this review. To the best of our knowledge, no previous study has quantitatively examined perspectives on future power prices and other factors by reviewing scenarios in market outlooks. The method is simple, yet reflects the lessons-learned from key market stakeholders experience. As the aim of this study is to summarize the lessons-learned in the power market outlooks, not to compare the models, we would like to point to other technical reviews, such as the review of 75 modeling tools by Ringkjøb et al. (2018), for the readers interested in energy models.

3 | OUTLOOKS AND SCENARIOS REVIEWED IN THIS STUDY

3.1 | Report selection criteria

The primary focus is reports that are widely applied or referred by local stakeholders. In addition, the following factors serve as study selection criteria: geographic focus, publication year, time horizon, and public availability. We target four Nordic countries excluding Iceland, which has an independent energy system. Considering the rapid development in energy policies and technologies, we have focused on publications released since 2016. As uncertainty increases over a longer time horizon, we are interested in studies covering at least the year 2030, but no later than the year 2050 for reasonable confidence. We assign public availability as one of the criteria because it enhances a report's visibility to any general reader and thus, possible influence. In addition, readers of this article, who are interested in certain reviewed studies, can easily refer to the original report. Finally, only scenarios with power prices revealed together with fuel and quota prices are discussed. Up to the beginning of 2020, these criteria include 43 scenarios from 15 studies published by 8 organizations. Table 1 summarizes the outlooks reviewed in this study. The original titles are listed to match the references. Subsequently, we refer to each outlook by its abbreviation consisting of the publisher and the publication year. Appendix contains short descriptions of the reviewed outlooks from each publisher to provide a quick guide to the reviewed material. All outlooks are available online at the time of the study.

3.2 | Scenario classification and framing

Outlook studies analyze power markets under various scenarios. A classic classification developed by Börjeson et al. (2006) categorizes scenarios by their objectives into three types: predictive, explorative, and normative. Predictive scenarios answer “What will happen?” and they are often used in short-term forecasts. Explorative scenarios answer

TABLE 1 List of reviewed outlooks and their abbreviation used in this study. The original outlook titles, covered time horizons, and publishers are summarized.

Abbreviation (publication year)	Original title and reference	Time horizon	Publisher
DK-E (2016)	Elprisscenarier (Capion & Larsen, 2017; Capion & Meibom, 2016)	2035	Dansk Energi (member organization for Danish energy companies)
DK-E (2017)		2035	
DK-E (2018)	Elpris Outlook (Capion et al., 2018; Poulsen et al., 2019)	2035	
DK-E (2019)		2040	
E.DK (2016)	Energinet.dk's analyseforudsætninger (Energinet, 2017; Energinet.dk, 2016)	2040	Energinet.dk (Danish TSO)
E.DK (2017)		2040	
EI (2016)	Ökad andel variabel elproduktion. Effekter på priser och producenters investeringsincitament (Energimarknadsinspektionen, 2016)	2030	Energimarknads-inspektionen (Swedish energy market authority)
EM (2017)	Scenarier över Sveriges energisystem (Energimyndigheten, 2017, 2019)	2050	Energimyndigheten (Swedish energy agency)
EM (2019)		2050	
SK (2019)	Långsiktig marknadsanalys (Brunge et al., 2019)	2040	Svenska Kraftnät (Swedish TSO)
NVE (2017)	Kraftmarkedsanalyse (Amundsen et al., 2017)	2030	Norges Vassdrags-og Energidirektorat (Norwegian regulator)
NVE (2019)	Langsiktig kraftmarkedsanalyse (Gogia et al., 2019)	2040	
SN (2016)	Langsiktig markedsanalyse-Norden og Europa (Bøhnsdalen et al., 2016; Bøhnsdalen et al., 2018)	2040	Statnett (Norwegian TSO)
SN (2018)		2040	
N-IEA (2016)	Nordic Energy Technology-Perspectives (IEA et al., 2016)	2050	IEA, Nordic Energy Research et al.

"What can happen?" and typically focus on the medium or longer run. Normative scenarios answer "How can a certain target be reached?" by optimizing modeling or back-casting. Nevertheless, we find that most reviewed studies are explorative or have a combination of objectives; thus, it is difficult to classify them according to these definitions. Scenario formation varies significantly from one report to the other and even evolves over time; however, several factors or similar definitions are used repeatedly in different outlooks. We cluster scenarios using their main definitions as the following:

- Reference — A scenario that is presented as a reference case, base case, or business-as-usual.
- High price — A scenario that applies higher fuel prices than the others, in most cases, also higher CO_2 prices.
- Low price — A scenario that applies lower fuel prices than the others, in most cases, also higher CO_2 prices.
- Green — A scenario that has lower emissions, supports renewables, represents ambitious climate actions, or has an emission target in line with the Paris Agreement.
- High emission — A scenario that has higher emissions or limited renewables.
- Others
  - Nuclear — A scenario with more nuclear power capacities than the other scenarios in the same study.
  - No nuclear — A scenario with less nuclear power capacities than the other scenarios in the same study.
  - Electrification — A scenario with high electrification in other energy sectors.
  - Warm — A scenario that assumes a warmer climate.

Clustering is helpful to analyze scenarios in different outlooks under comparable settings and it is also helpful to present readable figures in the latter sections. It is noteworthy that the clustering is based on the qualitative scenario definitions in each outlook, and no quantitative condition is applied by this study. In general, the reference cluster corresponds to the predictive scenarios, the green cluster corresponds to normative or explorative scenarios, and the rest of the clusters contain mainly the explorative scenarios. The scenarios in the "others" cluster are various case studies and should be interpreted with caution. To maintain the link between each data point and the source scenario, Table 2 lists the scenario clusters in this study and the scenarios within each cluster in their original names.

TABLE 2 Reviewed scenarios in each outlook. Scenarios in their original names are categorized according to their main definition.

Report	References	High price	Low price	Green	High emission	Others
DK-E (2016)		WEO	Forwards	Klima		Overflod (Nuclear)
DK-E (2017)		WEO	Forwards	Klima		
DK-E (2018)		WEO	Forwards			
DK-E (2019)	Blå			Grøn	Sort	
E.DK (2016)	REF[a]					
E.DK (2017)	REF[a]					
EI (2016)		Höga bränslepriser	Låga bränslepriser			Utfasning av kärnkraft (No nuclear)
EM (2017)	Referens EU	Höga fossilpriser	Lågt elpris	Lågt elpris + 18 TWh	Hög BNP	
EM (2019)	Referens EU			Lägre BNP	Lägre energipriser	Högre elektrifiering-(Electrification) Varmare klimat-(Warm)
SK (2019)	Ref	Hög	Låg			
NVE (2017)	Basis	Høy	Lav			
NVE (2019)	Basis	Høy	Lav			
SN (2016)	Basis	Høy	Lav			
SN (2018)	Basis	Høy	Lav			
N-IEA (2016)				CNS-B Baseline		CNS-B Nuclear fast phase-out (No Nuclear)

[a]There is no scenario in Energinet, (2017); Energinet.dk, (2016), so they are seen as reference cases.

3.3 | Focused parameters and data preparation

A primary interest in our review is future power prices, as this is the main deliverable of most outlook studies and is an important information for today's investment decisions. A common practice for power market outlooks is to apply a quantitative model with a set of assumptions to optimize energy supply and demand balance at a minimum cost, and the power prices are the marginal costs of electricity generation. Therefore, we summarize trends and differences in key power market drivers that affect the modeled prices in the reviewed outlook studies. Among all the relevant factors, the focused parameters in this study are nevertheless largely based on the preliminary observation of how the outlooks design their scenarios and reporting. Only the data that are disclosed in most outlooks can be compared.

The outlooks present data in various formats for various timelines, and we exclusively rely on data presented in the outlooks and their attached data files if available. Data are extracted directly from apparent texts, tables, and figures of every decade from 2020 to 2050, and there is no interpolation or extrapolation applied in this study to reflect specific parameters reported in a specific year. Price units are converted and expressed in USD/Mbtu for gas, USD/tonne for coal, EUR/tonne for CO_2 emission, and EUR/MWh for power. The choice of currencies reflects that gas and coal prices are dependent on the global market and are usually expressed in terms of USD, while CO_2 and power are traded within Europe and usually expressed in terms of EUR. Installed capacities are expressed in GW, and energy demands in TWh. Energy units are converted based on unit conversions from the IEA (2019). Prices are expressed in real values with the base year 2018. Price values found in the reviewed studies are converted to desired currencies first by exchange rates of the same year according to the European Central Bank (2019) and OFX (2020), followed by adjustments to 2018 prices using the consumer price index (CPI) in OECD (2019). For instance, if a power price from a report is given in NOK-2010/MWh, the price will first be converted to EUR using the exchange rate from 2010, and then CPI will be applied to convert the price from EUR-2010 to EUR-2018.

4 | LESSONS-LEARNED FROM THE MARKET OUTLOOKS

The main findings from reviewing the Nordic power market outlooks are reported in the following sections. We first concentrate on methodological issues, thereafter on data assumptions made in the analysis and observations regarding the outlook results, and finally on some aspects missing from current outlook studies.

4.1 | The models used for power market analyses have often limited capability to analyze final energy use beyond electricity

Table 3 summarizes the methodological features of the outlooks by publisher. More than half of the publishers use models that covers only electricity as the final energy product. These models consider electricity supply–demand balance and other details, such as grid restrictions (i.e., the Samnett model), and start-up and shut-down costs (i.e., the Sifre model and the BID model). The scenarios are usually predictive or explorative and have assumptions of how the future systems look like. The other publishers cover heat besides electricity in their models, where the interaction between heat and electricity is captured. With more flexibilities in terms of how future systems can operate and develop, these models are suitable for normative and explorative scenarios. All the reviewed outlooks using the models covering heat and electricity are also investment models, which allow endogenous capacity expansion of certain technologies, whereas the others covering solely electricity do not allow endogenous capacity expansion, but exogenously given assumptions for future capacities. Some of the former models are perfect foresight investment models, which optimize the system for all years at once, while others are myopic investment models that optimize the system year by year.

One common methodology limitation shared by these outlooks is that they are not able to model the entire energy sector (only electricity, or electricity plus district heat), or at least not able to include different sources of electricity consumption at an equivalent level of detail. Depending on the sectors covered in the analysis, the coverage of the source of electricity consumption varies. To an electricity-only model, the electricity consumption is a simple assumption or an assumption after advanced pre-analysis, whereas to an energy system model that covers not only the power sector, the electricity consumption is determined by an assumption combined with the results of electrification from other included sectors. For example, among the reviewed studies, the ones from Dansk Energi, Energimyndigheten, and the Nordic Energy Technology Perspectives (NETP) cover district heat in addition to the electricity sector; thus, their electricity consumption includes the need for district heat electrification. The transport sector is also covered indirectly in some of the reviewed scenarios. For example, Energimyndigheten uses dedicated transportation models to calculate the future energy use in the transport sector. The resulting electricity consumption in the transport sector is then applied as part of the final electricity demand in the TIMES-Nordic model. Another example is the Norwegian regulator NVE, which applies the TIMES model to analyze total final Norwegian electricity demand as inputs to Samnett and The-MA models for further power market analysis.

Electricity consumption is vital to the scale of a country's power system. In addition to GDP per capita and population growth, the electrification aiming at emission reduction plays a key role in shaping future electricity consumption. The effect goes beyond efficiency improvements. Especially in the Nordic countries with significant resources of non-fossil-based energy supply, electricity can provide clean fuel to other sectors and thus increase demand in the power sector. The review shows that the development of electricity consumption has not been as focused as the production in the reviewed outlooks, and that the interactions between the power sector and the other sectors through sector coupling are often over simplified, if not omitted.

Figure 1 summaries the power consumption applied in the reviewed scenarios. Overall, there are relatively small differences in the assumed consumption levels across outlook studies. All scenarios assume constant or slightly increased consumption, except for IEA (2016), which assumes Nordic carbon neutrality with aggressive building efficiency improvement implementation and an important biofuel role. Many of the green scenarios also assume less consumption than the reference scenarios. In contrast, the electrification scenario in EM (2019) sees the largest consumption growth of 38% from 2020 to 2050 as a result of high electrification in the heating, transport, and industry sectors. The contribution from electrification appears to have larger influence than the effect from efficiency or energy savings. Overall, we find that the majority of the reviewed scenarios might have underestimated the uncertainties in future electricity consumption.

TABLE 3 Summary of the models and key methodological features used to generate power prices by the reviewed report. The summary focuses on the main methodologies applied to the power price outlooks in the reviewed scenarios, and further details are found in the notes column and in the Appendix.

Report	Model used for the electricity price outlooks	Covered final energy product[a] (electricity/heat)	Investment foresight	Temporal resolution	Multiple weather years	Notes
DK-E (2016, 2017, 2018, 2019)	Balmorel	V/V	Myopic foresight	2184/year (13 representative weeks with 168 h in each week)	–	
E.DK (2016, 2017)	Sifre (Danish market) and BID (other markets)	V/–	–	8760/year	–	The Sifre model includes Danish power and heat markets.
EI (2016)	Apollo	V/–	–	8760/year	–	
EM (2017, 2019)	TIMES-Nordic	V/V	Perfect foresight	12/year (4 seasons with 3 timeslots in each season)	–	
SK (2019)	BID3 and EMPS	V/–	–	8760/year	V	Investment with perfect foresight is allowed in complementary scenarios, which are not included in this study due to insufficient data.
NVE (2017, 2019)	Samnett (Nordic market) and The-MA (other markets)	V/–	–	8760/year	V	The final Norwegian electricity demand is a TIMES model output, which covers all energy carriers.
SN (2016, 2018)	Samnett (Nordic market) and The-MA (other markets)	V/–	–	8760/year	V	
IEA (2016)	Balmorel	V/V	Myopic foresight	72/year	–	There are scenarios analyzed by the ETP-TIMES model, which covers the entire energy sector, but excluded in this study due to insufficient data.

[a]Some of the reports use extra models to cover other energy sectors, such as transport, and the resulting electricity demand is then used as input assumptions to the main models. See Appendix for details.

4.2 | Tradeoffs are often made between temporal granularity, weather uncertainties, and the computational complexity

With increasing penetration rate of VRE, the supply–demand balancing challenge requires finer temporal granularity to be reflected in the model analysis. The decision on temporal granularity in power market outlook studies is often a trade-off between required temporal accuracy to represent a realistic model and the computation resources. The finest temporal granularity of the reviewed studies is at an hourly level. All the electricity-only models used in the reviewed studies include full hours in a year, and NVE, Statnett, and Svenska Kraftnät also consider multiple weather years for hydropower modeling. The other models cover electricity and district heating sectors and enable the potential of

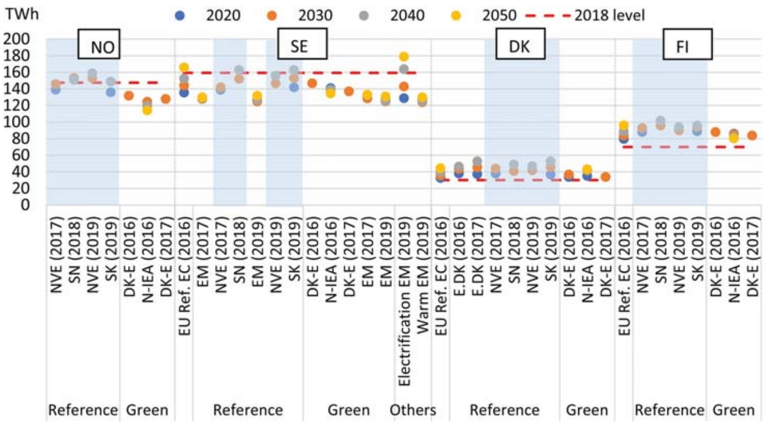

FIGURE 1 The electricity consumption in 2020, 2030, 2040, and 2050 in each Nordic country reported in the outlooks. The full scenario names are given in Table 2. The columns colored in blue are reports with electricity only models

power-to-heat technologies, but these models include fewer timesteps to represent a full year to mitigate the computational need. Note that this observation is based on the reviewed outlooks—there are other investment models not reviewed here with fine time resolution, or multiple weather years (for a cost of computational resources).

Weather impacts VRE and hydropower production, changes energy consumption volumes and patterns, and brings uncertainties. As noted by Cochran et al. (2014), all studies in their review assume particular weather year(s) in their scenario analyses. Most reviewed outlooks are not designed to address this issue, with few exceptions of stochastic hydropower production. In our sample of outlook reviews, 5 out of the 15 reports use more than one weather year in the analysis, while the remaining ones apply a single weather year. Depending on the scope of the analysis, assumptions of a single weather year may lead to results and conclusions that could be imprecise or even misleading. Moreover, climate change will affect temperatures, precipitation levels and wind speeds, all of which are affecting the energy markets. Uncertainties related to weather will increase with higher VRE shares on the supply side and more electricity used for heating on the demand side. Current and emerging research aim to cover weather uncertainties and climate impacts, but they are often not accounted for in extended power market outlooks (Füssel, 2019). Only one reviewed scenario from EM (2019) is designed to investigate the impact of a warmer climate.

As such, using a fine temporal granularity, multiple weather years, and accounting for climate change are of increasing importance with increasing time horizon of the outlook.

4.3 | Fuel and emission quota prices are key power price drivers in the coming two decades, with profound uncertainty

Fuel and emission quota prices are key power price drivers traditionally (Capion & Meibom, 2016), especially in power systems with significant shares of coal and gas power plants. Coal prices have declining influence on the Nordic power markets as there is no coal power generation in Sweden and Norway, and Finland and Denmark will ban coal in electricity production before 2029 and 2030.The indirect influence from the continent through the power exchange declines steadily with graduate coal phase-out. In this section, we focus on natural gas prices and the emission quota prices, both believed to have bigger influence in the following decades. The review shows that the gas and emission quota price assumptions are crucial to the reported power prices, and that there is a large degree of uncertainty within those assumptions.

The gas and emission quota prices are input assumptions for energy models to generate power prices in the outlook studies. Outlooks often use a low-price scenario and a high-price scenario to capture the range of uncertainties in power prices as a result of uncertain fuel and emission prices (Bøhnsdalen et al., 2018). Using forward prices is common for 2020 and 2030. Prognosis from well-recognized institutes such as the IEA and EC are also often applied. Fuel and emission prices in the New Policy Scenarios (NPS) by the IEA or the EU Reference scenario (European Commission, 2016) are popular references, especially for the reference scenarios. Summarizing the gas and emission price assumptions across the outlook scenarios illustrates the uncertainty space of the price assumptions across the publishers.

Figures 2 and 3 stack all gas and carbon prices found, labeled by the scenario group. Price ranges are concentrated within the reference, high-price, and low-price groups. Both figures illustrate substantial uncertainties for the long-term price development of these major power price drivers, and the price range is particularly large for emission quotas.

All scenarios except IEA (2016) apply either fixed or increasing gas prices over time. Gas prices in IEA (2016) refer to the 2-degree scenario. It is stated in the report that fossil-fuel prices will increase considerably towards 2030 and decrease slightly from 2030 to 2050 owing to decreasing demand. Natural gas is used extensively also for other purposes than electricity generation, and thus the wide range of gas price assumptions represents mainly profound uncertainty about the future prospects of the European gas market.

All scenarios agree on continued quota price increase until 2050, which suggests a shared opinion of a substantial incentive to switch from coal to gas, and from fossil fuels to renewables. The quota prices in the carbon market in Europe (EU ETS) are established by policy makers. The market supply side (allocation of emission allowances) is determined politically by the EU, and the policymakers are free to adjust the supply through ETS regulatory changes, which they have recently done. This is very different from most other markets, where supply to a large degree is linked to costs of investments and operations. The majority of the scenarios have underestimated the 2020 quota price, especially the ones published before 2018 as the price increased considerably that year after regulatory changes in early 2018. There is also a common trait that updates tend to modify and increase the price from the old ones, possibly due to the actual price development. The highest carbon prices always appear in the green group, especially in IEA (2016), which assumes carbon neutrality. The ranges between the lowest and highest quota prices applied in 2040 and 2050 are approximately 90 EUR.

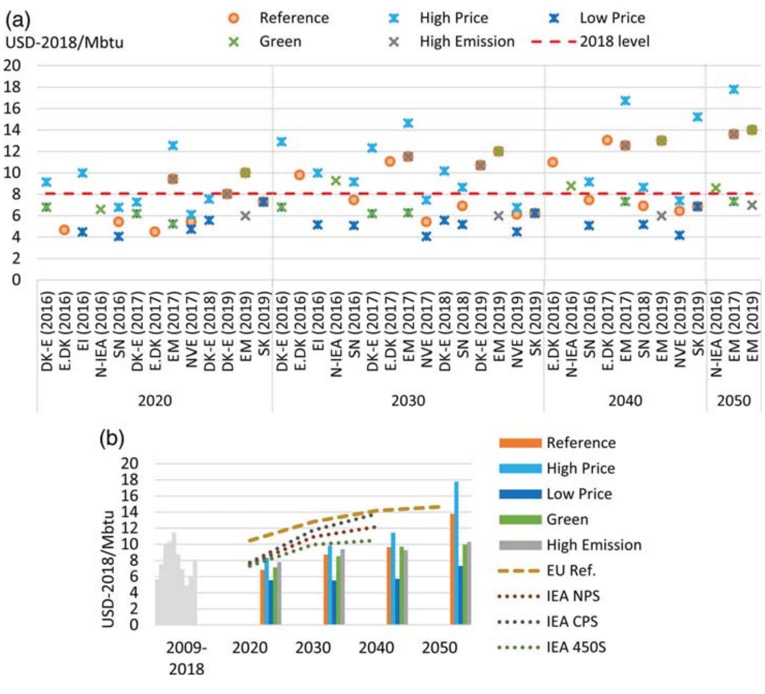

FIGURE 2 (a) Natural gas prices in 2020, 2030, 2040, and 2050 found in each scenario and the 2018 price level. (b) Historical prices from 2009 to 2018, average price assumptions in 2020, 2030, 2040, and 2050 by outlook scenario groups from the reviewed studies, EC (2016), and scenarios in IEA (2016). The full scenario names are given in Table 2

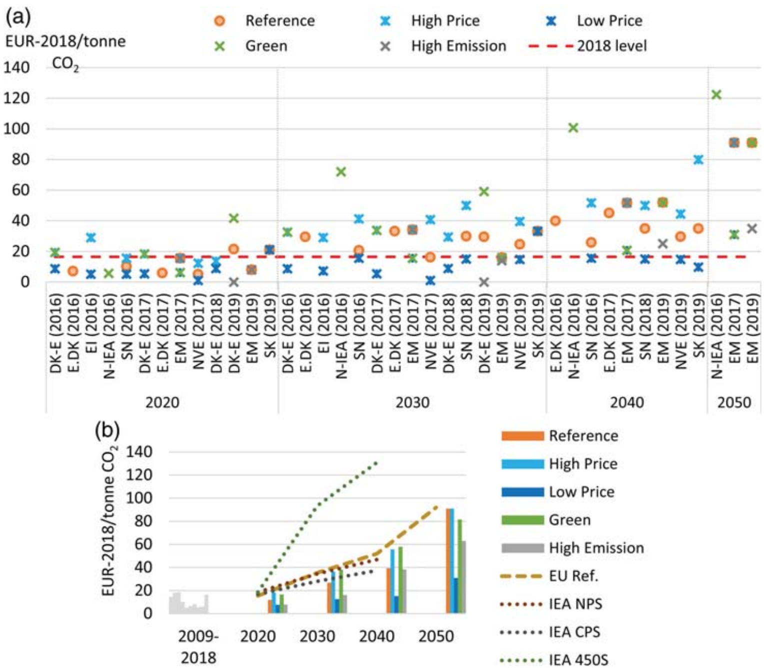

FIGURE 3 (a) Emission quota prices in 2020, 2030, 2040, and 2050 found in each scenario and the 2018 price level. (b) Historical prices from 2009 to 2018, average price assumptions in 2020, 2030, 2040, and 2050 by outlook scenario groups from the reviewed studies, EC (2016), and scenarios in IEA (2016). The full scenario names are given in Table 2

Assumed gas prices and quota prices are correlated to each other, as shown in Figure 4(a). The extent of the correlation depends on the scenario definitions. The reference, high-price, and low-price scenarios show strong gas and quota price correlations, which are expected considering fuel and quota prices are used to define the latter two groups of scenarios. The other two groups, green and high emission distinguish themselves primarily in quota prices, and less in gas prices. This implies that quota prices are more associated with emission level or renewable development than natural gas prices when designing outlook scenarios. Figure 4(b)–(e) illustrates the relationships between the power prices and gas prices, and between the power prices and the emission quota prices in Sweden and Denmark. Positive correlations to various degrees are observed. Overall, fuel and quota prices play important roles in setting the power prices in the next 10–20 years, but the influence will decline with increasing number of countries entering to the zero-emission era.

