THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

The roles of transmission and distribution networks in integrating variable renewable electricity generation

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ABSTRACT

Emission reduction targets, together with other factors, such as security of supply, are driving the expansion of variable renewable energy sources for electricity generation, mainly solar and wind power. Trading across the transmission grid is an important measure to handle the increased variability and to balance supply with demand. Connecting generation capacity at the distribution level as distributed generation may confer benefits on the system, although it could also impose new requirements on distribution systems. This work applies a cost-minimising investment model together with several economic dispatch models to study how transmission and distribution grids can be used in future scenarios with high penetration levels of solar and wind power.

We show that new congestion patterns arise in the European transmission system as a result of expansion of wind and solar power capacities, due to the low marginal costs of electricity at times of high output from these technologies. Furthermore, our results show that such instances of congestion may be difficult to handle with alternative variation management strategies, such as demand-side management (DSM), whereas for peak-load congestion, DSM may be an alternative to grid capacity expansion. We also find that rapid expansion of solar power generation within Europe could have a significant impact on marginal costs of electricity and could cause significant congestion during sunny seasons if its geographical distribution is uneven. However, we also show that distributed solar power can help to reduce losses if installations are optimised to maximise local consumption.

Keywords: energy systems modelling, power systems, electricity generation, variable renewables, demand-side management

Sammanfattning

Mål för utsläppsminskningar och även andra faktorer som försörjningstrygghet driver en utbyggnad av variabla förnybara energikällor för elproduktion, huvudsakligen sol- och vindkraft. Handel genom transmissionsnätet är ett viktigt verktyg för att hantera de ökade variationerna och balansera produktion och efterfrågan. Kapacitet som kopplas in på distributionsnätsnivå som distribuerad kapacitet kan också ge systemfördelar, men ställer nya krav på distributionssystemen. Detta arbete tillämpar en kostnadsminimerande investeringsmodell i kombination med flera produktionsoptimeringsmodeller för att studera hur användningen av tranmsissions- och distributionsnät kan komma att ändras i framtidsscenarier med höga nivåer av sol- och vindkraft.

Vi finner att expansionen av sol- och vindkraft kan leda till nya flaskhalsmönster i det europeiska transmissionssystemet på grund av de låga marginalkostnader på el som uppstår vid tidpunkter med hög produktion från dessa källor. Vidare visar resultaten att denna typ av flaskhalsproblematik kan vara svår att hantera med alternativa strategier som demand-side management (DSM), medan DSM kan vara ett alternativ till utbyggnad av transmissionsnätet i de fall där flaskhalsproblemen orsakas av hög efterfrågan. Vi finner också att en snabb utbyggnad av solkraft i Europa kan ha en betydande påverkan på marginalkostnaden för el och kan orsaka signifikant flaskhalsproblematik under soliga årstider om kapaciteten är geografiskt ojämnt fördelad. Å andra sidan visar våra resultat att distribuerad solkapacitet kan bidra till minskade förluster om installationerna optimeras för lokal konsumption.

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Joel Goop

Appended publications

This thesis consists of an extended summary and the following appended papers:

Paper I L. Göransson, J. Goop, M. Odenberger and F. Johnsson (2013). 'The role of Nordic hydropower to handle variations in the future European electricity system'. In: *Proceedings of the 12th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants (London, UK, 2013).* Langen, Germany: Energynautics, pp. 293–297.

Paper II L. Göransson, J. Goop, T. Unger, M. Odenberger and F. Johnsson (2014). 'Linkages between demand-side management and congestion in the European electricity transmission system'. *Energy* **69**, pp. 860–872.

Paper III J. Goop, M. Odenberger and F. Johnsson (2015a). 'Distributed solar and wind power – Impact on distribution losses'. Submitted for publication.

Paper IV J. Goop, M. Odenberger and F. Johnsson (2015b). 'Congestion patterns in the European electricity transmission grid with high levels of solar generation'. Draft, to be submitted for publication.

Papers I and II are the result of joint work with Lisa Göransson, whereby the author contributed with analysis and writing. Mikael Odenberger and Filip Johnsson have contributed with discussions and editing for all papers. Thomas Unger has contributed with discussions and editing for Paper II.

OTHER PUBLICATIONS

Other publications by the author not included in the thesis:

A L. Reichenberg, J. Goop, F. Johnsson and M. Odenberger (2013). ‘Maximizing value of wind power allocation : a multi-objective optimization approach’. In: *Proceedings of the 12th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants (London, UK, 2013).* Langen, Germany: Energynautics, pp. 804–807.

B J. Kjärstad, J. Goop, M. Odenberger and F. Johnsson (2014). ‘Development of a Methodology to Analyze the Geographical Distribution of CCS Plants and Ramp-up of CO2-flow Over Time’. *Energy Procedia* **63**, pp. 6871–6877.

Contents

CHAPTER 1

Introduction

Electricity has become a necessity in modern society. Everything from the computers that we use daily and associated communications infrastructure to public transportation systems all depend on a continuous and reliable supply of electricity. This supply has traditionally been dominated by plants that burn fossil fuels to create steam, which is then run through a turbine to generate power. Coal, natural gas, and oil account for the vast majority of the primary energy use for electricity generation globally (International Energy Agency, 2014a). As a consequence, power generation plants emit large amounts of CO_2. According to the International Energy Agency (2014b), electricity and heat generation accounted for 42 % of global CO_2 emissions in 2012. To combat anthropogenic climate change, it is clear that the power sector will have to undergo a comprehensive overhaul to significantly reduce its emissions. In the IPCC Fifth Assessment Report, CO_2 emissions from electricity generation are reduced to zero or negative levels before Year 2100 in all scenarios in which CO_2 concentration in the atmosphere is stabilised (Bruckner et al., 2014).

However, climate change is not the only issue, and other environmental problems as well as other concerns, such as security of supply, spur initiatives to reduce our dependence on fossil fuels and develop renewable energy sources for electricity production. Fluctuating or variable renewable power generation, in the form of wind and solar power, is currently growing quickly and will have to play an even greater role in the future, if emission targets are to be reached.

It is a fundamental property of electricity that there is always an equilibrium between the power that is fed into and taken out of the grid. Historically, demand has been the major unknown variable, and the operation of power plants has been adjusted to keep the system balanced. Every time a light was turned on somewhere a generator, connected to the same grid, had to increase its power output. With increasing amounts of electricity being generated from variable renewable energy sources, i.e., sources for which the dispatch is limited by weather conditions, the situation could be reversed and the supply side could become the main source of variability in the electricity system. Thus, whenever wind power generation increases or decreases, the surrounding system must adapt to maintain the balance.

There are several strategies to address variable generation. The traditional approach is to use dispatchable units already in the system, such as hydropower or conventional fossil-fuelled power plants. An alternative is the use of demand-side management (DSM) techniques, whereby electricity consumption is controlled, either by shedding load or shifting it in time. Storage of electricity, e.g., in batteries or pumped hydro storage, can also be used to manage variations in generation. Finally, and of most relevance to the present work, variability can be handled using the electric grids. The variations in the supply of, for example, wind power, can be reduced by trading across a geographical area that is sufficiently large so that the correlations between weather patterns decrease. In some cases, this can be accomplished by expanding the transmission grid. One can also build transmission capacity to access existing flexible assets and, for example, use Nordic hydropower to manage variations in continental Europe.

Distribution grids may also play an important role in integrating new renewable generating capacity. Since wind and solar power can be installed as relatively small units, they can be located in proximity to consumers, through distributed generation. This confers potential system benefits, such as reduced grid losses, and also enables close integration with DSM systems and local storage.

The grid infrastructure, which includes the transmission and distribution lines, transformers, and other equipment, has a relatively long life-time. Therefore, when we investigate future scenarios for the grids, it is appropriate and important that we base our analysis on the system that is currently in place. The work of this thesis is primarily concerned with how transmission and distribution grids could be utilised differently in future scenarios with a high penetration of variable renewable electricity generation. All the explored scenarios are firmly rooted in the present system.

1.1 Aim and scope of this thesis

This study focuses on how the role of the electricity transmission and distribution grids change as the penetration levels of variable renewable electricity generation increase and as consumers become engaged more actively through distributed generation and DSM. The overall aim is to obtain some insights into how all levels of the electricity grids, from transmission to distribution, interact and affect the challenges and opportunities for transforming the energy system to be more sustainable. The following important questions arise:

- How will the usage of transmission and distribution grids change as the levels of variable renewable electricity generation increase?
- How will the usage of the grids differ if there is a strong solar power expansion compared with a situation in which wind power dominates the renewable sources?
- Will grids be used differently if DSM is adopted widely?
- To what extent would it be beneficial to deploy renewable generation as distributed generation?
- What aspects of the electricity grids are important to consider when drafting policies that will affect the future energy system?

As these are broad questions, I cannot hope to provide complete answers to all of them in this thesis. Hopefully, the work presented here will improve our understanding of the underlying issues and clarify some aspects of each question.