4.4 | Renewable deployment will increase, but large variation is found across outlooks

An important driving force of the future power market is power generation capacity evolution. In the long term, power generation capacities are influenced by market signals as well as by policies. A general trend in Northwest Europe is to gradually phase out coal and limit nuclear power due to environmental and safety concerns, while VRE, especially wind and solar power, will steadily increase their electricity mix shares towards 2050.

Unlike the fuel and emission quota prices that are purely assumptions in the outlooks, wind capacities are model assumptions in some outlooks, while a mixture of assumptions and results in the others (from Dansk Energi, Energimyndigheten, and the NETP). The installed capacities in most of the outlooks are exogenous assumptions reflecting the expectation of wind deployment in each scenario. In the outlooks highlighted in green in Figure 5, wind capacities are optimization outputs based on minimizing system costs, with deterministic technology and fuel costs, which are quite uncertain in reality. One challenge encountered during the review process is that it is not always clear how the assumptions beyond the national targets are made, except a general statement such as "references from external reports" in Statnett's outlooks (Bøhnsdalen et al., 2016;

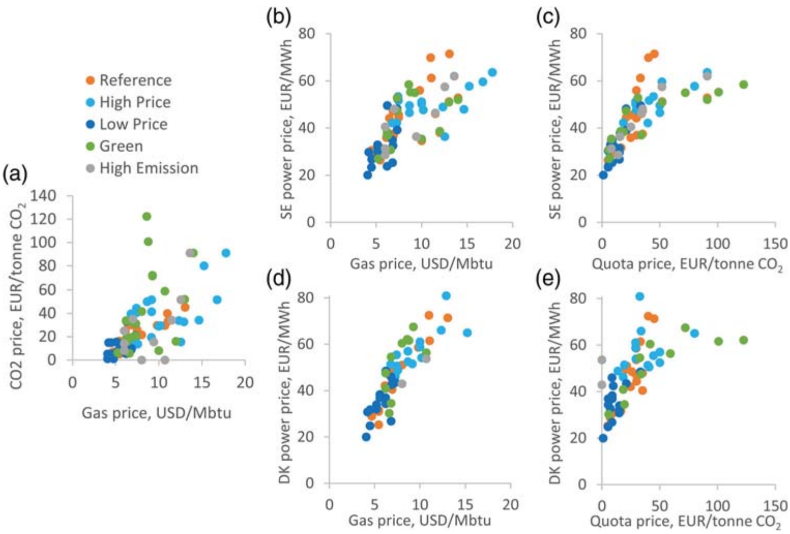

FIGURE 4 Summary of (a) emission quota price in EUR/tonne CO2 versus gas price in USD/Mbtu, (b) Swedish power price in EUR/MWh versus gas price and (c) emission quota price in EUR/tonne, (d) Danish power price in EUR/MWh versus gas price and (e) emission quota price in EUR/tonne. All data are from the reviewed outlook scenarios, colored by scenario group defined in Section 3.2

Bøhnsdalen et al., 2018). The other challenge is that not all outlooks present power generation in the same way. In this case, some of the outlooks present the installed capacity and some show the annual generation. Both capacity and annual generation are important information and should both be presented. As a compromise, Figure 5(a) displays the installed wind capacities listed in the reviewed scenarios, and Figure 5(b) displays the wind generation in outlooks showing the generation only.

Overall, the installed wind capacity is expected to increase, and it appears that the more recent the outlook is, the higher the future installed wind capacity it expects, regardless of the scenario group. The EU reference scenario published in 2016 appears to have underestimated the wind deployment in comparison to the reviewed Nordic outlooks. Norway, in addition to abundant hydropower supply, can increase as much as five times the wind capacity until 2050 according to the Nordic carbon neutral scenario in IEA (2016). The deployment, nonetheless, is subject to the availability of international transmissions as well as acceptance from the public.

Solar power is less important in the Nordics than wind power. Energimyndigheten (2017) suggests that solar PV investments are highly sensitive to power prices, and with high power prices, solar power production in Sweden (mainly from private houses) can increase 3–5 TWh after 2030, equivalent to 3–5 GW of installation, and remain at the same level towards 2050. Nuclear development reflects contemporary acceptance, not just economic competitiveness, but the analysis from Energimyndigheten reveals that nuclear power is unprofitable even when it is allowed as an investment option. The nuclear capacity in Finland is rather stable and newer outlook scenarios reflect the announced plans. Most studies do not specifically discuss gas power capacity. Growing wind power stimulates the need for regulated power, which may be one reason for the increasing gas power capacities indicated by EC (2016). It is expected that the gas power between 2030 and 2050 grows from 3.3 to 4.7 GW in Sweden, from 3.2 to 4.1 GW in Finland, and 1 to 4.3 GW in Denmark. The Nordic countries have all announced ambitious carbon neutrality strategies, but capacity adequacy is important to ensure energy security. The gas power plants have the potential to offset their emissions through other sectors or by using carbon capture technologies, or by switching to renewable gases.

4.5 | The growth of the onshore wind power in the Nordics appears to be restricted by factors beyond the economic potentials

There is no explicit wind energy target in the Nordics, and the amount of wind power in the reviewed studies is mainly an assessment of the modelers on what is feasible and realistic. Whether a wind project attracts investors is subject to

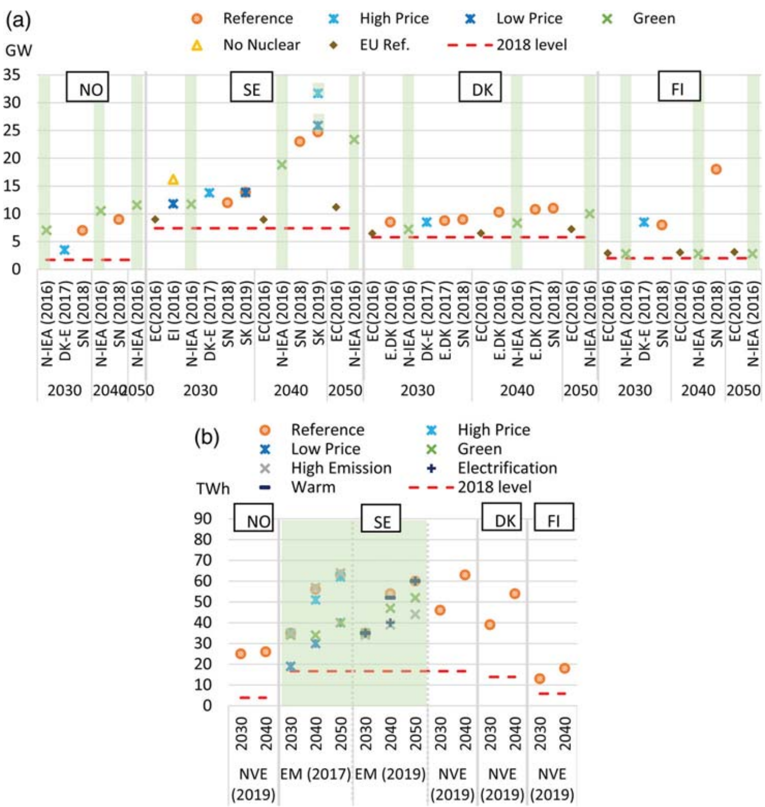

FIGURE 5 Wind capacity (a) and generation (b) in 2030, 2040, and 2050 found in each scenario in Nordic countries and the 2018 levels. The full scenario names are given in Table 2. The columns colored in green are the scenarios enabling wind capacity expansion investments in their models. Source of 2018 levels: Wind Europe (2019)

the outlook of the electricity market, technology costs, policies, and many other factors. Power prices are important investment signals for power producers. The projected power price levels after 2030 are in most scenarios well above the Nordic levelized cost of electricity (LCOE) of wind and solar PV. The LCOE of onshore wind reaches as low as 30–35 EUR/MWh in Norway (Bøhnsdalen et al., 2018) and around 37–56 EUR/MWh in Sweden (Energimyndigheten, 2019). Eventually, power generation investors will likely adapt to high prices by expanding their production capacities. These long-term effects are not consistently handled by models with exogenous capacity change assumptions.

However, average power prices exceeding LCOE for wind and solar will not automatically lead to new technology investments. First, wind and solar power generation are variable and produce when the wind is blowing, and the sun is shining. It is shown by, for example, Tveten et al. (2013) and Hirth (2013) that the merit order effect, causing lower prices with renewable generation, may be substantial in areas with large renewable shares and limited energy system flexibility. Deviation between power prices and LCOE of wind and solar power may hence be expected, also from a long-run perspective. Second, although the cost of wind turbines may be similar across countries and regions, the locational cost will typically differ due to different land prices, construction costs, and other factors. Finally, regulatory obstacles can also hamper new investments. This is especially relevant for wind power, as resistance towards new wind turbines from public protests or ecological concerns may prevent otherwise profitable investments. Social barriers are very case-specific, from environmental, political to cultural context. Over the last decade, with the number of installed wind turbines soaring, oppositions against wind power have also grown (Bolwig et al., 2020; Borch, 2018; Borch et al., 2020).

Overall, we observe that the onshore wind capacities in many reviewed scenarios appear low from today's perspectives, which may reflect recent rapid reductions in wind power costs as well as other changes in the energy sector, such as stricter climate targets. Future power prices in the outlooks are often found well above the LCOE of onshore wind. We do not have sufficient information to assess why the model results seemingly are limited by other factors than economic ones, but the merit order effect, uncertainties regarding the social acceptability of large amounts of onshore wind, or other non-economic factors are likely among the reasons.

4.6 | High average power prices and larger power price variation are expected by the outlooks

Power prices reported in the reviewed outlooks in each scenario are listed in Figure 6, divided into Figure 6(a) with models covering power and heat, and Figure 6(b) with models covering only electricity. The green columns in Figure 6 (a) are the ones with perfect foresight investments, and the blue ones are with myopic foresight. None of the outlook reports in Figure 6(b) include endogenous investments in their models, and hence future generation capacities are

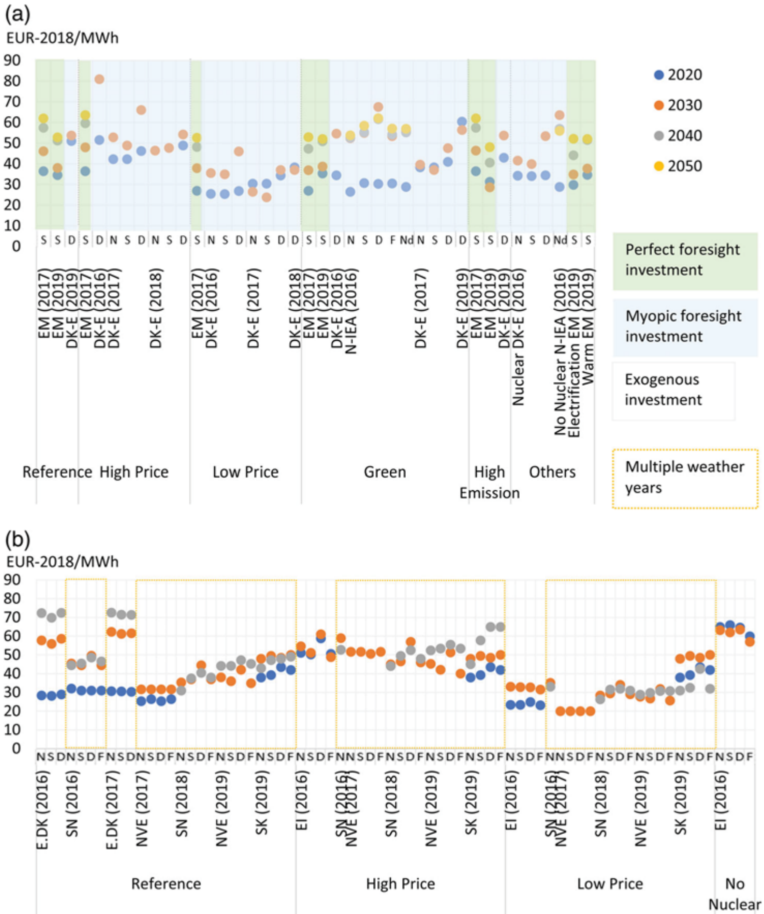

FIGURE 6 Modeled power prices in 2020, 2030, 2040, and 2050 found in reviewed outlook scenarios, using endogenous modeling of power-to-heat (a) or an electricity only model (b). N, Norway; S, Sweden; D, Denmark; F, Finland; Nd, Nordics. The columns colored in green are the scenarios enabling generation expansion investments with perfect foresight, the ones in blue are with myopic foresight for investment, and the ones in white are with exogenous capacity assumptions. The columns surrounded by yellow dot lines are the scenarios considering multiple weather years, while the others assume one normal weather year. The full scenario names are given in Table 2

input assumptions. The columns surrounded by yellow dot lines indicate the application of multiple weather years, which does not apply to any scenario in Figure 6(a).

Continuously growing power prices are reported in many studies. Most of the scenarios, except for the low-price scenarios, expect power prices after 2030 above 40 EUR/MWh, and the reported 2050 prices are at the 50–60 EUR/MWh levels. The modeled future prices fall roughly in the range of the prices in the past decade, between the lowest at 25 EUR/MWh in 2015 and the highest at 61 EUR/MWh in 2010. Denmark, which is closely connected to the continental market, generally has higher prices than the other Nordic countries. Nonetheless, the modeled future power prices show large uncertainties regardless of the scenario types. For example, differences in 2040 power prices found in two different studies within the reference group were as much as 35 EUR/MWh. It is worth mentioning that the modeled future prices should not be interpreted solely from the scenario definition, especially the additional scenarios that are not in the main clusters. The modeled prices are results of mixed factors.

In our sample, outlooks using a stochastic approach of multiple weather years show smaller price differences between the years than outlooks using a deterministic approach. One explanation is that the stochastic approaches implicitly assume close to normal weather conditions since they use multiple weather years and normally report the mean values of the simulated years. Apart from this, no obvious distinct pattern from differences in modeling methodology is observed, indicating that the choice of input data assumptions has more profound impact on power prices than the choice of model. Nevertheless, the choice of model may be of larger importance when focusing on price volatility, but this is beyond the scope of this review due to insufficient data.

More high-price hours and more low-price hours are expected with increasing VRE shares. Price variation is expressed in various forms across the outlooks, for example in duration curves by Dansk Energi and Statnett, in chronological price curves over a certain period by Energimarknadsinspektionen and NVE, or in bar charts showing differences between the maximum and minimum prices over a certain period by Svenska Kraftnät. Outlooks from Energinet and Energimyndigheten do not disclose quantified information of price variation. Price variation is important to assess the profitability of VRE and flexibility solutions (Hirth, 2013). The review shows that there is no standard format to disclose such information, but an overall tendency of greater variation is agreed.

Great price variation reflects the need for flexibility. Although no particular flexibility option is relied on heavily in the reviewed scenarios, a common approach is to include supplementary scenarios to illustrate the impact of certain flexibility options. For example, the impact of consumption flexibility and storage is investigated by IEA (2016), NVE (Amundsen et al., 2017; Gogia et al., 2019), and Svenska Kraftnät (Brunge et al., 2019), and a common finding is that consumption flexibility and storage can increase low prices and lower peak prices.

5 | RECOMMENDATIONS FOR OUTLOOK PUBLICATIONS

Power market outlook studies provide substantial value to medium-term and long-term decision-making in the energy sector. Meanwhile, publishers of outlook studies have significant influence, as the information that they provide can shape the future by how decision makers and power companies use this information. Based on this review experience of the 15 recent Nordic power market outlooks, we propose the following recommendations for future publications to provide more value to their readers.

5.1 | Best efforts should be done to ensure the clarity and transparency

The credibility of an outlook study improves when the methodology is transparent, and quantitative and qualitative assumptions are readily available. The importance of transparency has been addressed with a growing number of available quantitative analyses (Morrison, 2018). During the review process, we still at times find incomplete public information, such as in methodology, parameter definitions and references. Many factors can cause model output disagreements, which can lead to misinterpretation or misuse if a report is not clearly understood or correctly communicated. It is understandable for outlooks to focus on the aspects that are important to them in order to convey clear messages. One solution is to provide supplementary files containing more complete methodological details, input assumptions and output results. It increases the credibility when the analysis can be validated or replicated and can spark more discussions. There are also projects such as Open Energy Outlook (2016) aiming to enhance the value of energy modeling and its application in informing future policy efforts by putting the entire model with data in open source, with detailed documentation. Another example is the Open Energy Modeling Initiative (Openmod, n.d.), which is a community of modelers to promote open models and open data through discussion forum, workshops, and other activities. Besides increasing the credibility, more openness in energy modeling and data assumptions would benefit the energy modeling community as a whole.

5.2 | More attention to total electricity consumption is needed to capture the complex dynamics of energy efficiency, sector coupling, and new electricity-intensive industries

Compared to the production side, the reviewed outlooks take rather simplified approaches and write less about the electricity consumption side. The simplest approach is to assume a fixed consumption level, justified by assumptions about efficiency improvement and growing economy and population. Another common approach is to apply external references for determination of exogenously given consumption levels.

With more ambitious and broader emission reduction targets, assessments of electricity consumption development should be extended beyond changes in energy efficiency, demography, and the wider economy. Electrification and sector coupling are regarded as important aspects in the energy transition because they improve efficiency, flexibility, reliability, and adequacy of energy systems (Van Nuffel et al., 2018). With their increasing importance, future outlook publications should put more emphasis on these topics, and the models used to inform about the future energy system should to a larger degree reflect this expectation. Radical technological transformation must happen for net-zero transitions (IEA, 2020), and solutions such as electrification and hydrogen will have strong impact on final electricity demand. In addition, the emergence of new electricity-intensive industries such as data centers and battery factories in the Northern Europe will also stimulate electricity demand. Outlook publishers are advised to take these emerging driving forces of total electricity consumption into account in future publications.

5.3 | Underlying uncertainties must be highlighted and uncertainty techniques besides scenarios analysis can be applied

The large variation in assumptions related to the main power market drivers identified in this review is noteworthy because it indicates a large underlying future market development uncertainty. It is not necessarily a weakness that there is little consensus in the input data assumptions for, for example, fuel and carbon prices; however, it suggests that outlook studies should explicitly address the major market driver uncertainties and their impacts on power prices. An example of a good practice is the outlook SK (2019), where the procedure to set fuel and carbon price assumptions is explained and comparison with other studies is shown. We also encourage publishers to broaden their techniques to address uncertainties. Besides multiple weather years for stochastic hydropower modeling, scenario analysis is the only technique used in the reviewed outlooks for uncertainty analysis. Other uncertainty techniques, such as Monte–Carlo analysis, models to generate alternatives, and other approaches as mentioned by Yue et al. (2018), are yet to be applied in such analysis.

5.4 | Challenges related to sustainability and limitations of certain technologies arising from social oppositions should be explicitly addressed

The energy or the electricity sector is relevant for several of the Sustainable Development Goals proposed by the United Nation (SDSN, Columbia Center on Sustainable Investment, Business and Human Rights Resource Centre,, & Equitable Origin, 2019). The Nordic countries have performed well and are among the countries that scored the highest in the 2020 Europe Sustainable Development Report (SDSN & IEEP, 2020). Still, conflicts between renewable energy production and other sustainability goals, like preservation of eco-system functionality and biodiversity, will likely increase as the renewable shares increase. These conflicts are likely to affect the energy transition to an increasing extent. The energy mix may shift from the pure cost optimal solutions (i.e., from a narrow economic perspective) to more costly ones with less environmental footprints, which can also affect energy consumption in the long run. Based on the review studies, we conclude that the impacts of trade-offs between climate friendly energy production and other sustainability criteria should be discussed more explicitly in long-term outlook studies.

As discussed in the earlier sections, increasing social oppositions against certain technologies, such as onshore wind turbines and power transmission lines, are observed. Although the lack of social acceptance might have been embedded in the technology deployment assumptions, we recommend these challenges to be explicitly addressed. They are usually location-specific and culture-specific, and understanding specific difficulties is helpful for improving the presentation of such technologies in energy system models, especially when done transparently.

5.5 | Price volatility, technologies' market values, and sensitive parameters to power prices can be included for better interpretation

Future outlooks should also include parameters receiving increasing attention, such as short-term price volatility or the market values of different power generation technologies (Hirth, 2015). In this review, we focus on the annual power prices, partly because of the limitation of extracting data from charts in reviewed outlooks and partly because not all reviewed outlooks provide price volatility, but only annual averages. We believe that disclosing such information will attract and benefit more readers.

Helistö et al. (2017) use an analytical approach with the Balmorel model to explore the sensitivity of Northern European electricity prices. They compare how the average price and duration curves change under various given wind and solar shares, and their conclusions emphasize the importance of the whole supply and demand structure, such as the capacity mix and capacity margin. The initial goal of this review was to summarize drivers and uncertainties in the Nordic future power prices through reviewing the available market outlooks, but the scope was limited by the material. Each publisher uses different details of reporting and focus, which can also change by year. As a result, a literature review is less flexible about the choice of price drivers to review across the outlook studies. Factors that are neither disclosed nor focused by most of the studies are difficult to analyze. For example, while Swedish wind capacity can be found in five outlooks, the Swedish total generation capacity is revealed in only two outlooks. Maximum load assumptions are disclosed in only two reports from Energinet (the Danish TSO) out of 15 outlooks. It is beneficial to the interpretation of the power prices, if more sensitive drivers, such as capacity mix and capacity margin, are explicitly reported.

5.6 | In the phase of energy transition, the ability of a market outlook to provide the newest insights is highly appreciated

Outlook publications with frequent and regular updates are valuable during the time of energy transition, when studies can be outdated rather quickly. Taking the WEOs from the IEA, which are popular references in the energy sector, as an example, annual updates are released. Two update directions are observed: the design of the scenarios, and the future prices calibrated by the recent price development (Figure 7). We find a similar behavior in the reviewed outlooks,

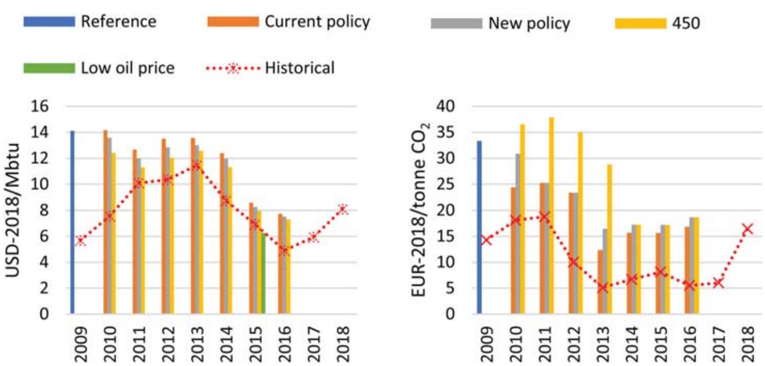

FIGURE 7 Natural gas prices (left) and emission quota prices in the EU ETS (right) in 2020 from IEA WEO released between 2009 and 2016, and the historical annual prices in the released year

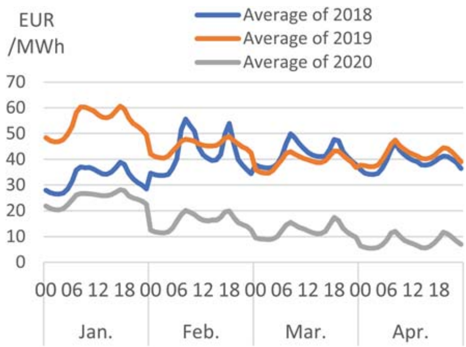

FIGURE 8 Nord Pool electricity spot market hourly price by month, average of all Nordic countries from week 1 to week 17 in 2018, 2019, and 2020

that newer publications have higher gas and emission quota prices, greater wind capacities, and more attention to electrification in general, following the price development and renewable deployment since 2016.

It is important to distinguish between the temporal drivers and the long-term impact of technology developments, policy priorities, and climate change, that are far more relevant in long-term analysis. For example, the influence of major policy announcements, such as EU Green Deal, is likely to sustain for decades. The impact of a single extreme weather event might not last, but new climate norms will have to be considered in long-term analyses. In early 2020, the world was hit strongly by the Covid-19 pandemic. Economic activities were interrupted globally, leading to minimum energy demand. For the first time in history, the US oil benchmark price turned negative in April 2020. Since February 2020, the Nord Pool spot market price has been around 60%–80% lower compared to the same period in the past 2 years (see Figure 8), as a result of reduced demand, low fuel prices, and mild weather. At the study completion, it remains unclear whether Covid-19 will create a new benchmark in the energy sector. Ad-hoc analysis in response to the impact of unexpected events will be helpful for timely decision-making. Long-term market studies should stay critical in the assessments of whether the influence of an event is only temporal or likely to last for decades.