This work does not focus on the technical details of grid operation. Instead, it attempts to place electricity grids in a techno-economic systems modelling context. Therefore, the scope is limited with respect to determining the technical requirements for the grid within the investigated future scenarios. In addition, the scope is restricted to the technical energy system and we do not model macroeconomic processes, which means that, for example, demand growth is exogenously given as an input to the models. The primary tools employed are an investment model, which is used to describe the evolution of the electricity supply system in different future scenarios and economic dispatch models, which are used to analyse the operational characteristics of the systems.

1.2 Related work

The issues related to the future development of electricity grids are approached from many different angles in the literature. Some studies have concluded that significant extensions of the transmission grid will be necessary as the penetration of variable renewable sources increase (see, for example, Kohler et al., 2010; Tröster et al., 2011).

Using an iterative approach, Fürsch et al. (2013) attempted to determine cost-optimal grid extensions in scenarios with 80 % renewables and 80 % reductions in CO_2 emissions. They optimised investments in grid and generation capacities in Europe one decade at a time up to Year 2050. For each decade, they also iterated between a "market model", an expanded version of an investment and dispatch model developed by Richter (2011), and a "transmission grid model" developed by Energynautics (for which they did not provide a reference). This procedure was meant to ensure that grid investments in the market model were correctly valued. Fürsch et al. found that integrating 80 % renewables in Year 2050 in a cost-optimal way would require a 76 % increase in the total transmission line length compared with the present situation. They also concluded that large investments in grid infrastructure would be motivated if they enabled utilisation of favourable renewable resources, and that grid extensions would generally be favoured over storage, which was used sparingly in their analysis.

The issue of transmission grid extensions to integrate variable renewables was also studied by Schaber et al. (2012). They used a linear cost-minimising model to identify optimal grid extension investments up to Year 2020. In their model, Europe was divided into 83 regions and optimised over 6 representative weeks from each of 8 years of weather data. Using this model, they investigated how revenues for power plant owners was geographically distributed in different scenarios and found that in the absence of extensions to the current grid there were significant differences in revenues, which could be evened out with cost-efficient investments in grid capacity.

When it comes to the distribution-level impacts of increased penetration levels of variable renewables, several studies have investigated the technical aspects of or strategies for connecting wind and solar power to distribution grids (Ai et al., 2014; Ochoa et al., 2008; Salih et al., 2014). Various groups have also investigated methods for determining the optimal size and location of these distributed generation plants (Gampa and Das, 2015; Moradi and Abedini, 2012). These studies generally represent distribution networks, as well as generators and loads in relatively high detail, although they are typically applied only to a small test network or a selected existing distribution network.

Tapia-Ahumada et al. (2013) adopted a more systems-oriented approach to study the impacts of distributed, micro-scale combined heat and power (micro-CHP). They used a combination of a long-term generation capacity expansion model, a short-term power dispatch model, and a separate model to optimise locally the usage of the micro-CHP based on electricity prices from the dispatch model. The local optimisation created a new load curve, which was fed back to the dispatch model in an iterative procedure. Their results showed that while micro-CHP could bring system benefits such as reduced emissions and peak load, the accrued benefits were dependent upon the technology mix of the surrounding electricity generation system and how the electricity tariff was formed.

1.3 Contribution of this work

The usage of electricity grids is strongly influenced by the economics of generation and the location of the generating power plants. Using techno-economic modelling, we can study how the usage of the grid changes in different future scenarios, and how it is affected by the development of the electricity generation system. It also enables us to investigate trade-offs between using the grid to manage variations and using other strategies, such as DSM or the cycling of thermal power plants.

While many studies in the literature have investigated the operation of transmission and distribution grids in much greater technical detail, we apply models that include a more developed description of the generation system. As more variable renewable sources enter the system, we also want to investigate how different variation management techniques, such as thermal power plant cycling and DSM, influence how the grid is used. Compared with other studies that have employed similar techno-economic modelling approaches, our focus is on how the grid is used in different future scenarios, that is, how trade patterns change or when and why congestion occurs, rather than the extent to which grid investments are needed or where the grid needs to be strengthened.

1.4 Disposition of the thesis

This thesis consists of four appended papers and this extended summary. The extended summary is divided into five chapters, where this introduction is the first. Chapter 2 explains some of the basic concepts for readers who are not familiar with the field and provides some context for the work, as well as a review of the relevant literature. Chapter 3 describes the main modelling techniques, input data, and assumptions used in the papers upon which the thesis is based. Chapter 4 presents the main findings from the work and, finally, Chapter 5 summarises the most important conclusions, discusses the validity of the results, and suggests pathways for future research.

CHAPTER 2

Background

This chapter provides a short introduction to concepts that are important for understanding the methods used and the results derived in this work.

2.1 Basics of electricity grids

To understand how grids are structured, we must introduce some basic concepts of electric circuits. We start with the potential, or voltage, defined at any point in an electrical circuit. The voltage at a given point is the energy that must be added per unit charge to bring a charged particle to that point from a zero potential reference, also known as the ground. We can now say that the particle possesses a certain amount of potential energy, since it has a natural tendency to "fall" back to the ground level and release its potential energy. An analogy is the water in a hydropower dam, which possesses potential energy because of its position above the zero-potential sea level. When the water is let out it releases its potential energy by falling towards the sea level, and that energy can be harvested and converted into mechanical or electrical energy. The higher the water can fall, the smaller the volumes that need to flow to extract a certain amount of instantaneous power. This concept can be translated back to electricity, where the volume of water flowing is analogous to the flow of charge in an electric circuit, called the current. The higher the voltage, the lower the current required to transmit a certain amount of instantaneous power. An introduction to the concepts of charge, voltage, and current can be found in the book by von Meier (2006).

The purpose of electricity transmission and distribution grids is to deliver power to those who want to consume it, at the locations and times that the consumers demand it. Electricity must also be supplied in a form that is amenable for consumers to use, which, among other things, means that the voltage has to be that required by the consumers' appliances. While this utilisation voltage varies around the world, it has been chosen to be safe and practical, typically in the range of 100–250 V (Willis, 2004). However, losses in transmission lines are related to the current flowing in the line, and if one attempted to transmit large quantities of power at these low voltages, the currents (and, as a consequence, the losses) would be very high. Since the alternating current systems that we mainly use for power transmission allow for relatively easy transformation between voltages, we usually choose high voltages when moving large amounts of power over long distances. However, there is a trade-off here as well, since equipment and lines for use at high voltages are significantly more expensive than those for low voltages. All these facts in combination with the traditional modes for generating electricity, which is also much more economical if performed in large centralised plants, has led to a system of hierarchical voltage levels (Willis, 2004). In this system, the centrally produced power is first transported in bulk at high (stepped up) voltage. As the grid branches out to reach all the consumers, less and less power flows in each individual branch, and the voltage is stepped down.

2.2 Power flow in AC networks

This section aims at giving the reader an understanding of the fundamentals of how AC power transmission works, even though it is only handled with strong simplifications in the modelling in the present work.

An AC transmission system is a network of nodes (also called buses), in which power can be absorbed or injected into the network. The edges that connect the nodes are transmission lines and other equipment, such as transformers. The electrical properties of each line (together with other pieces of equipment connected to the network) as well as what happens at each bus in terms of consumption or production, determines how power flows over the lines in the network. The work in this thesis does not focus on technical modelling of electric power systems, and we apply only a simplified power flow method in parts of the modelling. However, a basic grasp of AC power flow (sometimes called load flow) will help a reader understand the methods used and their limitations, as well as put the work in a proper context.

To understand AC power flow, we introduce the concepts of real and reactive power. In a direct current (DC) circuit, the power absorbed by a load is $P = VI$, where V is the voltage drop over the load and I the current through it. In an AC system in steady state, voltage and current vary over time as sinusoidal curves with the same frequency (usually 50 Hz in European power systems), but may be phase-shifted by a phase angle ϕ. Since both voltage and current vary with time, so does the instantaneous power $p(t) = v(t)i(t)$ absorbed by a load in an AC circuit. A load in an AC circuit can be thought of as having a resistive part R and a reactive part X, which combine into a complex impedance $Z = R + jX$. A purely resistive load only dissipates heat from the circuit and does not alter the phase of voltage or current. A purely reactive load shifts voltage and current 90° out of phase with each other, so that power is alternately absorbed by the load and returned from it. The average power absorbed by the resistive part of the load is known as real power and is $P = V_{\text{rms}} I_{\text{rms}} \cos\phi$, where V_{rms} and I_{rms} are the root mean square values of the voltage and current respectively. The real power is measured in the unit of watt (W) and is the only part of power that can do actual work at the load. The power absorbed by the reactive part of the load averages to zero over time, but has an amplitude of $Q = V_{\text{rms}} I_{\text{rms}} \sin\phi$. Q is known as the reactive power and although it has the same physical unit as P it is usually measured in volt-amperes reactive (var). The reactive power flow determines the maximum instantaneous current through lines and transformers and the resistive heat losses are proportional to the square of the current. Thus, reactive power transfer may limit the capacity for real power transfer in lines and transformers. (Glover et al., 2008)

To mathematically model the power flows in an AC network, four variables describe each bus i: voltage magnitude V_i and phase angle

δ_i, as well as real and reactive power (generated or consumed) P_i and Q_i. For each bus, two of the quantities are given as input and two are computed when solving the power flow problem. Which of the quantities that are specified for a given bus depends on what is connected to it. By applying Kirchoff's current law to a network with $N+1$ buses, we can obtain power balance equations for node i

$$P_i = V_i \sum_{k=1}^{N} V_k \big(G_{ik} \cos(\delta_i - \delta_k) + B_{ik} \sin(\delta_i - \delta_k)\big) \tag{2.1}$$

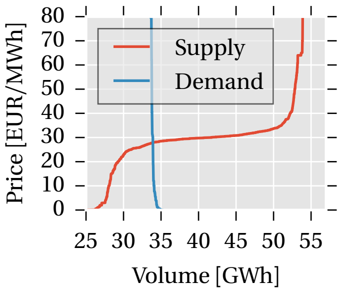
$$Q_i = V_i \sum_{k=1}^{N} V_k \big(G_{ik} \sin(\delta_i - \delta_k) - B_{ik} \cos(\delta_i - \delta_k)\big) \tag{2.2}$$

where G_{ik} is the conductance and B_{ik} the susceptance between the nodes i and k. The conductance and susceptance are the real and imaginary parts of the admittance $Y = G + jB$, which is the inverse of the impedance Z. (Glover et al., 2008)

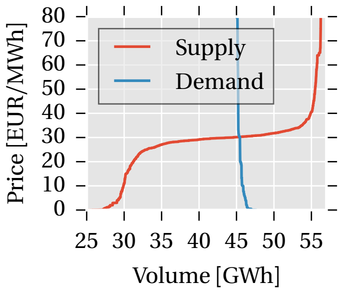
Equations (2.1) and (2.2) constitute a coupled non-linear equation system, which is time-consuming to solve for large and complex networks. To further complicate matters, P_i for generators, which is usually given as input when solving the power flow problem, is an unknown optimisation variable in the dispatch models applied in this work. Investment and dispatch models such as those we use, typically only consider real power and often disregard the power flow equations altogether. It is then assumed that electricity can be traded between connected regions with limits only on transfer capacity and without network constraints. We do, however, include an approximate power flow method, known as DC load flow, in parts of the dispatch modelling in this work. DC load flow approach is further described in Section 3.3.

2.3 The marginal cost of electricity

An important concept discussed throughout this work is the marginal cost of electricity or the marginal generation cost. In economics, the marginal cost of production of a commodity is the change (increase or decrease) in total production cost for producing one additional unit. A more formal definition is that the marginal cost is the derivative of



(a) Bids to Nord Pool Spot for 3 am.



(b) Bids to Nord Pool Spot for 4 pm.

Figure 2.1: Supply and demand bids to the Nord Pool Spot market on December 20th, 2014 for the hours of (a) 3 am and (b) 4 pm. While the supply bid curve changes slightly from the night to the afternoon, the main difference is seen for the demand, which is significantly higher in the afternoon. The price is therefore slightly higher in (b), although the supply curve is fairly flat at around 30 EUR/MWh for a wide range of volumes. Source: Nord Pool Spot (2014).

the total production cost with respect to the produced quantity of the commodity in question. For electricity, this means that the marginal cost of generation is the change in the total cost of generating electricity that would be caused by an infinitesimal increase in demand. If we simplify this somewhat and assume that we use the plants with the lowest running costs first, we can construct a supply curve. If there remains room to increase the output of the last plant brought into operation, the marginal generation cost would be the running cost of that last, most expensive plant. We usually say that the unit that determines the marginal generation cost is the unit "on the margin".

Economic theory states that in a perfect market, the market price should equal the marginal production cost. In a spot market for electricity, such as the Nordic electricity market Nord Pool Spot, producers and consumers of electricity (often through companies acting as intermediaries) hand in bids that state how much electricity they are prepared to buy or sell and at what price. These bids can be aggregated into supply and demand curves, and the intersection of the curves determines the market price and the volume that should be produced.

However, both the demand for electricity and the conditions to produce it, for example weather and fuel prices, can vary with respect to both space and time. In principle, the marginal cost of electricity could be different at every instant in time, and if there are limitations within the grid, the marginal cost could be different at each point at which a consumer is connected. This type of temporal and spatial resolution cannot be handled in a practical way by a real market. Therefore, bidding on electricity spot markets is often aggregated to once per hour and aggregated within some geographical region, which is called a *bidding area*. As an example, Figure 2.1 shows the total supply and demand curves for all the bidding areas in the Nord Pool Spot market combined for two distinct time-points (3 am and 4 pm) on December 20$^{\text{th}}$, 2014. The main difference between the two time-points is that the demand is significantly lower during night-time, which leads to a lower price even though the price decrease is counteracted by the fact that the supply curve is slightly shifted to the left for the night-time hour compared with the day-time hour. It is noteworthy that the demand curve is very steep, indicating that the demand for electricity is inelastic, at least in the short term. It is also evident that the supply curve is fairly flat for the Nordic system in the interval within which the demand is varying here, which means that the variations in price between night and day are relatively small.

2.4 Variable renewable electricity generation

Electricity generation from some renewable sources, e.g., wind and solar power, depends in real time on weather variations, such as wind speed or solar irradiation. Renewable generation technologies with such direct dependence upon changing weather conditions are referred to as *variable*, or sometimes *intermittent*. An important characteristic of variable renewable sources is that their associated running costs are close to zero. For this reason, it is usually preferable to utilise this renewable electricity whenever it is available. The near-zero running costs of the variable renewables place them in the left-most part of the supply curve. When electricity production from, for example, wind power is high, the supply curve shifts to the right and the price drops. With high shares of variable renewables in an electricity market, production can correlate negatively with the price. As the penetration levels of wind and solar power increase, there is a risk that the revenues for the owners of those plants will decrease.

Since variable renewable generation is prioritised in the dispatch, the flexible elements of the system have to adapt to the combined variations of demand and variable generation. The term *net demand* is therefore often used to denote demand minus the production from variable renewables. As opposed to the demand, the net demand can have a negative value if the level of variable generation exceeds the demand.

2.5 Marginal cost and congestion

Congestion occurs when limitations in the grid prevent electricity from the most desirable generating units from meeting demand. If we assume that the system is operated to provide electricity at the lowest possible cost (without risking safety, quality, or reliability), the most desirable generating units are those with the lowest marginal cost. If a region that has a low marginal cost of electricity is connected via the transmission grid to a region that has a high marginal cost, from an economic perspective, electricity should be exported from the low-cost region until either the marginal cost is the same in the two regions or the grid does not allow any more power to be transferred. If the grid is the limiting factor, the difference in marginal cost between the two regions will remain. The difference in marginal cost of electricity between the two regions is also equal to the marginal value of increased transfer capacity between the regions. Therefore, we consider differences in marginal cost between regions to be an indicator of congestion.

As the electricity supply is transformed, the transmission grid may have to be used differently, due to, for example, the following reasons:

- The locations of power plants can be changed. A wind power plant may, for example, be built where there are good wind conditions or where it is possible to obtain planning permission, and solar cells may be placed on rooftops if they are installed by private homeowners. This could lead to both an increased need for transmission capacity, for example, if remote locations are used for building power plants, or reduced need for transmission if, for example, plants are located closer to the sites of consumption.

- When a large share of the generation is derived from variable sources, it may be beneficial to avoid the extremes of the variations, both in terms of highs and lows. The grid can help to smoothen variability of the generation by connecting different locations, as shown by Reichenberg et al. (2014).
- To utilise fully other resources for managing variations in generation, such as flexible hydropower in the Nordic countries, an increase in grid capacity may also be necessary.

CHAPTER 3

Methods and modelling

Several different modelling approaches are applied in this work to study different future scenarios for the European electricity system and the operation of systems with high penetration levels of variable generation, such as wind and solar power.

3.1 Investment modelling – future scenarios

To study potential future developments of the electricity system in Europe, we construct, analyse, and compare different scenarios, which we investigate using the linear programming (LP) investment model ELIN, which was originally constructed by Odenberger (2009) and subsequently developed by Göransson (2014). ELIN is formulated as a cost-minimising, perfect-foresight model that focuses on the technical energy system, in a manner similar to that of commonly used energy systems models, such as MARKAL (Fishbone and Abilock, 1981) and TIMES (Loulou and Labriet, 2008). The model is fed input data on, for example, renewable resources, and exogenously provided with some assumptions about the future, such as projections of electricity demand and fuel prices. Given these data, the model identifies investments in power generation and transmission that result in the lowest system cost, i.e., the sum of the running costs and investment costs, while meeting system-wide and national targets for CO_2 emission reductions and energy from renewable sources.

The ELIN model is multi-regional and maintains energy balances for each region while allowing trade between the regions. The regions can be whole countries, although in this work a more high-resolution geographical subdivision, which is more suitable for studying grid issues, is used. The EU-27 countries, plus Norway and Switzerland but excluding the electrically isolated islands of Malta and Cyprus are divided into 50 regions based on transmission bottlenecks in the present and near-future European transmission grid according to the ENTSO-E (Göransson, 2014). Figure 3.1 shows the regional divisions used in the ELIN and EPOD models in the present work, together with the nodes used in the grid modelling described later in this chapter. The time-span investigated with the ELIN model in this work is from now up to Year 2050.