The review includes outlooks from eight different publishers. Two (Dansk Energi and Energinet) out of eight update their reports annually, and three (Energimyndigheten, NVE, and Statnett) have biannual updates. They adjust the assumptions and, sometimes, the scenario setup or report scopes to bring out the latest insights regarding technological development as well as policy means and targets. In light of the energy transition, outlooks should ideally have frequent updates to reflect the latest economic trends, policies, and long-term effects of major events to provide prompt information.

6 | CONCLUSIONS

This study reviews 43 scenarios in 15 recent Nordic power market outlooks with a particular emphasis on assumptions for major market drivers and their impacts on the modeled power prices. The review reveals expectations of growing trends of future power prices towards 2050, which are highly correlated with the gas and emission quota input assumptions. The assumptions for gas and carbon prices towards 2050 show profound uncertainty. The reported future power prices are found well above the LCOE of onshore wind power, which suggests that the assumed onshore wind deployment is restricted by factors beyond the economic potentials.

The demand side development is found less focused in our review, and most scenarios assume constant or slight increases in electricity consumption towards 2050. As a result of limited modeling scope, dynamics between electricity and other sectors are often simplified. Some of the outlooks expand the scope to include the heating sector, with computational tradeoffs, such as temporal granularity.

A set of recommendations for future outlook publications are proposed. Clarity and transparency are among the most important criteria. With increasing importance of sector coupling and electrification, more attention should be paid to electricity consumption development. Underlying uncertainties in the long-term market development must be highlighted, and uncertainty techniques beyond scenario analysis can be applied to a larger extent than today. Assessments of emerging environmental and social challenges are also valuable. With higher VRE share, information such as price volatility becomes essential in addition to the average prices. Lastly, new data and new information are formed constantly in this phase of transition, and the ability to include new data and information that affect the long-term development of the energy markets are highly appreciated. This review hopes to contribute to more credible and informative future power market outlook publications.

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CONFLICT OF INTEREST

The authors have declared no conflicts of interest for this article.

AUTHOR CONTRIBUTIONS

Yi-kuang Chen: Conceptualization; data curation; formal analysis; investigation; methodology; project administration; resources; validation; visualization; writing-original draft; writing-review & editing. **Anne Hexeberg:** Conceptualization; data curation; formal analysis; investigation; methodology; resources; validation; visualization; writing-original draft; writing-review & editing. **Knut Einar Rosendahl:** Formal analysis; investigation; methodology; resources; supervision; validation; visualization; writing-original draft; writing-review & editing. **Torjus Bolkesjø:** Conceptualization; formal analysis; funding acquisition; investigation; methodology; project administration; resources; supervision; validation; visualization; writing-original draft; writing-review & editing.

DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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ENDNOTE

[1] Iceland is excluded in the Nordic scope because it has an independent energy system.

RELATED WIREs ARTICLE

Energy scenarios: The value and limits of scenario analysis

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APPENDIX

DESCRIPTION OF THE REVIEWED OUTLOOKS

The following section includes short descriptions of the reviewed outlooks by publisher as a quick guide to the reviewed material.

Dansk Energi

Dansk Energi is a non-commercial lobby organization for Danish energy companies. They publish midterm electricity market outlooks annually to show electricity wholesale prices in Denmark and Northwestern Europe in possible future scenarios. This review includes the publications from 2016 to 2019. They are composed of similar structures including historical price developments, recent status, market scenarios for 2020–2035, and earnings of various producers. The

2016 and 2017 publications contain more details on methodologies, assumptions and results. The 2018 and 2019 publications contain much limited information and further data are only available to the members upon request. The scenario formations in outlooks until 2018 depend mainly on fuel and emission quota price assumptions, and the 2019 outlook formulates its main scenarios by the degree of the emission reduction commitment. Both the 2018 and 2019 outlooks develop several sensitivity scenarios from the main ones by varying technology investment costs or changing technology investment options, but they are excluded in this review because of the limited results that can be found in the public reports.

The analyses are based on the energy system model Balmorel with no-foresight investment. It assumes spot market only, and the modeling of the Nord Pool price ceiling (3000 EUR/MWh) is included. In the 2016–2018 outlooks, future transmission and most generation capacities are given exogenously in the reviewed scenarios, and the following technologies (gas turbines, gas cogenerations, coal cogenerations in Germany and Netherlands, wood pellet cogenerations, offshore wind, large scale solar PV, and woodchips CHP, biomass boilers and heat pumps in Denmark) can be invested if economically attractive. The 2019 outlook includes onshore wind, transmission (Blå and Grøn scenarios), batteries (Blå and Grøn scenarios), and long-term storage (Grøn scenario) investment possibilities.

Energinet

Energinet is an independent public enterprise owned by the Danish Ministry of Climate and Energy. They prepare annual documents and associated spreadsheets describing the assumptions used in internal analyses. This review takes the assumption reports released in 2016 and 2017. The newer versions do not include power prices and, thus, are excluded in this review scope. The reports are structured with chapters describing assumptions of economic growth, fuel, quota and energy prices, energy consumptions, generation facilities, international connections, gas sector development, and so on by 2040, and the reasonings behind. The 2017 report reveals that the assumptions of larger plant future capacities are set through dialogues with stakeholders and industry players, and that of small plants like PV, EV, and heat pumps apply general S-curve approach.

Two models are used to calculate electricity price projections on the basis of the analysis assumptions from 2020 to 2040. At first, the Energinet's BID model calculates the expected prices by simulating the North European electricity system in hourly resolution, taking start-up and shut-down costs into account. The resulting prices of the neighboring countries around Denmark are sent to the inhouse model SIFRE, which simulates the Danish electricity and heating system in hourly resolution and calculates the Danish spot prices. Although both models simulate hours prices, only annual average prices are shown in the Energinet's assumption reports.

Energimarknadsinspektionen

Energimarknadsinspektionen (Ei, the Swedish Energy Markets Inspectorate) is an authority which supervises the Swedish electricity, district heating and natural gas markets. The reviewed report was commissioned by the government to investigate the effects of increased variable electricity production share on prices. The report describes the historical and current Swedish electricity trading system, methodology, assumptions and scenarios, results of prices, profitability and investment incentives. The study horizon covers 2020 and 2030. The quantitative analysis is carried out by the electricity market model Apollo, which simulates the day-ahead market and covers European countries and the surrounding regions. Apollo simulates wholesale prices by minimizing the electricity production costs with given consumption, generation and transmission capacities, inflows, fuel and quota prices, and weather-dependent productions. The electricity demand is partly elastic that the consumption reduces if the price exceeds 200 EUR/MWh. The generation and transmission capacities follow nation's development plans. Three scenarios are analyzed, two with various fuel prices and one with nuclear phase-out.

Energimyndigheten

Energimyndigheten (the Swedish Energy Agency) works on behalf of the government and develops long-term energy system scenarios as a part of the basis for biannually climate reporting to the European Commission. This review covers the reports released in 2017 and 2019. It is stated that purpose of the reports is not to forecast but to show the uncertainties and how they affect outcomes. In accordance with the requirements of climate reporting, one reference scenario, one scenario with higher and one with lower CO_2 emissions are analyzed to estimate emission levels. In addition, the 2017 version includes two supply side scenarios and three transport sector scenarios, and the 2019 version includes three additional scenarios focusing on demand side. Note that only the scenarios showing electricity prices are reviewed in this study. The reports cover the whole Swedish energy sector, and the sectoral results are discussed by chapter.

TIMES-NORDIC is the model used by the Swedish Energy Agency for the analysis. It includes the Nordic and Baltic countries, Germany and Poland. The time horizon covers every 5 years until 2050 and a year is divided into 12 timesteps, consisting of four seasons and three times slots in each season. Besides existing capacities, the model can invest in new generation capacities, subject to potential constraints when applicable. For example, hydropower potential is very limited, and Swedish onshore wind has 100 TWh expansion potential. The transport sector is not modeled, but its electricity demand is an input to TIMES-NORDIC model. The reports show only the Swedish annual average electricity prices, defined by the marginal costs of electricity production, and the electricity prices are also used in sectorial analysis.

Svenska Kraftnät

Svenska Kraftnät is the authority responsible for Swedish transmission system. They publish their long-term market analysis every 2 years, but this review covers only the 2019 version, as the earlier ones are not available on their website. The analysis comes with an excel file containing the Swedish data including sectoral demand, generation and transmission capacities, fuel and emission quota prices.

The analysis is performed with two models, BID3 and EMPS. The simulation has hourly resolution and 31 weather years are taken into account. The reference scenario, representing the best estimate from 2020 to 2040, is based on the sustainable transition scenario in TYNDP 2018 and the generation capacities are given assumptions. Two complementary scenarios, high and low, are drawn in 2040 to mark the uncertainty space between business as usual and electricity being the primary energy carrier. In the complementary scenarios, the BID3 model seeks an optimal production mix, subject to maximum 20% capacity expansion of different types or power generation per country from the reference scenario. The report also analyzes the price volatilities, adequacy and stability of the Swedish power grids under various weather conditions or grid availability.

Norges Vassdrags-og Energidirektorat

Norges Vassdrags-og Energidirektorat (NVE, the Norwegian Water Resources and Energy Directorate) is an administrator managing Norway's water and energy resources. They publish annual power market analysis describing the Nordic power market development, and this review includes the 2017 and 2019 versions. The 2017 report covers until 2030 and the 2019 report covers until 2040.

NVE uses three optimization models. Firstly, TIMES model projects the Norwegian consumption of all energy carriers and the electricity demand is used in the other models. Secondly, The-MA model calculates power markets in the 19 European countries and finally, Samnett model with a Nordic focus calculates the Nordic prices taking 30 weather years and grid restrictions into account. The generation capacities are given assumptions. In addition to a base scenario, one high scenario and one low scenario draw the uncertainty space in fuel and emission quota assumptions. Norwegian price variations are further discussed under various conditions such as weather, international transmissions, and flexible demands.

Statnett

Statnett is the Norwegian power system operator and they publish the long-term market analysis every 2 years that covers the main trends, uncertainties and the most likely development in the power system. This review includes the 2016 and 2018 versions and they both cover the time horizon until 2040.

There are two main tools used for the analyses with given generation capacity and demand assumptions. The power market model BID covers 19 European countries with hourly resolution and generates power prices in the neighboring countries to be used in the second model Samnett. Samnett covers Nordics and Baltics and has detailed modeling of hydropower and transmission system. It is stated in the 2016 version that up to 50 historical weather years are simulated, while the 2018 version uses 29 weather years. Similar to the NVE's analyses, a base scenario plus one high and one low scenario marking the power price outcome space caused by uncertainties in input price assumptions.

Nordic Energy Technology Perspective (NETP)

Unlike the other reports included in this review that are published by one institute, the NETP is a collaborative work between the International Energy Agency and several Nordic research institutions. It provides a case study on how Nordics go beyond the 2°C target. The report consists of three chapters. The first chapter focuses on the whole energy sector in the Nordic countries and the decarbonization pathways. The second chapter focus solely on urban areas. This review focuses on chapter 3 where electricity system integration in the carbon neutral scenario is analyzed. Balmorel is the main tool for the analysis and it is coupled with the ETP-TIMES global model used in the first chapter. Same fuel and emission quota price assumptions used by ETP-TIMES and its electricity and district heat demand outputs are applied to Balmorel. Several iterations are done to harmonize both models. The time horizon covers until 2050 and a year is represented by 72 hours. Balmorel models generation capacity expansion and transmission investments after 2030 with myopic foresight.

Paper II

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Impact of fossil-free decentralized heating on northern European renewable energy deployment and the power system

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Balmorel

ABSTRACT

Complying with ambitious EU climate targets, decarbonization pathways for space heat and hot water, in addition to the centralized energy generation sector, are analyzed using the open energy modeling framework, Balmorel. Hybrid systems and simplified consumer preferences are incorporated in the investment choices for decentralized heat. Five scenarios are analyzed: three with varying heat demand developments by 2050, one acknowledging the presence of carbon-neutral gas, and one covering only power and centralized heat sectors for comparison. All scenarios must comply with the EU emission targets in both the Emission Trading System (ETS) and non-ETS sectors by 2030, followed by a linear reduction towards zero fossil CO_2 emissions by 2050. The optimization model reveals that the most cost-effective solution is electrification, which requires substantial investment in wind energy infrastructure. In the case of constant decentralized heat demand, the electricity demand will increase by one-third from the current level, consequently quintupling the installed wind capacity. Heat demand seasonality causes challenges leading to extreme high and low seasonal prices, and substantial curtailment in summer. Impacts on the power system have been underestimated because decarbonizing decentralized heat has not been considered. The results also imply a more important role for system integration.

1. Introduction

1.1. EU climate targets and the heating sector

Heating and cooling account for approximately 50% of the final energy demand in the European Union (EU), and about 75% of this energy is still generated from fossil fuels [1]. Rapid and deep decarbonization of the heating and cooling sector is among the main challenges in reaching the EU climate objectives for 2030 and 2050 [2]. Europe is on track to meet its 2020 targets, but further efforts are required in the next decade [3]. Emissions from different sources have followed different trends: sectors in the EU Emission Trading System (ETS) show sharper reductions than those covered by the Effort Sharing Regulation (ESR) (or Effort Sharing Decision, ESD, before 2020). European Environment Agency projects that the building sector is expected to contribute the most to the decrease in ESR in the next decade, through energy savings and renewable energy integration [3]. Nevertheless, it is a challenging task to reduce emissions in the building sector, considering that these annual emissions have increased from 2014 to 2016 by 8% and maintained a steady level [4]. Heating has the largest annual and peak demand among electricity, heating and cooling in many European countries [5], while its future trend has been challenging to assess and heavily influenced by multiple drivers [6]. Both increasing [7] and decreasing [7,8] trends have been projected and only the conclusion that the heating sector cannot be neglected in decarbonization debates remains undoubtably true.

1.2. Decarbonizing the end-use heat

Decarbonized heat leaves few options, including solar, biomass, clean gas and electricity (from renewable sources). Each option has its strengths and limitations, partly depending on whether it is used in centralized (typically district heating) or decentralized (also referred as individual) heating systems. Solar heat production in

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Northern Europe is limited in winter and has a major disadvantage of mismatch with heat demand. Using the area for PV panels instead of solar thermal collectors to generate electricity, which is a more valuable form of energy, is a better approach [9]. Biomass plays an important role in a climate-friendly future because of its broad applications, which implies the emergence of competition between heat generation and other biomass applications, such as transport or packaging [10,11]. Sustainable biomass supply is, however, limited and there are controversies around land-use and emission impacts for some biomass types [10,12]. Producing clean gas through power-to-gas (PtG) or CO_2 capture from natural gas represents an alternative pathway that utilizes in part the existing gas infrastructure to an extent. It enables the potential of substituting natural gas with clean gas, but costs are still high [13] and the accessibility of clean gas is limited by gas grids. Renewable electricity used in district heating may offer economically viable and flexible solutions [14] in addition to decarbonized heat, but challenges lie in sometimes unpopular expansions of power distribution and district heat grids. Social acceptability is another potential barrier for electrification and renewable energy development, leading to additional costs or changes in policies [15]. In short, as suggested in Ref. [7], heat decarbonization requires a bundle of strategies rather than a single solution.

Heating in Northern Europe is supplied through centralized and decentralized systems and few studies have attempted to address both. A model extension of the energy system framework TIMES for decentralized heat was developed in Refs. [16] and applied in Ref. [17]. It was concluded that reaching the German climate targets for residential heating requires deep insulation measures and a shift towards the use of heat pumps and solar thermal systems. Another example [18] adapted an iterative approach between the electricity and the heat system, symbolizing independent decision-making in the heating sector. The approach revealed a larger scale of heat electrification than a centralized approach in a high carbon price scenario. Nevertheless, such studies are limited to a local or national scale and the coverage and details of other sectors are often compromised [19].

1.3. System level implication

Energy system literature has focused less on heating than on electricity even though the demand for energy for heating purposes is larger than that for electricity. For example, Ref. [19] reviewed decentralized energy system modeling studies and found only 24% of the reviewed studies considered heating demand, while all covered electricity. Ref. [20] reviewed studies on 100% renewable energy systems and found that more than half of the reviewed studies considered only the electricity sector, but less than 35% covered the heating sector.

Low-carbon research combining the heat and electricity sectors becomes essential when power-to-heat (PtH) is repeatedly brought up [7,9,17,18,21–23]. The relevant technologies are already available and a dedicated review by Bloess, Schill and Zerrahn [24] affirms the contribution of P2H to emission reduction and renewable energy integration. Nevertheless, the power market implication is not the research focus of most studies reviewed, and only 2 [14,25] out of the 46 reviewed studies considered power prices and electricity demand simultaneously as primary or secondary considerations. Most of the studies are conducted at a national or city level, and almost half do not consider both the centralized and the decentralized heating sectors. While international dynamics might not be traditionally relevant in the context of heat markets alone, their importance increases when PtH is involved in shared power markets. A technical report published by the European Commission Joint Research Centre examined the effects of EU power and heat sector integration by simulating two pathways of heat sector transition: electrification and centralized cogeneration [26]. The report finds a substantial increase in winter peak demand, especially in Germany, France, and Poland, and potential power capacity inadequacy in the electrification pathway. Nevertheless, the study uses a dispatch model without considering subsequent capacity expansion. From the above discussions, we can identify the absence of literature on the impacts of end-use heat decarbonization on a 100% renewable power system over a large geographical area. This topic is highly relevant in Northern Europe, where potential impacts are prominent, and where the power markets are interconnected.

1.4. Research objectives and contributions

This study contributes to the literature on the topic of decarbonization by answering the following questions:

- What are the most cost-effective approaches for decarbonization of the heat and power sectors in Northern Europe?
- What is the consequential need for renewable deployment?
- What are the likely implications of decarbonization for the power system?

A methodological contribution of this work is an extended heat market module in the open model framework Balmorel, where the variabilities in renewable supply and energy demand are captured. In addition to the classic approach of system cost minimization, the heat module also takes decentralized characteristics and hybrid heating solutions into account. It enables realistic system-level assessments of the simultaneous decarbonization of the heat and power sectors between now and 2050. The subject is especially important for integrated Northern European power markets, which have a significant heat demand. The scope covers electricity, residential and tertiary space and water heating, as well as electric vehicles. To the best of our knowledge, there are no studies with the same international scope and details. This study reveals the importance of decentralized heat in a decarbonized energy system.

2. Methodology

2.1. Model overview

Balmorel, an open source energy system framework written in the GAMS language [27], was used for the analysis. The basic version models electricity and district heat sectors using partial equilibriums describing physical, technological, and regulatory constraints of energy flows and the conversion processes. Fig. 1 illustrates the classic Balmorel model structure and the extended system boundary covered in this study. The model applied in this study considers potential technology investments in addition to planned commission and decommission capacities to achieve the least cost solutions. Each country is further divided into regions, where electricity demands are defined, and areas, where district heat demands are defined. Electricity transmission is allowed between regions subject to the transmission capacities, while district heat supplies must meet the demand of the same area. The electricity sector and district heat sector are coupled through combined heat and power (CHP) plants and PtH technologies.

Time series data, such as wind and solar generation and demand profiles, are given at hourly resolution and then aggregated to reduce the computation load. The demand profile aggregation maintains the original maximum, minimum, and mean values within each aggregated period, while the weighted average values over each aggregated period are used for other parameters. The

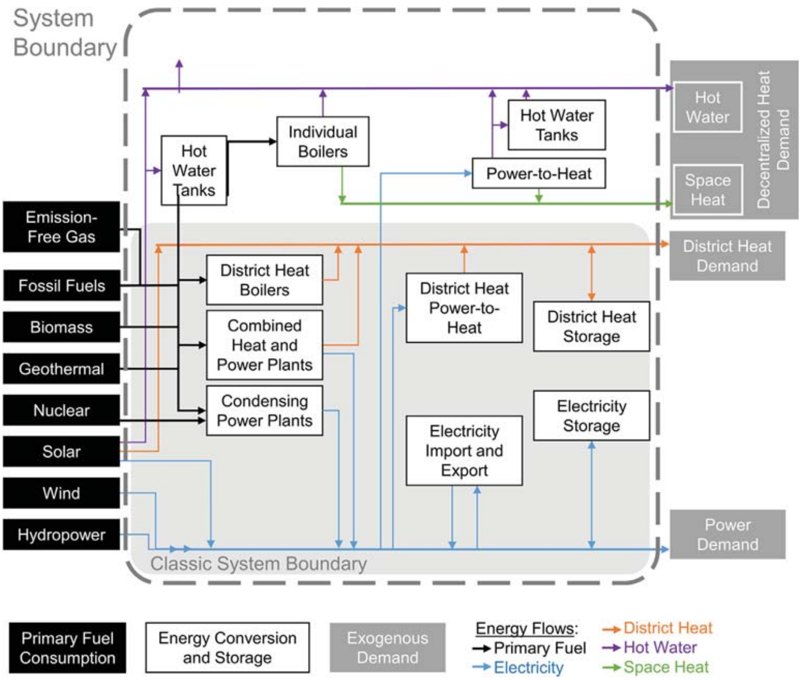


Fig. 1. Illustration of the structure of the energy system model that was adapted from Ref. [27] and modified to fit the current study.

optimization is made with perfect knowledge of the model year but no foresight beyond.

The following sections describe the most important approaches and assumptions, and the complete code and data are available on GitHub [28,29]. This model version is based on previous projects, including Flex4RES [30] and FutureGas [31,32]. In addition to the traditional components in power and district heat sectors, flexibility options including electric vehicles in the private transport sector with smart charging schemes and simplified demand response are applied. The amount of electricity that is responsive to power prices is limited by the technology adoption rates. Although some demand response technologies are used for heat load shifting, this study assumes that the adoption rates of demand response technologies are independent of heating system development. Fuel and electricity taxes and grid tariffs are accounted for in the cost minimization function, assuming the existing schemes apply throughout the modeling horizon.

2.2. Modeling of the decentralized heat sector

Decentralized heat in this study consists of space heat and domestic hot water, which are not provided by district heating networks. Decentralized heat for industrial use is not within the modeling scope, as it often requires high temperature levels. Each service has its own demand profile. The study applied a top-down modeling approach with moderate resolution as a compromise to preserve details while maintaining a reasonable model size. Within each model region, two additional decentralized heating areas, residential and commercial, are defined. Further details on the building level are omitted. All decentralized heating areas have non-interchangeable demand for space heat and hot water. Fig. 1 illustrates the relationships between the decentralized heat and centralized energy sectors.

The model provides defined sets of heating systems, called decentralized heating groups. Each decentralized heating group represents the aggregation of buildings with the same type of heating system. A decentralized heating group must be able to provide both space heat and domestic hot water from one or more heating technologies. This allows for the installation of hybrid heating systems, which benefit the energy transition [33]. The loading and unloading of hot water storage tanks are modeled explicitly with systems heated by electricity or solar energy to provide operational flexibility. Hot water tanks in other systems are only included in costs.

Unlike central power and heat generation plants, cost-effective options are not always embraced by consumers [34], who might tend to stay with a more familiar technology or avoid technologies involving building reconstruction. Two parameters mimicking willingness to shift are thus introduced: one for moving from one technology group to another, and the other for moving from a water-borne system to a non-water-borne system or vice versa.

3. Data, assumptions, and scenario design

3.1. Spatial and temporal scope

The geographic scope covered the Nordic countries (excluding Iceland), the Baltics, and the surrounding countries (Belgium, France, Germany, the Netherlands, Poland, and the UK). Nordic countries contained regions aligned with the Nord Pool spot market areas [35], Germany also contained four regions, representing congestion challenges, and the other countries contained one

Table 1
Examples of the gas and wood pellet price assumptions in various sectors applied in this study. Unit: EUR/GJ.

Fuel	Sector	2020	2030	2040	2050
Natural gas	Centralized plants	4.6	5.7	6.3	6.3
	Decentralized residential users in DK	5.6	7.0	7.7	7.7
	Decentralized residential users in UK	9.3	10.6	11.3	11.3
	Decentralized commercial users in DK	4.8	6.2	6.8	6.8
	Decentralized commercial users in UK	5.4	6.8	7.4	7.4
Wood pellets	Centralized plants	8.8	10.9	12.7	13.3
	Decentralized users in DK	11.7	13.7	15.6	16.1
	Decentralized users in UK	16.8	18.9	20.7	21.3
Clean gas (imported)	All	17.9	16.5	16.5	15.5
Clean gas (local)	All	48.3	39.7	34.1	28.4

region each. The time horizon in this study covered every decade from 2020 to 2050. The time steps in a year were reduced to 8 weeks (2 weeks in each season), with 24 2-h intervals (12 intervals representing a weekday and 12 intervals representing a weekend) in each week.

3.2. Fuel prices

The fuel prices were based on the assumptions in Ref. [36], while coal and gas price updates were obtained from the New Policy Scenario in Ref. [37] and nuclear price updates were obtained from TYNDP [38]. For the price of imported clean gas in this study, the price of synthetic gas from North Africa or Middle East PV, which is more price competitive compared to other sources [39], was applied. Country-dependent “premium charges” were added to natural gas, oil, and wood pellets used in decentralized heating, symbolizing the differences between the import and retail prices. Generally, the costs incurred by centralized energy generation plants were lower than those incurred by residential users. Table 1 illustrates some fuel price examples in different sectors and countries.

3.3. Renewable potential

Energy supplies will rely on renewables and nuclear, once fossil fuels are excluded. However, the availability of renewables is more geographically restricted and directly affects energy system decarbonization. In this study, we take different approaches to address the potential and availability issues depending on the type of renewable energy sources, i.e., solar, wind, and biomass. Hydropower capacity expansion is not one of the investment options because it is strictly environmentally regulated and most available sites are already developed in Northern Europe. Thus, hydropower potential is not discussed here.

3.3.1. Wind and solar

Installed wind and solar capacities are restricted by the technology type, terrain, land cover, distance to settlement or protected area, weather conditions, and more. In this study, we applied upper limits to installed capacities of onshore and offshore wind turbines, and solar PV panels in each modeled region. For the wind capacity limitations, we referred to the reference scenario in Refs. [40,41] and for the rooftop PV capacity limitations we referred to Ref. [42]. To reflect the potential unavailability of the best locations for wind triune installation owing to increasing social opposition, three resource levels, with equally distributed capacity potentials, were assigned in each region: one with standard full load hours (FLH) and two with ±20% of the standard FLH. Onshore wind turbines with the best resource level (120% of the standard FLH) were first installed until the one-third capacity potential was utilized. Then, the standard FLH was applied until the two-third potential was used, followed by the 80% standard FLH for the last third of the potential. The wind FLH assumptions depended on the installation year of the turbines, and they increased for the turbines installed in later years to reflect that future wind turbines relying on advanced technology may harvest more energy. As solar PV technologies are relatively mature, no obvious increase in FLH was assumed. Table 2 lists the assumptions of standard FLH and the maximum installed capacity of wind and solar PV by country.

3.3.2. Biomass

We applied country-dependent maximum annual fuel uses from local bioproducts, such as wastes, straw, and biogas. The availability of biomethane is subject to the availability of biogas and

Table 2
Assumptions of the wind and solar FLH and the installed capacity limits in the modeled countries.

Country	Full load hour, h					Installed capacity potential, GW		
	Solar PV	Onshore wind turbines		Offshore wind turbines		PV on buildings	Wind onshore	Wind offshore
		installed in 2020	installed in 2050	installed in 2020	installed in 2050			
Belgium	1010	2168	3177	3633	4434	12	18	2
Denmark	975	2403	3583	4021	4806	6	55	28
Estonia	999	2474	3140	2790	3920	1	27	1
Finland	900	2464	3583	3028	3961	5	31	21
France	1180	2168	3177	3633	4434	106	906	16
Germany	1083	2042	2405	3996	4460	95	144	28
Latvia	999	2559	3514	2915	3695	1	79	15
Lithuania	989	2255	2834	3385	4145	3	128	3
Netherlands	1000	2490	3262	3738	4434	18	49	48
Norway	899	2750	3585	3644	4353	5	28	12
Poland	1084	2295	2900	3363	4150	29	105	12
Sweden	996	2626	3663	3455	4322	7	138	31
UK	1099	2168	3177	3667	4572	40	230	104

straw. For woodchips and pellets that are commonly traded in international markets, we applied a stepwise cost function, assuming that every 25% change in volume increases the price by 12.5%.

3.4. Power transmission

The exiting AC transmission grids were modeled using the flow-based approach, and existing DC grids and new lines were modeled using the net-transfer-capacity approach [36]. Future capacities were consistent with the global climate action scenario in Ref. [43]. In addition, although national transmission between the regions could be expanded at a cost, it was assumed that no additional international transmission lines would be invested.

3.5. Decentralized heating systems

Table 3 lists the available heating technologies for decentralized users and heating groups in the model. The technology characteristic parameters are those of the technologies in a one-family house specified in the technology catalog published by the Danish Energy Agency (DEA) [44,45], which takes technology efficiency improvement into account. For simplicity, we assumed that all technologies could be installed in both residential and commercial areas. Air-to-air heat pumps (HPs) and wood stoves provide space heat only, solar heating and hot water storage tanks provide domestic hot water only, and the other technologies provide both heating services. Typically, the size of a water tank is determined by the heating system and the available space. According to DEA, the heat production capacity for an existing one-family unit ranges from 5 kW to 15 kW, and the storage capacity of a small-scale hot water tank is 2 kWh to 19 kWh. In this study, we assumed that the generation to storage capacity ratio in technology groups with a water tank was fixed at 4 kW to 1 kWh.

The coefficient of performance (COP) of an HP is calculated as the product of the Carnot efficiency (COP_{Carnot}) and the mechanical efficiency (η). The COP_{Carnot} is given by $T_H/(T_H\text{-}T_C)$, where T_H is the outlet and T_C is the inlet temperature in Kelvin. We assumed a fixed outlet temperature of 293 K (20 °C) for an air-to-air or 328 K (55 °C) for an air-to-water HP. The mechanical efficiency η is obtained by converting the stated COP in Ref. [44] with a standard inlet temperature of 280 K (7 °C). Finally, the actual COP at each hour is calculated as the mechanical efficiency multiplied by the Carnot efficiency, assuming the outdoor temperature as the inlet temperature, except for the air-to-air HP whose COP does not increase when the outdoor temperature is warmer than 10 °C to avoid unrealistic values. Table 4 lists the assumed mechanical efficiencies of the heat pumps in this study and the examples of actual COP calculated at various outdoor temperatures.

To the best of our knowledge, obtaining precise data on decentralized heating with the same level of detail for a large geographic region is challenging. In our approach, we used data assumptions from three main sources: Eurostat [46], national statistics [47–50] and Heat Roadmap Europe [51–53]. The starting point was the fuel consumption for heating obtained from EU and national statistics. Except for the derived heat, each fuel consumption was divided by the efficiency, assuming 100% for electricity, 90% for gas, 76% for solid fuels, 90% for oil and 80% for renewables and wastes, to obtain the decentralized heat demand and the fuel share. For countries without statistics in the commercial sector, residential and commercial final energy demand ratios found in Ref. [52] were applied. Each fuel was associated with one type of heating systems, and the share of installed heating system capacities were assumed to be the same as the above-mentioned fuel shares. The electricity used for heating was split into that used by HPs and electric boilers based on Ref. [54]. Note that the amount of electricity used in heating was excluded from the annual electricity demand to avoid double counting. Approximately 15% of the electricity demand was subtracted from the "net" electricity demand for decentralized heating purposes. Ideally, the seasonal differences in the net electricity demand profile should be less significant once the demand for heating is excluded, but the electricity demand profiles were not calibrated in this study, and the resulting peak electricity demands fell on the higher end. Table 5 lists the decentralized heat demand, the percentage used for hot water, and the ratio of electricity used for heating purposes by sector in each country. The decentralized heating demand profiles were derived using the method developed in Refs. [55]. The maximum heating loads were defined as the total installed heating capacities.

This study assumes that 20% of water-borne or non-water-borne systems can switch to the other type every decade because it involves a larger scale of system reconstruction, and that 30% can switch to a different type of heating group every decade. Nevertheless, fossil-fuel-based heating technologies are exceptions and coal and oil boilers are free to switch from 2030 and gas from 2040 to meet climate requirements.

Table 3
Technology groups included in the model. Note that the electric boiler option assumes also installation of electric radiators/panels, but for simplicity, this was not included in the model.

Sole suppliers	Combinations
Coal boiler	
Oil boiler	
Gas boiler	Gas boiler + air-to-water HP + water tank
	Gas boiler + solar heating + water tank
[a]Electric boiler + water tank	[a]Electric boiler + water tank + air-to-air HP
Air-to-water HP + water tank	
Biomass boiler	[a]Biomass boiler + wood stove
	Biomass boiler + solar heating + water tank

[a] A non-water-borne system.

Table 4
Assumptions for air-to-air and air-to-water heat pump efficiencies and COP values for outdoor temperatures of 0, 7, and 10 °C.

Type of heat pump	Investment year	Mechanical efficiency	COP at various temperature		
			0 °C	7 °C	10 °C
Air-to-air	Existing	22%	3.23	4.97	6.46
	2020	22%	3.30	5.07	6.59
	2030	23%	3.36	5.17	6.73
	2040	23%	3.43	5.28	6.86
	2050	24%	3.50	5.38	7.00
Air-to-water	Existing	51%	3.02	3.46	3.69
	2020	52%	3.12	3.58	3.81
	2030	55%	3.28	3.76	4.01
	2040	56%	3.36	3.85	4.10
	2050	58%	3.43	3.93	4.20

3.6. Climate targets

In this study, CO_2 caps that comply with EU climate targets were set. A total cap for power and district heat generation was set for all modeled countries, and national individual caps were set for decentralized heat generation. The same climate targets were set for all scenarios, and no emissions were allowed in 2050. Emissions from biomass were not restricted in this study.

3.6.1. Power and district heat sector

The centralized power and heat plants are covered by the EU

Table 5
Decentralized heat demand in TWh, the share of the demand for hot water usage, and the electricity demand used in heating in 2016 by sectors in the modeled countries.

Country	Decentralized heat demand, TWh	Hot water share	Decentralized heat demand, TWh	Hot water share	Electricity used for heating	
	Residential		Commercial		Residential	Commercial
Belgium	71.96	14%	27.83	9%	30%	3%
Denmark	20.70	18%	3.24	7%	13%	2%
Estonia	5.38	9%	1.47	5%	62%	1%
Finland	35.32	13%	10.81	25%	58%	14%
France	306.29	14%	106.60	19%	41%	3%
Germany	502.25	18%	185.45	9%	19%	8%
Latvia	5.60	21%	2.04	8%	24%	1%
Lithuania	6.55	9%	1.77	3%	11%	1%
Netherlands	79.64	20%	32.68	13%	9%	0%
Norway	22.83	29%	4.01	29%	41%	10%
Poland	115.78	17%	30.15	9%	12%	1%
Sweden	29.14	21%	5.12	21%	44%	11%
UK	384.13	22%	122.36	13%	23%	12%

ETS. The model scope covers only part of the ETS sector, so the approach is to use the 2020 emission level (with a quota price of 22 EUR/tCO_2) as a base. The official ETS sector targets are -21% in 2020 and -43% in 2030, with the 2005 levels as the baseline [56,57]. Assuming that both targets are achieved, 2030 emissions will be 72% of the 2020 level. Therefore, we applied a cap of -28% from 2020 to 2030, followed by a linear reduction towards zero CO_2 emissions in 2050.

3.6.2. Decentralized heat sector

Emissions from decentralized heating are not covered in the ETS. Emission cuts rely on country-specific emission targets and regulations [58,59]. Each member state proposes their emission reduction targets for 2020 and 2030, with the 2005 levels as the baseline, for the non-ETS sectors. Table 6 lists the targets and the applied CO_2 cap assumptions for 2020 and 2030. We applied the 2005 CO_2 emissions from fuel combustion in the residential and commercial or institutional sectors for each country found in Ref. [60] as baselines. Table 6 shows the 2020 and 2030 political targets and the absolute caps applied in the model (followed by a linear reduction towards zero CO_2 in 2050).

3.7. Scenarios

Three scenarios, HIGH, LOW, and DH, were set up with various assumptions for heat demand development. Efficiency improvement has been emphasized as one of the major decarbonization strategies, but the building retrofitting rates still show a moderate decrease. In this study, we considered various levels of decentralized heat development towards 2050, from staying constant in the HIGH scenario to decreasing overall by 37% in the LOW scenario. The HIGH scenario represented conservative technology development and no heat demand decrease, putting considerable pressure on decarbonization. The LOW scenario decrease ratio was derived by decreasing the space heat demand by the 2050 baseline scenario results in Ref. [51], which is aligned with the EU Reference Scenario 2016, while keeping the hot water demand constant. The district heat demand was independent of the decentralized heat sector in the model. In the HIGH scenario, the district heat demand assumptions followed Ref. [61], and in the LOW scenario, the demand in Western and Central Europe was modified with the baseline results in Ref. [51]. The third scenario, DH, represented heating system reconstruction with further energy savings and district heating expansion by applying the 2050 HRE scenario results in Ref. [51]. Table 7 summarizes the assumptions of heat demand development in each country by scenario. Electricity demand, excluding power to heat, was assumed as constant.

In addition, the CLEANGAS scenario enables emission-free gas from gas grids. One source of clean gas is local biomethane, which is cheaper but subject to the limited availability of biogas and straw. The other source is imported synthetic gas. The cost assumption refers to PtG from large PV farms in North Africa or the Middle East, which are from cheaper sources than from North and Baltic Sea offshore wind. The imported gas was assumed to be unlimited but more expensive than the local biomethane. The demand development in the HIGH scenario was applied to demonstrate a more stressed system. Finally, the NOIDVH scenario, as a comparison, models traditional power and district heat sectors and does not include a decentralized heat sector. It contains, nevertheless, the electricity demand currently used for heating. Table 8 summarizes the scenarios used in this study.

Table 6
Non-ETS emission reduction targets from 2015 in Effort Sharing Decisions and Regulations [58,59], and the CO_2 cap assumptions applied in the model for the decentralized heating sector. Note that Norway did not have a non-ETS target in 2020; the Swedish reduction target was applied instead.

Country	2020		2030	
	Target	CO_2 cap, Mt	Target	CO_2 cap, Mt
Belgium	-15%	23,056	-35%	17,631
Denmark	-20%	3974	-39%	3030
Estonia	11%	328	-13%	257
Finland	-16%	2681	-39%	1947
France	-14%	84,724	-37%	62,065
Germany	-14%	129,067	-38%	93,048
Latvia	17%	931	-6%	748
Lithuania	15%	1107	-9%	876
Netherlands	-16%	23,777	-36%	18,116
Norway	-17%	996	-40%	720
Poland	14%	47,935	-7%	39,105
Sweden	-17%	2340	-40%	1692
UK	-16%	88,912	-37%	66,684

4. Results and discussions

4.1. Fuel consumption

The modeled fuel consumption in the power and heating sectors decreases as a result of more efficient heating technologies. Nevertheless, the overall electricity demand increases because of the substantial increase in PtH use. In the HIGH scenario, where demand stays constant, the energy consumption is 38% less in 2050 compared to 2020 (Fig. 2). Energy sources change from fossil fuels and nuclear power to wind and electricity for heating. The amount of electricity needed to fully replace fossil-fueled heating reaches

Table 7
Heat demand assumptions and the shares of decentralized heat by country in 2020 and 2050.

Country	2020 (all scenarios)		2050 (HIGH)		2050 (LOW)		2050 (DH)	
	Total heat demand, TWh	Decentralized share	Total heat demand, TWh	Decentralized share	Total heat demand, TWh	Decentralized share	Total heat demand, TWh	Decentralized share
Belgium	107	93%	107	93%	107	88%	82	55%
Denmark	60	45%	56	48%	56	41%	49	40%
Estonia	12	59%	12	60%	12	47%	8	40%
Finland	123	35%	118	37%	118	21%	105	29%
France	438	94%	438	94%	438	94%	282	80%
Germany	825	86%	825	86%	825	77%	515	52%
Latvia	16	63%	17	62%	17	51%	11	44%
Lithuania	18	57%	15	64%	15	52%	10	45%
Netherlands	131	86%	131	86%	131	82%	103	43%
Norway	43	71%	39	78%	39	73%	31	72%
Poland	263	75%	295	67%	295	72%	145	58%
Sweden	122	27%	115	28%	115	23%	106	23%
UK	540	97%	540	97%	540	92%	426	61%

Table 8
Detailed information about the scenarios in this study.

Scenario	Detail	Heat demand development
HIGH	Includes decentralized heat decarbonization without great heat saving efforts.	See Table 7.
LOW	Includes decentralized heat decarbonization including heat saving efforts.	See Table 7.
DH	Includes decentralized heat decarbonization including heat saving efforts, and greater district heat expansion.	See Table 7.
CLEANGAS	Includes decentralized heat decarbonization with the presence of emission-free gas from grids.	Same as the HIGH scenario in Table 7.
NOIDVH	As a comparison excluding decentralized heat in decarbonization and centralized power and heat sector analysis.	District heat as in the HIGH scenario. Decentralized heat is not included, except for the current electric heating that is already counted in the electricity demand.

almost 700 TWh in the HIGH scenario, and over 80% of that is supplied to decentralized HPs. The total electricity demand by 2050, taking heat decarbonization into account, will increase from the current level of 2200 TWh by one-third in the HIGH scenario with constant decentralized heat demand, or by 22% in the LOW scenario with falling demand.

Fig. 2 also reveals the importance of natural gas in the energy transition. Although the emission restriction forbids natural gas use in 2050, gas consumption first increases to over 1900 TWh in 2030, and then decreases slightly to over 1500 TWh in 2040. Nevertheless, if emission-free gas is available, as in the CLEANGAS scenario, there will be clean gas consumption of approximately 440 TWh in 2050 to provide flexibility in the power and heat sectors.

4.2. Heat decarbonization

The current annual consumption of space heat and hot water in the modeled countries reaches approximately 2200 TWh, whereas it is 500 TWh for district heat. The modeling results reveal that electrification is the least expensive solution to replace fossil-based heating. As shown in Fig. 3, decentralized heat production first transits to the hybrid system with gas boilers plus HPs, which enables flexible and economic fuel use. Conventional electric heating systems are also upgraded to more efficient air-to-air HPs. In 2050, when no fossil emissions are allowed, decentralized heating switches completely to HPs and a small portion of renewable energy with biomass and solar heat. District heat generation follows a similar decarbonization path, with electrification replacing oil and coal. Almost half of the district heat will be electricity based by 2050, while the other half, supplied by biomass, will remain at a similar scale as of today.

Both the LOW and DH scenarios include building efficiency improvements that lead to decreased heat demand. Greater district heat expansion is also considered in the DH scenario. The same decarbonization strategy through hybrid systems and electrification is found in both scenarios, regardless of the heat demand development, but the amount of electricity needed for heating varies.

4.2.1. Alternative: clean gas — upgraded biogas and imported clean gas

If carbon-neutral gas is available, the transition is less disruptive. As shown in the CLEANGAS scenario in Fig. 3, almost two-thirds of the decentralized heat is supplied by heat pump hybrid gas boilers in 2050. The generation mix in the centralized heating system does not differ much from the HIGH scenario, indicating that decarbonization through electrification is preferred in the centralized heating system and that the decentralized heating system is less flexible and benefits more from the availability of carbon-neutral gas. The hybrid heating systems produce from local upgraded gas during peak hours or when HP performance is discounted owing to a low outdoor temperature (Fig. 4). One major advantage is the utilization of the existing gas infrastructure, which eases the pressure on power grids. The results reveal that electrification is still the major decarbonization strategy, but 15% of the decentralized heat will be supplied by upgraded gas in 2050 through the hybrid systems (Fig. 3). The results also indicate that the clean gas imported at the assumed price level is not cost competitive.

4.3. Renewable deployment

The required electricity is mainly supplied by wind and solar

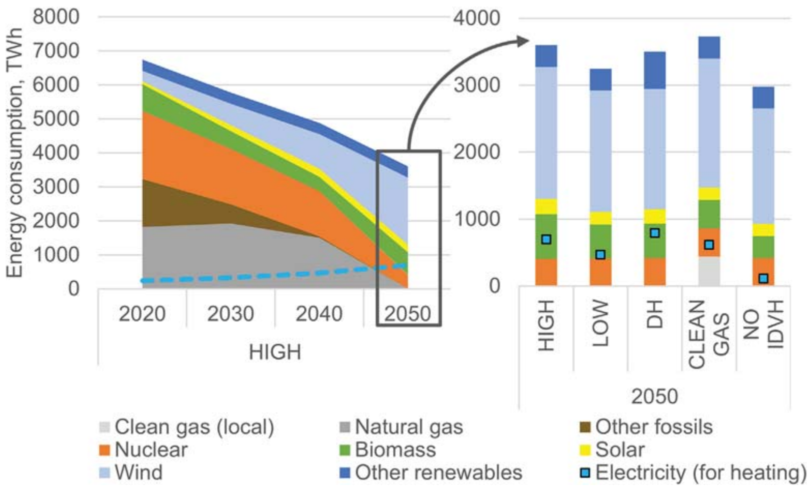


Fig. 2. Energy consumption in units of power, district heat and decentralized heat generation from 2020 to 2050 in the HIGH scenario (left), and in 2050 by scenario (right).

energy. To achieve the 2050 fossil-free goal, 760 GW wind and 190 GW PV capacities are needed in the HIGH scenario (Fig. 5). These are more than 5 times the current wind and 2.5 times the current PV levels, respectively. Approximately 170 GW wind and 40 GW PV capacities will be underestimated, if the decentralized heat decarbonization is not modeled (as in the NOIDVH scenario). If more effort is put into improving building efficiency and the heat demand decreases, PV capacities will be similar to the NOIDVH scenario, but the wind capacity will still be underestimated by 63 GW. If significant district heat expansion is also in place, 41 GW of additional wind capacity will be needed, despite more electricity being used in heating. This implies that district heat is a more flexible heating solution owing to its larger storage capacity and flexible CHP operation.

4.3.1. Wind potential

The amount of wind (especially onshore wind) required in 2050 in the HIGH scenario is substantial, which could raise questions on acceptance. The assumed limitations on wind power deployment consider current regulatory wind turbine set-back distances from settlements [41] and are less strict compared to those applied in previous studies under a similar framework that considered stronger social resistance for turbine installation [15,36]. Fig. 6 displays the percentage of the onshore wind installed potential that is utilized in each country. Western and Central European countries (France excluded) use more than half of the assumed capacity potential to decarbonize just the central power and heat production. The requirement of decarbonizing decentralized heat without energy savings will require using 100% of the assumed onshore wind potential in Germany. In comparison, the Nordic countries have a smaller demand, and more than 70% of the assumed potential is not used, even in the HIGH scenario. That implies that the Nordic countries could help decarbonize Western and Central Europe if more transmission lines were in place.

4.4. Power system implication

4.4.1. Peak load

One major challenge of heating system electrification is that its strong seasonality intensifies the power peak loads in winter. Demand response technologies offer limited relief because heat demand can only be shifted within the same week. Countries in the same climate zone have similar demand profiles, which unfortunately do not benefit from solar or run-of-river hydro production patterns. The overall peak load increases by 21% in the HIGH scenario in 2050 compared to the NOIDVH scenario (Table 9). The availability of clean gas, demand reduction, and district heat expansion help ease the pressure but still add 5–14% to the peak load. Germany faces the highest power grid pressure among all modeled countries, and the peak load in the HIGH scenario is 47% higher than in the NOIDVH scenario. In contrast, peak loads in countries such as Norway and Sweden, where electric heating is commonly used, decrease when the decentralized heating is included in the model. The reason is the increased use of heat pumps, which consume much less electricity providing the same amount of heat. Table 9 demonstrates the importance of including decentralized heat in decarbonization analyses, as it can affect peak loads in two ways.

4.4.2. Curtailment

A significant amount of wind is curtailed in 2050 (Fig. 7), especially in summer when the electricity demand is low. Although in the model, the excess wind power is simply shown as curtailment, it implies the potential for power-to-X application. Fig. 7 also indicates the importance of natural gas. Natural gas consumption remains at 83% in 2040 (Fig. 2), whereas the overall emissions are 37% compared to the 2020 levels. This is partly due to the emission intensity of natural gas being less than that of coal, and partly due to the need for a dispatchable supply increasing with the increase in VRE penetration. By 2050, natural gas cannot be used because of the strict emission restriction without the presence of CCS technologies. The large amount of wind curtailment in 2050 (but not in 2040) is a consequence of insufficient system flexibility. This is the reason why there is less curtailment in the CLEANGAS scenario than in the HIGH scenario in Fig. 7. The flexibility of the district heating systems also contributes to less curtailment in the DH scenario.