Given the long time horizon and computational limitations, the ELIN model has a relatively low time resolution of 16 time-steps within each year, corresponding to the day and night of weekdays and weekends for each of the four seasons. The model contains only a simplified description of trade between regions, which limits electricity trade to a specified maximum capacity for each interregional connection. Because of these simplifications in the ELIN model, snapshots of the scenario results are studied in more detail with the EPOD dispatch model, which is described in the next section.

3.2 Dispatch modelling – operation of power plants

Dispatch models typically determine how electricity generating units in a system are to be operated so as to serve consumers at the lowest cost (Göransson, 2014). The time span studied with dispatch models is typically up to 1 year, which is short enough to make the assumption that the system composition remains unaffected by new investments or the decommissioning of units. A relatively high time resolution, such as 1 hour, is usually chosen to capture more details of, for example, wind power variation and thermal power plant flexibility.

In this work, we apply two separate dispatch-type models. The first is the EPOD model, which was created within the research group (Unger and Odenberger, 2011) to be coupled with the ELIN model and further developed by Göransson (2014), as well as within this work (see Papers II and IV). The second is a single-region dispatch model developed in the present work and applied to western Denmark in Paper III.

The EPOD model as used in this work has the same geographical

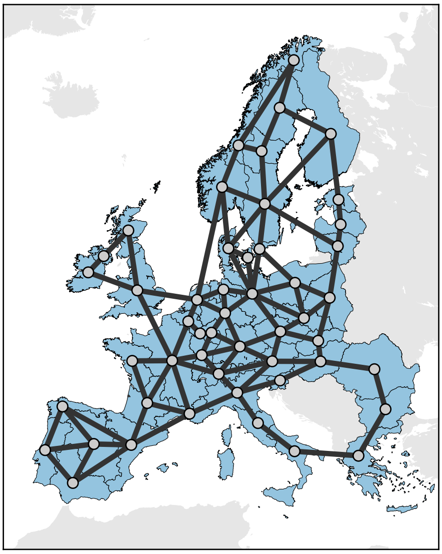


Figure 3.1: Map of the European transmission grid as described in the ELIN and EPOD models, and the regional division used in the models. Each point corresponds to a model region and a node in the grid model. Both AC and DC connections are included.

scope and resolution as the ELIN model, i.e., the same 50 regions covering the EU-27, Norway, and Switzerland but excluding Malta and Cyprus. The regional division used in the EPOD model was developed during earlier work within the research group, and was designed to describe also the European transmission grid. Thus, the regional division is not only based on the transmission bottlenecks described by the ENTSO-E (2010), but is defined so that each region consists of a set of NUTS2 regions, defined and used for EU statistics (European Commission, 2015), to enable the use of European statistics as input data. In the EPOD model, each region is used as a node in a transmission grid description that uses the DC load flow method (further described in Section 3.3). Figure 3.1 shows the nodes used in the grid modelling and the regions upon which they are based, together with the possible interconnections.

To study the electricity generation system in more detail than is possible with the ELIN model, the time resolution is much higher. It is possible to run EPOD with an hourly time resolution, although in order to match the European weather data used in this work, we apply a time resolution of 3 hours. With the chosen time resolution, the EPOD model calculates the cost-minimal dispatch over 1 year for a static system extracted for a selected year from the results of an ELIN run. Power plants are described as aggregates, where all the plants within a region that are similar with respect to fuel type, technology, and efficiency are described as a single unit.

The EPOD model also provides several methods for describing the limited flexibility of thermal power plants, i.e., start-up times and part-load limitations, and capturing the increased costs that arise from more flexible operation of these plants. The way in which the flexibility limitation of thermal power plants are included in the model is described in more detail by Göransson (2014).

The single-region dispatch model developed and used for Paper III describes the dispatch of the power plant fleet in a single region, within which we assume there are no grid bottlenecks. With a narrower geographical scope than the EPOD model, we can describe other aspects in greater detail. We represent three typical voltage levels with individual load profiles: low voltage (LV, typically ≤ 1 kV); medium voltage (MV, typically up to 30 kV); and high voltage (HV, ≥ 100 kV). This description is meant to capture the fact that different DG technologies connect at different voltage levels, both due to their typical sizes and the involvement of different actors, e.g., household consumers or utilities. The voltage levels have distinct load patterns, since they serve different types of consumers, and consequently the potential to consume electricity from DG locally will vary.

In the dispatch model described in Paper III, all large plants are represented individually with binary on-off variables. Smaller thermal plants, as well as solar and wind power plants, are aggregated, and for each aggregate, a continuous variable represents the capacity that is currently online. For each plant (or aggregate), a start-up time and a minimum load level are also specified, as well as the part-load efficiency. With binary variables, solving the optimisation problem can be time-consuming, so we adopted a rolling horizon approach, in which smaller optimisation problems, that span a shorter time interval, are solved sequentially. The model moves the optimisation time window forward in small steps, while fixing the previously obtained solutions, until a solution for the entire year is obtained. This model also includes simplified dispatch optimisation of district heating (DH) to describe more accurately the marginal value of heat from CHP plants.

The results reported in Paper III are based on the application of this model to the western Denmark system, albeit with load data from a German distribution system operator (DSO) and a DH load curve from Gothenburg, Sweden. Input data is mixed from different systems, mainly because of limited availability. However, the systems where chosen to be similar in some important respects, such as climate conditions. The power system configuration, i.e., technical and economic data for power plants, is based on the work by Göransson and Johnsson (2009) and updated with data from the power plant owners for Year 2012. Import and export prices to the neighbouring regions as well as CO_2 emission allowance prices are set to historical values in Year 2012.

3.3 Transmission grid modelling – DC load flow

To describe the power flow between regions in the model, the so-called "DC load flow" (or DC power flow) method is applied for the AC network. It is a linearisation of the full AC power flow (described in Section 2.2) and we derive it by making the assumptions that 1) voltage differences between nodes is negligible; 2) line reactances are much larger than line resistances ($X \gg R$); and 3) the difference in voltage angle $\Delta\theta_{ij}$ between nodes i and j is small, so that $\sin\left(\Delta\theta_{ij}\right) \approx \Delta\theta_{ij}$. If we also choose to consider only real power flows, the full power flow equations can be simplified as $P_{ij} = \Delta\theta_{ij}/X_{ij}$, where P_{ij} is the real power flow and X_{ij} is the reactance between nodes i and j. This relationship can be included as a constraint in the LP description of the economic dispatch problem, which makes it possible to approximate the power flow as part of the dispatch optimisation. For more information on DC load flow, Andersson (2008) describes the derivations of the DC load flow equations and puts them in the context of general power systems analysis. In addition, van den Bergh et al. (2014) describes how the equations are obtained and how they can be used in unit commitment and dispatch models.

3.4 Measuring congestion

A central part of this work is to analyse the congestion in the European transmission system in future scenarios. To accomplish this, we need ways to identify and measure congestion both at individual connections between regions and the overall systems level. In a perfect market and in a dispatch optimisation model, congestion at an individual connection can be identified as the difference in marginal generation cost between two connected nodes, which in our case corresponds to two connected regions. The rationale here is that if transmission between the two regions is not constrained (by thermal limits or network constraints) and the marginal costs (or market prices) are different in the two regions, then the region with the higher marginal cost imports from the region with the lower marginal cost until either the marginal costs are the same in both regions or there is a transmission constraint that limits the trade, i.e., congestion. The marginal value of alleviating this congestion can thereafter be quantified as the magnitude of the marginal cost difference between the two regions or nodes. This works well for our dispatch model results, although not necessarily for real markets, since prices do not necessarily reflect the local marginal cost, and since, in reality, different regions operate under different market conditions.

Measuring the overall system congestion, i.e., how congested the whole system is at any particular time, is not so straightforward. In Paper II, we argue that a wide spread of marginal costs over all the individual regions in the system is an indication of congestion. Therefore, we chose to define a measure of system congestion sc_t at time t as the standard deviation of the marginal cost over all regions at time t, as follows:

$$\mathrm{sc}_t = \sqrt{\frac{1}{N}\sum_{i\in I}\left(\overline{\mathrm{mc}}_t - \mathrm{mc}_{i,t}\right)^2}\,. \tag{3.1}$$

I is the set of all regions, N is the total number of regions, $\mathrm{mc}_{i,t}$ is the marginal cost in region i at time t, and $\overline{\mathrm{mc}}_t$ is the average marginal cost over all regions at time t.

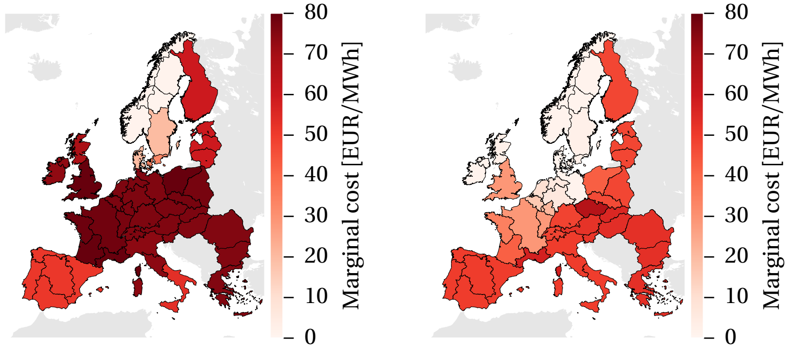
CHAPTER 4

Main findings

In this chapter, we review some of the most important findings, based on both results from the literature and the current work.

4.1 Renewables drive transmission expansion

The European transmission system will most likely have to be significantly expanded to facilitate transformation of the system. Tröster et al. (2011) have studied the development of the European transmission grid in scenarios with very high penetration levels of renewable sources, up to 99 % of total electricity generation in Year 2050. The share of variable generation lay in the range of 49–64 % in the scenarios for Year 2050. They concluded that significant grid extensions, i.e., 258 GW of new transmission capacity by Year 2030 and up to 344 GW if optimised to avoid curtailment, would be needed to accommodate such high levels of renewables. Tröster and colleagues further stated that an important task is to strengthen capacity in "priority areas", such as the zone from Spain via France to Central Europe and from Italy to Central Europe. The European Network of Transmission Operators for Electricity (ENTSO-E) also expects that the development of renewables will drive grid expansion (ENTSO-E, 2014), stating that interconnection capacities must on average double to Year 2030 across Europe and that a major concern will be to integrate more effectively the four main "electric peninsulas" of Italy, the Iberian Peninsula, the British Isles, and the Baltic countries. Fürsch et al. (2013) have stated that increasing the total transmission line length by 76 % (relative to its current length) would be beneficial from a least-cost perspective in a scenario in which 80 % renewables is reached by Year 2050.



(a) Peak load congestion **(b)** High wind congestion

Figure 4.1: Two congestion situations in the European transmission grid found in the dispatch modelling: (a) during a time-step with peak load and low wind; and (b) during a time-step with high wind power generation. The colours indicate the marginal costs in each region, with white being the lowest and dark-red representing the highest costs. Colour differences between neighbouring regions indicate congestion.

4.2 Congestion patterns in transmission

Variable renewable generation substantially alters how and when congestion occurs in the European transmission grid. Using the ELIN and EPOD models (see Chapter 3), we study the extent of congestion in scenarios with strong wind and/or solar power expansion in Papers II and IV. The system set-ups for selected years are extracted from the ELIN investment model and analysed individually in greater detail in the EPOD dispatch model. EPOD calculates the cost-optimal power plant dispatch, including a DC load flow grid model, over 1 year with a time resolution of 3 hours.

By analysing the marginal cost differences between regions, we can observe new congestion patterns caused by the increased penetration level of wind power. Figure 4.1 illustrates two different mechanisms that we have identified in our results—a “push” and a “pull” mechanism—that are implicated in congestion in the European transmission system. The figure shows the marginal cost in each region for two different time-steps, as derived from the dispatch model results for the Year 2020 scenario. The white indicates the lowest marginal cost and the dark-red colour indicates the highest marginal cost. Thus, colour differences between neighbouring regions indicate zones of congestion in the transmission grid. The first situation (Figure 4.1a) is a time-step with high load and generally low output from wind power, although with some solar generation, primarily on the Iberian Peninsula and in Italy. While marginal costs are high in central Europe, limited import capacity creates congestion between central continental Europe and the Nordic countries, the Iberian Peninsula, and southern Italy. This situation, where a deficit is driving up the marginal costs in central Europe and import is limited, can be described as "pull"-type congestion and is perhaps historically the more common of the two types. In the second situation (Figure 4.1b), even though surplus wind generation is available in a few regions, a limited export capacity leads to congestion, for example, between northern Germany and south-eastern Europe, as well as between Scotland and England and Wales. Congestion that is caused by a surplus driving down the marginal cost and export capacity that is limited can be described as "push"-type congestion and it can only occur when penetration levels are sufficiently high to lower significantly the marginal costs at the local level.

4.3 Congestion and demand-side management

DSM and grid expansion can both be seen as variation management strategies, i.e., ways to handle the increased variability that results from the expansion of variable renewable electricity generation. In Paper II, we analyse a Year 2020 scenario with the ELIN and EPOD modelling package, and use the congestion measure defined in Equation (3.1) to investigate how DSM in the form of load shifting would affect congestion in the transmission system and thereby, the value of grid expansion. The scenario used in this study includes national subsidies for renewables, as well as a focus on energy efficiency. In the Year 2020 system, this scenario entails high local penetration levels of wind power. When running this system in the dispatch model, we allow for a certain share of the hourly load to be delayed within a given time-span. In Paper II, we allow 5–20 % of the hourly demand to be

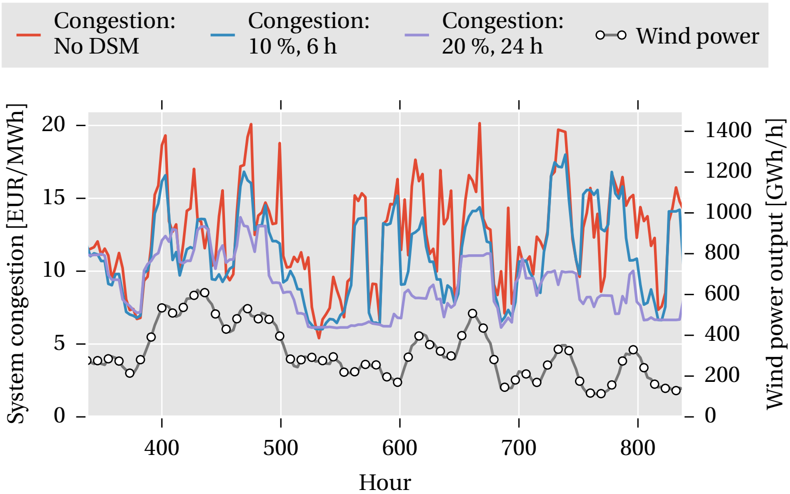


Figure 4.2: System congestion as a function of time over three winter weeks from the EPOD model results for the Year 2020 system (Paper II), shown without DSM and with two different levels of load shifting. The aggregated European wind power output is also shown.

moved within 6 hours or 24 hours.

Our results clearly show that load shifting could reduce congestion in the transmission system. Figure 4.2 shows the system congestion as a function of time over three winter weeks, as derived from our EPOD results for the Year 2020 system with different levels of load shifting available, together with the aggregated European wind power output. The highest congestion level occurs at peak load, when no DSM is available. With 10 % of the load being shiftable within 6 hours some of the most severe congestion situations can be mitigated. With a high level of load shifting, when 20 % is shiftable within 24 hours, the congestion can be significantly reduced.

However, not all of the congestion is caused by demand variations and even at the maximum level of load shifting investigated some congestion remains. We observe that the congestion in the highest load shifting case shown in Figure 4.2 follows quite well the variations in wind power output. The connection between wind power output and congestion reflects how congestion arises. In our results from Paper II, we identify three mechanisms that cause congestion at individual connections between regions:

- *Peak-load hour congestion* occurs when one of the two connected regions has a steep supply curve, leading to high marginal costs during peak-load hours. This usually occurs via the “pull”-type mechanism described in the previous section.

- *Low-load hour congestion* occurs when one of the two connected regions has a high penetration of wind power, leading to a very low marginal cost, primarily during low-load hours.

- *All-hour congestion* occurs between two regions that have such different system structures and different supply curves, so that there are permanent differences in marginal cost and therefore permanent congestion.

In many cases, load shifting can fairly easily reduce the peak-load marginal costs and thus, peak-load hour congestion can often be mitigated with DSM. The potential of DSM to reduce all-hour congestion depends on the specifics of the systems in the connected regions, as well as on how the marginal costs respond to load shifting. However, typical low-load hour congestion is usually caused by high wind power output in combination with low load, and it generally cannot be reduced with load shifting. When only a small load is available for shifting and wind power output is several times higher than the load, DSM cannot significantly affect the marginal cost, so the congestion remains. This means that to some extent grid expansion and DSM play the same roles in variation management, and in many cases they complement each other.