4.4.3. Power prices

The power prices presented here are defined by the marginal electricity costs. Fig. 8 demonstrates the weighted average price

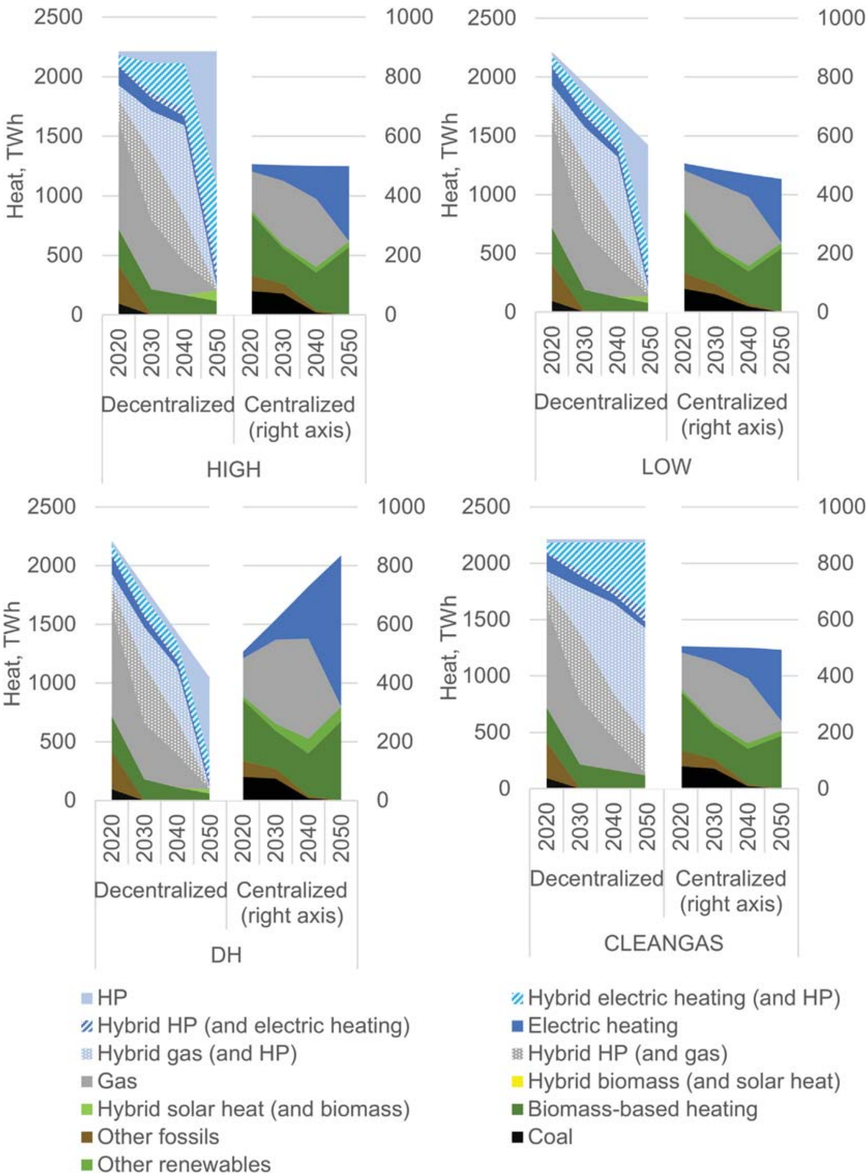


Fig. 3. Decentralized and centralized heat production in the 13 modeled countries from 2020 to 2050 in the HIGH, LOW, DH and CLEANGAS scenarios by heating technology and fuel.

development from 2020 to 2050 in Northern Germany, the UK, and Southern Sweden as examples. Generally, prices increase until 2040 as a result of gas being used as a substitute for cheaper but more CO_2 intense fossil fuels. In 2050, energy will be largely supplied by renewable energy sources. Power prices in most of the modeled countries drop from 10% to 32% compared to the prices in 2040. One exception is Germany in the HIGH scenario, where the power prices in 2050 appear significantly high. The country has the highest decarbonization pressure in the modeled sectors. In the HIGH scenario, the onshore wind capacity reaches its technical potential in 2050 in Germany (Section 4.3.1). The high prices indicate that additional generation units are needed, and the prices account for the investment costs of those addition units. Nevertheless, German prices are more comparable with other Western and Central European countries in other scenarios, where the electricity demand for heating is lower owing to building efficiency

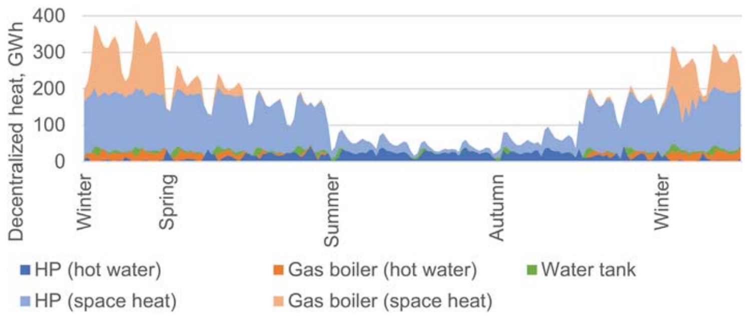


Fig. 4. Hourly heat production from gas boiler hybrid heat pump in 2050 in the CLEANGAS scenario. Each season consists of two weeks and each week is represented by a weekday and a weekend.

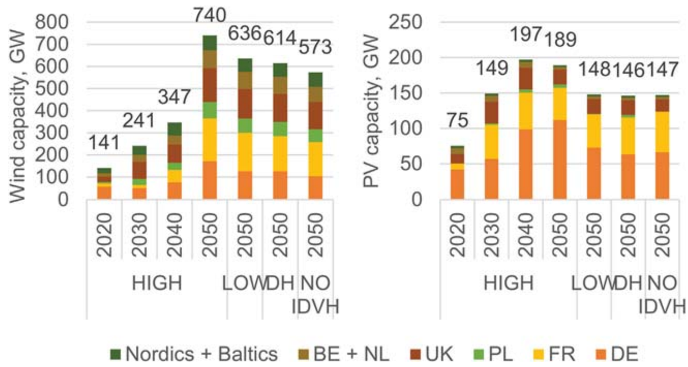


Fig. 5. Wind (left) and solar PV (right) and installed capacities.

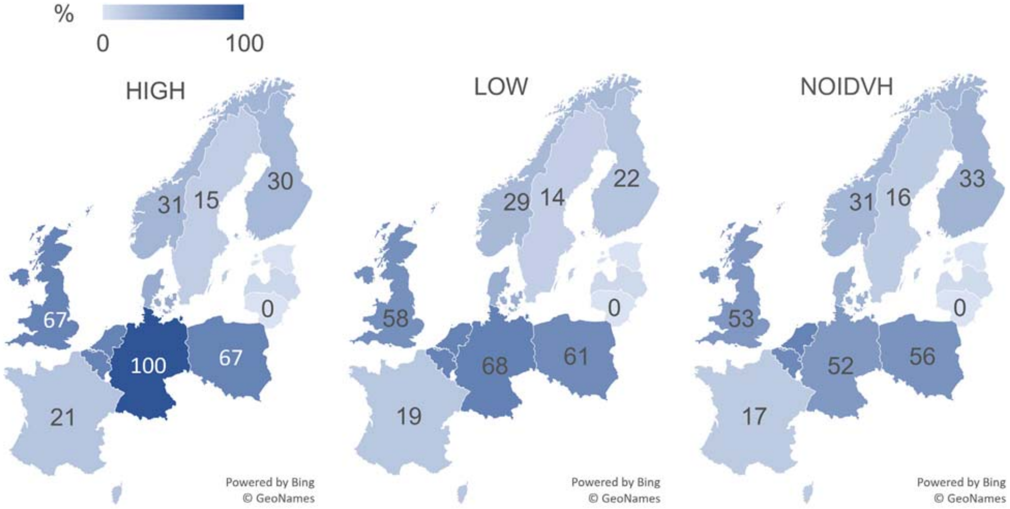
improvements and the availability of clean gas.

The annual power prices in the Nordic and Baltic countries are below 40 EUR/MWh, whereas those in Western European countries are well above this threshold. Such price differences are likely to stimulate additional transmission investments, especially between countries like Norway and Germany, or cause power intensive industries moving abroad from Western Europe to the north.

The seasonality in heat demand is transferred to the power prices through electrification, and seasonal price variations become significant over time. Fig. 9 illustrates the price duration curves in 2040, taking Northern Germany and Southern Sweden as examples. On one hand, winter power prices are significantly higher when the decentralized heating sector is decarbonized through electrification. On the other hand, in summer, prices are low, and excess renewable generation is simply curtailed. Notably, the peak price in Sweden is the highest in the NOIDVH scenario because the other decentralized scenarios opt for heat pumps with little electricity consumption (Section 4.4.1). Measures such as decreased heat demand, availability of clean gas, and district heat expansion help ease the seasonal price differences. By 2050, all scenarios show even more seasonality in power prices.

4.5. Challenges and opportunities

Heating sector electrification driven by efficient heat pumps stands out as a crucial element in all analyzed decarbonized scenarios, and wind will be the main power source. However, substantial wind capacity investments might increase land use conflicts and cause opposition. Fortunately, efforts to improve building efficiency or district heat expansion can lower the required wind capacities. The results reveal a limited role of biomass in heating decarbonization. Nevertheless, if wind deployment faces strong opposition, the importance of biomass heat would increase. Gas plays an important transition role, especially if clean gas is available. HP hybrid gas boilers can supplement each other and provide the most efficient fuel use. Further investigation into solutions that provide price-competitive carbon-neutral gases is worthwhile. Moreover, a large degree of electrification suggests distribution grid reinforcements will be important, although it is not within the modeling scope. Another advantage of using a hybrid heating system is that it decreases the risk of grid congestion. The challenges lie in maintaining the economic operation of gas grids with low utilization rates. Seasonal differences in electricity demand cause substantial wind curtailment in summer. It signals the importance of seasonal storage and power-to-X technologies in reaching climate goals. Furthermore, summer cooling demand in Northern Europe might rise as a result of climate change, and the seasonal electricity demand differences would be less significant. Although this study does not model transmission expansion investments, the results also highlight the opportunities for linking Western and Central Europe to the Nordic countries, which would be beneficial to the system because of the stronger wind winter generation, lower power prices and flexible hydropower in the Nordics [36].



Assumed potential, GW	BE	DE	DK	EE	FI	FR	LV	LT	NL	NO	PL	SE	UK
	18	144	55	27	31	906	79	128	49	28	105	138	230

Fig. 6. Installed onshore wind capacity in 2050 divided by the assumed potential in percentage. The assumed onshore wind capacity potential by country based on Refs. [40,41] is listed.

Table 9
Peak load differences compared to the NOIDVH scenario in 2050 in all modeled countries, and in Germany, UK, Norway, and Sweden respectively.

	HIGH	LOW	DH	CLEANGAS
All modeled countries	21%	7%	5%	14%
Germany	47%	19%	15%	22%
UK	26%	17%	16%	20%
Norway	-7%	-11%	-12%	-8%
Sweden	-14%	-16%	-16%	-12%

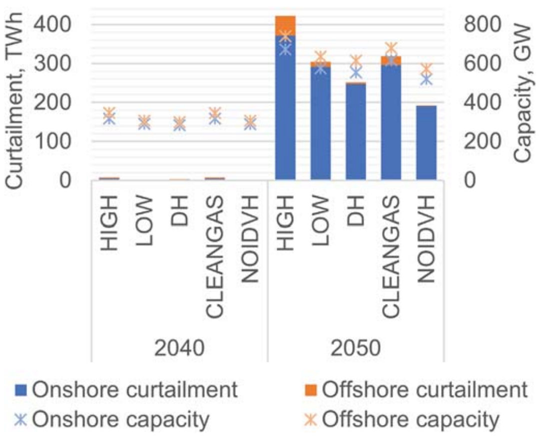


Fig. 7. Wind curtailment (bar, left axis) and installed capacities (marker, right axis) in 2040 and 2050.

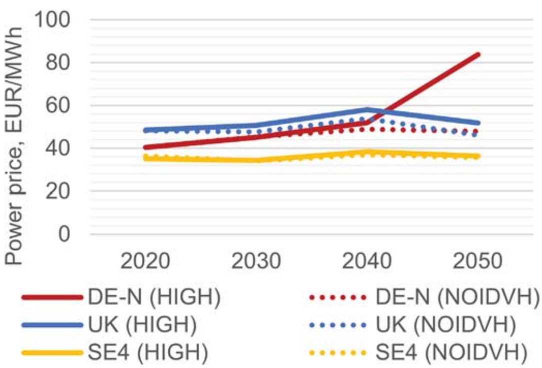


Fig. 8. Weighted average annual power prices in Northern Germany (DE-N) UK and Southern Sweden (SE4) from 2020 to 2050 in the HIGH scenario (solid lines) and the NOIDVH scenario (dot lines).

5. Conclusions

Decentralized heat should be discussed in the decarbonization debate. An investment model was used in this study to find cost-effective pathways toward decarbonization by 2050, complying with the EU emission targets for centralized and decentralized power and heat sectors. Electrification through heat pumps and hybrid heat pumps with gas boilers is found to be the optimal strategy. This is robust to changes in heat demand development owing to the superior efficiency and flexibility of this approach. By 2050, the electricity used for heating will range between 465 and 789 TWh, which is two to three times higher than the current level.

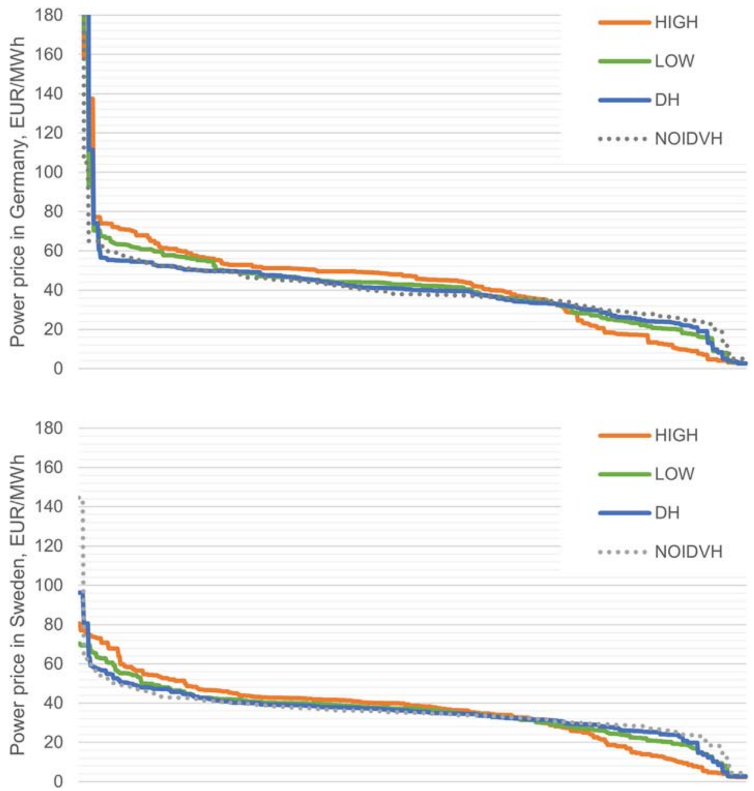


Fig. 9. Power price duration curves in Northern Germany (upper) and Southern Sweden (bottom) in 2040.

In the extreme case, current wind capacities of more than 5 times will be needed, and wind power capacity is underestimated by 170 GW if decarbonizing the decentralized heat sector is neglected. Building efficiency improvements or district heat expansion can decrease the need for additional wind capacity, but all scenarios for decarbonizing decentralized heat require at least 40 GW more wind power capacity compared to when the sector is not considered. The seasonality of heat demand will pose great challenges to the power system at deep heating sector decarbonization levels. A significant amount of wind capacity leads to curtailment and extremely low power prices in summer. In winter, taking Germany as an example, the peak load is increased by 47% and the average winter power prices can be very high unless the costs of technologies for seasonal storage are substantially reduced. The opposite effects are observed in the Nordic countries, where the winter peak load and power prices are lower than those in the case without decentralized heat modeling. This is because less electricity is needed by heat pumps than by current electric heating. The challenges also imply opportunities for seasonal storage technologies, power-to-X applications and transmission expansions between the Nordic and West European countries. Overall, the results emphasize the importance of considering decentralized heat in the analysis of deep decarbonized energy systems.

CRediT author statement

Yi-kuang Chen: Writing - Original Draft, Visualization, Conceptualization, Methodology, Software, Formal analysis, Investigation. Ida Græsted Jensen: Writing - Review & Editing, Conceptualization, Methodology, Software, Validation. Jon Gustav Kirkerud: Writing - Review & Editing, Conceptualization, Validation. Torjus Folsland Bolkesjø: Writing - Review & Editing, Conceptualization, Validation, Supervision, Project administration, Funding acquisition.

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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Paper III

Balancing GHG mitigation and land conflicts: Alternative Northern European energy system scenarios

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Abstract

Substantial renewable energy deployment is expected to achieve a low-carbon Northern European energy system, but the consequential large land requirement is a non-techno-economic aspect that might be omitted by many energy system optimization models. This study applies the modeling to generate alternatives (MGA) technique to the Balmorel energy system model. The approach searches for alternative solutions that minimize land requirements while meeting the low-carbon target, by allowing a 1% to 15% increase in system costs compared to a least-cost solution. Five alternative objectives are defined to reflect various aspects of land impact. The results show that the least-cost solution requires 1.2%–3.5% of the land in the modeled countries in 2040 for onshore wind and solar PV installations. A 10% increase in costs can reduce the land requirement by 60% by relying more on offshore wind and nuclear power. The latter technologies are, however, associated with higher risks and pose uncertainties in terms of reaching the climate targets in time. The changes in costs and land requirements imply significantly higher annual costs ranging from €200 k/km^2 to €700 k/km^2 to avoid land use for energy infrastructure. Overall, this study confirms that the energy transition strategies prioritizing land savings from energy infrastructure are feasible, but high risks and costs of land avoidance are involved.

Key words: land conflict; energy system; modeling to generate alternatives; uncertainty; energy transition

1. Introduction

Promoting renewable energy deployment is one of the key principles announced by the European Commission with regard to achieving a climate-neutral economy [1]. Electricity from renewable resources is expected to play an important role in the energy transition, and a large amount of new infrastructure for renewables is therefore foreseeable in the coming years [2–6].

Long-term analyses of future energy scenarios are often performed by energy system models to find an optimal system, which is often defined as a system with minimum costs or maximum social welfare. These models contain framework equations describing the relationships between the energy and mass flows, and a set of input parameters defining the economic, technological, and regulatory assumptions [7–9]. Nevertheless, energy system optimization models (ESOMs) are often only limited to techno-economic aspects. The resulting optimal solutions suggested by these models might not be "optimal" in real-world implications due to other non-techno-economic aspects, which are difficult or controversial to monetize [10, 11].

Land conflicts are one important non-techno-economic aspect, especially in the green transition context [12]. While some renewable energy sources can be regarded as inexhaustible, land is a limited resource. The scale of the required land for wind turbines and PV panels grows with an increase in the installed capacity. The requirement of suitable meteorological conditions for better generation efficiency makes the site selection for wind and PV farms even less flexible. Conflicts arise when new renewable projects compete against other land usage purposes, such as residential, recreational, agriculture, and nature conservation ones, or when they cause landscape disruptions [13–15]. Land conflicts bring challenges and uncertainties regarding a low-carbon future [16].

Such challenges can cause deviations from the least-cost solutions suggested by ESOMs in terms of system realization in the real world. One uncertainty assessment technique for ESOMs, called modeling to generate alternatives (MGA), addresses the outcome of a system with imperfect equations [17]. Unlike other uncertainty techniques, such as

Monte Carlo or stochastic analysis, which analyze the impact of uncertain parametric assumptions, the MGA technique alters the modeling algorithm to reveal near-optimal solutions under the same set of input assumptions [18]. The optimized solution from the original model serves as an anchor point, and the alternative solutions are produced within the near-optimal space. The MGA technique can be applied to reveal alternative solutions with unmodeled objectives beyond a single techno-economic aspect.

MGA has been applied to the energy sector to identify multiple near-optimal solutions, and there are examples of the application of MGA to well-established energy system models. Some literature aims to find the alternatives that are the most different from the optimal system. For example, DeCarolis et al. [19] applied the MGA technique to a bottom-up ESOM, Temoa, and highlighted the embedded uncertainties in the given results. Similar conclusions were drawn by Price and Keppo [20] with the implementation of the MGA technique to a global energy-environment-economy model, TIAM. The MGA technique revealed consistent and inconsistent insights across the multiple near-optimal scenarios.

Instead of using a search strategy to find the maximally different alternatives, Neumann and Brown [8] applied the MGA technique in the PyPSA model to explore the minima and maxima electricity generation from the pre-defined groups under strict emission reduction targets. The feasible space of the generation mix of a detailed Pan-European power system was demonstrated. There are also dedicated model frameworks that use the MGA technique as their core methodology. The model EXPANSE, as an example, was initially applied to the national energy sector [21–23] and later utilized for broader systems or combined with other techniques [22, 24]. All the MGA literature has concluded that unneglectable uncertainties can lie in the near-optimal space. Building upon the MGA technique, Pedersen et al. [10] proposed numerical formulations, named mapping all alternatives, to draw a continuum of near-optimal solutions. Nonetheless, no attempt has been made to combine the MGA technique with a qualitative aspect. This study aims to employ the MGA technique to purposefully search for alternatives in the near-optimal space.

By accepting higher system costs, energy systems that balance greenhouse gas (GHG) mitigation and land-use conflicts might face less opposition, and they are thus more likely to be realized. In contrast to the studies by Sasse and Trutnevyte [24] and Pedersen et al. [10], where land-use impact was subsequently analyzed for numerous generated alternatives, this study aims to explore the near-optimal space with an agenda of finding the alternatives with the least land-use impact. We apply the MGA technique with customized objectives to search for alternative energy systems that cause less land impact and to investigate how much land use can potentially be avoided by allowing higher system costs. This study is the first application of MGA to the Balmorel energy system model. It demonstrates a novel MGA approach and application and aims to propose alternative energy scenarios that balance the system costs and the land-use aspect while meeting the emission reduction targets.

2. Method and Data

2.1. Energy system model framework and assumptions

The Balmorel energy system model framework is applied in this study. The Balmorel model is programmed in the GAMS language. Its open source feature stimulates continuous development and allows flexible modeling settings [9]. For this study, the Balmorel model formulates linear optimization with the objective of minimizing the total system costs under a set of physical, economical, and regulatory constraints described by partial equilibriums. To satisfy the given inflexible electricity and district heat demands, the model invests in generation and storage technologies on top of capacities that are planned or not decommissioned. It is assumed that hydropower expansion is strictly regulated and that its capacity thus remains at the current level. The total system costs include the annualized investment costs of the endogenously invested generation, storage, and transmission technologies, the fixed and variable operation and maintenance costs of the generation, storage and transmission technologies, and the fuel costs. Costs and technology specifications are mainly extracted from the technology catalogue published by the Danish Energy Agency [25, 26], and the annualized investment costs are calculated with an assumed interest rate of 6% over the technology lifetime.

This study sets an emission cap in 2040 as a midway milestone between reaching the 2030 targets and carbon neutrality in 2050. The energy balance is met at an hourly level. For efficient computation and representativeness, two weekdays every two weeks (1248 hours in total) are chosen as representative timesteps for optimization, and the results are scaled up to calculate the annual values. Three spatial levels are defined hierarchically: country, region, and area. Thirteen European countries are included in the model: the four Nordic countries excluding Iceland, the three Baltic countries, and the surrounding countries, including Poland, Germany, the Netherlands, Belgium, France, and the United Kingdom. The Nordic countries are further divided into Nord Pool regions, and Germany consists of four regions to represent the powerline congestion challenges. Each of the other countries is one region in itself.

The electricity balance is met at the regional level, with the possibilities of power transmissions through interconnectors between regions. The default transmission capacity assumes that all projects in the TYNDP 2018 commissioned before 2035 are realized [27], and beyond that, the model can decide to invest in transmission capacity expansion up to 50% of the default capacity. The district heat balance is met at the area level, and no district heating expansion is assumed. The electricity and district heating sectors are coupled through combined heat and power plants (CHPs) and power-to-heat technologies.

The electricity demand is assumed to increase dramatically as 2050 approaches – with increase of 121% from 2015. It is based on the 1.5TECH scenario in an analysis from the European Commission [28], which is in line with net-zero GHG emissions in the EU in 2050. Most of the increase comes from the need to produce hydrogen or clean gases or liquid fuels, which are classified as e-fuels in Figure 1. The district heat demand is assumed to be constant. The energy demand and renewable resource profiles from the year 2012 are applied to represent a normal weather year. The electricity demand with regard to producing e-fuels is assumed to be constant throughout the year.

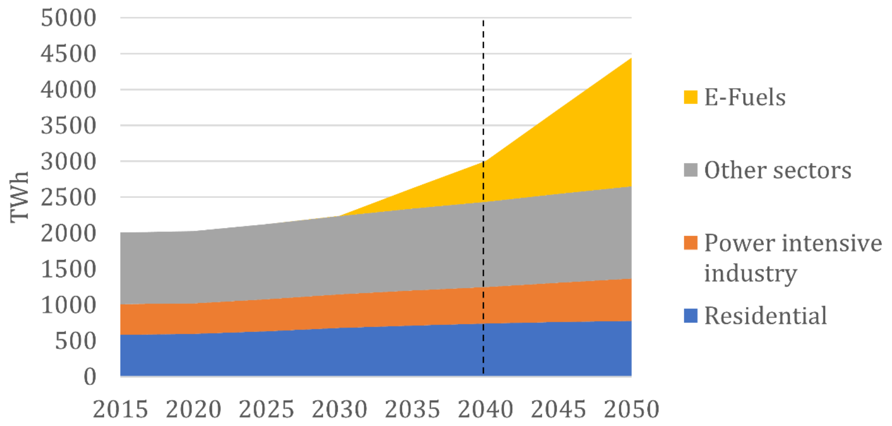

Figure 1. The assumption regarding electricity demand between 2020 and 2050 by sector aggregated based on all the modeled countries.

2.2. Renewable energy resources

The importance of modeling renewable resources in detail increases with the arise in renewable shares. Although the electricity balance is met at the regional level, solar and wind resources are not uniformly distributed within a region. This study uses the same approach as Gea-Bermúdez et al. [3], where three areas with different resource conditions (referred to as resource grades) are defined for each region. The three areas for offshore wind correspond to different distances from the shore and also affect offshore wind turbine costs. Technology potentials are defined for each resource condition as the maxima of the installed capacity by technology type.

The assumed potentials come from multiple references and contain a mix of physical, economic, and social implications [3, 29, 30]. In this study, we assume less opposition from the social and economic aspects but still intend to keep the heterogeneous resource conditions within the regions. As a result, for solar PV and onshore wind, the potentials in the areas with the third-best resource conditions are lifted. The offshore wind potentials in the "low restriction" scenario from [30] are applied, excluding the nearshore shallow areas and the floating turbine areas. The assumptions regarding installed capacity potential and the costs of solar PV and wind power can be found in the Appendix.

Local biofuel or fuel from waste streams are subject to annual available amounts. The supply of woody biomass, such as woodchips and wood pellets, is more flexible and is represented by stepwise fuel cost functions, assuming that every 25% change in volume increases the price by 12.5%. Hydropower potential is assumed to be already fully utilized in the modeled regions, and no endogenous capacity expansion is permitted.

2.3. Model-to-generate-alternatives

The MGA technique is used to search for alternative solutions in the feasible space near the optimal point. Four steps are involved (Figure 2):

- Step 1 — The ESOM is solved to find the minimum objective value and the corresponding system configuration.
- Step 2 — A user-defined slack value is defined to draw the near-optimal search space, and the original objective function becomes an upper-bound constraint.
- Step 3 — New objective functions are defined to search for alternative configurations within the near-optimal space.
- Step 4 — Steps 2 and 3 are repeated, and a bundle of alternative solutions that are generated from various slack values and the new objective functions are analyzed.

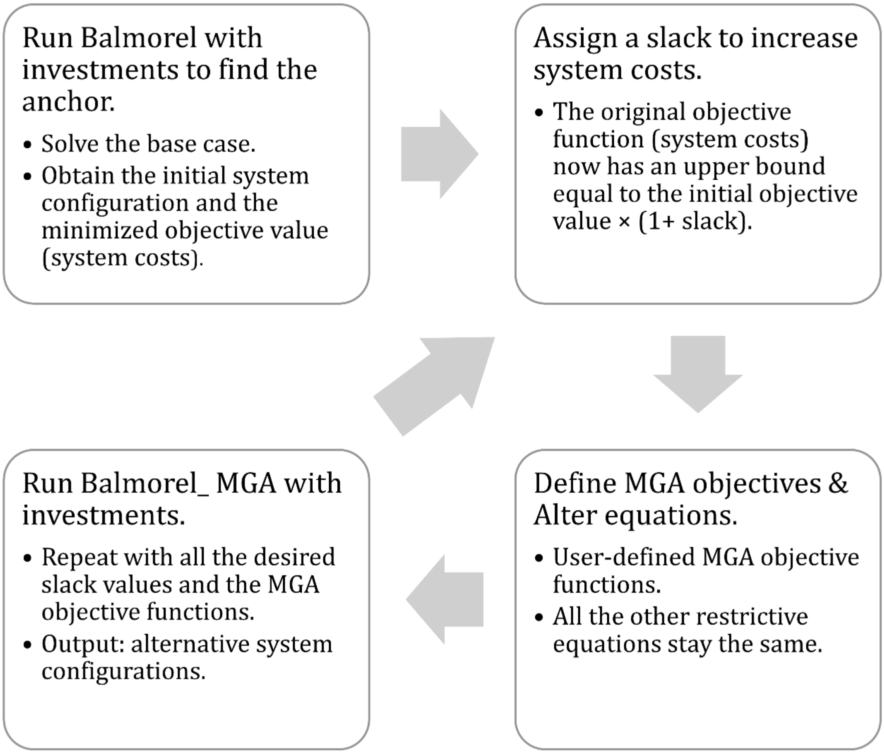

Figure 2. An overview of the MGA technique process.

In this study, the MGA technique is applied to the Balmorel energy system model. A slack value is assigned to the Balmorel objective, and it is interpreted as the additional system costs that can be tolerated. There are several search directions in which to proceed to find alternatives to the anchor point, such as the hop-skip-jump method [17, 19], the furthest solution points [20], or the minima and maxima values [8]. As concluded by Makowski et al. [31], the method of minimizing or maximizing a particular attribute gives the most diverse answers. This method combined with the land use aspects is applied to define the MGA objective functions in this study.

2.4. Scenarios

To reflect the various potential definitions of land impact, several MGA objective functions are defined. The scenarios are designed to tackle the land impact from the viewpoint of both global and national aspects. Two of the scenarios take a global perspective, where we are interested in the alternatives that use the least land overall and cause the least disturbance. The three remaining scenarios have a national strategy perspective, where land is regarded as a national resource and the countries are interested in the alternatives that use small amounts of their available land, which is assumed to be dependent on the land type. All the scenarios apply an equally strict emission restriction. Table 1 summarizes the objective functions and the implications of the MGA scenarios in this study.

Under the global perspective, two MGA scenarios are defined – MinLand and MinDisturb. The MGA objective function in the MinLand scenario is to minimize

$$OBJ\_MGA_{MinLand} = \sum_{c \in C} LAND_{c,y}$$

where $LAND_{c,y}$ is the land requirement of a country c in a given year y, and C represents the set of all the countries in the model. It searches for an alternative scenario, where land is seen as a public good and all countries work together to minimize the use of the land. The MGA objective function in the MinDisturb scenario is similarly defined to minimize

$$OBJ\_MGA_{MinDisturb} = \sum_{c \in C} AREA_{c,y}$$

where $AREA_{c,y}$ is the area that is potentially disturbed by the energy infrastructure, particularly by the wind turbines, both onshore and offshore.

Table 1. Summary of the MGA objective functions in this study and their implications.

MGA scenario	MGA objective function	Implication
Global		
MinLand	To minimize the total land requirement for energy purposes.	All types of physical land areas are equally important.
MinDisturb	To minimize the total disturbed area for energy purposes, including sea areas.	The disturbance from energy infrastructure, including sea areas, is expected to be at the minimum level. Areas impacted by onshore wind are assumed to be larger than those physically required by the turbines.
National strategy		
Potential	To minimize the sum of the shares of land used for energy purposes in the potential area in each country.	Land-use conflict tension is more intense in the regions with less potential land. The potential land excludes land covered with artificial areas, waters, and wetland.
LowImpact	To minimize the sum of the shares of land used for energy purposes in the low impact area in each country.	Energy infrastructures are regarded as significantly disturbing to the economic activities in forest and cropland areas, which are thus excluded from the potential land.
EcoSystem	To minimize the sum of the shares of land used for energy purposes in the areas excluding untouched nature in each country.	The main driver of the opposition is biodiversity. It is assumed that shrubland, grassland and bare land areas have lower economic values and are disturbed less. These land areas are excluded from the potential land.

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where $AREA_{c,y}$ is the area that is potentially disturbed by the energy infrastructure, particularly by the wind turbines, both onshore and offshore.

Under the national strategy perspective, it is assumed that no countries can "outsource" their land conflicts, neither are they willing to allocate more land than in the least-cost solution. In addition, the Potential, LowImpact, and EcoSystem scenarios use the land areas of various combinations of land types as proxies to represent the degrees of acceptance in each country in terms of various land conflict aspects. The MGA objective functions of these scenarios are to minimize, respectively:

$$OBJ\_MGA_{Potential} = \sum\nolimits_{c \in C} \frac{LAND_{c,y}}{LANDCOVER_{Potential,c}}$$

$$OBJ\_MGA_{LowImpact} = \sum\nolimits_{c \in C} \frac{LAND_{c,y}}{LANDCOVER_{LowImpact,c}}$$

$$OBJ\_MGA_{EcoSystem} = \sum\nolimits_{c \in C} \frac{LAND_{c,y}}{LANDCOVER_{EcoSystem,c}}$$

where $LANDCOVER_{Potentail,c}$, $LANDCOVER_{LowImpact,c}$, and $LANDCOVER_{EcoSystem,c}$ represent the land areas with less controversies in country c in the three MGA scenarios.

The Potential scenario searches for an alternative scenario that uses the minimal share of the potential land. In the LowImpact scenario, land types that are assumed to be more valuable or to have higher costs with regard to developing energy projects are excluded from the potential land. In the EcoSystem scenario, land types that are assumed to be less disturbed by human activities to have higher biodiversity are excluded from the potential land.

Each of the above-mentioned MGA objective functions is run with slacks of 1%, 2%, 2.5%, 5%, 7.5%, 10%, and 15%. Overall, in addition to the least-cost solution as the base scenario, 35 near-optimal MGA scenarios, which potentially lead to fewer land conflicts while achieving the low-carbon targets, are analyzed in this study.

2.5. The land requirement and areas that are potentially disturbed for energy production purposes

The land requirement in this study is defined as the land directly impacted by energy infrastructure, such as power plants, wind turbine bases and the spacing areas between turbines and solar PV modules, and the land impacted by fuel [32]. The land requirement for fuels traded on international markets or generated from waste streams is not considered. The land requirement for hydropower is also omitted because it is assumed that hydropower potential in the modeled countries is exhausted and that its expansion is not allowed.

The land requirement ($LAND_{c,y}$) is calculated as

$$LAND_{c,y} = \sum_{G,F} \left(LPF_G \times CAP_{G,c,y} + LEF_S \times CAP_{S,c,y} + LEF_F \times CONS_{F,c,y} \right) \forall\, c, y$$

where LPF_G is the land power factor in m^2/MW of the generation technology G, $CAP_{G,c,y}$ is the installed capacity in MW of the generation technology G in the year y, LEF_S is the land energy factor in m^2/MWh of the storage technology S, $CAP_{S,c,y}$ is the storage capacity in MWh of the storage technology S in the year y, LEF_F is the land energy factor in m^2/MWh of the fuel F, and $CONS_{F,c,y}$ is the fuel consumption in MWh of the fuel F in the year y.

The land factors are summarized in Table 2. Most of the data are extracted from the space requirement (i.e. the area occupied by the facility) listed in the technology catalogue [26]. Regarding onshore wind power, there are various definitions and values with regard to its land requirement, which is also highly location dependent. For this study, a data-driven spacing area estimation from Enevoldsen and Jacobson [33] for the operating onshore wind farms in Europe is applied, and the estimated onshore wind land factor is 50505 m^2/MW. The land factor for nuclear power is taken from the study by Cheng and Hammond [34], where the land takes for plant construction and operation (per installed capacity) and for fuel and waste storage and transport (per fuel consumption) are considered. In this study, it is assumed that the biofuels are agricultural waste or low economic value byproducts, and thus, no land factor is assigned.

The disturbed area ($AREA_{c,y}$) attempts to capture a more conservative disturbance estimation, especially with regard to the wind turbines. The land requirement ($AREA_{c,y}$) is calculated as

$$AREA_{c,y} = \sum_{G,F}\big(DAPF_{G_{wind}} \times CAP_{G_{wind},c,y} + LPF_{G_{non\_wind}} \times CAP_{G_{non\_wind},c,y} + LEF_S \times CAP_{S,c,y} + LEF_F \times CONS_{F,c,y}\big)\ \forall\, c,y$$

where $DAPF_{G_{wind}}$ is the disturbed area power factor in m^2/MW of the wind generation technology G_{wind}. For onshore wind turbines, the disturbed area factor is assumed to be 200000 m^2/MW, which is equivalent to an exclusion area of 1 km by 1 km for a 5 MW turbine, to account for noise and visual impact. Disturbed area factors are also assigned to the offshore wind turbines. The same values are assumed for nearshore turbines (within 22 km of the shore), and for turbines further away, the disturbed area factor is assumed to be 136000 m^2/MW, which is the average of the installed power density of offshore wind found in the literature [33]. It is equivalent to an area of 1.3 km by 1.3 km for a 12.5 MW turbine. For all the other technologies, their land factors are also used to calculate the disturbed area.

Table 2. A summary of the land factor assumptions applied in this study.

Land factor type	Technology	Value	Reference
Land power factor, generation technology (unit: m^2/MW)	Solid/liquid-fossil-fuel-based power plant	40	Own assumption
	Gas-based power plant	20–40	[26]
	Nuclear power plant	1000	[34]
	Gas-based CHP	20–25	[26]
	Wood-based CHP	40–700	[26]
	Straw-based CHP	200–1000	[26]
	Waste-based CHP	800–2500	[26]
	Gas engine	35	[26]
	Utility-scale PV	18000	[26]
	Onshore wind	50505	[33]
	Solid/liquid-fossil-fuel-based heating plant	10	Own assumption
	Gas-based heating plant	5	[26]
	Wood-based heating plant	50–200	[26]
	Straw-based heating plant	200	[26]
	Waste-based heating plant	540	[26]
	Heat pump	600–800	[26]
	Solar heating for district heat	4286	[26]
Land energy factor, energy storage technology (unit: m^2/MWh)	Utility-scale battery	6.25	[25]
	Pit storage	1.556	[25]
	Hot water tank	0.5	[25]
Land energy factor, fuel[1] (unit: m^2/MWh)	Nuclear	0.050	[34]
Disturbed area power factor (unit: m^2/MW)	Onshore wind	200000	Own assumption
	Nearshore wind	200000	Own assumption
	Farshore wind	136000	[33]

[1] No land factor is assigned to biomass, which is assumed to come from waste steams or low economic value byproducts.

2.6. Land cover and land cover types

This study focuses on land conflicts with energy purposes in multiple European countries. Besides the local weather conditions, the current status of the land also has a strong influence on the costs and the possible disturbance concerning the energy project development. The renewable potential and conditions defined for each region in the Balmorel energy system model are based on meteorological reanalysis data [29]. The areas based on land cover in each region are the aggregations of the NUTS 2 regional-level data from the 2015 LUCAS survey [35]. The Statistics Norway [36] 2020 data are aggregated to fit the land cover categories from the LUCAS survey for Norway. Figure 3 illustrates an overview of the land areas in each model country by land cover type. Based on the various implications of the MGA scenarios defined in Table 1, the land types that are considered less controversial to utilize in the national strategy scenarios are marked in Table 3.

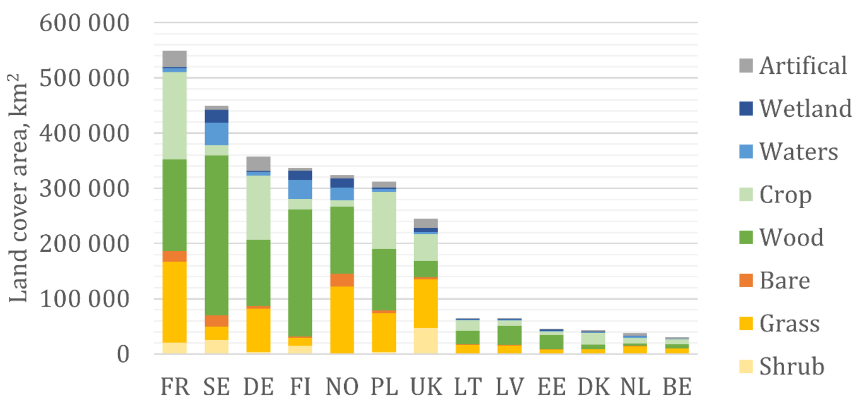

Figure 3. Areas by land cover type in the modeled countries.

Table 3. Types of land covers that are regarded as less controversial in the Potential, LowImpact, and EcoSystem MGA scenarios.

Land cover type	Potential	LowImpact	EcoSystem
Shrub	V	V	
Grass	V	V	
Bare land	V	V	
Wood	V		V
Crop	V		V
Waters			
Wetland			
Artificial			

3. Results and Discussion

3.1. Global perspective

This section presents the modeling results of the MinLand scenario, where the objective is to minimize the aggregated land use, and the MinDisturb scenario, where the aim is to minimize the disturbed area. The disturbed area by onshore and offshore wind turbines is assumed to be broader than their land use area.

The least-cost solution for 2040 reveals that 41% of the installed capacity in the power system in the modeled countries is solar PV and 31% is onshore wind. Figure 4 shows the total installed capacity in the power sector in 2040 in the MinLand and MinDisturb scenarios, with increasing system costs of 0% to 15% (slacks). In the alternative solutions, with a 1% increase in the annualized system costs, the onshore wind capacity decreases by 17% and that of PV by 12%. With an increase of 10% in the system costs, 69% of the onshore wind capacity and 40% of the PV capacity are replaced by nuclear power and the tripling of offshore wind. In the case where the disturbance from wind is even less tolerable, 366 GW of PV and wind are replaced by 74 GW of nuclear power.

The roles of offshore wind and nuclear power are the major differences between the MinLand and MinDisturb scenarios. Offshore wind appears more competitive than nuclear power in 2040, and nuclear investment is permitted only in certain countries. Therefore, offshore wind is favored when searching for alternatives with minimum land use, while if the potential onshore and offshore disturbance is to be minimized, the importance of nuclear energy will increase.

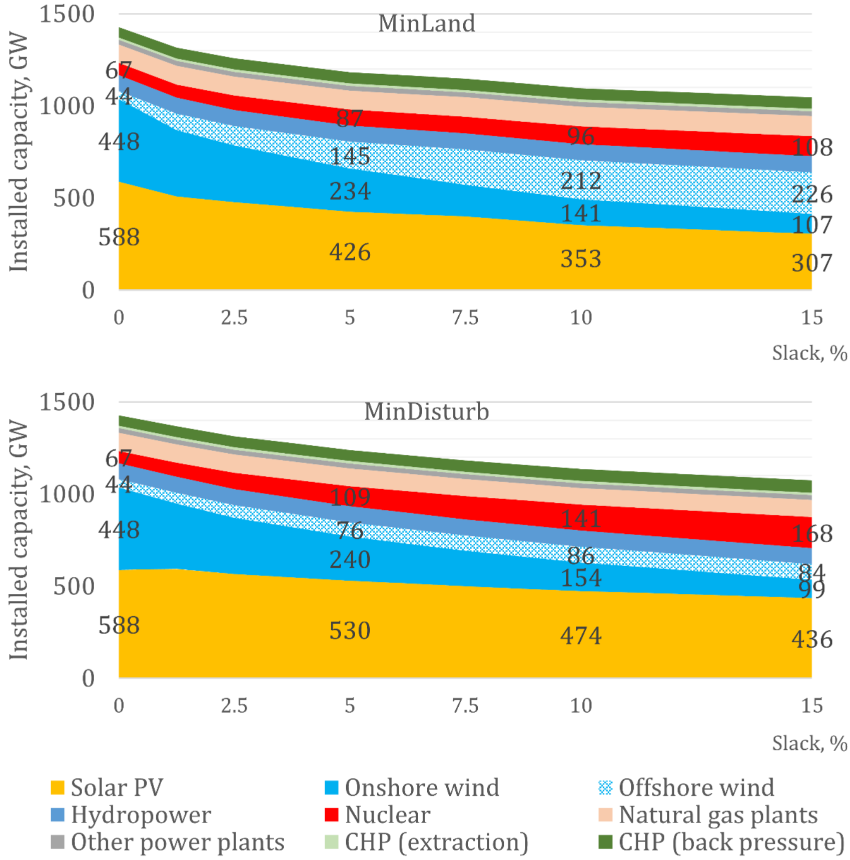

Figure 4. The total installed capacity in the power sector in all the modeled countries in 2040 in the MinLand and MinDisturb scenarios, with slack values of system cost increases between 0% and 15%.

With the assumed land and disturbed area factors, the above-mentioned capacities can be translated into land requirements (Figure 5) and disturbed areas (Figure 6) by scenario and the slack value. Figure 5 also includes the approximation of the land requirement in 2020 for comparison, using the same land factor assumptions and the aggregated share of the land requirement in all the modeled countries. The deterministic factors of land and area requirements are the installed capacities of solar PV and wind, and the other technologies constitute only marginal portions of the total land requirement.

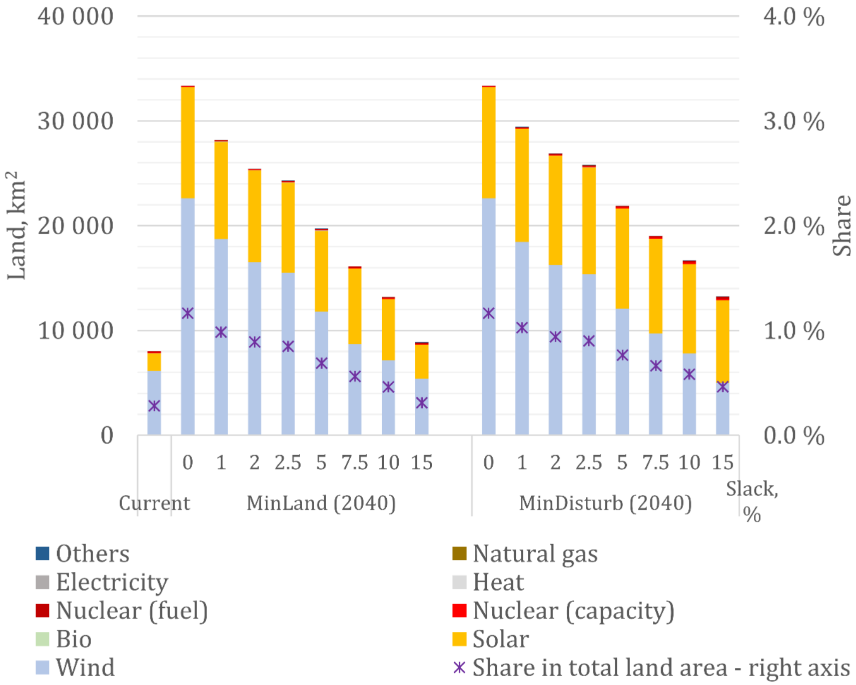

Figure 5. Land requirement by fuel type and the overall shares in all the modeled countries at the current level and in 2040 in the MinLand and MinDisturb scenarios.

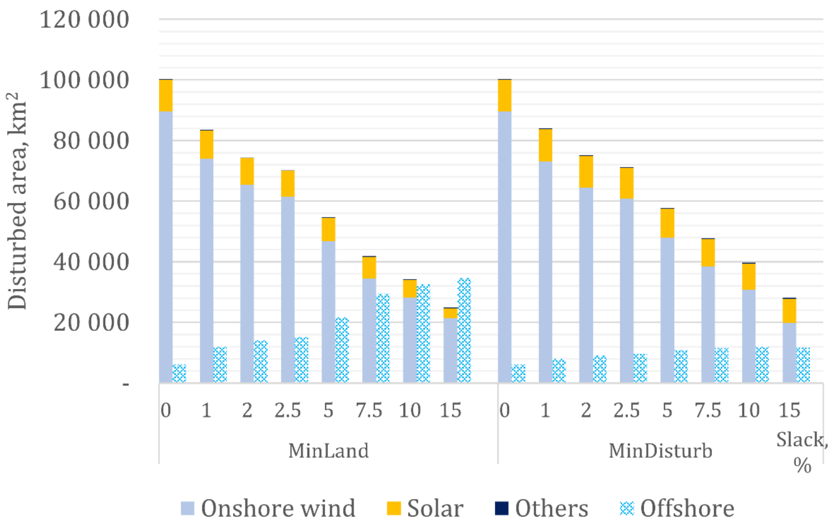

Figure 6. Onshore and offshore disturbed areas by technology type in all the modeled countries in 2040 in the MinLand and MinDisturb scenarios.

The area of required land for energy production in 2040 in the least-cost solution comprises approximately 1.2% of the aggregated land area, which is quadruple the 2020 level. A 5% increase in system costs reduces the land requirement by 40% compared to the least-cost scenario, a 10% increase in costs reduces the land requirement by 60%, and a 15% increase in costs can maintain the total land requirement more or less at the current level by shifting towards offshore resources and nuclear power.

The disturbed area presented in Figure 6 is defined to reflect a more extensive land impact from onshore wind than the required land area shown in Figure 5. With such an assumption, the impacted area of land in the least-cost solution is three times that of the previous estimate, meaning that 3.5% of the total land is used for energy generation purposes. In the MinDisturb scenario, where the goal is to minimize both onshore and offshore areas used for energy generation, the contribution from offshore wind is limited. With a 10% increase in system costs, the disturbance of more than 60000 km^2 of onshore areas is avoided, while the offshore disturbed area increases by less than 6000 km^2.