4.4 Transmission to access flexibility

The hydropower capacity in the Nordic countries is often mentioned as a potential resource to help surrounding regions to handle variations in generation, especially as wind and solar power installations are expanding. In Paper I, we investigate how trade patterns change in a Year 2020 scenario with strong wind power expansion in and around the Nordic region, new transmission lines between Norway and the UK, Germany, and Denmark, and strengthened internal trans-

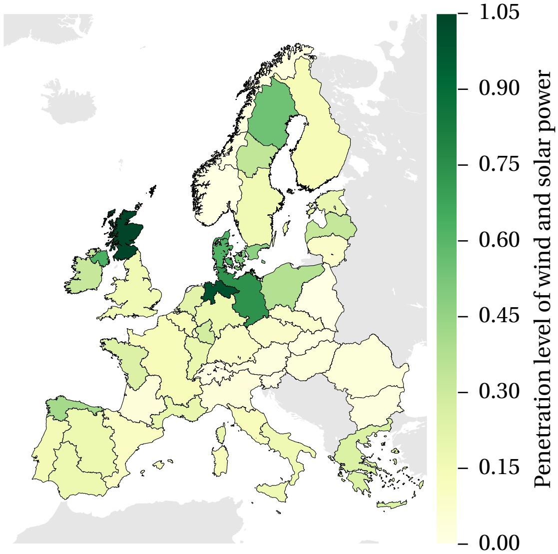


Figure 4.3: Penetration levels, i.e., annual electricity generation divided by annual demand, of wind and solar power in each of the modelled regions in the scenario analysed in Paper I. Many regions neighbouring the Nordic countries have high penetration levels of primarily wind power.

mission systems in Germany and the UK. Using the ELIN model (see Section 3.1), we construct a scenario for all of Europe, in which all the countries install renewable electricity generation according to their individual National Renewable Energy Allocation Plans (NREAPs). In addition, installed wind power in Sweden will reach up to 30 TW h/year by Year 2020, which is the planning target adopted by the Swedish Parliament (Swedish Energy Agency, 2014). Figure 4.3 shows the resulting penetration levels, i.e., annual electricity production divided by annual demand, of variable renewable generation for each of the model regions. Many of the regions with connections to Sweden or Norway, e.g., northern Germany, have high penetration levels of wind power in this scenario.

In Paper I, we show that Nordic hydropower, primarily the capacity located in Norway, can be used as a balancing resource. Norwegian hydropower is to a large extent located in the southern-most region of

Norway, which in this scenario has connections to Germany, the Netherlands, and the UK. Compared with the Swedish hydropower capacity, which is mostly located in the north of Sweden with additional grid bottlenecks in between, the Norwegian hydropower is more accessible for variation management. The mechanism in operation is that Norway imports electricity when wind power production is high, for example in northern Germany, and can export hydropower either back to Germany at another time-point or export a corresponding amount of electricity to the UK. Figure 4.4 shows how the import of electricity from Norway to Germany is governed by the wind power production. During periods of very high wind power production, Norway imports from Germany independently of the hydrological conditions (whether it is a wet, normal, or dry year). In a normal year, however, power is also imported when lower wind peaks coincide with low-demand periods. Under dry conditions, the trade pattern is determined mainly by demand variations. The figure clearly shows that the trade pattern is strongly affected by the hydrological conditions.

Our results also show that continued and increasing wind power investments, combined with the preservation of existing generating capacity online, would make Sweden a large net exporter by Year 2020. The scenario that we investigate has a higher penetration level of wind power in Sweden than is projected within the renewable certificate scheme currently in place, reaching a total of 30 TW h, and existing nuclear power stations also remain in operation. This leads to surplus electricity production on an annual basis. In our Year 2020 scenario, Sweden therefore exports a significant amount of electricity to Norway, both directly and via Denmark, and it is then redistributed to mainly Germany and the UK. Norway has an approximate net balance between imports and exports in the Year 2020 scenario.

4.5 The impact of solar power on marginal costs

In Paper IV, we investigate how high penetration levels of solar power would affect the European electricity system and compare two scenarios, in which we require very high shares of renewables. We run each scenario up to Year 2050 in the ELIN model and then extract Year 2022 and Year 2032 systems for further analysis in the EPOD model. The

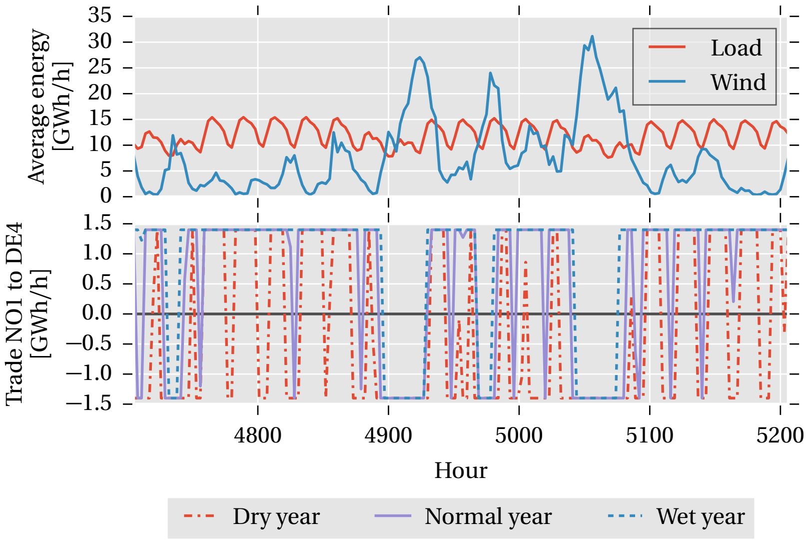


Figure 4.4: Trade flow of electricity between Germany and Norway (bottom panel) during three summer weeks in a modelled Year 2020 scenario, shown together with wind power production and demand in the German region (DE4) for the same time period (top panel). Positive values for the trade indicate that Norway is exporting to Germany and negative values indicate the opposite.

first scenario is the *Green Base* scenario, in which the model chooses between solar PVs, wind power, and biomass power plants, based solely on system cost minimisation. The second scenario is the *Net Metering* scenario, in which, as a simplified representation of an annual net metering scheme, we subtract the difference between retail and wholesale electricity prices in each country (according to the current situation), for each unit of solar power production up to the residential demand, from the objective function.

At penetration levels of 20–30 %, solar power has a major effect on the daily variations in the marginal cost of electricity, compared with the current situation where the daily variations are mainly determined by the load. Figure 4.5 shows the values for the production, import, and export of electricity in southern Germany (DE1) during two weeks in April, as derived from the EPOD results for Year 2022 together with the marginal generation cost. The marginal cost drops to almost zero

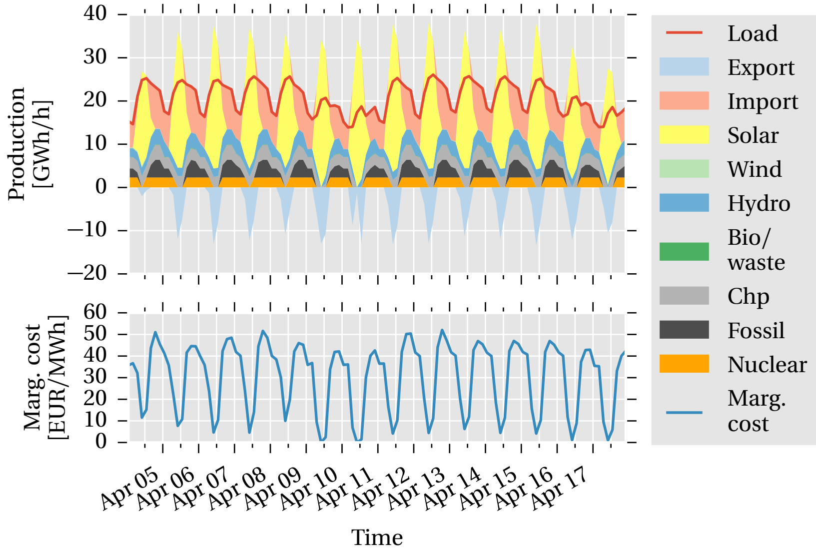


Figure 4.5: Production (top panel) and marginal cost of electricity (bottom panel) in the southern German region DE1 from the EPOD results for Year 2022 from the Net Metering scenario presented in Paper IV. The solar power production corresponds to 31 % of the annual electricity demand in this region.

every day at the solar peak production. The highest marginal cost occurs later in the evenings when solar production of electricity is low, even though demand remains high. The basis for these results is the Net Metering scenario, and the penetration level of solar power in DE1 is 31 %.