System costs are redistributed when the objective is altered. The results show that in the least-cost solution in 2040, the annual system cost is around €112 billion, which includes the annualized investment costs for generation, storage technologies, and transmissions, the fixed and variable operation and maintenance costs, and the fuel costs. Figure 7 illustrates how the costs are redistributed with a 10% slack in the system costs. In both the MinLand and MinDisturb scenarios, the costs shift from solar PV and onshore wind to offshore wind and nuclear power. The difference is that the additional costs of offshore wind are triple those of nuclear power in the MinLand scenario, and the opposite is true in the MinDisturb scenario. Moreover, less investment in storage is needed in the MinLand scenario, corresponding to a decrease in PV. Less investment in storage or transmission is needed in the MinDisturb scenario as the variable generation decreases.

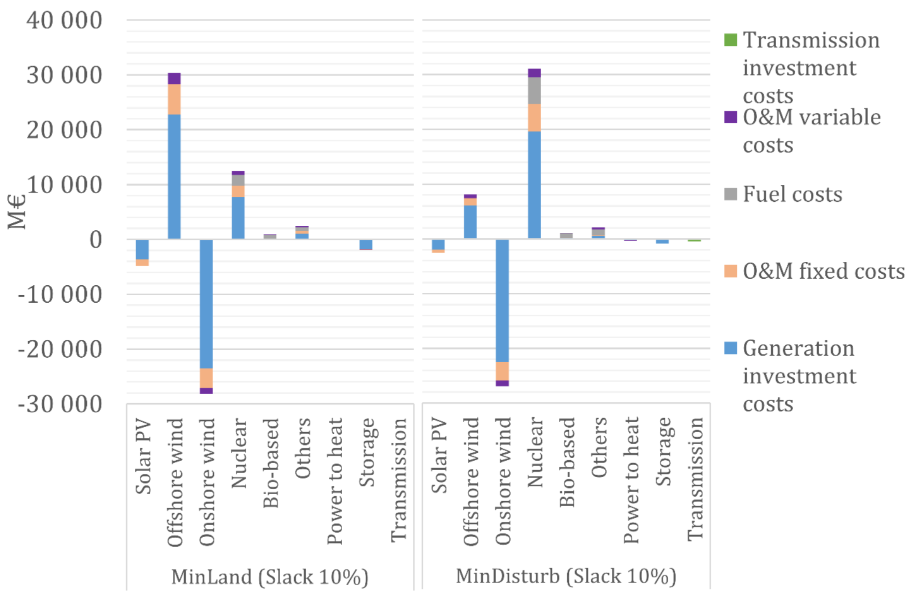

Figure 7. Change in the annual system costs with a 10% slack compared to the least-cost solution.

The least-cost solution indicates that the modeled countries obtain a 78% renewable share in the electricity mix in 2040, including 22% from PV, 41% from onshore wind, 4% from offshore wind, and 10% from hydropower (Figure 8). Adding 10% in system costs to reach the minimum land requirement increases the nuclear power share to 20% and that of offshore wind to 29% to replace onshore wind and PV. In the case of minimizing the disturbed area, the nuclear power share in the electricity mix exceeds 30%.

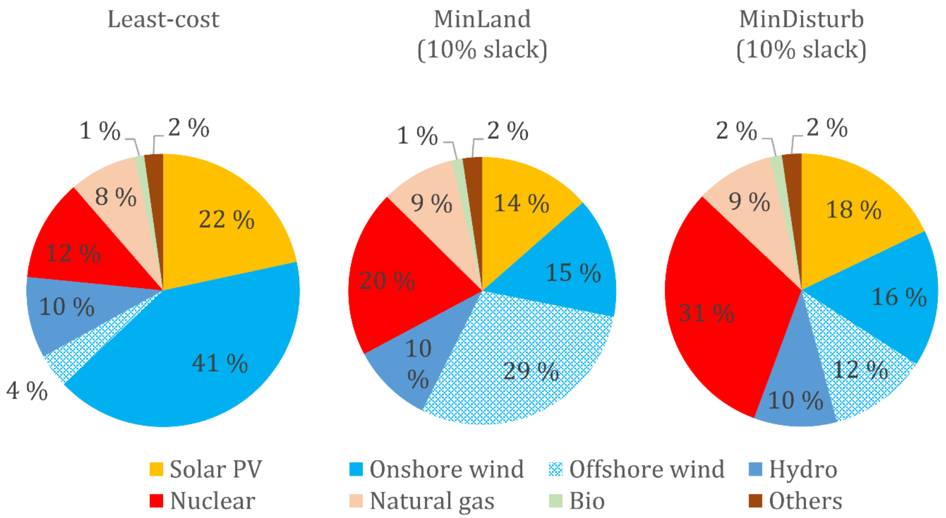

Figure 8. Electricity generation mix in the least-cost solution and in the alternatives with a 10% slack in terms of system costs.

The results presented above are encouraging as they show that a cost-effective and low-carbon Northern European energy system can be achieved by using merely 1.2% of the land for energy infrastructure. A pragmatic interpretation would be that it is possible to maintain biodiversity, scenic nature, and other ecosystem services on the remaining 98.8% of the land. However, energy infrastructure is highly controversial, and our results further show that land use can decrease by up to 75% if one accepts 15% higher costs and the risks and uncertainties associated with nuclear power and offshore wind.

3.2. National strategy perspective

Land use is mainly regulated by local or national policies, and the opportunities and challenges related to it may vary substantially across countries. Table 4 lists the share of land required in each modeled country. In the least-cost solution, three countries allocate more than 3% of their land to energy generation – Belgium (4.14%), the Netherlands

(4.04%), and Germany (3.21%). Among the modeled countries, Belgium and the Netherlands have the smallest territories and the highest population densities, and Germany has the highest energy demand. With a 10% increase in system costs to minimize the overall land requirements, these three countries can avoid using more than 2% of their land, although they still rank top when compared to the others.

The national strategy scenarios use the national land area to scale the impact, meaning it is less favorable to utilize land in countries with smaller available land areas. Except for Germany, no country will use more than 1% of its land for energy generation in these national strategy scenarios. The effect of weighing impact by land type can be observed by comparing the LowImpact and EcoSystem scenarios. It is less favorable to establish energy infrastructures in countries with high shares of wood- and cropland, such as Sweden and Germany, in the LowImpact scenario, whereas in the EcoSystem scenario, energy infrastructures are less favored in countries with high shares of shrub-, grass- and bare land where the visual impact may be particularly high, such as Norway and the UK. Overall, Table 4 shows that the amount of land planned for energy generation in each country depends on the objectives and the imposed land value, and that some countries are more flexible in terms of using their land resource for energy generation than others.

Nuclear power, solar PV, and onshore and offshore wind are the key technologies in the low-carbon energy system, and Figure 9 illustrates their installed capacity by geographical region in the least-cost scenario and in the MGA scenarios with a 10% increase in system costs. Due to various wind and solar conditions and different nuclear policies in each country, the generation investments focus on different technologies depending on the new objectives outlined.

Table 4. Share of the land used for energy production expressed in terms of the total land area by country in the least-cost solution and in the MGA scenarios with a 10% increase in system costs.

Country	Least-cost	Slack 10% MinLand	Potential	LowImpact	EcoSystem
BE	4.14%	1.67%	0.46%	0.46%	0.46%
DK	2.32%	0.25%	0.18%	0.18%	0.18%
EE	0.41%	0.03%	0.01%	0.01%	0.01%
FI	0.22%	0.10%	0.10%	0.03%	0.10%
FR	1.04%	0.58%	0.83%	0.74%	0.95%
DE	3.21%	1.17%	1.35%	1.12%	1.98%
LV	0.13%	0.03%	0.00%	0.00%	0.00%
LT	0.37%	0.03%	0.02%	0.01%	0.02%
NL	4.04%	1.54%	0.55%	0.55%	0.55%
NO	0.21%	0.20%	0.20%	0.21%	0.18%
PL	0.85%	0.18%	0.18%	0.07%	0.24%
SE	0.20%	0.11%	0.15%	0.07%	0.20%
UK	2.81%	1.03%	0.81%	1.85%	0.22%

Germany and Poland have relatively similar land type profiles (Figure 3), but the two countries have different renewable targets and nuclear policies. Consequently, Germany sees a large growth in offshore wind to substitute onshore wind in the MGA scenarios, but it still ranks top in terms of the used land share. Poland is more likely to rely on nuclear power, in addition to offshore wind, to relieve the land use stress, according to the model results.

The UK and the Northern European countries have good wind resources but less ideal solar conditions. In the MGA scenarios, these countries largely switch from onshore to offshore wind, and solar PV market shares are even lower than in the least-cost solution. Nevertheless, when the offshore disturbance is also to be minimized, as in the MinDisturb scenario, the UK largely shifts towards nuclear power, while the Northern European countries turn to PV due to limited nuclear expansion possibilities. The land type profiles in these two regions are different as well: the UK has more bare- and grassland, while the other Northern European countries have larger forests and croplands. As a result, in the UK onshore wind is even less advantageous than nuclear power and offshore wind in the EcoSystem scenario.

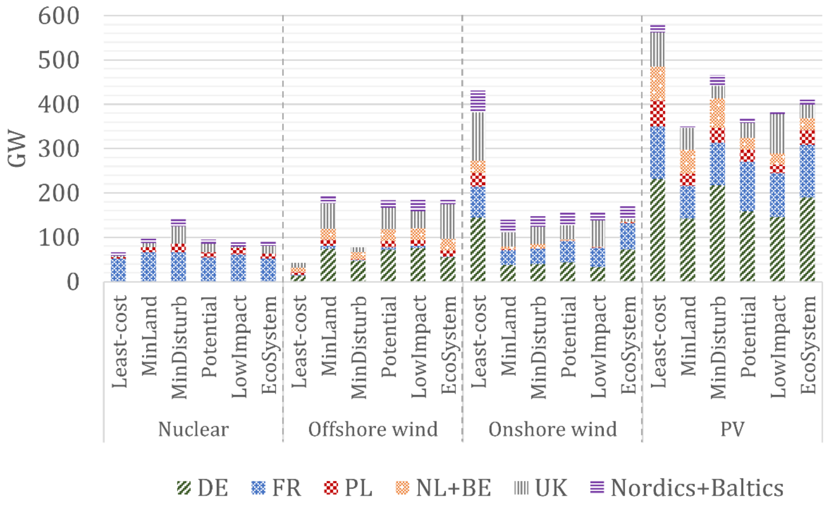

Figure 9. Installed capacity of nuclear power, wind, and solar PV in the least-cost solution and the MGA scenarios with a 10% slack.

3.3. The cost of land avoidance

The unit cost of land avoidance in terms of energy generation can be estimated by dividing the change in land requirement by the change in the total costs, as shown in Figure 10. By definition, MinLand is the scenario that minimizes the land requirement, and thus it has the lowest unit cost per saved land among all the MGA scenarios with the same slack. The average costs per saved land increase from €200 k/km^2 with just 1% higher system costs, to almost €700 k/km^2 with 15% higher system costs. This implies that similar to the abatement cost, the first square kilometers avoided are less costly and the costs increase when a larger area is to be evaded.

To provide some reference numbers regarding land prices, the prices of permanent grass land in 2018 in the modeled countries ranged from €216 k/km^2 in Latvia to €5762 k/km^2 in the Netherlands according to Eurostat [37]. Assuming a 6% interest rate and 25 years of payment, the annualized costs of permanent grassland range from €17 to €451 k/km^2. Another example price for comparison is the compensation paid to Norwegian forest owners for nature protection reasons, which typically ranges from €200 to €500 k/km^2

in total. The results indicate that the costs of deviating from the least-cost solution to avoid land use are considerably high.

Among the three MGA scenarios with a national strategy perspective, the EcoSystem scenario appears to have the highest costs. It implies that within the modeled region, assigning higher land avoidance pressure to countries with higher shrub-, bare-, and grass land shares is likely to be more costly than prioritizing land-use reduction in countries with larger shares of wood- and cropland.

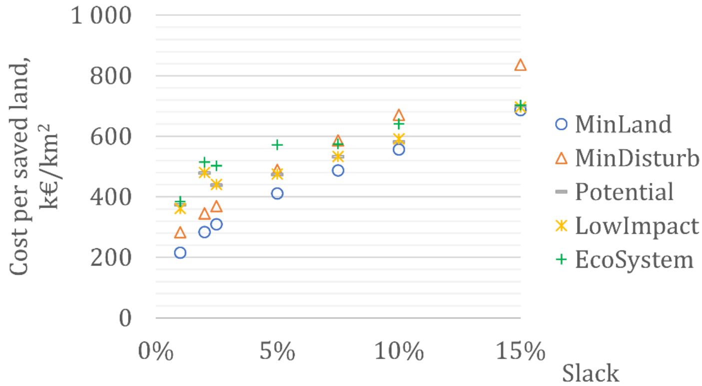

Figure 10. The annual costs per averted land by scenario.

3.4. Higher uncertainties and risks associated with less land-intensive alternatives

Nuclear power is an alternative energy source to wind and solar with modest land requirements per installed capacity. It provides a stable supply, and the costs associated with it may be cheaper than those of offshore wind in some cases. Nevertheless, nuclear power is excluded from the energy debate in many countries due to concerns about safety and risks. Regardless, nuclear power policy is rather a political decision.

In this study, it is assumed that the model can invest in nuclear power only in Finland, France, Lithuania, Poland, and the UK, and the results show that nuclear energy becomes more beneficial in these countries when land use is given increasing attention. The results are, however, sensitive to assumptions. This study does not attempt to pinpoint a "better" solution but to demonstrate the alternatives and compromises to consider when aiming to achieve a certain agenda.

It should be noted though, that both offshore wind and nuclear power are currently far more costly technologies than onshore wind and solar PV, and they also have substantially longer lead times. Policies prioritizing lower land use will hence not only be more costly but will likely also delay the energy transition towards net-zero. Moreover, the assumed cost reductions for offshore wind rely on the assumption that a global industry is able to spur technology learning that can dramatically decrease costs. Regarding nuclear power, recent examples from Finland and the UK have shown that the costs may be significantly higher than expected in these complex constructions. In summary, less land- intensive strategies are associated with a delay in climate change mitigations and higher economic risks.

3.5. The need for detailed assessments

Land-use conflicts often involve many complex aspects, such as social acceptance, biodiversity, and equality. The discussions and solutions should hence ideally be placed within a national or even local context. The value of different land types and the degree of the disruptions vary depending on history, the cultural background, economic activities, and the political climate. Moreover, the actual land requirement of the technologies depends on the plant design, technology development, and the local natural resource conditions. A study performed with field research, local surveys, and GIS tools can deliver a more tailored analysis.

Nevertheless, the purpose of this study is to illustrate the alternatives and compromises in achieving cost-effectiveness and moderating land conflicts. We have used representative assumptions and land cover statistics for approximation. While local considerations are important, this study and previous literature [6, 24, 38, 39] show how fewer investments in one region or country cause more investments in other regions or countries. The potential negative externalities may hence leak into other areas when planning does not take a holistic approach.

4. Conclusions

The present study addresses a low-carbon Northern European energy system and the land use required for different strategies regarding the energy transition. In line with existing literature, the least-cost solution includes massive investments in onshore wind power, supported by solar PV on the Continent. Such large wind and solar deployment would quadruple the land area needed for energy production in 2040 and require approximately 1.2% of the land in the modeled countries, or 3.5% when using a weightier estimate to account for a larger disturbed area from wind energy infrastructure. An alternative scenario, which minimizes the land use under the condition that the system costs cannot exceed the cost optimal solution by more than 10%, reduces the required land area by 60%. This latter scenario relies on the massive deployment of offshore wind and the increased use of nuclear power. If broader areas disturbed by both onshore and offshore wind power are considered in the optimization, the land minimizing solution leaves 31% of nuclear power in the power generation mix, and the shares of solar PV, onshore wind and offshore wind are 18%, 16% and 12%, respectively. The share of land used for energy generation varies substantially between countries due to different population densities and energy intensities. In the least-cost scenario, the land use for energy generation exceeds 4% in Belgium and the Netherlands, but allowing for 10% extra system costs can reduce their land use to approximately 1.5%.

There may be different motivations for saving land for other purposes than energy production. The scenario where the land categories of shrubland, grassland and bare land are protected leaves relatively high shares of solar PV on the Continent, in addition to substantial onshore wind in the Nordic countries. On the other hand, if energy generation infrastructures are to be avoided on agricultural land and in forest areas, in the UK, onshore wind and solar PV comprise larger market shares. The additional costs associated with the low land-use scenarios vary from €200 k/km^2 to €700 k/km^2 per year, which are manyfold when compared to any observable land values in property markets. As such, this study confirms that while many pathways to a low-carbon North European energy system are feasible, prioritizing less land-intensive alternatives over onshore wind and solar PV implies high costs per unit of land saved from energy infrastructures.

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Appendix

This section shows the summaries of the potential and cost assumptions of nuclear power (Table A.1), utility-scale PV (Table A.2), onshore wind (Table A.3), and offshore wind (Table A.4). The levelized costs of electricity (LCOE) are calculated based on a 6% interest rate over the technology lifetime.

Table A.1. A summary of the nuclear power cost assumptions.

Technology	Investment cost	Fixed O&M cost	Variable O&M cost	Fuel cost	Lifetime
Unit	M€/MW	M€/MW	€/MWh	€/MWh	year
Nuclear power	4.137	0.067	2.493	2.48	60

Table A.2. A summary of the assumptions regarding utility-scale PV's installed capacity potential and the LCOE by the modeled country.

Country	Capacity potential, GW			LCOE, €/MWh		
	Best resource	Second-best	Third-best	Min.	Average	Max.
BE	19.23		192.30	18.69	19.73	20.76
DE	199.23		1992.28	17.02	20.28	23.88
DK	34.50		344.96	18.18	19.29	20.08
EE	13.02		130.19	18.86	20.65	22.44
FI	14.69		146.94	23.52	25.36	27.20
FR	73.83	221.48	4429.55	13.79	15.96	18.70
LT	44.82		448.21	18.60	19.88	21.16
LV	22.87		228.74	18.78	20.35	21.92
NL	24.04		240.36	18.69	20.60	22.51
NO	11.65		116.46	20.00	22.83	27.50
PL	200.55		2005.50	18.18	20.80	23.42
SE	29.31		293.15	18.69	21.93	24.68
UK	27.25	81.75	1635.08	18.34	19.59	21.00

Table A.3. A summary of the assumptions regarding onshore wind power's installed capacity potential and the LCOE by the modeled country.

Country	Capacity potential, GW			LCOE, €/MWh		
	Best resource	Second-best	Third-best	Min.	Average	Max.
BE	2.20	4.38	54.75	28.55	32.44	37.80
DE	25.25	107.40	1326.50	25.56	33.48	55.13
DK	2.49	13.94	164.34	22.58	25.85	29.02
EE	3.22	12.88	161.00	26.92	34.68	42.22
FI	6.49	25.96	324.50	27.62	36.01	44.98
FR	34.10	136.41	1705.18	25.16	33.32	43.80
LT	8.98	35.92	449.00	28.77	33.09	38.52
LV	5.67	22.68	283.50	29.84	35.65	42.11
NL	1.79	7.16	89.51	24.02	29.01	34.51
NO	2.68	28.53	356.62	18.34	27.75	57.23
PL	31.40	125.59	1569.83	29.08	34.35	40.81
SE	14.27	57.08	713.50	22.16	34.45	53.44
UK	32.43	129.70	1621.25	20.07	24.03	28.80

Table A.4. A summary of the assumptions regarding offshore wind power's installed capacity potential and the LCOE by the modeled country.

Country	Capacity potential, GW			LCOE, €/MWh		
	Near-shore	Farshore, AC connected	Farshore, DC connected	Min.	Average	Max.
BE	0	0.17	0.15	49.99	55.36	60.73
DE	0.02	27.18	53.03	44.75	49.47	57.56
DK	7.85	28.99	81.25	42.55	47.67	57.10
EE	12.93	0.98	7.25	49.53	54.54	62.67
FI	29.97	8.51	33.48	55.13	60.73	69.83
FR	56.58	2.53	42.55	55.49	61.30	70.70
LT	2.15	0.39	7.28	47.93	52.76	60.62
LV	15.08	4.05	32.29	48.91	53.85	61.88
NL	0	13.01	73.83	48.58	51.16	55.92
NO	0.29	32.22	57.19	47.70	53.06	64.11
PL	4.08	8.29	24.42	46.18	50.83	58.39
SE	74.88	17.48	69.72	46.55	56.80	69.53
UK	146.31	62.12	128.70	45.41	50.31	62.12

Paper IV

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Research article

The role of cross-border power transmission in a renewable-rich power system – A model analysis for Northwestern Europe

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Variable renewable energy (VRE)

ABSTRACT

This study quantifies the economic potential of cross-border transmission to a decarbonized future Northwestern European power system through the energy model Balmorel. A scenario with modelled optimal transmission capacity at lowest total system costs is compared to the scenario with given capacity level of existing and planned projects. Increased transmission investments decrease total system costs and regional price difference. It benefits particularly wind power deployment and thus, lowers CO_2 emissions in the power and heat sector. The impacts are, nevertheless, distributed asymmetrically to northern and western stakeholders. Northern consumers receive higher power prices, but the revenues of wind and hydropower producers also increases. Meanwhile, western consumers receive lower power prices, but gas power producer revenues decrease.

1. Introduction

Large deployment of renewable energy sources is one of the major means for decarbonization in the energy sector. It is, however, well known that fluctuating characteristics of wind and solar power brings new technical and economic challenges to the energy system. To address these challenges, more solutions providing energy system flexibility are needed (Sovacool et al., 2018). The flexibility may be provided by increased supply side flexibility, new storage solutions or increased demand side management (Blumberga et al., 2015; Cebulla et al., 2017; Kirkerud et al., 2017; Skytte et al., 2017; Sneum et al., 2018; Soder et al., 2018; Tveten et al., 2016a; Vithayasrichareon et al., 2017). The main challenges for large-scale implementation are, however, high costs and/or low technical maturity for many of these options.

One potential option is increasing the interregional transmission capacities in accordance with the growing shares of variable renewable energy (VRE). Fundamentally, transmission lines are to send power from where it is generated to where it is used. Interconnecting regions opens up possibilities to exploit clean power from further or better sites and provides spatial flexibility. A larger and more diverse energy system can potentially lower total costs of energy transition (Ahmed et al., 2017; Boie et al., 2016; Tveten et al., 2016b). Indeed, to ensure meeting climate targets without sacrificing security of supply, several large-scale transmission projects are under construction or planned in Europe in the following decade (ENTSO-E – The European network for transmission system operators electricity, 2018; European Commission, 2017). An economic model by (Abrell and Rausch, 2016) have noted that transmission expansion benefits emission abatement only with increased renewable energy penetration, which coincides with European energy policy.

Some previous publications have studied the benefits of transmission in the context of fully renewable or low emission European power system. Results from (Becker et al., 2014; Rodriguez et al., 2014) have shown that transmission mitigates the need of backup energy. Schlachtberger et al. (2017, 2018) have performed a thorough analysis on cost benefits from zero to optimal grid expansions reaching a 95% CO_2 emission reduction target. Child et al. (2019) has urged that 100% renewable energy power sector by 2050 is achievable in Europe and increased transmission grids can contribute to faster defossilization at a lower cost. Nevertheless, cross-border transmission projects are complex and require long planning periods (Khuntia et al., 2016; Kishore and Singal, 2014). Several studies have also identified lack of appropriate

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regulatory design and coordination as main barriers and institutional change might be required (Andersen, 2014; Battaglini et al., 2012; Bergaentzle et al., 2019; Rumpf and Bjornebye, 2019). Increased local and general oppositions against power lines are also observed because of their health, visual and environmental impacts, but not least due to the fear of higher power prices in the exporting regions (Aas et al., 2014; European Commission, 2017). Realization of transmission projects can thus be uncertain, and it leads to further difficulties on national generation adequacy planning (Jaaskelainen et al., 2018).

The Northwestern European energy system should be particularly well suited for high geographical integration. The northern areas have abundant flexible hydropower. Other areas, like Denmark, have good potential of onshore and offshore wind power. Areas further south are well suited for solar PV and with larger energy markets. European countries have had successful experiences on emission reduction through Burden-Sharing Agreement, taking both efficiency and equality into account (Marklund and Samakovlis, 2007). Cross-border transmissions can also be seen as a physical form of regional efforts on emission reduction. Against this background, the objective of the present paper is to analyze and quantify how different levels of cross-border transmission capacities affect the power system and the power market in a decarbonized future towards 2050 in Northwestern Europe. We do so, by comparing model results from a detailed energy system model (Balmorel) where the transmission capacity is:

(i) kept constant at the current and planned level by 2030, and
(ii) allowed for additional investments in accordance with the system optimal levels.

Electric systems are complex to model by nature, in addition to the lack of transparent information from grid operators. This paper compares within the Balmorel energy system model two approaches of modelling existing transmission grids to better reflect physical flows in Northwestern Europe. Our study stands out by showing endogenous-determined generation and transmission capacities along a pathway to 2050. We reflect potential generation investment change as a result of increased competition, instead of ignoring generators response as criticized strongly by (de Nooij, 2011). Furthermore, (Schlachtberger et al., 2017, 2018) have pointed out the potential influence from other energy sector and (Thellufsen and Lund, 2017) has demonstrated the decreased benefits of transmission from sector coupling. Our model also includes the district heating sector to reflect possibility of power and heat coupling (combined heat and power generation as well as power-to-heat), although this is not emphasized in the result section below.

2. Methodology

2.1. General model design and assumptions

The analysis is performed with the open source energy system model – Balmorel (Wiese et al., 2018), programmed in GAMS language. It finds the optimal solution at the lowest total system costs, using partial equilibriums simulating electricity and district heat generation by bottom up approach. The solution satisfies a set of constraints, including (but not limited to) energy balance, technology operations, resource availability and regulatory constraints. This study uses the model version developed within *Flex4RES* project (Nordic Energy Research, 2018).

The objective of the model is to supply electrical and heat energy to cover demand in the modelled system: therefore, the demand-side consumption profile variation is a major driver of flexibility need. VRE such as supply from wind turbines and PV panels are another major source of flexibility need. Although their generation can be curtailed, the available power generation is constrained by the availability of the relevant resource. Inflexibility from demand and VRE is matched by a variety of flexibility options in the model: conventional thermal power plants, electricity- and heat storages, reservoir hydro power plants, power-to-heat technologies and cross-regional transmission capacity. The amount of hydro power plants is assumed to be constant throughout the modelling period, because of the assumption that the majority of feasible hydro power sites have already been utilized. The amounts of conventional, VRE generators, storages and power-to-heat technologies in the system are an endogenously modelled based on cost minimization principle. Flexibility from demand-side management, electric vehicles has not been considered in this modelling exercise.

The studied period covers the base year 2016 and every decade from 2020 to 2050. For an efficient but representative calculation, we aggregate modelled time series in a year into four seasons with 24 h each by duration curves and energy demand and renewable resource profiles in 2012, taking spatial and temporal correlations into account. The modelled countries consist of countries from Northern Europe (Nordics and Baltics, excluding Iceland) and from Western Europe (Belgium, Netherlands, France, Germany, Poland and the UK). In this analysis, most of our discussions focus on these two aggregated parts of Europe.

Costs and technical data of technologies, existing generation and transmission capacities, planned commissioning and decommissioning, energy demand, fuel and emission prices are determined exogenously. Table A.1 presents an overview of the most important assumptions. NETP 2016 project (Nordic Energy Research, 2016) serves as the main reference of input data. For emission costs assumptions, we apply European Emission Trading System (EU ETS) prices development in Current Policies Scenario in World Energy Outlook (2016) from IEA (International Energy Agency, 2016). The emission prices applied have moderate growth to reflect a scenario with no future presence of ground-breaking low-carbon technologies (Lundgren et al., 2015). Endogenously defined new power generation and storage capacity investments are allowed from 2020 and the decisions are made with a myopic view of the current modelled year.

2.2. Transmission modelling

This study models the transmission grid in a simplified manner, by depicting transmission capacities between regions. Nordic and Baltic countries are divided as in the bidding areas in the European power exchange Nord Pool (Nord Pool). The other countries are modelled as one region itself, except Germany which is divided into four regions. One aggregated line is assumed across two regions. This study uses two different approaches to model transmission grids: net transfer capacity (NTC) and flow-based (FB). The NTC approach is a more conservative method. To avoid physical power line constraints, both AC and DC grids are modelled as DC lines but use only the capacities that is always feasible regardless operation modes. The FB approach approximate actual power flows by power transfer distribution factors (PTDF) and line capacities. It relaxes capacity constraints compared to the NTC approach and allows more efficient grid utilization.

The mathematical formulation of the NTC approach is $z^{NTC} \leq \overline{z}^{NTC}$, where power flow z^{NTC} is bounded by the maximum line capacity $\overline{z}^{NTC}$. Same restriction applies in the FB approach that $z^{FB} \leq \overline{z}^{FB}$, where power flow z^{FB} is bounded by the maximum line capacity $\overline{z}^{FB}$. The magnitude of the maximum line capacities in the two approaches are different. NTC capacities ($\overline{z}^{NTC}$) are artificial flow potentials, calculated and published by the transmission system operator (TSO) in advance for market operators. FB capacities ($\overline{z}^{FB}$) are actual thermal limits of transmission lines. In addition, the flow dependencies in AC grids are described by $PTDF \times NEB^{FB} \leq \overline{z}^{FB}$ in the FB approach. The $PTDF$ is a dense matrix showing the inverse of the sparse line reactance matrix and it distributes flows according to the net balance NEB^{FB} at every single node in the system. As a TSO has to take into account all potential flows within a longer period, $\overline{z}^{NTC}$ is usually a conservative estimation. Contrarily, the FB approach allows for continuous updates on e.g. hourly basis which allows for a better utilization of the lines for the respective hour and system status. Therefore, the feasible operation space with the FB approach is equal or larger than the NTC approach, but at the same time, it accounts physical flows from the AC system in the model. Fig. 1 illustrates potential operation modes and feasible areas in both approaches.

In this study, both approaches are applied to existing AC transmission grids and results are compared. Any new grid is modelled by NTC approach i.e. as DC lines, to maintain a reasonable calculation time. Existing and announced grid capacities refer to PyPSA-Eur (Horsch et al., 2018) and grid development plans (ENTSO-E – The European network for transmission system operators electricity, 2018). Fig. 2 demonstrates the geographical modelling scope with the aggregated AC and DC transmission lines in the FB approach. Cost data of new transmission capacities are in principle derived from or estimated by established projects, assuming an annuity payment factor of 4.5% over 40 years. Table A.2 lists the total investment costs of transmission lines per capacity by connecting regions.

An efficiency of 95.8% and operation and maintenance cost of 0.1€ per MWh is applied to all transmission lines. In addition, lines have capacity rating at 90% to simulate potential power line outages.

2.3. Studied scenarios

This study aims to demonstrate impacts of cost-optimal level of transmission capacity, compared to existing and planned level. The reference scenario "Planned", as described in (i) in the introduction section, represents limited transmission expansion, causing by possible opposition or late planning. The "Optimal" scenario, as described in (ii) in the introduction section, removes constraints on transmission capacity expansion. Additional transmission capacities can be invested from 2030 in order to reach least system costs.

3. Results and discussions

3.1. Optimal transmission capacities

The modelling results demonstrate significant difference between the planned and the optimal level of transmission capacity expansions. Fig. 3 illustrates the results by the transmission modelling approach of existing AC grids in FB and NTC approach. In both approaches, exogenous and endogenous transmission expansions since 2030 are modelled as DC lines. Note that only cross-border transmission capacities are

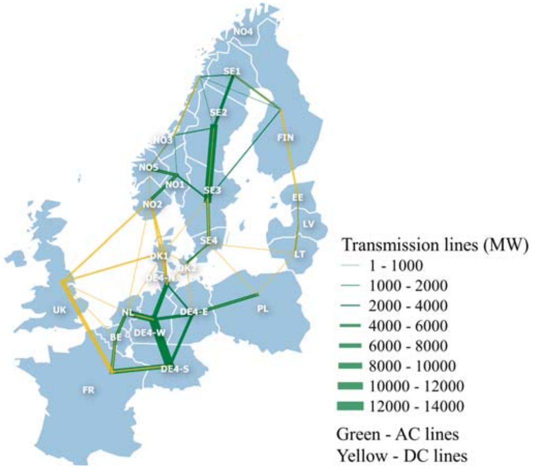

Fig. 2. Maps of the modelling regions in Balmorel with assumed AC and DC transmission capacities in the "Planned" scenario in 2030 with the FB approach.

discussed here.

Applying FB approach implies more existing grid capacities can be used, compared to a more conservative NTC approach. Although it potentially requires indirect transmission expansion, the optimal solution shows an overall 15 GW less of optimal cross-border transmission expansion. In the FB approach, while the planned cross-border transmission projects include around 21 GW by 2030 (half of which within western countries), the optimal investment suggests additionally 44 GW (half of which connect west and north). From 2030 to 2050, the optimal investments of cross-border transmission capacities reach over 76 GW. Compared to the planned capacity expansion by 2030, the additional endogenous investments between 2030 and 2050 suggest around four times more of the planned scale. The NTC approach suggests 20% more of endogenous investments compared to the FB approach.

Fig. 4 disaggregates the capacities by connecting countries and reveals further details by showing differences between optimal and planned capacities by 2050. In FB approach, the optimal scenario has close to 10 GW more of the capacity compared to the planned scenario in

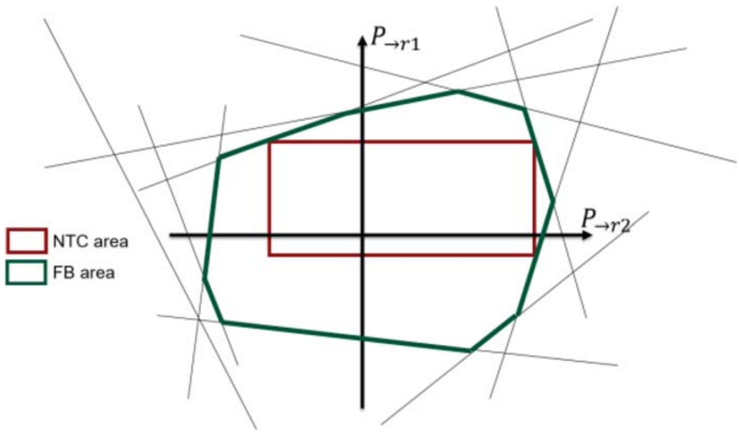

Fig. 1. Illustration of the feasible areas in an AC grid of two power flows from one node to region r1 and to region r2 in the NTC approach (red) and the FB approach (green). Black lines are the flow constraints from different transmission lines in the grid.

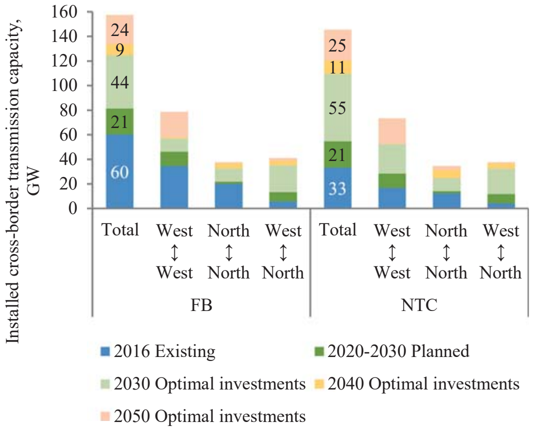

Fig. 3. Existing, endogenously and exogenously invested cross-border transmission capacities from 2016 to 2050 with FB approach and NTC approach of existing transmission grids.

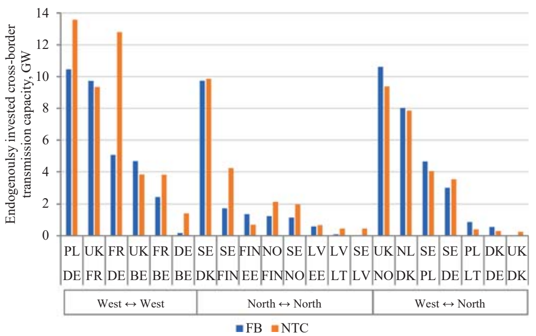

Fig. 4. Modelled endogenously invested transmission capacities until 2050 by interconnecting countries with FB approach and NTC approach of existing transmission grids.

Poland–Germany, the UK–France, Sweden–Denmark and the UK–Norway. The connection of Sweden–Poland is a completely new endogenous investment of 4.6 GW. Meanwhile, several lines do not increase their capacities endogenously, namely Belgium–Netherlands, Germany–Netherlands, Netherlands–the UK, Lithuania–Sweden, Germany–Norway, Netherlands–Norway and Denmark–the UK, apart from the planned ones. Some connections require more capacities, compared to NTC approach, even though the total amount decreases, reflecting complexities of AC and DC grid modelling due to physical constraints.

3.2. Power generation capacity mix

The development of installed power generation capacity in the planned scenario is shown in Fig. 5. As a result of coal and nuclear decommission policies, as well as increasing carbon prices, VRE is to a large extent replacing fossil fuels towards 2050 in both western and northern regions. The required capacity for a secure energy supply increases with increasing VRE share.

The modelling of endogenous grid investments shows that when optimal transmission capacities are in place, more renewables can

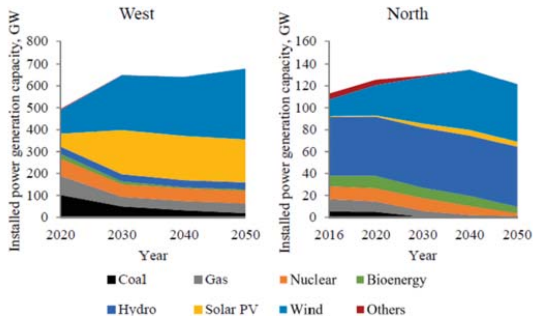

Fig. 5. Modelled installed power generation capacity in the planned scenario by fuels from 2020 to 2050 with FB approach of existing transmission grids in Western and Northern Europe.

substitute fossil fuels. With the FB approach, 26 GW of wind from Northern Europe together with 13 GW of wind in Western Europe replace 30 GW of fossil fuel based generation in the west (Fig. 6). Although other renewables also have more installed capacities, increased transmission capacities benefit significantly more to wind than to other renewables because it has more diverse production profiles across geographic regions, compared to solar PV that has more uniform generation profile. Higher transmission capacities provide compensating possibilities from wind power to other regions. Wind resource is also better in the north than in the western regions in the sense of full load hours and generation profiles, which leads to lower costs of new wind energy and more extensive investments into wind in the north than in the west when transmission capacity is large enough.

3.3. Emission impacts

Fig. 7 shows the modelled relationships between assumed EU ETS prices and total CO_2 emissions from the power and district heat sectors for both scenarios. From 2030, fossil-based power generation is largely replaced by renewables because of both decommissioning policies and higher carbon prices, but it still leaves over 263 million tons of CO_2 emissions. In 2050, emissions are further reduced to 69 million tons. Allowing more transmission capacities contributes to further 25% emission reduction in 2030 and brings the emission down to 24 million tons in 2050.

With the assumed carbon prices, Northern European countries almost achieve their carbon neutral target by 2050 without additional transmission capacities. The effects of transmission lines in emission

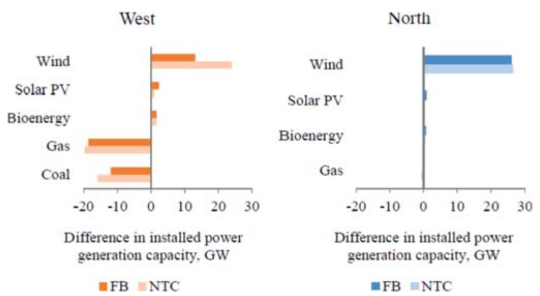

Fig. 6. Modelled difference in installed power generation capacity in 2050 by fuels between the optimal and the planned scenarios with FB approach and NTC approach of existing transmission grids in Western and Northern Europe.

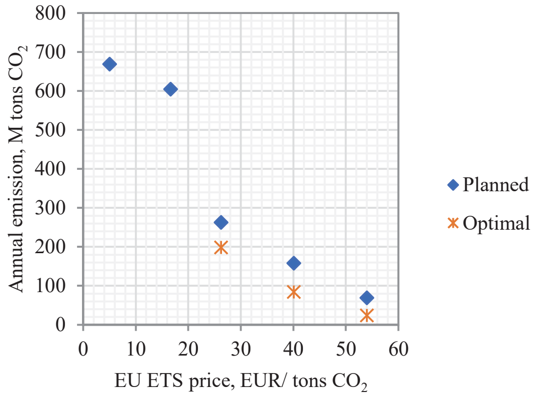

Fig. 7. Total emission levels in all model countries and corresponding EU ETS price assumptions in each modelled year.

Table 1
Modelled difference in CO_2 emission levels in million-ton between the optimal and the planned scenarios from 2030 to 2050 in western and northern Europe.

Region	2030	2040	2050
West	−65	−73	−45
North	0.70	0.04	−0.13

reduction are, however, more obvious in western region where currently thermal power dominates (Table 1).

3.4. Power prices

The annual prices in Fig. 8 are represented by chronological averages of marginal costs of electricity. Increased transmission lines lift average prices of all modelled countries up a little but decreases spatial and temporal price differences. Taking Norway and the UK as an example, in 2020 with 1.4 GW of planned interconnector, the price difference stay around 25€ per MWh until 2050. If the transmission capacity between the two countries expands 10 GW more by 2050, the price difference decreases to 10€ per MWh instead. Increasing transmission lines shifts up prices in low-price regions (i.e. Norway), drives down prices in high-

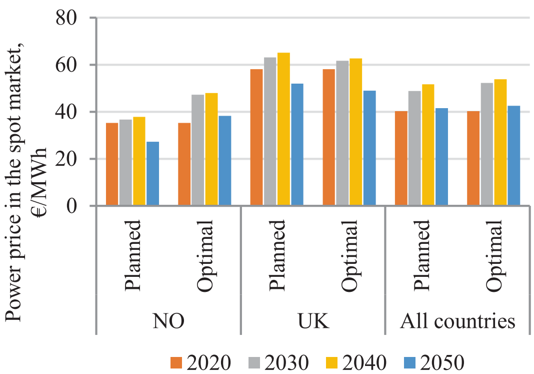

Fig. 8. Modelled average power prices from 2020 to 2050 in Norway, the UK and all modelled countries.

price regions (i.e. the UK) and leads to closer relations of power prices between connecting regions.

3.5. Distributional effects

Allowing optimal transmission capacities lowers the total system costs (Fig. 9). Additional transmission investments replace parts of fuel and emission costs. It is a win for all modelled countries as one in the economic aspect.

However, benefits from transmission lines are distributed asymmetrically not only among producers and consumers but also in different countries. Fig. 10 shows the modelled producer revenues and consumer costs in 2050 of the planned scenario and the optimal scenario. Producer revenues are defined as sum of spot prices multiplied by power generation in each hour and consumer costs are defined as sum of spot prices multiplied by power consumption. For gas power producers in western region, revenues from power generation decrease by 4 billion euros when more transmission capacities are in place. Nuclear power producers receive a billion-euro higher revenues in the optimal scenario though. In addition, consumers in western countries can save almost 6 billion euros, equivalent to 3€ per MWh. Northern power producer revenues increase by 8 billion euros. The biggest winners are hydropower producers that count half of the increase, followed by wind power producers with the highest growth rate of 67%. But the consumer costs of electricity in the Northern countries increase by 3 billion euros, equivalent to 21% higher per unit of electricity. The unequally distributed benefits among stakeholders within and between countries needs to be addressed by authorities in order to utilize the flexibility potential of increased transmission grids. If addressed well, it might help gain local supports as in wind farm experiences (Mulvaney et al., 2013; Warren and McFadyen, 2010).

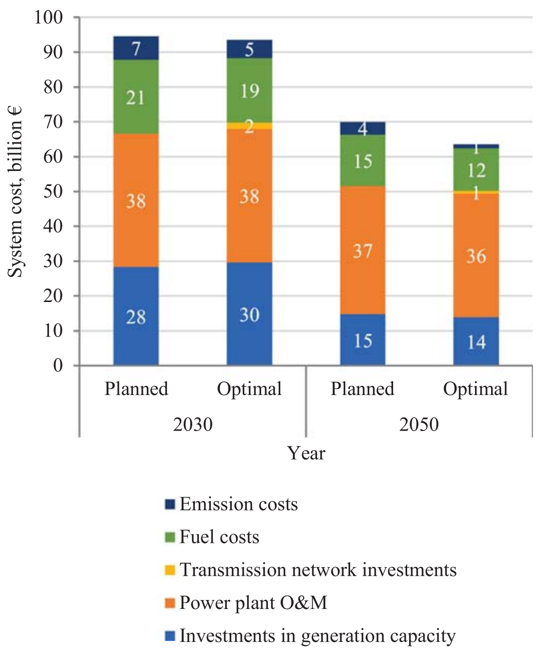

Fig. 9. Total system costs and cost components in 2030 and 2050 with FB approach of existing transmission grids.

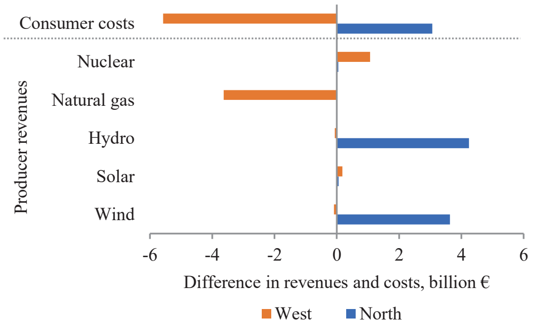

Fig. 10. Modelled difference in producer revenues by fuels and consumer costs between the optimal and the planned scenarios in 2050 with FB approach of existing transmission grids in Western and Northern Europe.

4. Conclusions

This paper quantifies the economic impacts of cross-border transmission in Northwestern Europe using an energy system model which includes a detailed representation of the power as well as the district heating sector. The "planned" scenario defines transmission capacities exogenously as the existing level in 2016, plus the planned level by 2030, remaining constant until 2050. In the "optimal" scenario, the model additionally allows endogenous transmission investments from 2030 to 2050. We adapt both FB and NTC approaches to model existing grids but focus on results from FB approach. All new grids are modelled by NTC approach or as DC lines.

The optimal scenario suggests additional 76 GW of cross-border transmission capacity expansion from 2030 to 2050, which is almost four times of the planned expansion (21 GW) by 2030. With increased transmission capacity in place, more wind power is installed to substitute fossil fuel based energy, contributing to 40% less of total emission between 2030 and 2050. Total system costs also decrease by more than 5% in the "optimal" scenario relative to the "Planned" scenario. Benefits from higher transmission capacities are, nevertheless, asymmetrically distributed among regions and players. In terms of generation technologies, wind power benefits significantly more than any other technologies, including solar PV, thanks to its diverse spatial production profiles. In terms of regions, Western European countries experience decreases in producer revenues and consumer costs, while the opposite happens to Northern Europe. In average, western consumers pay 6% less per unit of electricity, but prices for northern consumers are 21% higher. The study demonstrates why internationally asymmetric benefits and costs is likely a main barrier to increased power exchange cooperation in the future but it also indicates potential resolutions through cooperation and proper policy design. Policies that can mitigate these distributional effects are probably necessary for a full utilization of the large benefits of high transmission line capacities in renewable-rich power systems.

The results of this study can support energy system planners and investors on their decision-making and reinforce the importance of cross-border power transmission in the energy transition context.

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Appendix. Model assumptions

Table A.1
Assumptions of fuel prices, emission prices and annual electricity demand from 2016 to 2050.

	Fuel prices				Emission prices	Annual electricity demand	
Unit	€/MWh				€/tCO_2	TWh	
Year	Coal	Lignite	Natural gas	Biomass		North	West
2016	7.6	4.5	15	22–31	5	400	1715
2020	8.3	2.7	20	22–31	17	401	1750
2030	9.6	3.7	30	30–38	26	403	1788
2040	9.9	3.6	33	37–45	40	393	1734
2050	10.1	3.5	37	39–47	54	381	1732

Table A.2
Investment cost assumptions in k€ per MW of new transmission lines applied in the study.

Link	Cost
NO2—UK	1215
DK1—UK	1196
NO2—DE4-N	1186
SE3—EE	1000
SE3—LV	1000
SE4—LT	990
NL—UK	872
SE4—PL	862
DK1—NL	843
SE3—FIN	794
SE3—DK1	774
FR—UK	735
SE4—DE4-N	725
NO2—DK1	696
FIN—EE	676
BE—FR	568
DE4-E—DE4-N	568
DE4-E—DE4-S	568
DE4-E—DE4-W	568
DE4-E—PL	568
DE4-S—FR	568
DE4-S—NL	568
DE4-W—DE4-N	568
DE4-W—DE4-S	568
DK1—DE4-N	568
DK2—DE4-N	568
LT—PL	568
NO1—NO3	568
NO1—SE3	568
NO3—NO4	568
NO3—SE2	568
NO4—FIN	568
SE1—FIN	568
SE1—SE2	568
SE2—SE3	568
SE3—SE4	568
BE—DE4-S	539
NO4—SE2	539
NO1—NO5	519
DK1—DK2	510
NO1—NO2	510
NO3—NO5	510
NO2—NO5	490
NO4—SE1	490
BE—NL	451
EE—LV	451
LV—LT	451
SE4—DK2	421
BE—UK	402

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