The predictable and recurring marginal cost differences during the day create an opportunity for storage to become more profitable. If we assume that storage would allow shifting demand within each day from the hour with the highest marginal cost to the hour with the lowest marginal cost, we can obtain a simple estimate of the marginal storage value by summing the maximum marginal cost difference over all the days of the year. Figure 4.6 shows the estimated marginal storage values for two German and two Swedish regions, calculated from the from EPOD modelling for the Net Metering and Green Base scenarios for Year 2032. The solar power penetration is substantially higher

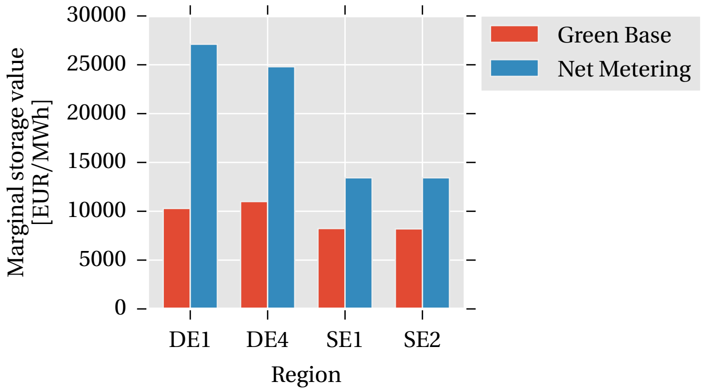
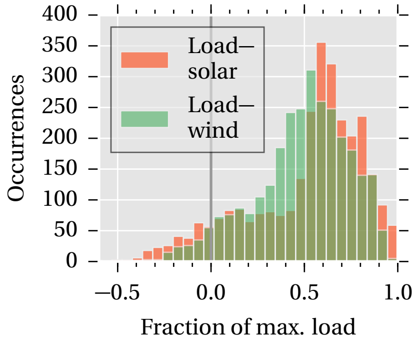


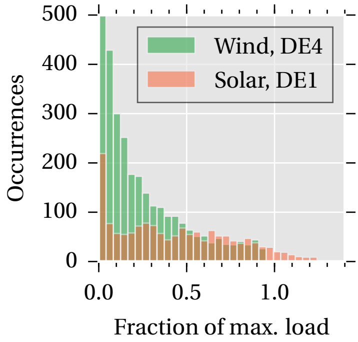
Figure 4.6: Marginal value of daily electricity storage in two German and two Swedish regions calculated from the marginal costs from the EPOD modelling for the Net Metering and Green Base scenarios for Year 2032. In all regions, the penetration level of solar power is below ≤ 10 % in the Green Base scenario and around 30 % in the Net Metering scenario.

in the Net Metering scenario, around 30 % compared with ≤ 10 % in the Green Base scenario, in all four regions. As a consequence, the marginal storage value is also significantly higher. However, the figure shows that the effect is weaker in Sweden, possibly since hydropower dampens many of the marginal cost peaks that determine the marginal storage value.

The main reason for the strong impact that solar power has on the marginal cost of electricity is the nature of its production pattern. Solar power without storage can only produce electricity during the light hours of the day and it is also, at least in the northern parts of Europe, strongly concentrated to the spring and summer seasons. As a result, solar power produces much more of its output close to the rated power than does wind power. Figure 4.7 shows the distributions of solar and wind power outputs (Figure 4.7b) and the distributions of net load, i.e., load minus solar or wind power output (Figure 4.7a), for a wind-dominated region in northern Germany (DE4) and a solar-dominated region in southern Germany (DE1) from the EPOD modelling runs for Year 2022 in the Net Metering scenario. The figures show that wind power more strongly reduces peak load hours than does solar power,



(a) Net load distributions in a wind-dominated region and a solar-dominated region.



(b) Distributions of output from wind power in a wind-dominated region (DE4), and solar power in a solar dominated region (DE1).

Figure 4.7: Distributions of the: (a) wind power net load (load—wind) in the wind-dominated region DE4 in northern Germany and solar power net load (load—solar) in the solar-dominated region DE1 in southern Germany; and (b) outputs from wind power in DE4 and solar power in DE1. The results are from the EPOD modelling for the Year 2022 Net Metering scenario. In both figures, the output and net load values are normalised to the maximum load in each region. Zero output hours have been excluded from the solar power output in (b).

since the peak load hours occur during winter and wind power output is also higher in winter than in summer. It is also clear that solar power generates significantly more surplus hours, i.e., hours with a negative net load.

4.6 Solar power and congestion

In the analyses performes in Paper IV, we investigate the effect that solar power has on congestion in the Net Metering scenario. We use the *system congestion* measure defined and presented in Paper II and described in Section 3.4. Figure 4.8 shows the average system congestion values for April–September (denoted summer) and October–March (denoted winter). We base these values on the EPOD results

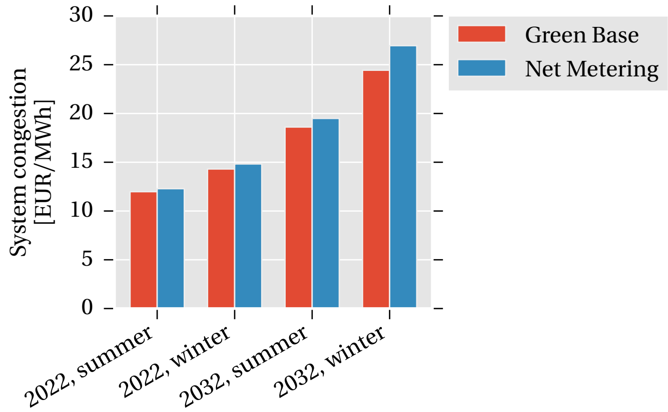
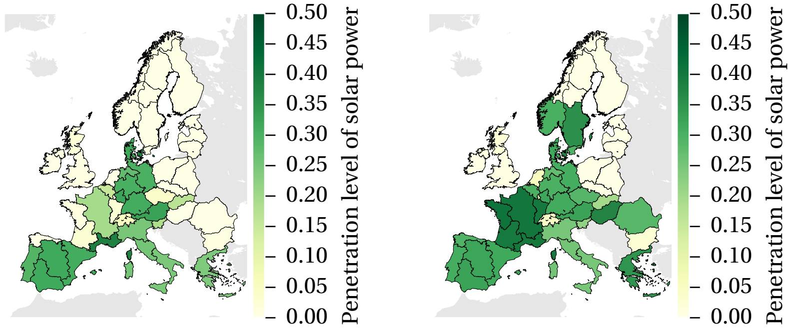


Figure 4.8: Average system congestion for April–September (denoted summer) and October–March (denoted winter) from the EPOD dispatch modelling results from the Green Base and Net Metering scenarios for Year 2022 and Year 2032.

for the Year 2022 and Year 2032 systems from the Green Base and Net Metering scenarios. The Net Metering scenario with higher solar penetration levels has consistently higher system congestion values.

We find, however, that the total solar power output across Europe does not necessarily correlate with system congestion. Initially, in the dispatch modelling of the Year 2020 system using the Net Metering scenario, aggregated solar power output strongly correlates with system congestion during the summer. The reason for this is that solar power expands unevenly in the Net Metering scenario, fully utilising the countries with the largest differences between spot market and retail prices first. During the summer season in the Year 2022 system, the main cause of high system congestion is that regions with high solar penetration levels experience low marginal costs at the solar peak each day, whereas many of the neighbouring regions have high marginal costs at the same time. Penetration levels in the modelled regions for the Net Metering scenario in Year 2022 and 2032 are shown in Figure 4.3. In 2030, the solar power penetration levels are more even across most of the regions, which means that at the solar peaks, marginal costs are low in most regions, which in turn leads to lower system congestion. In contrast, hours with high system congestion



(a) Net Metering scenario 2020.

(b) Net Metering scenario 2030.

Figure 4.9: The regional penetration levels of solar power from the Net Metering scenario from Paper IV for (a) 2020 and (b) 2030. The expansion is initially uneven over Europe because the investments are initially taken in the countries where the net metering benefits are the largest. As the potential is filled up, the expansion spreads.

often occur when there is little or no solar production of electricity and there is a scarcity of electricity in some regions.

4.7 Distribution systems – hosting new generation

A hot topic in energy research during the last ten years has been distributed generation (DG). While the definitions of DG in the literature vary, we focus on generating capacity that is connected to low or medium voltages, up to approximately 30 kV. A literature study reveals that since distribution grids were not designed to host generators, significant adaptations may have to be made. There are several technical factors that limit the amount of capacity that can be integrated into the existing systems:

- It can be difficult to keep the voltage within the allowed limits (Driesen and Belmans, 2006; Coster et al., 2011), mainly due to so-called *voltage rise* (Masters, 2002).
- The thermal capacities of lines and equipment may not be sufficient to cope with new peaks caused by the distributed generat-

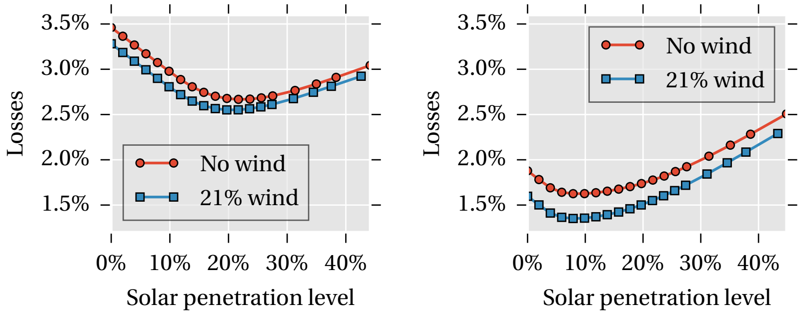
ors (Barker and de Mello, 2000; Masters, 2002).

However, several potential benefits are also mentioned in the literature:

- DG can reduce losses when it is placed close to the load (Barker and de Mello, 2000; Dondi et al., 2002; Pepermans et al., 2005).
- When demand increases, DG can potentially avoid or delay investments in increased grid capacity (Driesen and Belmans, 2006; Harrison et al., 2007; Lopes et al., 2007).

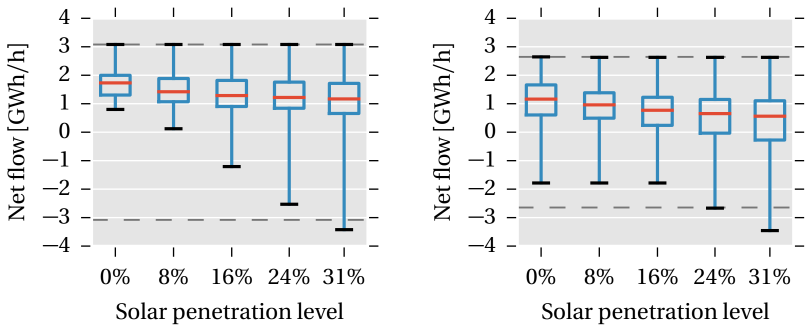
Our modelling results, further described in Paper III, show that there is potential to reduce grid losses when the electricity from DG is consumed locally and replaces electricity imported from higher voltage levels. We use a single-region dispatch model that describes western Denmark, where typical voltage levels of the distribution grids are described separately with their own load curves and where each generating unit is connected to one of the voltage levels. Whenever power is exchanged between voltage levels a constant percentage is subtracted as a loss. We then sweep the penetration levels of wind power, which we assume is connected to the medium-voltage level, and of solar power, which we assume is connected to the low-voltage level. Figure 4.10 shows how the total annual energy losses change with the penetration level of solar power in the low-voltage grid. Initially losses decrease as all generated solar electricity can be consumed locally in the low-voltage grid. However, as the penetration level reaches and then exceeds 15 % the rate of decrease in losses slows as more of the generated electricity has to be exported up to higher voltage levels, incurring new losses in the process. Above a penetration level of approximately 20 %, the losses begin to increase above the minimum point.

From the same dispatch model results, we conclude that when solar power production and load have inverse seasonal variations, solar PVs have very limited potential to reduce the maximum flow of power between voltage levels in the distribution grid. Therefore, solar PVs have limited potential to delay investments in increased grid capacity as the load grows. Figure 4.11 shows the distribution of hourly power transfer between the voltage levels as a function of the solar power penetration level. The figure clearly demonstrates



(a) Load mainly at low voltage. **(b)** Load mainly at medium voltage.

Figure 4.10: Annual energy losses from the dispatch modelling of the western Denmark system as a function of solar power penetration level, with (a) load concentrated mainly to the low-voltage level (70 % of total annual consumption) and (b) load concentrated to the medium-voltage level (70 % of total annual consumption).



(a) Medium voltage to low voltage. **(b)** High voltage to medium voltage.

Figure 4.11: Distributions of hourly power transfers between the voltage levels as a function of solar power penetration level for: (a) flows from the medium-voltage (MV) level to the low-voltage (LV) level; and (b) flows from the high-voltage (HV) level to the MV level. The upper and lower values mark the maximum and minimum flows, respectively, and the upper and lower borders of the box correspond to the upper and lower quartiles of the distribution, respectively. The red line indicates the median value.

how the peak downstream flow is entirely unaffected by increased penetration of solar PVs in the low-voltage grid. However, at relatively low penetration levels, around 10 %, negative flows, i.e., situations in which electricity is exported from the low-voltage level up to higher voltage levels, start to occur.

CHAPTER 5

Discussion, conclusions and outlook

This chapter summarizes the main results into conclusions and discusses the validity of the results obtained in this work. The chapter ends with an outlook and some issues to be explored in future work.

5.1 Discussion

The work presented in this thesis focuses on analysing how the transmission and distribution grid infrastructure is used in future scenarios with high penetration levels of variable renewables. We have not focused on how the grid should be expanded and at which locations it is optimal to make new investments. Especially in the longer time perspective, it is difficult to capture these issues, since optimal grid investments over periods of decades are largely dependent upon what happens on an hourly or even shorter time-scale. While this is a limitation of the present work, it presents an interesting pathway for investigation in future studies. The ELIN-EPOD modelling package does, however, capture the regional development of balanced generation systems and their behaviours on shorter time-scales. This development also describes the value of transferring electricity between regions and how this changes over time.

Another limitation of the methods used here is that we do not include any detailed electrical modelling of the grids. The reason for this is that we wish to include, for example, economical aspects, wider system boundaries, and relatively large geographical scopes. Incorporating detailed grid descriptions into such widely scoped models would not only create computational difficulties, but would also be problematic from a data availability perspective.

The strongest impact of the present work lies in the demonstration of how renewables can take over the role of demand as the main determining factor for how power is traded and how grids are used. We have also been able to investigate some interactions between trade across the transmission grid and other variation management strategies, issues which warrant further study.

5.2 Main conclusions

At the beginning of this thesis, the important questions investigated in this work were listed (see Section 1.1). Here, I pick up that thread and summarise our findings with respect to each question.

How will the usage of transmission and distribution grids change as levels of variable renewable electricity generation increase?

From our modelling results, it is clear that increasing amounts of solar and wind power will have a strong effect on the marginal cost of electricity, which will lead to new trade patterns across the transmission system. Both wind and solar power produce electricity at near-zero marginal cost, which means that when they are productive they lower marginal costs locally in their region and encourage exportation to neighbouring regions.

Changes in the usage of the transmission grid reflect where new renewable capacity is located. In our wind-dominated scenarios, the wind power is highly concentrated to regions with good wind conditions such as northern Germany and Scotland. The trade patterns for these regions with very high penetration levels of wind power become completely governed by the wind variations. This creates new congestion situations, when there are near-zero marginal costs in wind-dense regions and insufficient export capacity to raise marginal costs to the levels existing in neighbouring regions.

The generating capacity hosted in distribution grids is already significant and it will increase further if the expansion of small-scale solar power continues on its present path. This will change the usage of distribution grids completely, from a system that passively transports electricity from a substation to consumers to one that handles production and even exports electricity to the transmission level. There are a number of technical challenges related to this transition, such as voltage regulation in distribution systems with high levels of solar PVs, which will most probably lead to an increased need for investment in lines and equipment within distribution systems. There are also some potential benefits to be derived, mainly in terms of reducing the energy transported through the distribution grids, which could decrease losses. Solar PVs have very limited potentials to affect the peak flows through the grids, at least at locations in which the seasonal variations of solar output and load are opposite.

How will the usage of the grids differ if there is a strong solar power expansion compared with a situation in which wind power dominates the renewable sources?

Solar power is very "peaky" in the sense that it gives a very high output almost every day during the sunny seasons. This yields very low net demand and low marginal cost in the middle of the day and a strong net demand peak in the evening with high marginal cost. Compared with wind power, the patterns for solar power are more synchronised over large geographical areas. The variability is therefore more difficult to mitigate with trade across the transmission system, if the solar capacity is evenly spread out geographically. In that case, the solar power output variations are more amenable to management with energy storage or load shifting than with trade. If the solar capacity is more unevenly distributed geographically it can give rise to congestion when the solar output is peaking, leading to near-zero marginal costs that cannot be increased by exportation.

Will grids be used differently if DSM is adopted widely?

DSM in the form of load shifting can alleviate congestion related to peak load situations. Therefore, it could reduce the need for new grid investments and increase utilisation of the transmission lines in those cases in which congestion is caused by high load. If the congestion is caused by permanent differences in the marginal costs between regions or by limited export capacity in situations with high output from solar or wind power, load shifting has a limited potential to affect congestion.

To what extent would it be beneficial to deploy renewable generation as distributed generation?

Currently, distributed generation is expanding mainly with regard to solar PVs. Our results show that solar PVs in low-voltage distribution grids can reduce distribution losses by displacing energy imported from the higher-voltage levels. However, we observe that, in the absence of storage or load shifting, the losses start to increase again at local penetration levels of around 15 %. This can be viewed as the upper limit for loss reduction benefits; taking local grid limitations into account would lower this value even further. We also see that the potential for solar PVs to reduce the maximum power flow between voltage levels is very limited as long as the solar power peak and the demand peak occur during different seasons and no local storage is installed. However, the distributed form can bring other benefits, such as engaging the public in energy issues and spreading the ownership of generating capacity.

What aspects of the electricity grids are important to consider when drafting policies that will affect the future energy system?

A conclusion we can draw from this work is that the development of renewable generation capacity will strongly affect the requirements for both transmission and distribution grids. How the grids are developed will also affect where and when renewable investments are profitable and desirable from a systems perspective. Policies that influence investments in grid capacity should be co-optimised and co-ordinated with policies that affect both investments in renewables and variation management options, such as DSM or storage.

5.3 Future research

The work presented in this thesis opens up several new avenues for research. A general target for future work in this field is to improve modelling of the impacts of short-term variations from solar and wind power for investment decisions, e.g., regarding transmission grid capacity. In most current investment models, these decisions are based on more long-term energy balances and bulk flows, whereas it has become clear, not least from the present work, that shorter-term variations exert strong influences on how the grid is used and where it needs to be strengthened.

Another issue that I would like to study in the future is the potential trade-offs and synergies between variation management strategies, such as DSM, storage, and the utilisation of connections to heating systems, and how these would affect the role of the grid. This applies both to the local level, where the grid benefits of distributed generation could be significantly amplified using such strategies locally, as well as at the transmission level, where these variation management strategies act as a potential competitor or as a complement to new grid investments.

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